The Prospects for Pumped Storage Hydropower in Alaska

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Dan R. Bishop	Golden Valley Electric Association
Bryan Carey	Alaska Energy Authority
Josh Craft	Matanuska Electric Association
Mike Craft	Alaska Environmental Power, LLC
Michael Deegan	Waste Management
Dustin Highers	Chugach Electric Association
Rhett Hurless	Absaroka Energy, LLC
Clay Koplin	Cordova Electric Cooperative
Brian Murkowski	Ocean Renewable Power Corp.
Jack Newell	Bureau of Ocean Energy Management
Devany Plentovich	DeerStone Consulting, LLC
Michael Rovito	Alaska Power Association
Rob Roys	Launch Alaska
Ceal Smith	Alaska Institute for Climate and Energy

HydroWIRES

In April 2019, WPTO launched the HydroWIRES Initiative[1] to understand, enable, and improve hydropower and pumped storage hydropower's (PSH's) contributions to reliability, resilience, and integration in the rapidly evolving U.S. electricity system. The unique characteristics of hydropower, including PSH, make it well suited to provide a range of storage, generation flexibility, and other grid services to support the cost-effective integration of variable renewable resources.

The U.S. electricity system is rapidly evolving, bringing both opportunities and challenges for the hydropower sector. While increasing deployment of variable renewables such as wind and solar has enabled low-cost, clean energy in many U.S. regions, it has also created a need for resources that can store energy or quickly change their operations to ensure a reliable and

[1] Hydropower and Water Innovation for a Resilient Electricity System ("HydroWIRES")

resilient grid. Hydropower (including PSH) is not only a supplier of bulk, low-cost, renewable energy but also a source of large-scale flexibility and a force multiplier for other renewable power generation sources. Realizing this potential requires innovation in several areas: understanding value drivers for hydropower in evolving system conditions, describing flexible capabilities and associated tradeoffs associated with hydropower meeting system needs, optimizing hydropower operations and planning, and developing innovative technologies that enable hydropower to operate more flexibly.

HydroWIRES is distinguished in its close engagement with the DOE national laboratories. Five national laboratories—Argonne National Laboratory, Idaho National Laboratory, National Renewable Energy Laboratory, Oak Ridge National Laboratory, and Pacific Northwest National Laboratory—work as a team to provide strategic insight and develop connections across the HydroWIRES portfolio, as well as broader DOE and national laboratory efforts such as the Grid Modernization Initiative.

Research efforts under the HydroWIRES Initiative are designed to benefit hydropower owners and operators, independent system operators, regional transmission organizations, regulators, original equipment manufacturers, and environmental organizations by developing data, analysis, models, and technology research and development that can improve their capabilities and inform their decisions.

More information about HydroWIRES is available at https://energy.gov/hydrowires.

The Prospects for Pumped Storage Hydropower in Alaska

Vladimir Koritarov[1]
Jonghwan Kwon[1]
Patrick Balducci[1]
Elise DeGeorge[2]
Caitlyn Clark[2]
Jal Desai[2]
Rebecca Meadows[2]
Sean Esterly[2]
Donna Heimiller[2]
Sherry Stout[2]
Michael Ingram[2]
Evan Rosenlieb[2]

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[1] Argonne National Laboratory
[2] National Renewable Energy Laboratory

Executive Summary

Key Takeaways

- The resource mapping analysis confirmed that numerous locations in Alaska are suitable for the development of pumped storage hydropower (PSH) projects, both larger grid-scale projects and smaller projects that could be suitable for remote communities.
- The resource assessment for larger, grid-scale projects showed the potential for more than 1,800 closed-loop systems in Alaska, with a total energy storage capacity of about 4 terawatt hours (TWh).
- Because of their small reservoir sizes and dam heights, many locations were identified as potentially suitable for small-scale PSH systems. Nearly 50% of the identified potentially suitable small-scale PSH sites are in Southeast Alaska.
- PSH candidate sites were part of the optimal capacity expansion solution in all scenarios analyzed for the Railbelt system. Depending on the scenario, the new PSH capacity that the model selected for the analysis period until 2046 ranged from 300 MW to 600 MW. The locations and timing of new PSH investments vary in different scenarios.
- Lithium-ion batteries were also selected a source of new generating capacity in all analyzed scenarios for the Railbelt system, indicating that the system will need a mix of short- and long-duration energy storage to support variable renewable energy sources and provide system reliability in the future.
- For rural communities, analysis results showed that PSH suitability is very site-specific; in addition to diesel fuel costs and PSH capital costs, suitability depends heavily on available renewable resources and existing infrastructure (e.g., reservoirs, transmission access and construction road access).
- The analysis for rural communities also showed that PSH projects with 10-hour energy storage are likely to be more economical for remote community applications in Alaska than those with larger reservoirs that could provide 10 days of energy storage.
- Lithium-ion batteries seem to be an economically more viable energy storage option for small, remote communities in Alaska.

ES.1 Background

The electric power system in Alaska is unique, consisting of two larger transmission systems (the Railbelt and Southeast Alaska) and more than 150 small, isolated systems serving remote communities. The Railbelt and Southeast Alaska systems are not connected to one another through transmission links. The Railbelt system is the larger of the two, consisting of five interconnected electric utilities stretching from Fairbanks in the north, down to Anchorage and the Kenai peninsula in the south. The Southeast Alaska system serves Juneau and some of the surrounding coastal areas (Alaska Panhandle region). There are also more than 150 isolated municipal power systems serving mostly remote and rural communities. Because of large distances between cities in Alaska, most of these remote systems are expected to remain isolated for the foreseeable future, essentially continuing to operate as isolated microgrids.

Compared with the lower 48 states, the cost of electricity in Alaska is high, especially in remote communities. Because of the high transportation costs for diesel fuel, which is mostly used for electricity generation in remote communities, the cost of electricity in some small communities can be up to four times the cost in communities served by the Railbelt system. For this reason, many remote communities would like to increase electricity generation from local renewable resources (such as wind, solar, and hydropower, where available), thus reducing the electricity generation costs and dependence on fossil fuels. Similarly, an increased share of solar, wind, and hydropower generation also has the potential to reduce electricity generation costs in the larger transmission grids (Railbelt and Southeast Alaska). One advantage of the larger, interconnected transmission grids, such as the Railbelt system, is that such a system would be able to accommodate larger projects, thus benefiting from economies of scale.

To support the larger share of wind and solar generation resources, energy storage will be needed to smooth their variability and provide backup capacity and energy when wind or solar generation is scarce. While different energy storage technologies are currently available, the scope of this study was limited to examination of whether PSH would be a viable energy storage option for Alaska.

PSH is a proven, commercially available energy storage technology that provides a very efficient way to store large amounts of energy. PSH currently provides the largest share of grid-scale energy storage in the United States: about 93 percent of all energy storage capacity, according to the 2021 Hydropower Market Report (DOE, 2021). Worldwide, PSH provides a similar percentage of the total grid-scale energy storage capacity.

Historically, most PSH projects have been built with large capacity—typically several hundred megawatts (MWs)—to leverage economies of scale, i.e., the investment costs (in dollars per kilowatt or kilowatt hour [$/kW or $/kWh]) are generally smaller for larger projects. However, in recent years, utilities have been investigating smaller PSH designs, with sizes on the order of several MWs or less, because such projects can be integrated into hybrid projects that include smaller wind and solar installations. The small PSH projects are typically envisioned with a modular design that employs standardized and prefabricated components to reduce the overall costs. While the specific capital costs of larger PSH projects are very competitive—comparable to or lower than those of other energy storage technologies (Mongird et al., 2020)—the costs of smaller PSH designs can be quite high. However, every PSH project is unique, and the capital costs are very site-specific.

ES.2 Study Objectives

The key objective of this study was to investigate the prospects and needs for PSH in Alaska, both in the integrated Railbelt system and in the isolated, remote communities. Another objective was to provide decision makers with actionable information about the viability of PSH in Alaska.

This information could be used to develop effective policy, regulation, and system operation practices, as well as to inform investment decision making.

ES.3 Key Study Findings

ES.3.1 PSH Resource Potential

To analyze the prospects of PSH in Alaska, the project team first performed a geospatial analysis and mapping of PSH resource potential in Alaska to identify locations suitable for PSH development. A geographic information system (GIS) model was applied to assess the number of potential PSH sites in Alaska, as well as their estimated reservoir sizes and MW capacities. The assessment leveraged a recent effort by the National Renewable Energy Laboratory (NREL) that was funded by the U.S. Department of Energy's (DOE's) Water Power Technologies Office (WPTO) to assess the PSH resource potential in the United States (Rosenlieb et al., 2022). In addition to assessment of potential sites for larger PSH projects, the NREL team modified the GIS model for this study to also allow for mapping of sites that would be suitable for very small potential PSH projects, such as those for isolated remote communities in Alaska. The PSH resource mapping analysis revealed numerous potential PSH development sites in Alaska. The resource assessment for larger, grid-scale PSH projects showed the potential for more than 1,800 closed-loop systems in Alaska, with a total energy storage capacity of about 4 TWh. Similarly, because of their small reservoir sizes and dam heights, many locations were identified as potentially suitable for smaller-scale PSH systems. For this reason, the project team used a set of screening filters and criteria to identify the most suitable locations for small PSH projects, applying the filters to the analysis of PSH viability in remote communities.

ES.3.2 Railbelt System Analysis

For the Railbelt system analysis, Argonne used its A-LEAF (Argonne Low-Carbon Electricity Analysis Framework) model to investigate the needs and potential timing and locations of PSH capacity in the integrated Railbelt system. The modeling capabilities for A-LEAF include both production cost analysis and least-cost capacity expansion analysis. For the Railbelt system, the project team assessed the present status of generation and transmission resources, past electricity demand trends, and expected overall demand growth in the next 25 years. The project team also addressed planned additions and retirements of generating capacities, as well as the projections of new wind and solar generation.

In addition to generic PSH candidates, the long-term capacity expansion options for the Railbelt system included natural gas combined cycle (NGCC) units (with and without carbon capture and sequestration [CCS]), combustion turbines, wind, solar, and batteries. Based on this information, the project team defined several long-term development scenarios for the Railbelt system and simulated them using the A-LEAF model. For each of the scenarios, the team conducted a simplified expansion analysis for the study period 2025–2050, with a time step of 3 years. To avoid the "end effect" of optimization, which can skew the modeling results at the end of the study period, the modeling results are presented for the analysis period 2025–2046.

The results show that PSH capacity is part of the optimal capacity expansion solution in all analyzed scenarios (Figure ES-1). The model selected between 300 MW and 600 MW of new PSH capacity in the different scenarios. Because the Railbelt system in A-LEAF was modeled as an integrated system consisting of four zones, the modeling results also provided zonal locations of future PSH additions, in addition to the energy storage capacity needs and approximate timing of new PSH additions. One of the key findings of the A-LEAF modeling is that the Railbelt system will need both short- and long-duration energy storage in the future. In addition to new PSH capacity, which was assumed to provide 10-hour energy storage, the optimal expansion solutions for all analyzed scenarios also included new battery capacity, assumed to provide short-term (4-hour) energy storage. A mix of short- and long-duration energy storage can balance the operational variability of wind and solar generation and provide reliability and backup capacity for longer periods when little wind and solar generation is available or during outages of conventional generating units and/or transmission lines.

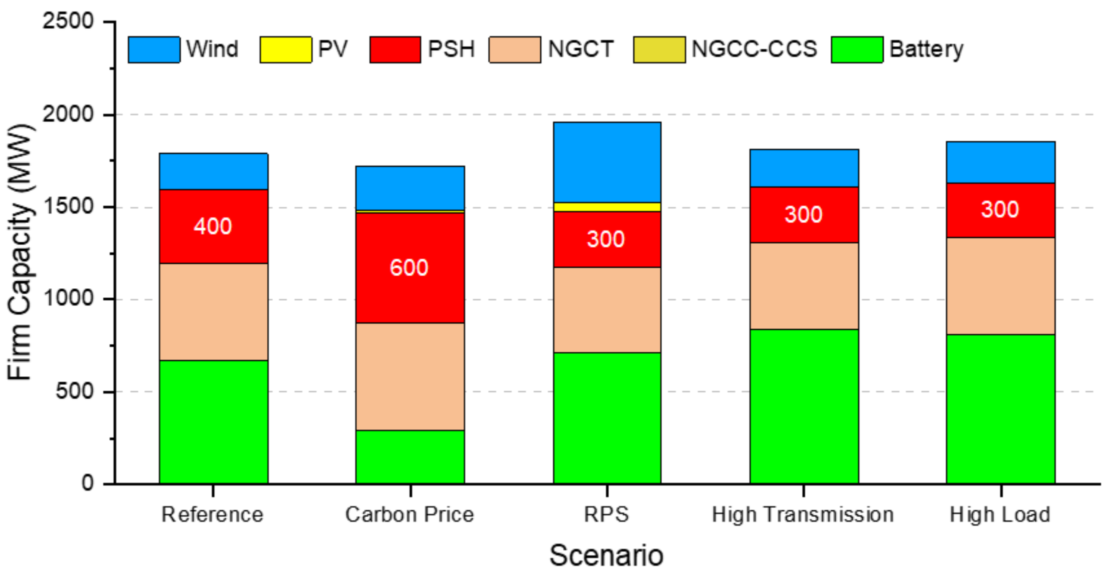

Figure ES-1 New Capacity Additions in the Railbelt System by 2046 in Different Scenarios

ES.3.3 Remote Communities Analysis

Because of their small size and isolated operations—similar to operations of microgrids —the analysis for remote communities was performed using a different technical approach than the one applied for the Railbelt system. The HOMER (Hybrid Optimization Model for Electric Renewables) was used to analyze the viability of small PSH projects in rural communities. After PSH resource mapping identified a total of 192 remote communities with potential sites suitable for small PSH projects, the project team employed several filtering or screening criteria to identify a small number of the most promising sites and representative communities for analysis. This filtering analysis resulted in 18 communities with potential for PSH development. Because this number was still too large for individual analyses using HOMER, the team developed a set of scenarios to investigate whether small PSH projects would provide technically feasible and economically viable capacity additions for rural communities.

The analysis examined several potential designs for PSH projects that could be suitable for remote communities; based on the results, the team selected a small closed-loop PSH design (<1 MW) that uses pump-as-turbine and either reservoirs or steel tanks for both the upper and lower reservoirs. Using this PSH design, the HOMER analysis was conducted for three scenarios: Scenario 1, which assumed large PSH reservoirs that could provide 10-day energy storage to the community; Scenario 2, which assumed the same PSH project but with smaller storage tanks, providing 10 hours of energy storage; and Scenario 3, in which the remote community relies on 4-hour energy storage provided by lithium-ion batteries instead of PSH plants. Each scenario was also analyzed for two charging options: (1) only wind and solar energy are used for charging (e.g., to pump water into the upper PSH reservoir), or (2) both diesel generation and renewable generation are used for charging. Finally, the team completed a site-specific case study for a community in Alaska to investigate the cost viability of including PSH with a proposed run-of-river (ROR) hydropower plant.

The results of the HOMER analysis indicate that, based on their high investment cost, small PSH projects are unlikely to be economically viable for applications in small remote communities. The team performed sensitivity analyses of PSH capital costs and the price of diesel fuel to determine at what point PSH projects may become economically viable. The analysis showed that, for Alaska applications, PSH projects with 10-hour energy storage are likely to be more economical than those with larger reservoirs providing 10 days of energy storage for the remote communities.

For the PSH project providing 10 hours of storage, diesel fuel costs would need to be above ~$6 per gallon (at the assumed PSH capital costs of $1,800 per kWh) for a PSH project to offer a cost-competitive storage solution (Figure ES-2). Adding PSH allows for high renewable energy penetration and can reduce diesel fuel usage by more than ~80%, depending on the microgrid configuration.

With regard to charging options, if only wind and solar generation are used for pumping, their available pumping energy would be insufficient to fill the large, 10-day PSH reservoir. However, if diesel generation is also used for pumping, the reservoir can be filled most months of the year, with slightly lower renewable energy penetrations but similar costs. For Scenario 2, assuming a smaller, 10-hour PSH reservoir, both charging options would be able to fill the reservoir most months of the year.

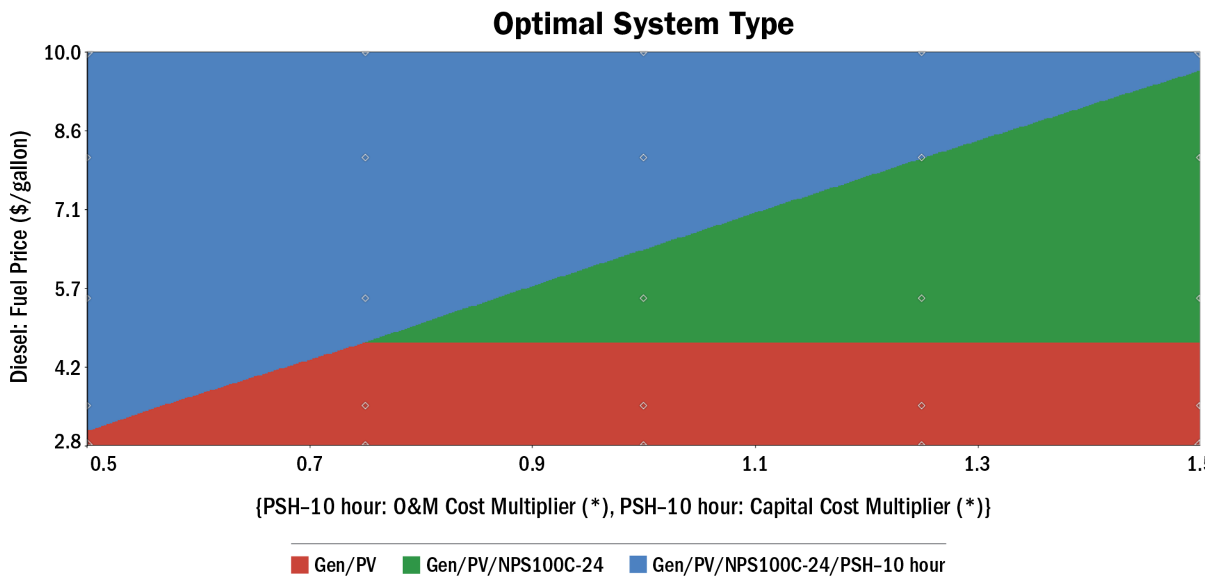

Figure ES-2 HOMER Optimal System Type Plot – Scenario 2: 10-hour Energy Storage

The results for Scenario 3 show that lithium-ion batteries provide an economically viable storage solution for small remote communities; the range of cost effectiveness increases when compared with Scenarios 1 and 2. However, compared with PSH storage options in Scenarios 1 and 2, the diesel reduction potential significantly decreases.

Finally, the site-specific case study—which analyzed the addition of a ~200-kW modular PSH plant providing 12 hours of storage to a planned ROR plant in False Pass, Alaska—indicated that, although the addition of PSH would significantly reduce the size of the ROR plant required to provide a similar diesel fuel reduction (compared with the ROR plant alone), the cost of energy would more than double. The addition of solar and lithium-ion batteries also reduces the size of the ROR project, provides the lowest-cost option with the highest reduction in diesel fuel, but only supplies 2 hours of storage duration.

ES.4 References

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Acronyms and Abbreviations

A-LEAF	Argonne Low-carbon Electricity Analysis Framework
Argonne	Argonne National Laboratory
C2C	Communities to Clean Energy Program
CAPEX	capital expenditure
CCS	carbon capture and sequestration
CEA	Chugach Electric Association
CO_2	carbon dioxide
DEM	digital elevation model
DHI	diffused horizontal irradiance
DNI	direct normal irradiance
DOE	Department of Energy
DR	demand response
EIA	Energy Information Administration
EPRI	Electric Power Research Institute
ETIPP	Energy Transitions Initiative Partnership Project
FERC	Federal Energy Regulatory Commission
gal	gallon(s)
GEP	generation expansion planning
GHI	global horizontal irradiance
GIS	geographic information system
GVEA	Golden Valley Electric Association
GW	gigawatt
GWh	gigawatt-hour
h	hour(s)
HEA	Homer Electric Association
HOMER	Hybrid Optimization Model for Electric Renewables
ITC	investment tax credit
J	joule(s)
JBER	Joint Base Elmendorf Richardson
kg	kilogram(s)
km	kilometer
kW	kilowatt
kWh	kilowatt-hour
LCOE	levelized cost of electricity
LFP	lithium ferro phosphate
m	meter(s)
m^3	cubic meter(s)
mi	mile(s)
m-PSH	modular PSH

MEA	Matanuska Electric Association
MERRA	Modern-Era Retrospective analysis for Research and Applications
ML	megaliter
MMBtu	million British thermal units
MW	megawatt
MWh	megawatt-hour
NASA	National Aeronautics and Space Administration
NG-CC	natural gas combined cycle
NG-CT	natural gas combustion turbine
NG-IC	natural gas internal combustion
NMRSD	normalized root mean square error deviation
NPC	net present cost
NREL	National Renewable Energy Laboratory
NSRDB	National Solar Radiation Database
O&M	operations and maintenance
Oil-CC	oil – combined cycle
Oil-CT	oil – combustion turbine
Oil-IC	oil – internal combustion
PAT	pump-as-turbine
PLC	programmable logic controller
POWER	Prediction of Worldwide Energy Resources
PRM	planning reserve margin
PSH	pumped storage hydropower
PTC	production tax credit
PV	photovoltaic
ROR	run-of-river
RPS	renewable portfolio standard
SCED	security-constrained economic dispatch
SENA	Shell Energy North America
SOC	state of charge
s	second(s)
TWh	terawatt hour
VRE	variable renewable energy
WACC	weighted average cost of capital
WPTO	Water Power Technologies Office
yr	year(s)
Z	solar zenith angle

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1.0 Introduction

Pumped storage hydropower (PSH) represents the bulk of the United States' current energy storage capacity. According to the *U.S. Hydropower Market Report* (DOE, 2021), there are 43 PSH plants in the United States providing a total of 22 gigawatts (GW) of installed capacity. Most of this capacity was built between 1960 and 1990.

PSH is a commercially mature and proven method of energy storage characterized by competitive round-trip efficiency and long plant lifetimes. These qualities make PSH a very attractive potential solution to energy storage needs, particularly for longer-duration (8 hours or more) storage, as variable wind and solar production continue to comprise an ever-larger portion of the United States' energy portfolio. PSH can shift excess renewable energy from periods of low demand to peak times, smooth fluctuations in variable renewable generation output, and provide reliability and resilience to the electric grid during periods of low resource adequacy. These services are particularly advantageous in Alaska, where wind and solar resource potential varies seasonally (i.e., little to no daylight during winter months) and cold climate affects battery performance. PSH storage with wind and/or solar hybrid plants represents an opportunity to further smooth power output and reduce the variability of wind and solar generation.

1.1 Key Aspects of Electrical Grid in Alaska

The state of Alaska has a unique electric power system, comprising two larger transmission grids (Railbelt and Southeast Alaska) and more than 150 small, stand-alone power systems that serve remote communities (Figure 1-1). The Railbelt and the Southeast Alaska power grids are not directly connected to one another through transmission links.

The Railbelt integrated grid is the larger of the two power systems and consists of several electric utilities that serve about two-thirds of the Alaskan population. The system extends from Fairbanks in the north, to Anchorage, and down to the Kenai peninsula.

Most rural communities in Alaska do not have access to the grid and are served by consumer-owned electric cooperatives. Because of their remote locations, many of these cooperatives rely on expensive diesel-fueled generation to satisfy the electricity demand of their communities. Therefore, the electricity prices in rural communities are significantly higher than those in urban areas.

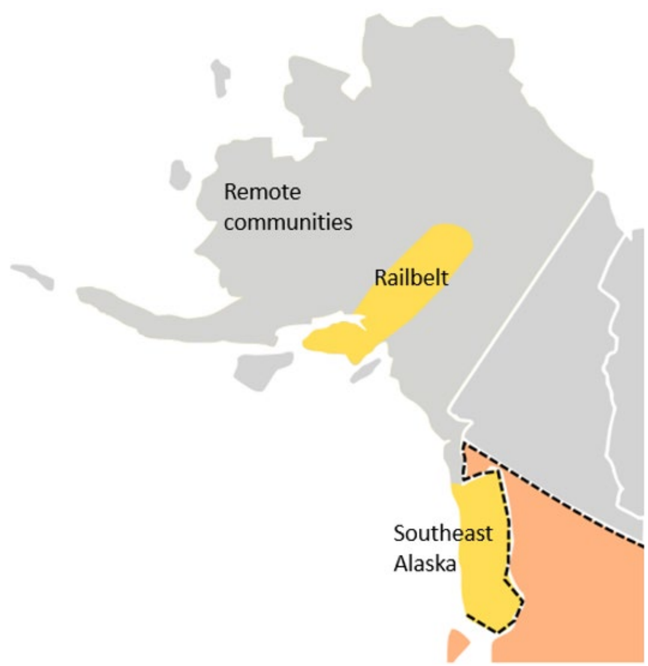

Figure 1-1 Electric Power System in Alaska

According to the Energy Information Administration (EIA, 2022), in 2019 about 30% of electricity generation in Alaska was from renewable energy resources: about 27% from hydropower and 3% from wind and solar generation. With the expected increase in wind and solar generation in the future, the role of energy storage becomes increasingly important. Considering the power system characteristics in Alaska, energy storage technologies that can supply electricity over an extended period, such as PSH, may play a key role in ensuring the reliability and resiliency of integrated and rural power systems.

1.2 Study Objectives

The overarching objective of this study was to investigate the prospects and opportunities for PSH in Alaska. As an energy storage technology, PSH may play an important role in supporting other energy needs in Alaska, such as:

- Developing clean renewable electricity generation, primarily wind, solar, and hydropower.
- Developing long-duration energy storage to support variable renewables in the unique conditions in Alaska, both in the integrated power systems and in remote communities.
- Reducing the cost of electricity and making it more equitable for remote communities, which currently rely on expensive diesel generation.
- Meeting environmental goals for clean electricity generation.
- Supporting the reliable and resilient operation of integrated and isolated power systems in Alaska.

Another objective for this study was to provide decision makers with actionable information about the viability of PSH in Alaska that can be used to develop effective policy, regulation, and system operation practices.

1.3 Technical Approach

This study investigated the potential viability and opportunities for PSH in both the integrated Railbelt system and in remote rural communities. The project team started with the data collection effort to accurately describe the existing power system in Alaska and its generation, transmission, and demand resources. The team then assessed overall PSH resource potential in Alaska using geospatial mapping analysis to identify locations in Alaska that are suitable for PSH development. In addition to potential sites for larger PSH projects, such as those that could be integrated into the Railbelt system, the mapping analysis also investigated potential locations for smaller PSH projects (e.g., about 1 megawatt [MW] or less) that could fit the energy storage needs of remote communities. The resource mapping analysis also provided an estimate of the total PSH resource potential in Alaska, in terms of terawatt hours (TWh) of stored energy.

Next, the project team identified suitable PSH candidate options for the integrated Railbelt system and for the remote communities. The Railbelt system will have the capabilities to potentially implement larger PSH projects (e.g., 100 MW or more), while isolated rural systems can take advantage of several small or scalable (i.e., modular) PSH technologies identified by the project team.

The approaches used to analyze PSH options in the Railbelt system and in rural communities were customized to reflect their different sizes, generation mixes, and operation practices. These approaches are briefly outlined below.

1.3.1 Railbelt System Analysis

The analysis for the Railbelt system started with an assessment of the present status of generation and transmission resources, past electricity demand growth trends, and expected load growth in the next 25 years. The analysis also addressed the planned additions and retirements of generation and transmission capacities, as well as the projections of new wind and solar generation. Based on this information, the project team defined a set of scenarios to describe different options for future development of electricity demand, generation fleet and transmission network, additions of wind and solar capacity, and other aspects of future power system operation. The team used the A-LEAF (Argonne Least-Cost Electricity Modeling Framework) model to simulate system operation for different development scenarios and to estimate the needs for energy storage capacity. In the analysis of different scenarios, generic 100-MW PSH projects were used as potential expansion candidates, in addition to batteries, wind, solar, and other options.

This analysis was designed to provide insights into the potential size and timing of PSH additions into the integrated Railbelt system that are based on estimated future system needs in each of the analyzed scenarios. It was not designed to provide a definitive expansion plan nor make recommendations for the construction of specific PSH candidate projects. Such an analysis would require more detailed system modeling and simulation, which could be performed in future studies.

1.3.2 Rural Communities Analysis

Starting from the geographic information system (GIS) mapping analysis of PSH resources in Alaska, the project team performed a filtering process to identify a small number of representative rural communities with different characteristics that could be analyzed to evaluate the viability of small PSH projects in Alaska. The filters and criteria for the selection of representative communities were developed in collaboration with the project Advisory Group and other stakeholders in Alaska. The selection process resulted in identification of 18 remote communities that were deemed—based on their size, load profiles, generation mix, and other factors—to be most suitable for potential PSH development. The project team used HOMER (Hybrid Optimization Model for Electric Renewables) to analyze the viability of small PSH projects in remote communities, developing several potential PSH design scenarios for the analysis. One scenario assumed a smaller reservoir that would provide the community with 10 hours of energy storage. Another assumed a much larger PSH reservoir that could satisfy the community electricity demand over a 10-day period. A third, alternative scenario assumed that lithium-ion batteries would be used as a storage option replacing PSH. Finally, the team completed sensitivity studies on diesel fuel prices and other factors to determine the economic viability of PSH for these communities across a range of possible options.

1.4 Project Team

The project team for this study comprised researchers from two DOE national laboratories that have experience with the PSH technologies and power systems in Alaska: Argonne National Laboratory (Argonne) and the National Renewable Energy Laboratory (NREL). Argonne served as the lead lab for this project, performing the analysis for the integrated Railbelt system, while NREL performed the GIS mapping analysis and the analysis of remote communities. Both teams collaborated very closely to ensure that their analyses were consistent with regard to modeling assumptions and other inputs.

1.5 Report Organization

Section 2 of the report provides an overview of the GIS mapping analysis used to identify PSH resource potential in Alaska. Section 3 describes the analysis of future needs for energy storage in the Railbelt system, and the potential timing and locations of new PSH capacity, while Section 4 covers analysis of the suitability of small PSH projects in remote communities. A summary of key study findings is provided in Section 5, while Section 6 lists the references that were used during the project. Appendix A (Rural Community PSH Potential Filtering Results) provides details on the filtering process applied to determine potentially suitable locations for small-scale PSH projects in rural communities. Appendix B (HOMER Input Summary) summarizes HOMER modeling inputs.

1.6 References

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EIA, 2022. "Alaska State Profile and Energy Estimates," February 17. Available at: https://www.eia.gov/state/analysis.php?sid=AK. Accessed February 2023.

2.0 Analysis of PSH Resource Potential

This resource analysis was performed to better understand the potential for development of PSH in Alaska to serve as a long-duration storage option for wind and solar resources. The resource analysis included (1) a resource assessment for PSH and (2) a complementarity analysis for wind and solar. Individual sites were not modeled in sufficient detail for project-level development, but the modeling results do provide valuable insights into potential resource areas across Alaska, sufficient to potentially provide estimates for a range of long-term development scenarios. However, because the technologies, economics, and design of PSH projects are site- and community-specific, additional evaluation and analysis are needed for project-level development.

2.1 GIS Mapping Methodology

For this study, the project team used a geospatial model to identify potential locations for new, closed-loop PSH sites from digital elevation model (DEM) input. For the national resource assessment, the model parameters were established to identify large, grid-scale energy storage projects: specifically, potential reservoirs with a surface area of at least 10 hectares, dam heights of 40 meters (m), and a minimum head height between upper and lower reservoirs of 300 m. These methods were used for a U.S.-wide resource assessment of closed loop PSH (Rosenlieb et al., 2022), where the geospatial methods are documented in detail. These constraints on potential PSH system configurations lead to almost all modeled systems having energy storage capacities between 1 and 10 GWh (which translates to installed generation capacities of 100 MW to 1 GW when sized for 10 hours of storage).

The dataset of modeled PSH produced for this national resource assessment is used as input for potential locations and sizes of systems for the Railbelt analysis portion of the project. However, a more customized cost analysis is applied for these systems (described in Chapter 3). While the cost analysis differs, the potential energy storage capacity of the modeled systems is a straightforward function of the water volume capacity and head height of the system, along with a single assumption of mechanical efficiency, and therefore does not depend on any cost model assumptions. The formula for system capacity is as follows:

$$E_s = V_w \times 0.85 \times 9.8 \times h \times \sqrt{0.8} \times 1/3.6 \tag{1}$$

where:

E_s = energy storage capacity of the system (megawatt-hours [MWh])

V_w = water volume of system (megaliters [ML])

.85 = assumed usable proportion of water

9.8 = acceleration due to gravity of 9.8 m/s^2

h = average hydraulic head, measured as elevation difference between upper and lower reservoir (m)

0.8 = assumed round-trip efficiency of system

1/3.6 = unit conversion factor incorporating the number of kilograms (kg) per ML of water and the number of joules (J) per MWh.

While these modeled systems were appropriate to use for the Railbelt analysis, for the remote community analysis, the resulting PSH systems are far too large. Small, off-grid communities may need systems with installed capacities of far less than the hundreds of MW that the above system configurations tend to produce—potentially on the order of kW instead of MW. There are three ways that the project team changed the model to help produce systems of much smaller sizes than those in the national resource assessment (used for the Railbelt analysis):

1. The minimum surface area of considered reservoirs was reduced from 10 to 3.6 hectares. While, in theory, even smaller reservoirs may be useful in such small-scale systems, this limit was chosen based on concerns that the input 30-m resolution DEM may not reliably resolve reservoirs of a smaller size.

2. In addition to the 40-m dam heights used in the national resource assessment, additional reservoirs were generated with dam heights of 10, 20, and 30 m. For any given location, a lower dam height will generate a smaller reservoir with a smaller volume.

3. The minimum head height considered was lowered considerably, from 300 m to 10 m.

These three changes significantly reduce the range of energy storage capacities of modeled systems such that most of the installed capacities for 10-h storage systems are in the low-MW range, reducing the total capacity of the systems by two orders of magnitude.

There are two other differences in how the team analyzed the small-scale PSH systems. First, because the PSH systems are so much smaller than the grid-scale storage for which the model was built, the cost model that was developed for the system is not valid. Such small systems generally require very different equipment than the larger systems: for instance, separate pump and turbines instead of the more common reversible turbines and above-ground penstocks instead of below ground. Therefore, a cost-optimized final set of systems was not developed as was done for the national resource assessment. Instead, all potential reservoirs were considered as potential locations with specific sites considered in the analysis using a simple cost model. The small-scale PSH modeling was also limited to within 25 km of the communities and then further restricted to within 5 km because proximity to the communities is important in minimizing cost and development effort. The modeling produced more than 3.5 million potential reservoirs within 25 km, and nearly 200,000 within 5 km. This initial dataset has no exclusions applied and is only limited by suitable topography.

In addition, because of the potentially lower environmental impact of such small systems, the land use exclusions were relaxed considerably in further screening of potential reservoirs. Primarily, the team removed the requirement for systems to be closed loop, so reservoirs that intersect with existing water bodies and waterways were not excluded. Two scenarios were developed that paired potential reservoirs that could be used for PSH. The S1 scenario excluded protected federal lands (e.g., wildlife refuges, wilderness areas, national parks), urban areas, critical habitats, and glaciers; the S2 scenario excluded the same protected lands as S1 and added an exclusion for wetlands with a 1,000-foot buffer. These exclusions were added to help identify potential PSH opportunities that would have reduced permitting requirements and would be the most cost effective. The filters applied to the delineated reservoirs can be varied to account for different potential development scenarios and re-paired to define potential new systems.

2.2 PSH Resource Potential in Alaska

The utility-scale resource assessment performed using the system configuration assumptions described above for Alaska identified 1,819 potential closed-loop PSH systems in the state, with a total energy storage capacity of more than 4 TWh, which would compare favorably to Alaska's total annual electricity consumption of 5.9 TWh in 2020 (EIA, 2020). However, modeled systems had a wide range of costs, from $1,161/kW–$7,786/kW, as estimated by the simple cost model, underlining the fact that, while the potential for large amounts of energy storage exists in Alaska, not all PSH development is likely to be economically feasible. For more details on the national PSH resource assessment in Alaska, please reference Rosenlieb et al. (2022). In addition, these potential systems are distributed across Alaska; not just in the Railbelt region, where utility-scale development is more likely to occur (Figure 2-1).

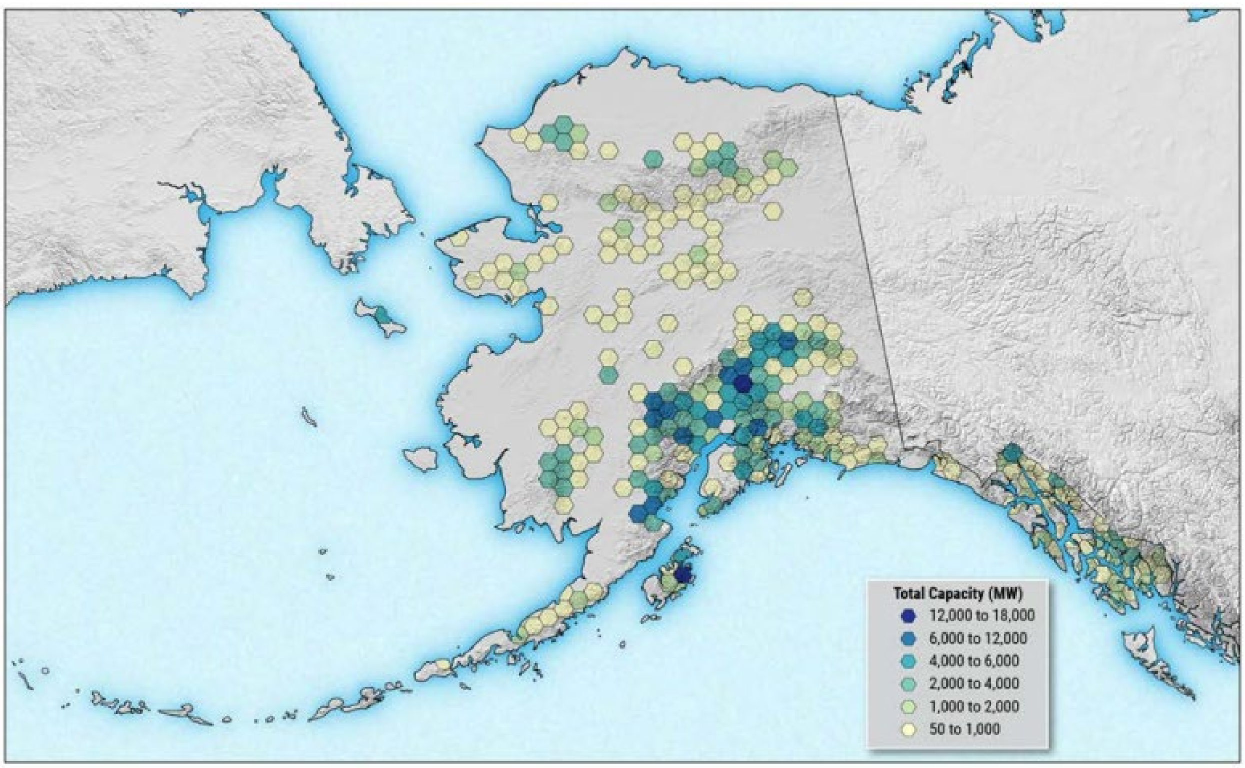

Figure 2-1 Potential Sites for Grid-Scale PSH Projects in Alaska

Modeling of smaller-scale PSH systems for remote communities revealed many potential sites for small-scale systems, with a range of potential energy storage of a few MWh to 100 MWh (Figure 2-2). Modeled systems have considerable overlap because of the multiple dam heights considered, and many have characteristics that would likely make them economically infeasible (e.g., head heights that are too low, reservoirs that are too small). While this approach retains the full breadth of potential reservoir options to be evaluated with other community screening factors to identify PSH opportunities for remote communities, it makes it impossible to assess the total PSH resource potential for small-scale systems.

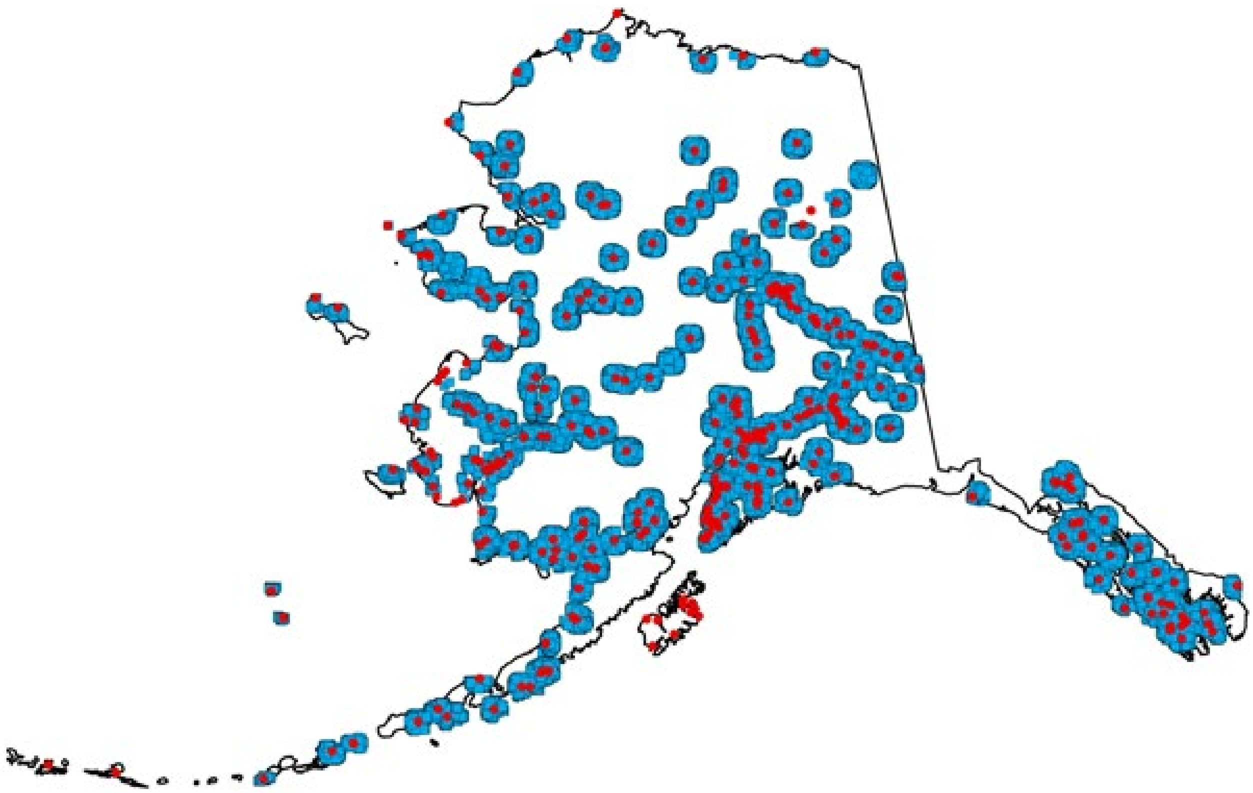

Figure 2-2 Potential Sites of Small-Scale PSH Projects in Alaska

2.3 Wind and Solar Resource Complementarity Analysis

Using the list of potential PSH locations generated by the PSH resource assessment model, the project team assessed solar and wind resource complementarity at each location by employing the methods described by Clark et al. (2022) in a national complementarity analysis. For each location, the National Aeronautics and Space Administration's (NASA's) Prediction of Worldwide Energy Resources (POWER) project was used to collect wind and solar resource data spanning 10 years, from 2011–2020 (NASA, 2021). The team assumed that 10 years of data was sufficient to account for interannual variation. NASA POWER uses satellite data and data from the Modern-Era Retrospective analysis for Research and Applications, Version 2 (MERRA-2) as the basis of the platform. Wind speed and direction were measured at 50-m hub heights for the Alaska wind data, and global horizontal irradiance (GHI) was calculated using Equation 2.

$$GHI = DHI + DNI \times \cos(Z) \quad (2)$$

where DHI is the diffused horizontal irradiance, DNI is the direct normal irradiance, and Z is the solar zenith angle. We assumed that ground-reflected radiation is insignificant compared with direct and diffuse radiation.

Using wind speed and GHI, the team measured complementarity by calculating the Pearson r coefficient using Equation 3.

$$r = \frac{\sum(x - \bar{x})(y - \bar{y})}{\sqrt{\sum(x - \bar{x})^2(y - \bar{y})^2}} \tag{3}$$

where $\bar{x}$ is the mean of the vector x, $\bar{y}$ is the mean of the vector y, and the vectors x and y represent the wind and solar data, respectively. The resulting Pearson r coefficient is on a scale from -1 to 1, with a score of -1 representing perfect negative correlation, a score of 0 representing no correlation, and a score of 1 representing perfect positive correlation. A perfect positive correlation means that the wind and solar resource profiles occur at the same time at a given location, while a perfect negative correlation means that the wind and solar resource profiles are perfectly complementary, occurring inversely at a given location.

Complementarity was measured over four time scales: annual versus monthly and daily-averaged versus hourly-averaged:

1. The annual, daily-averaged complementarity metric calculates a Pearson r coefficient across the 24-hourly wind and solar resource values for each day from 2011–2020, then averages those 365 values to provide a single, annual value. The annual, daily-averaged complementarity metric does not consider seasonal or diurnal patterns but gives a general indication for overall complementarity of a given location for sizing and siting considerations.

2. The annual, hourly-averaged complementarity metric calculates the complementarity for every hour from 2011–2020 and averages those 8,760 values over the year. The annual, hourly-averaged complementarity metric does not consider seasonality but does consider diurnal patterns.

3. The monthly, daily-averaged complementarity metric calculates a Pearson r coefficient across the 24-hourly wind and solar resource values for each day from 2011–2020 and averages those values over each month (approximately 30 values), resulting in 12 seasonally dependent complementarity values.

4. The monthly, hourly-averaged complementarity metric calculates the Pearson r coefficient for each hour from 2011–2020 and averages those values over each month (approximately 720 values). This method results in a metric that considers season and diurnal patterns and is well-suited for assessing resource availability to serve hourly demand or other grid services.

The solar and wind resource abundance in Alaska is measured by annual average wind speed (Figure 2-3) and annual average GHI (Figure 2-4).

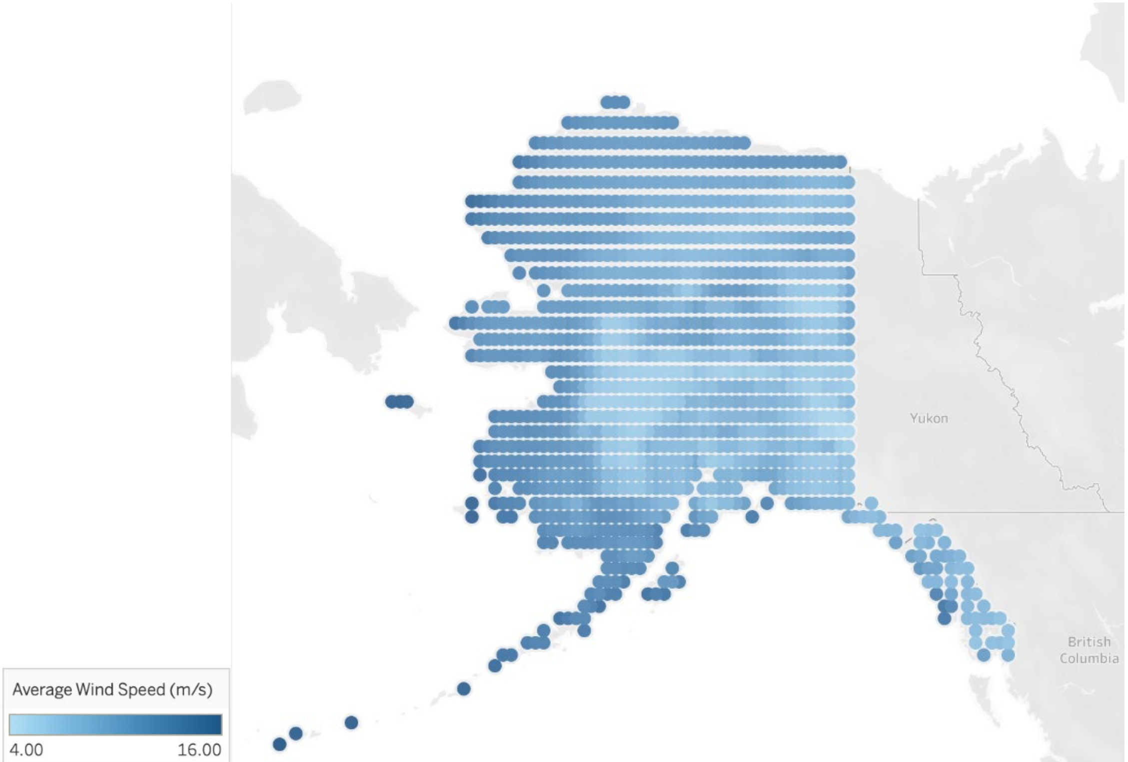

Figure 2-3 Annual Average Wind Speed, Measured at 50 Meters

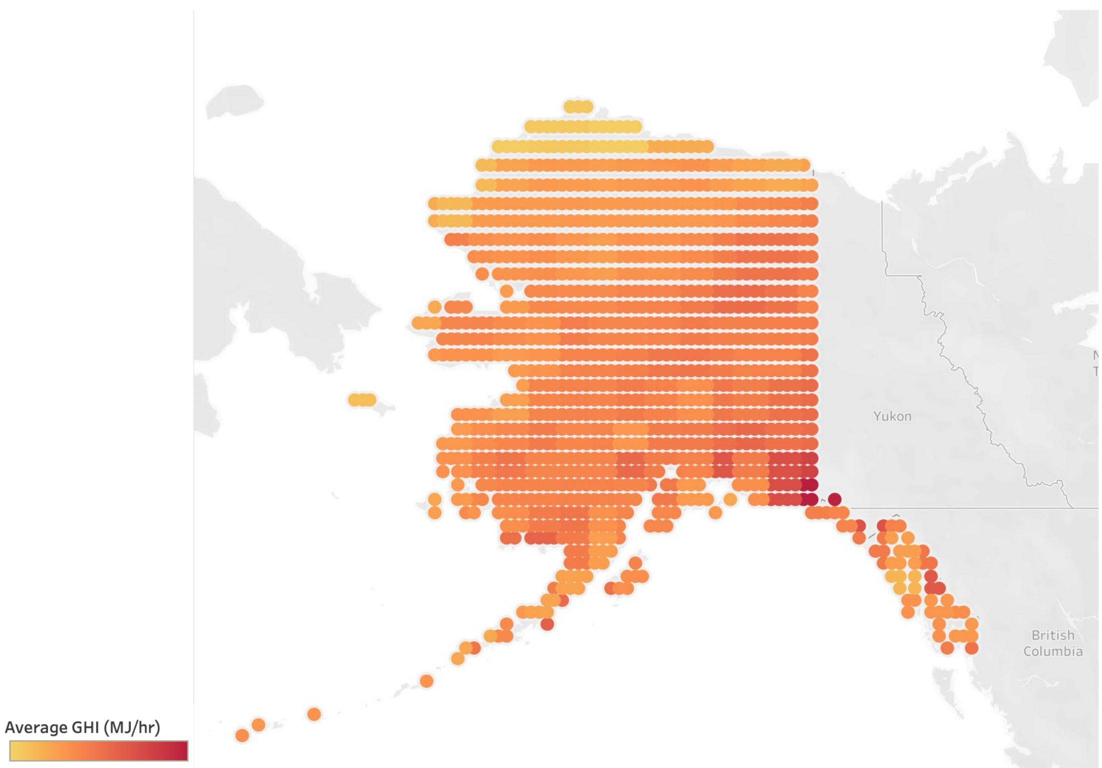

Figure 2-4 Annual Average GHI, Measured at 2 Meters

The coastal regions of Alaska, particularly the western coast, are abundant in wind resources. These regions align most with remote communities, rather than the Railbelt communities. However, good wind resources are also available in the Railbelt communities and in the southern coastal areas, where there is also good PSH potential. This pattern persists across seasons, with more abundant wind resources in the western part of the state and some areas in the south.

Solar resources are, overall, poor in Alaska compared with other regions in the United States, but there is still potential to provide solar power to communities, given the relatively smaller loads (especially in remote communities). This analysis measured solar resources in GHI, which does not fully account for solar energy captured by vertically mounted or actuating solar panels, which are more common in Alaska. There is a relatively higher abundance of solar energy in the southern region of the state, particularly southeastern regions. Solar energy can likely provide some electricity within a hybrid system, particularly if used (1) as a secondary power source to drive the PSH power plant, complementing wind generation, or (2) for small loads more typical in remote Alaskan communities.

The annual solar-wind complementarity in Alaska is depicted for the daily-averaged method in Figure 2-5 and the hourly-averaged method in Figure 2-6.

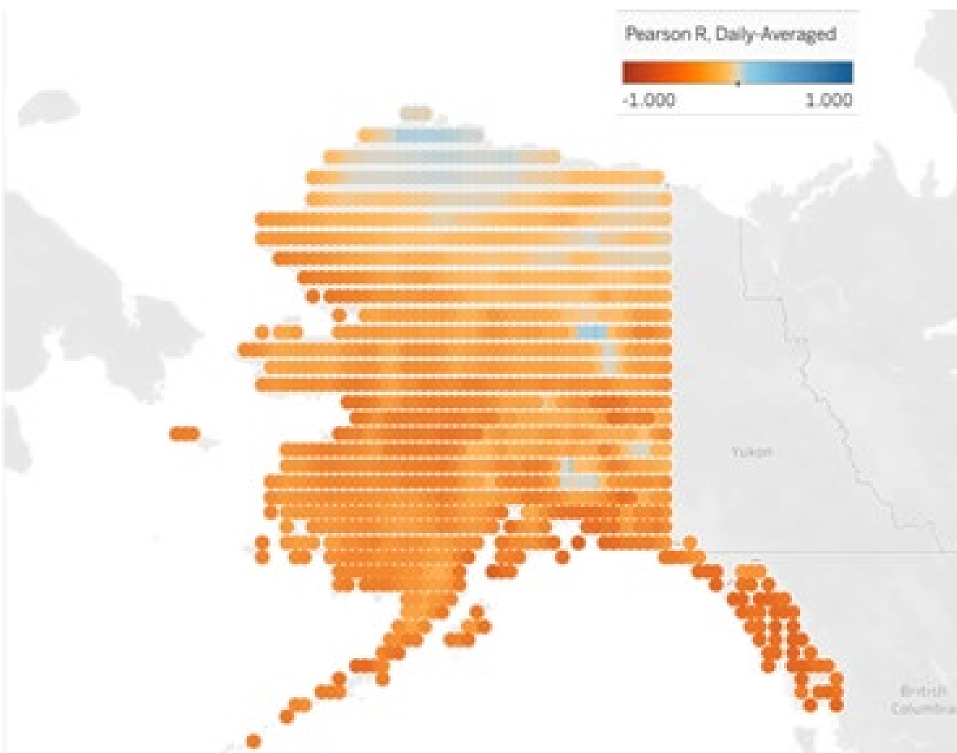

Figure 2-5 Annual Wind-Solar Complementarity (Measured by Pearson r Coefficient), Daily-Averaged

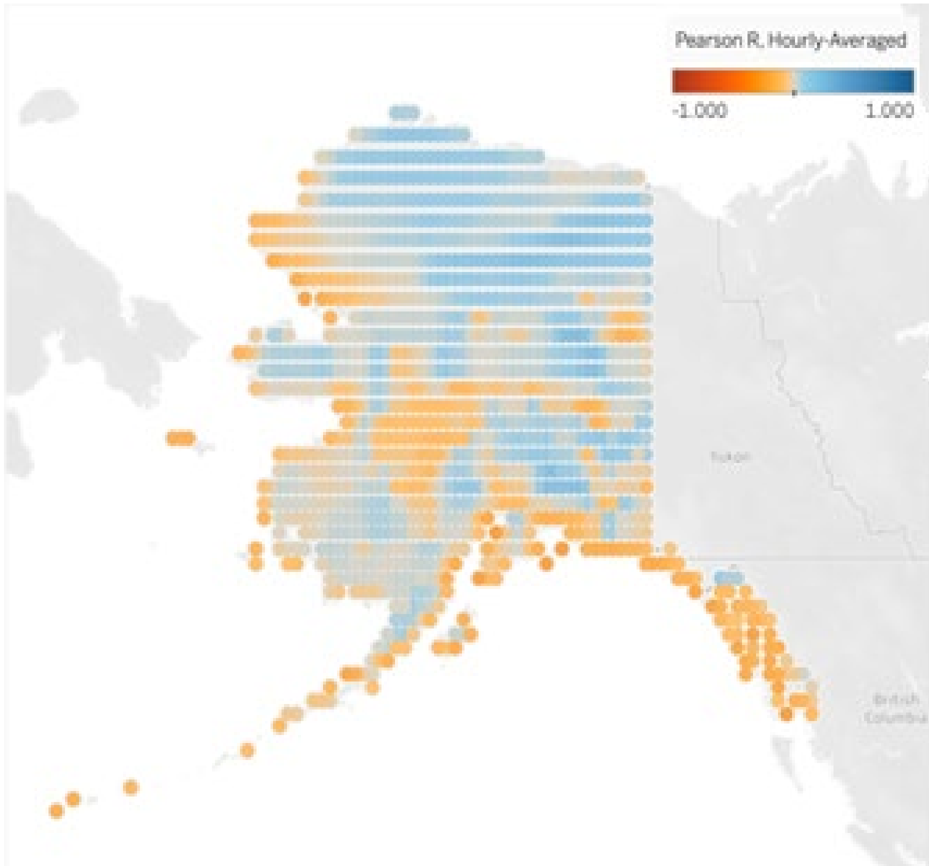

Figure 2-6 Annual Wind-Solar Complementarity (Measured by Pearson r Coefficient), Hourly-Averaged

Both annual daily-averaged and hourly-averaged complementarity analyses also suggest more complementary solar and wind resources along the southern coast and in some areas along the western coast. There are also complementary solar and wind resources in inland areas in the south of the state, particularly in the valleys of the Yukon River basin between the Brooks and Alaska mountain ranges. These low-lying areas in the Yukon River basin align with some potential PSH resource sites and are also closer to some of the larger communities and load centers in and surrounding the Railbelt communities. This alignment suggests that there is potential to use wind and solar hybrid power plants to help drive PSH systems and that there are nearby load centers that could enhance the techno-economic feasibility of such a system in communities along the southern coast and in the Yukon River basin.

As stated above, complementarity is important when assessing where PSH can support hybrid power plants. Dily-averaged complementarity is particularly relevant for wind-solar-PSH systems, because PSH acts as a long-term storage option, decreasing reliance on wind and solar resources to meet load and service demands. Complementarity of wind and solar technologies could be a factor in determining the cost effectiveness of PSH in remote and Railbelt locations.

2.4 References

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3.0 Railbelt System Analysis

Maintaining reliable electric power systems is critical in modern society, especially given the increasing electrification of sectors such as transportation and industry. Meanwhile, the power industry is facing a rapid evolution driven by recent technical advancements, increasing penetration of variable renewable energy (VRE) (e.g., wind, solar, and energy storage) resources, and increasing interdependence with other energy systems. In addition, the U.S. government has established ambitious decarbonization goals, led by the Biden Administration's target to produce 100% of electricity from carbon-free resources by 2035. These challenges and goals increase the complexity of power system planning while also highlighting the critical importance of designing systems that can deliver reliable, clean, and affordable electricity to consumers.

Transforming the power systems to incorporate large shares of VRE comes with operational challenges, particularly in delivering the needed flexibility to balance energy supply and demand. PSH is a proven commercial technology that can significantly contribute to the electric power grid with its capability to provide various grid services, such as energy arbitrage, ancillary services, and flexibility services. This chapter describes how the project team performed a simplified, long-term generation expansion planning (GEP) analysis for Alaska's Railbelt system to assess the needs and opportunities for PSH, given likely future power system development scenarios.

3.1 Technical Approach

The simplified, long-term GEP study for the Railbelt system assessed the possible size, location, technology, and timing of new PSH investments in multiple scenarios. GEP models have been widely developed and applied in power system planning studies to assess future generation portfolios in terms of their economic impacts, resultant resource adequacy, and reliability, while also analyzing the implications of different policies and regulations (Koltsaklis and Dagoumas, 2018). Least-cost, optimization-based GEP models are often used by vertically integrated utilities that own generation and transmission systems in a given region and conduct their own expansion planning through integrated resource planning studies (Twitchell and Cooke, 2021). We studied the future generation portfolios of the Railbelt system using a GEP model in A-LEAF (Kwon, 2021).

A-LEAF is an integrated, national-scale power system simulation framework that has been applied to analyze different issues related to power system evolution (Kwon et al., 2020; Levin et al., 2019). A-LEAF includes a suite of generation and transmission expansion, unit commitment, and economic dispatch models, as shown in Figure 3-1. It can be used to determine the least-cost generation investment and retirement plan, transmission investment plan, and hourly or sub-hourly system scheduling, all under a range of user-defined input assumptions for technology characteristics, electricity demand profiles, system requirements, and electricity market designs.

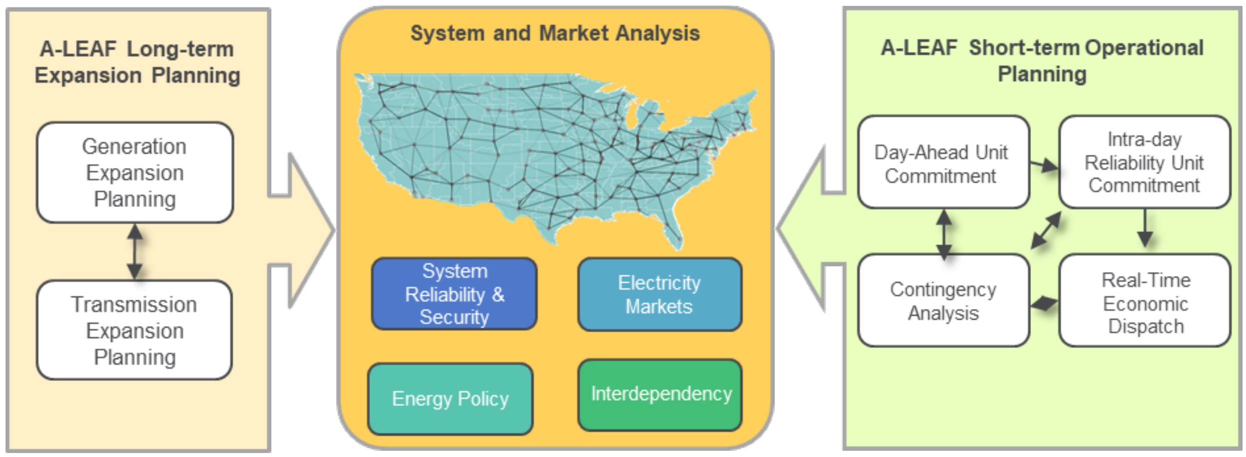


Figure 3-1 Overview of A-LEAF

The Argonne team is working on making A-LEAF—along with documentation that contains a detailed discussion of the mathematical formulation of the models and data—open to the public. In this report, we describe only the key characteristics of the GEP model in A-LEAF.

The GEP model in A-LEAF is a least-cost linear programming model that determines the timing, location, and size of new assets in the system over a multi-year planning horizon while ensuring that the total expected cost of power supply, including investment and operating costs, is minimized. Figure 3-2 presents the basic concept of the long-term GEP process in A-LEAF.

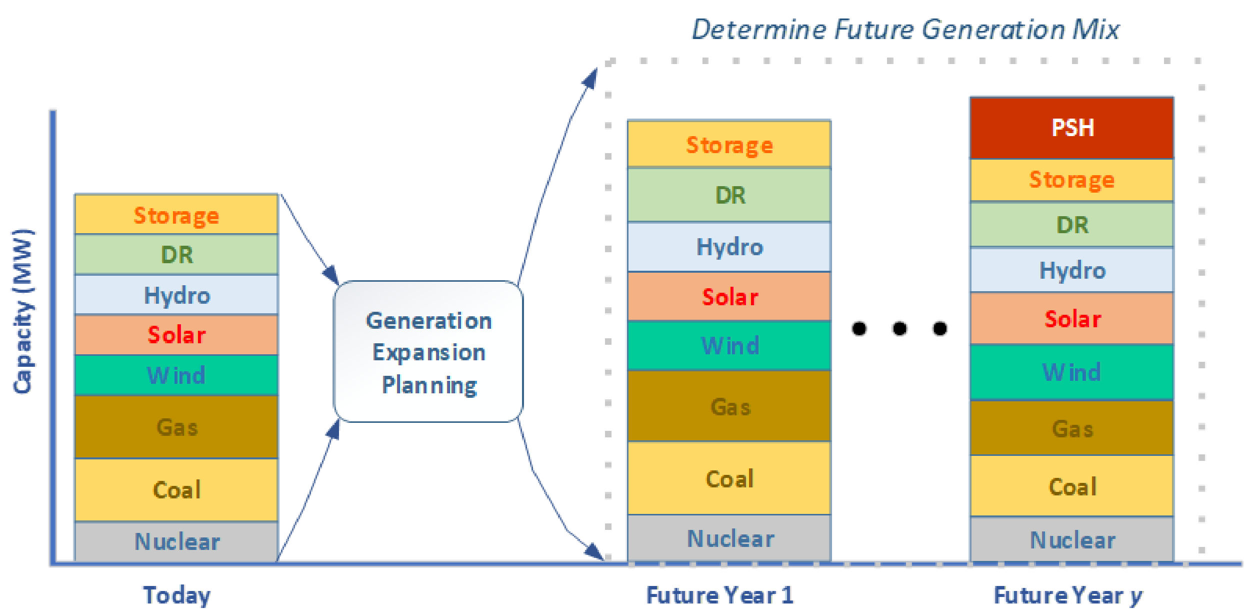


Figure 3-2 Overview of Long-term Generation Expansion Planning in A-LEAF

The least-cost objective function includes the costs for new generation investment and retirement, fixed and variable operation and maintenance (O&M), fuel, involuntary load curtailments, and applicable policy-related incentives or requirements. System costs are minimized while considering constraints related to maximum and minimum regional generation capacity investments, system operations, system resource adequacy, technical characteristics of generation and energy storage resources, and policies and regulations. Each of these is described in more detail below.

Power System Expansion

The GEP model determines the timing, location, and size of new generation and transmission assets while considering the resource potential for variable renewable energy resources, such as wind and solar. In addition, the model considers the age-based retirement of existing generators while making investment decisions for new assets. Finally, A-LEAF also considers the possibility of retiring existing generation units to reduce total system costs over the analyzed time horizon.

Power System Operations

A security-constrained economic dispatch (SCED) formulation is applied in the GEP model to manage the dispatch of generation and energy storage assets and procurement of ancillary services. The modeled economic dispatch formulation includes constraints for (1) load balance, (2) power flow and transmission limits, (3) operating reserve requirements, and (4) generator operating limits. The load balance constraints ensure that enough power is supplied to meet the demand in each region in each time interval. The power flows between regions are constrained by the transfer capability of transmission lines. Lastly, the GEP model procures frequency regulation and operating reserves while respecting the operating limits of generating resources.

Resource Adequacy

Power systems need to secure sufficient generating resources to maintain a reliable supply of electricity with limited risk of involuntary load-shedding events. A common resource adequacy metric that is widely used in GEP models is planning reserve margin (PRM), which reflects the system-wide firm capacity of generating resources (i.e., net available capacity from conventional generation plus firm capacity available from variable renewables) above the projected annual peak demand. In A-LEAF, the PRM constraints enforce the minimum PRM levels for each modeled region.

Technical Characteristics of Energy Storage

The GEP model includes a detailed representation of the physical and operational constraints of energy storage resources. The model allows such resources to provide all considered grid services, including capacity, energy, and operating reserves. Modelers can define the capacity of storage resources in the system, or A-LEAF can endogenously determine the optimal capacities of new storage assets. In addition, A-LEAF tracks and optimizes the state-of-charge (SOC) levels of energy storage resources through intertemporal constraints. Lastly, the total amount of energy an energy storage resource can be expected to store and deliver over a year is considered in A-LEAF by using an energy throughput constraint, which serves as a proxy for capturing the cycle life specifications of energy storage resources, particularly battery storage technologies.

Policy and Regulations

Policies and regulations modeled in A-LEAF include technology-specific subsidies, renewable portfolio standards (RPS), emission regulations, and carbon tax. First, the subsidy mechanisms implemented in A-LEAF include production tax credit (PTC) and investment tax credit (ITC). Second, A-LEAF models a simplified RPS program that ensures the total annual generation from applicable VRE resources exceeds a predefined RPS target percentage of system-wide annual demand. However, A-LEAF does not model other complex rules of RPS programs, including managing renewable energy certificates. Third, the emission regulations are modeled with caps on power plant carbon dioxide (CO_2) emissions. Lastly, the carbon tax policy is implemented to reflect the social cost of carbon emissions in the planning and operations of power systems.

While the goal was a simplified GEP analysis to assess the prospects of PSH in the Railbelt system for a set of plausible future scenarios, the analysis had certain limitations because of rather limited publicly available data and information related to the generation and transmission topology of the system, chronological time-series data for demand and variable renewable energy generation potentials, and operational details for the five utilities in the Railbelt system. Therefore, our analysis should not be viewed as a detailed, integrated, resource planning study of the Railbelt system, which would require far more resources and detailed analysis.

3.2 Description of the Existing System

Alaska's Railbelt power system extends from Fairbanks to the Kenai Peninsula and serves about 70% of Alaska's population. This section provides a description of the Railbelt power system based on system data obtained from a recent NREL report (Denholm et al., 2022).

The Railbelt system is served by five electrical utilities: Golden Valley Electric Association (GVEA), Matanuska Electric Association (MEA), Chugach Electric Association (CEA), Homer Electric Association (HEA), and the City of Seward. For this study, the Railbelt system is represented as a zonal network using four zones, as shown in Table 3-1 and Figure 3-3. The four zones are electrically connected by three transmission lines. The Fairbanks zone is connected to the Matanuska zone through the Alaska Intertie, which has 75 MW of transfer capability. The transmission line connecting the Matanuska and Anchorage zones has a capacity of 247 MW. The Anchorage and Kenai-Seward zones are connected via the Southern Intertie with 75 MW of capacity, which is assumed to be expanded to 100 MW from 2030. The increased capacity of the Southern Intertie is obtained from (Denholm et al., 2022). We assumed that there are no internal congestions within each zone.

Table 3-1 Zonal Representation of the Railbelt System

Zone	Local Utilities	Winter Peak Demand (MW)
Fairbanks	Golden Valley Electric Association	194
Matanuska	Matanuska Electric Association	131
Anchorage	Chugach Electric Association	352
Kenai-Seward	Homer Electric Association, City of Seward	78

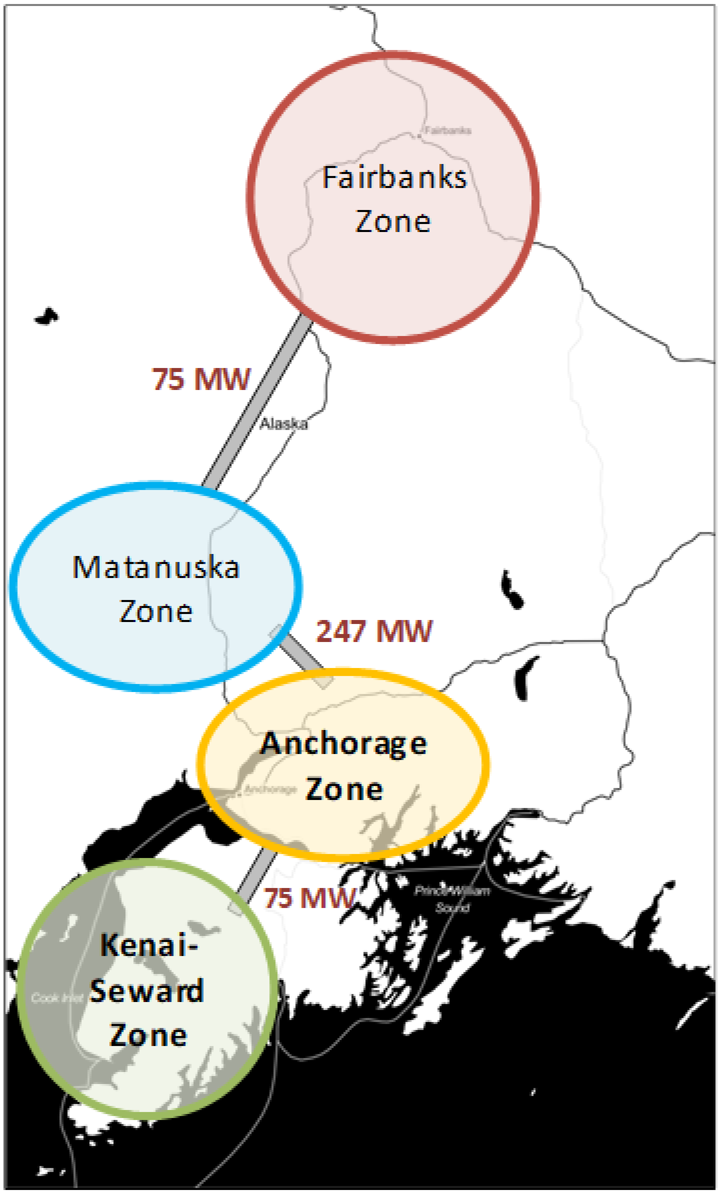


Figure 3-3 Modeled Railbelt Transmission System with Four Zones

Although the modeled four zones are electrically connected by transmission lines, the radial structure of the transmission topology prevents efficient sharing of generating reserves. Thus, the regions are largely operated independently with a very high planning reserve margin (Denholm et al., 2022). Table 3-2 summarizes the existing generating resources in the Railbelt system in 2020, obtained from EIA (2017a). The generation capacities listed in Table 3-2 reflect the winter capacity of each technology because the Railbelt system is a winter-peaking system. The current system-wide total capacity is 1,795 MW, and the winter peak demand of the Railbelt system is 755 MW.

Table 3-2 Existing Generating Resources in the Railbelt System (Winter Capacity in MW)

Generator Type[a]	Fairbanks	Matanuska	Anchorage	Kenai-Seward
Coal	75			
NGCC			414.2	82
NGCT			385.8	120
NG-IC		165		
Oil-CC	60		2	
Oil-CT	144.5			
Oil-IC	65			17.8
Hydro			40	139
Battery	40 (10 MWh)			46.5 (93 MWh)
PV				
Wind	26.6		17.6	
Geothermal			7	
Total Installed Capacity (MW)	**346.1**	**165**	**866.6**	**405.3**

[a] NGCC = natural gas combined cycle, NGCT = natural gas combustion turbine, NG-IC = natural gas internal combustion, Oil-CC = combined cycle, Oil-CT = oil combustion turbine, Oil-IC = oil internal combustion, PV = photovoltaic.

The GEP study we conducted requires chronological, time-series data for demand and variable renewable energy generation (i.e., hydro, PV, and wind). We assume that the existing hydropower plants have fixed hourly available generation capacity without considering water availability in the reservoirs; the model is allowed to dispatch the hydropower plants up to the fixed hourly available generation capacity. Similarly, the wind and PV resources have the hourly generation profile, and the model determines the dispatch setpoint of these resources subject to the hourly generation availability (i.e., curtailment is allowed in this study). The hourly wind generation profile in the Anchorage zone is based on the historic hourly generation profile of a wind plant in the region, obtained from Denholm et al. (2022). The hourly wind generation profiles for the other three zones are estimated based on the average wind speed data obtained from the "Global Wind Atlas" (DTU Wind Energy et al., 2023), as shown in Figure 3-4. The hourly PV generation profiles for each modeled zone were obtained from NREL's PVWatts calculator. Figure 3-5 presents the average hourly PV capacity factors in the four zones each month.

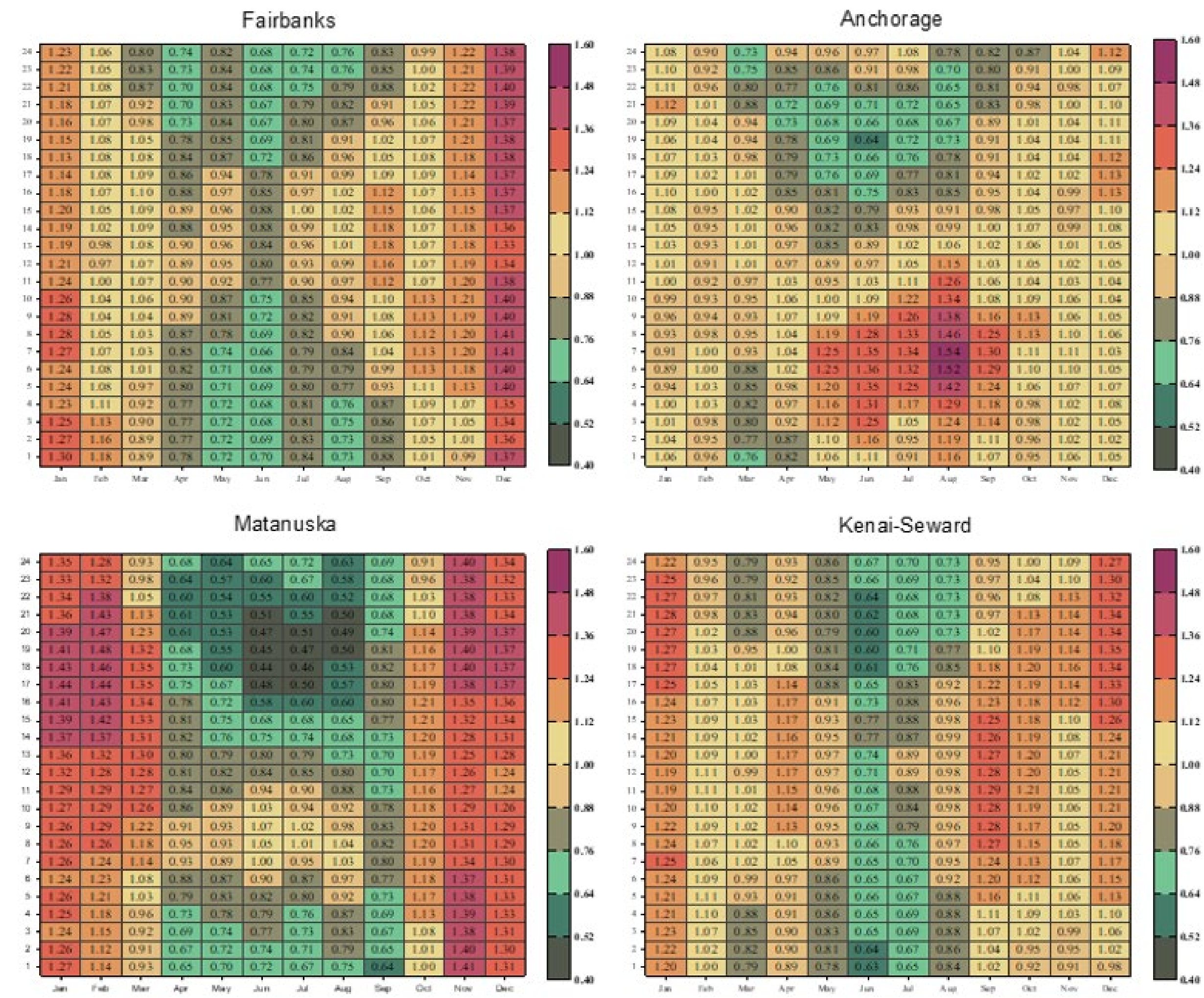


Figure 3-4 Average Hourly Wind Speeds in Each Month for the Four Modeled Zones (m/s)

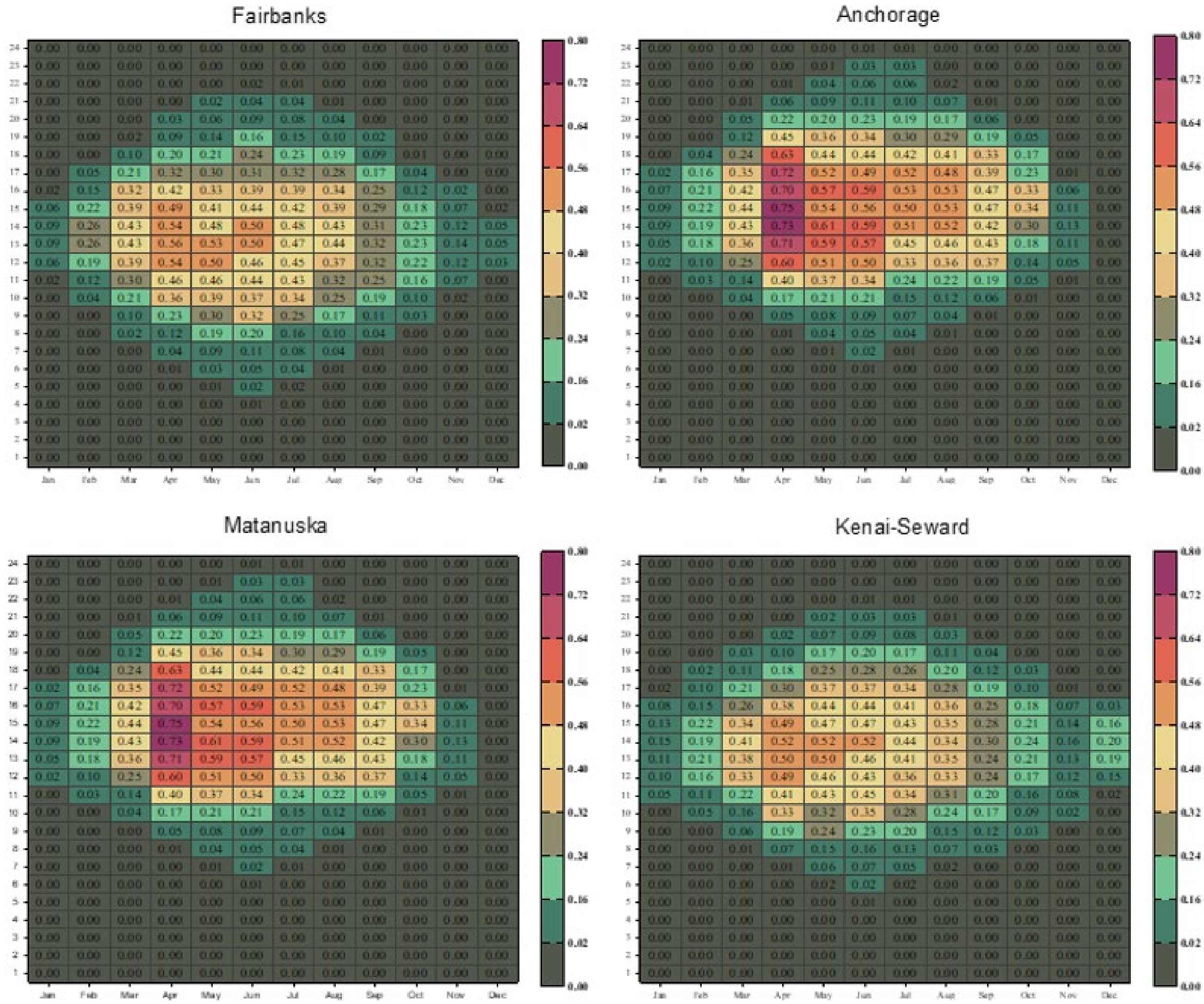


Figure 3-5 Average Hourly PV Capacity Factor in Each Month for the Four Modeled Zones

Because the five utilities in the Railbelt system operate largely independently due to the system's unique structure, the Railbelt system does not have an independent system operator that is responsible for maintaining system reliability and managing daily operations. However, for our study, because we are not performing integrated resource planning for each utility in the system, we assume there is an independent system operator. This assumption allows us to perform a GEP study of the whole Railbelt system with optimal system operations (i.e., the economic dispatch model optimizes the operation of the Railbelt system as a whole). However, to reflect the existing operational practices in the Railbelt system, we assigned a large amount of operating reserve requirements in each zone; in addition, we do not allow reserve sharing between zones. Each of the four zones modeled in this study must procure the defined operating reserve. In this way, we reflect the independent operations of the zones while performing a centralized GEP study.

The project team also assumed that the frequency regulation reserve requirement is equal to 2% of demand in each zone in each time interval (Denholm et al., 2022). We used an *N-N-2* criterion to determine each zone's contingency reserve requirements. The *N-N-2* criterion mandates securing an *N-1* status after the simultaneous loss of any two elements (generators or transmission lines) in the system. The *N-1* status means that the system is required to recover from the loss of any single bulk element without inconveniencing customers (i.e., involuntary load shedding). In this study, we considered the two largest elements in each zone to determine the contingency reserve requirements. We assumed that each zone must have enough generation capacity after the loss of the two largest elements and must be able to respond to the successive loss of the third-largest element in the system. Table 3-3 summarizes the defined contingency reserve requirements for each zone. We assume the contingency reserve requirements do not change over time in this study.

Table 3-3 The Modeled Contingency Reserve Requirement for Each Zone

Zone	Largest Generator (MW) – [A]	2nd Largest Generator (MW) – [B]	3rd Largest Generator (MW) – [C]	Maximum Import (MW) – [D]	Peak Demand (MW) –[E]	Contingency Reserve Requirement (MW)
Fairbanks	64	60	53	75	194	199 Min(A+B+D, E)
Matanuska	16.5	16.5	46.5	101	131	134 Min(A+B+D, E)
Anchorage	86.5	81.8	80.1	75	352	243 Min(A+B+D, E)
Kenai-Seward	63	63	49	75	78	175 Min(A+B+C, E)

In addition, we assumed that a resource providing the contingency reserve must be able to maintain the awarded reserve capacity for 8 hours continuously. This requirement is particularly important for the Railbelt system because of the potential loss of the main intertie lines. The 8-hour requirement is based on the average outage duration of the transmission lines with capacities below 345 kV in the lower 48 states, as shown in Figure 3-6, which was created using the transmission availability data from the North American Electric Reliability Corporation (NERC, 2022).

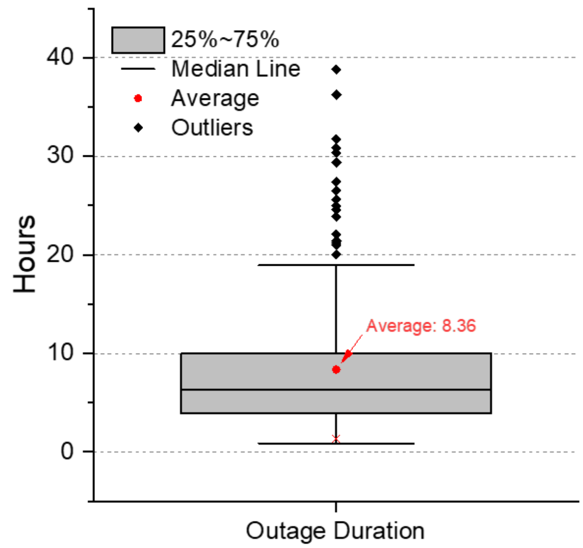


Figure 3-6 Historical Outage Duration of Overhead Transmission Lines

Presently, the reserve margin of the Railbelt system is high—about 140%—compared with typical reserve margins of systems in the lower 48 states, which are about 13–17% (Denholm et al., 2022). This high reserve margin reflects the unique operational and structural characteristics of the Railbelt system, which has a weak radial transmission network. The reserve margin is calculated based on the firm capacity of generating resources and the peak demand of the system; the number shows the relative margin of the available generating capacity compared with the peak demand of the system. The capacity credits for different technologies are estimated based on forced outage rates, for thermal resources, and based on average generation capability during peak period for VRE resources (Byers, Levin, and Botterud, 2018). In this study, we used the average generation capacity during periods when demand is over 80% of the peak demand to determine the capacity credits for wind and PV resources, as summarized in Table 3-4.

Table 3-4 Capacity Credits for Different Generating Technologies (%)

	Zone			
Generator Type	**Fairbanks**	**Matanuska**	**Anchorage**	**Kenai-Seward**
Hydro	22.5	19.1	30.2	21.3
Battery	100.0	100.0	100.0	100.0
PV	6.0	3.6	12.4	5.8
Wind	32.8	35.3	27.4	33.6
PSH	100.0	100.0	100.0	100.0

Finally, we apply 30% as the minimum PRM in the GEP model (Black & Veatch, 2010). The GEP model in A-LEAF has a PRM constraint that forces the total firm capacity in the system to be larger than a pre-determined minimum PRM value. As with the operating reserve constraints, we model maintenance of the PRMs by each modeled zone instead of systemwide to reflect the unique characteristics of the Railbelt system. Although we use 30% as the minimum value, the system still procures much more capacity due to the high operating reserve requirements, and the resulting PRMs are the output of the GEP model. Therefore, using the minimum PRM constraints ensures that each zone has at least 30% of PRMs throughout the planning horizon, but the required or appropriate PRM levels for each zone are then calculated by the GEP model and are the output of the simulation.

3.3 Analysis Design

3.3.1 Planning Horizon

This section describes the case study design and development scenarios that we selected for the analysis. We performed a long-term GEP analysis with a study period from 2025–2050. To avoid the end-effect of optimization, which can skew the modeling results at the end of the study period, the modeling results are presented for the analysis period from 2025–2046. We assumed that investment decisions are made every 3 years and that demand would grow by a total 19.9% by 2050, with an annual increase of 0.65%, which is based on the expected population growth in the Railbelt zones (Denholm et al., 2022).

3.3.2 Temporal Resolution

A-LEAF determines the optimal generation mix over the whole planning horizon while considering the economic operations of the system in each year of the study period. Ideally, the system operations should consider the entire year (i.e., 8,760 hours); however, considering such a large problem is computationally challenging, especially in a multi-year optimization problem. Therefore, we use a scenario-reduction algorithm to select representative days that can efficiently capture the operating conditions of the whole year using a limited number of days. We use a backward scenario-reduction algorithm in this study (Growe-Kuska et al., 2003) that finds a pre-determined number of representative days by iteratively merging days with similar characteristics (e.g., load pattern, wind and PV generation profiles). We used 28 representative days per year. Figure 3-7 compares the net load duration curves derived from the selected 28 representative days and the whole year of data. The duration curves show that the selected representative days can capture the operating conditions of the whole year well, with the normalized root mean square error deviation (NRMSD) value of 0.008.

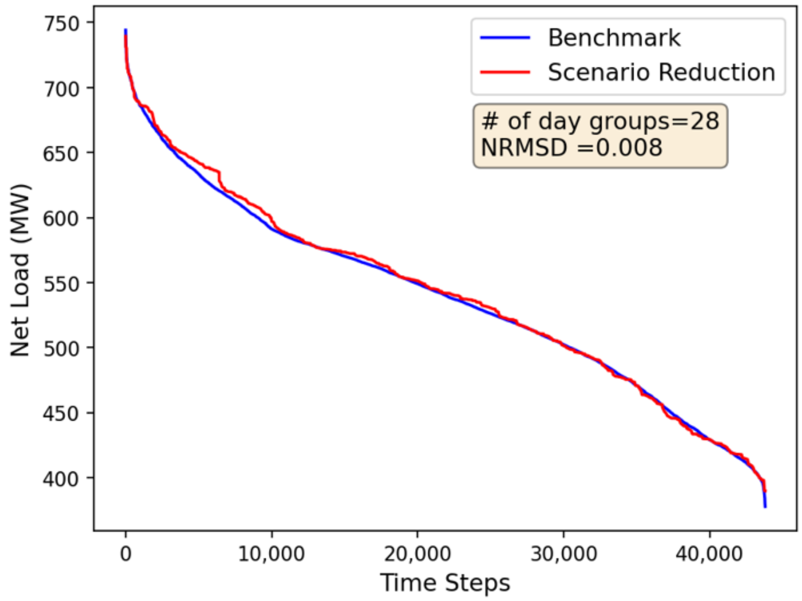


Figure 3-7 Comparison of Net Load Duration Curves Generated from the Selected Representative Day Groups (Red) and Whole Hours in a Year (Blue)

3.3.3 Investment Candidate Technologies

We use seven technologies as investment options: NGCC, NGCC-CCS, NGCT, PV, land-based wind, battery, and PSH, as summarized in Table 3-5. The financial parameters were obtained from NREL's *Annual Technology Baseline* (NREL, 2022) and the *Energy Storage Technology and Cost Characterization Report* (Mongird et al., 2020). We use a 10-MW, 4-hour Li-ion battery technology (i.e., 40-MWh technology) and a 100-MW PSH with a 10-hour storage duration (i.e., 1,000 MWh). The annualized capital expenditure (CAPEX) is calculated considering the lifespan and the weighted average cost of capital (WACC) value of 0.057 for each technology. The team allowed PV and wind resources to provide the contingency reserve by reducing their outputs below available generation capability (i.e., the provision of contingency reserve from PV and wind requires curtailments of their outputs). Lastly, we assumed that the earliest in-service year for PSH and NGCC-CCS is 2030, considering the long development lead time of these projects.

We also incorporated cost scaling factors to account for the higher expenses in Alaska compared with other states. These factors are sourced from EIA (EIA 2017b). In addition, a 1.125 scaling factor was added for batteries to account for the necessary cold temperature packaging outlined in *Energy Profile: Kotzebue* (Robb, 2022). Because the EIA report does not include a scaling factor for PSH, we used an average, as shown in Table 3-6.

Table 3-5 Model Parameters for Investment Candidate Technologies in 2030

Technology	NGCC	NGCC-CCS	NGCT	PV	Wind	Battery	PSH
Capacity (MW)	250	250	60	50	50	10	100
Storage Duration (h)	-	-	-	-	-	4	10
CAPEX ($/kW)	912.3	2,001.0	780.7	754.4	955.9	99.0	1,209.0
CAPEX ($/kWh)	-	-	-	-	-	299.3	76.0
Annualized CAPEX ($/kW)	58.4	128.0	54.9	33.7	50.8	10.0	69.2
Annualized CAPEX ($/kWh)	-	-	-	-	-	30.2	4.3
Fixed O&M Cost ($/kW-Year)	28.0	62.0	21.0	15.2	39.0	3.3	30.4
Variable O&M Cost ($/kWh)	2.0	6.0	5.0	0.0	0.0	0.5	0.5
Lifespan (years)	40	40	30	30	20	15	100

Table 3-6 Location-based Cost Scaling Factors

Zones	NGCC	NGCC-CCS	NGCT	PV	Wind	Battery	PSH
Fairbanks	1.35	1.32	1.30	1.43	1.56	1.32	1.38
Matanuska	1.30	1.28	1.26	1.22	1.30	1.19	1.26
Anchorage	1.30	1.28	1.26	1.22	1.30	1.19	1.26
Kenai-Seward	1.30	1.28	1.26	1.22	1.30	1.19	1.26

The team applied the annual energy throughput constraints to battery technology. As briefly described above, we applied the annual energy throughput constraints to limit the annual amount of charging and discharging of energy. The purpose of considering this constraint was to prevent an over-utilization of battery resources in the least-cost GEP model due to the zero marginal variable costs. In practice, the technology has a limited cycling capability caused by the potential degradation of assets. Therefore, it is important to capture the operational limits of the technology in a GEP study. We did not apply the energy throughput constraints for PSH. Finally, because the battery technology CAPEX (Mongird et al., 2020) reflects only the estimated cost in 2030, we applied a learning-based capital cost curve for battery technologies so that the optimization process can consider reasonable capital costs over the planning horizon, as shown in Figure 3-8.

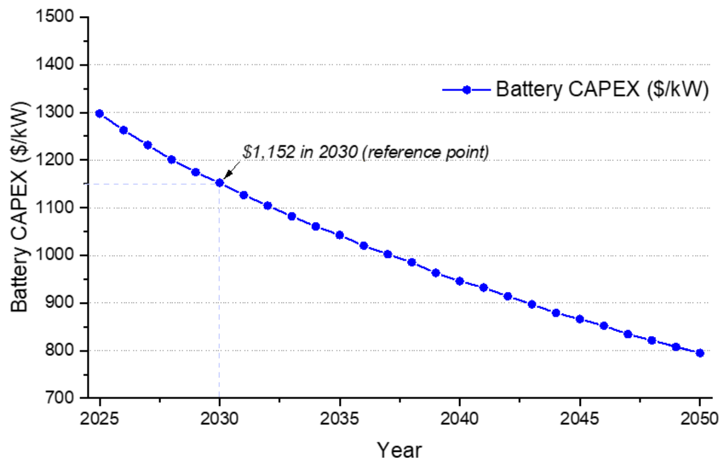


Figure 3-8 Li-Ion Battery Technology CAPEX Changes over the Study Period

3.3.4 Age-based Retirements

The project team did not apply economic retirement of existing resources; instead, we applied age-based retirements of these resources. The age-based retirements do not represent the actual retirement schedule of the five utilities because of the lack of publicly available data. We considered the current age of the existing resources and their expected lifespan (Table 3-7). Note that the table only includes the generators that are subject to age-based retirements within the planning horizon of this analysis (i.e., by 2050).

In addition, we introduced a two-phase approach for age-based retirements for the following reasons: (1) many resources in the Railbelt system are already operating beyond their expected lifespan, and (2) publicly available data regarding the retirement schedules of existing resources is lacking. If we simply model age-based retirements based on the current age and the expected lifespan of the resources, too many resources would be subject to retirement in the first planning stage (i.e., 2025). The first phase covers the planning horizon from 2025 to 2030. In the first phase, we allowed extended operations of older generators until 2030 while ensuring that all the generators subject to age-based retirements are retired by the end of 2030. The optimization engine determines the optimal timing of retirements in the first phase. In the second phase, the resources subject to age-based retirements are retired according to the schedule presented in Table 3-7 without an option for extended operations.

Table 3-7 Age-based Retirement Schedule of Existing Units in the Railbelt System

Generator ID	Technology[a]	Capacity (MW)	Lifespan (Year)	Operating Year	Retirement Year
Battery Energy Storage System	Battery	40	20	2003	2024
Healy #1	Coal	25	55	1967	2047
Healy #2	Coal	50	40	1998	2024
Joint Base Elmendorf Richardson (JBER) Landfill Gas Power Plant #1	Geothermal	1.4	15	2012	2027
JBER Landfill Gas Power Plant #2	Geothermal	1.4	15	2012	2027
JBER Landfill Gas Power Plant #3	Geothermal	1.4	15	2012	2027
JBER Landfill Gas Power Plant #4	Geothermal	1.4	15	2012	2027
JBER Landfill Gas Power Plant #5	Geothermal	1.4	15	2013	2028
George M. Sullivan Generation Plant 2 #1	NG-CC	81.8	43	1979	2022
George M. Sullivan Generation Plant 2 #5	NG-CT	86.5	38	1984	2022
Nikiski Combined Cycle #1	NG-CC	42	40	1986	2026
Beluga #1	NG-CT	19.6	54	1968	2022
Beluga #2	NG-CT	64.8	50	1972	2022
Beluga #3	NG-CT	68.7	47	1975	2022
Beluga #4	NG-CT	80.1	44	1978	2022
Anchorage 1 #1	NG-CT	33.2	50	1972	2022
Anchorage 1 #2	NG-CT	32.9	30	2007	2037
Bernice Lake #1	NG-CT	19	51	1971	2022
Bernice Lake #2	NG-CT	26	44	1978	2022
Bernice Lake #3	NG-CT	26	41	1981	2022
Soldotna	NG-CT	49	30	2014	2044
Eklutna Generation Station #1	NG-IC	16.5	30	2015	2045
Eklutna Generation Station #2	NG-IC	16.5	30	2015	2045
Eklutna Generation Station #3	NG-IC	16.5	30	2015	2045
Eklutna Generation Station #4	NG-IC	16.5	30	2015	2045
Eklutna Generation Station #5	NG-IC	16.5	30	2015	2045
Eklutna Generation Station #6	NG-IC	16.5	30	2015	2045
Eklutna Generation Station #7	NG-IC	16.5	30	2015	2045
Eklutna Generation Station #8	NG-IC	16.5	30	2015	2045
Eklutna Generation Station #9	NG-IC	16.5	30	2015	2045
Eklutna Generation Station #10	NG-IC	16.5	30	2015	2045
Eva Creek Wind	Wind	24.6	20	2013	2033
Fire Island Wind #1	Wind	18	20	2012	2032
Anchorage 1	Oil-CC	2	30	2012	2042
Fairbanks #1	Oil-CT	17.7	51	1971	2032
Fairbanks #2	Oil-CT	17.7	50	1972	2032

Table 3-7 (cont.)

Generator ID	Technology[a]	Capacity (MW)	Lifespan (Year)	Operating Year	Retirement Year
North Pole #1	Oil-CT	60	46	1976	2032
North Pole #2	Oil-CT	64	45	1977	2032
Healy	Oil-CT	2.8	55	1967	2032
North Pole #1	Oil-CC	12	30	2007	2037
North Pole #2	Oil-CC	53	30	2007	2037
Seward (AK) #1	Oil-IC	2.5	47	1975	2022
Seward (AK) #2	Oil-IC	2.5	37	1985	2022
Seward (AK) #3	Oil-IC	2.5	36	1986	2022
Seward (AK) #4	Oil-IC	2.8	30	2000	2030
Seward (AK) #5	Oil-IC	2.8	30	2010	2040
Seward (AK) #6	Oil-IC	2.5	30	2010	2040
Seldovia #1	Oil-IC	1.2	30	2004	2034
Seldovia #2	Oil-IC	1	30	2017	2047
Fire Island Wind #2	Wind	27	20	2026	2046

[a] NG-CC = natural gas combined cycle, NG-CT = natural gas combustion turbine, NG-IC = natural gas internal combustion

3.3.5 Fuel Prices

We used base fuel prices in the Railbelt system, sourced from Denholm et al. (2022) (Table 3-8). In addition, we applied escalation factors for each fuel type for future years; these are based on fuel price projections reported in EIA (2022) and illustrated in Figure 3-9.

Table 3-8 Base Fuel Prices ($/MMBtu[a])

Zone	NGCC	NGCC-CCS	NGCT
Fairbanks	4.8	9.1	17.2
Matanuska	4.8	8.2	17.2
Anchorage	4.8	7.6	17.2
Kenai-Seward	4.8	8.0	17.2

[a] MMBtu = million British thermal unit(s)

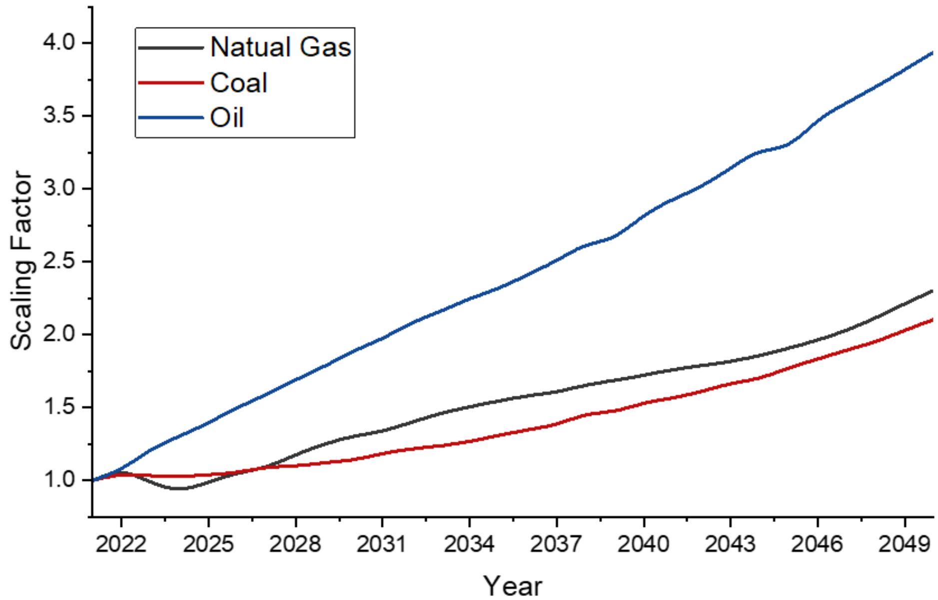


Figure 3-9 Fuel Price Projections

3.3.6 Scenarios

In addition to the reference case, we considered four other scenarios for this analysis (Table 3-9). The Carbon Price scenario considers a carbon price of $40/ton of CO_2 to assess the impact of the social cost of carbon emissions on planning decisions. In the RPS scenario, we modeled an RPS program with a target of 80% by 2040, as studied in Denholm et al. (2022). Table 3-10 lists the annual RPS targets modeled in the RPS scenario. We used an additional 10% winter peak increase in the High-Load scenario. The High-Transmission scenario assumes increased transmission capacity for the Alaska intertie and the Southern intertie. The increased transmission capacities are obtained from Denholm et al. (2022). All scenarios except the Carbon Price scenario include both ITC and PTC that are extended by the Inflation Reduction Act of 2022, signed on August 16, 2022 (White House.gov, 2022). In this study, we used a 40% rate of ITC for PV, battery, and PSH, assuming the new projects can meet the prevailing wage and apprenticeship requirements and satisfy the domestic content requirement. However, we did not use the additional tax credits related to environmental justice and energy community support. Similarly, we used 1.65 cents/kWh of PTC for wind. Both the ITC and PTC phase out at the end of 2034.

Table 3-9 Scenario Definitions

Scenario	Load	Topology	Environmental Policy
Reference	19.9% increase by 2050	Exiting topology	ITC (40%), PTC (1.65 cents/kWh)
Carbon Price	Same as Reference	Same as Reference	Carbon price ($40/ton of CO_2)
RPS	Same as Reference	Same as Reference	RPS with an 80% target, ITC (40%), PTC (1.65 cents/kWh)
High-Transmission	Same as Reference	AK intertie: 75 -> 250 MW Southern intertie: 75 -> 100 MW	Same as Reference
High-Load	Additional 10% winter peak increase	Same as Reference	Same as Reference

Table 3-10 RPS Targets

Year	RPS Target (%)	Year	RPS Target (%)
2024	0.0	**2033**	28.5
2025	2.5	**2034**	33.5
2026	4.0	**2035**	41.0
2027	5.5	**2036**	48.5
2028	8.0	**2037**	56.0
2029	11.5	**2038**	63.5
2030	15.0	**2039**	71.0
2031	18.5	**2040**	80.0
2032	23.5	**2041 – 2046**	80.0

3.4 Summary of Modeling Results

This section presents a summary of the results obtained for the four scenarios (plus reference case). The results underline the need for long-duration energy storage (i.e., PSH) in all scenarios. The PSH candidates were selected as part of the optimal capacity expansion solutions, as summarized in Figure 3-10 and Table 3-11. The following subsections provide further details about the simulation results for each modeled scenario.

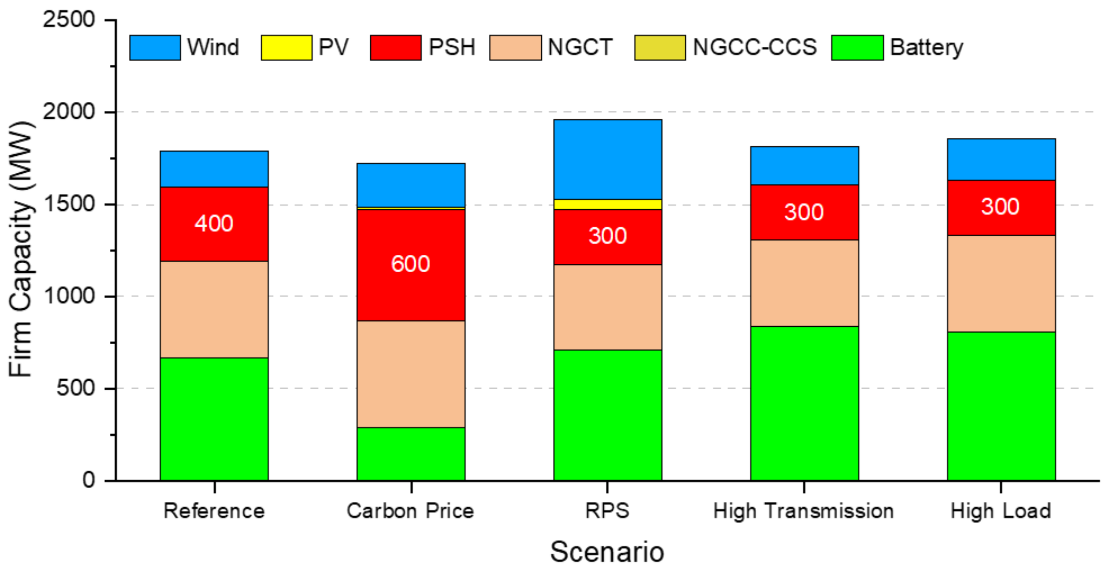


Figure 3-10 System-wide Added New Capacity by 2046 in Different Scenarios

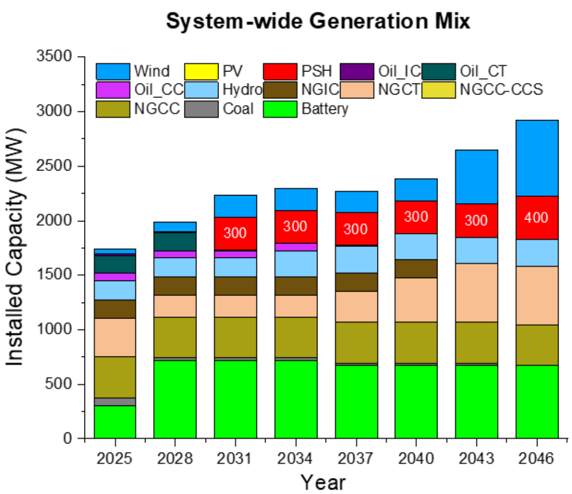
Table 3-11 System-wide Added New Capacity by 2046 in Different Scenarios[a]

Scenario	Wind	PV	PSH	NGCT	NGCC-CCS	Battery
Reference	700 *(196)*	0 *(0)*	400 *(400)*	540 *(522)*	0 *(0)*	670 *(670)*
Carbon Price	850 *(238)*	100 *(11)*	600 *(600)*	600 *(580)*	0 *(0)*	290 *(290)*
RPS	1550 *(434)*	450 *(49.5)*	300 *(300)*	480 *(464)*	0 *(0)*	710 *(710)*
High-Transmission	750 *(210)*	0 *(0)*	300 *(300)*	480 *(464)*	0 *(0)*	840 *(840)*
High-Load	800 *(224)*	0 *(0)*	300 *(300)*	540 *(522)*	0 *(0)*	810 *(810)*

[a] Values are in MWs of installed capacity and firm capacity (in parentheses).

3.4.1 Reference Case

The reference case represents the optimal generation expansion solution, which is determined by economic factors and modeled reliability constraints. Figure 3-11 shows the system-wide generation mix, in terms of both installed and firm capacity. The figure also shows the PRM levels throughout the planning period, which initially rise before remaining within a range of 130–160% in later years.



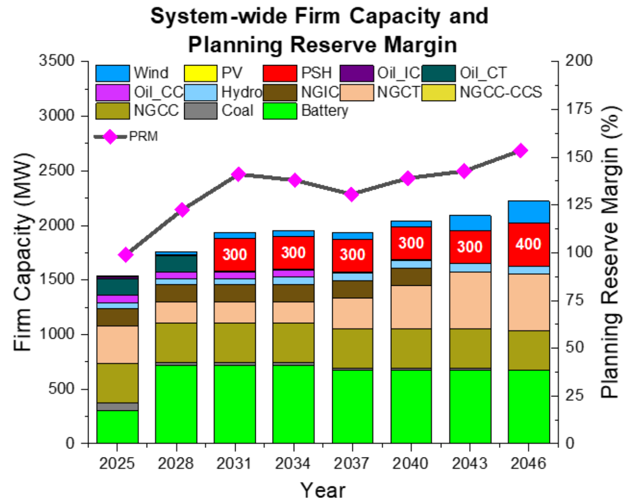


Figure 3-11 System-wide Generation Mix (left) and Firm Capacity with Planning Reserve Margin (right) in the Reference Case

Figures 3-12 and 3-13 illustrate the new investments and retirements (respectively) of power generation resources by zone. Figure 3-14 shows the regional generation mix. The analysis shows that the retirement of thermal resources in the Anchorage zone is offset by new investments in NG-CT, battery, and PSH capacity in the early years. In contrast, the Fairbanks zone compensates for thermal retirements with a combination of new battery, wind, and PSH investments because the Fairbanks zone will likely not have access to natural gas before 2035. The results show 100 MW PSH investments in 2031 in the Fairbanks and Matanuska zones. In addition, 100 MW PSH investments are planned for 2031 and 2046 in the Anchorage zone. The earliest in-service year for PSH is assumed to be 2030, which accounts for a long construction time.

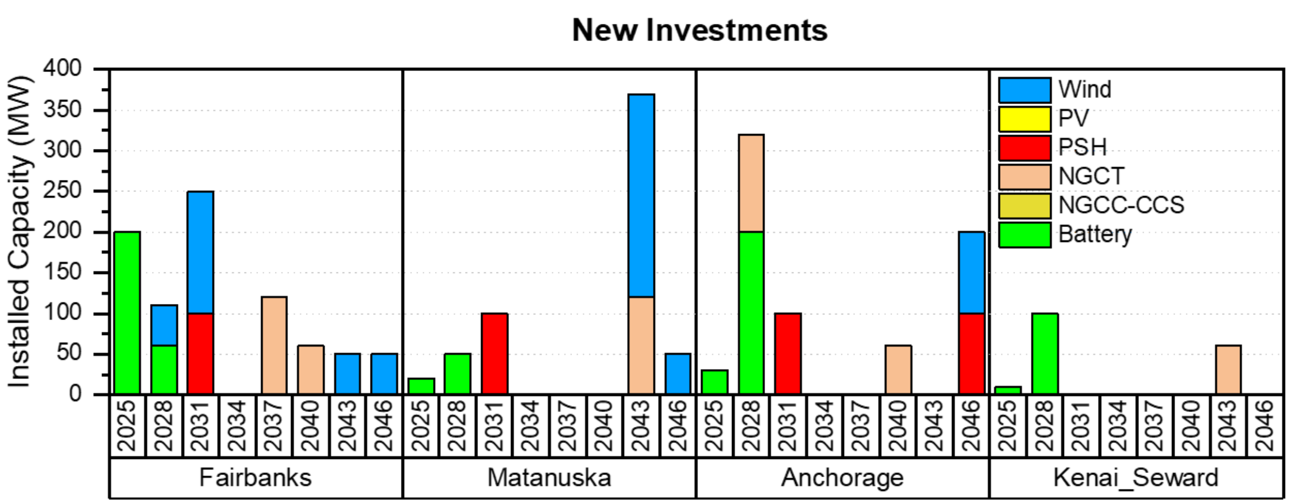


Figure 3-12 New Investments in Each Zone in the Reference Case

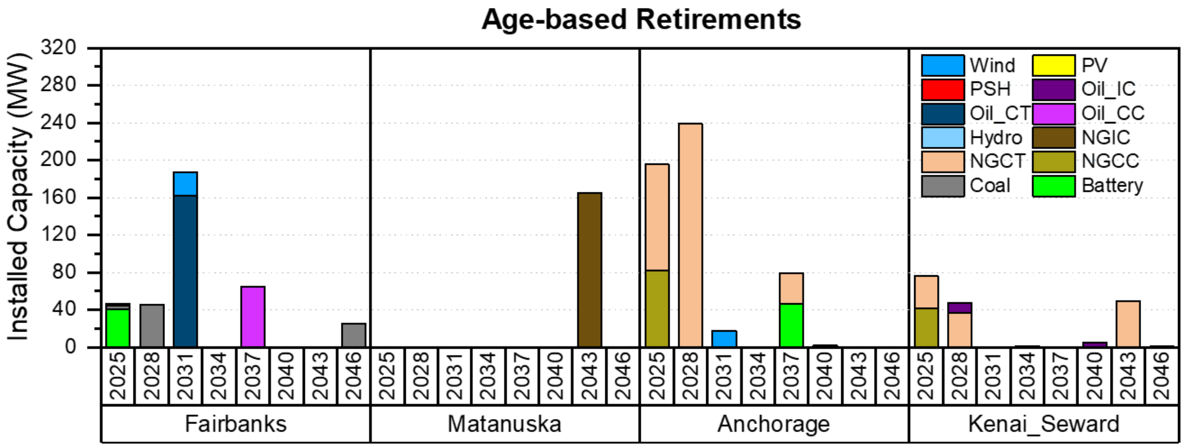


Figure 3-13 Age-based Retirements in Each Zone in the Reference Case

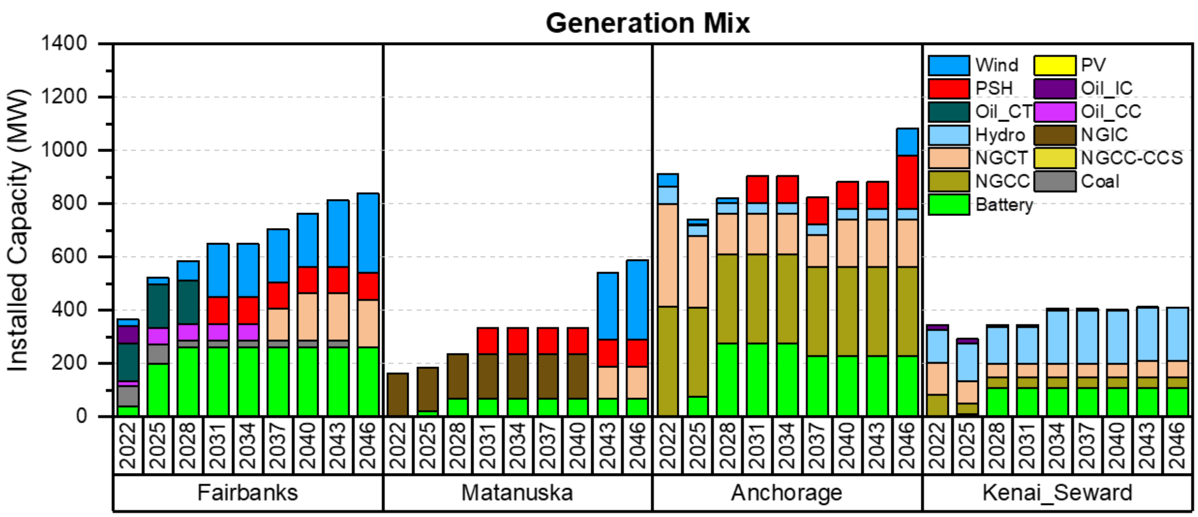


Figure 3-14 Generation Mix of Each Zone in the Reference Case

3.4.2 Carbon Price Scenario

In the Carbon Price scenario, $40/ton of carbon price was added to the marginal cost of thermal generators based on their emission levels. The added carbon price increases the operating costs of thermal generators in the system; therefore, the results show increased wind, PV and PSH investments compared with the reference case. The Carbon Price scenario highlights the effect of tax credits on battery investments, with a substantial decrease in battery investments in the absence of ITC in the scenario. This decrease is offset by an increase in PSH investments, as shown in Figure 3-15.

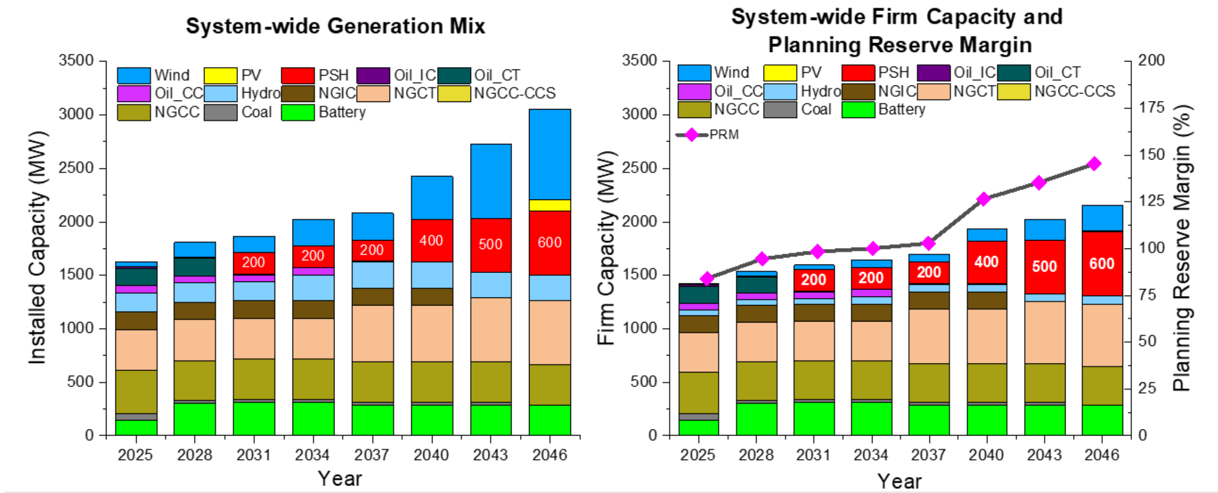


Figure 3-15 System-wide Generation Mix (left) and Firm Capacity with Planning Reserve Margin (right) in the Carbon Price Scenario

Like the reference case, new investments in battery, wind, and NG-CT replace the retired capacity of existing thermal resources in all the modeled zones except for Fairbanks, as shown in Figures 3-16 and 3-17. The Fairbanks zone shows higher battery investments in the early years, compared with the reference case because of the limited access to natural gas. The results show a total of 600 MW of PSH investments. 100-MW PSH investments are planned for 2031 in both the Fairbanks and Matanuska zones. The Matanuska zone has additional PSH investment in 2046. The Anchorage and Kenai-Seward zones expect PSH investments in later years, with Anchorage anticipating 200 MW PSH investment in 2040 and Kenai-Seward zone expecting 100 MW PSH investment in 2043. Like the reference case, the Anchorage zone shows a higher total system installed capacity than other zones (Figure 3-18).

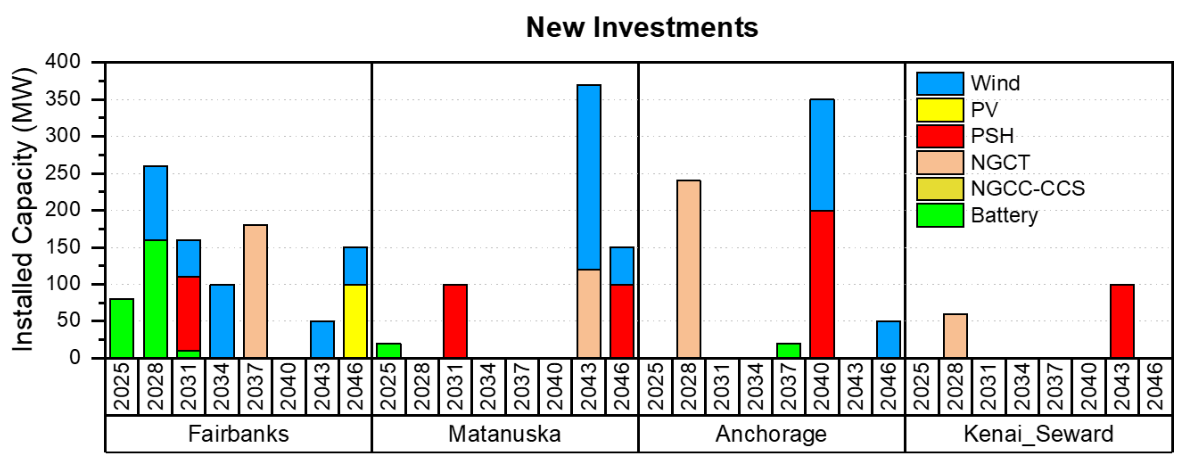


Figure 3-16 New Investments in Each Zone in the Carbon Price Scenario

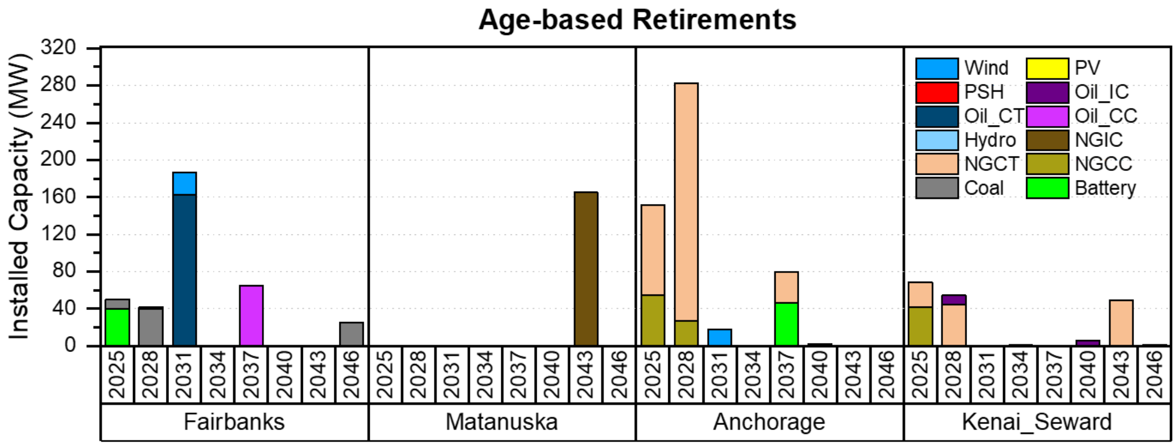


Figure 3-17 Age-based Retirements in Each Zone in the Carbon Price Scenario

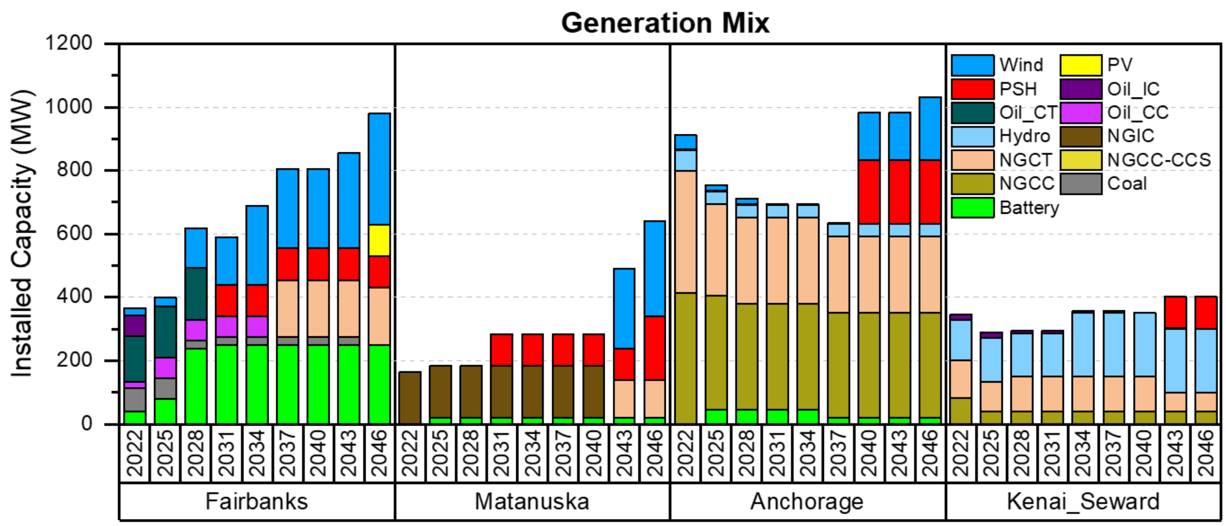


Figure 3-18 Generation Mix of Each Zone in the Carbon Price Scenario

3.4.3 RPS Scenario

The RPS scenario mandates that the system has enough VRE capacity to supply 80% of the total annual demand by 2040; however, the RPS constraint in A-LEAF does not require that 80% of system demand be supplied by VRE resources in each time interval within the year. In addition, the RPS requirements are enforced in each of the four zones independently. Figure 3-19 shows higher PRM levels compared with the reference case due to the increased investments in wind, PV, and battery resources.

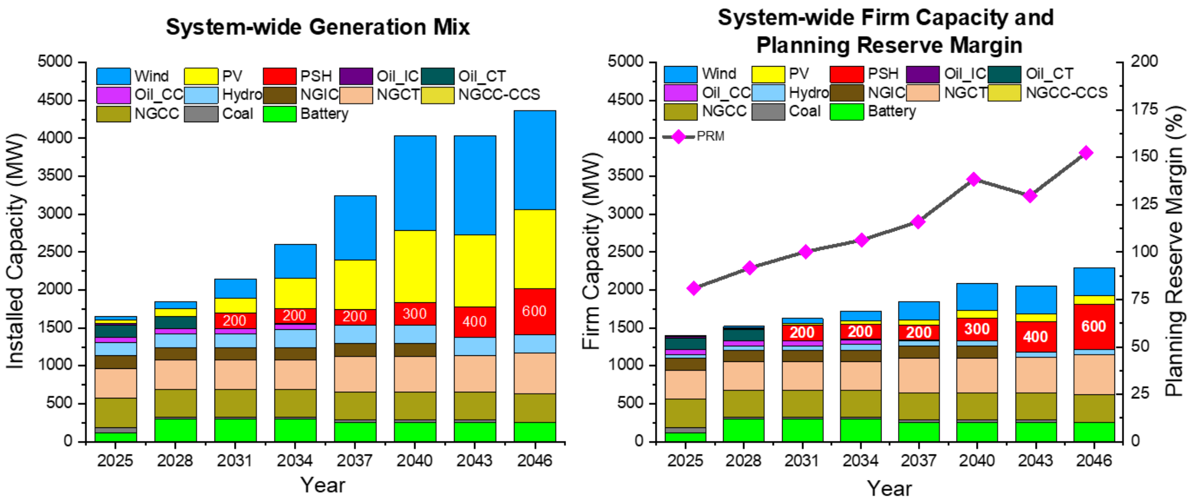


Figure 3-19 System-wide Generation Mix (left) and Firm Capacity with Planning Reserve Margin (right) in the RPS Scenario

The RPS scenario shows a rapid increase in PV and wind investments (Figures 3-20 and 3-21). The increased firm capacity of PV, wind, and battery resources effectively compensates for the retirement of thermal generators. In addition, the high penetration of VRE resources promotes increased investment in energy storage. However, because the earliest PSH service year is assumed to be 2030, battery investments are elevated in the early years, and PSH investments are deferred. The results show a total of 300 MW of PSH investments, including a 100-MW investment in 2031 in the Fairbanks zone, a 100-MW investment in 2043 in the Matanuska zone, and a 100-MW investment in 2031 in the Anchorage zone. Like the reference case, the Anchorage zone has the highest total system installed capacity among the zones, yet the Fairbanks and Matanuska zones also show an increased total system capacity in the RPS scenario, as shown in Figure 3-22.

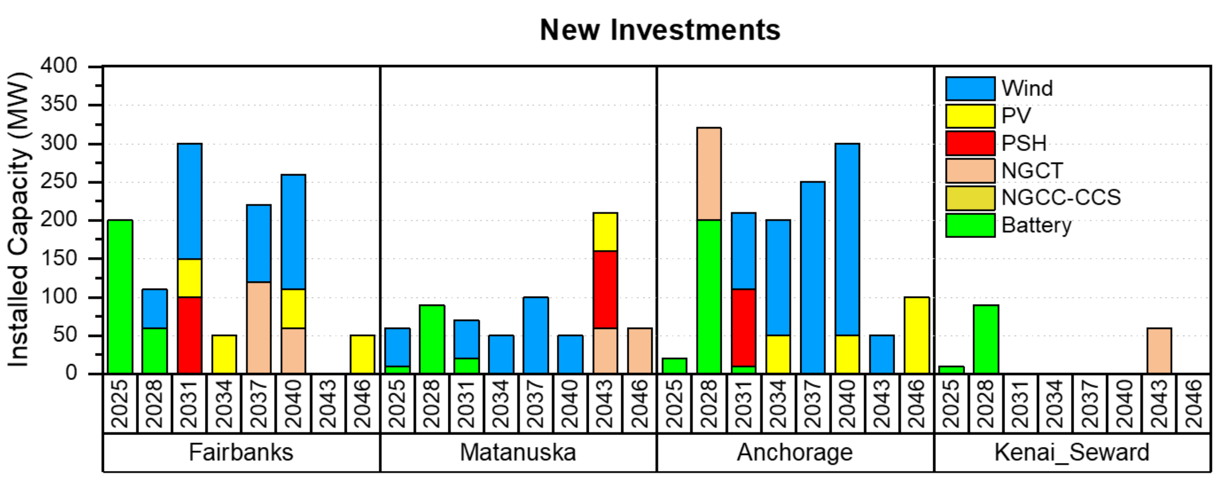


Figure 3-20 New Investments in Each Zone in the RPS Scenario

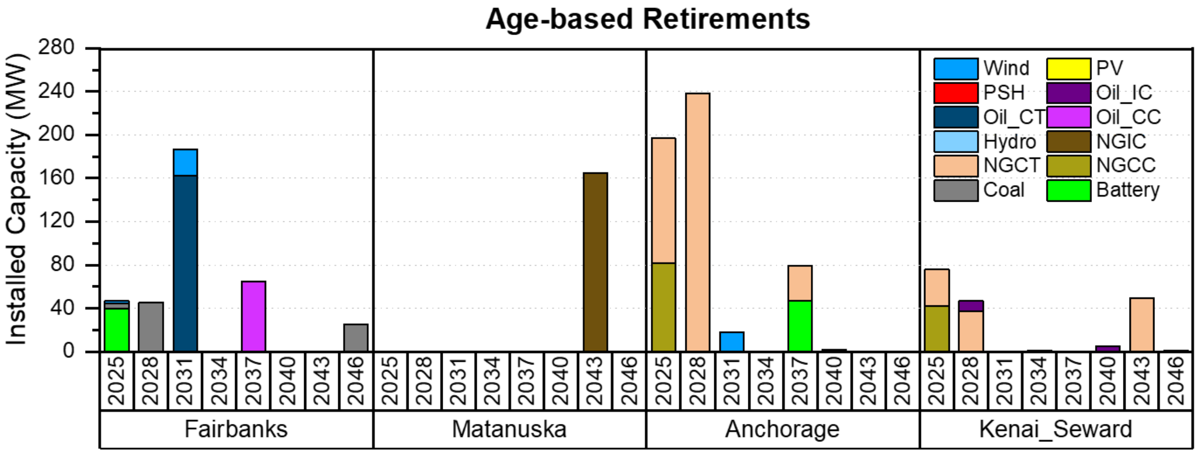


Figure 3-21 Age-based Retirements in Each Zone in the RPS Scenario

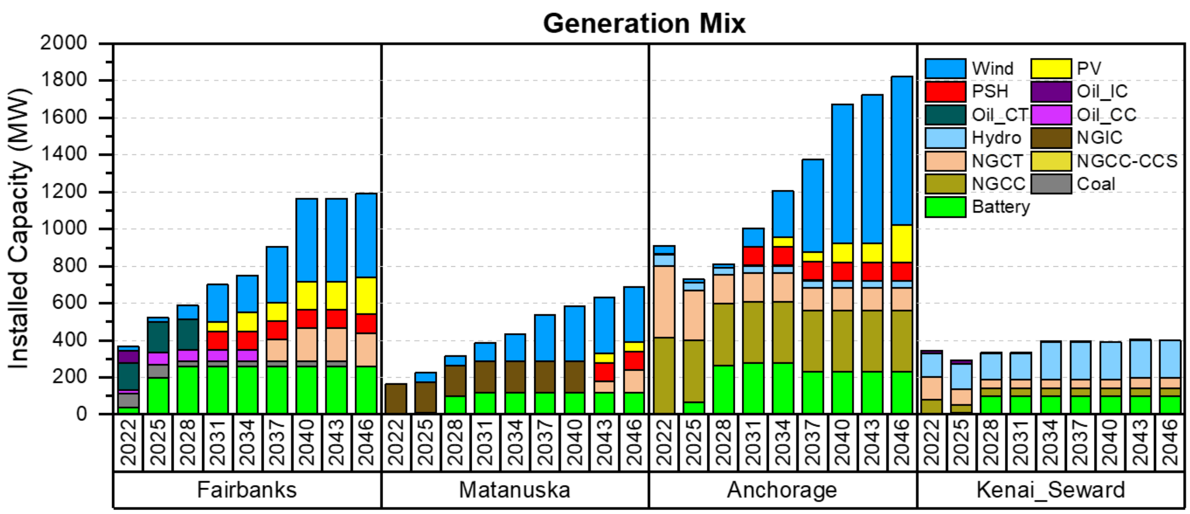


Figure 3-22 Generation Mix of Each Zone in the RPS Scenario

3.4.4 High-Transmission Scenario

The High-Transmission scenario has increased transfer capacity of the Alaska intertie that is often congested. The capacity of the Alaska intertie is assumed to be increased from 75 MW to 250 MW by 2040. The systemwide PRM levels over the planning horizon are similar to those in the reference case, as shown in Figure 3-23.

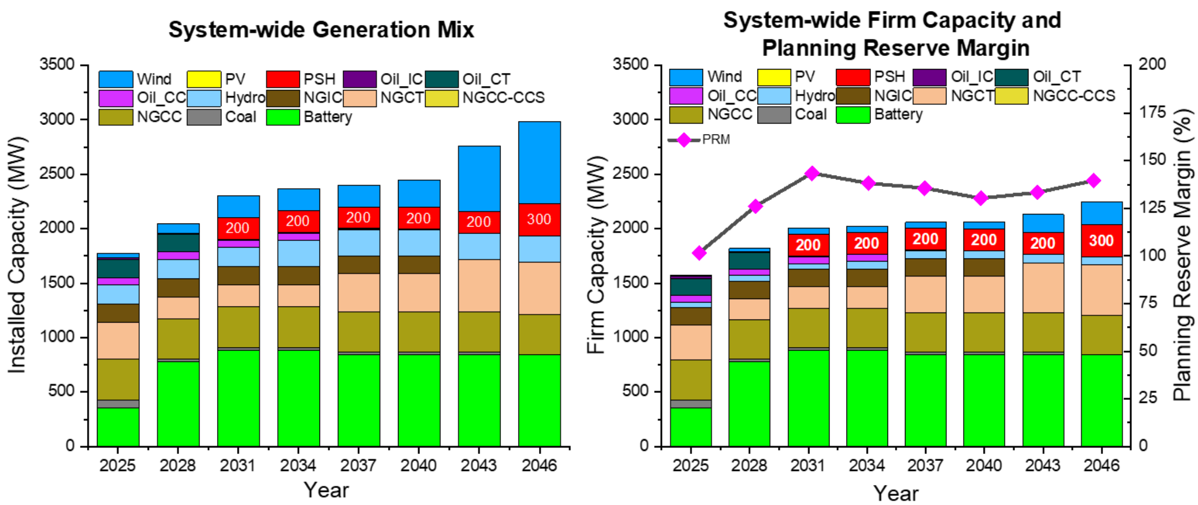


Figure 3-23 System-wide Generation Mix (Left) and Firm Capacity with Planning Reserve Margin (Right) in the High-Transmission Scenario

Like the reference case, the system has new thermal investments in the early years to cover the retired capacity of thermal resources (Figures 3-24 and 3-25). The High-Transmission scenario shows increased wind investments after the expansion of the Alaska intertie in 2040. In addition, the increased intertie capacity eliminates the need for wind and NG-CT investments in the Fairbanks zone in later years. The results show a total of 300 MW of PSH investments, including a 100-MW investment in 2031 in the Fairbanks and Matanuska zones and a 100-MW investment in 2046 in the Anchorage zone. The regional generation portfolio in Figure 3-26 shows that the Anchorage and Fairbanks zones have higher total system installed capacities than other zones.

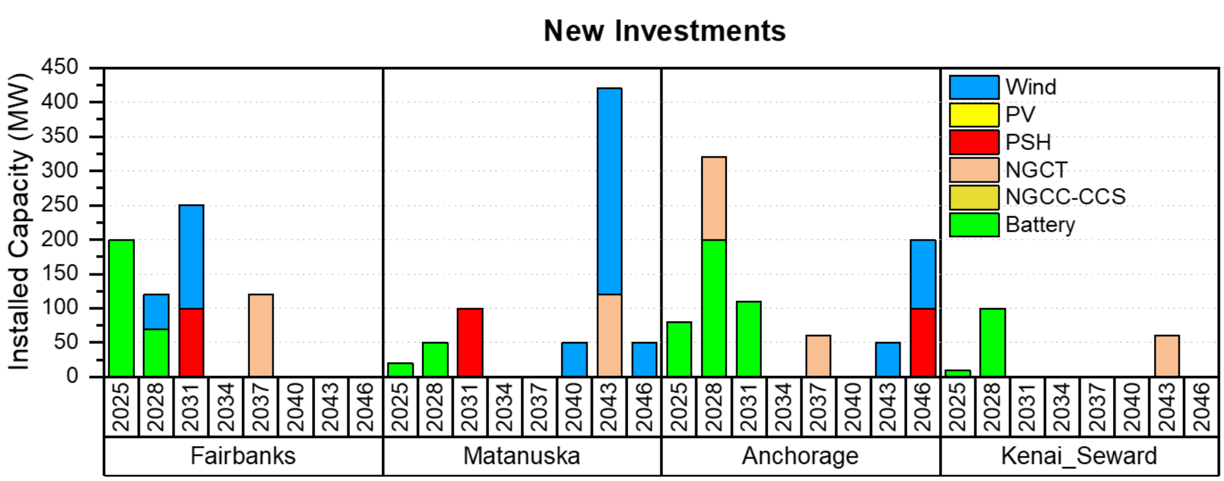


Figure 3-24 New Investments in Each Zone in the High-Transmission Scenario

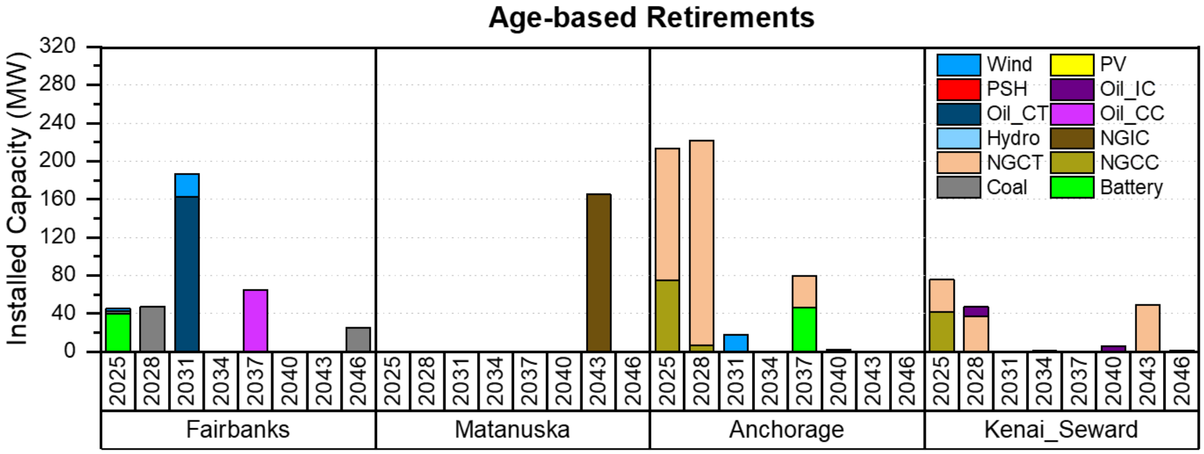


Figure 3-25 Age-based Retirements in Each Zone in the High-Transmission Scenario

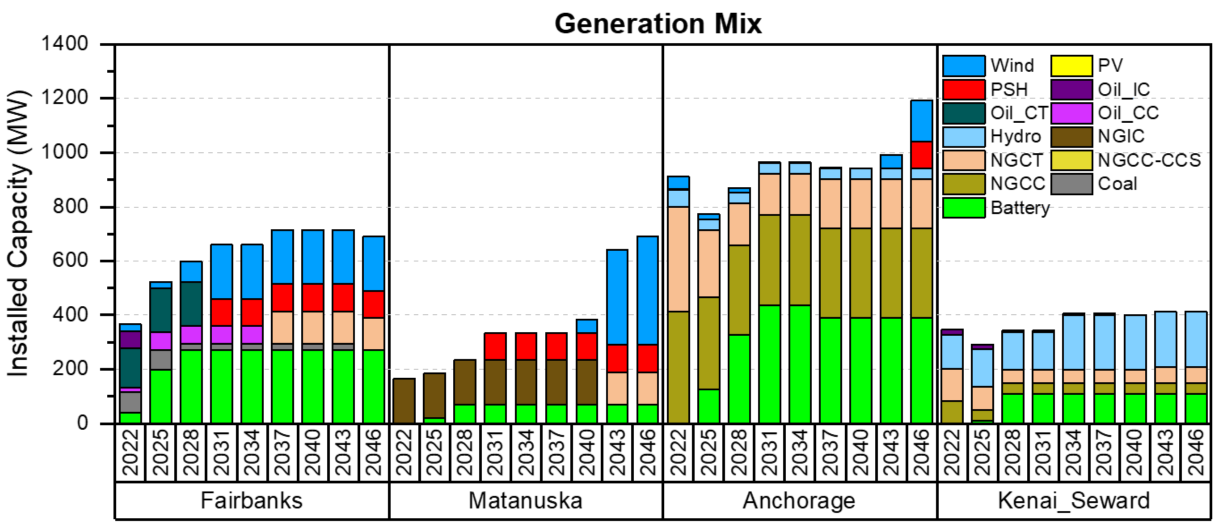


Figure 3-26 Generation Mix of Each Zone in the High-Transmission Scenario

3.4.5 High-Load Scenario

The High-Load scenario has an additional 10% peak load increase over the reference case; the only difference between the High-Load scenario and the reference case is the rate of load increase over the planning horizon. As expected, the results, presented in Figure 3-27, show additional capacity investments to meet the increased load.

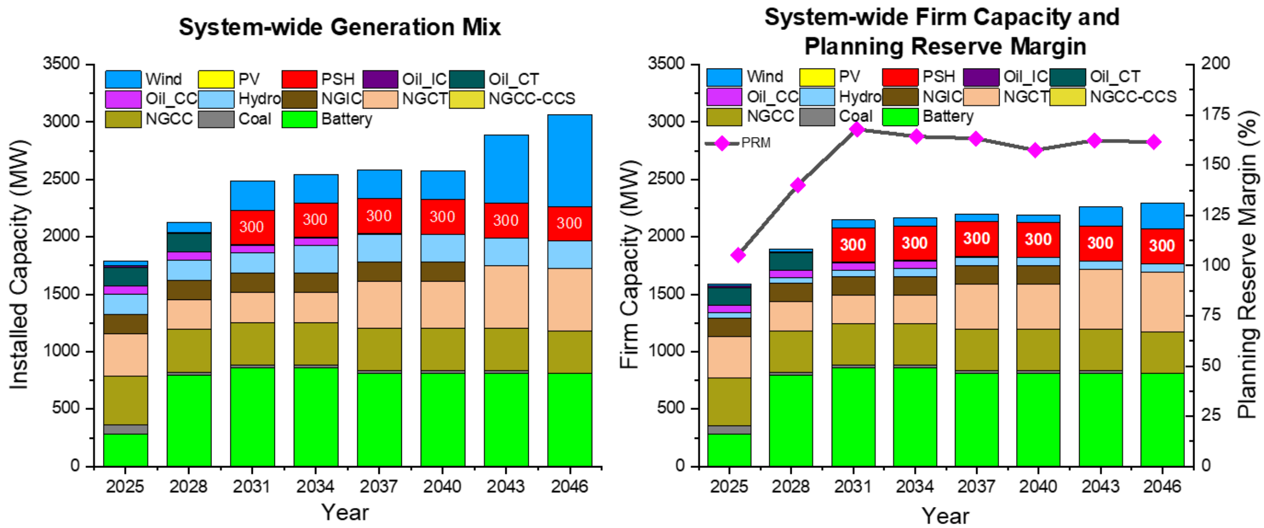


Figure 3-27 System-wide Generation Mix (left) and Firm Capacity with Planning Reserve Margin (right) in the High-Load Scenario

As in the reference case, the High-Load scenario demonstrates investments in battery, NG-CT, wind, and PSH in the early stages to compensate for reduced thermal capacity due to age-based retirements (Figures 3-28 and 3-29). In addition, the increased load levels are met by additional wind and battery investments. The early increase in battery investments leads to fewer PSH investments compared with the reference case. The system has 100-MW PSH investments planned for 2031 in both the Fairbanks and Anchorage zones. The results obtained for generation mix in each zone in the High-Load scenario are shown in Figure 3-30.

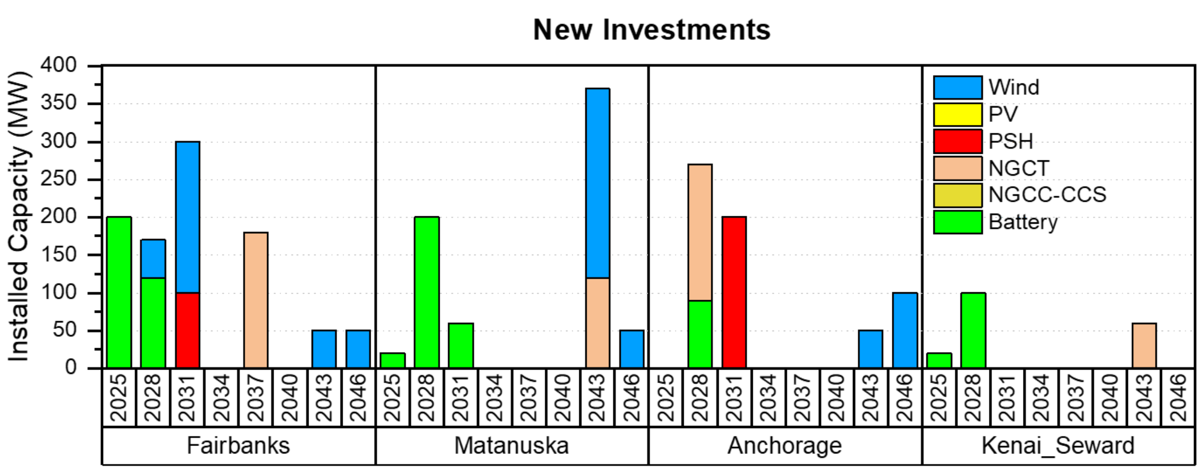


Figure 3-28 New Investments in Each Zone in the High-Load Scenario

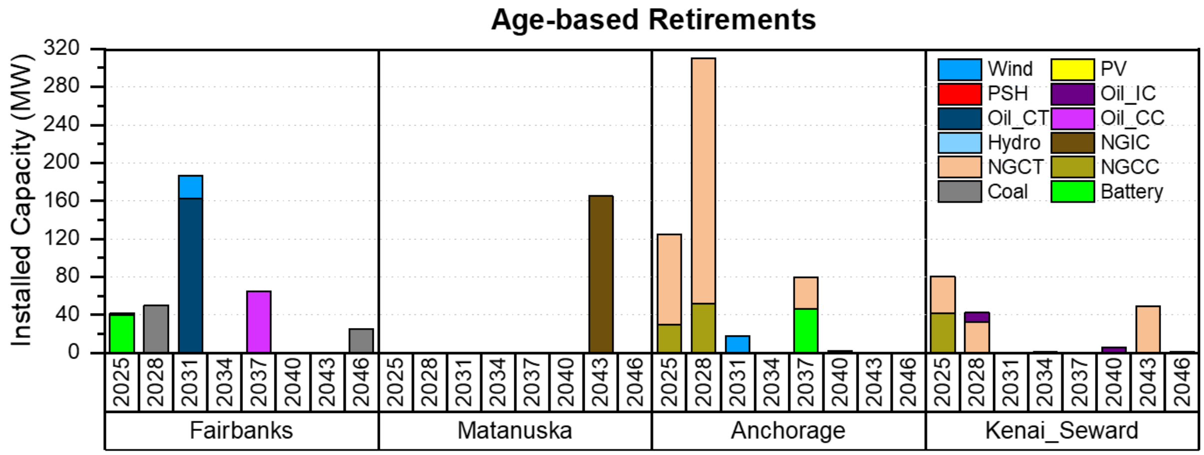


Figure 3-29 Age-based Retirements in Each Zone in the High-Load Scenario

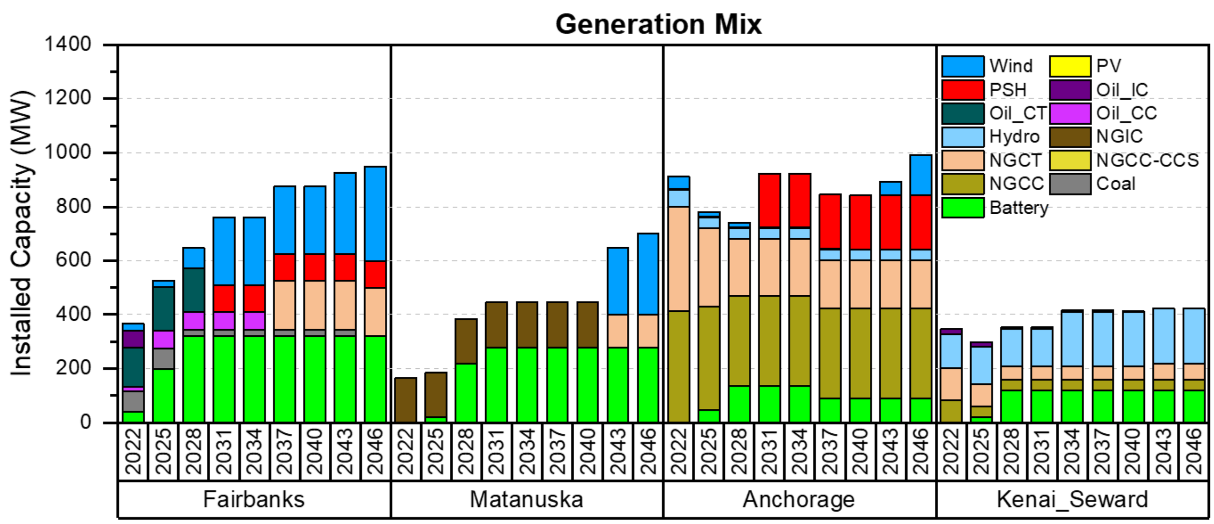


Figure 3-30 Generation Mix of Each Zone in the High-Load Scenario

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4.0 Remote Communities Analysis

Most communities in Alaska are not served by the interconnected Railbelt transmission system and are isolated from urban centers. Approximately 200 stand-alone grids serve remote Alaskan villages, where the cost of electricity can be up to four times the cost for grid-connected communities because of the reliance on diesel generation and the cost to transport diesel fuel to remote locations (Riley et al., 2016). In addition to the high cost of energy, disruptions in the diesel supply chain can have significant impacts on communities and often result in emergency situations (e.g., homes and buildings cannot be heated, or communities are forced to pay exorbitant fees for alternative shipping options). To help overcome these challenges, some Alaskan communities have turned to microgrids that use renewable energy and energy storage technologies to reduce their reliance on diesel generators.

As the energy storage sector continues to undergo changes in technologies and costs, evaluating which technologies are most economically feasible for remote Alaskan communities can help overcome energy barriers and support successful renewable energy projects. A recent inventory of renewable and energy storage projects in Alaska estimates approximately 10 MW of installed storage capacity in 14 remote communities (Renewable Energy Alaska Project, 2021). The storage technology type is predominantly lithium-ion batteries, with a few lead-acid and flywheel installations. However, lithium-ion battery storage comes with challenges, including cost, temperature control, and O&M needs within the communities, as well as community concerns with disposal after useful life.

PSH can fill a unique role in the Alaskan energy market. As communities look to further reduce diesel usage through additional renewables and meet growing electrification demands, longer-duration storage becomes more critical. Daylight shortages in Alaska also create a need for longer-duration storage (i.e., 8-12 hours or more) to cover nighttime loads.

PSH has several additional advantages as an energy storage technology. Typically, the lifespan of PSH systems can be 50 years or more without significant degradation of performance, and systems are often designed for 80 or more years of operation. However, there are also challenges including high installation costs, lengthy permitting cycles, and operational challenges in cold climates due to icing.

This portion of the project seeks to address energy storage challenges in Alaska's remote communities by assessing the technical and economic feasibility of small-scale PSH technologies. The objective is to assess the costs effectiveness of distributed (<1MW) PSH technologies for remote communities with potential PSH resources and accompanying variable renewable energy resources that require energy storage. The project team completed the following tasks to meet this project objective:

- Performed analysis and filtering of remote communities where PSH is technically feasible.

- Evaluated PSH technology options suitable for remote communities.

- Performed economic analysis for a representative community to analyze economic viability for PSH.

- Validated technical assumptions and evaluated community readiness through outreach to 1–2 remote communities.

We intend for the results of the project to allow communities with potential PSH resources to determine whether a more in-depth and site-specific assessment for PSH project development is warranted.

4.1 Filtering of PSH Potential for Remote Communities

The technical approach for assessing the PSH potential in Alaska's non-Railbelt communities involved identifying communities with PSH reservoir potential, selecting communities that have characteristics conducive to PSH where it will contribute to lower project costs, collecting data, and conducting technoeconomic modeling and analysis using HOMER software for remote Alaska communities.

As described in Section 2.0, the project team used a global data set adapted for U.S.-specific development criteria to identify communities with PSH potential. Using the data set, the team conducted a topographic-based GIS analysis to identify potential PSH reservoir locations. We then identified locations where potential reservoirs could be paired, to represent the upper and lower reservoirs for PSH, using spatial analysis. The GIS analysis identified 280 remote and Railbelt communities that have PSH reservoir potential.

The project team applied a filtering process to the results of the GIS analysis to identify communities with optimal characteristics for an economically feasible PSH project. The results of the filtering process are intended to identify communities where PSH projects will have a greater likelihood of being cost effective. The objective of the filtering process was to provide informed insight about a community's PSH potential to enable community stakeholders to evaluate energy storage options. However, it is important to note that any community with an identified potential PSH resource would still require a detailed, site-specific evaluation to determine whether PSH technology would be technically and economically feasible in their location.

The filtering characteristics were identified based on feedback from stakeholders in Alaska, small- and large-scale hydropower developers, and Alaska power providers. The following filtering characteristics were applied in the analysis to identify communities with the highest potential for technically and economically feasible PSH opportunities:

- Non-Railbelt community—Railbelt communities connected to a centralized power system were removed for this portion of the study, which focused on remote communities.

- Penstock[2] length ÷ head height = <12 (Electric Power Research Institute [EPRI], 1990).

- Head[3] height greater than 100 m and two times greater than the upper and lower reservoir dam height.[4]

- Population greater than 250—According to Alaska developers, communities with populations below 250 will likely face additional capacity and economic challenges.

- No wetland areas—Communities and potential project sites located within federally recognized wetland areas would introduce additional permitting and logistical challenges, increasing the costs of PSH and decreasing the probability of a cost-effective project. These sites would need further evaluation for PSH economic feasibility.

Figure 4-1 provides an overview of the filtering process and the number of communities that qualify under each filtering characteristic.

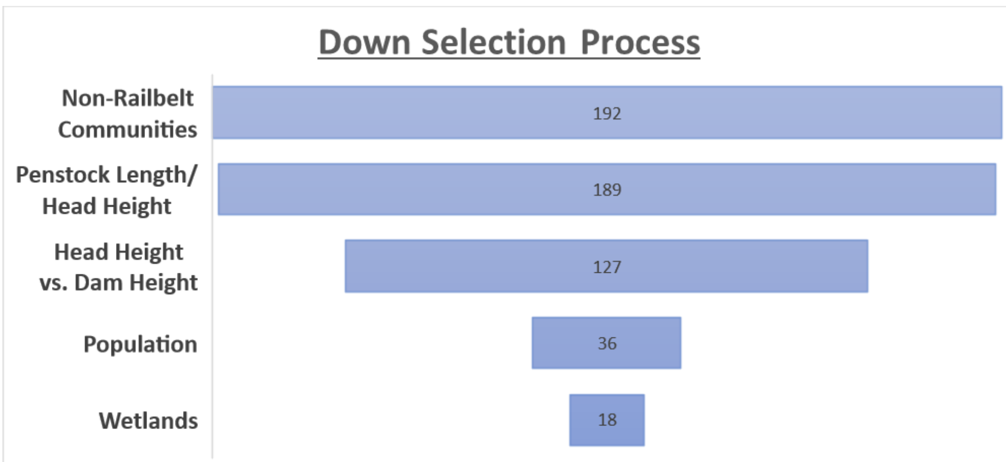

Figure 4-1 Filtering Process and Number of Communities that Qualify under Each Criterion

4.1.1 Community PSH Potential Based on Filtering Results

This section provides the results of the filtering process with maps identifying the communities that remain after each criterion. Lists of the communities that qualify under different criteria can also be found in Appendix A: Rural Community PSH Potential Filtering Results. This information is intended to help inform communities of their PSH potential and provide insight into the cost-effectiveness of developing a PSH project in that community. Section 4.2.4 provides a more detailed assessment of the technoeconomic feasibility of PSH by modeling and analyzing PSH systems for remote communities.

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2 Structure, such as a pipe or channel, that carries water from the dam to the turbines.

3 The vertical distance that water falls in a hydropower system.

4 Physical limitation to restrict the head variation at the turbine to less than 50% of the design head.

In total, 280 remote and Railbelt communities had hydropower reservoir potential based on topographic-based GIS analysis. After omitting the Railbelt communities, a total of 192 remote communities with PSH reservoir potential remained (Figure 4-2).

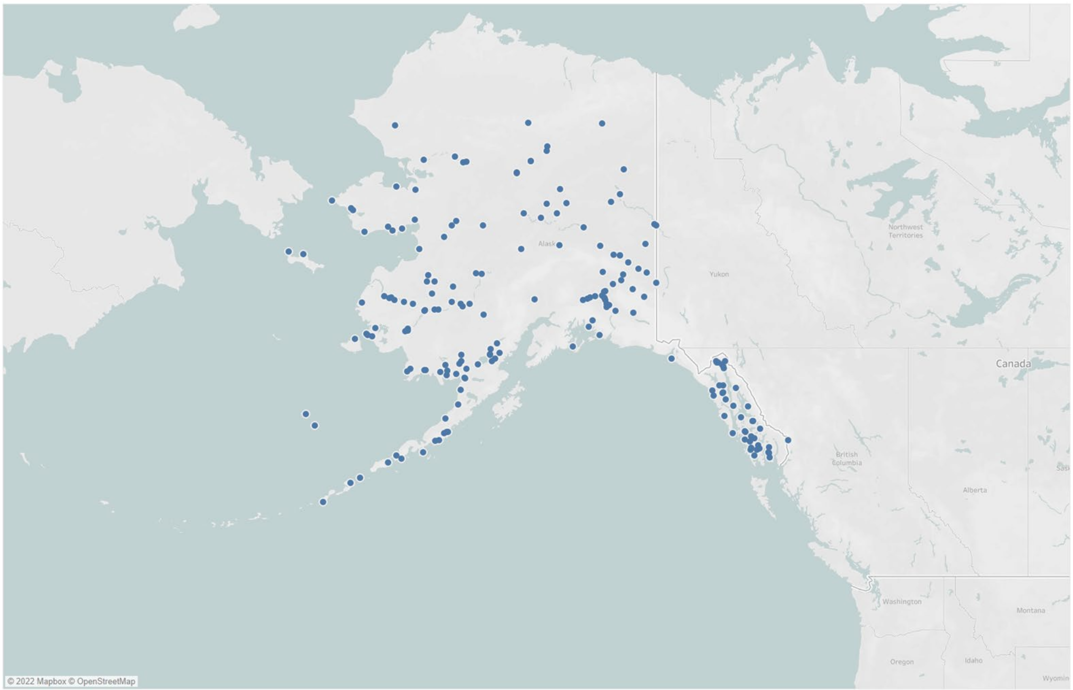

Figure 4-2 Remote Communities with PSH Reservoir Potential Based on Topographic-based GIS Data

Based on the GIS analysis, all 192 remote communities have technical potential for PSH, but further evaluation was needed to determine whether the PSH would be economically feasible in each community. To determine the threshold for both technically and economically feasible PSH opportunities in remote communities, the team applied the filtering process to identify communities that would have optimal PSH resources and characteristics, resulting in a higher likelihood of identifying cost-effective opportunities.

Using the topographic-based GIS data, we determined the head height of the reservoir, as well as the potential penstock lengths, based on the distance of the identified potential reservoir location from the community center. Only communities with potential head heights of 100 m or more, a reflection of potential power generation, were considered. For communities with a potential head height of 100 m or more, we applied a simple equation using the penstock length and head height data points:

$$\textit{Penstock Length} \div \textit{Head Height} = <12 \tag{4}$$

Based on meetings with small-hydro developers and the EPRI *Pumped-Storage Planning and Evaluation Guide* (EPRI, 1990), if the resulting number is less than 12, the PSH potential would have higher cost-effective power production. After applying this filter, four communities were omitted, leaving 189 communities (Figure 4-3).

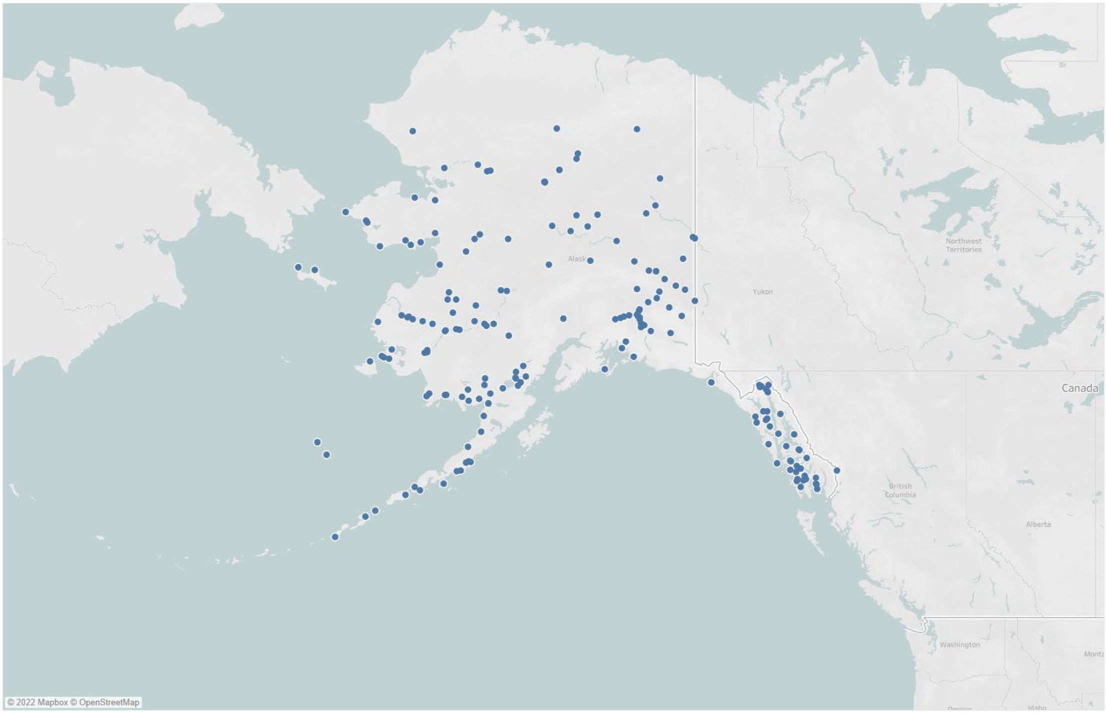

Figure 4-3 Remote Communities with an Optimal Penstock Length-to-Head Height Ratio for Small Hydro Development

The third set of filtering criteria we applied compared the head height to the dam height of both the upper and lower reservoirs. To maintain adequate head on a turbine, the reduction in head through the generation cycle needs to be minimized. Assuming the site is designed for the generation cycle to empty and refill each reservoir, the head height (measured as the vertical distance between the crest of the upper and lower reservoirs) must be greater than twice the upper and lower reservoir dam heights. This restriction limits the variation in head from 100% to 50%, which is generally the acceptable variation in head for a pump turbine.

$$\textit{Head Height} > 2x\ (\textit{Upper Reservoir Dam Height} + \textit{Lower Reservoir Dam Height}) \qquad (5)$$

After we applied this filtering criteria, a total of 127 remote communities remained (Figure 4-4).

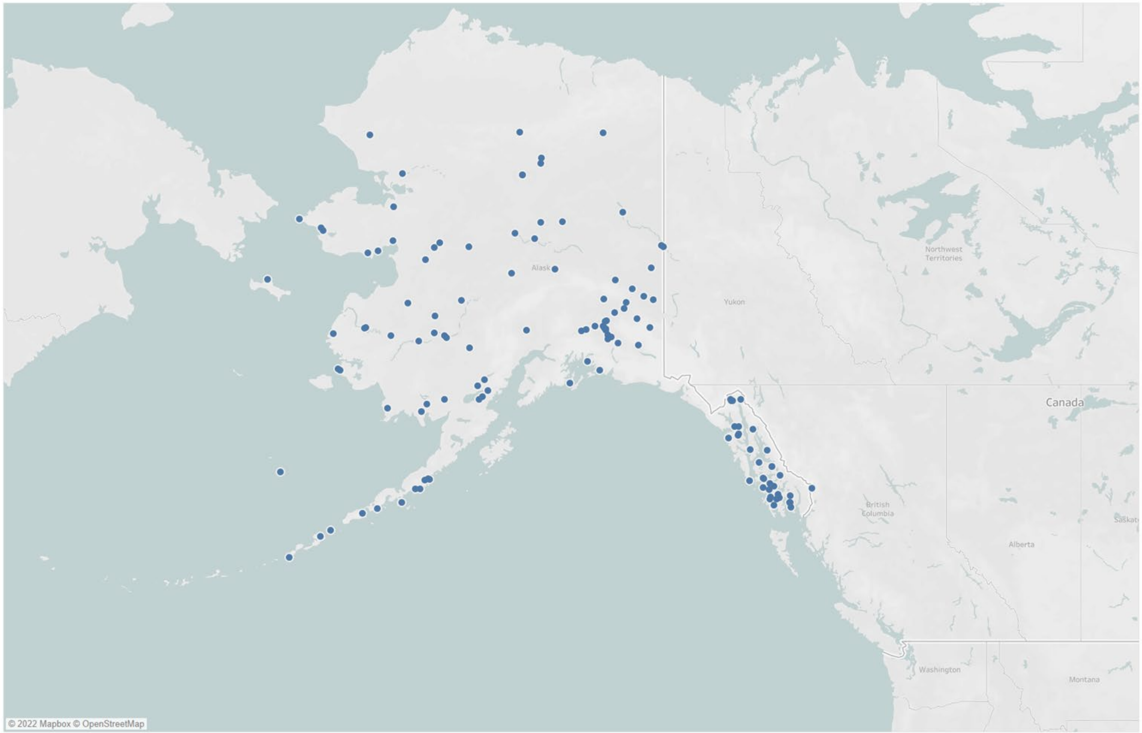

Figure 4-4 Communities with Potential PSH Reservoirs with Cost-effective Head Height

Based on conversations with stakeholders and developers in Alaska, including the Alaska Native Tribal Health Consortium and the Advisory Group, the team applied a population filter. Communities with populations below 250 would have lower power demands, and a high-capital-cost technology like PSH would to be unlikely to be cost-effective. To confirm this assumption, further evaluation at the individual community level would be needed.

Of the remaining 127 remote communities, only 36 had populations of 250 or more (Figure 4-5).

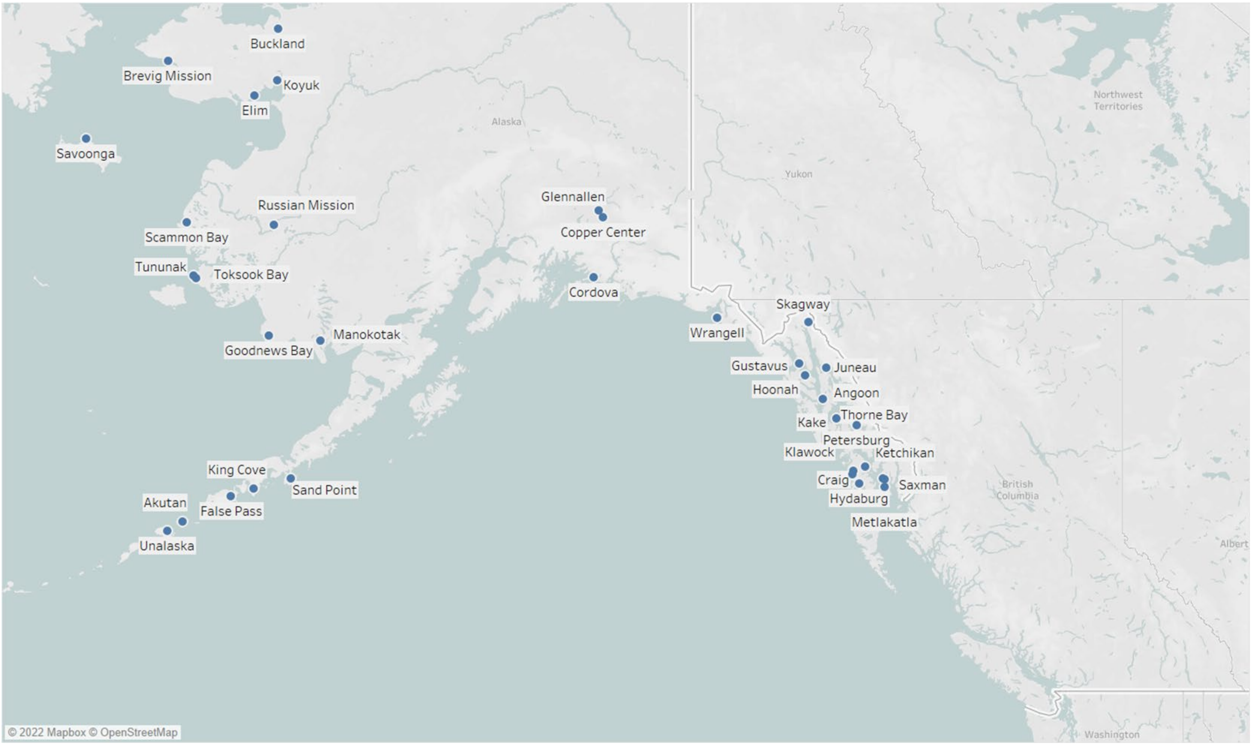

Figure 4-5 PSH Potential Communities with Populations of 250 or Greater

The final filter applied eliminated remote communities whose PSH potential resource was located within federally designated wetland areas. While this project did not attempt to quantify the costs of developing PSH in wetland areas, we assume that such development may result in additional permitting and logistical challenges, increasing the costs of PSH. After filtering out remote communities with potential PSH resources located within wetlands, 18 communities remained (Figure 4-6).

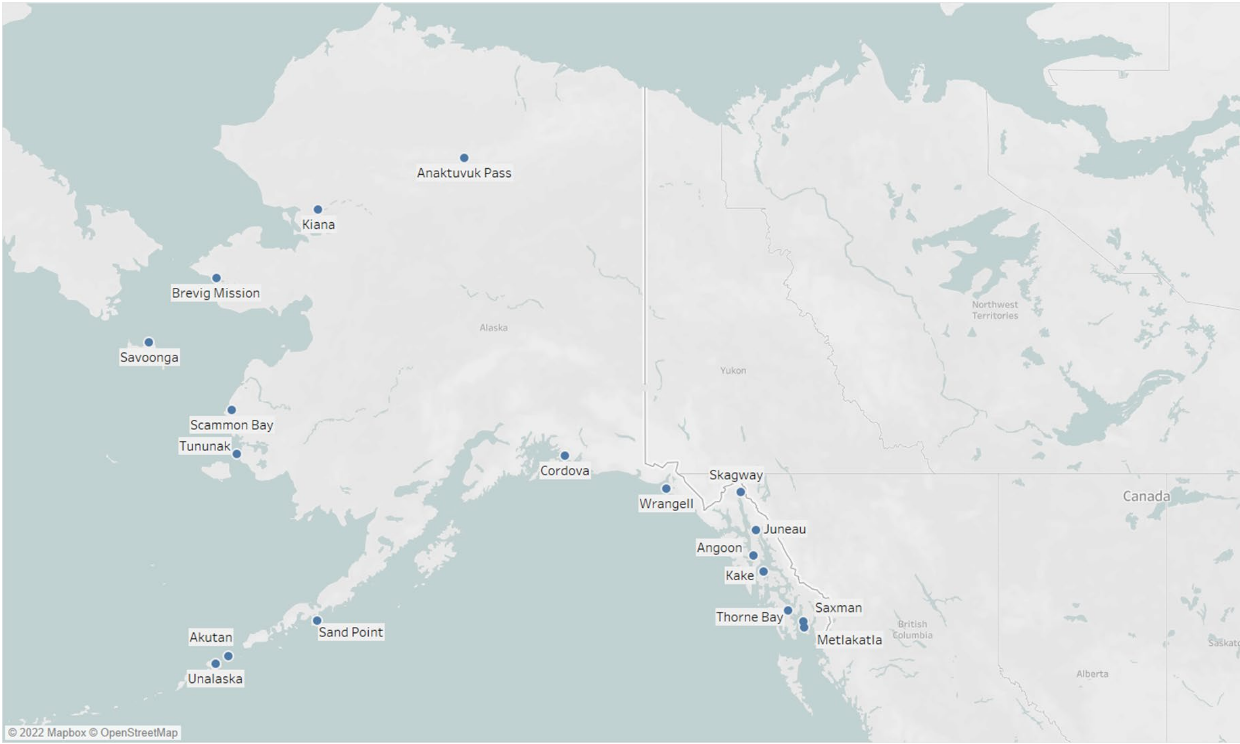

Figure 4-6 Remote Communities that Meet All Filtering Characteristics and Are Not Located in Wetland Areas

4.2 PSH Technology Options for Remote Communities

Roughly one in eleven Alaskans lives in remote areas, with a third living in the regional centers of Barrow, Bethel, Dillingham, Kotzebue, and Nome—towns with populations in the thousands—and the rest living in nearly 150 small communities with average populations of fewer than 300 (Goldsmith, 2008). These small, remote communities primarily have small energy loads (less than 1 MW). While most PSH technologies are designed and implemented to meet energy demands over 1 MW, several can be customized to meet the smaller energy loads in remote Alaskan communities.

The following section provides an overview of some of these system designs and commercially available and emerging technologies.

4.2.1 System Design

There are generally two types of PSH system designs: open-loop or closed-loop (Figure 4-7). An open-loop system has a continuous source of downstream water that is pumped uphill to an upper storage reservoir. In an open-loop system, the reservoirs can be naturally occurring lakes or manmade reservoirs. By contrast, closed-loop systems pump water from a lower storage reservoir, which is not continuously filled with water and is generally not connected to a flowing source. Closed-loop projects generally affect the environment on a more localized level and for a shorter duration than open-loop systems because of their location "off-stream." Therefore, closed-loop projects likely have greater siting flexibility than open-loop projects. To further increase siting flexibility, fabricated tanks can be used for the upper or lower reservoirs in place of open reservoirs that take advantage of the natural landscape. The use of storage tanks can increase siting options, reduce permitting challenges, and potentially reduce project costs.

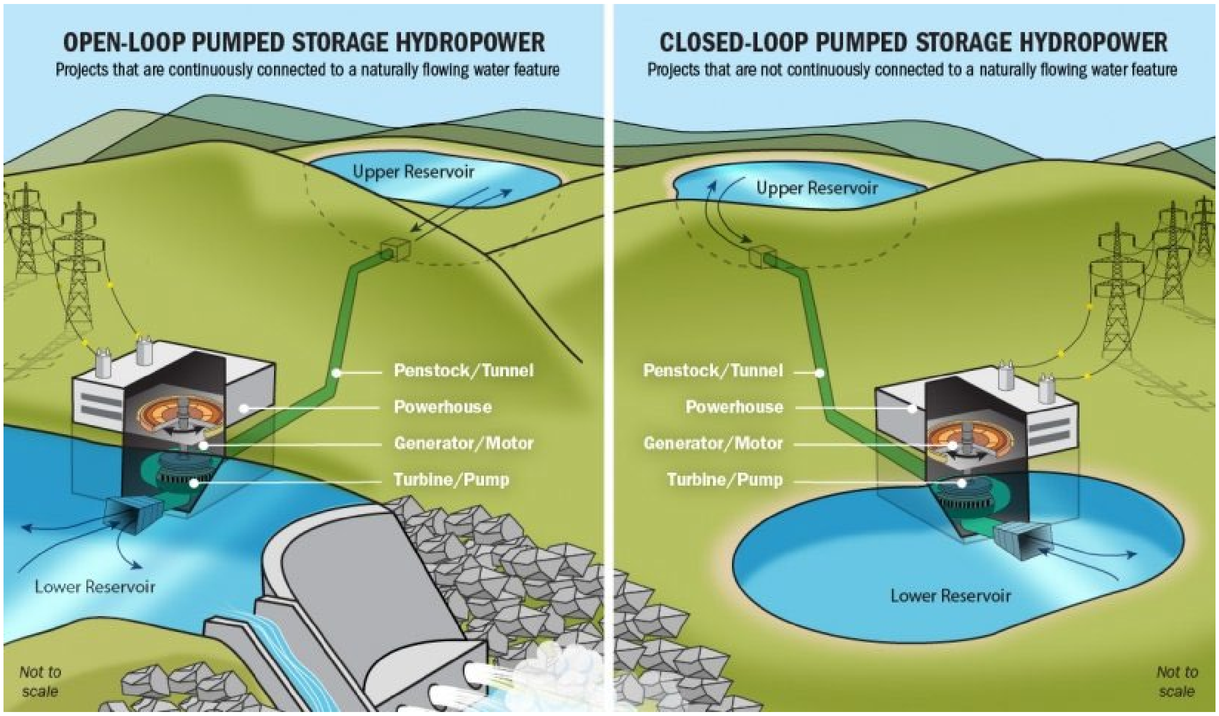

Figure 4-7 Illustration of Open-loop and Closed-loop PSH Systems (Source: DOE, undated)

For a small-scale PSH projects, a common approach is to install independent pump and generator sets, rather than customized, reversible pump-turbines. Such sets allow systems operators to use off-the-shelf components and scale them by increasing or decreasing the number of sets installed to reduce equipment costs. Scaling the size and number of pump and generator sets can also allow for greater control of the rate of pumping into the upper reservoir.

Certain conventional hydroelectric plants can be converted to pumped storage plants, known as pump-back PSH plants. This conversion adds separate pumps or reversible turbines to allow water to be moved from a lower reservoir back to an upper reservoir. Water can be pumped back during periods of low energy demand when excess energy from wind and/or solar generation is available. This approach reduces the need for curtailment of variable wind/solar generation and can conserve water in the upper reservoir, which can be important during dry seasons or periods of high energy demand and when there is not much wind/solar energy available.

4.2.2 Permafrost and Freezing

In Alaska, permafrost and freezing are two environmental conditions that should be assessed during the conceptual and design phases of PSH development. Permafrost, defined as any soil or rock that remains at or below 0°C/32°F for two or more consecutive years and may or may not contain ground ice (Denali Commission, 2019), can provide a stable surface while it is frozen. However, when permafrost thaws, it can cause surface areas to shift and move. Repeated thawing and freezing further exacerbates the movement. Thawing permafrost could result in damage to infrastructure, such as PSH penstocks, reservoir tanks, and transmission systems. It is possible to mitigate some impacts from permafrost thawing with measures that will also increase project costs. Some mitigation measures may include placing penstocks above ground on support structures designed to shift with shifting permafrost and placing reservoir tanks on adjustable surface slabs. Because of the impacts of thawing permafrost, efforts to avoid permafrost areas should be made when possible. For projects that cannot avoid siting in permafrost areas, mitigation measures and their associated costs should be included in the system design.

Communities where temperatures consistently fall below 0°C/32°F for consecutive days will need to consider the impacts of frozen water on a PSH system. Frozen water can impact dams from expansion; block spillways, intakes, and penstocks; and reduce the amount of free-flowing water available for power generation. Standard PSH systems can operate in environments where occasional freezing occurs but will experience reductions in energy production. Locations that experience long periods of below-freezing temperatures will likely need to implement design measures to allow the PSH system to continue to operate and mitigate damage to infrastructure. Numerous mitigation methods have been used to mitigate the impacts of frozen water on hydro systems, and each will need to be considered and evaluated based on location, budget, and energy needs, among other factors. Mitigation measures will typically increase the project cost and should be accounted for in budgeting. It is essential to assess the risk from frozen water during the conceptual and design phases, estimate the impact on the PSH system, and evaluate the inclusion of mitigation measures (Gebre, 2013).

4.2.3 Existing and Emerging Technologies

Multiple existing and emerging technologies are available that can be used for small-scale PSH systems. Traditional hydropower systems have large upfront capital costs that often deter small hydropower development. To help reduce costs, technologies that use standardized, modular hydropower systems are being developed and implemented. Modular hydropower and modular pumped storage hydropower (m-PSH) seek to reduce costs by standardizing the design, manufacturing, construction, and operation, while also reducing the environmental impacts and site requirements. For Alaska applications, the availability of small, transportable modular systems would help address the high construction and transportation costs that communities throughout Alaska experience.

The sections below provide brief summaries of some of the technologies that could be used in remote, small-scale applications. The information presented here, and additional information on other pumped storage hydropower technologies, can be found in the DOE-sponsored 2022 Argonne report, *A Review of Technology Innovations for Pumped Storage Hydropower* (Koritarov et al., 2022).

4.2.3.1 ***Shell Energy North America Hydro Battery System***

The proposed Shell Energy North America (SENA) Hydro Battery is a small m-PSH concept that uses storage tanks and floating membrane reservoirs and can be configured as a closed-loop or open-loop system (Figure 4-8). Power capacity is similarly scalable with independent pump and generator sets. The reference configuration (Hydro Battery Pearl Hill) would be capable of generating up to 5 MW of power while pumping at up to 9 MW.

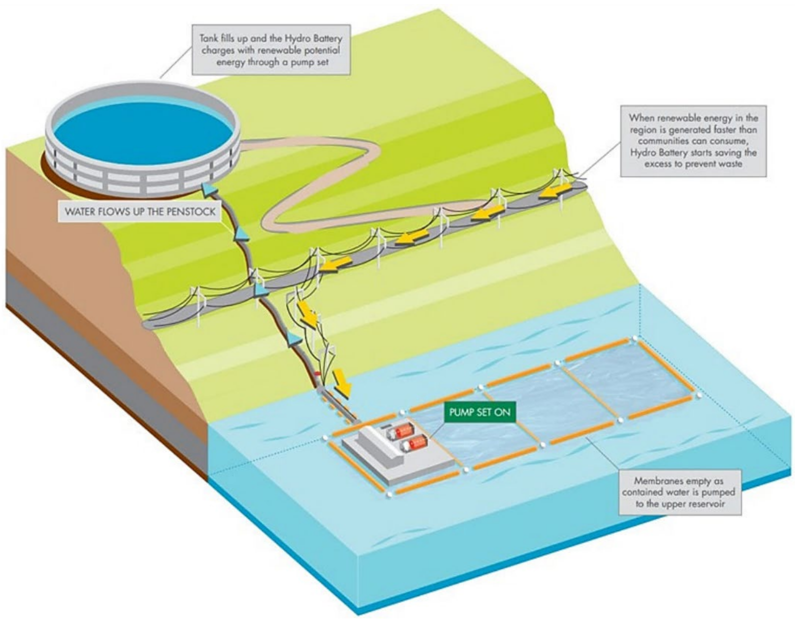

Figure 4-8 SENA PSH Rendering (Source: Balducci et al., 2018)

The SENA Hydro Battery has four operating modes:

1. Pumping Mode—Water is pumped from the lower reservoir to the upper reservoir using five water pumps located at the lower reservoir. Each pump has its own discharge valve and recycle control valve. During tank filling, a platform isolation valve and tank isolation valve are open. Water continues to fill the tank until either a stop command is issued, or a high-water level is reached. When pumping, a fish screen motor slowly moves to keep the screen free from debris. Initial filling of the penstock is done locally by operating the pumps using the local hand-off-auto switches and manipulating the pump discharge and recycle valves manually.

2. Generating Mode—In the generating mode, water flows from the upper reservoir through the penstock to spin the turbine generator. The turbine control system keeps the generated power in sync with the local electrical system, and power is exported onto the 25-kV grid through the power module. The amount of power output by the generator is controlled by a manual set point sent from programmable logic controller (PLC)-A to the generator PLC located in the generator module.

3. Spinning Mode—In spinning mode, the turbine inlet valve remains open, but the water jet nozzles remain closed. The turbine runner spins freely while the generator is synchronized to the grid and rotates using power from the utility system to overcome friction and resistance.

4. Standby Mode—When not operating in either generating or spinning mode, the pump discharge valves and turbine inlet valves are closed while manual penstock isolation valves remain open.

4.2.3.2 *Absaroka Energy Modular Pumped Storage*

Absaroka Energy has implemented m-PSH systems using a simple and inexpensive foundation and fabricated tanks for water storage (Figure 4-9). To date, the facilities Absaroka has developed are between 5 and 50 MW with an 8- to 24-hour storage capacity (Absaroka Energy LLC, 2020). In most cases, the pumphouse and penstock are partially or fully underground. The minimal footprint and standardized approach may help reduce costs for implementation in remote Alaska communities and allow implementation of PSH where it is not feasible for traditional PSH systems.

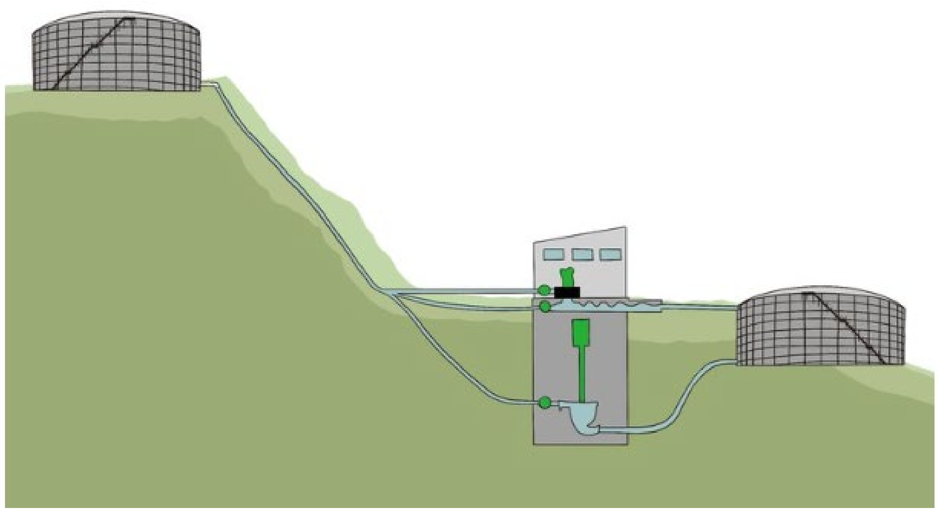

Figure 4-9 Modular Pumped Storage Hydro (Source: Absaroka Energy LLC, 2020)

4.2.3.3 *PSH Using Submersible Pump-Turbines and Motor-Generators*

Obermeyer Hydro, Inc. worked with NREL, with support from DOE, on the development of a cost-effective, small-scale pumped storage configuration using submersible pump-turbines and motor-generators (Obermeyer Hydro, Inc., 2018). While conventional PSH plants typically use reversible pump-turbines that are submerged in water and non-submerged motor-generators above them in the powerhouse, this technology proposes that both pump-turbine and motor-generator be submerged in a vertical shaft (or “well”), thus avoiding the need for construction of an elaborate underground powerhouse.

This technology, illustrated in Figure 4-10, has the potential to reduce the costs and time for construction of new PSH plants because it eliminates the need for an underground powerhouse. Instead, it requires construction of straight vertical wells to house the pump-turbine and motor-generator for each generating unit. The machines can be lowered into the well or raised up for inspection and maintenance by using auxiliary water pressure acting on a hoisting piston below each machine.

Because of the small footprint and minimal civil works required for the construction of wells to house generating units, this technology may also be applicable for the development of pumped storage capabilities at existing hydropower plants, as well as for applications at non-power dams. Obermeyer Hydro is currently developing a prototype unit to confirm the simulation results obtained for the operation and efficiency of reversible pump-turbine with flow inverter.

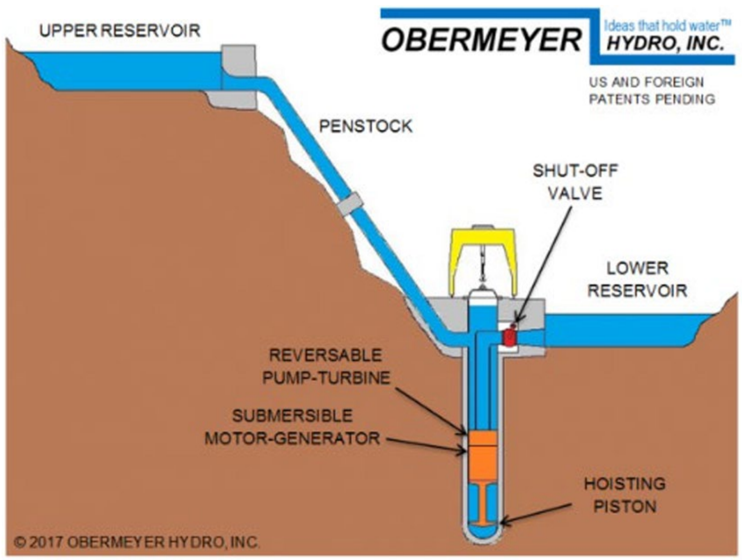

Figure 4-10 Cross-Section of PSH Plant Using Submerged Pump Turbine and Motor Generator (Source: Koritarov et al. 2022)

4.2.3.4 *Use of Existing Mines*

The use of existing mines is an extremely attractive m-PSH development opportunity, because many sites have paired reservoirs with a substantial elevation differential, existing transmission lines, and have no immediately identifiable repurposed use. Standard dimensions are used for mine shafts, meaning a modular approach to water conveyance system design and construction could be employed. If the site can be classified as closed-loop, environmental and regulatory requirements may be significantly less burdensome, shortcutting the critical path to project viability. As of 2011, a quarter of Federal Energy Regulatory Commission (FERC)-issued preliminary permits for large-scale PSH were for projects that included an underground cavern as a lower reservoir (Yang and Jackson, 2011). The novelty of this m-PSH opportunity is in the cost reduction, implementation time predictability, and risk reduction achieved through modularization of components designed for a standard installation (Witt et al., 2015).

4.2.3.5 *Seawater Capture*

For coastal locations, it is possible to use seawater as the resource for the PSH. In the most common application, water would be pumped from the ocean to an upper reservoir, reducing the need for a lower reservoir. However, the use of seawater increases corrosion within the system and requires an upper reservoir that would prohibit leaking. Leakage of seawater from the upper reservoir could result in contamination of the environment and freshwater resources. Because of these risks, increased design requirements and costs should be evaluated when considering this technology.

4.2.4 Technoeconomic Analysis for Remote Communities

Based on the results of the filtering process described in Section 4.1, the project team selected and analyzed a representative community using the HOMER microgrid simulation and optimization software. The analysis evaluated a distributed PSH project (<1 MW) for storing excess wind or solar to provide load leveling or peak shifting, backup power, and longer-duration storage for an isolated community that primarily relies on diesel generation for electricity.

A hypothetical community was used to test the capabilities and parameters of the HOMER model and to further understand community characteristics that impact PSH project costs in Alaska. The community characteristics include larger-than-average annual diesel generation, moderate-to-good wind resources, and moderate PSH resources. Using site-specific resource data, the analysis optimized the following variables:

- Number of wind turbines (fixed turbine with a rated power of 100 kW)
- PV capacity (kW)

The representative system, illustrated in Figure 4-11, assumes a simple PSH configuration employing a pump that can be operated in reverse mode and used as a turbine (pump-as-turbine [PAT]). PATs have lower efficiencies than systems that employ separate pumps and turbines, but they offer many advantages for remote communities, including:

- Capacity to work in low heads and small flow
- Mass-manufactured product that is easily maintained
- Can significantly reduce CAPEX

The following three scenarios were evaluated for the representative community:

- Scenario 1: An actual reservoir pairing from the PSH Resource Assessment (Section 2.1) that has a capacity to cover the energy demand in the community for about 10 days (a 100-hour storage)
- Scenario 2: A smaller reservoir/tank in that could cover the peak load for 10 hours

- Scenario 3: PSH in Scenario 2 compared with lithium-ion batteries

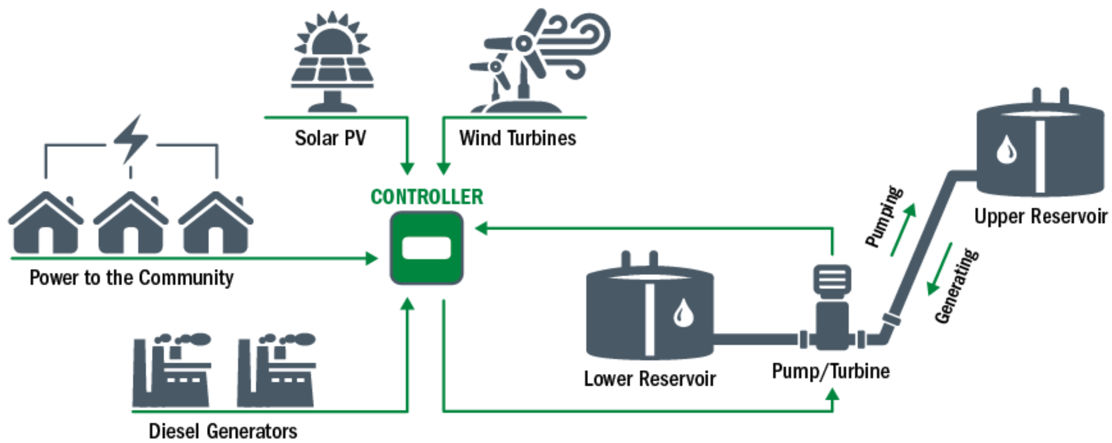

Figure 4-11 Representative Small PSH System Modeled in HOMER – Scenario 2

With this initial HOMER modeling, the goal was to establish a range of installed costs where distributed PSH (< 1 MW) could be a cost-effective storage choice for a remote Alaskan community. However, given that the PSH costs vary widely depending on the site and data to establish the feasibility of small-scale systems are lacking (Witt et al., 2015), the approach included estimating initial costs from literature and developer feedback and then completing sensitivity studies around the initial rough cost estimate to examine a target range of costs. The team also completed sensitivity studies for diesel costs and wind resource availability, because both vary significantly across communities with viable PSH resources. Finally, all scenarios incorporated the ITC direct-pay provision that is included in the Inflation Reduction Act of 2022 (White House.gov, 2022). In all scenarios, we use a 40% rate of ITC taken as a reduction from initial capital costs for PV, wind, battery, and PSH. Table 4-1 summarizes key inputs that are constant across all scenarios.

In addition, all assumptions in the scenario analysis were validated through community outreach and analysis completed for a specific project, as summarized in the case study described in Section 4.2.4.5.

Appendix B provides a summary of all HOMER inputs.

Table 4-1 Key Input Assumptions across All Scenarios

Input	Assumption
Project	
Discount rate	4.5
Nominal inflation rate	2.5
Analysis period	25 years
Electric Load	
Annual load	1,864,055 kWh annually
Peak load	365kW, winter peaking
Diesel	
Cost of diesel fuel	$3.52 per gallon with sensitivity study [5]
Diesel costs (replacement; O&M)	$1,200 per kW; $0.10/operating h/kW
Wind and Solar	
Solar costs (capital; replacement; O&M)	$1,800/kW (includes 40% reduction in CAPEX from ITC); $3,000/kW; 32/kW/year
Solar resource data	National Solar Radiation Database (NSRDB)
Solar derating factor	80%
Solar lifetime	25 years
Wind costs (capital; replacement; O&M)	$540,000 (includes 40% reduction in CAPEX from ITC); $900,000; $10,000 /year[6;]
Wind resource data	Measured Wind Speed Data (Vaught 2008)
Wind turbine losses	20%
Wind turbine lifetime	20 years
Storage	
PSH storage costs	Per strategy with sensitivity study (summarized in sections below)
Lithium-ion costs (capital; replacement; O&M; life expectancy, SOC range)	$1,200/kWh[7] (includes 40% reduction in CAPEX from ITC); $1,200/kWh; 32/kW/year; $10 per kWh per year; 15 years; 10%–100%
Controller strategy	Load following—replenishing the reservoir only from renewables; and Cycle-charging—replenishing the reservoir from both diesel and renewables

4.2.4.1 *Scenario 1: Longer Duration PSH Storage (10 Days)*

Total construction costs associated with new PSH development vary widely depending on the project's location, site-specific conditions, existing infrastructure, and PSH facility design. Table 4-2 summarizes costs and project characteristics for Scenario 1 and other similarly sized projects found through our literature review.

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5 Levelized cost of diesel fuel ranges over the next 25 years were established for the filtered communities using the AEA base price and escalation for evaluating the Round 14 Renewable Energy Funds projects. This method resulted in a range of $2.80–$8.07 per gallon.

6 Cost estimate from 100-kW manufacturer for installed costs in Alaska.

7 Estimates are for total installed costs of the system, including inverter and balance-of-system costs.

In the lower 48 states, PSH installed costs are typically in the $4,000–$5,000 range per installed kW for a 5-MW project. Cost drivers in PSH projects are the reservoirs or storage tanks, as well as the civil works, which include water conveyances, powerhouse, and construction access road. In Alaska, however, the cost of connecting to a remote community can be the most expensive element of the project. While Alaska has labor and expertise advantages from the oil industry, additional challenges include increased shipping and labor costs. These factors could raise the estimated cost for a 5-MW project to $6,000–$7,500 or more per installed kW, depending on construction access and proximity to existing transmission lines.[8]

Table 4-2 PSH Cost Estimates from Literature Related to Scenario 1 Assumptions

Project Details	Scenario 1 - Long Duration	m-PSH Case Study 1 (Witt et al., 2015)	m-PSH Case Study 2 (Witt et al., 2015)	SENA (Balducci et al., 2018)
Type	Closed loop	Closed loop	Open loop	Closed loop
Location	Alaska	Kentucky	Tennessee	Pacific Northwest
Upper reservoir volume (m^3)	361,483	200,627	Storage tank	Steel tank - 32,687
Lower reservoir volume (m^3)	370,623	Cavern	Existing lake	Floating membrane
Head height (m)	60	152	88	419
Penstock length (m)	630	518	729	1768
Discharge (m^3/s)	1	5.58	6.7	35.3
Interconnect (mi)	3			
Discharge time (h)	100	10	5	6
Turbine	PAT-500 kW	Francis turbine -5 MW	Francis turbine -5 MW	5 MW
Pump	PAT-500 kW	5 MW		5 MW
Storage capacity (MWh)	52.6[9]	50	25	30
Efficiency (%)	80	85	90	
Expected life (yr)	50			
Year of estimate	2022	2015	2015	2018
Estimated Costs ($)				
Reservoirs		750,000	4,160,000	19,300,000
Civil works		5,465,000	6,021,800	
Power plant equipment		5,029,450	6,414,725	
Switchyard		35,000	300,000	
Transmission			100,000	
Contingency		750,000	2,124,566	
Indirect costs			4,249,131	$3,000,000
Total installed cost ($)	37,500,000 with sensitivity	12,029,450	23,370,222	22,290,000
$/kWh	713	241	935	743
Annual O&M Cost ($)	600,000			400,000

[8] Cost estimates from modular PSH developer for Alaska.

[9] Estimated using the formula used for estimating system capacity, as described in Section 2.1.

For this scenario, we use a 40% rate of ITC taken as a reduction in initial capital costs for PSH, resulting in an assumed installed cost of $22,500,000 for Scenario 1.

The Optimal System Type (Figure 4-12) shows the lowest-cost microgrid configuration (e.g., diesel-storage or wind: diesel [black], diesel/PV [red], diesel/PV/wind [green], and diesel/PV/wind/PSH [blue]) across the two sensitivity ranges of diesel and PSH costs.

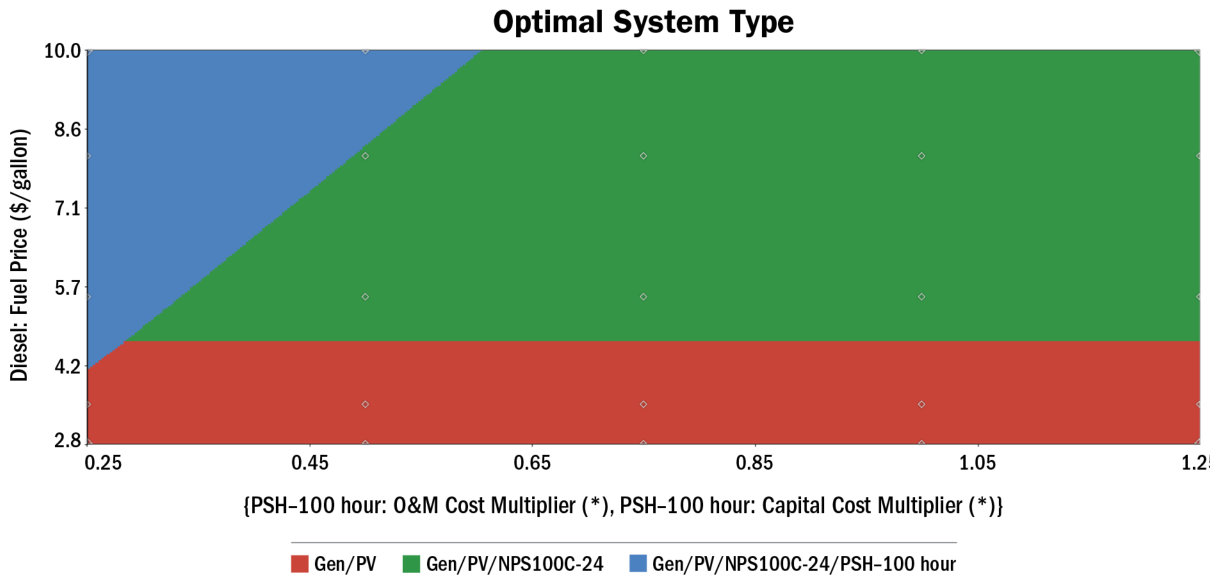

Figure 4-12 HOMER Optimal System Type Plot – Scenario 1

For the PSH project with Scenario 1 characteristics (providing 100 h of storage to a remote community with this load and renewable resources), diesel costs would need to be above $4.00 per gallon and installed costs for the PSH project below 60% of the assumed capital costs (including incentives) (i.e., ~$2,500 per kW or $250 per kWh) for a PSH project to offer a cost-competitive storage solution. For projects of this size to make economic sense for communities with high diesel cost and moderate-to-good wind resources, PSH technology options with significantly reduced CAPEX costs, such as those that use existing mines or reservoirs, would need to be found. However, communities with high diesel costs are also those where fuel transport is expensive, which results in higher costs for renewable energy and storage projects as well. While not cost effective without a significant reduction in CAPEX costs, adding PSH does allow for significantly higher amounts of renewable energy penetration and can reduce diesel fuel usage by more than 90%, depending on the microgrid configuration.

The economic feasibility of a larger-capacity project depends on numerous site factors, as discussed above, but is also largely driven by the amount of renewable energy needed to pump enough water to fully recharge the PSH reservoir. In addition to the cost challenges associated with a longer-duration storage project, there is also the challenge of recharging the reservoir once depleted. Figure 4-13 shows the SOC of the upper PSH reservoir throughout the year for Scenario 1, if a load-following controller strategy is used. This strategy assumes that diesel units only operate to serve the primary load and that only renewables are used to replenish the reservoir. The reservoir can only fully recharge in the summer months when the PV array is producing enough solar electricity to augment wind turbine production.

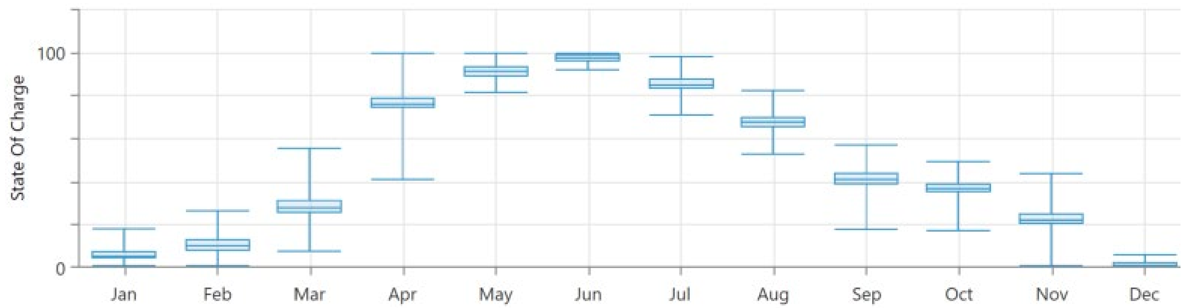

Figure 4-13 PSH Upper Reservoir SOC/Fill – Scenario 1, Load-Following Controller Strategy

If a cycle-charging controller strategy is modeled, in which diesel generators mostly operate at full power output (with higher efficiencies) to serve the primary load and in which excess diesel generation, along with renewables, is used to replenish the reservoir, the reservoir can fully recharge in most months. Figure 4-14 shows the results for this cycle-charging controller strategy. In addition, because the diesels are operating at a higher efficiency, diesel fuel usage increases only by ~3% and less solar energy is needed (see tables in Section 4.2.4.4).

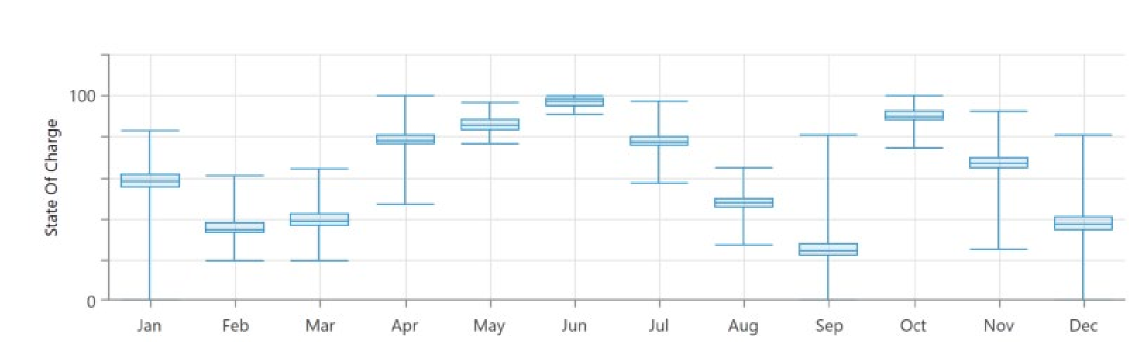

Figure 4-14 PSH Upper Reservoir SOC/Fill – Scenario 1, Cycle-Charging Controller Strategy

4.2.4.2 *Scenario 2 – Shorter Duration PSH Storage (10 Hours)*

Optimizing reservoir volume is critical to maximize load leveling, optimize the renewables, and minimize the entire CAPEX for the system. Given the constraints that PSH would need to meet to be cost effective in Scenario 1, the project team modeled a second scenario with significantly smaller reservoirs that allows for the use of storage tanks.

Table 4-3 summarizes costs and project characteristics for Scenario 2 and another similarly sized projects found through the literature review.

Table 4-3 PSH Cost Estimates from Literature Related to Scenario 2 Assumptions

Project Details	Scenario 2	ORNL – Biosphere (Witt et al., 2016)
Type	Closed loop	Closed loop
Location	Alaska	Tennessee
Upper reservoir vol (m^3)	36,148	Storage tank – 15, 142
Lower reservoir vol (m^3)	37,062	Storage tank – 15, 142
Head height (m)	60	154
Penstock length (m)	630	842
Discharge (m^3/s)	1	0.34
Interconnect (mi)	3	
Discharge time (h)	10	12.5
Turbine	Pump-as-turbine – 500 kW	Pelton turbine – 450 kW
Pump	Pump-as-turbine – 500 kW	825 kW
Storage capacity (kWh)	5,024	5,500
Efficiency (%)	80	90
Expected life (yr)	50	50
Year of estimate	2022	2016
Estimated Costs ($)		
Reservoirs		2,743,174
Civil Works		421,090
Power Plant Equipment		1,035,772
Switchyard		101,137
Transmission		57,701
Contingency		810,729
Indirect Costs		1,162,512
Total Installed Cost ($)	14,500,000 with sensitivity study[10]	6,332,115
$/kW	29,000	13,665
$/kWh	2,900	1,129
Annual O&M Cost ($)	160,000	

For this scenario, we use a 40% rate of ITC taken as a reduction in initial capital costs for PSH, resulting in an assumed installed cost of ~$9,000,000 or $1,800 per kWh for Scenario 2.

The Optimal System Type (Figure 4-15) for the PSH project with Scenario 2 characteristics (providing 10 hours of storage to a remote community with this load and renewable resources), diesel costs would need to be above ~$6.40 per gallon at assumed PSH installed costs of $1,800 per kWh, for a PSH project to offer a cost-competitive storage solution. Adding PSH allows for high amounts of renewable energy penetration and can reduce diesel fuel use by upwards of ~80%, depending on the microgrid configuration.

[10] Cost estimates from modular PSH developer for Alaska.

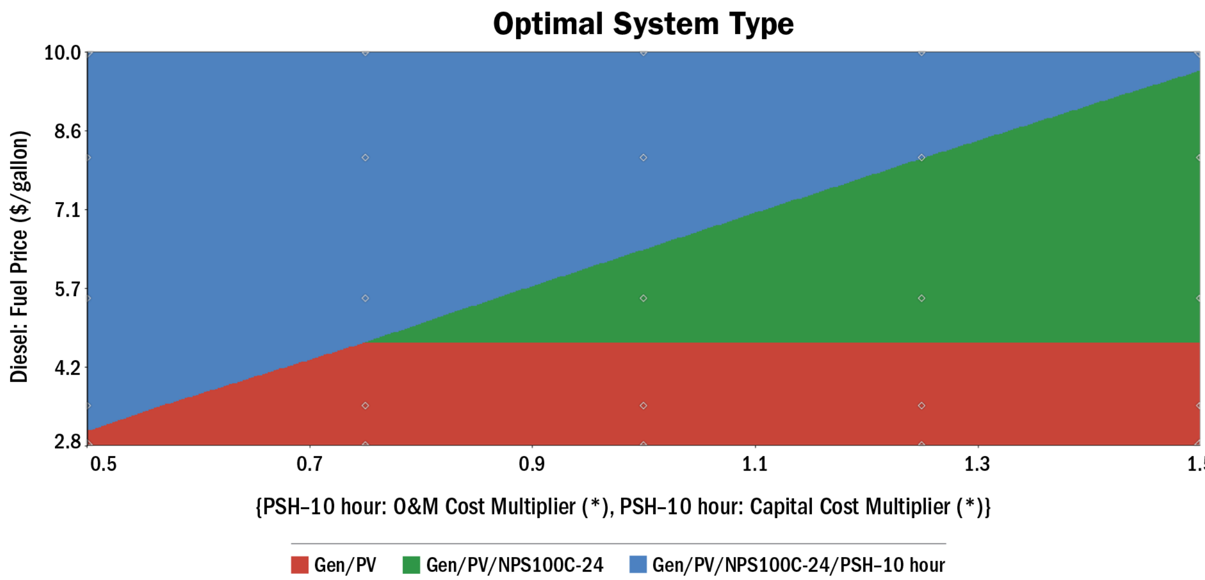

Figure 4-15 HOMER Optimal System Type Plot: Scenario 2

Figure 4-16 shows the SOC of the upper reservoir throughout the year for Scenario 2 with a load-following controller strategy. The reservoir can fully recharge, except for in the late fall months when solar generation is low but is able to fully recharge again when wind resources are at their highest in January and into late winter. Interestingly, a cycle-charging strategy (Figure 4-17) reduces renewable energy penetration by 10% but at slightly lower costs (see tables in Section 4.2.4.4).

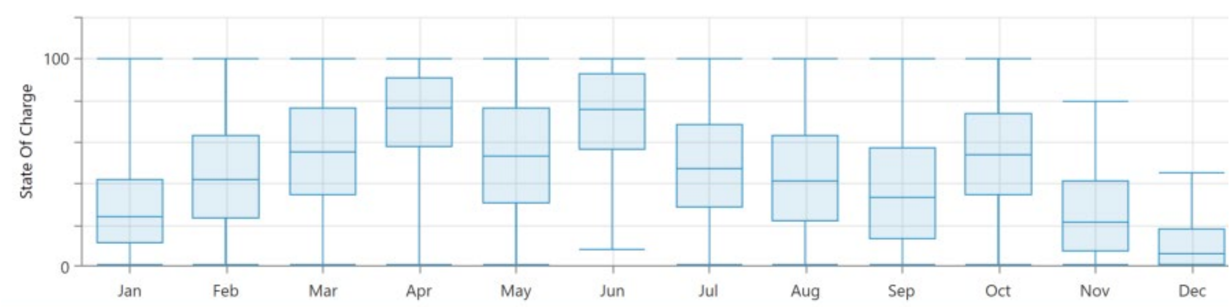

Figure 4-16 PSH Upper Reservoir SOC/Fill – Scenario 2, Load-Following Controller Strategy

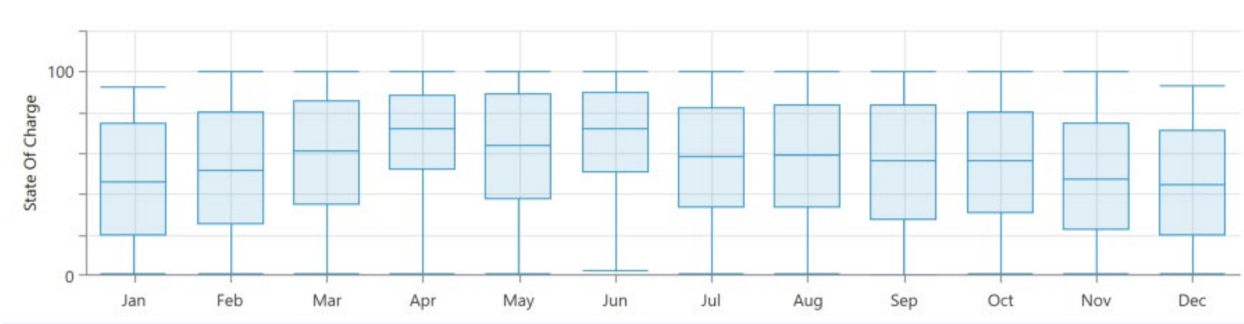

Figure 4-17 PSH Upper Reservoir SOC/Fill – Scenario 2, Cycle-Charging Controller Strategy

4.2.4.3 *Scenario 3 – Lithium-Ion Storage*

This scenario considered lithium-ion batteries instead of PSH as the energy storage option for remote communities. Compared with PSH, lithium-ion batteries have higher energy density, but shorter storage duration and cycle life. In addition, remote communities in Alaska often wish to avoid energy storage systems that use hazardous materials to avoid future disposal issues. Recent lithium-ion battery installations in Alaska are pursuing alternate lithium-ion battery chemical configurations that utilize phosphate (LFP) instead of cobalt. While LFP batteries are more expensive, they can operate over a wider SOC, exhibit longer cycle life, and eliminate hazardous waste disposal concerns.

For Scenario 3, using the characteristics summarized in 4-1, the analysis shows that at the full range of diesel prices ($3–$10 per gallon) and the full range of lithium-ion battery costs studied ($600–$3,000 per kWh), optimal system types always include some combination of PV, wind, and lithium-ion batteries. While the range of cost effectiveness increases compared with Scenarios 1 and 2, the diesel reduction potential also decreases, as does the storage capacity or duration (see tables in Section 4.2.4.4).

4.2.4.4 *Comparison of Scenarios*

Tables 4-4 and 4-5 summarize the overall results for all three scenarios by controller strategy. Table 4-4 provides a summary of results for the load-following controller strategy. The results show that Scenario 1 is not cost-effective over most diesel and PSH installed cost ranges. However, as mentioned above, these results are very site-specific. Also, given that the reservoir cannot fully recharge for many months of the year if only wind and solar energy are used for pumping (Figure 4-13), the longer-duration storage would not always be available. Scenario 2 makes economic sense at a wider range of diesel costs and installed PSH costs but provides a slightly lower diesel fuel reduction compared with Scenario 1 for the representative community. Scenario 3 is a cost-effective energy storage solution across the wide range of diesel and installed costs studied, but only provides for shorter-duration energy storage (2–4 hours), which will not fully cover the long, dark, winter evenings in Alaska when the load is high, but renewable generation is limited.

Table 4-4 Summary of Results, All Scenarios, Load-Following Controller Strategy

Category	Baseline	Scenario 1 – 100-hour PSH	Scenario 2 – 10-hour PSH	Scenario 3 – Lithium-ion batteries
Electric load (kWh/yr)	1,864,055	1,864,055	1,864,055	1,864,055
Diesel price ($/gal)	3.51	3.51	3.51	3.51
Diesel generators [(# units) kW]	(1) 410	(1) 410	(1) 410	(1) 410
Battery storage [duration (capacity in kWh)]		PSH -100 h (52,637)	PSH-10 h (5,264)	Lithium ion (470)
Solar PV (kW)		1,002	1,005	442
Wind turbines [(# units) kW]		(6) 600	(5) 500	(4) 400
Levelized cost of electricity (LCOE) ($/kWh)	0.45	1.18	0.60	0.39
Net present cost (NPC) ($M)	16.3	43.4	21.8	14.4
Non-fuel costs ($/year)	359,160	721,622	308,737	264,994
Fuel costs ($/year)	470,429	29,017	66,476	225,185
CO_2 emissions (kg/yr)	1,324,087	81,674	187,105	633,814
Fuel consumption (gal)	133,643	8,244	18,885	63,972
Diesel fuel use reduction (%)		94	86	52

Table 4-5 provides a summary of results for the cycle-charging controller strategy. Compared with the results presented in Table 4-4 for the load-following controller strategy, using diesel generation in addition to wind and solar generation to charge the reservoir provides similar results in cost and fuel savings for all scenarios because the diesels operate more efficiently at full load.

Table 4-5 Summary of Results, All Scenarios, Cycle-Charging Controller Strategy

Category	Baseline	Scenario 1 – 100-hour PSH	Scenario 2 – 10-hour PSH	Scenario 3 - Lithium-ion batteries
Electric load (kWh/year)	1,864,055	1,864,055	1,864,055	1,864,055
Diesel price ($/gallon)	3.51	3.51	3.51	3.51
Diesel generators [(# units) kW]	(1) 410	(1) 410	(1) 410	(1) 410
Battery storage [duration (capacity in kWh)]		PSH -100 h (52,637)	PSH-10 h (5,264)	Lithium ion (460)
Solar PV (kW)		909	979	401
Wind turbines [(# units) kW]		(6) 600	(4) 400	(4) 400
LCOE ($/kWh)	0.45	1.18	0.58	0.37
NPC ($M)	16.3	43.3	21.4	14.1
Non-fuel costs ($/year)	359,160	711,687	282,964	229,121
Fuel costs ($/year)	470,429	43,095	108,308	232,958
CO_2 emissions (kg/yr)	1,324,087	121,296	285,696	655,693
Fuel consumption (gal)	133,643	12,243	30,769	66,180
Diesel fuel use reduction (%)		91	77	50

Results are very site specific and, in addition to diesel and installation costs, they depend heavily on the renewable resource. The reference project modeled for this site was a location with good wind resources but relatively lower PSH resources, with the head of 60 m. Most developers look for sites with 300 m of head or more. Selecting higher-head sites reduces the size of the reservoirs or tanks used for water storage, the diameter of the penstock, the overall size of pump and turbine units, and all water-handling components.

Remote locations that have higher head are primarily in Southeast Alaska, where 90% of the generation is already supplied from hydro generation. However, there are challenges with seasonal storage, and communities increasingly rely on diesel generation to meet hydro supply shortages caused by drought conditions during the summer, as well as growing demand from electrification. These challenges underscore the need to identify cost-effective methods to capture the spillover so that it can be used to cover the load during the low-water-flow months in the winter.

Depending on the configuration, some existing storage dams could be retrofitted to include a pumping function to a new upper reservoir to capture spillover. This pump-back PSH functionality can be added to existing facilities to enhance a facility's flexibility and maximize its utilization. The case study described in the next section incorporated a site-specific analysis that included hydropower for a shorter-duration PSH project, sized similarly to Scenario 2.

4.2.4.5 *Case Study – False Pass*

Through community outreach, undertaken in parallel with the filtering process described in Section 4.1, the project team identified the City of False Pass as a good candidate to further evaluate the cost effectiveness of a potential shorter-duration PSH hydro project (similar to Scenario 2) that would augment a potential ROR hydro project. Table 4-6 lists key inputs used in the case study. Note that the discount rate and analysis period differ from those used in the scenario analyses in order to align with other feasibility studies performed for the city for the ROR project.

Table 4-6 Key Input Assumptions

Input	Assumption
Project	
Discount rate	5.5
Nominal inflation rate	2.5
Analysis period	50 years
Electric Load	
Annual load	709,995 kWh annually
Peak load	143 kW, winter peaking
Diesel	
Cost of diesel fuel	$3.06 per gallon with sensitivity study
Diesel costs (Replacement; O&M)	$1,200 per kW; $0.10/op.hr./kW
Wind and Solar	
Solar costs (capital; replacement; O&M)	$1,800/kW (includes 40% reduction in CAPEX from ITC); $3,000/kW; 32/kW/year
Solar resource data	NSRDB
Solar derating factor	80%
Solar lifetime	25 years
ROR costs (capital; O&M)	$5,080,000; $25,300 /year
ROR lifetime	50 years
Storage	
Lithium-ion costs (capital; replacement; O&M; life expectancy, SOC range)	$1,200/kWh[11] (includes 40% reduction in CAPEX from ITC); $1,200/kWh; 32/kW/year; $10 per kWh per year; 15 years; 10%-100%
Controller Strategy	Load Following – replenishing the reservoir is only from renewables; and Cycle Charging – replenishing the reservoir comes from both diesel units and renewables

[11] Estimates are for total installed costs of the system, including inverter and balance-of-system costs.

Table 4-7 summarizes costs and project characteristics for a modular PSH project using storage tanks.

Table 4-7 Modular PSH Cost Estimates for False Pass

Project Details	False Pass
Type	Closed loop
Upper reservoir volume (m^3)	5,678
Lower reservoir volume (m^3)	5,678
Head height (m)	183
Penstock length (m)	1,143
Discharge (m^3/s)	0.2
Discharge time (hours)	12
Turbine (kW)	217
Storage capacity (kWh)	2,608
Efficiency (%)	80
Expected Life (yr)	50
Year of estimate	2022
Project Costs ($)	
Preliminary site investigations	500,000
Inlet and penstock	2,700,000
Powerhouse	1,000,000
Equipment and installation	7,000,000
Transmission	1,700,000
General construction costs	1,500,000
Total installed cost	14,400,000
$/kW	66,359
$/kWh	5,521
Annual O&M Cost	180,000

For this scenario, we use a 40% rate of ITC taken as a reduction from initial capital costs for PSH, resulting in an assumed installed cost of ~$8,640,000 or $1,800 per kWh for the modular system.

Table 4-8 provides a summary of results for the following three scenarios:

- Addition of 180-kW ROR plant
- ROR with PSH
- ROR with lithium-ion batteries

The addition of a ~200-kW modular PSH plant significantly reduces the size of the ROR plant while providing a similar amount of diesel fuel reduction; however, it more than doubles the cost of energy. The addition of solar and lithium-ion batteries also reduces the size of the ROR project, provides the lowest-cost option with the highest reduction in diesel fuel, but only supplies 2 hours of storage.

Table 4-8 Summary of Results, False Pass Case Study

Category	Baseline	Scenario 1: 180 kW ROR	Scenario 2: 12-hour PSH	Scenario 3: Lithium-ion batteries
Electric load (kWh/year)	709,995	709,995	709,995	709,995
Diesel price ($/gallon)	3.06	3.06	3.06	3.06
Diesel generators [(# units) kW]	(2) 175; 125	(1) 125	(1) 125	(1) 125
Energy storage [duration (capacity in kWh)]		n/a	12 h (2,608)	2 h (150)
Solar PV (kWh)		n/a	91,511 kWh	31,287 kWh
Solar PV (kW)		n/a	97.3	50
ROR (kW)		180	90	110
LCOE ($/kWh)	0.40	0.38	0.95	0.27
Net present cost ($M)	7.4	7.1	17.6	5.1
Non-fuel costs ($/year)	111,565	55,175	207,364	32,910
Fuel costs ($/year)	170,802	23,357	26,240	21,303
CO_2 emissions (kg/yr)	551,540	82,555	84,731	68,791
Fuel consumption (gal)	55,711	10,776	8,559	6,948
Diesel fuel use reduction (%)		81	85	88
Excess electricity (kWh)	–	522,270	40,802	113,010
Dispatch strategy	–	n/a	Cycle Charging	Cycle Charging

The City of False Pass is interconnected to a local fish processing plant that uses almost the same quantity of diesel fuel as the city on annual basis (Wright, 2014). The same three scenarios were modeled again, but this time, with double the electric load to roughly simulate the ROR plus storage serving the fish-processing facility, as well as the community. Because of the lack of actual load data for the fish-processing plant, the impacts of the plant on the seasonality of the combined load were not considered.

Table 4-9 summarizes the results when doubling the load. In these cases, the disparity between costs of a ROR system with and without PSH decreases, and the PSH system offers a significant reduction in diesel fuel over the ROR system alone. The scenario with solar and lithium-ion batteries still offers the most cost-competitive solution, with a significant increase in renewable energy penetration compared with the ROR system alone.

Table 4-9 Summary of Results, False Pass Case Study with Double the Load

Category	Baseline	Scenario 1: 180kW ROR	Scenario 2: PSH	Scenario 3: Lithium-ion batteries
Electric load (kWh/yr)	1,460,000	1,460,000	1,460,000	1,460,000
Diesel price ($/gal)	3.06	$3.06	3.06	3.06
Diesel generators [(# units) kW]	(3) 205; 175; 125	(3) 205; 175; 125	(3) 205; 175; 125	(3) 205; 175; 125
Energy storage [duration (capacity in kWh)]		n/a	12 h (2,608)	1 h (178)
Solar PV (kWh)		n/a	142,436 kWh	41,789 kWh
Solar PV (kW)		n/a	199	161
ROR (kW)		180	180	180
LCOE ($/kWh)	0.40	0.32	0.58	0.26
NPC ($M)	$14.0	$12.0	$22.0	$9.8
Non-fuel costs ($/year)	343,215	139,118	236,402	72,612
Fuel costs ($/year)	194,077	124,148	55,498	68,203
CO_2 emissions (kg/yr)	1,108,278	400,888	179,209	220,235
Fuel Consumption (gal)	111,948	40,494	18,102	22,246
Diesel fuel use reduction (%)		64	84	80
Excess electricity (kWh)	–	160,416	69,094	109,649
Dispatch strategy	–	n/a	Cycle Charging	Cycle Charging

4.2.5 Energy Project Development Support Programs for Communities and Tribes

This project included assessment and validation of the technical viability of PSH in Alaska, in part, to empower future applicants of federally funded, community-focused programs to consider including hydropower and PSH in their applications. While the results provide insight into the overall technical and economic feasibility of PSH in remote Alaska communities, each community is unique, and site-specific analysis should be conducted as part of any PSH project development.

It was beyond the scope of this project to model and analyze the technoeconomic potential for each community. However, there are many programs available that address communities' unique energy system goals and diverse stakeholder priorities that could be used to further assess PSH feasibility for specific communities. Many of these support programs include technical assistance and, potentially, funding for hydropower projects. Support often includes, among other activities, energy planning, energy system modeling, technology feasibility and scenarios, identification of partnership opportunities, procurement pathways, energy equity considerations, and economic analysis. These support programs can be used to advance pre-project development, project design, implementation, and O&M. Some federal programs are listed here, but the list is not comprehensive and other programs may be available at the federal, state, and local levels.

Current federal programs include, but are not limited to, the following:

- Communities LEAP (Local Energy Action Program)
- C2C (Communities to Clean Energy Program)
- Rural and Remote Communities Consortia
- ETIPP (Energy Transitions Initiative Partnership Project)
- Bureau of Indian Energy
- DOE Office of Indian Energy

Remote Alaskan communities that are considering PSH projects can take advantage of these programs to further refine their PSH technoeconomic potential, model potential system designs, and develop materials that could assist in applying for funding opportunities.

4.2.6 Limitations

This assessment of PSH potential in remote Alaska communities was a broad, initial examination of the PSH technical potential and economic feasibility of deploying small-scale PSH systems for energy storage. However, the authors of this study acknowledge that there were limitations that should be acknowledged when considering the results.

The limitations identified by the authors and peer reviewers of this study include the following:

- A bottom-up cost model is needed for small-scale PSH projects so that more detailed trade-off studies can be undertaken, such as the impact of head height and site-specific factors such as constructability and distance to transmission.
- The GIS approach did not fully account for locations suitable for modular reservoir-tank PSH systems. The minimum surface area of considered reservoirs was reduced from 10 hectares to 3.6 hectares for the rural GIS analysis. However, although smaller reservoirs may be useful in such small-scale systems, this limit was chosen based on concerns that the input 30-m resolution DEM may not be able to reliably resolve reservoirs of a smaller size or opportunities where modular tank systems could be cost effective.

- Land ownership data was not incorporated into the GIS approach. Including this data would provide further insight into ownership and permitting challenges that could impact projects costs.

- Cost estimates for small-scale modular PSH were for one technology type from one developer.

- The economic model does not assign extra value for longer durations of storage and the resiliency they could provide to the community.

- Barriers to collecting data for individual communities limited the authors' ability to perform several site-specific case studies and evaluate PSH potential in more than one community. Two communities were initially identified for site-specific modeling, but the lack of data and/or the inability of the community to provide necessary data limited the analysis to one community. For future studies, we recommend that research teams work closely with communities for a longer period to assist them in collecting the necessary data.

- The timeline and available resources for the project limited the number of communities that could be modeled and analyzed. Expanding this study to include additional communities with optimal attributes for PSH development would provide further insight into the feasibility of PSH in remote Alaskan communities.

Please see Appendix C for an additional rural case study that evaluated the impacts of increased head height, wind energy generation, and load for Scenario 1.

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5.0 Summary of Key Study Findings

The key findings of this study are summarized in the following sections.

5.1 Analysis of PSH Resource Potential

- The GIS resource mapping analysis showed numerous potential sites that could be used for PSH development in Alaska. In addition to the resource assessment for larger PSH projects (those that could be suitable for the Railbelt system), the project team modified the GIS model to allow for mapping of sites that could be suitable for very small-scale (< 1 MW) PSH projects that would serve remote communities.

- The resource assessment for larger, grid-scale projects showed the potential for more than 1,800 closed-loop PSH systems in Alaska, with a total energy storage capacity of about 4 TWh.

- Small reservoir sizes and dam heights in many locations offer potentially suitable sites for small-scale PSH systems to serve remote communities in Alaska. For this resource-mapping analysis, the project team used a set of screening filters and criteria to identify the most suitable locations for small PSH projects. Nearly 50% of the potentially suitable small-scale PSH sites identified are in Southeast Alaska.

5.2 Railbelt System Analysis

- The Railbelt system analysis revealed the need for both short- and long-duration energy storage (i.e., PSH) in all scenarios. The optimal future generation portfolios in all scenarios include new PSH capacity between 300 MW and 600 MW. The location and timing of new PSH investments vary in different scenarios.

- The Railbelt system analysis considers the age-based retirement of existing electricity generation resources. The results show that the retirement capacity of thermal generating resources is replaced by new NG-CT, wind, battery, and PSH resources.

- The RPS scenario shows a rapid investment in wind and battery capacity due to the RPS target of 80% by 2040. The A-LEAF model does not add new NG-CT resources, except in the Anchorage zone, to compensate for the retired thermal capacity in the early years.

- This analysis also examined the impact of the ITC for PV and battery, as well as the PTC for wind. The Carbon Price scenario, which assumes a carbon price of \$40/ton of CO_2, is the only scenario that did not consider ITC and PTC, and its results show a substantial decrease in battery investments compared with other scenarios. This decrease is offset by an increase in PSH investments.

- The short construction period of battery resources (compared with PSH) results in higher battery investments in the early years in the RPS and High-Load scenarios, which results in reduced PSH investments in the system.

5.3 Remote Communities Analysis

- Scenario 1 (PSH with 100 hours of storage) is not cost effective compared with most diesel and PSH installed cost ranges studied for the representative community.
  - PSH costs would need to be 60% or less of the assumed capital costs including incentives, or ~$2,500 per kW or $250 per kWh, for a PSH project to offer a cost-competitive storage solution. PSH technology options with significantly reduced CAPEX costs, such as the use of existing mines or existing reservoirs, would need to be found. However, communities with high diesel costs are also those where fuel transport is expensive, which results in higher costs for renewable energy and storage projects as well.
  - If a load-following controller strategy is used, in which diesels only operate to serve the primary load and only renewables are used to replenish the PSH reservoir, the reservoir cannot be fully replenished in the late fall and early winter.
  - If a cycle-charging controller strategy is used, when diesel generation—in addition to wind and solar generation—can be used for pumping, water storage in the upper reservoir can be replenished in most months.
- Scenario 2 (PSH with 10 hours of storage) makes economic sense for a wider range of diesel fuel costs and installed PSH costs and, compared with Scenario 1, provides similar diesel fuel reduction for the representative community.
  - Diesel costs would need to be above ~$6 per gallon at assumed installed costs of $1,800 per kWh (includes incentives) for the PSH project to offer a cost-competitive storage solution.
  - In the load-following controller strategy, the PSH reservoir can fully recharge in all months, except November and December, when solar generation is low. If a cycle-charging controller strategy is used, the reservoir can be replenished in all months of the year.
- For Scenarios 1 and 2:
  - If a cycle-charging control strategy is used, in which diesel generators operate at full power output when needed to serve the primary load and excess diesel generation (along with renewables) is used to replenish the PSH reservoir, the reservoir can fully recharge in most months at slightly lower costs and renewable energy penetrations.
  - Adding PSH allows for high amounts of renewable energy penetration and can reduce diesel fuel usage by more than 70%.

- Scenario 3 (Lithium-ion battery), which assumes that energy storage is provided by lithium-ion batteries instead of PSH, is a cost-effective solution across a wide range of diesel and installed costs.
  - At the full range of diesel prices ($3–$10 per gallon) and lithium-ion battery costs studied ($600–$3,000 per kWh), optimal system types always include some combination of PV, wind, and lithium-ion batteries. While the range of cost effectiveness increases when compared with Scenarios 1 and 2, the diesel reduction potential also significantly decreases, as does the storage capacity or duration.
- Results are very site-specific and, in addition to diesel fuel and PSH installation costs, depend heavily on the renewable resource and existing infrastructure (e.g., reservoirs, transmission access, and construction road access).
- The reference project modeled for Scenarios 1, 2, and 3 was a location with good wind resources but relatively lower PSH resources with the head of 60 m. Most developers look for sites with 300 m of head or more. A site-specific case study was undertaken with a higher head but showed similar results.
- Remote locations that have higher head are primarily in Southeast Alaska, where 90% of electricity demand is already supplied from hydro generation. However, there are challenges with seasonal storage, and communities increasingly rely on diesel generation to meet hydro supply shortages because of drought conditions during the summer, as well as growing demand from electrification. These challenges highlight the need to identify cost-effective methods to capture the spillover so that it can be used to cover the load during low-water-flow months in the winter.
- The project team examined the addition of a ~200-kW modular PSH plant to a planned ROR plant in False Pass, Alaska; the analysis included site-specific project costs. In this case, the addition of PSH significantly reduces the size of the ROR plant needed to provide a similar reduction in diesel fuel, but it results in more than double the cost of energy. The addition of solar and lithium-ion batteries also reduces the size of the ROR project, provides the lowest-cost option with the highest reduction in diesel fuel, but supplies only 2 hours of storage. The sensitivity study on load that the team performed showed that as the load increases, the disparity between the costs of a ROR system with and without PSH decreases, and that the PSH system offers a significant reduction in diesel fuel compared with the ROR system alone. The scenario with solar and lithium-ion batteries still offers the most cost-competitive solution, with a significant increase in renewable energy penetration compared with the ROR system alone.

Appendix A. Rural Community PSH Potential Filtering Results

A.1 Non-Railbelt Communities with PSH Resources

The GIS analysis identified the following 192 communities with PSH reservoir potential.

Akutan
Alatna
Alcan Border
Aleknagik
Allakaket
Ambler
Anaktuvuk Pass
Angoon
Aniak
Anvik
Arctic Village
Bethel
Bettles
Brevig Mission
Buckland
Central
Chalkyitsik
Chenega Bay
Chicken
Chignik
Chignik Lagoon
Chignik Lake
Chisana
Chistochina
Chitina
Chuathbaluk
Circle
Clark's Point
Coffman Cove
Cold Bay
Coldfoot
Copper Center
Cordova
Covenant Life
Craig
Crooked Creek
Deering
Dillingham
Dot Lake
Dot Lake
Village
Dry Creek
Eagle
Eagle Village
Edna Bay
Egegik
Eielson AFB
Ekwok
Elfin Cove
Elim
Eureka
Roadhouse
Evansville
Excursion Inlet
False Pass
Ferry
Flat
Fort Greely
Gakona
Gambell
Game Creek
Glennallen
Golovin
Goodnews Bay
Grayling
Gulkana
Gustavus
Haines
Hobart Bay
Hollis
Holy Cross
Hoonah
Hydaburg
Hyder
Igiugig
Iliamna
Ivanof Bay
Juneau
Kake
Kaltag
Kasaan
Kenny Lake
Ketchikan
Kiana
King Cove
Klawock
Klukwan
Kobuk
Kokhanok
Koliganek
Koyuk
Koyukuk
Kupreanof
Lake
Minchumina
Levelock
Lime Village
Livengood
Loring
Lower Kalskag
Lutak
Manley Hot
Springs
Manokotak
Marshall
McCarthy
McGrath
Mekoryuk
Mendeltna
Mentasta Lake
Mertarvik
Metlakatla
Minto
Mosquito Lake
Mountain
Village
Mud Bay
Nabesna
Naknek
Napakiak
Naukati Bay
Nelchina
New Allakaket
New Stuyahok
Newhalen
Nightmute
Nikolski
Nome
Nondalton
Northway
Junction
Nulato
Oscarville
Paxson
Pedro Bay
Pelican
Perryville
Petersburg
Pilot Point
Pilot Station
Pitkas Point
Platinum
Point Baker
Pope-Vannoy
Landing
Port Alexander
Port Alsworth
Port Heiden
Port Protection
Portage Creek
Rampart
Red Devil
Red Dog Mine
Ruby
Russian
Mission
Sand Point
Savoonga
Saxman
Scammon Bay
Shageluk
Shungnak
Silver Springs
Sitka
Skagway
Skwentna
Slana
Sleetmute
South Naknek
St. George
St. Mary's
St. Paul
Stevens Village
Stony River
Takotna
Tanacross
Tanana
Tatitlek
Tazlina
Teller
Tenakee
Springs
Tetlin
Thorne Bay
Togiak
Toksook Bay
Tolsona
Tonsina
Tununak
Twin Hills

Unalakleet
Unalaska
Upper Kalskag
Valdez
Wales
Whale Pass
White Mountain
Willow Creek
Wiseman
Wrangell
Yakutat

A.2 Penstock Length ÷ Head Height = < 12

After applying the second filter, the following 189 communities were identified as having PSH potential with an optimal penstock length-to-head height ratio.

Akutan
Alatna
Alcan Border
Aleknagik
Allakaket
Ambler
Anaktuvuk Pass
Angoon
Aniak
Anvik
Arctic Village
Bethel
Bettles
Brevig Mission
Buckland
Central
Chalkyitsik
Chenega Bay
Chicken
Chignik
Chignik Lagoon
Chignik Lake
Chisana
Chistochina
Chitina
Chuathbaluk
Circle
Clark's Point
Coffman Cove
Cold Bay
Coldfoot
Copper Center
Cordova
Covenant Life
Craig
Crooked Creek
Deering
Dot Lake
Dot Lake Village
Dry Creek
Eagle
Eagle Village
Edna Bay
Egegik
Eielson AFB
Elfin Cove
Elim
Eureka Roadhouse
Evansville
Excursion Inlet
False Pass
Ferry
Flat
Fort Greely
Gakona
Gambell
Game Creek
Glennallen
Golovin
Goodnews Bay
Grayling
Gulkana
Gustavus
Haines
Hobart Bay
Hollis
Holy Cross
Hoonah
Hydaburg
Hyder
Igiugig
Iliamna
Ivanof Bay
Juneau
Kake
Kaltag
Kasaan
Kenny Lake
Ketchikan
Kiana
King Cove
Klawock
Klukwan
Kobuk
Kokhanok
Koliganek
Koyuk
Koyukuk
Kupreanof Lake
Minchumina
Levelock
Lime Village
Livengood
Loring
Lower Kalskag
Lutak
Manley Hot Springs
Manokotak
Marshall
McCarthy
McGrath
Mekoryuk
Mendeltna
Mentasta Lake
Mertarvik
Metlakatla
Minto
Mosquito Lake
Mountain Village
Mud Bay
Nabesna
Naknek
Napakiak
Naukati Bay
Nelchina
New Allakaket
New Stuyahok
Newhalen
Nightmute
Nikolski
Nome
Nondalton
Northway Junction
Nulato
Oscarville
Paxson
Pedro Bay
Pelican
Perryville
Petersburg
Pilot Point
Pilot Station
Pitkas Point
Platinum
Point Baker
Pope-Vannoy Landing
Port Alexander
Port Alsworth
Port Heiden
Port Protection
Portage Creek
Rampart
Red Devil
Red Dog Mine
Ruby
Russian Mission
Sand Point
Savoonga
Saxman
Scammon Bay
Shageluk
Shungnak
Silver Springs
Sitka
Skagway
Skwentna
Slana
Sleetmute
South Naknek
St. George
St. Mary's
St. Paul
Stony River
Takotna
Tanacross
Tanana
Tatitlek
Tazlina
Teller
Tenakee Springs
Tetlin
Thorne Bay
Togiak
Toksook Bay
Tolsona
Tonsina

Tununak
Twin Hills
Unalakleet
Unalaska
Upper Kalskag
Valdez
Wales
Whale Pass
White Mountain
Willow Creek
Wiseman
Wrangell
Yakuta

A.3 Head Height is Greater than 100 Meters and Two Times Greater than the Upper and Lower Reservoir Dam Height

After filtering for head heights that were greater than twice the upper and lower reservoir dam height, the following 127 communities remained.

Akutan
Aleknagik
Anaktuvuk Pass
Angoon
Arctic Village
Bettles
Brevig Mission
Buckland
Chenega Bay
Chicken
Chignik
Chignik Lagoon
Chignik Lake
Chisana
Chistochina
Chitina
Chuathbaluk
Circle
Coffman Cove
Coldfoot
Copper Center
Cordova
Covenant Life
Craig
Crooked Creek
Dry Creek
Eagle
Eagle Village
Edna Bay
Elim
Eureka Roadhouse
Evansville
Excursion Inlet
False Pass
Ferry
Flat
Gakona
Game Creek
Glennallen
Golovin
Goodnews Bay
Grayling
Gulkana
Gustavus
Hobart Bay
Hollis
Hoonah
Hydaburg
Hyder
Ivanof Bay
Juneau
Kake
Kaltag
Kasaan
Kenny Lake
Ketchikan
Kiana
King Cove
Klawock
Klukwan
Kokhanok
Koyuk
Koyukuk
Kupreanof
Lake Minchumina
Lime Village
Livengood
Loring
Manley Hot Springs
Manokotak
McCarthy
Mentasta Lake
Metlakatla
Mosquito Lake
Nabesna
Naukati Bay
Nelchina
New Stuyahok
Nikolski
Nondalton
Northway Junction
Nulato
Paxson
Pedro Bay
Pelican
Perryville
Petersburg
Pitkas Point
Point Baker
Pope-Vannoy Landing
Port Alexander
Port Alsworth
Port Protection
Rampart
Red Devil
Red Dog Mine
Ruby
Russian Mission
Sand Point
Savoonga
Saxman
Scammon Bay
Silver Springs
Skagway
Skwentna
Slana
Sleetmute
St. George
St. Mary's
Takotna
Tanacross
Tanana
Tatitlek
Tazlina
Teller
Tetlin
Thorne Bay
Toksook Bay
Tolsona
Tonsina
Tununak
Unalaska
Wales
Whale Pass
Willow Creek
Wiseman
Wrangell

A.4 Population Greater than 250

According to Alaska developers, communities with populations below 250 will likely face additional capacity and economic challenges. After applying this filter, the following 36 communities remained.

Akutan
Anaktuvuk Pass
Angoon
Brevig Mission
Buckland
Copper Center
Cordova
Craig
Elim
False Pass
Glennallen
Goodnews Bay
Gustavus
Hoonah
Hydaburg
Juneau
Kake
Ketchikan
Kiana
King Cove
Klawock
Koyuk
Manokotak
Metlakatla
Petersburg
Russian Mission
Sand Point
Savoonga
Saxman
Scammon Bay
Skagway
Thorne Bay
Toksook Bay
Tununak
Unalaska
Wrangell

A.5 Federally Recognized Wetland Areas

Communities and potential project sites located within federally recognized wetland areas would introduce additional permitting and logistical challenges, increasing the costs of PSH and decreasing the probability of a cost-effective project. These sites would need further evaluation for PSH economic feasibility.

After removing communities where the PSH resource was located within federally recognized wetland areas, the following 18 communities remain.

Akutan
Anaktuvuk Pass
Angoon
Brevig Mission
Cordova
Juneau
Kake
Kiana
Metlakatla
Sand Point
Savoonga
Saxman
Scammon Bay
Skagway
Thorne Bay
Tununak
Unalaska
Wrangell

Appendix B. HOMER Input Summary

Project Location

Location	Main St., New Stuyahok, AK 99636, USA
Latitude	59 degrees 27.08 minutes north
Longitude	157 degrees 18.86 minutes west
Time zone	America/Anchorage

Load: Electric

Data source	Imported
Daily noise	7%
Hourly noise	6%
Scaled annual average	5,107.001 kWh/d
Scaled peak load	364.5142 kW
Load factor	0.5838

Microgrid Controller: HOMER Load Following

Quantity	Capital	Replacement	O&M
1	$0.00	$0.00	$0.00

Minimization strategy	Economic
Allow multiple generators to operate simultaneously	Yes
Allow systems with generator capacity less than peak load	Yes
Allow diesel off operation	Yes

Microgrid Controller: HOMER Cycle Charging

Quantity	Capital	Replacement	O&M
1	$0.00	$0.00	$0.00

Minimization strategy	Economic
Setpoint state of charge	80
Allow multiple generators to operate simultaneously	Yes
Allow systems with generator capacity less than peak load	Yes
Allow diesel off operation	Yes

PV: Generic flat-plate PV

Size	Capital	Replacement	O&M

Sizes to consider	0,1000
Lifetime	25 years
Derating factor	80%
Tracking system	No Tracking
Slope	59.451 deg
Azimuth	0.000 deg
Ground reflectance	20.0%

Solar Resource

Scaled annual average	2.64 kWh/m^2/d

Wind Turbine: Northern Power NPS100C-24

Quantity	Capital	Replacement	O&M
1	$540,000.00	$900,000.00	$10,000.00

Wind Resource

Scaled annual average	5.43

Generator: Autosize Genset

Size	Capital	Replacement	O&M
1.00	$0.00	$1,200.00	$0.10

Sizes to consider	410
Lifetime	219,000 h
Min. load ratio	25%
Heat recovery ratio	0%
Fuel used	Diesel
Fuel curve intercept	0.0184 L/h/kW
Fuel curve slope	0.2360 L/h/kW

Fuel: Diesel

Price	$ 0.93/L
Lower heating value	43.2 MJ/kg
Density	820.00 kg/m^3
Carbon content	88.0%
Sulfur content	0.4%

Converter

Size	Capital	Replacement	O&M
1.00	$0.00	$0.00	$0.00

Sizes to consider	0,550 kW
Lifetime	25 years
Inverter can parallel with AC generator	Yes

Economics

Annual real interest rate	2%
Project lifetime	25 years
Capacity shortage penalty	$0/kWh
System fixed capital cost	0
System fixed O&M cost	0

System Control

Timestep length in minutes	60
Multi-year enabled	No
Allow systems with multiple generators	Yes
Allow systems with multiple wind turbine types	Yes
Battery autonomy threshold	2
Maximum renewable penetration threshold	55
Warn about renewable penetration	Yes

Optimizer

Maximum simulations	10,000
System design precision	0.01

NPC precision	0.01
Minimum spacing	0
Focus factor	20.3099493107297
Optimize category winners	Yes
Use base case	No

Emissions

Carbon dioxide penalty	$ 0/t
Carbon monoxide penalty	$ 0/t
Unburned hydrocarbons penalty	$ 0/t
Particulate matter penalty	$ 0/t
Sulfur dioxide penalty	$ 0/t
Nitrogen oxides penalty	$ 0/t

Constraints

Maximum annual capacity shortage	0
Minimum renewable fraction	0
Operating reserve as percentage of hourly load	10
Operating reserve as percentage of peak load	0
Operating reserve as percentage of solar power output	80
Operating reserve as percentage of wind power output	50

Appendix C: Impact of Increased Head Height and Wind Energy Generation on Longer-Duration PSH Storage Scenario Evaluated for Representative Rural Community

To further address Advisory Group feedback, as well as incorporate feedback from an additional developer on installed costs for distributed PSH (< 1 MW) projects in rural Alaskan communities, we modified the Scenario 1 model to account for:

- An increase in hub height from 60 m to 200 m for the modeled PSH system.
- A larger wind turbine to achieve economies of scale with increased wind generation.

The feedback we received on construction costs for distributed PSH indicate that, while such costs vary significantly from site to site, the cost estimates obtained from the literature review would now likely be on the order of 50%–100% compared with the pre-pandemic prices we assumed (Tables 4-2 and 4-3 in Section 4). Because of the lack of a bottom-up cost model and site-specific cost uncertainties, no changes in costs were made to the PSH systems based on the additional feedback received from the developer or for increased head height. In addition, all other key input assumptions for this revised scenario remained the same as those presented in Table 4-1 in Section 4, except for the wind turbine costs, which were modified to increase the turbine size from 100 kW to 900 kW. Revised wind turbine input assumptions are as follows:[12]

- Installed costs: $3,600,000 (includes a 40% rate of ITC taken as a reduction from initial capital costs)
- Replacement costs: $6,000,000
- O&M costs: $42,000 per year

Table C-1 presents project characteristics and cost estimates for the revised Scenario 1.

Table C-1 PSH Project Characteristics and Cost Estimates for Revised Scenario 1 with Increased Head Height

Project Details	Scenario 1: Long-Duration PSH
Type	Closed loop
Location	Alaska
Upper reservoir volume (m^3)	361,483
Lower reservoir volume (m^3)	370,623
Head height (m)	200
Penstock length (m)	630
Discharge (m^3/s)	1
Interconnect (mi)	3

[12] Cost estimate for 900-kW wind turbine assuming installed costs for Alaska.

Project Details	Scenario 1: Long-Duration PSH
Discharge time (h)	300
Turbine	PAT-550 kW
Pump	PAT-550 kW
Storage capacity (MWh)	167.5[a]
Efficiency (%)	80
Expected life (yr)	50
Year of estimate	2022
Total installed cost ($)	37,500,000 with sensitivity
$/kWh	224
Annual O&M Cost ($)	600,000

[a] Estimated using the formula used for estimating system capacity, as described in Section 2.1.

For this scenario, we again use a 40% rate of ITC, taken as a reduction in initial capital costs for PSH, resulting in an assumed installed cost of $22,500,000. This rate is consistent with the assumptions applied throughout this report.

The Optimal System Type (Figure C-1) shows the lowest-cost microgrid configuration (e.g., diesel-storage or wind: diesel [black], diesel/PV [red], diesel/PV/wind [green], and diesel/PV/wind/PSH [blue]) across the two sensitivity ranges of diesel and PSH costs.

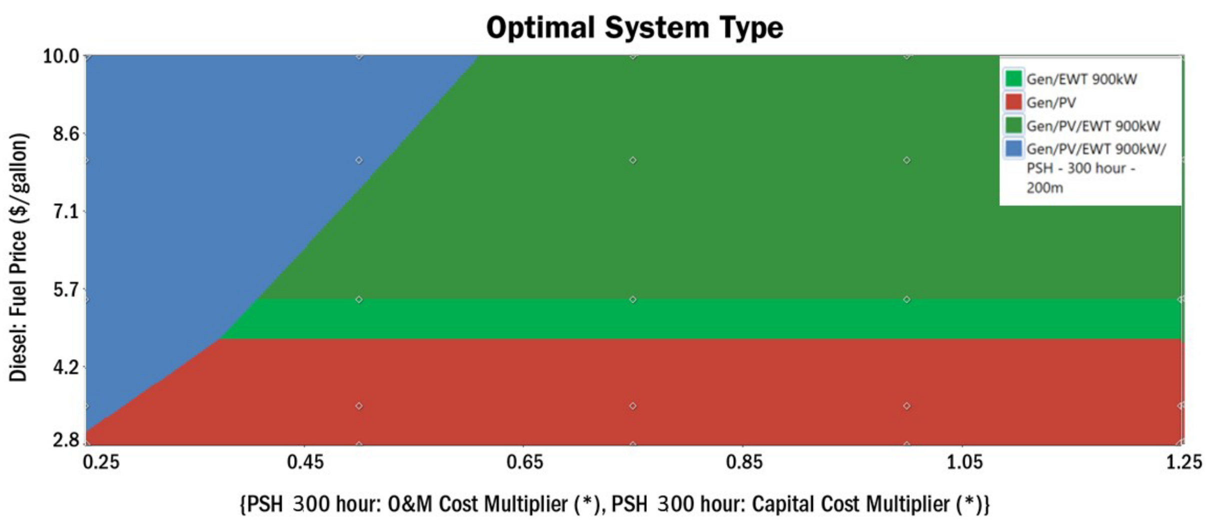

Figure C-1 HOMER Optimal System Type Plot – Scenario 1 with Increased Head Height

For the PSH project with the revised Scenario 1 characteristics (200-m head height providing up to 300 h of storage to a remote community with this load and renewable resources), PSH projects make economic sense for a wider range of diesel costs compared with Scenario 1using a 60-m head height. Although the increased head height approximately triples the storage capacity without increasing the reservoir sizes (because the technoeconomic model does not assign value to increased storage capacity), the cost savings are not significant. The value of the PSH system in the existing technoeconomic model is to store excess renewables and to meet the load when solar and wind energy are not available to fully do so. For this case study, the longest-duration storage needed to meet the load, when renewables cannot, never exceeds 2 to 3 days.

Table C-2 compares the impact of head height and a larger wind turbine generator on the findings for Scenario 1 for the load-following controller strategy at average forecasted diesel prices for the down-selected communities. Because the diesel-fired generators are used so little in the revised Scenario with additional storage capacity, the benefits of cycle charging are not realized as they are with the lower head height.

Table C-2 Increased Head Height Comparison, Scenario 1, Load-Following Controller Strategy

Category	Baseline	Scenario 1 – 100-hour PSH (60-m head height)	Revised Scenario 1 – 300-hour PSH (200-m head height)
Electric load (kWh/yr)	1,864,055	1,864,055	1,864,055
Diesel price ($/gal)	3.51	3.51	3.51
Diesel generators [(# units) kW]	(1) 410	(1) 410	(1) 410
Battery storage [duration (capacity in kWh)]		PSH -100 h (52,637)	PSH-300 h (167,457)
Solar PV (kW)		1,002	346
Wind turbines [(# units) kW]		(6) 600	(1) 900
Levelized cost of electricity (LCOE) ($/kWh)	0.45	1.18	1.11
Net present cost (NPC) ($M)	16.3	43.4	40.6
Non-fuel costs ($/year)	359,160	721,622	654,625
Fuel costs ($/year)	470,429	29,017	457
CO_2 emissions (kg/yr)	1,324,087	81,674	1,285
Fuel consumption (gal)	133,643	8,244	130
Diesel fuel use reduction (%)		94	99.9

Table C-3 compares the impact of head height, a larger wind turbine generator, and increased electricity demand (doubling the load as a rough approximation for electrifying space and water heating in this community) to the diesel-only baseline at average forecasted diesel prices for the down-selected communities. With increased electrical load, a second wind turbine is added and the reservoir is utilized more throughout the year to meet the load when the renewables cannot, offsetting more diesel fuel use and improving the economics of the PSH project. The Optimal System Type (Figure C-2) now includes a wider range of PSH project costs that are economical;

however, for the assumed PSH costs (including the ITC), diesel costs would need to be approximately $10 per gallon for a PSH to provide a lower-cost solution.

Table C-3 Increased Head Height and Load Comparison, Scenario 1, Load-Following Controller Strategy

Category	Baseline	Revised Scenario 1 – 300-hour PSH (increased head height)
Electric load (kWh/yr)	3,728,110	3,728,110
Diesel price ($/gal)	3.51	3.51
Diesel generators [(# units) kW]	(1) 810	(1) 410
Battery storage [duration (capacity in kWh)]		PSH-300 h (167,457)
Solar PV (kW)		1,324
Wind turbines [(# units) kW]		(2) 1,800
Levelized cost of electricity (LCOE) ($/kWh)	0.44	0.69
Net present cost (NPC) ($M)	32.2	50.4
Non-fuel costs ($/year)	709,560	776,108
Fuel costs ($/year)	928,861	38,903
CO_2 emissions (kg/yr)	2,614,409	109,498
Fuel consumption (gal)	263,849	11,051
Diesel fuel use reduction (%)		96

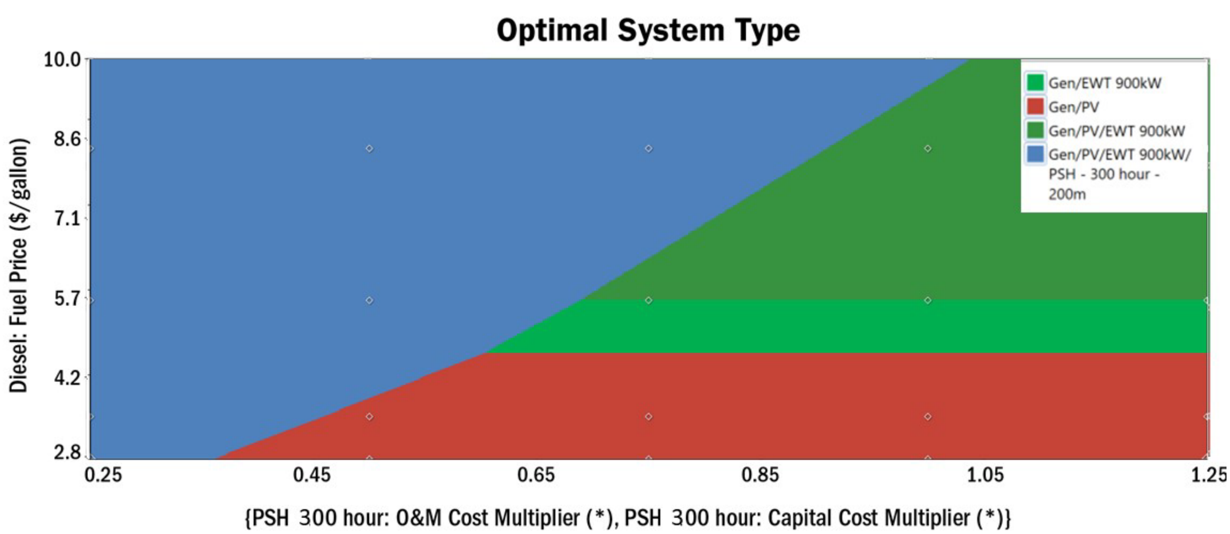

Figure C-2 HOMER Optimal System Type Plot – Scenario 1 with Increased Head Height and Increased Load

The existing model does not add value to storage capacity beyond meeting the load when the renewables cannot (in this case 2–3 days). Rural communities have not identified a clear need for storage beyond meeting the load. Further work is needed to better understand and quantify the need and value that multi-day storage projects can bring to rural Alaskan communities. The results of such work may determine whether PSH makes economic sense compared with other storage alternatives in certain communities: for example, those where fuel must be flown in and winter weather could prevent a delivery for multiple days, resulting in fuel shortages. In such a case, more than 3 days of storage could be extremely valuable. More effort is needed to identify and quantify such projects.

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