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

Paul Denholm, Marty Schwarz, and Lauren Streitmatter

National Renewable Energy Laboratory

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List of Acronyms

AC	alternating current
ACEP	Alaska Center for Energy and Power
AEA	Alaska Energy Authority
AEO	Annual Energy Outlook
ATB	Annual Technology Baseline
CC	combined cycle
CEM	capacity expansion model
CHP	combined heat and power
CT	combustion turbine
DC	direct current
DPV	distributed PV
EIA	U.S. Energy Information Administration
EV	electric vehicle
GVEA	Golden Valley Electric Association
GWh	gigawatt-hours
HEA	Homer Electric Association
HVDC	high-voltage direct current
IRA	Inflation Reduction Act
IBR	inverter-based resources
ICE	internal combustion engine
ITC	investment tax credit
LCOE	levelized cost of energy
LNG	liquified natural gas
MEA	Matanuska Electric Association
MMBtu	million British thermal units
MW	megawatts
MWh	megawatt-hours
NPV	net present value
NREL	National Renewable Energy Laboratory
O&M	operations and maintenance
PCM	production cost model
PM	particulate matter
PPA	power purchase agreement
PV	photovoltaics
REC	renewable energy certificate
RIRP	Regional Integrated Resource Plan
RPS	renewable portfolio standard
T&D	transmission and distribution
TWh	terawatt-hours

Executive Summary

The Alaska Railbelt utilities face growing challenges because of the declining supply of natural gas from the Cook Inlet and substantial projected price increases. Renewable energy in the form of wind and solar is a potentially cost-competitive option to reduce reliance on natural gas, which in 2022 provided nearly two-thirds of the Railbelt electricity demand.

This study examines the system-level costs and benefits of increased renewable energy deployment in the Railbelt grid,[1] in the context of a proposed 80% renewable portfolio standard (RPS). This work studies the period from 2024 to 2040 and uses a model that simulates the planning, evolution, and operation of the power system to identify the mix of resources that maintains system reliability at the lowest electricity system cost over the period of analysis. The model tracks several reliability metrics, including the ability to serve demand during all hours of the year, even when normal power system failures occur. The model includes several measures (and associated costs) to address the variable output of renewable resources, including additional operating reserves, fuel storage, cycling of fossil plants, and additional equipment needed to maintain system stability.

We evaluated three scenarios for comparison. The first scenario (referred to as No New RE) does not allow for any new renewable capacity. The second (Reference) is a scenario without an RPS requirement and represents the least-cost mix of resources. The third (RPS) enforces the RPS trajectory where at least 80% of generation in the entire Railbelt must be derived from renewable resources by 2040.

We assume that the following technologies (both existing and new) are eligible to meet RPS requirements: wind, solar, geothermal, tidal, hydropower, biomass, and landfill gas—and we include both existing and new deployments. Apart from retiring one relatively small power plant, the model includes and maintains **all** existing hydropower and fossil generation resources that continue to provide important reliability services. We also include the option to add new fossil fuel generators and energy storage. We capture the impact of existing federal tax credits, including the 40% investment tax for energy communities detailed in the main report, but assume no other changes to state or federal policies. We assume load growth resulting from population increases and electric vehicle (EV) adoption, with EV demand driving most of this growth (we assume that 20% of all vehicles in the Railbelt are electrified by 2040.)

The primary goal of this current study is to examine **differences** in total electricity system costs associated with deploying various amounts of renewable energy. In all scenarios, there will be many common costs, including maintenance of existing transmission and distribution assets, existing debt on generation assets, existing power purchase agreements, and many administrative costs. These are shown at the bottom of Figure ES-1. Because the goal of this study is to compare differences in system costs resulting from different generation mixes, we do not estimate these common costs. Instead, we focus on factors that may vary across the different scenarios, including investments in new fossil and renewable generators, and all fuel and other

1 The Railbelt power system extends from Fairbanks through Anchorage to the Kenai Peninsula and consists of five utilities: the Golden Valley Electric Association, Chugach Electric Association, the Matanuska Energy Association, City of Seward, and Homer Electric Association.

variable costs from both new and existing resources. The system cost includes measures needed to address the variability and uncertainty of renewable energy, sometimes referred to as "integration costs." Throughout this report, all results are presented in $2023.

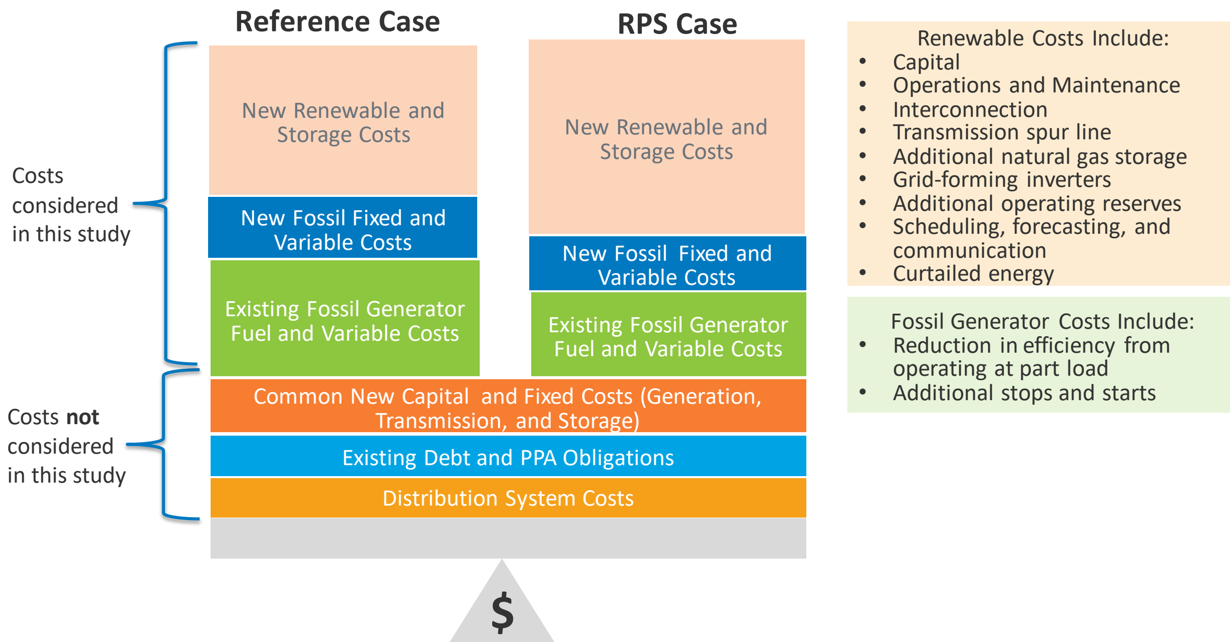


Figure ES-1. Types of energy system costs considered in the analysis, depicted for two of the three scenarios assessed (Reference and RPS). Because the overall study objective is to estimate the difference in costs among the three scenarios, common costs are not considered in the analysis.

The study presents six key findings.

Finding #1: The Least-Cost (Reference) Scenario Results in Substantial Deployment of Renewable Energy and Cost Savings

The primary driver for economic deployment of new renewables is their ability to reduce the quantity of fuel used in the existing fossil generators that serve the majority of Railbelt demand. The cost of gas generation is expected to increase substantially because of the expected need for imported liquified natural gas (LNG) at costs of at least $12.6 per million cubic feet ($2023) starting in 2028.[2] This results in fuel-related costs of the most-efficient (lowest-cost) gas-powered plants in the Railbelt increasing to more than $90/MWh in the late 2020s. Because of continued technology improvements and the assumed eligibility of wind and solar for the 40% investment tax credit (ITC), the cost of acquiring new solar and wind resources is expected to be substantially less than the cost of fuel for existing natural-gas-powered generators. Cost and performance of renewable technologies is based on the mid-case projections from the National Renewable Energy Laboratory's (NREL's) 2023 Annual Technology Baseline, and an Alaska-specific multiplier was applied to reflect higher capital and operating costs in Alaska. This result

[2] $12.2 per million CF in $2023.

in levelized costs that are expected to be below $80/MWh for solar and below $70/MWh for wind in the coming years. These costs are before consideration of the additional need for new wind transmission interconnections, natural gas fuel storage, and impacts of addressing renewable variability, which are included in the full cost accounting and discussed in more detail in Finding #6.

After the impact of the need to address variability and uncertainty of the wind and solar is included, these resources achieve "breakeven" conditions with variable costs of the most efficient gas plants operating on imported LNG. As a result of this growing cost differential, the model chooses to build large amounts of wind and some solar to reduce overall system costs, and the Reference scenario reaches a 76% contribution from renewables by 2040 (Figure ES-2). (We discuss potential trends that may occur after 2040 in Section 7.7.4.)

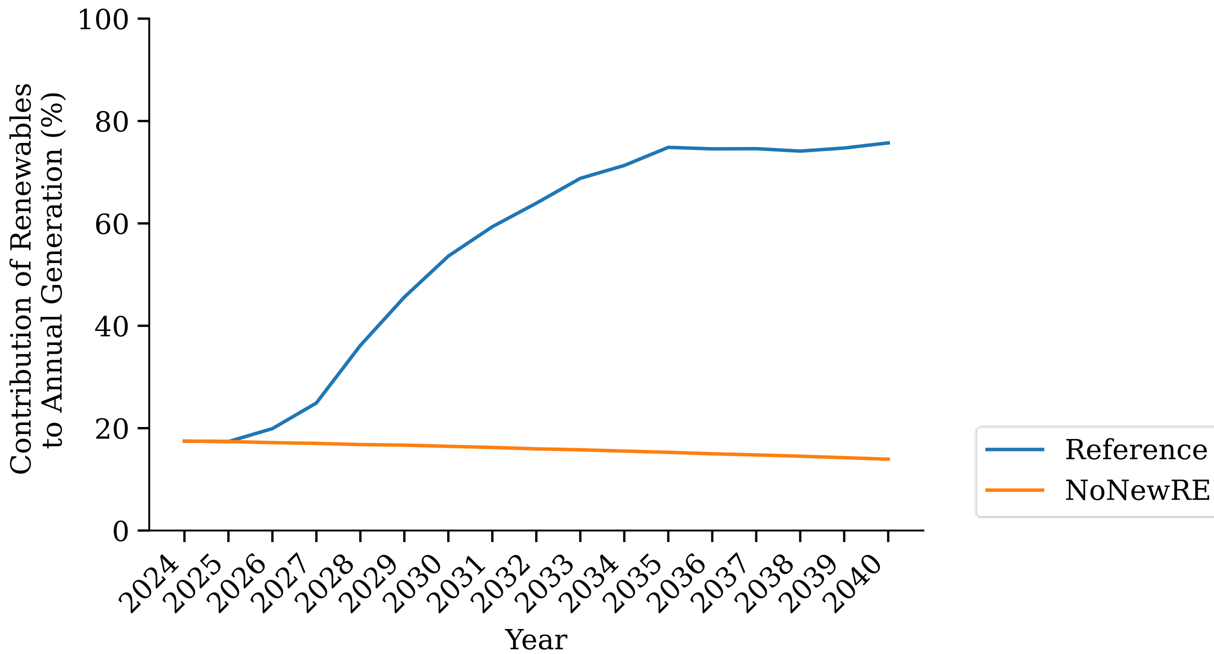


Figure ES-2. Contribution of renewable energy to the Alaska Railbelt grid in the Reference and No New RE scenarios

Figure ES-3 compares the evaluated costs in these scenarios, meaning the total of all system costs that may vary across the different scenarios (fixed costs for new generators and variable costs for all existing and new generators). Costs that do not vary across scenarios (e.g., servicing existing debt, transmission, and distribution costs) are not included in these comparisons. Figure ES-3 (top) shows the annual cost difference between the No New RE and Reference scenarios, with savings shown as a positive value and costs shown as negative. The increased cost of renewable energy purchases is more than offset by the decrease in fuel-related costs, which produces a net savings (black line) which averages about $105 million/year from 2030 to 2040.

The Reference scenario avoids about $4.2 billion in fuel and other costs from 2024 to 2040. This avoided cost requires renewable purchases and other costs of about $2.9 billion, resulting in a cumulative (non-discounted) savings from 2024 to 2040 in the Reference scenario of about $1.3

billion. Figure ES-3 (bottom) summarizes the difference in cumulative net present value (NPV) of evaluated costs over the evaluation period (2024–2040), across a range of discount rates.

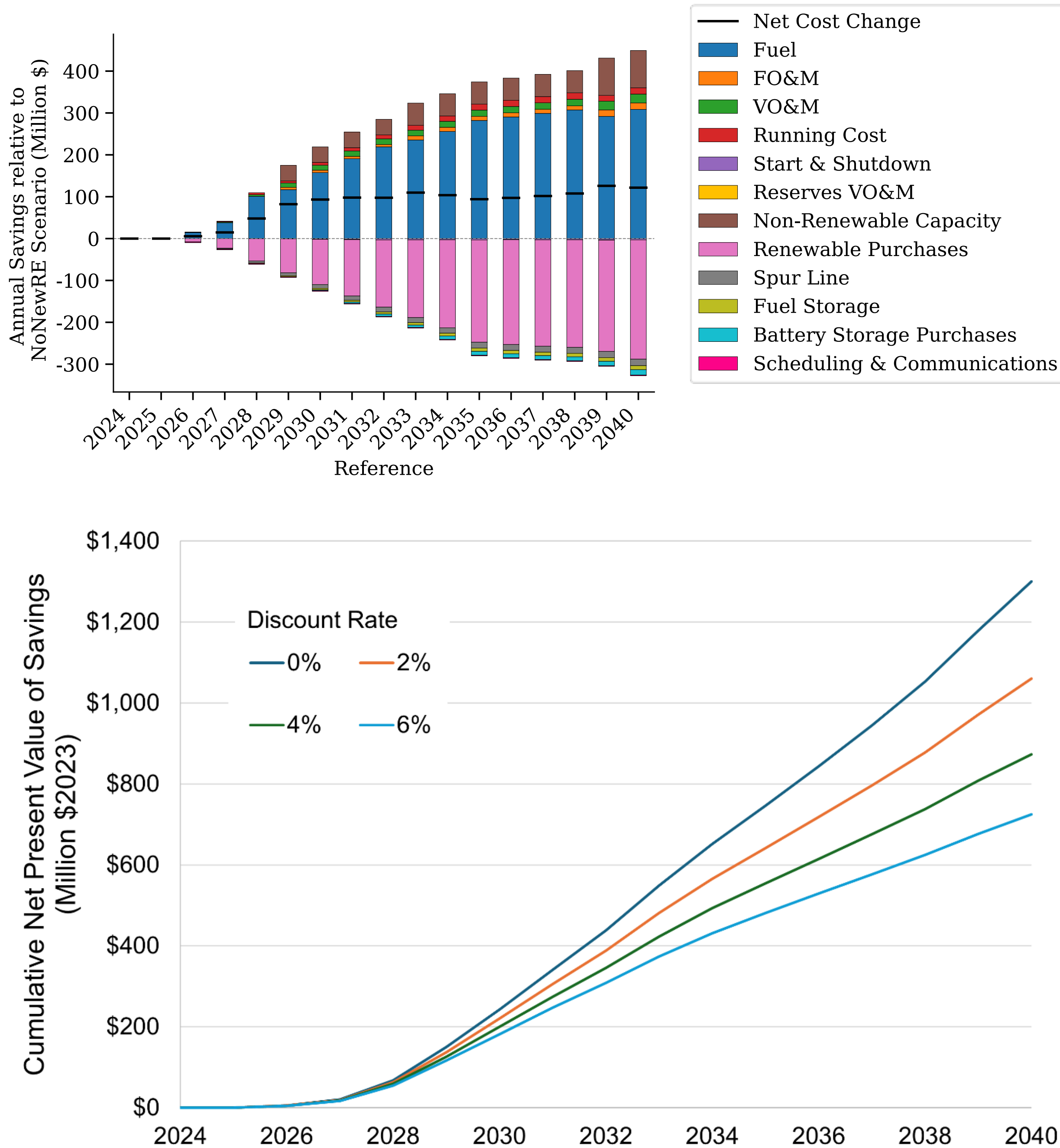
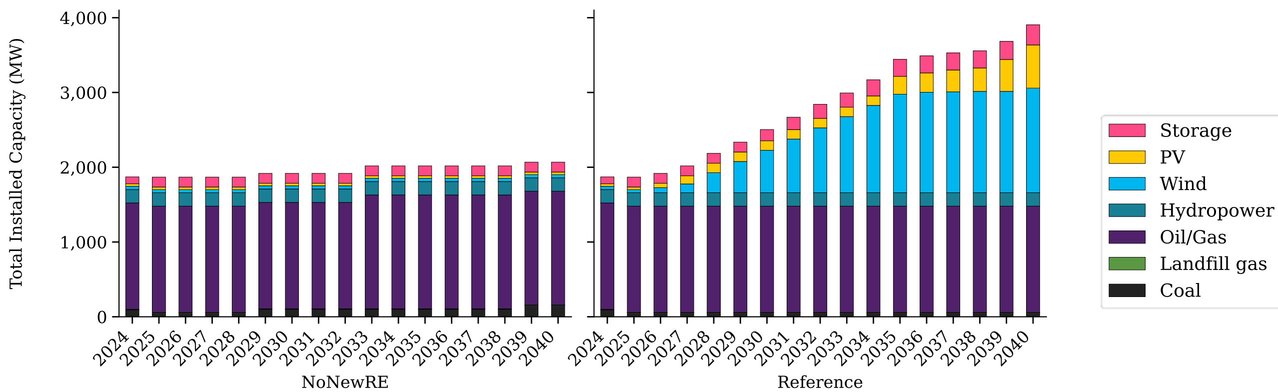


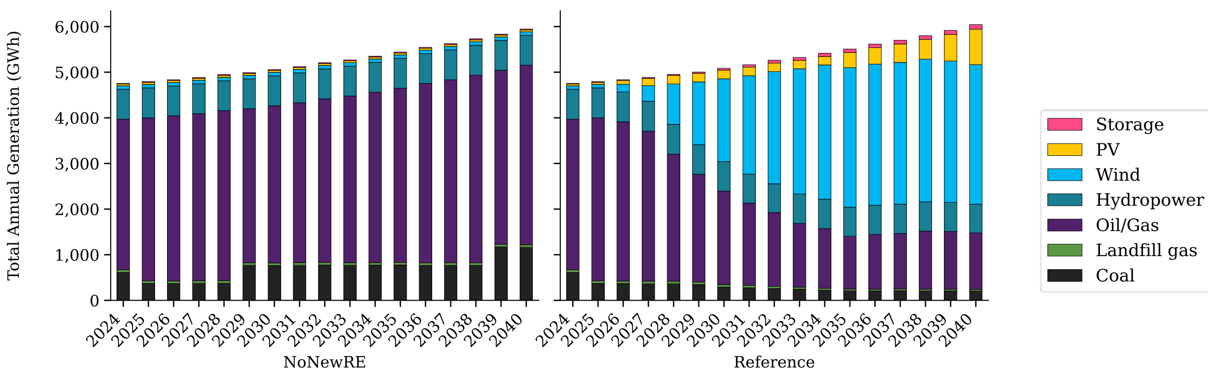
Figure ES-3. Total annual savings ($2023) associated with the Reference scenario compared to the No New RE scenario (top) shows annual savings of about $100 million per year in the early 2030s. The cumulative (non-discounted) savings from 2024 to 2040 (bottom) reaches $1.3 billion. The net present value of those cumulative savings is less, depending on discount rate used.

Finding #2: The Least-Cost (Reference) Scenario Relies on a Mix of Renewable Energy Resources and Locations

The Reference scenario deploys a mix of wind and solar resources, with wind providing most of the new capacity, growing to about 51% of annual generation in 2040. Figure ES-4 shows the capacity mix (top) and generation mix (bottom) between 2024 and 2040 for the No New RE and Reference scenarios.



a) Capacity by type



b) Generation by type

Figure ES-4. Capacity (top) and generation mix (bottom) over time in the No New RE and Reference scenarios

Finding #3: The 80% RPS Has Limited Impact on System Costs, With Much Greater Uncertainty Driven by Future Costs of Renewables and Other Resources

Adding the RPS requirement has a small impact on the overall savings associated with deployment of renewable energy compared to the Reference scenario. The Reference (least-cost) scenario achieves a 76% contribution from renewable resources in 2040. Above this level of renewable generation, additional renewables have a slightly higher cost than operating existing gas plants based on the increasing curtailment (unusable generation) of wind and solar during periods when the supply of renewables exceeds electricity demand. We assume that all renewable energy must be paid for regardless of whether it is used.

Figure ES-5 shows the annual savings associated with the Reference and RPS scenarios compared to the No New RE scenario. The Reference (blue) line is the annual savings shown previously in ES-3 (top). The RPS line shows the reduction in savings associated with the RPS scenario resulting in about a $19 million cost (or $19 million reduction in benefits compared to the Reference scenario) in 2040. This is less than a 2% decrease in cumulative savings. Because the additional cost occurs almost entirely in 2040 and given the significant uncertainty in future costs of renewables, fossil fuels, load growth, and other factors, there is essentially no meaningful difference between the Reference scenario and the 80% RPS scenario. For comparison, Figure ES-5 also shows how changes in the cost of renewables would have a greater impact on the overall benefits of deploying renewable resources. A 10% reduction in the cost of renewables (blue line) would increase the cumulative (non-discounted) savings by about $220M from 2024 to 2040 (to nearly $1.6 billion). Increasing the cost of renewables by 20% (purple line) reduces the cumulative benefits by about $470 M (to about $900 million).

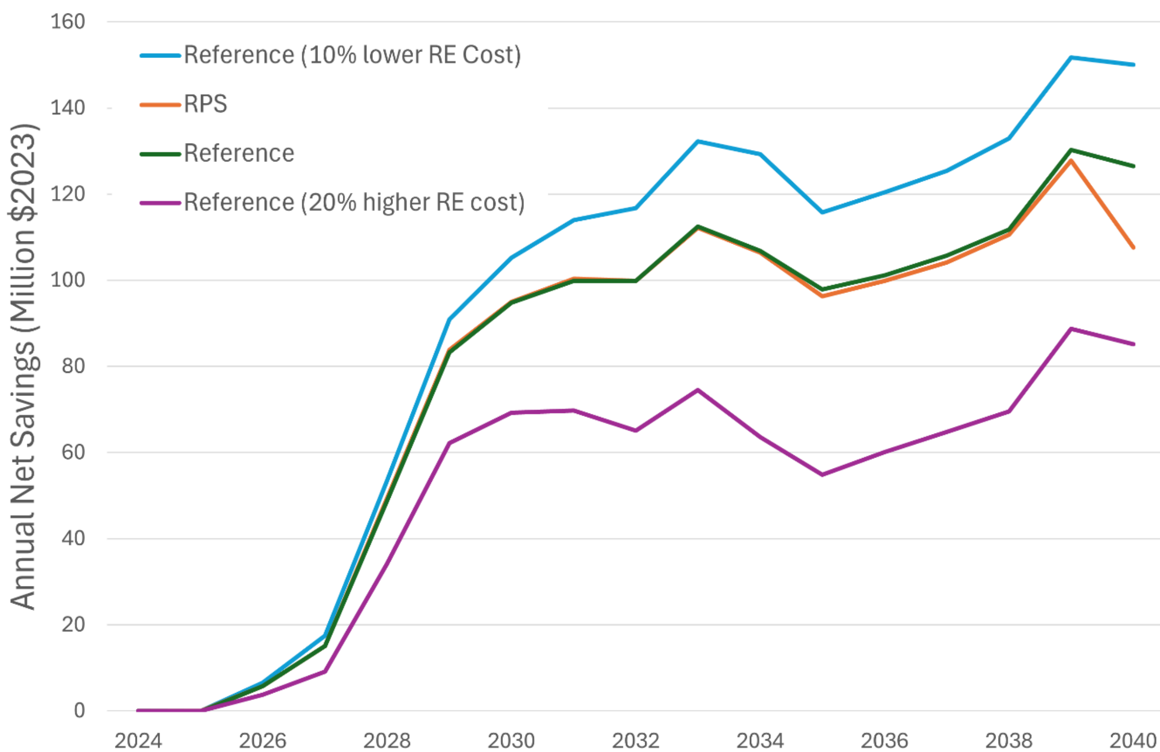


Figure ES-5. Requiring an 80% RPS reduces net savings associated by deploying renewable energy by about $19 million in 2040, which is less than a 2% change in cumulative savings. Overall, these differences are very small given the large uncertainty in future costs of fuels and renewable generation demonstrated by the much larger impact of a change in the assumed cost of renewable energy shown in the high- and low-cost renewable energy sensitivities.

These results suggest that any increase in system costs associated with an 80% RPS (compared to the Reference scenario) are likely to occur well past 2030, when there will be greater technological certainty and adjustments to RPS targets could be made to ensure least-cost deployments.

Finding #4: Demand Is Met in All Scenarios, Relying Heavily on Use of Existing Hydro and Fossil-Fueled Generators During Periods of Low Renewable Output

Wind and solar resources provide significant cost savings by avoiding fuel use in existing generators, but maintaining reliable operation in these scenarios depends significantly on continued use of existing hydropower and fossil generators. There are many periods of low wind and solar output, and these periods can last for many hours. This demonstrates a fundamental change in how electricity generation is planned, where renewables may provide the majority of the *energy* requirements on an annual basis, but with fossil resources providing a larger fraction of the *capacity* requirements.

Finding #5: High-RE Systems Will Require Substantial Changes to How the System Is Operated

The use of highly variable resources will require changes to how the system will maintain supply-and-demand balance. These changes include increased variation in output from existing fossil and hydropower plants and variation in transmission flows along the interties. We assume that planning and operating are performed in a coordinated manner to minimize cost and ensure resource adequacy and operational reliability across the entire Railbelt system, but that each utility can operate independently. This kind of operation, including Railbelt-wide joint dispatch, may require changes to contractual agreements or other practices to minimize the costs of operating the system.

The system will need to rely increasingly on dispatching wind and solar generators by curtailing their output (but still paying for the lost energy production at full price). The output from wind power plants can be controlled over the available output range in less than 1 minute, while the output from solar can be controlled over its output range in a few seconds. This will be needed to maintain supply/demand balance but also for the provision of operating reserves from renewable resources. Although the majority of operating reserves are derived from storage and existing fossil and hydropower plants, wind and solar may play an increasing role in providing operating reserves.

Finding #6: Cost Impacts of Addressing Variability and Uncertainty Are Modest Relative to Savings but With Remaining Uncertainties

All results presented in this analysis **include** the impact of several factors associated with integrating renewables and addressing variability and uncertainty, which increases the cost or reduces the net value of renewable energy. To clarify these changes in costs, Figure ES-6 illustrates how addressing renewable variability and uncertainty impacts the net overall value of renewable energy seen in the Reference scenario.

The left set of bars shows the total costs of renewable energy purchases and integration. The bottom (pink) bar is the cost of renewable purchases, which captures all the annual fixed and variable costs from the wind and solar power plants. By 2040, these direct project costs are about $285M/year. Additional direct costs assumed for both wind and solar include spur line cost and substation upgrades, natural gas storage and scheduling, communication, and forecasting, adding about $27M/year by 2040. Additional factors include the costs associated with additional starts and stops of power plants, the reduction in avoided natural gas associated with responding to variability and uncertainty, and additional operating reserves. These are "embedded" in the results seen previously, but additional analysis was performed to isolate these costs—which are estimated at about $18M/year by 2040. Combined, integration-related factors add about $45M/year in 2040 to the cost of purchasing solar and wind energy.

The right set of bars shows the value of the fuel and variable costs avoided by this generation. The difference in the total renewables cost (left bars) and avoided costs (right) produce the net value, which averages about $105 million per year beginning in 2030 as shown in Finding #1.

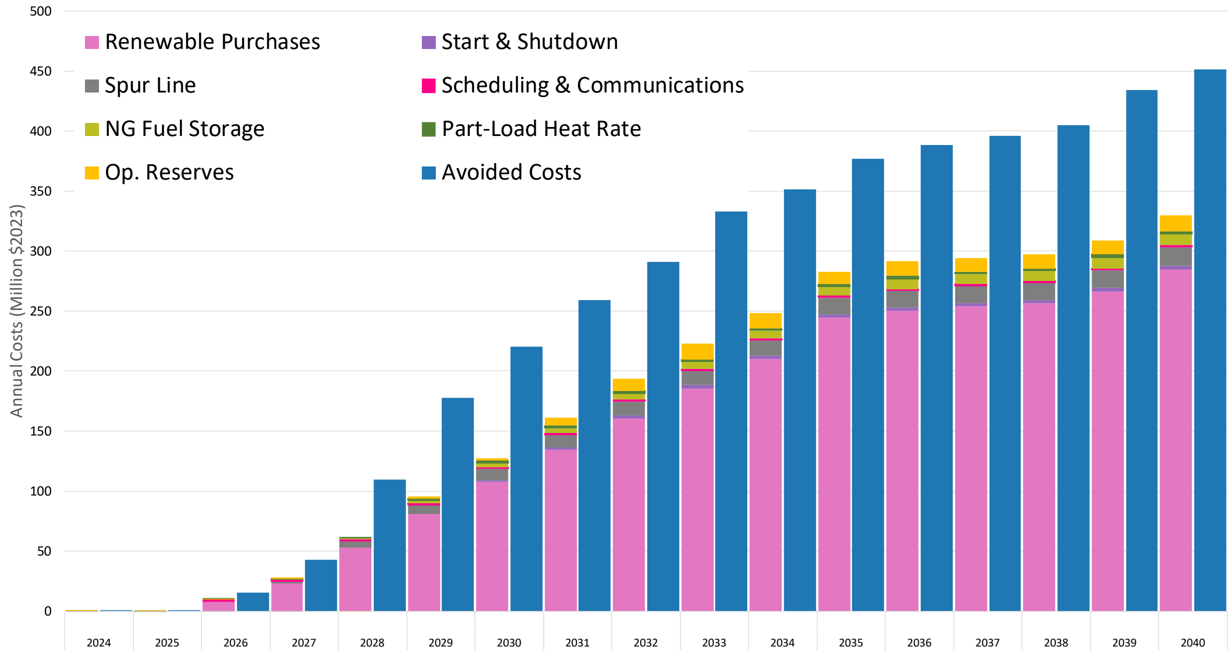


Figure ES-6. Annual costs of renewable energy, including integrating and addressing resource variability, are shown in the left set of bars. These costs are included in all scenarios but are broken out here for clarity. These increase renewable costs by about 16% compared to only the cost of the renewable generator and interconnection. The right bars show the value of avoided variable costs, with the difference being the net savings associated with renewable deployment.

These impacts are important not only to accurately assess the value of variable and uncertain resources but also to consider when allocating system costs across multiple utilities. There is still considerable uncertainty about some of these factors, particularly natural gas fuel storage. Additional issues related to maintaining system stability with high levels of inverter-based resources must also be addressed and may incur additional costs, which can be compared to the annual savings.

Conclusions and Caveats

The high projected prices for natural gas in the Railbelt region make the addition of renewable resources potentially cost-competitive despite challenges including development costs, moderate resource quality, and the small system size, which increase the relative impact of variability and uncertainty. Based on the assumptions used in this analysis, achieving more than a 75% contribution of renewables toward Railbelt electricity by 2040 appears to be the least-cost option. Moving to an 80% RPS slightly decreases the cumulative cost savings that result from renewables deployment (by about 1%) because the mismatch of renewable supply and electricity demand limits the ability of renewables to displace the remaining fossil generation without further cost reductions or use of new technologies such as seasonal storage.

There are several significant uncertainties around the scenarios evaluated in this work. Among them are the potential load growth driven by EVs and the future price of natural gas.

This analysis was conducted based on the information available within timing constraints. It is a starting point for additional research and consideration of investment or policy options. Other factors that can inform decision making are not considered here. The analysis results are not intended to be the sole basis of investment, policy, or regulatory decisions but are rather intended to improve the understanding of the cost impacts of an 80% RPS. Only direct costs are measured; other potential benefits of renewable energy such as energy security and reduced exposure to fuel price volatility are not considered. We also do not consider potential benefits associated with improved local air quality, which is a concern in several areas of Alaska's Railbelt that are at, or nearing, nonattainment status for fine particulate matter ($PM_{2.5}$). Additional modeling will be required to further validate the findings of this work, including changes and associated additional costs that are likely needed to ensure stable operation when nearly all the grid's electricity is being derived from inverter-based wind, solar, and storage.

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1 Introduction

The Alaska Railbelt utilities face growing challenges associated with the declining supply of natural gas from the Cook Inlet, with substantial price increases projected. Because of this, renewable energy in the form of wind and solar is a potentially cost-competitive option to reduce reliance on natural gas, which in 2022 provided nearly two-thirds of the Railbelt electricity demand.

This study performs an analysis of the system costs and benefits of adding renewable energy to the Alaska Railbelt grid. The study is motivated in part by a proposed 80% renewable portfolio standard (RPS).[3]

1.1 Study Goals

The primary goal of this current study is to examine **differences** in total system costs associated with deploying various amounts of renewable energy. We examine three main scenarios: 1) a scenario where no additional renewable energy is added, 2) a reference scenario that develops the least-cost mix of resources, and 3) an 80% RPS scenario.

The cost framework is conceptually illustrated in Figure 1. In all scenarios, there are many common costs, shown at the bottom of Figure 1. Because the goal of this study is to compare differences in costs resulting from different generation mixes, we do not estimate these common costs.[4] This study examines the elements shown at the top of Figure 1, including all factors that may vary under different portfolios and listed next.

[3] Described in proposed Senate Bill No. 101 33-LS0365\R at https://www.akleg.gov/PDF/33/Bills/SB0101A.PDF.
[4] Estimating total costs will be required to determine total revenue requirements and establishing rates and rate structures across various customer classes.

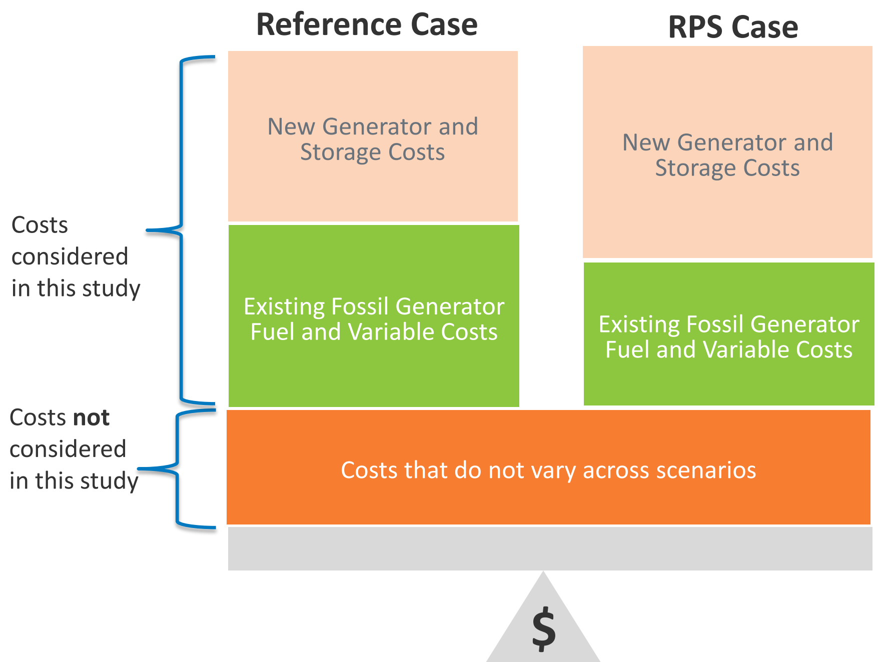

Figure 1. Types of energy system costs considered in the analysis, depicted for two of the three scenarios assessed (Reference and RPS). Because the overall study objective is to estimate the difference in costs among the three scenarios, common costs are not considered in the analysis.

Cost considered in the study include the following:

- Capital costs and fixed operations and maintenance (O&M) for all new renewable and fossil generators. For renewables, this could be obtained via a power purchase agreement (PPA).
- Cost premiums for siting and operating in Alaska.
- Variable costs associated with all existing plants and new plants, including fuel and O&M. This includes changes to fossil plant operation because of increased variability from:
  - Impacts of part-load heat rate because of increased cycling and load following
  - Additional startup costs of fossil plants.
- Costs associated with integrating new renewable resources, including:
  - Additional operating reserves
  - Grid-forming inverters
  - Additional natural gas fuel storage
  - Curtailment
  - Scheduling, communication, and forecasting costs
  - New transmission spur lines and substation upgrades.

Costs not included are those that are not expected to change across the various scenarios:

- Debt on existing assets and existing PPAs
- Fixed O&M on existing assets

- Administrative and billing costs
- 86 MW of energy storage currently proposed or under development
- Distribution system costs
- Maintenance and upgrades of the existing transmission network not associated with new renewable generators
- Upgrades to the Kenai Intertie associated with the Railbelt Innovative Resiliency Project
- Infrastructure associated with electric vehicles (EVs).

1.2 General Approach

The study follows the traditional principles of least-cost resource planning, sometimes referred to as integrated resource planning. The study uses a standard commercially available model that simulates the evolution and operation of the power system to identify the mix of resources that maintains system reliability at the lowest life cycle cost. It begins with the existing generation mix and adds new resources it identifies as providing electricity with the lowest overall cost, considering all fixed and variable costs. The model tracks several reliability metrics, including the ability to serve demand during all hours of the year, and maintains adequate reserves to address generator failures. Across the various scenarios, we report differences in generation mix and costs on both an annualized basis and net present value (NPV).

1.3 Caveats

This analysis was conducted based on the information available within timing constraints. It is a starting point for additional research and consideration of investment or policy options. Other factors that can inform decision making are not considered here. The analysis results are not intended to be the sole basis of investment, policy, or regulatory decisions but are rather intended to understand the cost impacts of increased renewable deployment, including impacts of an 80% RPS. Only direct system costs are measured—other potential benefits of renewable energy such as energy security and reduced exposure to fuel price volatility are not considered. We also do not consider potential benefits associated with improved local air quality, which is a concern in several areas of Alaska's Railbelt that are at, or nearing, nonattainment status for fine particulate matter ($PM_{2.5}$).[5]

[5] State of Alaska Department of Transportation & Public Facilities, *2020–2023 Statewide Transportation Improvement Program (STIP).* Approved November 23, 2021, Amendment 3 and Incorporated Administrative Modifications (State of Alaska Department of Transportation and Public Facilities, 2021). https://dot.alaska.gov/stwdplng/cip/stip/assets/STIP.pdf.

2 Overview of the Alaska Railbelt System

This analysis applies to Alaska's Railbelt power system, which extends from Fairbanks through Anchorage to the Kenai Peninsula and consists of four electric cooperatives and one municipally owned (not-for-profit) utility that serve about 75% of Alaska's electricity (Table 1).[6]

Table 1. Characteristics of Alaska's Railbelt Utilities

Data are for 2022 and from U.S. Energy Information Administration (EIA) Form 861.[a]

Utility	Annual Sales (GWh)	Customer Accounts (thousands)	Fraction of Railbelt Annual Demand (%)
Chugach Electric Association	1,903	113	43
Golden Valley Electric Association	1,244	48	28
Matanuska Electric Association	766	69	17
Homer Electric Association	453	33	10
City of Seward Electric Department	53	3	1
Total[b]	**4,404**	**266**	**100**

[a] "Annual Electric Power Industry Report, Form EIA-861 detailed data files." EIA, https://www.eia.gov/electricity/data/eia861/.

[b] This does not include about 254 GWh of electricity lost in transmission and distribution plus electricity consumed by the utility. The total net generation requirement in 2022 was about 4,698 GWh.

Overall, the system obtains the majority of its electricity from fossil resources, summarized in Table 2.[7]

Table 2. 2022 Railbelt Utility Generation Mix[8]

Technology	Capacity (MW)	Energy (GWh)	Generation Fraction
Natural gas	1,332.6	3,052	64%
Coal	117.5	545	11%
Oil	268.9	444	9%
Hydropower	189.8	578	12%
Wind	44.5	107	2%
Landfill gas	11.5	41	1%
Total	**1,965**	**4,766**	**100%**

[6] This table does not include some of the electricity consumed by large users that supply a portion of their own demand, including the University of Alaska Fairbanks or military bases.
[7] Data do not include the contribution from solar or small hydropower.
[8] Totals may not add up to 100% because of rounding. Data from EIA Form 860 and Form 923 for the year 2022. Only large generators are listed, and this does not include distributed resources. List includes Aurora but not CHP

Figure 2 illustrates Alaska's Railbelt region. Fairbanks is served by the Golden Valley Electric Association (GVEA). For the purposes of modeling, we combined the Chugach Electric Association (serving Anchorage), the Matanuska Energy Association (MEA), and the City of Seward Electric Department into a single zone we refer to as "Central" throughout this study. The Homer Electric Association (HEA) serves the Kenai Peninsula.

plants at UAF, industrial, or military sites. https://www.eia.gov/electricity/data/eia860/; https://www.eia.gov/electricity/data/eia923/.

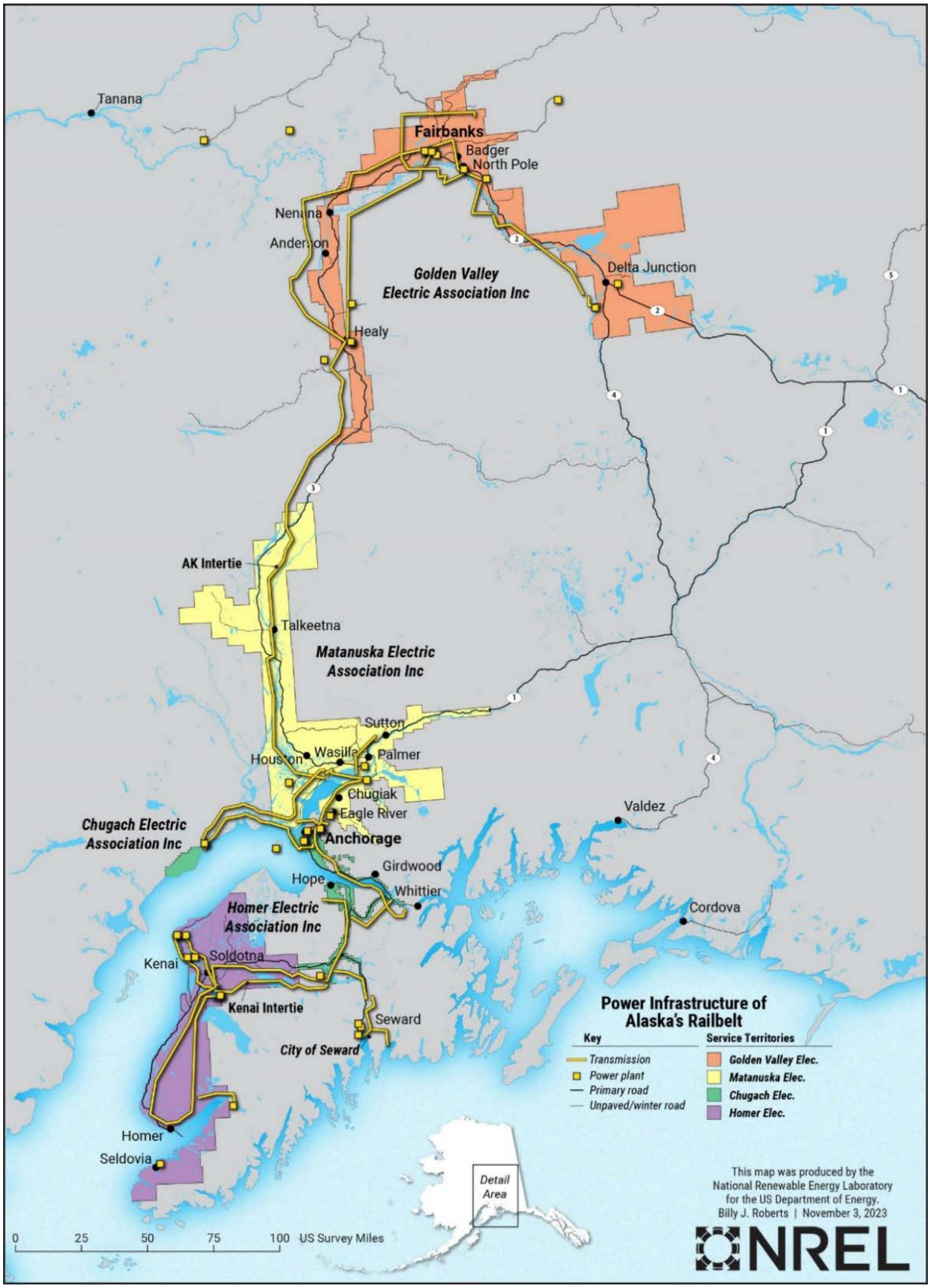

Figure 2. Map of Alaska's Railbelt power system[9]

[9]Data from Alaska Energy Data Gateway, Electric Service Areas. Alaska Energy Authority, 2020. https://gis.data.alaska.gov/datasets/DCCED::electric-service-areas/explore?location=61.907409%2C-147.863943%2C6.00.

3 Modeling Methods and Assumptions

This work studies the period from 2024 to 2040 and follows a standard least-cost planning approach using models and general assumptions described in this section.

3.1 Modeling Approach

The study uses a modeling approach illustrated conceptually in Figure 3 and described in detail next.

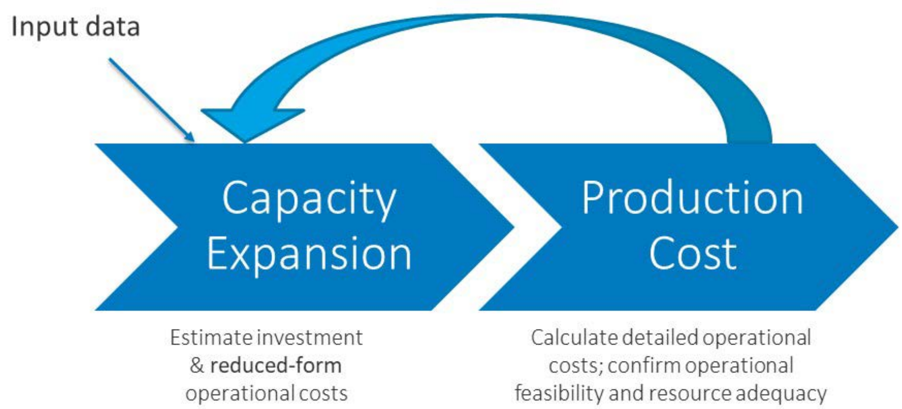

Figure 3. Summary of study modeling flow[10]

3.1.1 Capacity Expansion Modeling

Capacity expansion analysis is the central modeling element of the study because it produces the generation mix and estimates the total system costs associated with each scenario. Within the capacity expansion modeling step, the study identifies future generation and transmission portfolios to achieve renewable energy targets at least cost.

Modeling the expansion of the bulk power system, including utility-scale (noncustomer-sited) generators and transmission, is performed with the PLEXOS Long-Term Model.[11] The capacity expansion model (CEM) considers capital costs, fixed and variable O&M costs, and fuel costs, moving forward in time in 1-year increments over the study period (2024–2040). Investment decisions for the type, amount, and location of new capacity are determined with a least-cost optimization that ensures the provision of power system resources required to meet load reliably in all hours and meets all other constraints and policies.

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[10] Brinkman, Gregory, Dominique Bain, Grant Buster, Caroline Draxl, Paritosh Das, Jonathan Ho, and Eduardo Ibanez et al. 2021. *The North American Renewable Integration Study: A U.S. Perspective—Executive Summary*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-79224-ES. https://www.nrel.gov/docs/fy21osti/79224-ES.pdf.
[11] https://www.energyexemplar.com/plexos.

3.1.2 Production Cost Modeling

The production cost model (PCM) is used to simulate the hourly operations of the future systems identified by the CEM and to validate the ability of those systems to balance generation and load.[12] We use the PLEXOS Medium-Term/Short-Term model, a commercially available PCM (sometimes referred to as a unit commitment and dispatch model). This is the same model used in a previous NREL report that analyzed several aspects of how Alaska's Railbelt grid might be operated in 2040 when providing 80% of electricity generation from renewable energy resources.[13]

The system details generated by the CEM (types, capacities, and locations of transmission, renewable generation, and conventional generation), are passed to the PCM, along with hourly load and variable generation data and hourly operating reserve requirements.[14] The PCM calculates operational costs and ensures that adequate reserves are maintained under the given set of weather and load conditions.[15]

This type of simulation is an iterative process. The PCM provides necessary feedback to the CEM to determine more definitively if the built system can operate feasibly. If PLEXOS identifies unserved energy (i.e., load that the system is unable to serve) or other constraint violations (e.g., reserves shortages or hydro violations), the CEM can be refined to incorporate additional constraints or requirements, which directly impacts the resulting build decisions.

3.2 Reliability- and Resource-Adequacy-Related Assumptions

3.2.1 Planning and Operation

We assume that planning is performed in a coordinated manner to minimize cost and ensure resource adequacy and operational reliability across the entire Railbelt system. Practically speaking, this does not require a single entity to plan the system but does require coordination across the utilities—including likely joint planning of assets, particularly those generation assets that provide energy to multiple utilities. This process could include joint ownership of plants, shared PPAs, or any other policy mechanism that maximizes planning efficiency.

Likewise, we assume coordinated system operation (joint dispatch), meaning that the generators and transmission assets are operated in a manner to produce the overall least systemwide cost, while maintaining independent reliability in each of the utility zones. We do not include the costs associated with full system coordination but do include an additional cost in the Reference and RPS scenarios associated with scheduling and forecasting additional renewable resources (see

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[12] This model was used in the previous Railbelt study.

[13] Denholm, P.; M. Schwarz, E. DeGeorge, S. Stout, and N. Wiltse. 2022. *Renewable Portfolio Standard Assessment for Alaska's Railbelt*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-5700-81698.

[14] Operating reserves represent generator capacity available to address variability and uncertainty in generation supply and demand and include contingency, flexibility, and regulating reserves. Reserves can be held by partially loaded generators (or offline generators, depending on the type of reserve) with sufficient ramp to respond in a given time frame.

[15] NREL often evaluates subhourly variability, but insufficient data were available to consider the impact of increased subhourly variability in this study; instead, we used estimates for operating reserve requirements needed to address ramp rate requirements within the hour.

Section 3.3.5). This study did not assume any specific regulatory approach that might achieve this type of operation, and this does not require utilities to merge or otherwise lose independence to ensure local reliability and rate setting.

We assume that each utility zone can be islanded and operated in isolation and maintain resource adequacy. During islanded operation, the 80% RPS requirement is not enforced.

3.2.2 Resource Adequacy (Planning Reserve Margin) Assumptions

We require sufficient capacity to reliably serve load during all hours of the year, including times of system stress, which are often peak-load or peak-net-load[16] conditions—of which the magnitude and timing are uncertain. The total firm capacity requirement is typically defined as expected peak load in each year plus a predetermined generation capacity margin (the planning reserve margin) for reliability. Based on previous Railbelt utility studies, we maintain a 30% planning reserve margin in each zone, meaning that installed dependable capacity must be at least 30% higher than the expected peak demand in each year.[17] The capacity must be located within the zone, so imports on the interties do not count toward the planning reserve margin.

Firm capacity differs from total nominal or nameplate capacity—it is the portion of nominal capacity that is reliably available during times of system stress. We assume that all existing thermal and hydropower plants are eligible to contribute to the planning reserve margin. The ability of wind and solar resources to serve peak demand (capacity credit; see Appendix A) is substantially lower than those of hydropower and thermal assets and described in the technology discussions in Appendix C.

3.2.3 Operational Reliability Assumptions

We require operating reserve to ensure that there is sufficient capacity that can quickly vary output to 1) address unexpected generator or transmission line outages; 2) respond to short-term random variation in load, wind, and solar output; and 3) balance out longer-term (up to 1 hour) uncertainty and forecast errors in net load, including ramping.[18] We require contingency spinning reserves to address rapid failures of large plants or transmission lines (80 MW) and regulating reserves (2% of load in Central and HEA and 5% in GVEA) to address rapid and unpredictable variations in load. We also include additional operating reserves to address the variability of wind and solar (see Section 3.3.2). Further description is provided in Appendix B.7.

3.3 Addressing Wind and Solar Variability and Uncertainty

The variability and uncertainty of wind and solar can create changes in how the system is planned and operated. These changes are sometimes considered in terms of an "integration cost,"

[16] The concept of "net load" is commonly used in systems with large amounts of renewable resources and refers to the normal load minus the contribution of wind and solar. This is important because it determines the amount of hydropower, fossil, or other resources needed to ensure reliability.
[17] See section 8.1 in the 2010 Alaska Railbelt Regional Integrated Resource Plan (RIRP) 2010. https://www.akenergyauthority.org/Portals/0/Publications%20and%20Resources/2010.02.01%20Alaska%20Railbelt%20Integrated%20Resource%20Plan%20(RIRP)%20Study.pdf?ver=2022-03-22-115635-150.
[18] See Table B-6 for further discussion of treatment of operating reserves.

although there is no clear definition of what these costs are or how to quantify them.[19] In some scenarios, they may be direct hardware costs associated with the installation of individual renewable energy projects. These costs are captured in the project costs as modeled, and for wind, include the costs of transmission interconnections. Many historical integration costs studies focused on the change in value of renewable energy as it is deployed compared to more traditional generation sources.[20]

Overall, we capture the impact of wind and solar on the overall system cost via the simulation of systems with and without the addition of renewable energy. The following subsections discuss how we consider six general categories of impact, including the potential changes to system costs.

3.3.1 Increased Cycling and Part-Load Operation of Thermal Plants

Renewable energy resources can reduce the amount of variable costs associated with operation of fossil-fueled power plants, including fuel, O&M, and starts. As an example, a 2013 National Renewable Energy Laboratory (NREL) study of wind and solar providing 33% of the electricity in the western United States found that inclusion of thermal plant cycling reduces the value of renewable resources by $0.1–$0.7/MWh (in $2011).[21]

As the net load variability increases, thermal plants will spend a greater fraction of time operating at part load and with an increased number of generator starts. Power plants operating at part load are less efficient than at full load, meaning that their average heat rate under scenarios with more wind and solar may increase. This tends to somewhat reduce the overall benefits of wind and solar. This impact is captured using heat rate curves, which measure how the performance of the plants changes as a function of generation.

The net benefits of wind and solar may also be reduced from the increased number of thermal plant starts. During startup, power plants require additional fuel to spin up the turbine and synchronize it to the grid and incur costs associated with wear and tear, increased maintenance, and other direct costs. Values for start fuel requirements and other costs were obtained from the Railbelt utilities and other sources described in Appendix B.2.

3.3.2 Increased Operating Reserves

Wind and solar add variability to net load across multiple time scales and with various degrees of uncertainty. To address variability and uncertainty of wind and solar, we add operating reserves.

Operating reserves causes three changes to system planning and operation that increase the costs (or decrease the value) of wind and solar. The first is if new capacity resources are required specifically to address the operating reserve requirements. The second change is less-efficient

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[19] Michael Milligan, Erik Ela, Bri-Mathias Hodge, Brendan Kirby, Debra Lew, Charlton Clark, Jennifer DeCesaro, and Kevin Lynn. 2011. "Integration of Variable Generation, Cost-Causation, and Integration Costs." *The Electricity Journal* 24(9): 51–63. ISSN 1040-6190. https://doi.org/10.1016/j.tej.2011.10.011.

[20] A. D. Mills, R. H. Wiser, "Changes in the economic value of photovoltaic generation at high penetration levels: A pilot case study of California" in 2012 IEEE 38th Photovoltaic Specialists Conference (PVSC) (2012), pp. 1–9.).

[21] Lew, D., Brinkman, G., Ibanez, E., Florita, A., Heaney, M., Hodge, B. M., Hummon, M., Stark, G., King, J., Lefton, S. A., Kumar, N., Agan, D., Jordan, G., and Venkataraman, S. Western Wind and Solar Integration Study Phase 2. United States: 2013. Web. doi:10.2172/1095399. https://www.nrel.gov/docs/fy13osti/55588.pdf.

dispatch.[22] Because more "headroom" is needed to increase output, thermal plants will spend more time operating at partial load, and there will be greater use of batteries to provide reserves (meaning that they cannot be used to provide other services), or the system may require more curtailed wind and solar (decreasing their ability to offset fossil generators).[23] The third change is additional cycling of power plants responding to subhourly variability. In combination, these impacts result in a reduction in avoided costs compared to a scenario where an increase in operating reserves is not required.

The amount of reserves needed as a function of wind and solar deployment varies significantly based on the size of the system.[24] In large systems, a relatively small increase is required—often just a small percentage of the combined output of wind and solar. This is because of the impact of spatial variability, which smooths the combined output of a diverse supply of resources. As the system decreases in size, there is less diversity, and the net ramp rates increase. There are limited studies of reserve requirements for a system the size of Alaska.[25] Based on the relatively small size of the Alaska system and limited data available, we assume a much higher level of reserves compared to Lower 48 utility systems.[26] Operating reserves are required primarily to address the unpredictable portion of the wind and solar variability or to address variability that occurs faster than normal system scheduling and dispatch. We make the conservative assumption that wind ramp events are essentially unforecastable in the subhourly time frame.

Based on this assumption, the available wind and solar data sets require maintaining sufficient operating reserves to accommodate a 60% change in output from the aggregated wind resources in each zone in less than 30 minutes. We meet this requirement in the form of two operating reserve products. The first is a traditional rapid-response regulating reserve product from a synchronized generator or energy storage equal to at least 20% of wind output that addresses the short-term (<10-minute) variability. The second reserve product (supporting 40% of wind output) is a slower (<30-minute) flexible ramping product used to address the longer-term variability. This product has been used in a variety of locations in the Lower 48 as a lower-cost alternative to addressing solar and wind variability only with fast-responding units. With a combination of reserve products, initial response to an unforecasted ramping event is from the

[22] Hummon, M., P. Denholm, J. Jorgenson, D. Palchak, B. Kirby, and O. Ma. 2013. *Fundamental Drivers of the Cost and Price of Operating Reserves*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-58465.
[23] This is sometimes referred to as the "opportunity cost" of providing reserves particularly in regions with wholesale markets because a unit providing reserves cannot sell energy losing the opportunity to increase revenue.
[24] P. L. Denholm, Y. Sun, and T. T. Mai. 2019. *An Introduction to Grid Services: Concepts, Technical Requirements, and Provision from Wind*. Golden, CO: National Renewable Energy Laboratory. NREL/PR-6A20-73590. https:/doi.org/10.2172/1505934.
[25] The Hawaii Electric system is somewhat close in size and physically small, which reduces opportunities for spatial diversity. However, this system has very different load patterns, and most renewable capacity is in the form of solar—so likely of limited value. An example study of this system is https://www.ferc.gov/sites/default/files/2020-08/W3B-3_Ela.pdf.
[26] NREL typically calculates reserve requirements by examining the size of unforecastable ramp events from potential combinations of new wind and solar generators. This requires detailed subhourly data sets, which were not available for this study. For additional discussion, see https://www.nrel.gov/docs/fy14osti/61016.pdf.

faster regulating reserves (which begin responding in a few seconds or less), and sustained longer ramps are then addressed by flexibility reserves.[27]

We also require 30% of online solar to be supported by operating reserves (20% from fast-responding regulating reserves and 10% by a flexible ramping reserve).[28] In addition to these requirements, we maintain the 80 MW of fast contingency reserve response, even when the largest thermal generator online is less than this amount. This means that during periods of the highest level of wind and solar contribution, we exceed the 60% requirement.

Note that operating reserves are not intended to balance supply and demand over longer (multi-hour) time periods or provide energy during periods of low wind and solar output. Maintaining service during periods of low wind and solar output is accomplished via the planning reserve margin, which establishes resource adequacy.

3.3.3 Natural Gas Fuel Storage

The Alaska Railbelt system depends on a limited natural gas pipeline supply network and has limited storage capability. This may increase the challenge of responding to net load variability using the existing natural gas power plant fleet. Deploying renewable energy will decrease the average natural gas consumption rate. However, it can increase the *changes* in consumption rate (flow rate in the natural gas supply system), and the actual supply needed is less predictable. This presents challenges to how the system is scheduled as well as the technical capacity of the system to vary the supply of natural gas. To address this challenge, Railbelt utilities are considering the addition of natural gas fuel storage, acting as a buffer to address the increased variability and uncertainty of natural gas demand. To capture this, we included the cost of fuel storage required to supply natural gas fuel for thermal generation entirely from storage for 99% of all 24-hour periods, assuming a 40% forecast error in renewable resources. We note that this quantity of storage does not ensure deliverability and further analysis is required to ensure the variability in demand can be met. The capital cost of new aboveground fuel storage is assumed to be $2.5/cubic foot, which we assume is not eligible for the investment tax credit (ITC) and financed at the same rate as a new gas plant.[29] This cost is applied proportionally to all additional renewable capacity based on the average contribution of all renewables to the increased variability of natural gas demand.[30]

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[27] P. L. Denholm, Y. Sun, and T. T. Mai. 2019. *An Introduction to Grid Services: Concepts, Technical Requirements, and Provision from Wind*. Golden, CO: National Renewable Energy Laboratory. NREL/PR-6A20-73590. https:/doi.org/10.2172/1505934.

[28] We do not require operating reserves to address longer-term solar ramps driven by sunrise and sunset because these are predictable and addressed via ramp constraints in the system dispatch. The model ensures that the available generation capacity can ramp to meet predictable hourly ramps in the same manner as predictable changes in load.

[29] Note that this is the capital cost, not the variable cost of fuel storage. The costs are based on correspondence with Chugach, reporting a value of $30 million for 12 million cubic feet of storage. Note that because we apply these costs as a proportion of renewable capacity, this implies a continuous deployment of incremental amounts of gas storage, while actual deployment would likely occur in larger discrete projects to take advantage of economy of scale.

[30] This cost can *potentially* be compared to the cost of existing underground storage provided by Cook Inlet Natural Gas Storage Alaska. For example, see 2023 Expansion Inception Rates at https://aws.state.ak.us/OnlinePublicNotices/Notices/View.aspx?id=213184. These costs are quoted on a per unit

3.3.4 Renewable Curtailment

The impact of renewable curtailment on overall value is included in the analysis. All potential renewable energy production must be paid for **at full price** regardless of whether it is used. Although curtailment of wind generation would produce a small reduction in O&M costs, this value is not included.

3.3.5 Renewable Scheduling and Forecasting

We add a system scheduling, communications, and forecasting cost of renewables once wind and solar provide more than 20% of annual generation. The assumed cost is $1.5 million/year based on scheduling tariffs from ISO-NE.[31] Note that this does not include all the costs associated with establishing joint dispatch including investments in software, communication systems, and training. Joint dispatch would provide benefits even without the additional renewables and is assumed in all scenarios—including the No New RE scenario—and the benefits of joint dispatch are not isolated to compare to potential additional costs.

3.3.6 Accommodating Inverter-Based Resources

Large deployment of inverter-based resources including solar, wind, and battery plants can result in decommitting (turning off) thermal and hydropower resources that use synchronous generators. This can reduce the inherent inertial response and provision of fault current available in the grid in addition to other services that stabilize the system. To replace these services, several options are possible, including the use of grid-forming inverters, other power-electronics-based options, increased transmission capacity, or use of synchronous machines, including synchronous condensers, which includes modifying existing generators to act as synchronous condensers. A combination of approaches is likely; note that the cost-optimal mix of these resources has not been identified. For the purposes of the analysis, we assume that grid-forming inverters will be deployed as part of the solution to maintain stability. We therefore require all new wind solar, wind, and battery plants to have grid-forming inverter capabilities in the year at which instantaneous contribution of inverter-based resources in any region during any point in the year hits 50%. We assume a 20% cost premium over grid-following inverters. We also compare potential overall savings to additional measures that may be necessary, including the use of dedicated new synchronous condensers.

4 Scenarios Evaluated

4.1 Scenario Overview

We evaluated three scenarios for comparison. The first scenario (referred to as No New RE) does not allow for any new renewable construction. The second (Reference) is a reference scenario

actually stored as opposed to the cost of physical capacity. To make this comparison, we would need to understand the actual utilization of energy storage in the future, which would require a greater understanding of the forecast error in wind and solar power production and the actual storage withdrawals, and we do not have good estimates. However, assuming a range of utilization between 10% and 20% per day, the assumed cost of $2.5/cubic foot capital cost would correspond to a variable cost of about $3–$6/MCF.

[31] https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_4/section_iva.pdf.

without an RPS requirement and represents the overall least-cost mix of resources. The third (RPS) enforces the RPS trajectory. Two sensitivities are also performed for the Reference and RPS scenarios, which examine the impact of higher and lower renewable resource costs. Each scenario maintains the same minimum planning reserve margin requirement.

4.2 RPS Target

The RPS in this study approximates the **proposed** policy in Senate Bill 101.[32] Table 3 summarizes the RPS targets, defined as fraction of annual generation (not sales).[33] The RPS as modeled in this analysis is defined as a target for the entire Railbelt and is not enforced for individual utilities. This formulation of the RPS implies frictionless trading of renewable resources between zones via renewable energy certificates (RECS) or other mechanisms and would require appropriate allocation of costs associated with integration and balancing among the participants. We do not extend REC trading beyond the Railbelt, and we assume full compliance with the RPS.[34] We also did not consider other possible policy options such as credit banking.[35] We do not consider requirements that may occur after 2040 but discuss potential cost trends that may occur after 2040 in Section 7.7.4. The RPS scenario we evaluate requires sufficient generation capacity to meet 80% of annual generation after considering the deliverability of each renewable resource because of transmission congestion, losses in storage, and curtailment resulting from oversupply during periods of high renewable energy output or low electricity demand.

Table 3. Assumed Railbelt RPS Requirement Based on Proposed Senate Bill 101

Year	Value
2027	25%
2035	55%
2040	80%

The RPS target is enforced in the planning process and not during system operation, including periods of extended outage condition.[36] There is no preference for dispatch of RE resources during operation on any basis other than variable cost.

4.3 Eligible Technologies

We assume that RPS-eligible technologies include wind, solar, geothermal, tidal, hydropower, biomass, and landfill gas and include both existing and new deployments. The SB101 language

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[32] https://www.akleg.gov/PDF/33/Bills/SB0101A.PDF.

[33] Our study assumes that the RPS requirement must be met for the year listed and so is more aggressive than the SB101 requirement, which sets the target the last day of each year.

[34] The current bill includes a $20/MWh compliance penalty, but we assume full compliance to determine the actual cost associated with additional renewables.

[35] For additional discussion of RPS design and features, see Renewable Portfolio Standards, NREL, https://www.nrel.gov/state-local-tribal/basics-portfolio-standards.html.

[36] We assume that achieving the RPS is contingent on normal operation of the interties but that maintaining reliability is not. Average outage rate on the intertie from 2012 to 2021 was about 1.3%. https://www.akenergyauthority.org/Portals/0/RailBeltEnergy/IMC/2022/2022.05.20/8A.%20%20AlaskaIntertieStrategicPlanningUpdate%202022-05-20%20rev0.pdf?ver=2022-05-19-133503-887.

includes energy efficiency; however, this was not included in the analysis because of lack of data (amount and cost of savings and impact on load shape).

4.4 Other Policies

We include all federal policies, including the investment and production tax credits as currently modeled in the NREL 2023 Annual Technology Baseline (ATB) (discussed in detail in Section 6.4.1). We assume no other changes to state policies, meaning:

- No state carbon pricing or other policies
- No changes to state air quality standards or emission control requirements/emissions fees.

5 Reference Assumptions

The study began with the development of a power system model of the existing Alaska Railbelt system that could be used as an initial starting point for the 2024 simulation year. After establishing a base system, we developed a set of assumed changes that are common across scenarios, including load growth and certain resource additions and retirements between 2024 and 2040. Note that throughout this report, all data we share is from publicly available data sources.

5.1 Load

5.1.1 Load Shape

For each of the three zones (GVEA, Central, and HEA, shown in Figure 2), we first established an initial load shape.[37] Hourly load shapes are based on 2018 because it corresponds to the availability of simulated wind resource data. These hourly load profiles form the basis for the total generation requirement in each region (considering transmission and distribution losses).

Figure 4 provides examples of the hourly load profiles in each of these regions, which varies as a function of time of day and season. Figure 4(a) shows daily load profiles in 2018 for the Central region (combining Chugach Electric Association, MEA, and Seward), GVEA, and HEA in the 4-day period with highest (systemwide) annual demand, which occurred during the hour ending at 7 p.m. on January 25. Figure 4(b) shows the total systemwide demand for this period as well as for the periods with the lowest systemwide demand in October and the highest systemwide summer demand in July.[38] The Railbelt system is strongly winter-peaking.[39]

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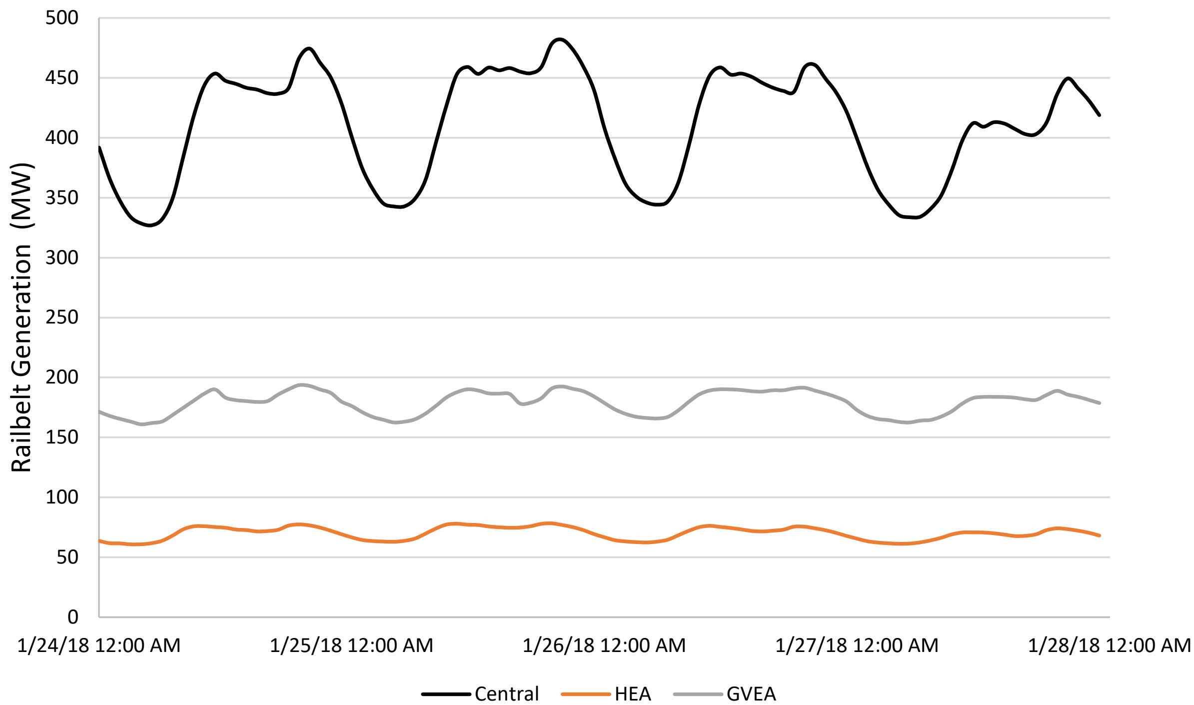
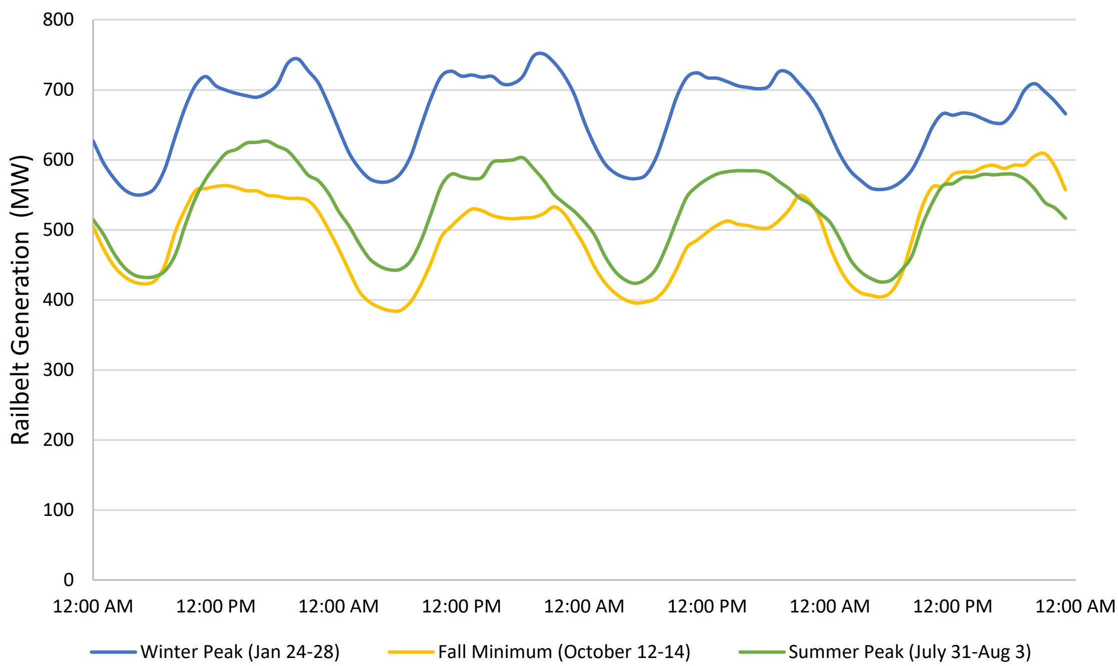
[37] Data provided by AEA.

[38] Maximum and minimum demand periods for individual utilities may be different from those for the overall system. Note that the terms generation, load, and demand throughout this report refer to the generation required to serve the end-use demand plus transmission losses. Therefore, numbers will generally be about 6% higher on average compared to actual sales to end customers. This reflects transmission and distribution losses.

[39] The strong winter peak makes it easier to analyze the potential contribution from solar toward resource adequacy and operational reliability. For this study, we assume it is zero, unlike in summer-peaking systems where photovoltaics (PV) contribution can be significant but requires detailed analysis of time-coincident output of solar energy and demand peaks.



(a) Winter peak generation for three modeled utility regions: Central, GVEA, and HEA



(b) Total generation in three periods in Alaska's Railbelt

Figure 4. Daily and seasonal generation profiles for 2018

5.1.2 Prescribed Load Growth, Including Electric Vehicles

To account for load growth, demand profiles were scaled based on regional population growth estimates from the Alaska Department of Labor and Workforce Development.[40] Estimated population growth is about 4.5% across the entire Railbelt from 2021 to 2040 but with significant variation regionally. This scaling resulted in an annual generation requirement of about 4.76 TWh in 2024 (the initial study year) and 4.86 TWh in 2040 (Table 4).[41] Peak generation grows from 735 MW in 2024 to 763 MW in 2040. No change in load shape from different electricity use patterns or weather is assumed, and we do not assume changes to load shape because of addition or retirement of large industrial loads. We also do not assume any additional energy efficiency, demand response, or load flexibility measures.

Table 4. Assumed Load Growth Based on Population (before addition of electric vehicles)

Region	Generation Requirement		Total Increase (%)
	2024	2040	
Central	2,972	3,132	5.4%
Golden Valley Electric Association	1,242	1,264	1.8%
Homer Electric Association	473	464	-1.8%
Total[a]	4,686	4,860	3.7%

[a]Totals may not add up to 100% because of rounding.

In addition to load growth based on population, we added a base level of EV adoption using data gathered by the Alaska Center for Energy and Power.[42] For the Reference scenario, we used the most conservative (lowest) growth level, from the "AEA continued" forecast, which results in about 110,000 vehicles (about 20% of all vehicles in the Railbelt) in 2040 (additional details provided in Appendix B.6).[43] The total increase in generation requirements by 2040 is about 16% (782 GWh, including a transmission and distribution [T&D] loss multiplier of 1.057).[44] EV charging is assumed to be unmanaged, so potentially significant benefits of controlled charging are not included.

[40] https://live.laborstats.alaska.gov/pop/projections/pub/popproj.pdf.
[41] Actual generation requirement in 2022 was about 4.7 TWh (see Table 1), so this results in a 10% increase from 2022 to 2040.
[42] Cicilio, P.; Francisco, A.; Morelli, C.; Wilber, M.; Pike, C.; VanderMeer, J.; Colt, S.; Pride, D.; Helder, N.K. Load, Electrification Adoption, and Behind-the-Meter Solar Forecasts for Alaska's Railbelt Transmission System. Energies 2023, 16, 6117. https://doi.org/10.3390/en16176117 https://www.mdpi.com/1996-1073/16/17/6117.
[43] ACEP provides two other adoption scenarios that were not used in this report, including a "moderate" forecast, which assumes 150,000 EVs in 2040 (30% of all vehicles) and adds another 367 GWh of load, or an "aggressive" forecast, which roughly doubles EV adoption by 2040.
[44] This is based on an average 5.4% T&D loss factor based on a 2022 Railbelt average from EIA form 860.

5.2 Generation Resources

5.2.1 Existing Generation Resources

A database of existing plants was derived from Railbelt utilities and publicly available data sources.[45] There are some small differences between the data shared in this document related to existing power plant performance and the data we use in the model databases (where we defer to utility-provided data sets). We also assume a total of 16.9 MW of distributed solar installed by the end of 2023 based on Alaska Center for Energy and Power (ACEP) estimates.[46] Table 5 summarizes the systemwide capacity and mix for the initial 2024 conditions.

Table 5. Initial (2024) Generation Resource Mix for the Utilities in Alaska's Railbelt[47]

Generator Type	Capacity (MW)			
	HEA	Central	GVEA	Total
Combustion turbine (CT)	124	424	0	548
Internal combustion (IC)	0	165	0	165
Combined cycle (CC)	80	366	60	506
Oil steam	18	0	185	203
Coal steam	0	0	93	93
Hydropower	120	59	0	179
Wind	0	18	25	43
Landfill gas	0	7	0	7
Solar (utility-scale plus distributed)	3	12	19	34
Energy storage	46	0	40	86
Total	391	1,143	535	2,069

Key parameters required for modeling the operation of these existing plants include capacity (see Appendix A), operating costs (fuel, variable O&M, and startup costs). Fuel costs are the product

45 "Form EIA-860 Detailed Data with Previous Form Data (EIA-860A/860B)," EIA, https://www.eia.gov/electricity/data/eia860/.
"Form EIA-923 Detailed Data with Previous Form Data (EIA-906/920)," EIA, https://www.eia.gov/electricity/data/eia923/.

46 Generation of DPV would be typically captured in load profiles. Because we are using 2018 data with limited PV adoption, we add DPV profiles separately. In 2022, utilities had about 2,200 customers, with 13.2 MW of PV under "net metering," of which 11 MW was residential (EIA 860). Projections for the end of 2023 (adding about 3.7 MW of distributed PV) are from ACEP Cicilio, P.; Francisco, A.; Morelli, C.; Wilber, M.; Pike, C.; VanderMeer, J.; Colt, S.; Pride, D.; Helder, N.K. Load, Electrification Adoption, and Behind-the-Meter Solar Forecasts for Alaska's Railbelt Transmission System. *Energies* **2023**, *16*, 6117. https://doi.org/10.3390/en16176117 https://www.mdpi.com/1996-1073/16/17/6117.

47 Location represents the physical location and does not consider the regional allocation of energy from various resources, such as the share of Bradley Lake allocated to utilities outside of the HEA region.

of the price of fuel and the heat rate (fuel consumed per unit of generation). Fuel prices are discussed in Section 5.4. Other data are from plant-level data provided by the utilities or from a similar plant when not provided. Heat rate data include impact of part-load operation.

We also consider operating constraints for all plants, including operating range (minimum output), minimum on/off time (hours the plant must stay on once turned on, or hours the plant must stay off once turned off), and ramp rate (how quickly the plant can change output).[48]

Fixed costs of **existing** assets, including fixed O&M and outstanding debt payments, are not considered because these are the same in all scenarios. Changes in O&M associated with increased cycling in response to renewable deployment is captured by the variable costs, particularly the increased annual number of starts and associated costs. Appendix B provides a of every generation resource assumed in the initial 2024 system, including treatment of power plant efficiency and hydropower operation.

5.2.2 Assumed Base Scenario Retirements and Additions

In addition to capacity that existed on January 1, 2024, we assume near-term additions of two battery plants currently planned for completion in the near future. We assume a 40-MW/2-hr system in the Central region completed at the beginning of 2025 and a 46-MW/2-hr system in GVEA completed at the beginning of 2026 (which replaces the existing 15-minute system). Costs of these new facilities are not considered because they are included in all scenarios. There are several proposed wind and solar plants;[49] these were not included so we could fully account for the costs of new renewable capacity, including balancing and integration.

Most of the existing capacity is retained through the 2040 study period. Based on feedback from Railbelt utilities, we assume retirement only of Healy Unit 2 in 2025.

5.3 Transmission

Our model aggregated Alaska's Railbelt power system into three transmission zones, illustrated in Figure 2. Transmission is not modeled within each of the three zones. All five utilities are electrically interconnected, which allows the utilities to exchange resources and thus improve the economic operation of the grid. However, the connection between GVEA and the utilities to the south via the Alaska Intertie is limited; also limited are the connections to HEA through the Kenai Intertie (see Figure 2 for the location of these interties). Because transmission outages can occur, these regions must be able to operate independently.

[48] Although we allow combined-cycle plants to operate over their full range (with a simplified heat rate curve that captures operation over multiple modes), we require all starts to assume the mode of operation with the longest start time and with the highest start costs. Our assumption substantially reduces the operational flexibility of the plants and their ability to quickly start individual gas turbines when responding to unforecasted changes in wind and solar. This conservative assumption is intended to offset some of the limitations created by the lack of forecast error in the wind, solar, and load data sets.

[49] For example: https://aws.state.ak.us/OnlinePublicNotices/Notices/View.aspx?id=206903.

Between each zone, we represent the interties using the following assumptions in all scenarios:

- **Alaska Intertie:** Runs from Healy to Willow. We assume 78 MW of available transfer capacity[50] and a 6% loss rate on transfers on the existing AK Intertie.[51] We do not consider any potential upgrades to the Alaska Intertie, so the maximum transfer limit stays at 78 MW over the time frame of the study.
- **Kenai Intertie:** Runs from Soldotna to Quartz Creek and is currently rated at about 75 MW of capacity, and we assume an 8% loss rate.[52] We assume that it is upgraded to 185 MW of capacity in 2033 as part of the Railbelt Innovative Resiliency Project.[53] The cost of intertie upgrade is not considered because it applies to all scenarios.[54]

The only other changes to the transmission network are interconnections for new wind where costs vary with distance and size, as discussed in Appendix C.1. For the rest of the T&D system, we assume that average historical loss rates do not change (these losses are embedded in the total generation profiles).

5.4 Fuel Prices

Figure 5 shows assumed fuel price projection in $2023.[55] Prices for natural gas in the near term are from the AEA and assume a transition to liquified natural gas (LNG) imports.[56] We assume that LNG becomes available in 2028 and establishes the avoided cost of all natural gas purchases starting in that year. The initial cost assumed of gas (delivered to the point of use) is $12.1/MMBtu in $2023,[57] and we also assume a 0.5%/year real price increase and that fuel prices are constant throughout each year. We do not consider the potential impacts of fuel price volatility and the potential benefits of renewable energy to provide bill stability via long-term fixed cost contracts. We also note that there is considerable uncertainty about the various options available for future natural gas supplies and cost.

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[50] Ongoing studies by AEA and others have considered an upgrade to the Alaska Intertie; however, this has not been considered in this study. For example, a possible increase to 195 MW of capacity and reduction of losses to about 3%. From: Alaska Intertie Strategic Planning Update, May 20, 2022. https://www.akenergyauthority.org/Portals/0/RailBeltEnergy/IMC/2022/2022.05.20/8A.%20%20AlaskaIntertieStrategicPlanningUpdate%202022-05-20%20rev0.pdf?ver=2022-05-19-133503-887.

[51] The loss rate will actually vary as a function of flow on the line; however, we use a simplified average loss rate based on Figure 4.1 in the 2010 RIRP.

[52] Also a simplified average loss rate based on Figure 4.1 in the 2010 RIRP.

[53] This upgraded capacity value is based on the Railbelt Innovative Resiliency Project application "Battery Energy Storage/HVDC Coordinated Control," which states, "studies indicate the southern transfer limit could likely be increased by over 150%," which results in a capacity of at least 185 MW.

[54] The project received $413M in funding.

[55] Prices for fuel oil and initial price of natural gas from AEA "Alaska Energy Authority Renewable Energy Fund Program Round 14 November 16, 2021." Prices for coal from GVEA filings - Compilation of GVEA Usibelli Coal Invoices and assumes a small real (above inflation) increase based on AEA projections.

[56] Discussion of declining natural gas production from Cook Inlet is provided by https://dog.dnr.alaska.gov/Documents/ResourceEvaluation/Cook_Inlet_Gas_Forecast_Report_2022.pdf.

[57] https://www.enstarnaturalgas.com/wp-content/uploads/2023/06/CIGSP-Phase-I-Report-BRG-28June2023.pdf.

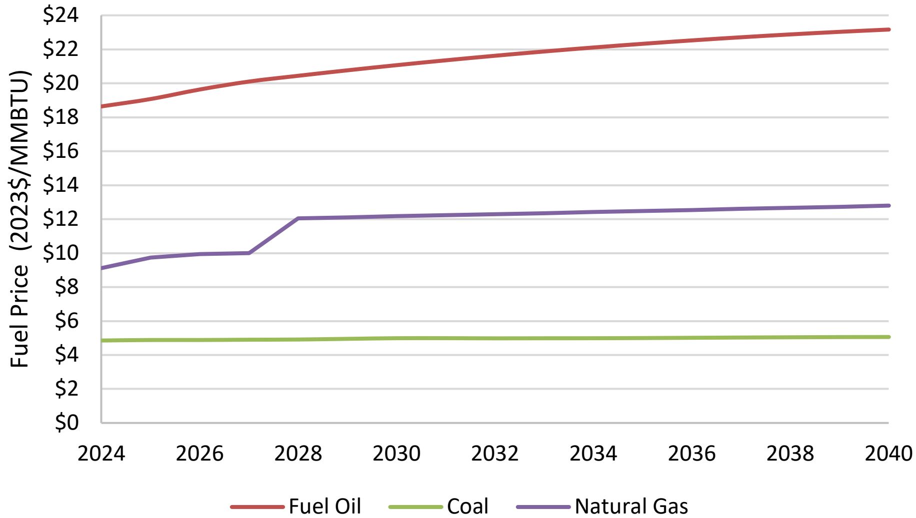
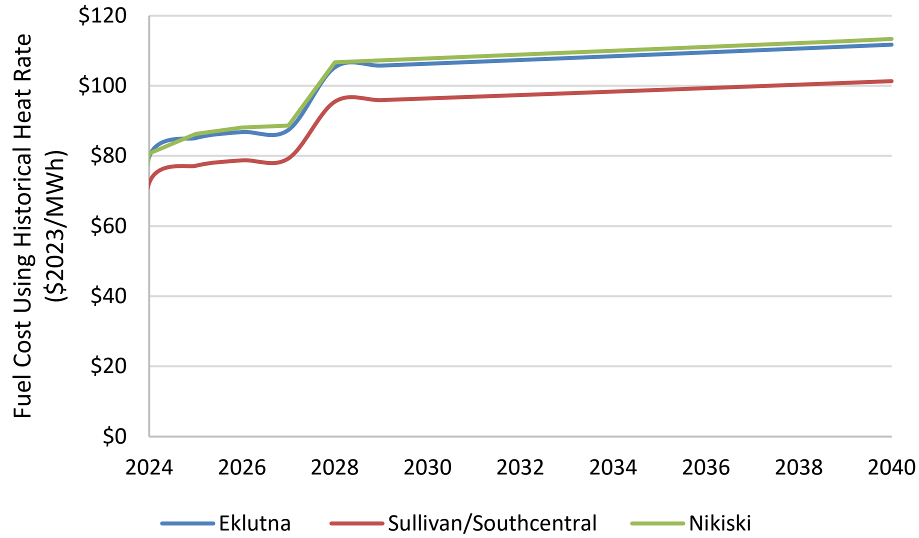


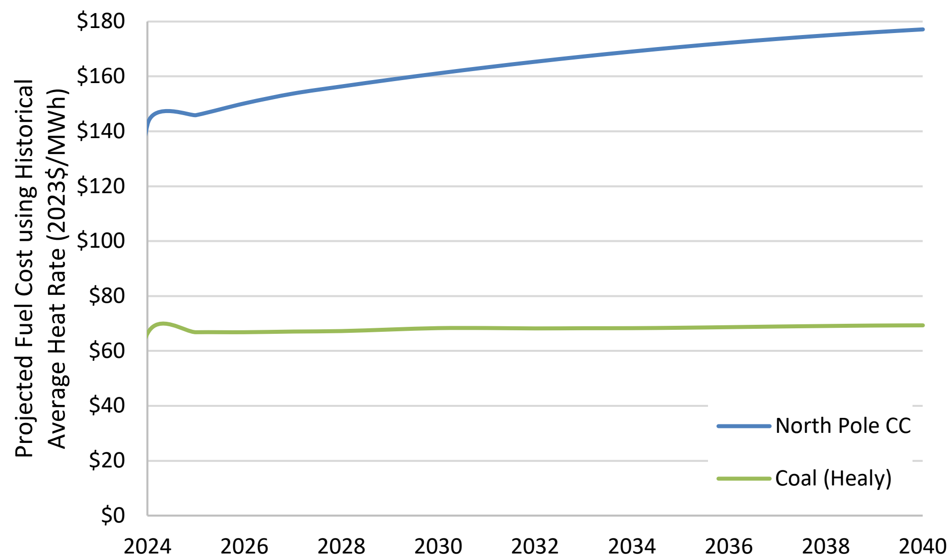
Figure 5. Assumed fuel price projection

Figure 6 shows the fuel costs translated into generation cost ($/MWh) for the six fossil fuel plants that provided more than 90% of all fossil generation on the Railbelt in 2022 (and more than 75% of all generation).[58] Figure 6a shows costs for the four natural-gas-fueled plants in the Central region that provided the most significant generation in 2022. Figure 6b shows a coal and an oil-fired combined-cycle (CC) plant in the GVEA region. These curves do not show the costs of running peaking and backup plants that can have significantly higher fuel costs but rarely run.

[58] See Appendix B for 2022 generation and heat rate data.



a) Natural gas (Central and HEA regions)



b) Coal and fuel oil (GVEA region)

Figure 6. Fuel cost projection for existing fossil-fueled plants using 2022 reported heat rate values

6 New Generator Availability, Cost, and Performance Assumptions

This section provides an overview of cost and performance assumptions. Additional details, including tables of costs and financial parameters, are provided in Appendix C.

6.1 Technologies Evaluated

Table 6 lists generation options considered.

Table 6. Supply-Side Technologies Considered

Technology	Notes
Fossil	
Coal and Gas Cogeneration	Not considered with exceptions noted
Conventional Coal	Existing and new
Combined Cycle (CCGT)	Existing and new
Combustion Turbine	Existing and new
Internal Combustion Engine	Only existing capacity[59]
Oil/Gas Steam	Only existing capacity
Renewables	
Biomass (solid biomass combustion)	No (preliminary analysis indicated that this would not be competitive)
Geothermal	New capacity at a single location after 2030
Hydropower	Existing plants plus new run-of-river; no new conventional hydro
Landfill Gas	Only existing capacity
Land-Based Wind	Existing and new (only utility-scale)
Offshore Wind	New capacity after 2030 in the Cook Inlet
Rooftop PV	Only existing capacity in base scenario; prescribed builds as a sensitivity
Tidal	No
Utility-Scale PV	Existing and new
Storage	
Battery Storage	Existing and new
Pumped Storage Hydro	No[60]

Technologies not listed are not considered, including fossil with carbon capture and storage, small modular nuclear, or hydrogen fuels.

6.1.1 Completion Dates

All new generation capacity is assumed to be completed and available at full capacity at midnight on January 1 of the year it enters service. This assumption applies to all other changes

[59] Internal combustion units may have some advantages over new CT or CCGT capacity not captured in this study, as discussed in Appendix C.9.

[60] We did not have sufficient cost and performance data to evaluate pumped storage hydropower, but previous analysis indicates that there are several potentially suitable sites for pumped storage. See Koritarov, V., Meadows, R., Kwon, J., Esterly, S., Balducci, P., Heimiller, D., DeGeorge, E., Stout, S., Clark, C., Ingram, M., Desai, J., and Rosenlieb, E. The Prospects for Pumped Storage Hydropower in Alaska. United States: N. p., 2023. Web. doi:10.2172/1987825. https://publications.anl.gov/anlpubs/2023/07/183313.pdf.

to the model as well, so all prescribed builds, retirements, and load growth occur at midnight on January 1.

6.1.2 Treatment of Customer-Sited Resources

Rooftop and distributed solar are eligible to contribute toward the RPS in SB101. Modeling distributed solar, including costs and benefits, is challenging because of the many assumptions needed about adoption rates and estimates of possible cross-subsidies from the utility to the customers, from customers to the utility, or across customer classes. Analysis needs to consider how rate structures may evolve, and the impact of feed-in tariffs or net metering regulations. Prior analysis of distributed solar adoption by NREL has been performed using the agent-based dGen adoption model; however, this model has not been applied to Alaska.[61]

To avoid the need to quantify the impact of net metering regulations and associated costs, in the base scenario we assume that all solar after 2024 is deployed or acquired by the utility at the costs described in Appendix C.3. We assume a total of 16.9 MW of distributed solar installed by the end of 2023 (discussed previously), but after this point there is no new distributed solar deployment by utility customers in the Railbelt. This means that all costs associated with new solar are borne by the utility and there are no cross-subsidies. Although this allows for an easier direct comparison across scenarios, a scenario with zero distributed solar adoption is unrealistic. Therefore, we also developed a distributed solar sensitivity scenario. We use projections from ACEP using its moderate forecast, which assumes about 210 MW of rooftop solar by 2040, with trajectory provided in Figure 41 in Appendix C.

We do not consider the impact of customer-sited storage or wind. Distributed wind is common in Alaska, although more common in remote locations.[62] Future analysis could consider the impact of these technologies but with the same caveats regarding the need to analyze rate structures, revenue requirements, and potential cross-subsidies.

6.2 Cost Assumptions

For most renewable technologies and storage, we used projections of the costs and performance from NREL's 2023 Annual Technology Baseline.[63] For each technology, the ATB provides projections of future costs (including capital, financing, grid connection, and fixed and variable O&M) from present day to 2050 and reflects representative conditions in the Lower 48 states. Costs include all components needed to install and interconnect the generator to the local grid but not spur line costs, which must be added separately. Costs in the ATB are reported in $2021, which is inflated to $2023 for this study using an inflation factor of 1.12.[64] For this study, we used the *mid* cost projections from the ATB, and we then applied a technology-specific multiplier to all fixed and variable cost components. This factor is applied to all regions and reflects an overall mix of Alaskan conditions, including generally higher costs of transportation

[61] https://www.nrel.gov/analysis/dgen/.
[62] https://www.energy.gov/sites/default/files/2022-08/distributed_wind_market_report_2022.pdf.
[63] https://atb.nrel.gov/.
[64] Price escalators from the CPI: https://www.usinflationcalculator.com/inflation/consumer-price-index-and-annual-percent-changes-from-1913-to-2008/.

and construction and relatively immature markets (meaning limited vendors and developers in Alaska). For less mature technologies (those with limited deployment in Alaska), the multiplier decreases over time. Figure 7 shows the assumed multipliers applied to ATB capital and O&M costs. The decline is partially a result in the assumption of a maturing market that would likely require sustained deployment of these technologies over many years. Note that these values apply to the initial cost of an individual project and do not decline for that project after it is installed.

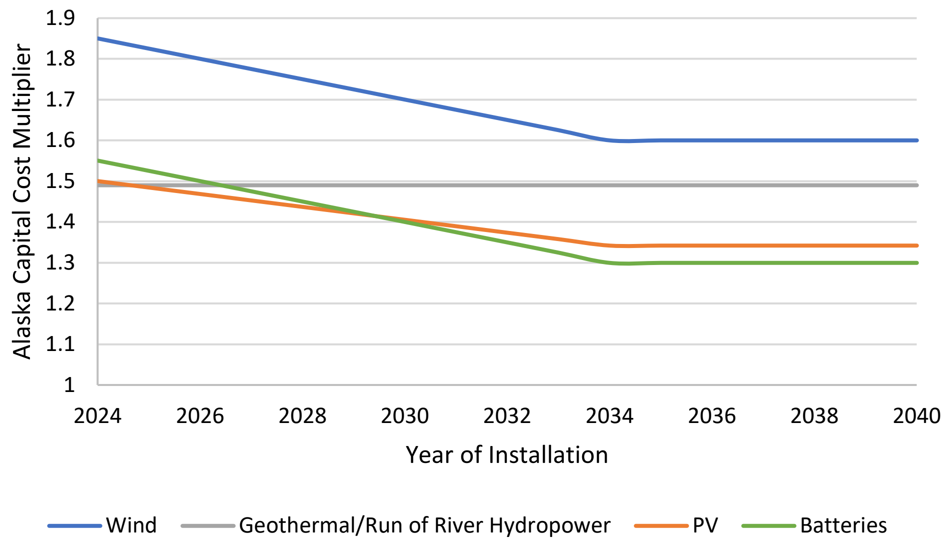


Figure 7. Assumed Alaska cost multipliers added to all capital costs and O&M costs for renewable generators and batteries

Figure 8 shows capital cost assumptions for wind and solar, reported in 2023$/kW$_{ac}$. Values for other technologies are provided in Appendix C. The lower (dotted) lines represent projections for the Lower 48 region from the ATB where a decline in costs is expected based on declining installed costs and operating costs.[65] The Alaska (solid) lines are the product of the ATB costs and Alaska multiplier.[66]

[65] Wiser, Bolinger et al. LBNL, U.S. Department of Energy Office of Energy Efficiency and Renewable Energy. Land-Based Wind Market Report: 2021 Edition. http://www.osti.gov.
[66] The U.S. EIA uses a wind multiplier of 1.3 in Anchorage and 1.56 for wind in the Fairbanks region. (https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf). We assume that it will take 10 years of deployment to achieve a mature market in Alaska.

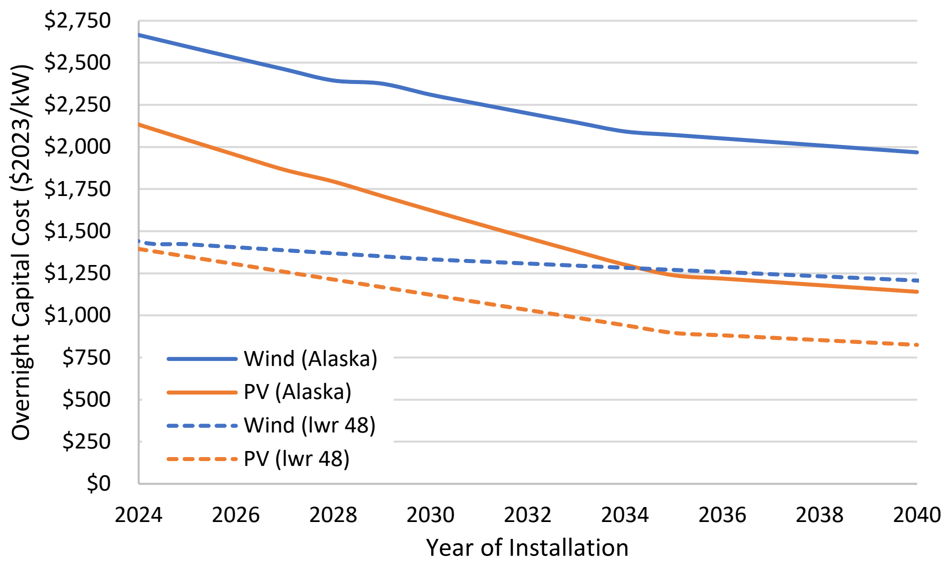


Figure 8. Assumed overnight capital cost for utility-scale PV and land-based wind. Costs do not include fuel storage or spur line costs, which are calculated separately.

Spur line costs are added for wind, geothermal, and PV, assuming a blended average distance-based spur line cost of $11/kW-km (and assumed to be eligible for the ITC), with distance by technology discussed in Appendix C. Additional substation upgrades for wind and solar projects are assumed to add $25/kW and are assumed to not be eligible for the ITC.[67]

We also perform two cost sensitivities, where the low-cost sensitivity applies a 10% cost reduction to all renewable energy technologies and a high-cost sensitivity increases renewable energy costs by 20%.

For cost of new fossil fuel resources, we relied primarily on the 2010 Regional Integrated Resource Plant (RIRP) study[68] and adjusted to $2023 to account for inflation and technology improvements based on trends observed from EIA Annual Energy Outlook (AEO).[69] A further cost reduction between 2023 and 2040 is based on the ATB 2023 projections, assuming continued technology improvements. Capital costs tend to be higher than NREL ATB values, likely reflecting higher Alaska construction costs, but also demonstrating the impact of smaller unit size, reducing economy-of-scale benefits.

[67] Substation costs are derived from Lopez, A. et al. 2024. Solar Photovoltaics and Land-Based Wind Technical Potential and Supply Curves for the Contiguous United States: 2023 Edition. NREL/TP-6A20-87843.https://www.nrel.gov/docs/fy24osti/87843.pdf. We applied a 1.5 Alaska multiplier to the highest cost values in Table 9 and adjusted to $2023.

[68] https://www.akenergyauthority.org/Portals/0/Publications%20and%20Resources/2010.02.01%20Alaska%20Railbelt%20Integrated%20Resource%20Plan%20(RIRP)%20Study.pdf?ver=2022-03-22-115635-150.

[69] Although the ATB provides more recent cost estimates for large fossil fuel plants in the Lower 48, the RIRP study has detailed analysis of the Alaska-specific costs of developing new fossil-fueled plants.

6.3 Resource Availability and Performance

The performance of wind and solar depends highly on geographical region. For wind, we applied a land suitability screen and identified 37 sites with a total of about 2,900 MW of capacity, with methods described in detail in Appendix C.1.Hourly performance was simulated at each location, and the annual average capacity factor was between 31% and 43% with a fleet average of 36%.

For solar, we used solar profiles generated for four locations in Alaska using both tracking and fixed-tilt systems, assuming a 1.5 DC/AC ratio. The annual capacity factor, based on the system's AC rating, is about 15%–17%.[70]

6.4 Financing Assumptions

The analysis used a standard project financing approach, as is typical in integrated resource planning. For each technology, annual fixed and variable cost components are calculated. The annual fixed component includes the overnight capital cost multiplied by a fixed charge rate. The fixed charge rate is derived from multiple factors, including the cost of capital, capital recovery period, construction time, interest rate, and inflation and is described in detail in the 2023 ATB. A table of fixed charge rates used for each technology is provided in Appendix C.8.

We do not prescribe an ownership or development model. These plants could be developed by the individual utilities or acquired via a PPA.[71] This implies that the total cost of ownership (measured by either NPV or levelized cost of energy [LCOE]) would be the same in both approaches. The fixed charge rate is the same each year, resulting in an annual payment that is constant in $2023 (real dollars), which means that it increases in actual (nominal) dollars at the rate of inflation. This is similar to current PPA structures with escalation clauses, but in this case the escalation clause changes based on inflation rates.

If acquired via a PPA, the off-taker (utility) must take all energy generated for the purposes of cost recovery. This means that energy may be curtailed during operation to maintain supply/demand balance, **but curtailed energy must still be paid for.**

6.4.1 Treatment of Tax Credits in the Inflation Reduction Act

A variety of technologies are eligible for tax credits as part of the Inflation Reduction Act (IRA). Most eligible technologies installed in 2025 or later have the option of choosing the production tax credit or the investment tax credit. For the purposes of calculating a constant (levelized) cost of energy from various resources, the production tax credit value is levelized using financial parameters described in the ATB; however, the net result is a value of about $21.5/MWh (in $2023). This is less than the current (non-levelized) value of $27.5/MWh.[72] The base investment tax credit is 30% and 40% in certain locations defined as "energy communities."[73] We assume that the Railbelt is eligible for the 40% ITC. Projects may also be eligible for a higher ITC value

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[70] The relatively high capacity factor is a result of the high DC/AC ratio of 1.5. The DC capacity factor is about 13%.
[71] The cost of the power purchase agreement (in $/MWh) is calculated using a set of equations described in detail in the tab labeled "Financial Definitions" in the 2023 ATB spreadsheet. The LCOE equation is at the top of the page.
[72] https://www.epa.gov/green-power-markets/summary-inflation-reduction-act-provisions-related-renewable-energy.
[73] https://arcgis.netl.doe.gov/portal/apps/experiencebuilder/experience/?id=a2ce47d4721a477a8701bd0e08495e1d

if using domestically sourced content, but we make the more conservative assumption of the lower ITC value.

The model is allowed to choose whichever incentive (ITC or PTC) minimized cost as allowed by current regulations. The tax credits remain available to the end of the 2040 study period.[74]

6.5 Levelized Cost/PPA Price Summary

Figure 9 provides an example of the assumed **initial** PPA price in constant $2023 for a subset of technologies, where the date represents the year the project enters into service. The costs for wind and solar decline over time because of technology improvements and market maturity following the curves shown in Section 6.2. These costs do not include transmission interconnections for wind—or the requirements to address variability and uncertainty including fuel storage and operating reserves, which are also calculated separately—with details provided in Appendix C.

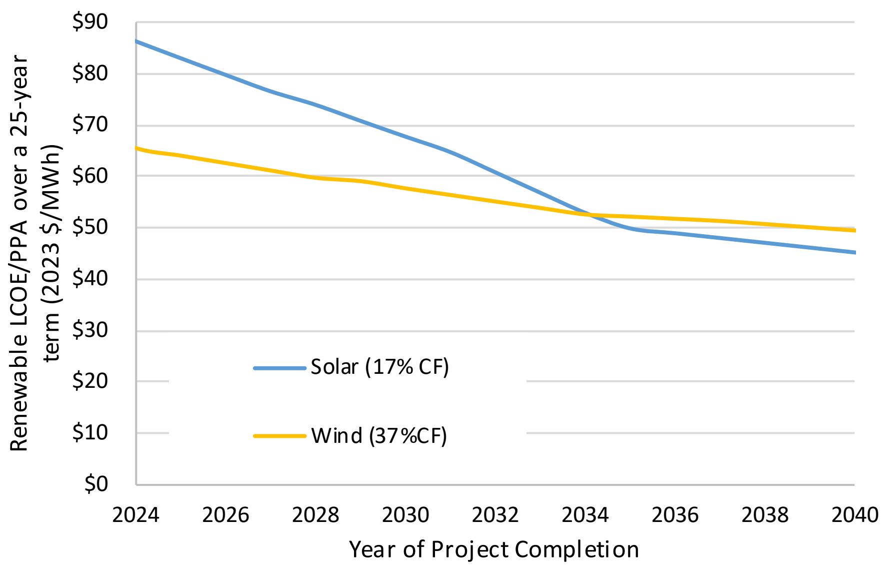

Figure 9. Example of assumed cost trajectories for wind and solar assuming a 37% capacity factor for wind and a 17% capacity factor for solar. Costs (in $2023) are fixed for a 25-year period from the date of completion and include the 40% ITC. This example represents a small subset of the complete set of resources and locations available and does not include additional costs associated with interconnection and addressing resource variability.

The values in Figure 9 represent the initial cost of energy assuming a 25-year contract, meaning that the cost of energy stays constant (in $2023). Figure 10 illustrates the translation between constant (real) dollars and nominal (actual) dollars using the wind price curve from Figure 9 as an example. The black line is the same initial cost curve in constant $2023. The solid lines are

[74] We assume that the tax credits will begin to phase out in 2038, based on when the Mid-case of the National Renewable Energy Laboratory's 2022 Standard Scenarios reaches the Inflation Reduction Act of 2022's emissions reduction targets (Gagnon et al. 2022). However, because of "safe harbor" provisions, we assume that they remain available for projects completed by January 1, 2040 (the last date we assume that new projections are completed in this analysis).

the contract costs for projects constructed in 2026 and 2030 in $2023. Therefore, for a project completed in 2026, the utility would pay about $63/MWh (solid blue line) for all generation (including curtailed generation) from the project in $2023 for the next 25 years. The dotted lines are the cost in actual (nominal) dollars assuming a 2.5% escalator. Therefore, the initial contract price on January 1, 2026, would be at $68/MWh increasing by 2.5% each year after. In 2030, the cost of wind is assumed to decrease by about 10% in real ($2023) dollars, but this decline is offset by inflation, so the initial cost in nominal dollars in 2030 is about the same as in 2026. This same escalation in nominal dollars would apply to other technologies including solar.[75]

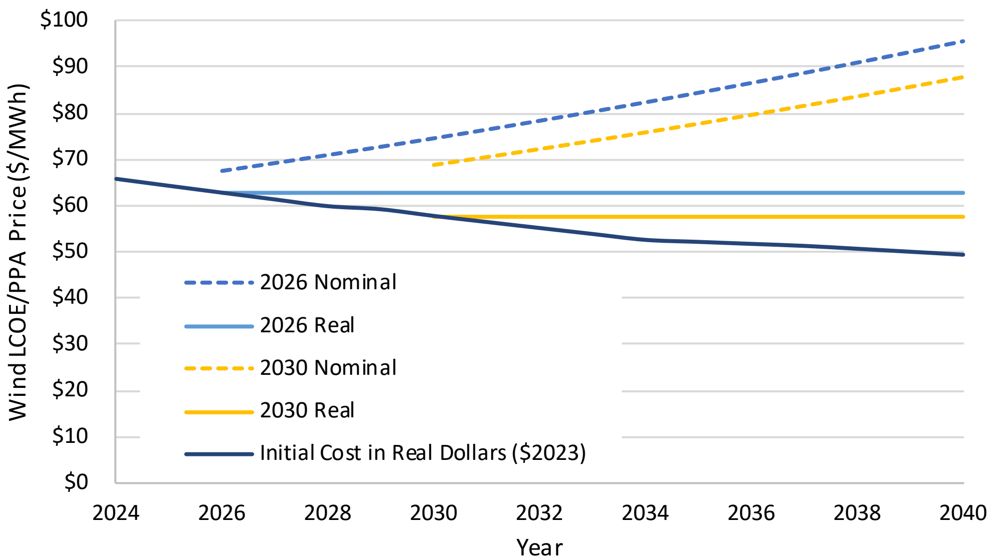

Figure 10. The assumed PPA price trajectory for wind for a location with a 37% capacity factor. The black line is the initial cost in constant $2023. The solid lines are the contract costs for projects constructed in 2026 and 2030 in $2023. The dotted lines are the cost in actual (nominal) dollars assuming a 2.5% escalator.

The combination of variation in wind resources plus spur line costs means a range of costs, particularly for wind. Figure 11 shows the amount of wind deployable at various costs for 2026 and 2030 (in $2023), in the form of a supply curve. This curve includes the spur line costs, which are assumed to be eligible for the 40% ITC, but it does not include natural gas storage and other integration needs, which are calculated separately and included in the full results shown in the following sections.

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[75] For comparison, the PPA price for the Houston (Alaska) solar project is 6.7 cents/kWh with a 1.5%/year escalator clause, while we assume a 2.5% escalation http://rca.alaska.gov/RCAWeb/ViewFile.aspx?id=5F71A11E-BC9D-457A-AD43-B6F765243017.

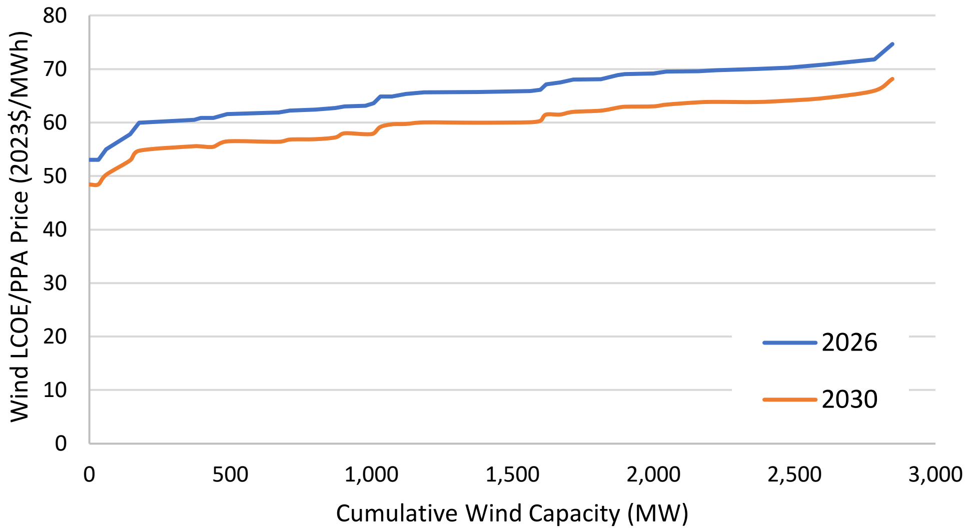


Figure 11. Wind LCOE supply curve for 2026 and 2030, including spur line cost and variation in capacity factor. Costs (in $2023) are fixed for a 25-year period from the date of completion and include a 40% ITC for both the wind plant and spur line.

7 Key Findings

7.1 Finding #1: The Least-Cost (Reference) Scenario Results in Substantial Deployment of Renewable Energy and Cost Savings

In the future evolution of the Railbelt power system, the primary driver for economic deployment of new renewables is their ability to reduce the fuel and other costs of operating existing fossil generators. After adding the costs of transmission interconnection, natural gas fuel storage, and other measures needed to address variability, the model identifies wind and solar resources that have lower life cycle costs than running existing natural gas plants as early as 2025, particularly because the model foresees the increase in natural gas costs occurring in 2028. Additional wind and solar resources achieve breakeven conditions in subsequent years, and by about 2030, many of the potential wind and solar resources in the Railbelt region have lower costs than operating any existing gas plant in the system.

As a result, the model chooses to build large amounts of wind and solar to reduce overall costs. Figure 12 shows the contribution of renewable energy in the No New RE and Reference scenarios. In the No New RE scenario, the contribution (as a fraction of generation) decreases slowly as load grows. In the Reference scenario, the contribution of renewables increases greatly because of their ability to provide electricity at costs that are lower than the cost of running existing gas plants, even including costs required to address variability and uncertainty (see Key Finding #6). The growth in renewable deployment slows considerably in the mid-2030s (when its contribution reaches about 75%) as the ability of renewables to cost-effectively offset additional natural gas use drops because of integration challenges, discussed in Section 7.7.2. The Reference scenario reaches a 76% contribution from renewables by 2040.

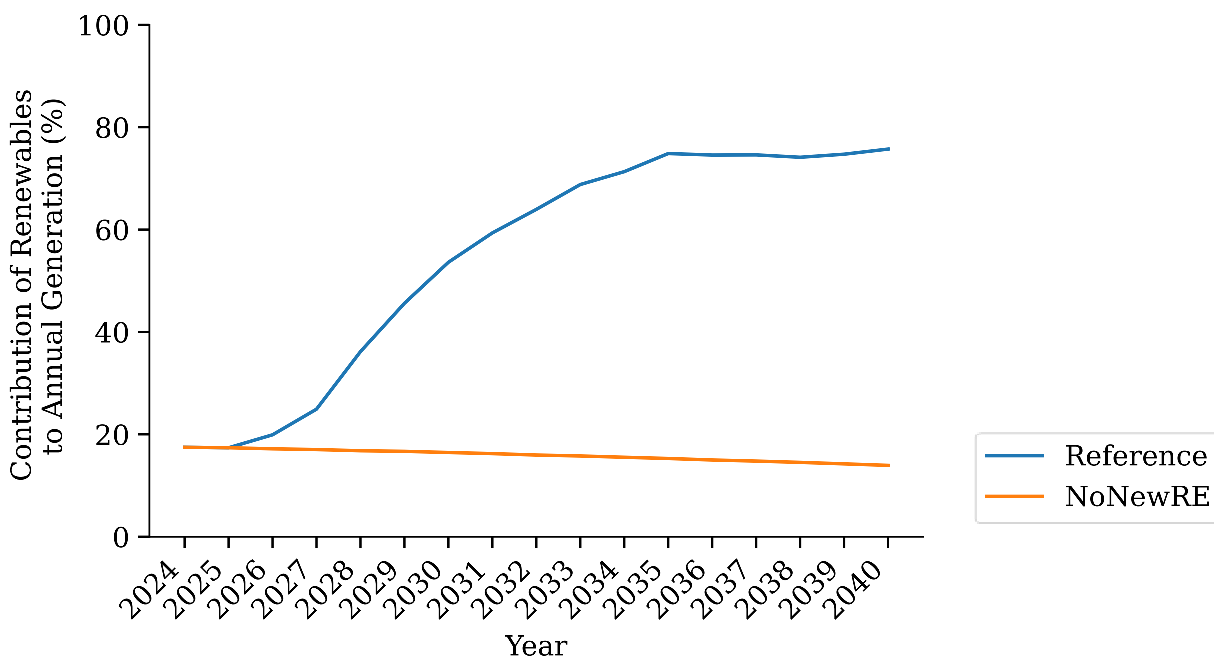
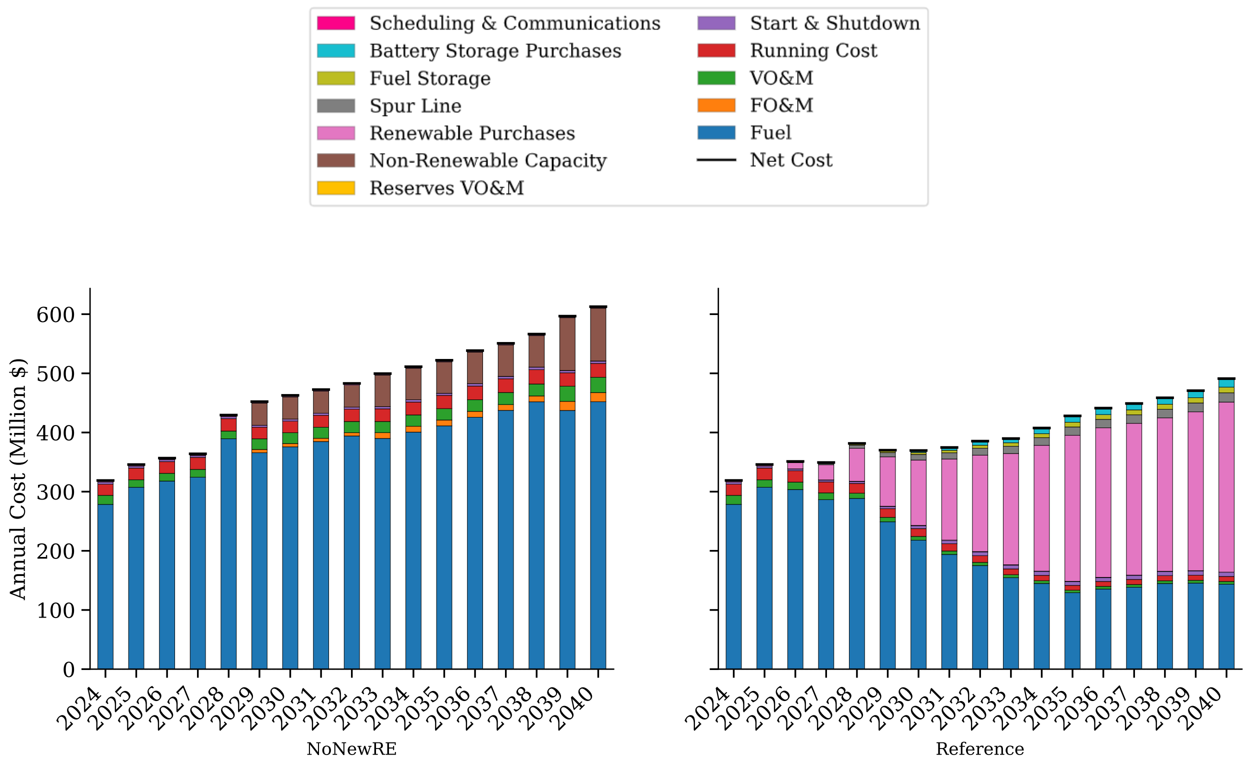


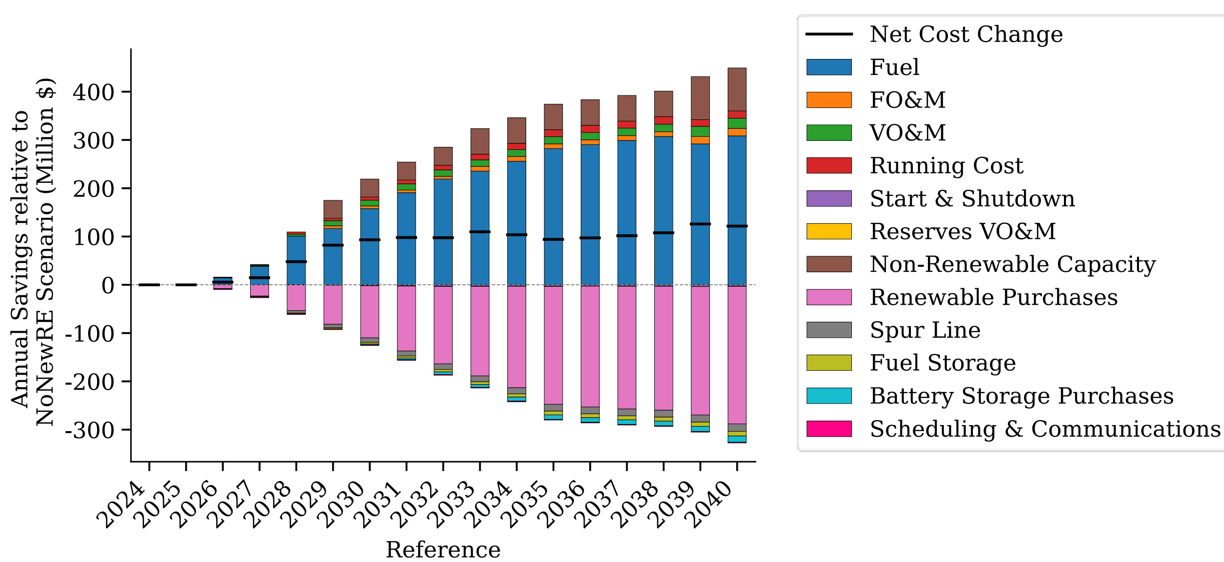
Figure 12. Contribution of renewable energy increases to about 76% in the Reference scenario

Figure 13 compares the evaluated costs in these scenarios, meaning the total of all costs that may vary across the different scenarios. As discussed previously, these costs **do not** include common costs, such as outstanding debt, existing or planned transmission (including the Kenai Intertie upgrade), and all costs associated with the distribution system. The common costs would be in addition to these costs. Figure 13 (top) shows the evaluated annual cost components in constant $2023. The left curve shows the No New RE scenario, with costs increasing steadily because of both load growth and fuel cost increases, and fuel purchases exceeding $350 million/year by the late 2020s. The right curve shows the Reference scenario, showing the significant reduction in fuel costs and increase in renewable purchase costs. The reduction in fuel costs includes the impacts of addressing variability of the resources, including additional operating reserves and thermal plant cycling—including startup and shutdown costs, discussed in more detail in Finding #6.

Figure 13b shows the difference between the two scenarios, with savings shown as a positive value and costs shown as negative. The increase in renewable energy purchases is more than offset by the decrease in fuel-related costs, which produces a net savings (black line) of over $100 million/year by the early 2030s.



a) Annual cost (non-discounted)



b) Annual savings (non-discounted)

Figure 13. Total annual costs ($2023) in the No New RE and Reference scenarios (top) and the net savings (bottom) resulting from deployment of renewable energy. This includes only evaluated costs and not costs common to all scenarios. Color key applies to both figures. Net savings average about $105 million/year from 2030 to 2040.

The Reference scenario avoids about $4.2 billion in fuel and other expenses from 2024 to 2040. This avoided cost requires renewable purchases and other costs of about $2.9 billion, resulting in a cumulative (non-discounted) savings from 2024 to 2040 in the Reference scenario of about $1.3 billion. Figure 14 summarizes the cumulative NPV of savings over the evaluation period (2024–2040), using a range of discount rates. Note that this considers only costs and benefits that occur prior to 2040, and many of these costs and benefits will continue to accrue past 2040.[76] The values in Figure 14 should not be compared to the full life cycle costs of projects with costs and benefits that continue past 2040.

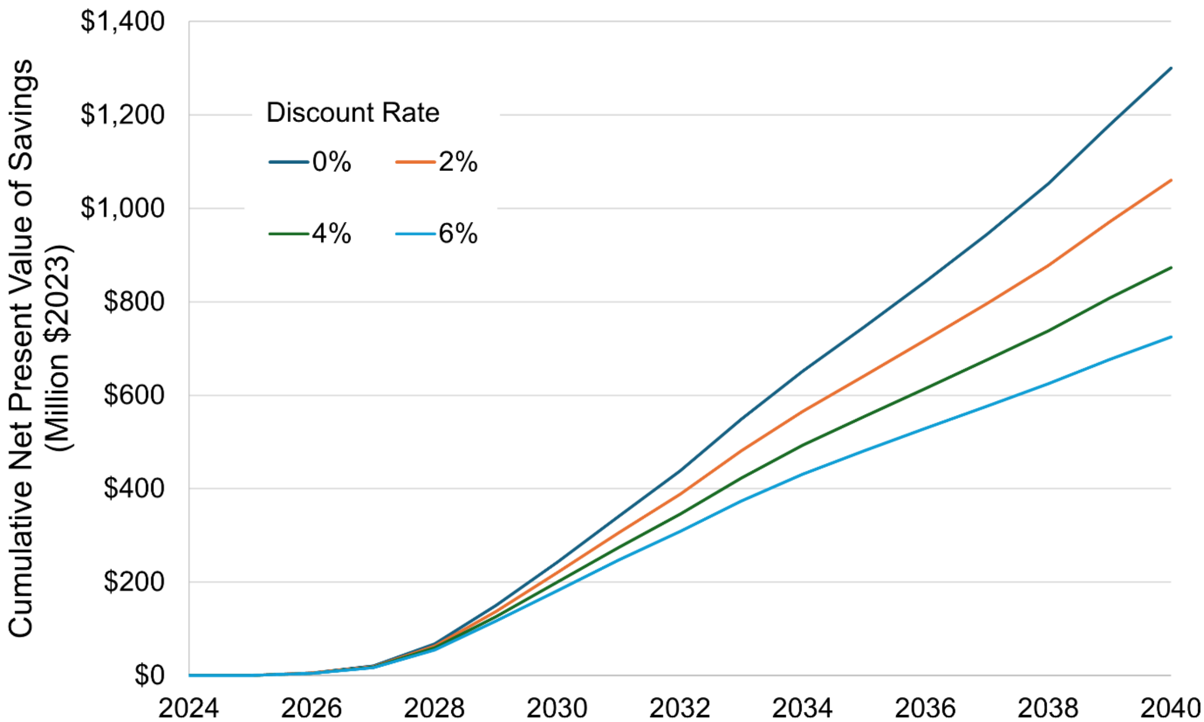


Figure 14. The cumulative (non-discounted) savings from 2024 to 2040 reach $1.3 billion. The net present value of those cumulative savings is less, depending on discount rate used. NPV of net savings does not include costs and savings that occur past 2040.

7.2 Finding #2: The Least-Cost (Reference) Scenario Relies on a Mix of Renewable Energy Resources and Locations

The Reference scenario deploys a mix of wind and solar resources, with wind providing the majority of new capacity. Figure 15 shows the capacity mix (top) and generation mix (bottom) between 2024 and 2040 for the No New RE and Reference scenarios. The generation mix excludes curtailed wind and solar energy; however, the costs of curtailed energy are included.

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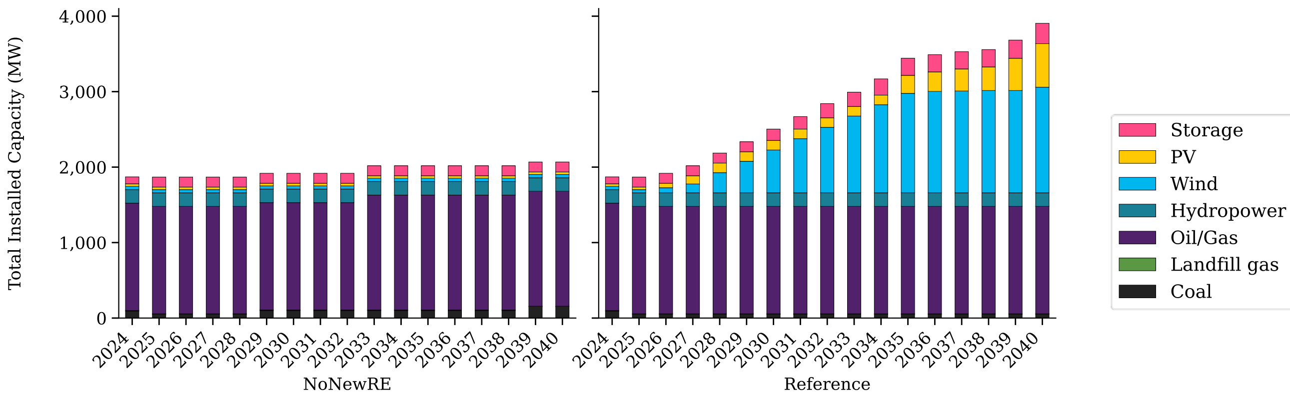
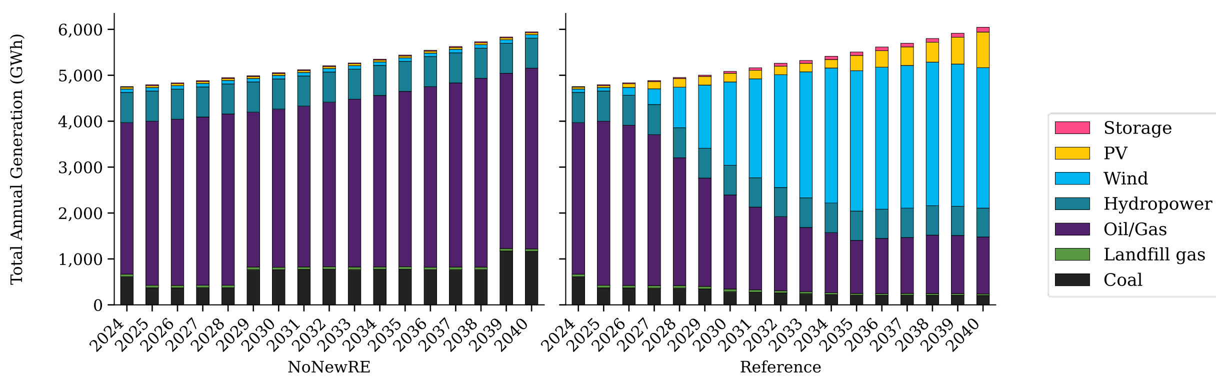
[76] Any comparison between the full cost of a project and the values in Figure 14 will omit a large fraction of the costs and benefits. In the most extreme example, the values in Figure 14 capture only a few percent of the costs and benefits of projects installed in 2040 because it includes only a single year. Any comparison of additional projects should use annualized values and compare those annualized values to those in Figure 13.



a) Capacity by type



b) Generation by type

Figure 15. Capacity (top) and generation mix (bottom) over time in the No New RE and Reference scenarios

Table 7 shows the mix of capacity and energy contributions in 2040, with wind providing about 59% of Railbelt electricity in 2040. A map showing wind deployments by area is provided in Figure 16.. Only land-based wind was deployed in the Reference scenario, driven by the higher cost of offshore wind, combined with the limited transmission capacity needed to deliver this energy into the Central zone. Offshore wind projects will have to be relatively large to achieve the assumed costs, and large offshore wind plants will often exceed spare capacity on the Kenai Intertie—even with upgrades (see Key Finding #6).

Table 7. Capacity and Generation by Type in 2040

Technology Type	No New RE			Reference		
	Capacity (MW)	Annual Energy (GWh)	Annual Energy (%)	Capacity (MW)	Annual Energy (GWh)[77]	Annual Energy (%)
Fossil	1,673	5,100	86%	1,473	1,442	24%
Land-Based Wind	43	76	1%	1,400	3,058	51%
Solar	34	42	1%	577	776	13%
Hydropower	179	653	11%	179	629	11%
Other Renewables	7	55	1%	7	36	1%
Storage (net generation)	133	20 (-4)		270	102 (-19)	
Total	2,068	5,926	100%	3,905	5,941	100%

Figure 16 provides the quantity of deployed wind and solar power plants in each zone. More wind is deployed in the GVEA and HEA zones, due to higher quality resources. Solar is added primarily in the central zone. However, we also note that the quality of the solar data available for Alaska is relatively poor and may not reflect actual regional variability of the resource that could alter regional siting.

[77] Generation values are after removing curtailment (which must still be paid for). Curtailment of generators is based on marginal cost. For plants with zero generation cost (wind and solar), plants taking the ITC will be curtailed before those taking the PTC.

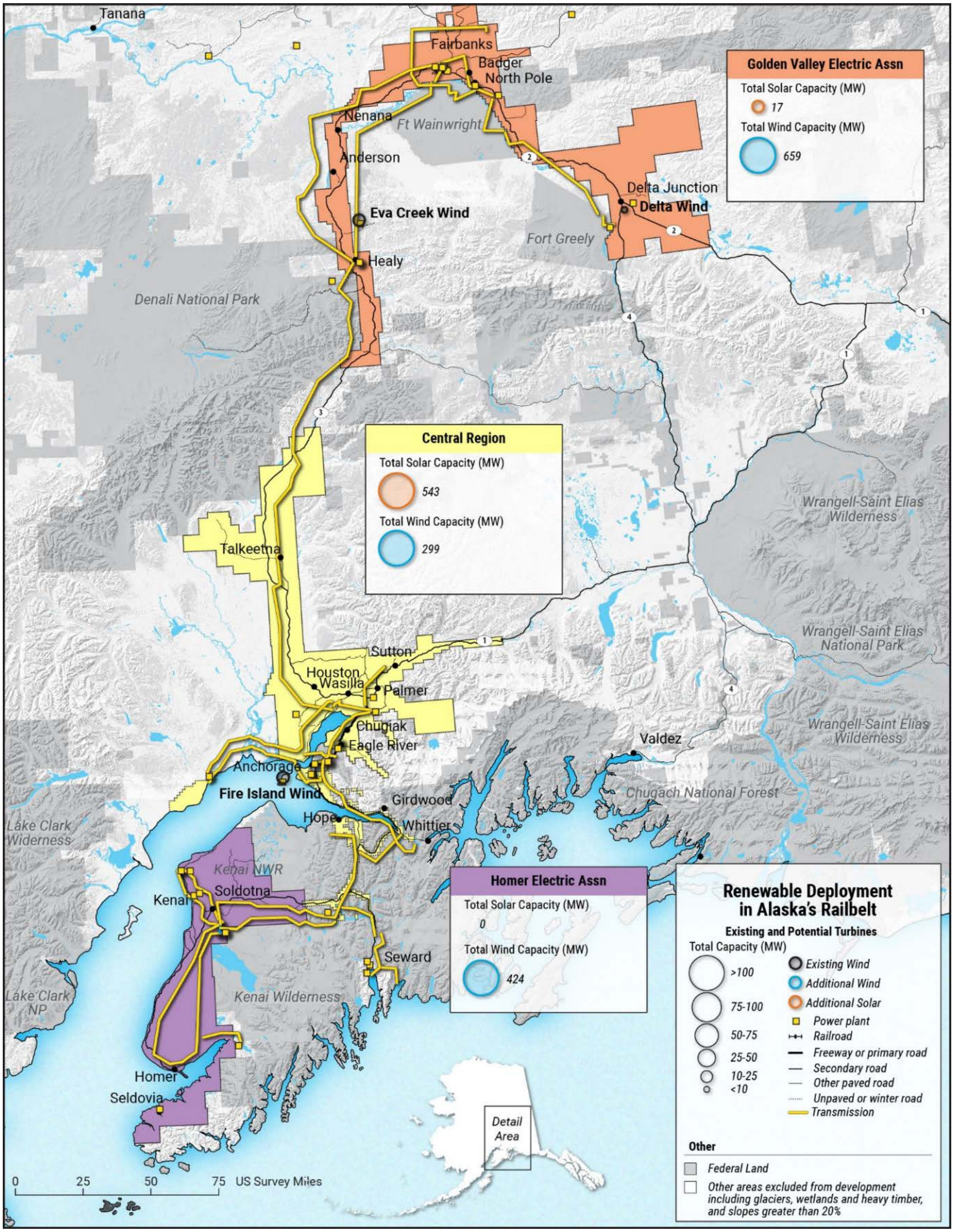


Figure 16. Capacity of wind and solar power plants deployed in each zone in the Reference scenario.

7.3 Finding #3: The 80% RPS Has Limited Impact on Costs Compared to the Reference (Least-Cost) Scenario

Adding the RPS requirement has a small impact on the overall results because the Reference (Least-Cost) scenario achieves a 76% contribution from renewable resources in 2040. The installed capacity mix in the RPS scenario is nearly identical to the Reference scenario before 2040, and there are then small differences in 2040. The most significant is the additional 50 MW of geothermal capacity installed in 2040. Geothermal is likely chosen because a greater fraction of its production occurs when it can be used, compared to wind and solar, which experience high levels of incremental curtailment and unusable generation at increased levels of deployment—which is discussed in more detail in Section 7.7.2.

The difference in cumulative savings between the Reference scenario and the RPS scenario is less than 2%. Based on the assumptions used in this work and given the significant uncertainty in future costs of renewables, fossil fuels, load growth, and other factors, this means that there is essentially no meaningful difference between the Reference scenario and an 80% RPS scenario. It also means that any increase in costs associated with an 80% RPS (compared to the Reference scenario) is likely to occur well past 2030, when there will be greater technological certainty and adjustments to RPS targets could be made to ensure least-cost deployments.

To demonstrate the sensitivity of overall results to changes in assumptions, Figure 17 shows the annual savings associated with the Reference and RPS scenarios compared to the No New RE scenario. The Reference (blue) line is the annual savings shown in Figure 13b. The RPS line shows the reduction in savings associated with the RPS scenario resulting in about a $19M cost (or $19M reduction in benefits compared to the Reference scenario) in 2040. However, relatively small changes in the cost of renewables (or other factors such as the cost of natural gas) would have a greater impact on the overall benefits of deploying renewable resources. A 10% reduction in the cost of renewables (green) would increase the savings by about $20M/year starting in the early 2030s and would increase cumulative (non-discounted) savings by about $220M from 2024 to 2040. Increasing the cost of renewables by 20% reduces net savings by $40M/year during many years and cumulatively reduces benefits by about $470 M.

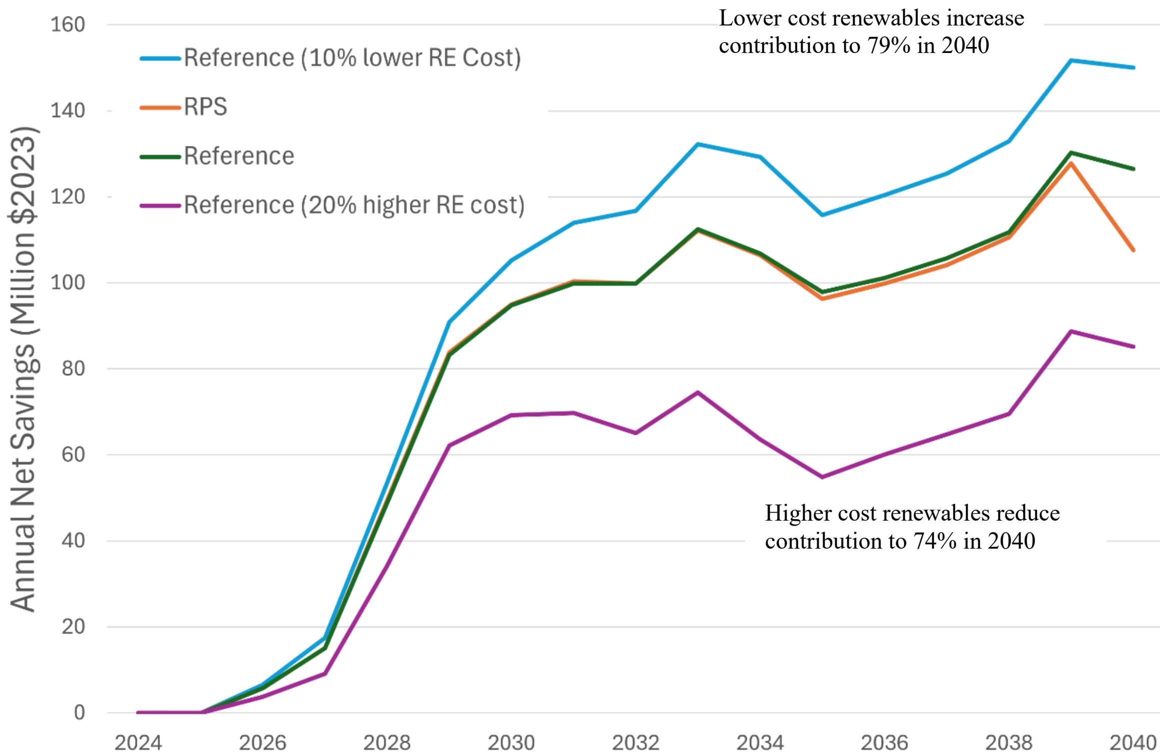


Figure 17. Requiring an 80% RPS reduces the net savings from deploying renewable energy by about $19 million in 2040, which is less than a 2% change in cumulative savings. Overall, these differences are very small given the large uncertainty in future costs of fuels and renewable generation demonstrated by the much larger impact of a change in the assumed cost of renewable energy shown in the high- and low-cost RE sensitivities.

7.4 Finding #4: Demand Is Met in All Scenarios, Relying Heavily on Existing Hydro and Fossil-Fueled Generators During Periods of Low Renewable Output

Wind and solar resources provide significant cost savings by providing energy at a lower cost than fuel used in existing generators, but maintaining reliable operation in these scenarios during periods of low wind and solar output depends significantly on continued use of existing hydropower and fossil generators. The system maintains a greater than 30% reserve margin in each zone, with existing hydropower and fossil generators providing the majority of this capacity (a list of generators is provided in Appendix B).

Figure 18a shows the Railbelt-wide system dispatch during the annual peak period, including the hour of peak demand occurring on the evening of January 11 in 2040. During this hour, wind output is very high, and provides 78% of total demand. However, examining only this single hour overstates the ability of wind to reliably and consistently meet demand. Previous analysis of systems throughout the United States have demonstrated that resource adequacy analysis must increasingly look at periods of peak net demand (demand minus the contribution of wind and solar). Figure 18b shows the system dispatch during the period of highest dependence on hydropower and fossil plants. On December 13, more than 80% of demand during some hours is met by existing fossil resources in the Reference scenario during a period of particularly low wind output. Figure 18c shows another example, where demand is relatively low (only about 500 MW), but there is very little renewable output and significant fossil generation is required.

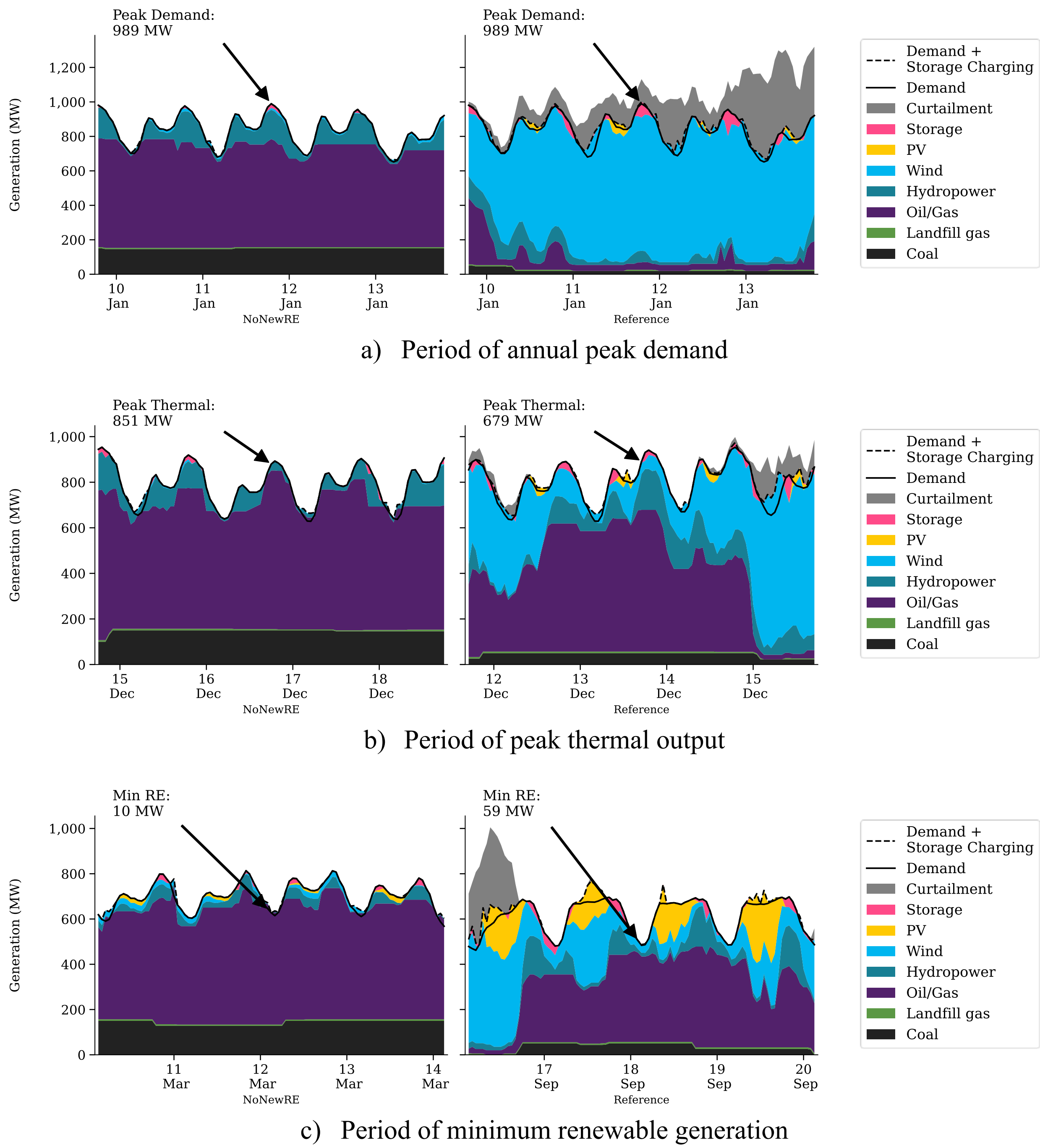


Figure 18. System dispatch during the period of peak demand (a), a period of peak fossil plant output (b), and a period of minimum wind renewable output (c) demonstrating the reliance on existing hydropower and fossil generators to provide resource adequacy

The results of this analysis demonstrate a fundamental change in how electricity generation is planned, where renewables may provide the majority of the *energy* requirements, and fossil resources provide a larger fraction of the *capacity* requirements.

7.5 Finding #5: Large Contributions of Renewable Generation Will Require Substantial Changes to How the System Is Operated

The use of highly variable resources will require changes to how the system will maintain supply-and-demand balance. Figure 19 shows the fraction of total generation met by wind and solar during each hour of the year in the 2040 Reference scenario, illustrating the large range of instantaneous contributions of wind and solar.

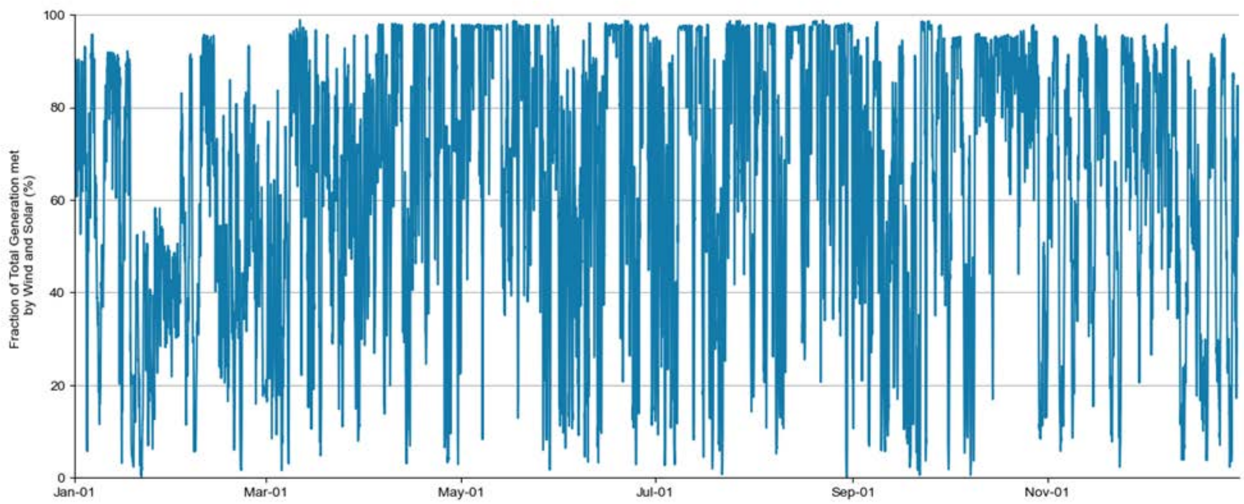


Figure 19. Fraction of load met by wind and solar shows dramatic variability on an hourly and daily basis

The large variation in the contribution of wind and solar will require changes to how the balance of the system is operated. Figure 20 shows an example where, during the afternoon of November 4, there is a rapid decrease in both wind and solar generation, followed by very large contributions of renewables a few days later. In this section, we demonstrate four changes needed to achieve these levels of renewable contributions while maintaining reliable operations.

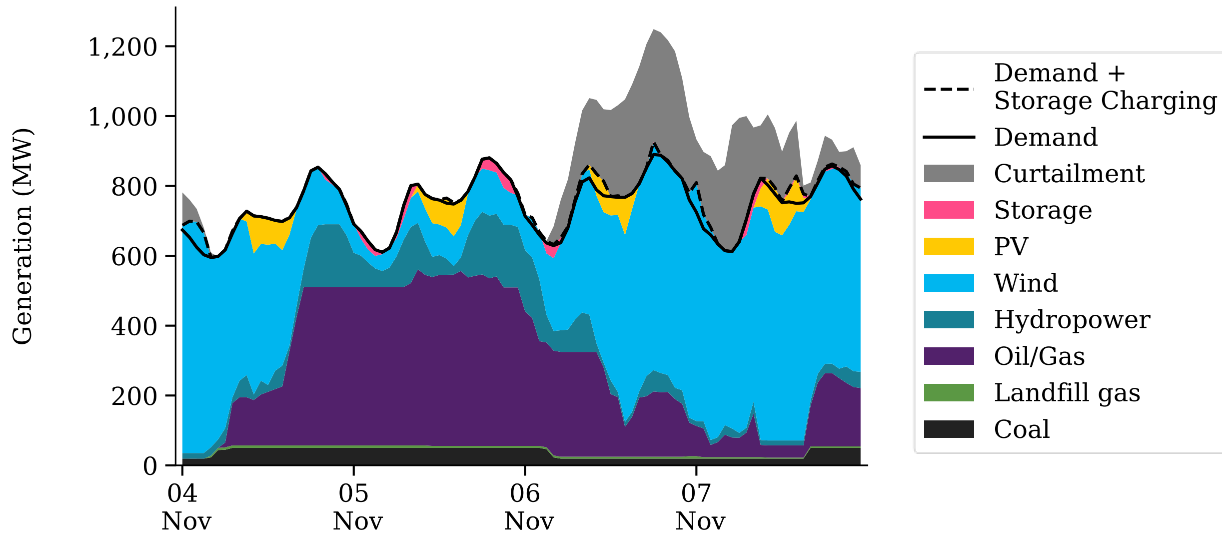


Figure 20. An example period in the 2040 Reference scenario with a rapid change in renewable output and response from hydropower and fossil generators

7.5.1 Increased Ramping and Part-Load Operation of Thermal Plants

The increased contribution of renewables inherently reduces the generation from existing fossil resources and changes how those resources are operated. Figure 21 isolates the response of the fossil-fueled generators to the variation in renewable output shown in Figure 20. On the afternoon of November 4, the wind and solar output (gray) drops continuously and the other generators in the system must increase output, with fossil generation (orange) increasing by 388 MW in this period, increasing as much as 133 MW during 1 hour.

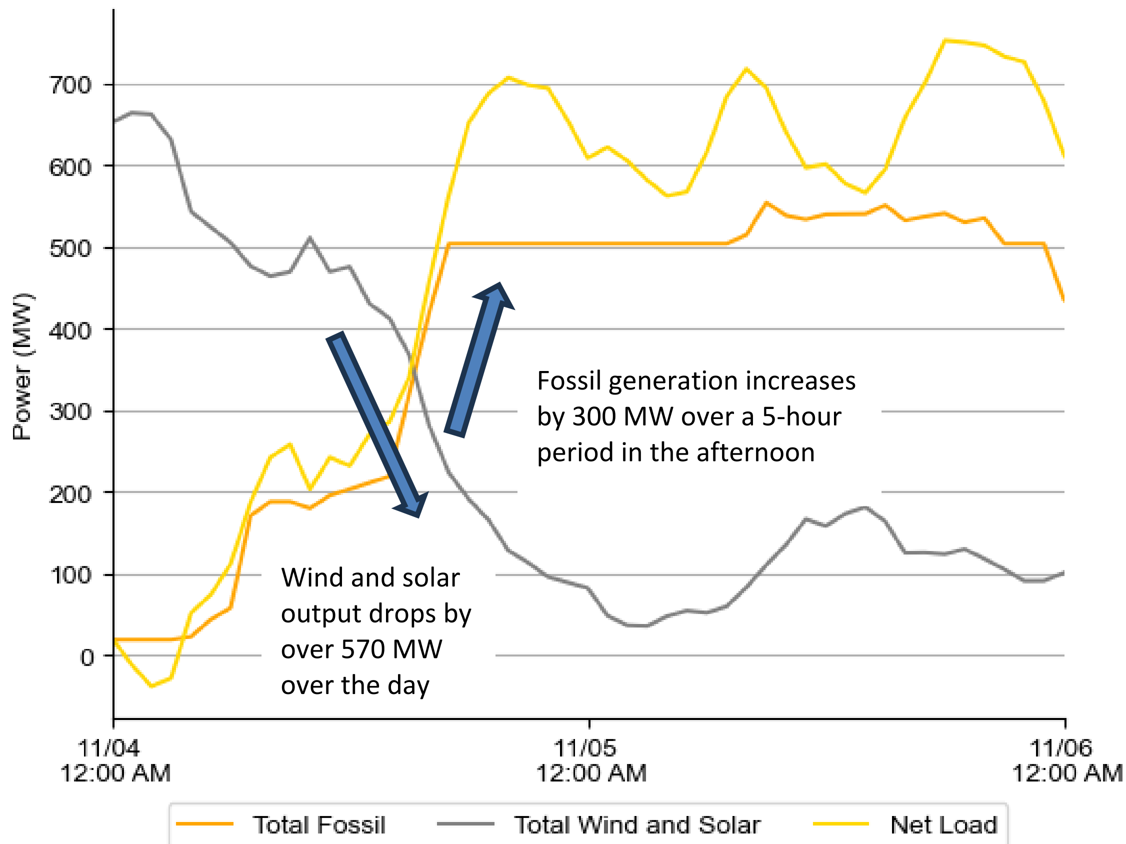


Figure 21. Response of Railbelt fossil fuel generators (orange) to a large reduction in wind and solar output (gray) on November 4, 2040, in the Reference scenario

As a result of this type of operation, fossil fuel plants will spend more time varying output. Note that Figure 21 does not show unpredictable subhourly variability that would be addressed via the additional operating reserves assumed in this study and accounted for in the avoided cost calculations. Figure 22 summarizes the fraction of time the Southcentral Power Project spends in four different operational modes. (This does not include the fraction of time that the plant is unavailable because of forced outages or for scheduled maintenance.) This plant is one the most-efficient and lowest-cost gas-fired generators and currently operates at very high capacity factors (about 70% in 2022).[78] In the figure, the red bar represents full output, and in the 2024 simulation, the plant spends most of the time operating in this mode. As renewable generation increases and net load decreases, the plant spends more time operating at less than full output and varying output between minimum and maximum, shown in the green bar. The plant also spends a greater amount of time operating at its minimum generation point (orange bar). This occurs when net load drops substantially but the plant must remain online to provide operating reserves or be able to respond quickly to an increase in net load. Because we assume a 9-hour startup time, along with a minimum down time, the plant cannot turn off unless it will not be

[78] Data from EIA Form 923 for 2022.

needed for this multi-hour period.[79] The blue bar represents the fraction of time the plant is turned off (not committed) during multi-hour or multiday periods of very high wind and solar output.

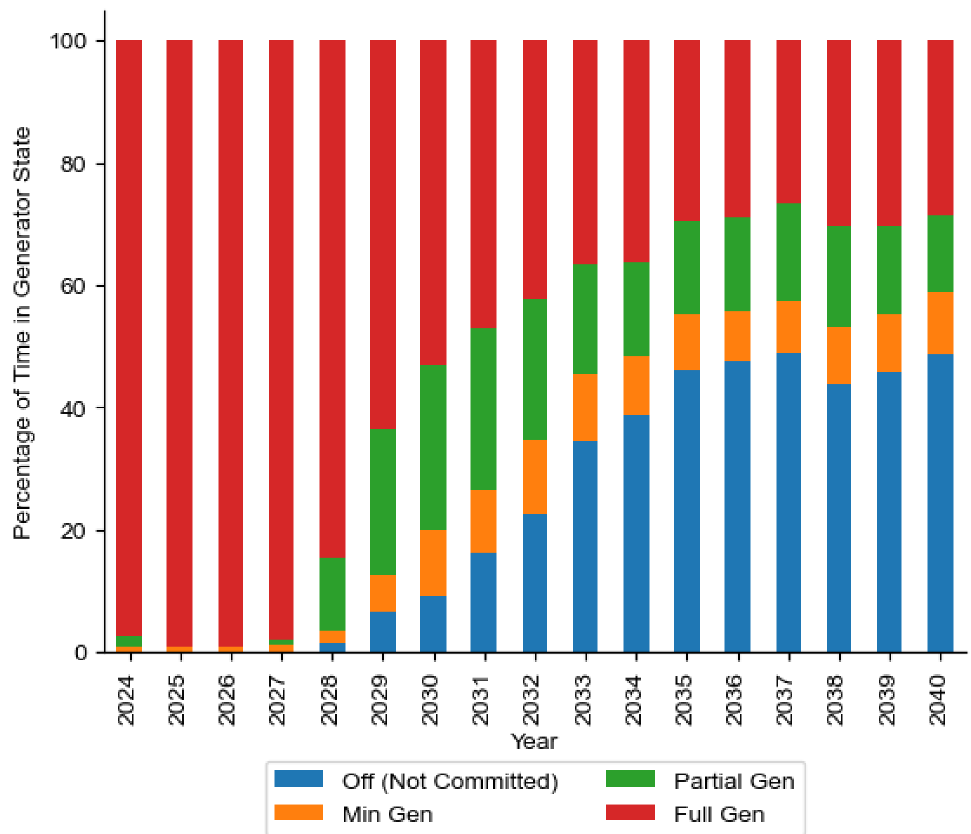


Figure 22. Transition of the Southcentral combined-cycle plant from base load to load-following and peaking operation

Figure 23 shows the weighted average capacity factor for the two Central region combined-cycle units in the No New RE and the Reference scenarios. The actual reported value in 2022 (71%) is shown in the blue dot.[80] The modeled capacity factors are higher, likely because of differences in assumed outages and maintenance schedules and the assumption of an optimized dispatch across the entire Railbelt. The capacity factors in the Reference scenario then drop significantly as their use is offset by renewable generation.

[79] As noted previously, we do not have forecast error for our wind, solar, and load data. This underestimates the challenge of scheduling thermal plants. This is partially compensated for by the reserve requirements, particularly the flexible ramping capacity, as well as the fuel storage requirements and the assumption that all combined-cycle plants must always operate in full combined-cycle mode. Operation of the individual gas turbines would provide more rapid response and a lower minimum generation level. Our assumption substantially reduces the operational flexibility but should offset some of the limitations created by assuming perfect forecasts.

[80] The plants are the George M. Sullivan Generation Plant and the Southcentral Power Project. Data for 2022 generation from EIA 923.

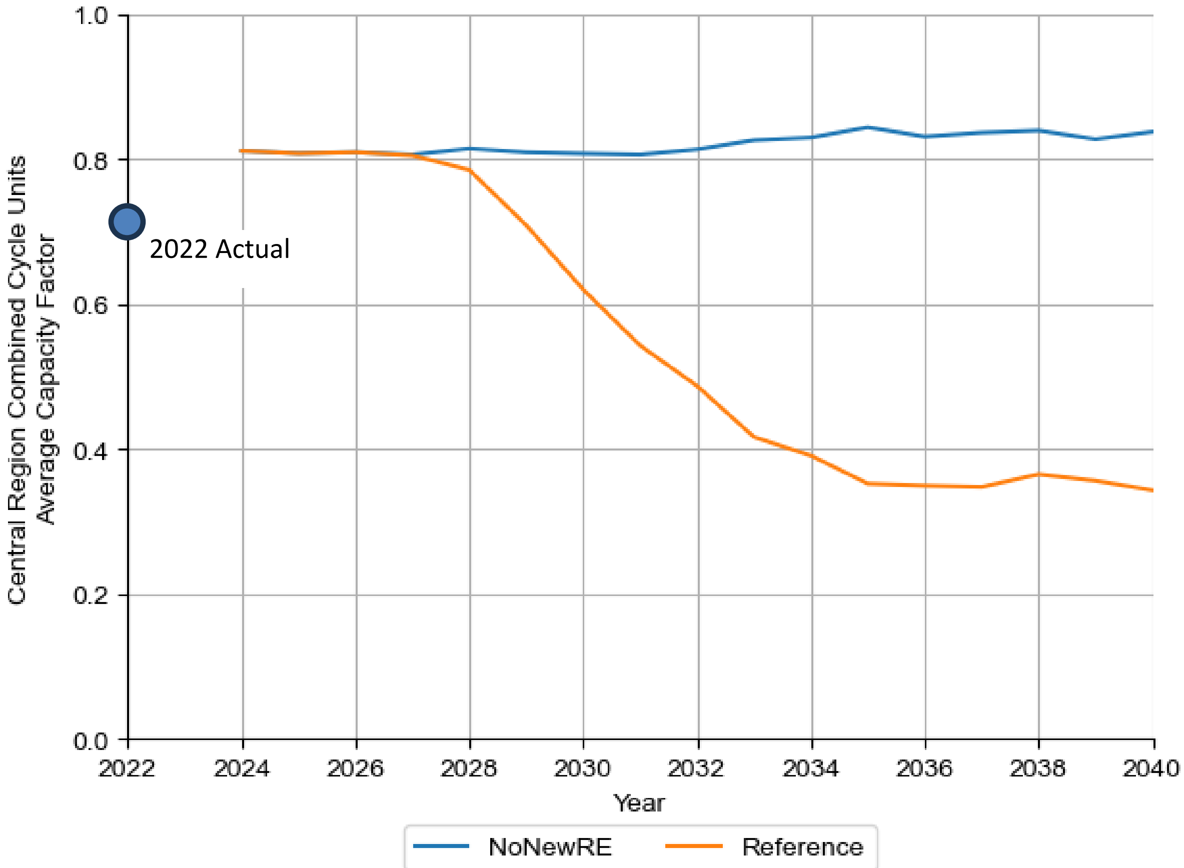


Figure 23. Declining capacity factor of Central region combined-cycle plants

This change in operation has important implications for fuel scheduling, plant efficiency, and maintenance requirements. These issues and cost implications are discussed in Key Finding #6.

7.5.2 Changes in Hydropower Plant Operation

As with thermal plants, the operation of hydropower units also changes with increased deployment of wind and solar. Because several hydropower units have storage, they are particularly useful for managing variability and uncertainty. Figure 24 provides an example of the response from the Bradley Lake plant during the 4-day period shown in Figure 20. In this example, the output of Bradley Lake (green) is shown along with the Railbelt-wide net load in yellow. During the early morning of November 4, renewable generation exceeds demand, resulting in very little net load to be met with hydropower or fossil generation. Bradley Lake operates at its minimum output level during this period, and the plant operates at minimum output about 40% of the time during the entire year in the 2040 Reference scenario. The rapid reduction in wind and solar output on this day requires Bradley Lake to increase output to maximum over this period, then continue to vary output in response to net load—driven by renewable output across the entire Railbelt. This kind of operation, assuming Railbelt-wide joint dispatch, may require changes to contractual agreements or other practices to minimize the costs of operating the system.

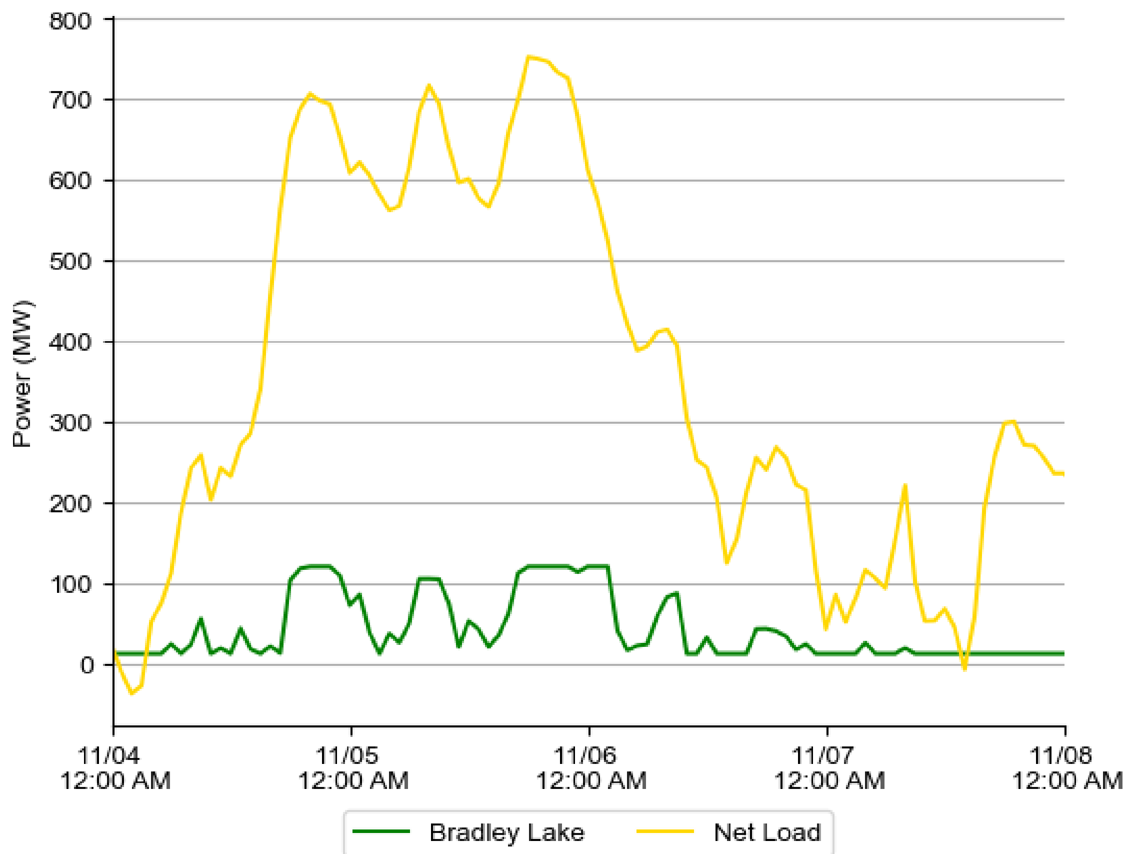


Figure 24. Operation of the Bradley Lake hydropower plant during periods of highly variable renewable output

7.5.3 Changes to Intertie Flow

To minimize the costs of system operation across the entire Railbelt, the scenarios assume that both the Alaska and Kenai interties may be operated in response to the increased regional variability of energy supplies. This means that the power flow across the intertie (including direction of flow) may change rapidly. Figure 25 shows the same 4-day period as Figure 24, illustrating the changes occurring on the northern part of the Railbelt. At the beginning of this period, the supply of wind in the GVEA region (orange) exceeds its local demand, and this excess supply of wind can be used to offset gas-fired generation in the Central region. This extra wind energy is exported across the AK Intertie, and north to south intertie flow (black) is represented by a positive value. However the wind is steadily decreasing during this period, and shortly after noon it becomes economic for GVEA to import electricity, represented by a negative flow (south to north) on the AK Intertie which operates at maximum capacity for most of November 5. Starting on the evening of November 5, there is a rapid increase in wind, which exceeds GVEA load producing a negative net demand (gray), so flows on the Intertie flip back to positive values, and flow at maximum capacity for much of November 6.

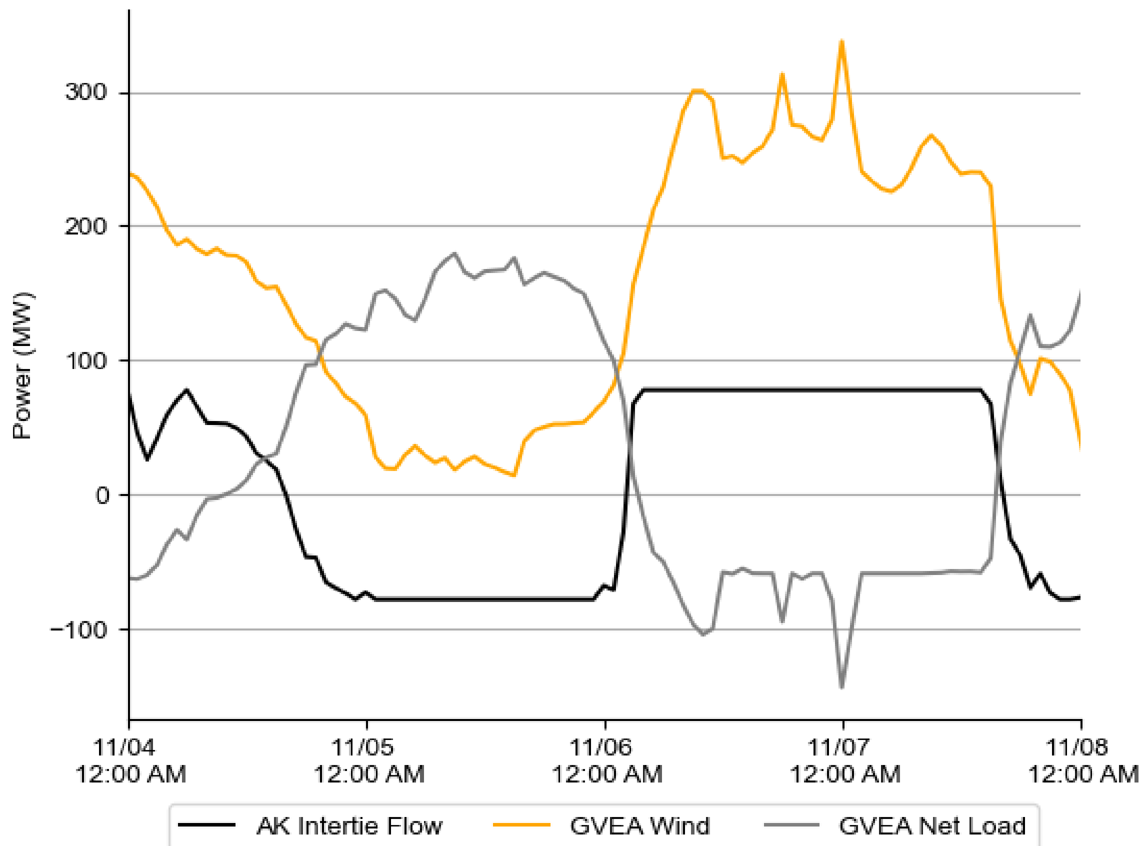


Figure 25. Flow on the Alaska Intertie (black) in 2040 in the Reference scenario depends largely on the supply of wind (orange) in the GVEA region. Positive numbers represent a flow from GVEA to the Central region.

Figure 26 (top) shows the flow on the Alaska Intertie using a duration curve, which indicates the number of hours per year the intertie flows are at or above a certain level. In this case, a positive value represents flow from GVEA to the Central region. In 2024 (black), the intertie is used primarily to import lower-cost natural gas generation into GVEA from the Central region and reduce the need to operate more-expensive oil-fired units. The 2040 No New RE scenario (blue) GVEA remains largely an importer, but there is some flow north to south because of the addition of coal-fired capacity in the GVEA area that results in occasional periods where this lower (variable cost) resource is available. In the Reference Scenario, a very large amount of wind is built in the GVEA area due to the availability of higher quality wind, and the intertie spends more than half the time flowing toward the Central region. For similar reasons flows on the Kenai Intertie (bottom) are largely from HEA to Central, exporting generation from Bradley Lake as well as substantial additional wind in the Reference scenario.

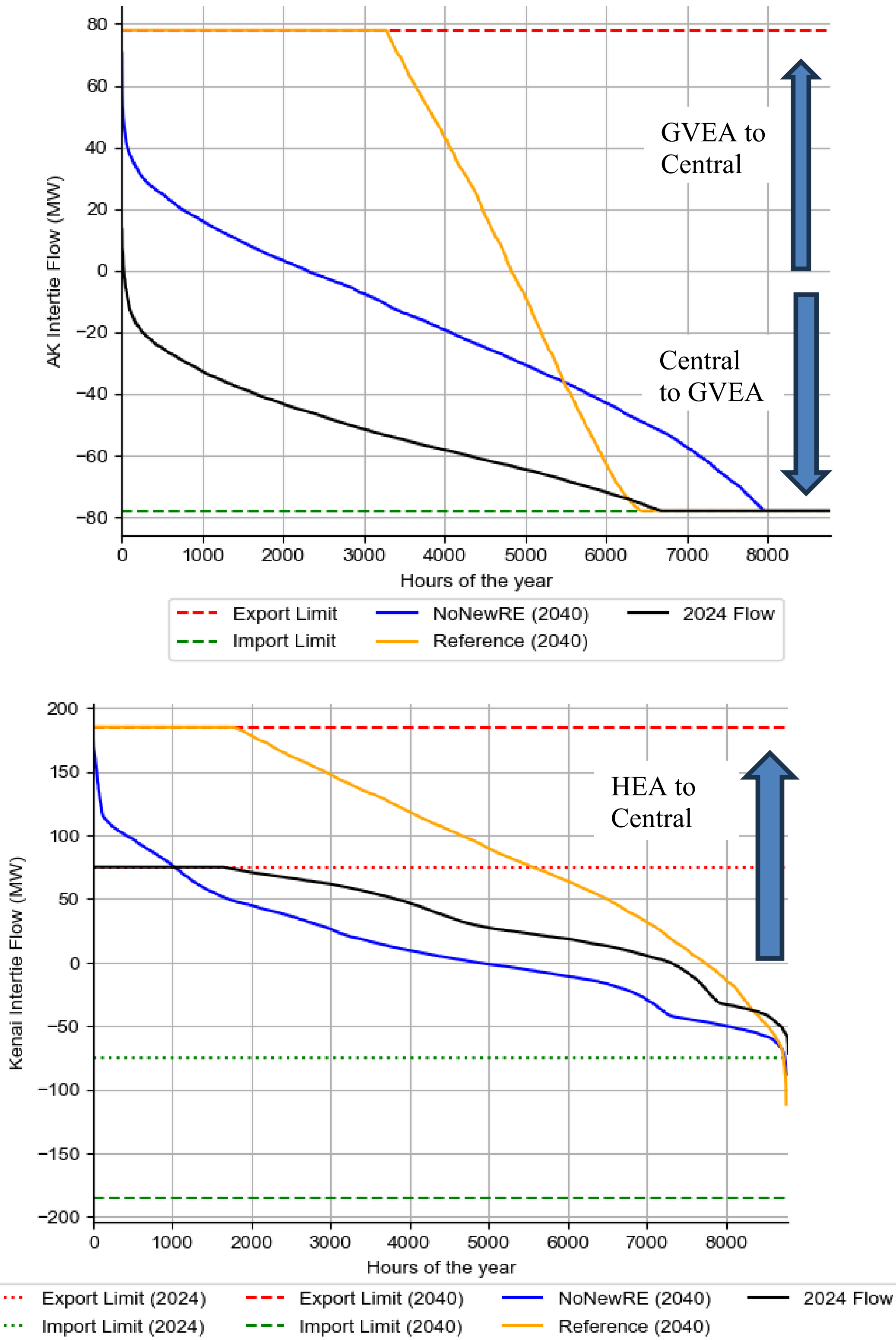


Figure 26. Regional transmission flows, where positive values represent flows from north to Central (AK Intertie) and south to Central (Kenai Intertie)

7.5.4 Renewables Dispatch for Balancing Load and for Reserve Provision

Wind and solar energy have zero fuel costs, and when acquired via power purchase agreements are often considered "must-take" resources—meaning that the utility must pay for all output from the plant. This means that choosing to curtail renewable output reduces its economic value. However, as costs of renewable energy fall and contribution increases, there will be greater need to vary the output of renewable generators, dispatching the resource by reducing its output to less than it could generate under prevailing weather conditions.[81]

The need to curtail energy is shown previously in Figure 20 when during the afternoon of November 8, the supply of renewable energy exceeds the demand for electricity across the entire Railbelt. The output of all hydropower and fossil generators is reduced to minimum, with some fossil generators remaining online so they can increase output during a later hour. Some of the excess renewables are stored (shown by the demand plus storage charging line), but there is still surplus energy that must be curtailed. During other hours, curtailment results from limited transmission capacity. For example, on November 6, there is significant curtailment but also large amounts of fossil generation that could have potentially been reduced. But some of the oversupply of renewables occurs in the GVEA area, seen in Figure 25, where the net load falls well below zero. The oversupply is greater than the transmission capacity of the AK Intertie, and there is substantial curtailment of wind energy.

Curtailment could be reduced by increased use of storage, but using storage exclusively to avoid curtailment has limited cost-effectiveness. Storage has the highest value when it can provide multiple services, including provision of operating reserves. In systems without significant renewable generation, operating reserves must respond to the potential rapid loss of conventional generators because of failure or to the random and uncertain variations in supply. In a system with large amounts of renewables, operating reserves must also address their variable and uncertain nature.

Figure 27 (top) shows the total assumed (upward) operating reserve requirement in the No New RE and Reference scenarios (black line). This is expressed in terms of GW-hrs, which is a unit of responsive capacity available for a certain amount of time.[82] This means that 1,000 GW-hr corresponds to having, on average, 114 MW (0.114 GW) of upward reserve capacity during each hour of the year (8,760 total hours per year). By 2040, the Reference scenario requires, on average, about 340 MW of available capacity to provide these reserves, which more than doubles the reserve capacity needed on average in the No New RE scenario. At the same time, the reduced generation from existing fossil and hydropower plants increases their availability to

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[81] Curtailment of renewable energy is technically easy and involves the reduction in output of generation from the power plant. With wind, this involves mechanically changing the angle of the wind turbine rotors to reduce their efficiency in converting wind energy to mechanical energy. In a solar plant, the power electronics are instructed to convert less of the direct current electricity supply coming from the panels to grid power.

[82] In the charts, the total reserves provided exceed the requirement. This is because during some periods, the available spare capacity from wind and hydropower generators providing energy exceeds the requirement. For example, if the demand for electricity is 300 MW and this is met by two 200-MW generators, there is 100 MW of "headroom" in these generators—some of which could be used to provide reserves. We included downward reserve requirements in the simulations but do not show these results because they are typically far less costly to provide than upward reserves.

provide these reserves. Curtailed wind and solar also provide an increasing amount of reserves. Wind has been used to provide regulating reserve in the United States since the early 2010s.[83] The output from the wind power plant can be increased or decreased in a controlled manner over its available output range in less than 1 minute, while the output from solar can be controlled over its output range in a few seconds. It is generally uneconomic to curtail wind and solar just for provision of reserves if they could otherwise avoid fossil generation; curtailed renewable energy must be paid for at the same rate as consumed renewable energy.

Figure 27 (bottom) shows the upward reserve requirement by type as well as the resource providing those reserves. Contingency reserves require very rapid response and so is mostly provided by batteries, which can respond nearly instantly. Wind and solar can also provide frequency-responsive reserves, and all new wind turbines sold in the United States are required to have frequency-responsive capability. However, for the purposes of this analysis, we did not allow wind and solar to provide contingency reserves.

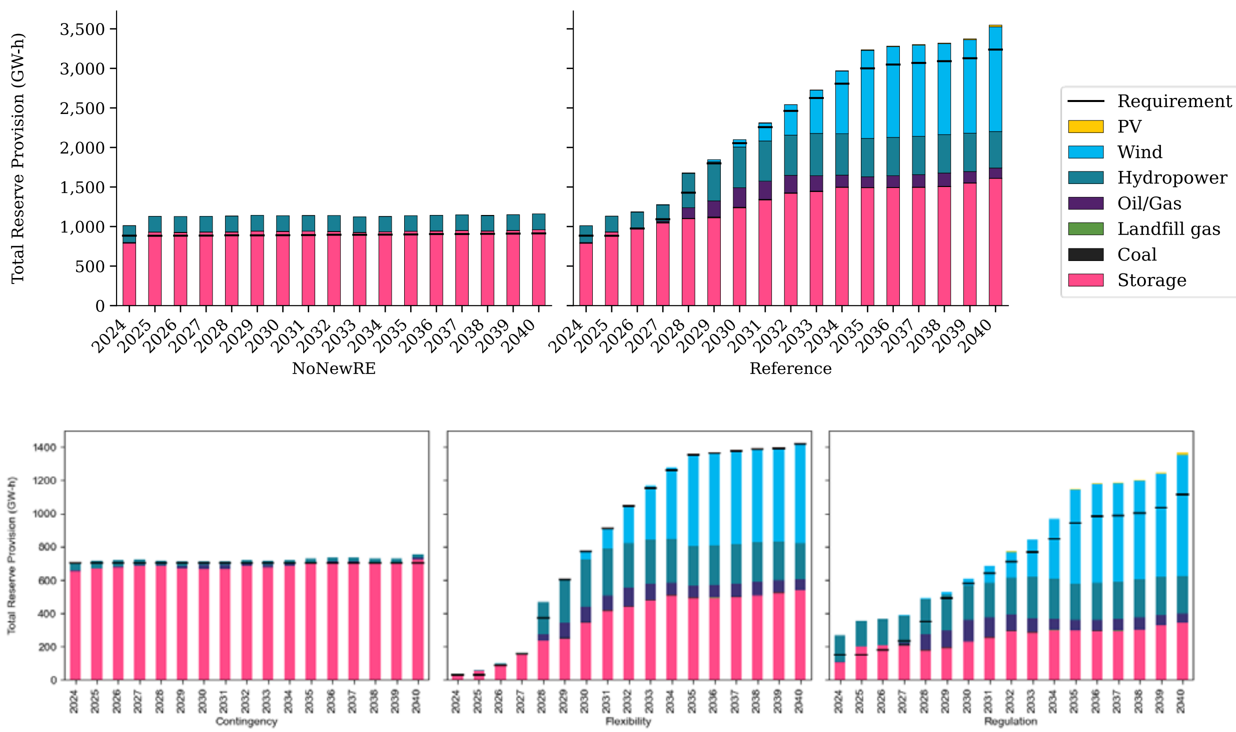

Figure 27. Total annual operating (upward) reserves provision by generator type (top) in the No New RE and Reference scenarios. Total requirement is the black bar. Reserves requirement by type for the Reference scenario is shown in the bottom. The same legend applies to all plots.

[83] P. L. Denholm, Y. Sun, and T. T. Mai, 2019. An Introduction to Grid Services: Concepts, Technical Requirements, and Provision from Wind. Golden, CO: National Renewable Energy Laboratory. NREL/PR-6A20-73590. https:/doi.org/10.2172/1505934.

7.6 Finding #6: Cost Impacts of Addressing Variability and Uncertainty Are Modest Relative to Savings but With Remaining Uncertainties

All results presented in this analysis **include** the impact of several factors associated with addressing variability and uncertainty, which increases the cost or reduces the net value of renewable energy. Additional capital costs needed to support renewable integration can increase the total cost of the renewable scenario, while variability of renewable supply can change how the fossil fleet is operated and reduces the amount of fuel avoided.

Some of these increases in costs, including fuel storage and power plant starts, are shown in previous results, but others—including additional operating reserves and impacts of part-load heat rate—are "embedded" in the results and must be isolated through additional analysis.

For example, Figure 28 shows the total start costs (fuel and nonfuel costs including addition maintenance) in the No New RE scenario (blue) and the Reference scenario (orange). By the early 2030s, the Reference scenario incurs about $3 million per year in additional costs (which are embedded in all results shown previously).

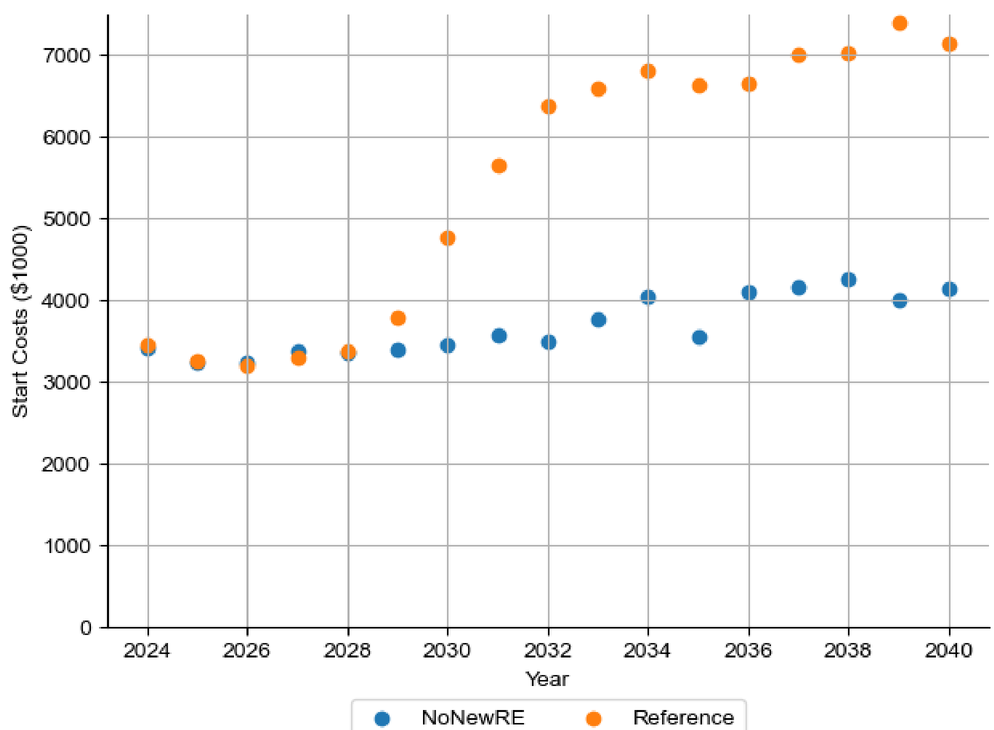

Figure 28. Annual fossil plant start costs are about $3 million greater per year by the early 2030s in the Reference scenario compared to the No New RE scenario

Figure 29 summarizes the impact of all these factors, showing the annual cost of renewable purchases plus costs associated with addressing renewable variability and uncertainty. The left set of bars show the total costs of renewable energy purchases and integration. The bottom four bars are the same as shown previously, including the cost of renewable purchases, spur line costs, natural gas storage and scheduling/forecasting.

In addition to these “direct” costs, we also add the three bars associated with changes in costs associated with system operation that result from wind and solar variability. The first is the increased costs associated with plant stops and starts shown in Figure 29. The next is the impact of part load heat rate, which is not necessarily a “cost” but actually a reduction in value of avoided fuel. The deployment of renewables in the Refence Scenario decreases total natural gas generation by about 68%, but the reduced efficiency of operation for the remaining generation slightly decreases the value of this reduced generation. Across the entire fleet, part-load operation reduces the value of renewables by about $2 million/year after 2030. Ascribing this as a cost therefore is potentially misleading, since it is a reduction in value as opposed to a direct cost, and can result in potential double counting. This is one example of how methods to calculate “integration costs” of renewable resource is challenging and somewhat controversial.[84]

A similar approach was taken to calculate the impact of additional operating reserves, which may also include both an increase in costs (if new generation resources are required) and a reduction in value when plants providing reserves operate less efficiently.[85]

Overall, the costs of integrating wind and solar and addressing variability add about $45M/year by 2040 (and about $435M cumulatively from 2024-2040). This can be compared to the potential value costs avoided by this generation.[86] The difference in the total renewables cost (left bars in Figure 29) and avoided costs (right) produces the net value, which averages $105M from 2030 to 2040 as shown in Finding #1.

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[84] Milligan, M., Ela, E., Hodge, B. M., Kirby, B., Lew, D., Clark, C., DeCesaro, J., and Lynn, K. Cost-Causation and Integration Cost Analysis for Variable Generation. United States: 2011. Web. doi:10.2172/1018105.

[85] To isolate the impact of additional operating reserves because of wind and solar, we analyzed a scenario where the additional operating reserve requirement because of new renewable capacity was not included.

[86] To avoid double counting, the costs associated with embedded factors such as part-load heat rate must be added back into the avoided fuel quantities. This is because all values for avoided fuel reported earlier already include the impact of part-load heat rates. If we back-calculate this impact and add this as a cost to renewables, we must then subtract this “negative benefit” from the avoided fuel.

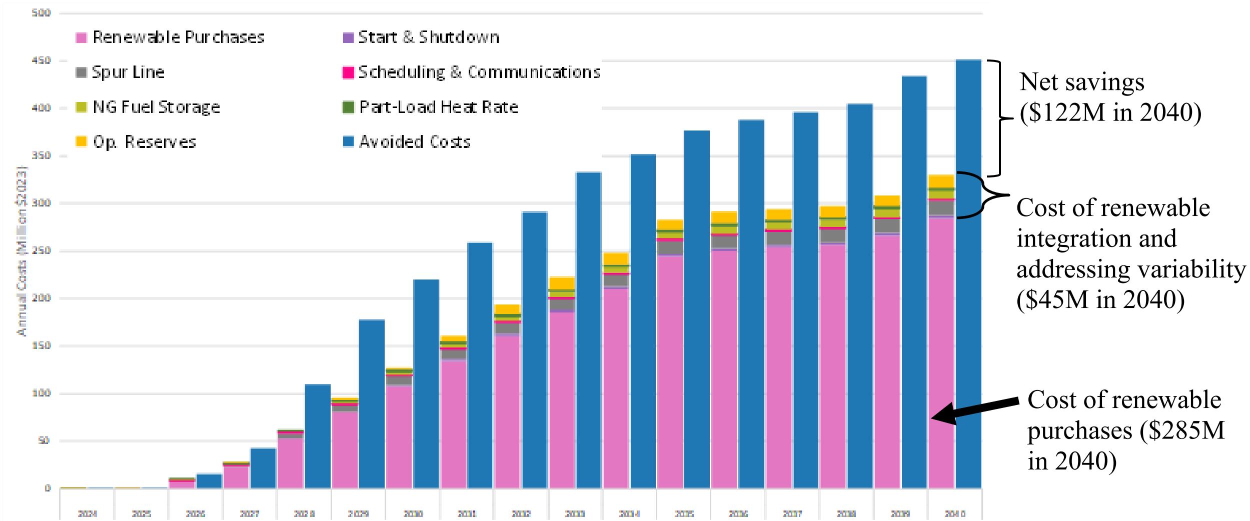


Figure 29. Annual costs ($2023) of renewable energy, including integration and addressing resource variability, are shown in the left set of bars. These costs are included in all scenarios but are broken out here for clarity. These increase renewable costs by about 16% compared to the cost of only the renewable generator and interconnection. The right (blue) bars show the value of avoided variable costs, with the difference being the net savings associated with renewable deployment.

Although it can be difficult to determine the costs associated with integrating renewable energy, these impacts are important not only to accurately assess the value of variable and uncertain resources but also to consider when allocating system costs across multiple utilities. These costs may be borne disproportionately by certain utility-owned assets, particularly those that provide the majority of the load-following and cycling required.

There is still considerable uncertainty about these factors, particularly natural gas fuel storage. Figure 30 shows the daily fuel requirements for all natural-gas-fueled plants in the Railbelt. In the No New RE scenario, the fuel use largely tracks the overall seasonal load patterns, and the range of daily natural gas fuel demand over the entire year is between 54,00 and 130,000 MMBtu. The Reference scenario always uses less gas during any given day but with larger day-to-day variability.

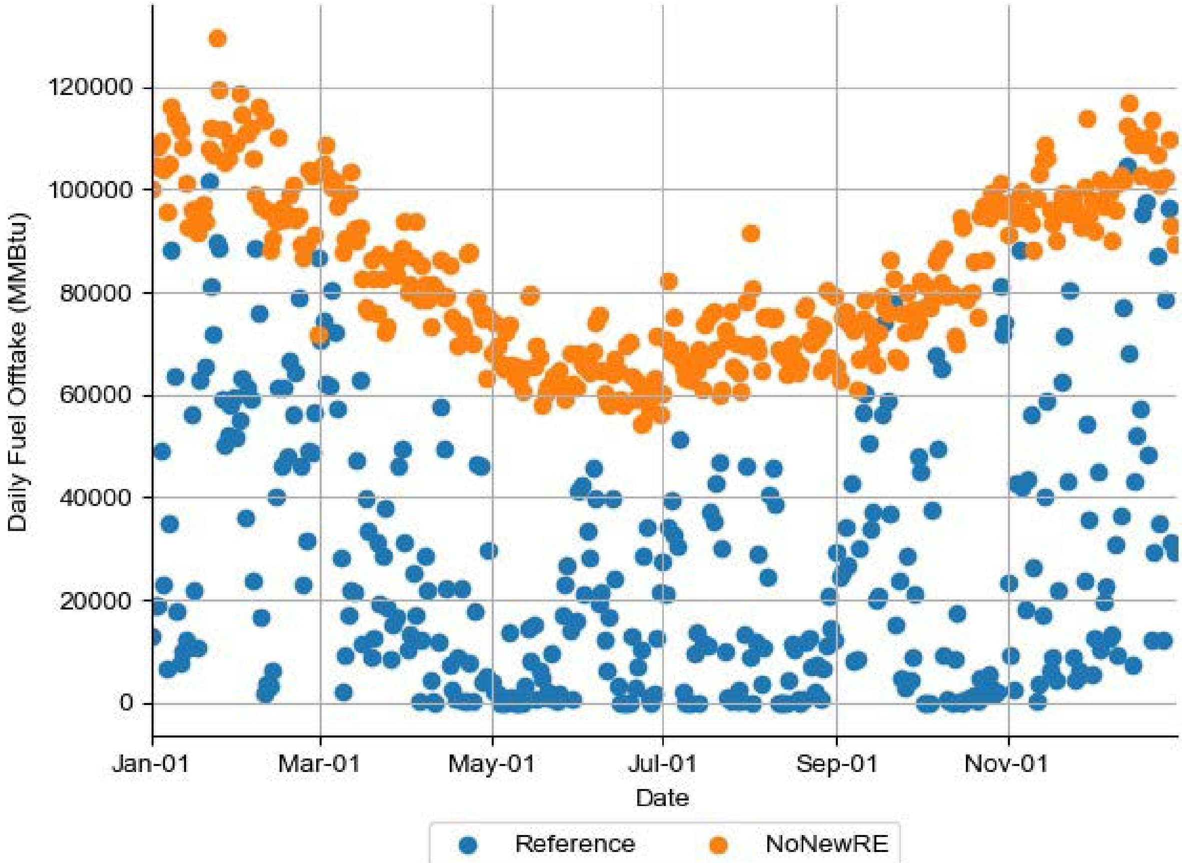


Figure 30. Daily natural gas fuel consumption in 2040

The actual impacts of this gas demand variability are difficult to assess. We add about 40 million standard cubic feet of storage in the Reference scenario by 2040 to accommodate the increased variability in natural gas use. The costs of this storage increase over time, reaching about $9.5 million/year in the base scenario. Additional issues related to fuel scheduling may be contractual and are beyond the scope of this analysis. Some gas demand variability may be mitigated by changing operational practices. The costs of these mitigation options would need to be compared to additional flexibility in the natural gas supply.

7.7 Additional Findings

7.7.1 Potential Distributed PV Adoption Must Be Evaluated in the Context of Incentives and Rate Structure Changes

The distributed PV (DPV) sensitivity assumes that customers adopt rooftop and other DPV based on the schedule in Figure 41 and are responsible for all capital and O&M costs. The utility incurs the integration-related costs associated with providing operating reserves, plant cycling, and fuel storage. However, distribution system upgrades or incentives are not accounted for.

As a result of the additional generation on the system, the Railbelt utilities do not need to provide as much energy. Figure 31 summarizes the change in generation mix in the DPV sensitivity, where the added PV offsets mostly utility-procured solar but also some wind generation from existing fossil generation. This also means that the DPV sensitivity provides a slightly higher renewable fraction than the Reference scenario.

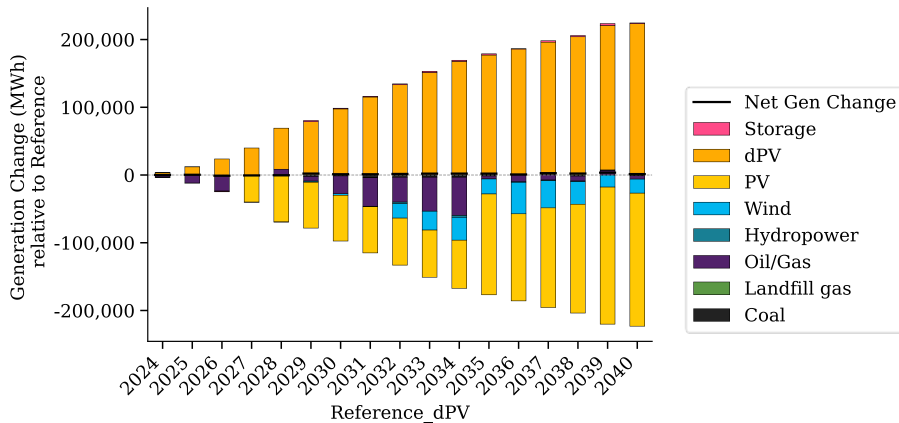


Figure 31. Changes in generation mix between the Reference scenario and DPV sensitivity

If the capital costs of deploying DPV are borne entirely by the consumer, this results in a reduction in expenditures by the utility. This is shown in Figure 32 (top) as the annual reduction in costs by category in the DPV sensitivity compared to the Reference scenario. The use of DPV reduces costs of both utility-scale renewables (both wind and solar) and natural gas. Figure 32 (bottom) shows the effective avoided cost associated with this distributed PV, or the utility expenditures required per unit of distributed PV generation.

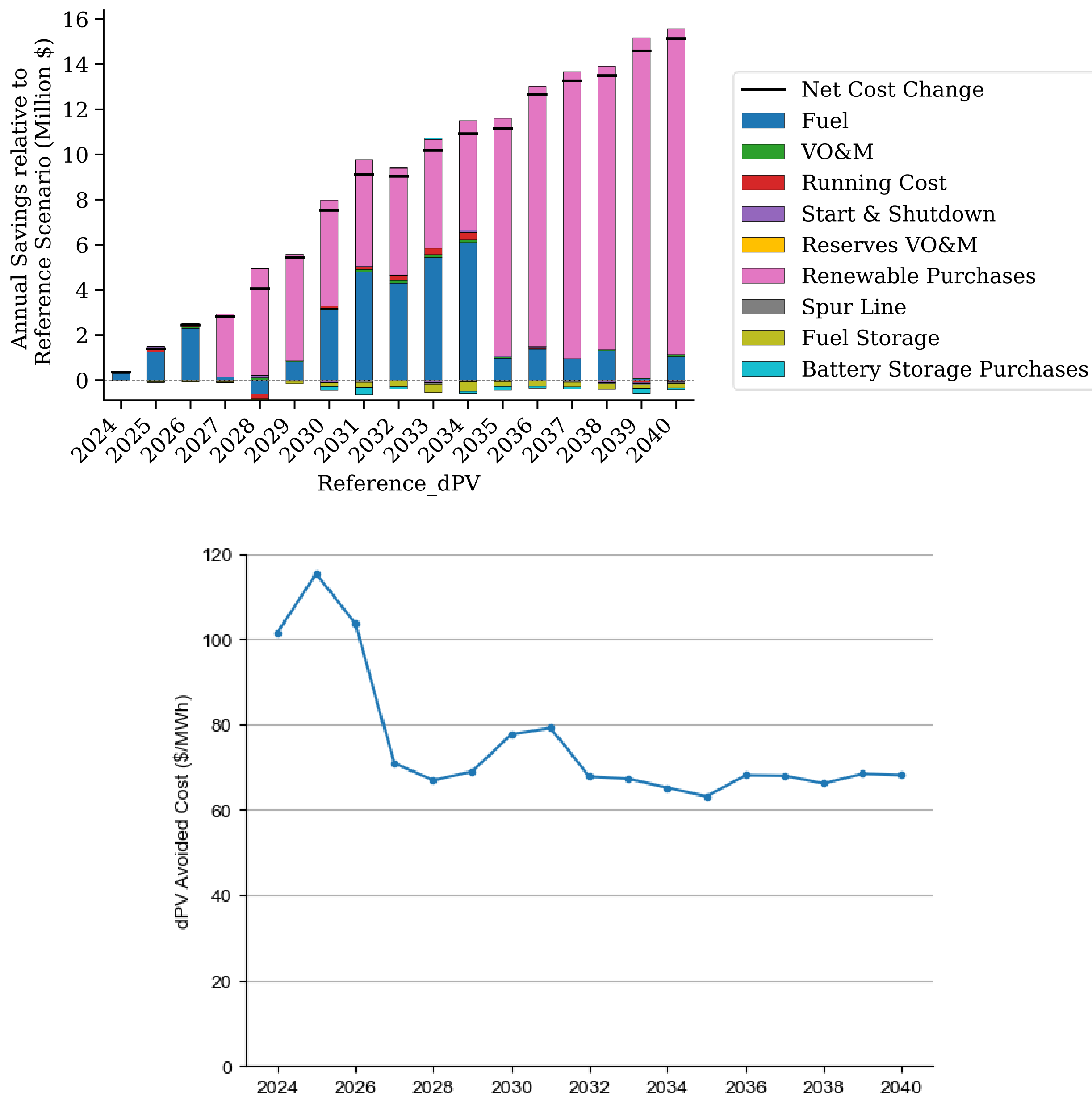
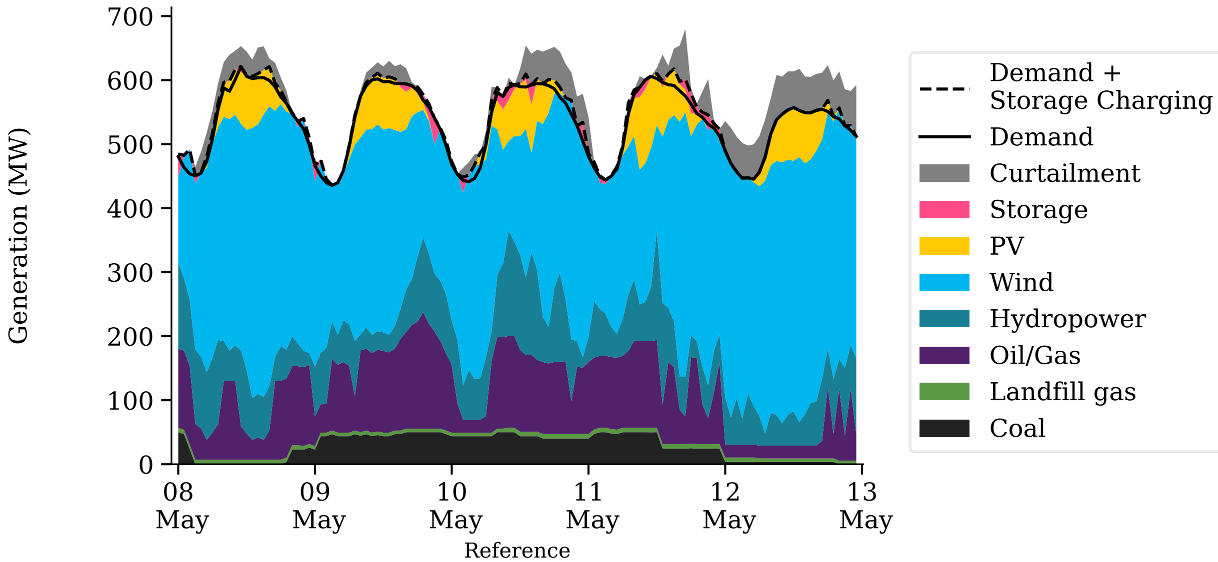


Figure 32. Changes in annual costs, with the DPV sensitivity (top) showing reduction in required utility expenditures. The avoided cost associated with the DPV sensitivity (bottom) shows the costs utilities would have to pay for electricity to replace the DPV.

An important question is how the benefits of reduced utility expenditures compare to the actual costs needed to achieve this scenario. These costs include potential incentives or system upgrades required to achieve this level of deployment. Determining this would require a more detailed analysis of existing and future rate structures, potential adoption patterns, and Alaska-specific conditions of solar performance and distribution networks. This includes consideration of how reduction in revenue from consumers would impact the portion of bills associated with fixed costs of generation, transmission, and distribution, which are likely not reduced with the use of DPV in a winter-peaking system such as Alaska.

7.7.2 The Small Increase in Costs Associated With an 80% RPS Are Largely Because of Renewable Curtailment

Figure 10 (Section 7.1) shows that new wind and solar are substantially cheaper than the variable cost of power plant operation, and the results of the Reference scenario show significant benefits of deployment. However, as deployment increases (particularly as it approaches 80%), the value of renewables drops because of a variety of factors, including the use of lower-quality wind resources (as the best sites are used up) and increased curtailment of renewables. Curtailment increases the cost of renewables because it represents energy that must be paid for but is not actually used. Curtailment results from the supply-demand mismatch of renewables and demand and limits to transmission capacity. Figure 33 illustrates this issue, showing the systemwide dispatch during a 5-day period in the Reference scenario. The top figure shows the year 2030, where the annual contribution of renewables reaches about 54%, but there is significant hourly and seasonal variation in renewable contribution. During this 5-day period, we begin to see periods when the amount of renewable supply exceeds electricity demand. Some of this extra renewable supply can be stored, but there is still an oversupply that must be curtailed. The bottom figure showing the same period from 2032 when annual renewable contribution has increased to 64%. During these five days renewables have largely displaced fossil generation, and most additional renewable generation during this period will be curtailed.



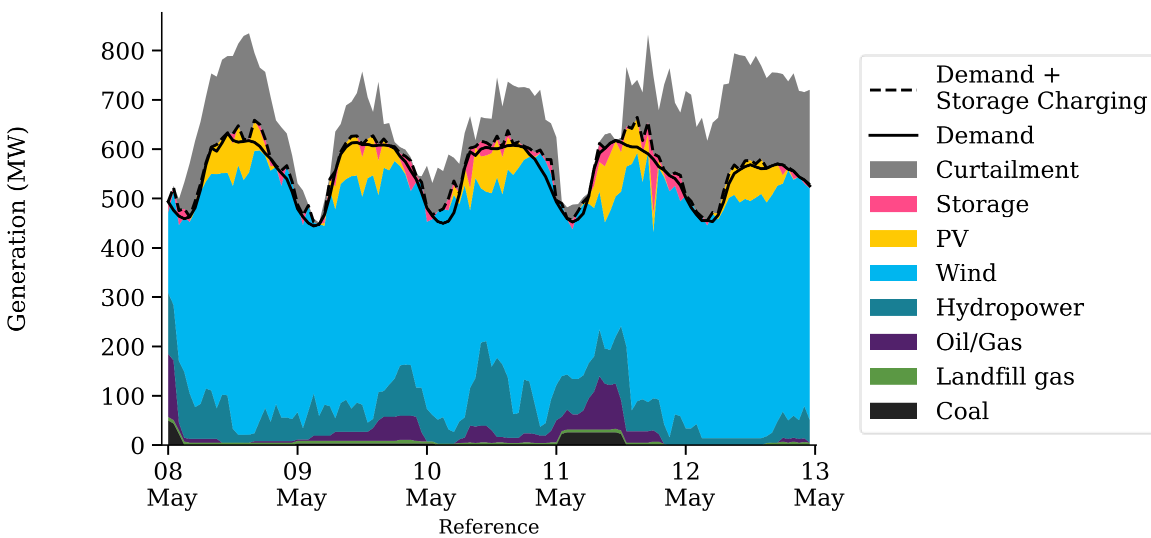


Figure 33. Curtailment occurring on a 5-day period in 2030 with annual renewable contribution of 54% (top) and 2032 (bottom) when the annual contribution of renewables has increased to 64%

Figure 34 shows the fraction of solar and wind energy curtailed as a function of renewable energy fraction in the Reference and RPS scenarios. In all figures and results throughout this report, renewable generation—and the fraction of generation from renewables—considers only the usable supply. Curtailed renewables do not count towards their contribution, but this curtailed energy must still be paid for. Curtailment rates vary regionally, with wind in GVEA having much higher levels due to transmission constraints.

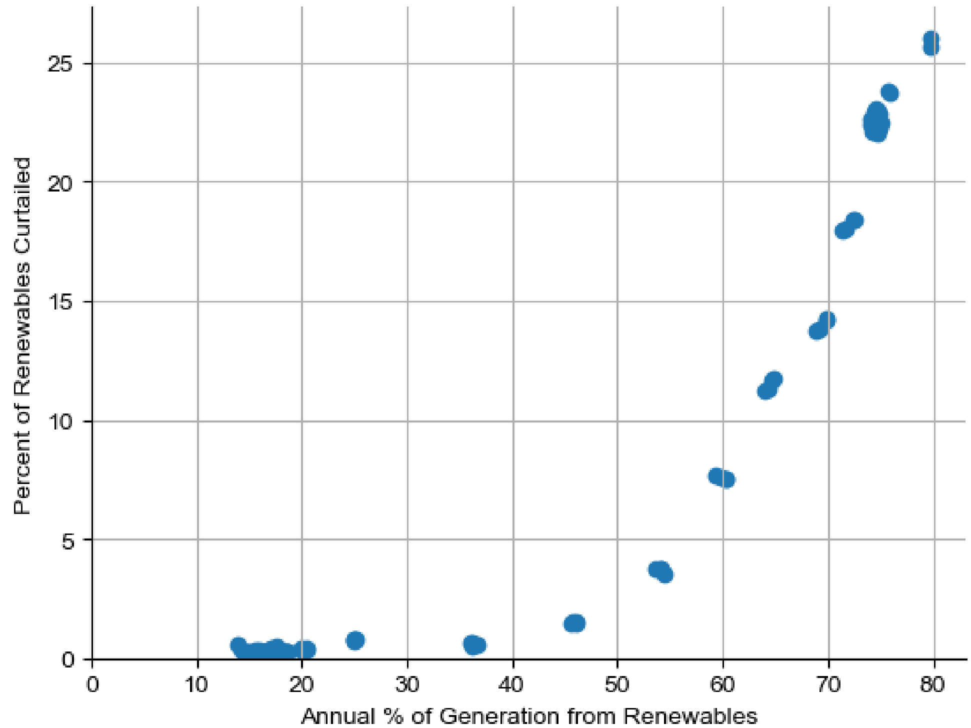


Figure 34. Annual wind and solar curtailment rate shows a dramatic increase when renewable contribution exceeds 50%-60%

Significant curtailment does not occur until renewable contribution exceeds 50%–60%, but the rate of curtailment increases dramatically after this point because the demand for electricity is completely met by renewable energy in many hours of the year. As curtailment rates increase, the effective cost of additional renewable energy increases, and each unit of renewable energy production curtailed is unable to avoid fossil generation. This increase in cost (or decline in value, depending on perspective) is inherently calculated by the model because it performs hourly simulations that determine the fuel avoided by additional renewable generation. Figure 34 shows the average curtailment rates, but the incremental (marginal) curtailment rates are much higher. For example, in the Reference scenario (with 76% renewable contribution in 2040), more than 50% of the potential generation from additional renewable capacity (meaning capacity added to increase the renewable contribution beyond 76%) is curtailed. This means that the effective capacity factor of this additional resource is less than half the potential capacity factor of an uncurtailed resource, and the effective LCOE of the usable wind generation is more than twice the base (uncurtailed) LCOE.[87] Cost of new wind and solar installed in 2040 has fallen to about $50/MWh (including transmission and natural gas storage), but the effective LCOE of incremental wind and solar after curtailment is over $100/MWh (in $2023). This net cost is higher than the avoided cost of running the remaining gas plants, so it is uneconomical to add

[87] This is because the effective LCOE is equal to the annual cost divided by annual generation. If annual generation drops by half, the effective LCOE doubles because the same amount of costs must be recovered by a smaller amount of usable energy.

additional wind beyond about 76%, which explains why the model stops building additional renewable capacity in the Reference scenario.

This increase in curtailment can be mitigated to some extent via storage, but the seasonal mismatch of supply and demand limits the ability of technologies such as batteries to cost-effectively shift supply of renewable resources—and other technologies, such as longer-duration storage (not evaluated in this work) may be needed to address this decline in renewable value in an 80% RPS.

7.7.3 There May Be Additional Costs or Operational Requirements To Address the Reduced Role of Synchronous Generation and Increased Contribution of Inverter-Based Resources

Wind, solar, and battery storage use inverters, as opposed to the synchronous generators used by fossil and hydropower generators. Inverter-based resources (IBRs) do not have the same characteristics as synchronous machines, including the lack of real physical inertial response and lack of fault current provision. Alternatively, IBRs can react more rapidly than synchronous machines to frequency deviations if programmed to do so.[88]

In these simulations, we placed no restrictions on the instantaneous contribution of inverter-based resources, and although the simulations do not reach 100% IBR contribution in part because of the minimum generation levels on hydropower units, the levels are likely high enough to require additional changes to maintain frequency stability, system strength, and fault current (among other factors). We assume the extensive use of grid-forming inverters (and add associated costs) to address some of these issues, but without further study it is not possible to determine further changes needed or quantify possible cost impacts. However, we note that there are several possible pathways to allow for such high levels of IBRs. In the shortest term, this could include changing unit commitment and dispatch to ensure that a certain amount of synchronous generation remains online. This has been performed in locations including Texas and Ireland. The limitation of this approach is the increase in costs associated with keeping thermal plants operating at minimum generation levels and associated curtailment. This is typically considered a temporary measure as grid operators deploy the necessary technologies to allow for greater instantaneous IBR contribution.

There are a variety of approaches to provide the necessary grid services, but one of the more commonly discussed is the use of synchronous condensers. Synchronous condensers would spin up during periods of very high IBR contribution, particularly if grid-forming inverters are unable to provide all the necessary services to maintain frequency stability, system strength, or fault current. This approach is likely more expensive compared to approaches based on power electronics but has the advantage of being well understood and provides a “bookend” for a possible upper bound of costs that maintains a synchronous-machine-based grid.

The construction of dedicated new synchronous condensers can be compared to the savings calculated in this work. The average annual savings from 2030 to 2040 is about $105M/year

[88] Denholm, P., Y. Sun, and T. Mai. 2019. *An Introduction to Grid Services: Concepts, Technical Requirements, and Provision from Wind*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-72578.

($2023). The annual cost of financing and operating 250 MW of new synchronous condensers at $300/kW would be about $10M/year.[89] This would reduce the annual benefits of renewables by about 10% to about $95M/year over the 2030 to 2040 time frame. Further analysis is required to determine the least-cost approach to maintain grid services. For example, in addition to power-electronics-based alternatives, existing plants may potentially be retrofitted to operate as synchronous condensers, reducing costs.[90]

7.7.4 Replacing Retiring Renewables Beyond 2040 Should Be Less Expensive Than Additional Natural Gas Generation

This analysis extends only to 2040. Beyond this date, there will be eventual retirements of wind and solar projects, although we assume that this will not be required at significant scale before about 2050. With the expiration of the federal tax credits, the cost of building new wind and solar increases. Looking beyond 2040 is highly speculative, but with the assumed cost trajectories for natural gas, wind, and solar, adding new wind and solar after 2040 will still be less expensive than burning natural gas. Removing all tax credits, the projected LCOE in 2041 (in $2023) for wind with a capacity factor of at least 33% would be less than $80/MWh, and the LCOE of solar would be less than $70/MWh. The fuel-related costs of running existing natural gas plants would be more than $90/MWh, so wind and solar without tax incentives will be less than the cost of generation from gas. The cost of new wind and solar does not consider the potential replacement of natural gas storage infrastructure and some other costs of integration nor does it consider the opportunity to repower existing plants with new equipment, avoiding many of the site development costs.

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[89] This would maintain over 400 MW of synchronous machine capacity throughout the Railbelt when including existing hydropower capacity. In addition to capital costs, this value assumes a $15/kW-year fixed O&M cost. Synchronous condensers also require operating costs including energy used to drive the machine. Most of the operation of the synchronous condensers will occur during periods of significant curtailment; therefore, unused renewable energy will be used for a large fraction of this energy.

[90] An example of an LM6000 gas turbine retrofit is discussed here: https://www.turbomachinerymag.com/view/spinning-reserve-commonwealth-chesapeake-gives-lm6000s-double-duty.

8 Conclusions

The projected prices for natural gas in the Railbelt region result in costs of generation from existing natural gas plants in the range of $70 to $80/MWh by the end of this decade, with considerable price uncertainty and potential volatility. With projected declines in the cost of wind and solar, along with the extension of federal tax credits, these resources can offer generation with stable, long-term contracts at less than the projected cost of natural gas generation in this time frame. Based on the assumptions used in this analysis, achieving more than a 75% contribution of renewables toward Railbelt electricity by 2040 appears to be the least-cost option. This includes the impact of additional costs associated with natural gas storage and other requirements to address the variability and uncertainty of wind and solar generation. Moving to an 80% RPS slightly decreases the overall benefit of renewables deployment because the mismatch of renewable supply and electricity demand limits the ability of renewables to displace the remaining fossil generation. However, based on the modeling assumptions used, the cost difference between the least-cost scenario and the RPS scenario is very small—especially compared to the impact of the uncertainty range of future prices of renewables and natural gas. There are also several other significant uncertainties around the scenarios evaluated in this work that could impact this result, including the potential load growth driven by EVs and electric heating.

Additional modeling will be required to validate the findings of this work, particularly in the changes to operation needed. This includes additional modeling to ensure system stability during periods when inverter-based wind, solar, and storage provide most of the energy as well as required hardware costs to address the lack of synchronous generators during these periods. In addition, the following items would allow for a more comprehensive assessment of renewable energy options in the Railbelt:

- Improved solar data. The impact of solar variability could not be accurately assessed in this modeling because of a lack of time-synchronized solar data across large regions.
- Analysis of wind and solar forecast error and sub-hourly variability.
- Impact of changing weather patterns.
- Modeling transmission options for the Alaska Intertie upgrades and assessing transmission alternatives.
- Deeper assessment of distributed resources such as solar, wind, and storage, including impacts on utility revenue and cost recovery.
- Detailed analysis of new hydro options.
- Consideration of capital costs of natural gas infrastructure including required storage and deliverability under uncertainty.

Appendix A. Capacity- and Energy-Related Terms

Capacity (also “nameplate capacity” or “peak capacity”) generally refers to the rated output of a power plant when operating at maximum output. The capacity of individual power plants is typically measured in kilowatts (kW) or megawatts (MW). The cumulative capacity of systems is often measured in gigawatts (GW) or terawatts (TW). Capacity of power plants is typically measured by their net AC rating, and we use this standard in this report.

Energy, in this report, refers to electricity generated and used for lighting, appliances, etc. It is typically measured in kilowatt-hours (kWh) and represents one kW of power used for an hour.

Capacity factor (%) is a measure of how much energy is produced by a plant compared to its maximum output. It is calculated by dividing the total energy produced during some period of time by the amount of energy it would have produced if it ran at full output over that period.

Capacity credit is a measure of the contribution of a power plant to resource adequacy, meaning the ability of a system to reliably meet demand during all hours of the year. It is measured in terms of either capacity (kW, MW) or the fraction of its nameplate capacity (%) and indicates the amount or portion of the nameplate capacity that is reliably available to meet load during times of highest system demand—typically the highest net load hours of the year.

Appendix B. Base Modeling Assumptions

B.1 Utility-Owned Fossil Generators

Table B-1 summarizes data for existing utility-owned assets using data submitted by each utility to the Energy Information Administration (EIA) on Form 860m.[91] Based on feedback including proprietary data from individual utilities, there are some small differences between these data and data actually used in the model. Utility names and plant names are abbreviated for brevity.

Table B-1. Existing Railbelt Fossil Fuel Generators (data as reported to EIA)

Utility Name	Plant Name	Gen. ID	Nameplate Cap. (MW)	Net Summer Cap. (MW)	Net Winter Cap. (MW)	Type	Operating Year	Status
Chugach	Hank Nikkels	3R	48.9	29.3	32.9	NGCT	2007	OP
Chugach	Hank Nikkels	P1 BS	2.0	2.0	2.0	Oil ICE	2012	OP
Chugach	George M Sullivan	7	102.6	102.6	81.8	NGCT	1979	OP
Chugach	George M Sullivan	CC	151.7	129.0	129.0	NGCC	2017	OP
Chugach	George M Sullivan	GT8	92.6	77.7	86.5	NGCT	1984	SB
Chugach	Southcentral	CC	203.9	169.7	203.4	NGCC	2013	OP
Chugach	Beluga	1	16.0	18.9	19.6	NGCT	1968	SB
Chugach	Beluga	3	59.1	58.0	64.8	NGCT	1972	SB
Chugach	Beluga	5	68.3	61.4	68.7	NGCT	1975	SB
Chugach	Beluga	7	76.5	70.6	80.1	NGCT	1978	SB
Seward	Seward	3	2.5	2.5	2.5	Oil ICE	1975	OP
Seward	Seward	4	2.5	2.5	2.5	Oil ICE	1986	OP
Seward	Seward	5	2.5	2.5	2.5	Oil ICE	1985	OP
Seward	Seward	6	2.8	2.8	2.8	Oil ICE	2000	OP
Seward	Seward	N1/N2	5.3	5.3	5.6	Oil ICE	2010	OP
GVEA	Healy	1	28.0	25.0	25.0	Coal	1967	OP
GVEA	Healy	2	62.0	50.0	50.0	Coal	1998	OP
GVEA	North Pole	1	60.5	44.0	60.0	Oil CT	1976	OP
GVEA	North Pole	2	60.5	50.0	64.0	Oil CT	1977	OP
GVEA	North Pole	GT3/STG1	60.0	51.0	65.0	Oil CC	2007	OP
GVEA	Fairbanks	GT1	18.4	15.5	17.7	Oil CT	1971	OP
GVEA	Fairbanks	GT2	18.4	15.0	17.7	Oil CT	1972	OP
GVEA	Delta Power	6	23.1	23.1	26.0	Oil CT	1976	SB
HEA	Seldovia	5	1.2	1.2	1.2	Oil ICE	2004	OP
HEA	Seldovia	7	1.0	1.0	1.0	Oil ICE	2017	OP
HEA	Bernice Lake	2	20.7	17.0	19.0	NGCT	1971	OP

[91] https://www.eia.gov/electricity/data/eia860m/.

Utility Name	Plant Name	Gen. ID	Nameplate Cap. (MW)	Net Summer Cap. (MW)	Net Winter Cap. (MW)	Type	Operating Year	Status
Utility Name	Plant Name	Gen. ID	Nameplate Cap. (MW)	Net Summer Cap. (MW)	Net Winter Cap. (MW)	Type	Operating Year	Status
HEA	Bernice Lake	3	28.8	22.9	26.0	NGCT	1978	OP
HEA	Bernice Lake	4	27.2	22.5	26.0	NGCT	1981	OP
HEA	Nikiski	GT1	40.8	37.9	42.0	NGCC	1986	OP
HEA	Nikiski	ST1	40.0	38.0	40.0	NGCC	2013	OP
HEA	Soldotna	1	50.0	44.0	49.0	NGCT	2014	OP
MEA	Eklutna Gen. Station	01-10	171	165	165	NG ICE	2015	OP

Table B-2 provides the average heat rate as reported to EIA[92] in 2022, for plants that produced at least 70 GWh in 2022. These plants provided about 80% of Railbelt generation and 94% of fossil generation in 2022.

Table B-2. Average Heat Rate for Major Fossil Fuel Generators (producing at least 70 GWh in 2022)

Utility Name	Plant Name	Gen. ID	Nameplate Cap. (MW)	Type	2022 Reported Heat Rate	2022 Reported Generation (GWh)
Chugach	George M Sullivan	CC	151.7	NGCC	7,920	872
Chugach	Southcentral	CC	203.9	NGCC	7,650	1,151
GVEA	Healy	1/2	90	Coal	13,680	405
GVEA	North Pole Gas Turbine	1/2	121	Oil CT	11,650	71
GVEA	North Pole Combined Cycle	GT3/STG1	60.0	Oil CC	7,660	354
HEA	Nikiski Combined Cycle	GT1	81	NGCC	8,950	432
MEA	Eklutna Gen. Station	01-10	171	NG ICE	8,730	532

B.2 Heat Rate and Start Cost Modeling

All generators of significant size are modeled with a heat rate curve to capture the potential decrease in efficiency associated with increased cycling operation. Heat rate values are derived from utility data and public sources.[93] Figure 35 provides an example of the simplified heat rate curve used for the Southcentral combined-cycle (CC) unit in Alaska, which we show as a

[92] https://www.eia.gov/electricity/data/eia923/.

[93] For example, for Chugach, we used the "2021 Heat Rate Analysis Report" that includes heat rate curves for its thermal fleet.

function of full output.[94] We do not include the impact of part-load operation on very small plants (<10 MW), especially because most of those plants rarely run.

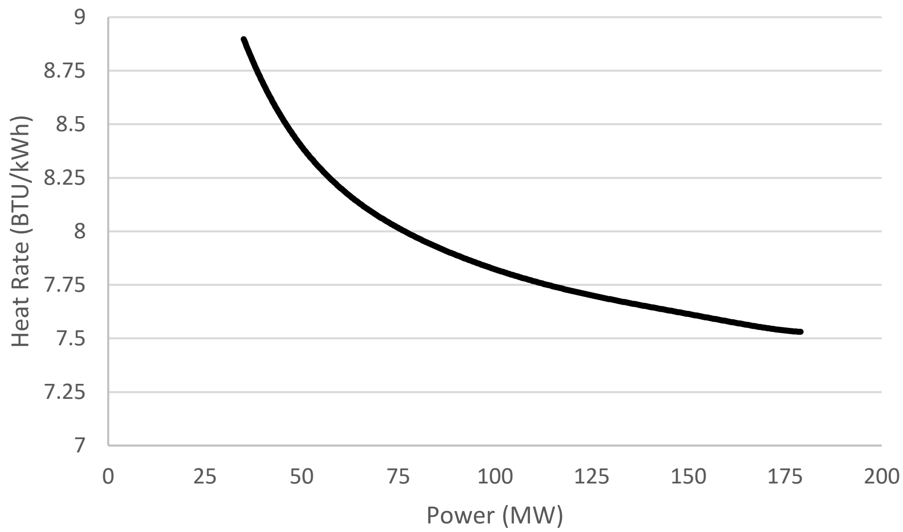

Figure 35. Example simplified heat rate curve for the Southcentral combined-cycle generator

Start costs include both the start fuel requirements and nonfuel costs. Data were derived from the utilities or from previous National Renewable Energy Laboratory (NREL) studies where utility data were not available.[95] For CC plants, we assume that all starts require operation in full CC mode (all gas turbines) and not the operation of individual combustion turbines without the steam turbine. This is a conservative estimate that reduces the flexibility of the system.

B.3 Treatment of CHP Plants and Other Nonutility-Owned Generators

There are about 100 MW of nonutility fossil-fueled generation facilities in the Railbelt and connected to the Railbelt grid. These are largely combined heat and power (CHP) plants serving military bases, industrial customers, and the University of Alaska-Fairbanks (UAF). These plants largely serve native loads, and load data from the utilities do not include the load served by these CHP plants. Railbelt utilities make no significant purchases of energy from these resources except Aurora and UAF. Aurora is a coal-fired plant that provides combined heat and power to Fairbanks, and because it provides heating, is modeled as a must-run unit throughout the winter (January through April; October through December). During this period, Aurora is committed and can vary its output between 19 MW and 22 MW. During the summer, it is treated as a utility-dispatched resource.[96] Based on data from Golden Valley Electric Association (GVEA), we also assume that 4 MW of UAF (coal generation) capacity is utility-dispatched.

B.4 Hydropower

Existing hydropower plants are listed in Table B-3.

[94] We use a "piecewise linear" approximation of the polynomial heat rate curve.
[95] WWSIS-2.
[96] This may require changes to long-term purchase contracts.

Table B-3. Existing Railbelt Hydropower Plants

Name	Power	Minimum Generation Level	Notes
Bradley Lake 1	60	6	EIA lists as 63 for all three ratings
Bradley Lake 2	60	6	EIA lists as 63
Cooper Lake 1	9.7	6.5	
Cooper Lake 2	9.7	6.5	
Eklutna Hydro 1	20	3.0	EIA lists as 22
Eklutna Hydro 2	20	3.0	EIA lists as 22

Plants are dispatched based on maximum and minimum outputs, and we assumed a monthly average water supply for existing hydropower generators (Table B-4). Monthly water supply for existing hydropower generators was obtained from EIA-923 and from the Alaska Energy Authority (AEA).

Table B-4. Monthly Water Budget for Existing Railbelt Hydropower Plants

	Monthly Water Availability (GWh)		
Month	Bradley Lake Units 1 and 2	Cooper Lake Units 1 and 2	Eklutna Hydro Units 1 and 2
Jan	19.83	1.85	7.1
Feb	16.5	1.54	5.91
Mar	15.82	1.47	5.67
Apr	13.96	1.3	5
May	17.29	1.61	6.19
Jun	18.62	1.73	6.67
Jul	16.58	1.54	5.94
Aug	15.64	1.46	5.6
Sep	12.83	1.19	4.59
Oct	13.17	1.23	4.71
Nov	15.43	1.44	5.52
Dec	19.83	1.84	7.1

B.5 Other Existing Resources

Table B-5 lists other generation resources in operation in the Railbelt. Location of existing wind is shown in Figure 37.

Table B-5. Existing Railbelt Renewable Generators

Name	Nameplate Capacity (MW)	Type
Fire Island Wind	18	Wind
Eva Creek Wind	24.6	Wind
Delta Wind Farm	1.9	Wind
JBER	11.5	LFG
Willow Solar	1	Solar
Houston Solar	6 (8.5 DC Rating)	Solar

B.6 Electric Vehicle Adoption

For the Reference scenario, we used the lowest growth level, from the "AEA continued" forecast, shown in Figure 36, which results in about 110,000 vehicles (about 20% of all vehicles in the Railbelt) in 2040 (left y-axis). Annual customer demand at the meter is shown in the right axis (before transmission and distribution [T&D] losses). Demand profiles (including additional T&D losses) for 2040 are shown in Figure 36 (bottom) and vary hourly and seasonally, based on driving patterns and demonstrating the impact of cold-weather performance.[97] For other years, the profiles are scaled proportionally to the number of vehicles shown in the top of the figure. The loads were allocated to the three zones based on Alaska Center for Energy and Power (ACEP) data.[98] We assume that the charging demand profiles are completely inflexible.

[97] The ACEP study uses typical weather year data, which do not match the 2018 weather year used in our study, which could over- or underestimate the actual impacts of vehicle charging during any given hour or day. The most significant impact in our use of these mismatched data could be underestimating the load on a peak demand day, resulting in an overestimation of resource adequacy. Fortunately, the demand in the ACEP data on the day of our studies' peak demand day is close to the annual peak demand in the ACEP data, minimizing this concern.

[98] Cicilio, P.; Francisco, A.; Morelli, C.; Wilber, M.; Pike, C.; VanderMeer, J.; Colt, S.; Pride, D.; Helder, N.K. Load, Electrification Adoption, and Behind-the-Meter Solar Forecasts for Alaska's Railbelt Transmission System. *Energies* **2023**, *16*, 6117. https://doi.org/10.3390/en16176117

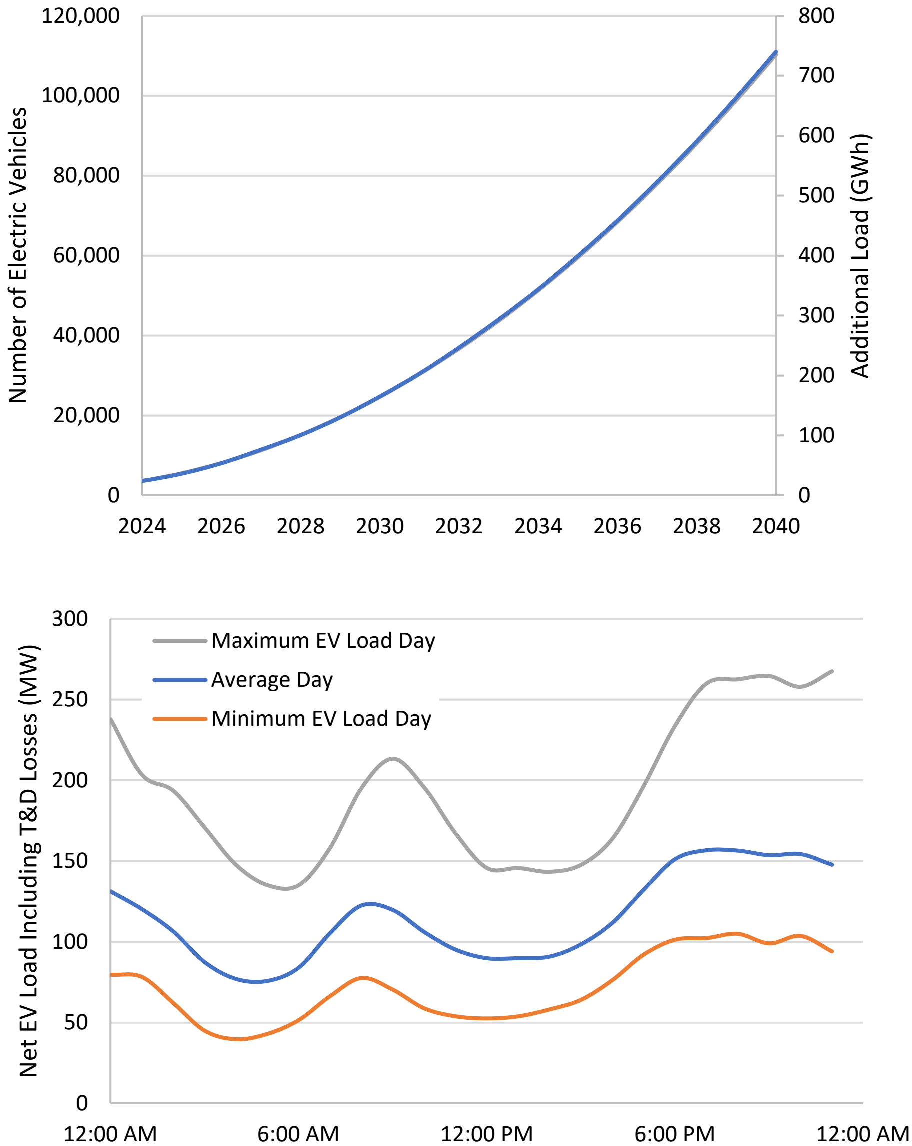

Figure 36. EV adoptions (top) and Reference scenario charging profiles in 2040 (bottom)

B.7 Operating Reserves

Table B-6. details the assumptions of operating reserves as modeled. Unless otherwise noted, the reserve product is provided for each zone individually, and reserves are not shared between zones.

The additional reserve requirement for renewable energy was based on the maximum 1-hour ramp as a fraction of generation, equal to about 60% for wind. We assume that this entire 1-hour ramp must be served by operating reserves split between a fast component (regulation) and a slow component (flexibility).

Table B-6. Summary of Operating Reserve Modeling

Parameter	Assumption
Contingency	80 MW for the entire Railbelt. Provided primarily with battery energy storage systems, but some can be met using synchronized generators with a sufficiently fast response rate (full response in 60 seconds).
Regulation	2% of load in Homer Electric Association (HEA) and Central. 5% of load in GVEA based on utility feedback. Regulation for wind and solar is 20% of combined output in each hour. Must be provided by synchronized generators or batteries with a 10-minute response. Requirement is symmetric in both directions, meaning that the same amount of both upward and downward reserves is required in all time periods.
Flexibility	40% of wind plus 10% of solar output (including distributed photovoltaics [DPV]). Must be provided by synchronized generators or batteries with a 30-minute response requirement. Requirement is symmetric in both directions.
Fossil/hydro eligibility	All fossil and hydro plants can provide all reserves, limited by ramp rate and operational status, including online status (for synchronized reserves) and available headroom at current dispatch point.
Additional subhourly cycling costs of fossil units	We assign a cost of $4.5/MWh for units providing operating reserves to represent additional subhourly response.[99] This value is in addition to the impacts of additional starts and part-load (steady-state) operation that result from additional operating reserves; these are calculated separately.
Renewable eligibility	Wind and PV can provide regulation and flexibility, but not contingency, reserves after 2024. This is performed by curtailing the output of the plant.[100] DPV cannot provide reserves.
Reserve sharing across zones	Not allowed, except for contingency reserves.

We did allow for occasional reserve shortages, particularly because these conditions were already experiencing failures of the largest single system component, which sets the maximum reserve requirement. We assume a cost of unserved operating reserves (violation of reserve shortage) equal to $10,000/MW-h.[101]

[99] Value based on Hummon, M., P. Denholm, J. Jorgenson, D. Palchak, B. Kirby, and O. Ma. 2013. *Fundamental Drivers of the Cost and Price of Operating Reserves*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-58465.

[100] This is already common practice in several regions, most notably in Texas. Milligan, M., B. Frew, B. Kirby, M. Schuerger, K. Clark, D. Lew, P. Denholm, B. Zavadil, M. O'Malley, and B. Tsuchida. 2015. "Alternatives No More: Wind and Solar Power Are Mainstays of a Clean, Reliable, Affordable Grid." *IEEE Power and Energy Magazine* 13(6): 78–87. (See also https://www.nrel.gov/docs/fy19osti/73866.pdf)

[101] This is the cost of 1 MW of capacity unavailable for reserves in 1 hour. Therefore, this is a unit of capacity over time, not energy. This is a soft constraint to allow the model to solve in challenging time periods.

Appendix C. Generator Cost and Performance Assumptions for New Resources

Summary tables of costs for each technology are provided in Appendix 0, with a description in the following subsections.

C.1 Land-Based Wind

We obtained simulated hourly wind production data for 38 sites with a total of about 2.9 GW of capacity using the 2018 weather year. Wind production data are simulated from ERA5 wind reanalysis data from 2000 to 2020 at 100 m, sped up using annual average wind speeds from UL's 200-m resolution downscaled wind resource models that consider terrain and other factors. A power curve from the GE 3.4-MW/140-m turbine at hub heights of 100 m and 120 m was applied to estimate production. Total losses of 17% are included (electrical losses, turbulence, wake losses, downtime, cold weather package energy consumption).[102] Total resource availability was based on land ownership and other exclusions, assuming a packing density of wind of 3 MW/km^2.

We process the native wind speed data into inputs for the capacity expansion model as follows. This processing is all performed using NREL's renewable energy potential (reV) tool.[103] First, we apply a turbine power curve to the wind resource data (as mentioned previously) to produce hourly capacity factor profiles at each 4-km grid cell. These cells are then masked with the exclusion layer (shown in Figure 37) to eliminate land ineligible for wind turbine development. The identified sites have a capacity factor range of 31% to 44% with a weighted average of about 36%.

[102] Using NREL's renewable energy potential (reV) tool with NASA data for the year 2018.

[103] Maclaurin, Galen, Nick Grue, Anthony Lopez, Donna Heimiller, Michael Rossol, Grant Buster, and Travis Williams. 2019. *The Renewable Energy Potential (reV) Model: A Geospatial Platform for Technical Potential and Supply Curve Modeling*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-73067. https://www.nrel.gov/docs/fy19osti/73067.pdf.

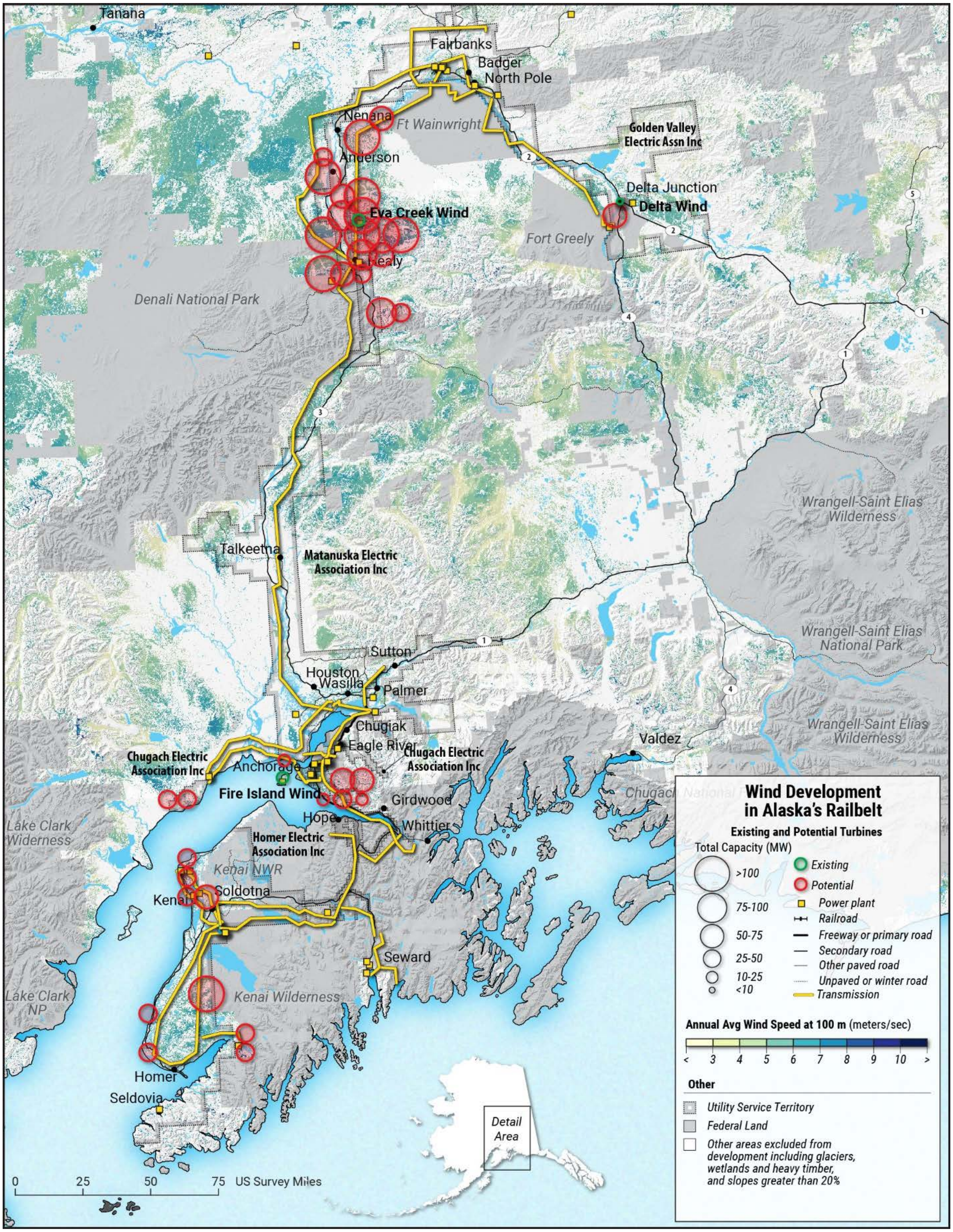

Figure 37. Railbelt wind resource and location of wind site evaluated

Using an algorithm that optimizes turbine spacing in the resulting masked cells, we assign each cell a maximum technical potential of wind capacity in MW. Next, we determine the interconnection cost of each of these hypothetical wind farms by identifying the least-cost spur line to connect it to the existing transmission network. This spur line cost is added to the base capital cost of the wind plant. Spur line costs are estimated using the distance from the center of the wind farm to the local transmission network, assuming a blended average distance-based spur line cost of $11/kW-km ($17.7/kW-mile). This assumes a lower voltage (69-kV) interconnection for smaller plants (<100 MW) using a single circuit, or a higher voltage (138-kV) double-circuit line for larger plants.[104] We assume that the cost of the spur line is eligible for the ITC and financed with the same terms as the wind plant.

The interconnection costs of each grid cell, combined with their technical wind potential, makes up a supply curve. This, along with the representative hourly capacity factor profiles, is used by the capacity expansion model. The model may then choose between various locations considering the potential trade-off between performance and distance.

[104] Value based on discussions with various stakeholders.

Table C-1. Location and Performance of Available Wind Sites Evaluated

Potential Capacity (MW)	Lat.	Long.	Zone	Capacity Factor	Spur Line Distance (km)	Spur Line Cost Per KW ($)
195	63.974	-148.406	GVEA	41.2%	36.4	400
192	64.093	-148.858	GVEA	35.3%	8.3	92
185	64.005	-149.346	GVEA	34.5%	1.0	11
182	63.99	-148.876	GVEA	36.9%	3.0	33
177	63.982	-148.641	GVEA	34.5%	33.6	369
142	64.505	-148.784	GVEA	32.6%	2.1	23
130	64.196	-148.839	GVEA	32.3%	3.8	42
113	60.028	-151.154	Homer	32.7%	5.3	58
113	63.8	-149.379	GVEA	34.9%	26.1	287
102	64.314	-149.296	GVEA	33.0%	2.1	23
97	64.101	-149.094	GVEA	34.4%	12.0	131
90	63.887	-148.894	GVEA	36.6%	3.3	36
85	63.571	-148.716	GVEA	41.3%	53.3	586
74	63.879	-148.66	GVEA	38.0%	21.0	231
71	63.792	-149.146	GVEA	36.6%	4.3	48
64	63.959	-145.805	GVEA	31.1%	8.4	92
63	61.119	-149.553	Central	35.8%	13.7	150
62	61.112	-149.339	Central	34.3%	20.3	224
61	64.599	-148.525	GVEA	33.1%	2.2	24
50	60.542	-151.109	Homer	33.6%	1.0	11
49	61.061	-151.276	Central	39.8%	29.6	325
47	59.731	-151.797	Homer	33.5%	1.8	20
45	60.649	-151.311	Homer	37.3%	0.7	8
45	64.417	-149.279	GVEA	32.7%	1.3	15
41	63.563	-148.484	GVEA	39.0%	82.6	909
40	60.752	-151.303	Homer	37.5%	10.4	115
36	59.937	-151.783	Homer	34.7%	4.9	54
33	61.065	-151.49	Central	40.3%	44.2	486
32	59.812	-150.76	Homer	43.7%	34.1	375
32	59.71	-150.77	Homer	38.7%	35.0	385
29	60.547	-151.32	Homer	35.9%	2.8	30
28	63.785	-148.912	GVEA	42.2%	8.9	98
25	61.017	-149.567	Central	33.2%	3.8	42
24	61.01	-149.354	Central	35.5%	5.8	64
23	61.242	-150.183	Central	38.1%	8.7	96
20	61.023	-149.781	Central	35.6%	20.5	225

Cost estimates use the 2023 ATB using the "technology 3" category, which assumes a 3.3-MW turbine with a 148-meter rotor diameter and a 100-meter hub height, designed for a typical capacity factor of about 33%.[105] The ATB data assume a 200-MW wind plant while the largest individual wind plant in our data set is less than that. The reduced economy of scale benefits are captured in the Alaska multiplier, which assumes that even in a mature market, the cost of wind in Alaska is 60% higher than the ATB assumptions.

Figure 38 shows the estimated LCOE (or fixed PPA contract price) across a range of capacity factors, before the addition of transmission interconnection costs or fuel storage costs. The values in Figure 38 (which vary across the sites according to actual resource quality and interconnection costs) represent the cost in the initial year of operation, which are constant in real dollars ($2023) but would escalate at 2.5% per year in nominal dollars. The model generally adds resources with this range of capacity factors, with a fleet average capacity factor of 35.9% in the Reference scenario. For comparison, we also show average PPA price for contracts in the Lower 48 signed from 2019 to 2023, adjusted to $2023.[106] The dot is the capacity weighted average, while the bar shows the range for the 80th percentile of contracts in the data set.

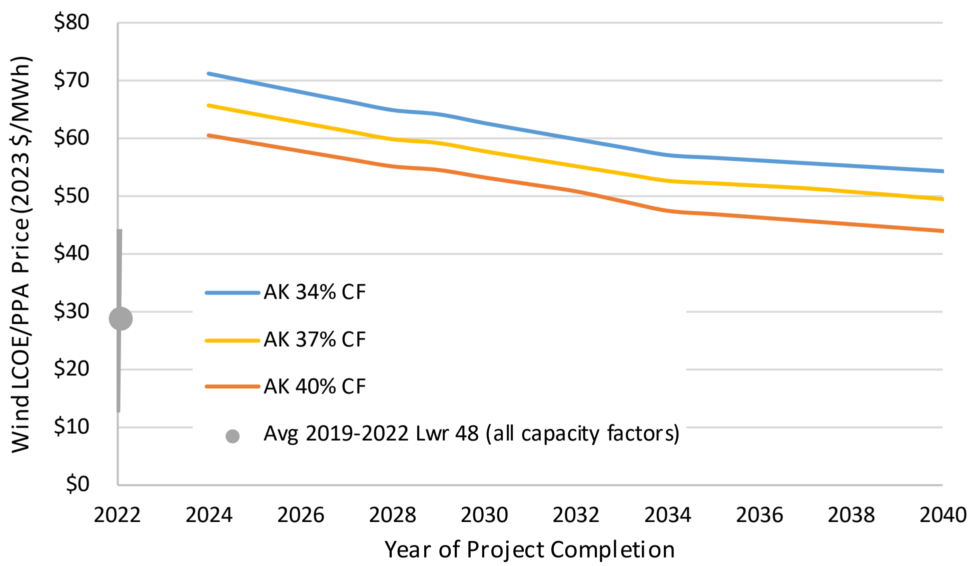

Figure 38. Assumed LCOE/PPA price projections for utility-scale wind operating with an average) (not including transmission). The PPA price is fixed (in real $2023) for 25 years from the year of installation, which corresponds to an escalation at the rate of inflation in nominal dollars.

Wind is assumed to be fully dispatchable (up to the output reflecting wind conditions at any given time) but acts as a financial "must-take" resource if obtained by a PPA. Based on the contribution of wind during peak demand periods, we assume a capacity credit (contribution of wind toward resource adequacy) equal to 10% of nameplate.

No new wind is allowed before the end of 2026. Starting in 2027, we assume that no more than 150 MW of wind can be completed per year.

[105] https://atb.nrel.gov/electricity/2023/land-based_wind.
[106] https://emp.lbl.gov/wind-power-purchase-agreement-ppa-prices.

C.2 Offshore Wind

We assume that offshore wind may be deployed starting in 2030. We did not use ATB values for cost and performance; instead, we used data from a pending NREL study to be released in 2024.[107] Figure 39 summarizes assumed capital cost (top) and levelized cost of energy (bottom) values for fixed-base and floating offshore wind deployed in the Cook Inlet. Costs include the interconnection to a point near Homer. Estimated capacity factors are in the range of 50% to 52%, which is significantly higher than land-based values. However, the overall cost of energy is significantly higher than land-based wind, and offshore wind was not deployed in the scenarios evaluated.

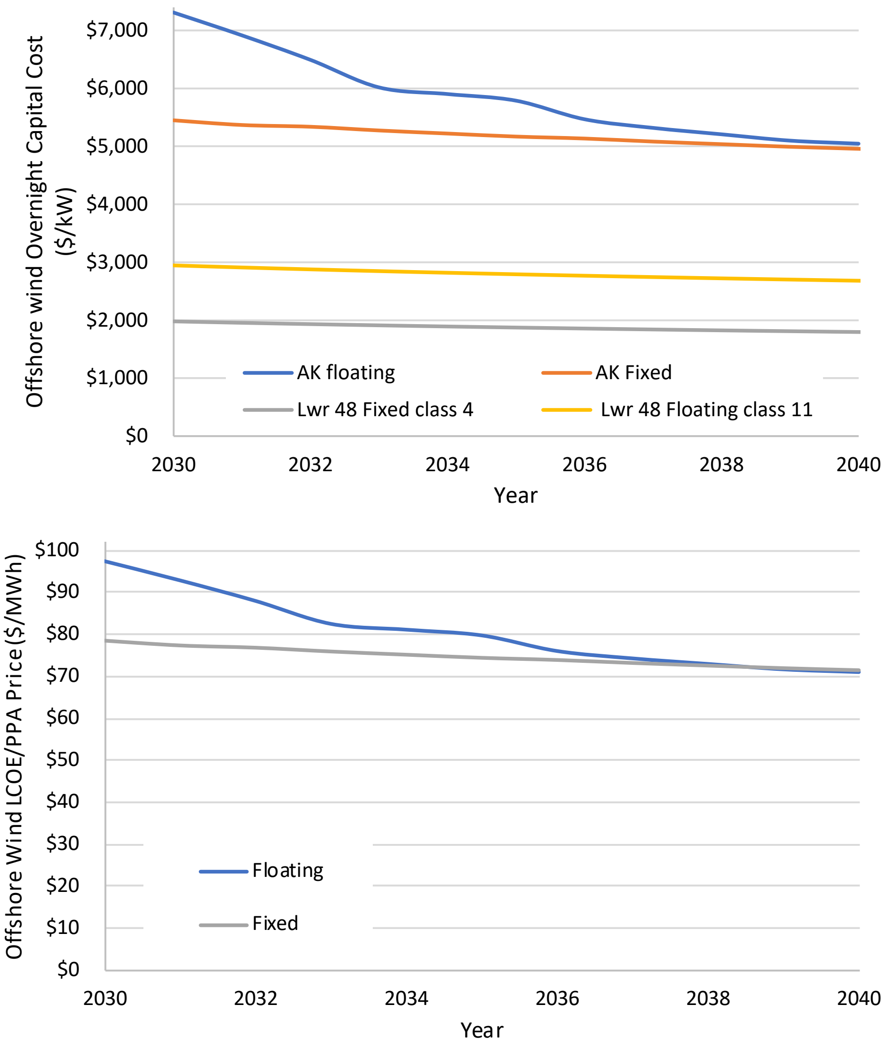

Figure 39. CapEx projections for offshore wind (top) and LCOE/PPA price projections assuming a 51% capacity factor (bottom). Cost assumes underwater transmission line connecting to the HEA system near Homer. The PPA price is fixed for 25 years from the year of installation.

[107] Tentative title: Feasibility Study for Renewable Energy Technologies in Alaskan Offshore Waters.

C.3 Solar (PV)

We used solar profiles generated for four locations in Alaska using both tracking and fixed-tilt systems, assuming a 1.5 DC/AC ratio.[108] PV packing density in terms of MW of DC module capacity (MW/km^2) is 32 MW/km^2.

These data sets use older resource data that are not time-synchronized with our meteorological year of 2018 because there were no alternative data available above latitude 60°N in the time frame of the study. The lack of time-synchronized data for PV is generally not desirable because it can lead to over- or underestimates of PV output during summer peak demand periods. However, the lack of strong summer peaks in Alaska mitigates this data limitation. Because Alaska is a winter-peaking system, the contribution of solar during the peak is typically extremely low, and we therefore assume zero contribution of PV toward resource adequacy. We assume that PV acts only as an "energy saver" and does not by itself reduce the need for firm generation resources.

As with wind, solar is assumed to be fully dispatchable (up to the output reflecting weather conditions at any given time) but acts as a financial "must-take" resource. New solar cannot be completed before 2025. Assumed growth caps for solar limit deployment to 25 MW/year from 2025 to 2026, increasing to 100 MW/year in 2027. We assume that solar is deployed close to existing transmission, and requires a relatively small spur line, which we assume adds $22/kW and is assumed to be eligible for the 40% ITC.

C.4 Rooftop and Distributed Solar

Figure 41 summarizes the assumed adoption rate in the DPV sensitivity using the most conservative ACEP projections.[109] Rooftop PV production is treated as a reduction in load, and we assume that it cannot be dispatched by the utility. PV profiles are multiplied by 1.057 to account for avoided T&D losses because generation is at (or very close) to the point of use. Deployment of a significant amount of rooftop PV will require utilities to have "visibility" into the amount deployed for planning and operations. As with utility-scale solar, distributed solar is assigned zero capacity credit toward resource adequacy and requires additional operating reserves and fuel storage to address additional uncertainty. In this sensitivity, we assume that the adoption occurs both in the Reference and RPS scenarios and therefore has no impact on the relative costs of the RPS. This sensitivity allows for estimates of potential avoided costs and can then be compared to alternative portfolios.

[108] https://pvwatts.nrel.gov/.

[109] Cicilio, P.; Francisco, A.; Morelli, C.; Wilber, M.; Pike, C.; VanderMeer, J.; Colt, S.; Pride, D.; Helder, N.K. Load, Electrification Adoption, and Behind-the-Meter Solar Forecasts for Alaska's Railbelt Transmission System. *Energies* **2023**, *16*, 6117. https://doi.org/10.3390/en16176117

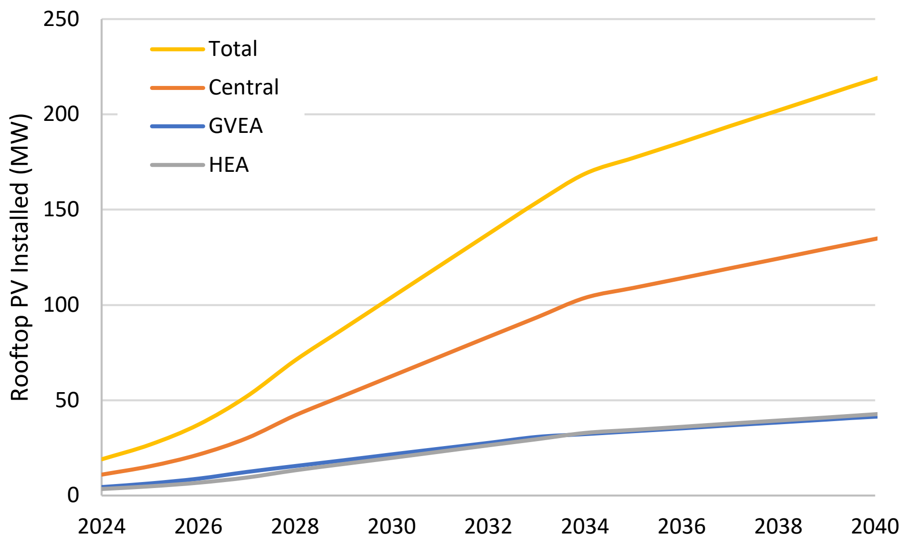

Figure 40. Assumed distributed/rooftop PV adoption in the DPV sensitivity

C.5 Geothermal

We assume that up to 100 MW (in 50-MW blocks) of geothermal energy (Binary Hydrothermal) could be completed beginning in 2034 at Mt. Spurr.[110] Figure 41 shows the capital cost (top) and LCOE (bottom) for new geothermal, which could represent a PPA price of a fixed 30-year contract. The figure does not include the additional cost of a 73-km transmission line required to connect the Mt. Spurr site to the meshed transmission network near Port Mackenzie. For this cost, we use the same assumptions as wind spur lines. Geothermal is modeled as a dispatchable resource with zero-variable cost.[111] However, if acquired via PPA, curtailed geothermal energy must still be paid for. We do not require additional fuel storage or increased operating reserve provisions because of any geothermal plant builds. Geothermal plants are assumed to have the same resource adequacy contribution as fossil-fueled generators.

[110] This estimate was derived from conversations with Cyrq Energy. For more information, see this report: WH Pacific. 2013. *Renewable Energy in Alaska*. Golden, CO: National Renewable Energy Laboratory. NREL/SR-7A40-47176. https://www.nrel.gov/docs/fy13osti/47176.pdf.

[111] There is a small variable cost, which is captured in the fixed O&M for the purposes of modeling, assuming baseload generation with 80% capacity factor.

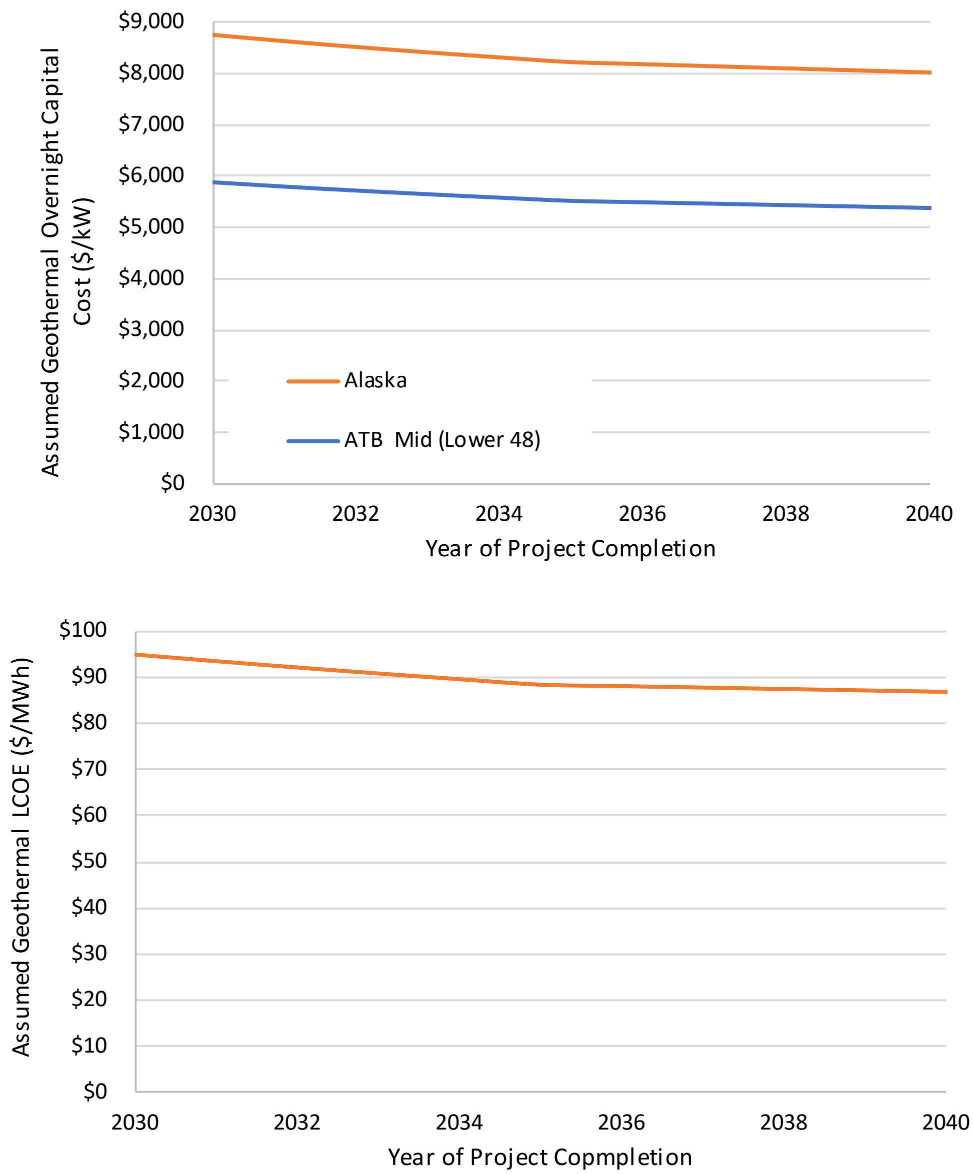

Figure 41. Assumed geothermal capital cost (top) and LCOE (bottom)

Figure 42 shows the location of Mt. Spurr as well as other geothermal resources that could be used for heating and other applications.

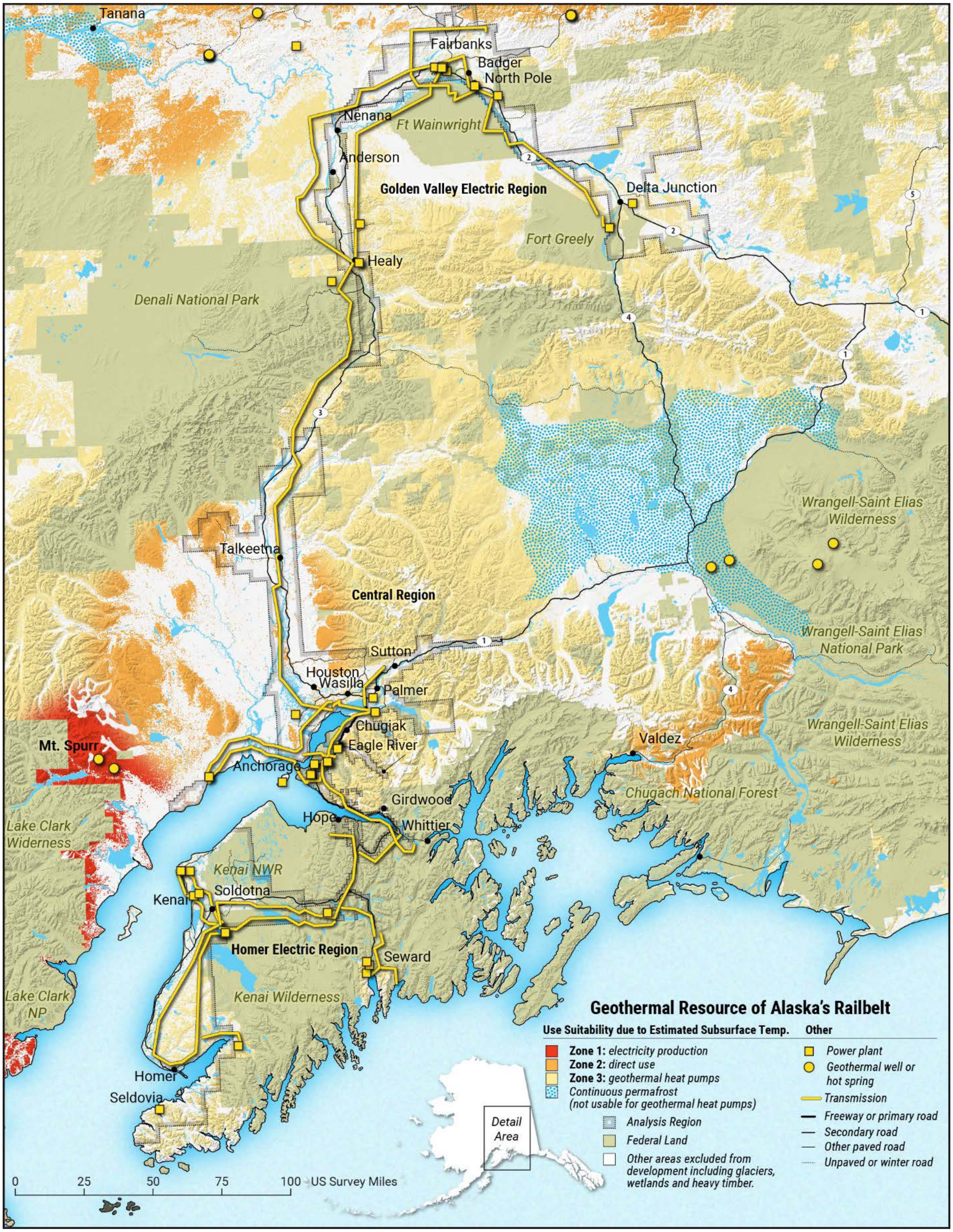

Figure 42. Potential locations for geothermal resources in Alaska

C.6 Hydropower

The base scenario includes all existing hydropower and the option to develop up to 25 MW of "run-of-river" hydropower, with a predetermined hourly generation profile (see Figure 44). This capacity is deployable in the Central region with a capital cost of $11,582/kW and a fixed O&M of $209/kW-year. This results in an LCOE/PPA price of $138/MWh. Capacity can be added beginning in 2027. Assumed capacity credit is 13% based on expected winter output. No other new hydropower capacity is modeled, but future work should consider new hydropower options including pumped storage hydropower.[112]

Figure 43 shows the location of existing and historically proposed plants as well as other locations with large hydropower potential. None of the major proposed projects was considered in this study. Only resources within 50 miles of rail lines are shown.

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[112] For a discussion of potential pumped storage hydropower opportunities in the Railbelt, see: https://publications.anl.gov/anlpubs/2023/07/183313.pdf.

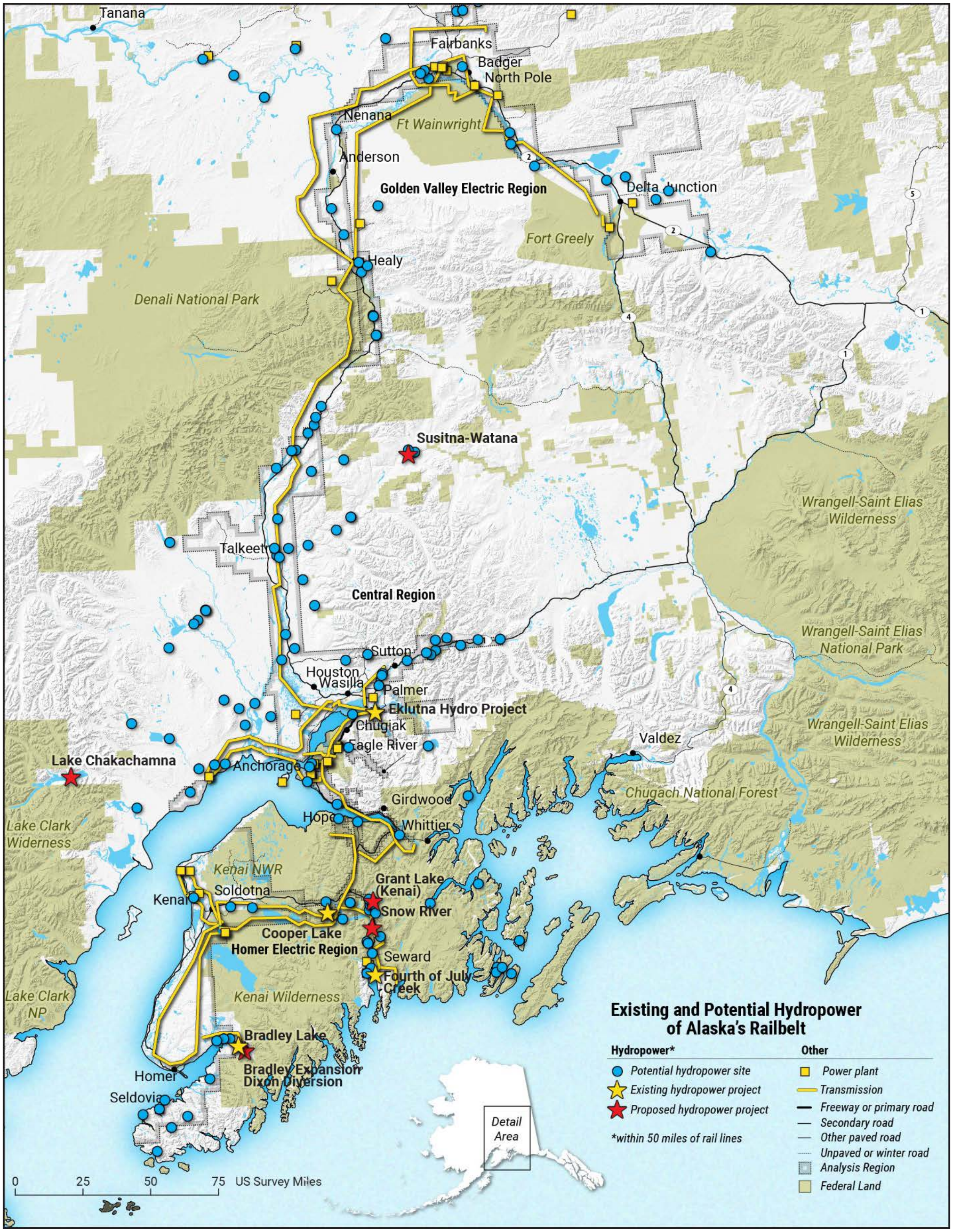

Figure 43. Location of existing and potential new hydropower resources

For run-of-river projects, we use the 2023 ATB assumptions for "NSD 3" hydropower plants, assuming an initial capital cost of $6,936/kW and a fixed O&M of $135/kW-year. We apply a 1.46 multiplier to both values. A single representative hourly profile (Figure 44) is applied to all run-of-river projects.[113]

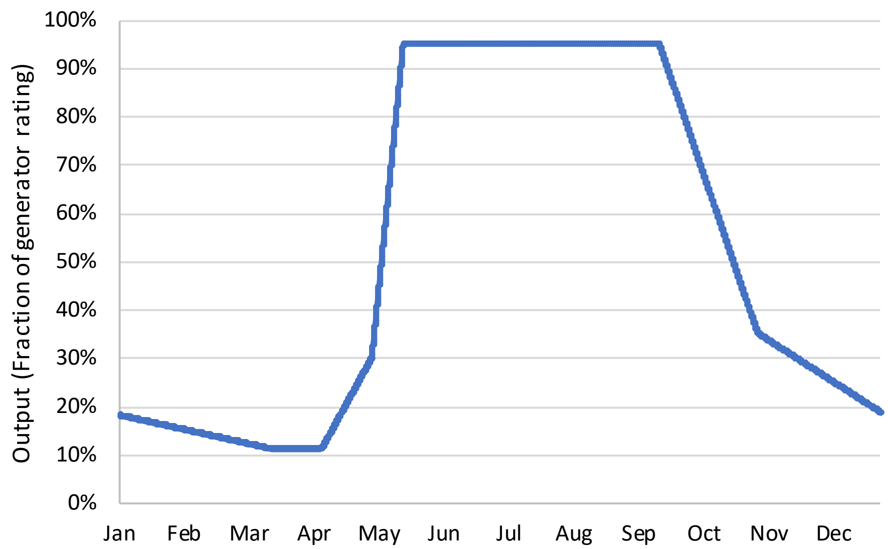

Figure 44. Assumed output profile (fraction of installed capacity) for new run-of-river hydropower

C.7 Biomass and Landfill Gas

We assume that adequate fuel (wood) is available for up to a 50-MW plant at a fuel cost of $5–$9/MMBtu. Assumed plant costs are $7,729/kW based on the cost of a new coal plant and the price premium for biomass using the difference between coal and biomass from the ATB mid scenario. At these costs, new biomass was not competitive in initial analysis, and new biomass was dropped from further study.

We did not consider landfill gas collection expansion and assumed continued operation of existing facilities at historical generation rates.

C.8 Energy Storage

We consider battery storage with discrete duration options of 2, 4, 6, 8, and 10 hours and assume an 85% round-trip efficiency. Figure 45 shows the assumed capital cost trajectory for new battery systems with a 15-year life. These values include all equipment for "turnkey" operation and generic substation upgrades including switchgear and transformer.[114] We assume an economic life of 25 years, which requires augmentation of the battery modules in Year 15 to maintain technical performance. This is calculated by adding the discounted capital cost of new

[113] Assumption based on conversations with Joel Groves at Polarconsult Alaska, Inc. Profiles derived from "Response to Chugach RFP 21-23 Providing Conceptual Guidance on 'Category 2' Small Hydro Projects."
[114] A table listing items included in costs is provided here: https://atb.nrel.gov/electricity/2023/utility-scale_battery_storage.

battery modules to the initial capital cost. In addition to capital and fixed O&M, we include a variable O&M of $2/MWh.[115]

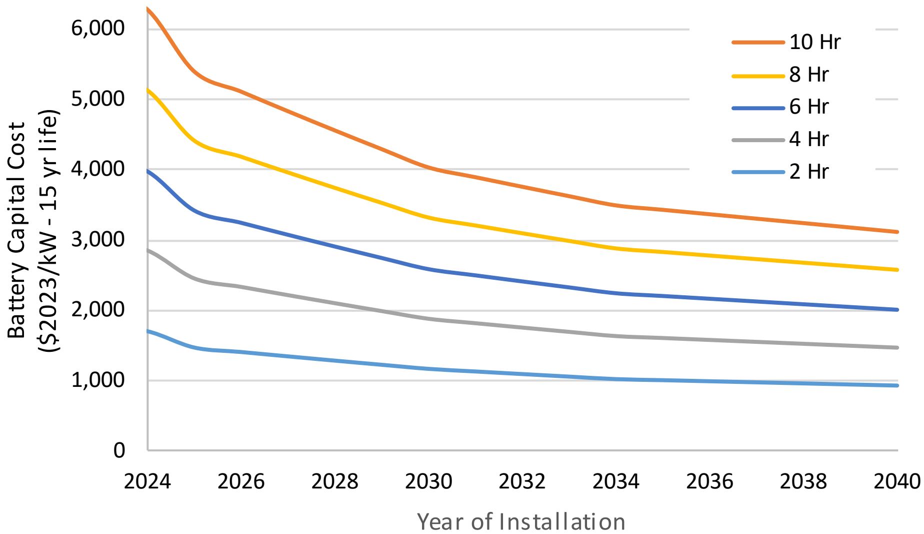

Figure 45. Assumed battery cost trajectory ($2023 with a 15 year life)

[115] Storage Futures cost and performance study.

C.9 Summary Cost and Financial Parameters for Renewable Generators and Storage

Table C-2. Overnight Capital Costs (2023$/kW)

	Land-based Wind	PV	Geothermal	Hydro (Run of River)	Battery-2HR–	Battery-4HR-	Battery-6HR-	Battery-8HR-	Battery-10HR-
2024	2,664	2,133	9,823	11,575	1,701	2,845	3,989	5,132	6,276
2025	2,595	2,042	9,584	11,575	1,473	2,453	3,433	4,414	5,394
2026	2,528	1,952	9,376	11,575	1,410	2,335	3,259	4,184	5,108
2027	2,461	1,864	9,193	11,575	1,349	2,219	3,089	3,959	4,828
2028	2,395	1,795	9,029	11,575	1,290	2,106	2,922	3,739	4,555
2029	2,376	1,709	8,881	11,575	1,231	1,996	2,760	3,524	4,288
2030	2,310	1,625	8,747	11,575	1,174	1,888	2,601	3,314	4,028
2031	2,255	1,542	8,623	11,575	1,137	1,825	2,513	3,201	3,889
2032	2,200	1,460	8,510	11,575	1,101	1,764	2,427	3,090	3,753
2033	2,146	1,380	8,405	11,575	1,066	1,704	2,342	2,981	3,619
2034	2,092	1,302	8,307	11,575	1,030	1,645	2,259	2,873	3,487
2035	2,072	1,239	8,216	11,575	1,015	1,618	2,220	2,822	3,424
2036	2,051	1,219	8,175	11,575	1,000	1,591	2,181	2,771	3,361
2037	2,030	1,200	8,134	11,575	985	1,564	2,142	2,720	3,298
2038	2,010	1,180	8,093	11,575	970	1,537	2,103	2,669	3,235
2039	1,989	1,161	8,053	11,575	955	1,510	2,064	2,618	3,173
2040	1,969	1,141	8,012	11,575	940	1,483	2,025	2,567	3,110

Table C-3. Fixed Charge Rates, Including the Impact of the ITC

	Land-Based Wind		PV		Geothermal	Hydro (Run of River)	Battery
Year	w/ITC	w/PTC	w/ITC	w/PTC	w/ITC	w/ITC	w/ITC
2024	4.86%	8.47%	4.24%	7.29%	6.01%	4.47%	4.38%
2025	4.88%	8.50%	4.25%	7.32%	6.00%	4.48%	4.41%
2026	4.90%	8.54%	4.26%	7.34%	6.00%	4.24%	4.48%
2027	4.92%	8.57%	4.28%	7.36%	5.99%	4.24%	4.50%
2028	4.94%	8.61%	4.29%	7.39%	5.98%	4.24%	4.50%
2029	4.96%	8.64%	4.31%	7.41%	5.97%	4.24%	4.50%
2030	4.98%	8.68%	4.32%	7.44%	5.97%	4.24%	4.50%
2031	4.99%	8.69%	4.34%	7.47%	5.96%	4.24%	4.50%
2032	5.00%	8.71%	4.36%	7.50%	5.95%	4.24%	4.50%
2033	5.01%	8.72%	4.38%	7.54%	5.95%	4.24%	4.50%
2034	5.01%	8.74%	4.40%	7.57%	5.94%	4.24%	4.50%
2035	5.02%	8.75%	4.42%	7.61%	5.93%	4.24%	4.50%
2036	5.03%	8.77%	4.43%	7.63%	5.93%	4.24%	4.50%
2037	5.04%	8.78%	4.44%	7.64%	5.93%	4.24%	4.50%
2038	5.05%	8.80%	4.45%	7.65%	5.93%	4.24%	4.50%
2039	5.06%	8.81%	4.46%	7.67%	5.93%	4.24%	4.50%
2040	5.07%	8.83%	4.46%	7.68%	5.93%	4.24%	4.50%

Table C-4. PTC Value (2023$/MWh): Applied If the Model Chooses To Take the PTC With the Higher Fixed Charge Rate

	Wind	PV
2024	21.62	21.62
2025	21.66	21.66
2026	21.70	21.70
2027	21.74	21.74
2028	21.78	21.78
2029	21.82	21.82
2030	21.87	21.87
2031	21.88	21.88
2032	21.90	21.90
2033	21.92	21.92
2034	21.93	21.93
2035	21.95	21.95
2036	21.97	21.97
2037	21.99	21.99
2038	22.01	22.01
2039	22.03	22.03
2040	22.05	22.05

Table C-5. Fixed O&M Value (2023$/kW-year)

	Wind - Onshore	PV	Geothermal	Hydro (Run of River)	Battery - 2HR -	Battery - 4HR -	Battery - 6HR -	Battery - 8HR -	Battery - 10HR -
2024	77	35	242	225	43	71	100	128	157
2025	75	34	239	225	37	61	86	110	135
2026	74	33	236	225	35	58	81	105	128
2027	72	32	233	225	34	55	77	99	121
2028	70	31	230	225	32	53	73	93	114
2029	69	29	226	225	31	50	69	88	107
2030	67	28	223	225	29	47	65	83	101
2031	65	27	220	225	28	46	63	80	97
2032	64	26	217	225	28	44	61	77	94
2033	62	25	214	225	27	43	59	75	90
2034	61	24	210	225	26	41	56	72	87
2035	60	23	207	225	25	40	55	71	86
2036	60	23	207	225	25	40	55	69	84
2037	59	23	207	225	25	39	54	68	82
2038	59	23	207	225	24	38	53	67	81
2039	58	23	207	225	24	38	52	65	79
2040	58	22	207	225	24	37	51	64	78

C.10 New Fossil

New combustion turbine (CT) generators may be constructed beginning in 2026, combined-cycle (CC) generators in 2027, and new coal in 2029.

Table C-6 shows previous estimates for the costs of new CT and CCGT power plants from the 2010 Alaska Railbelt Regional Integrated Resource Plan (RIRP).[116] The first four rows are estimated costs, with two costs for each technology based on size. We use the midpoint estimates from these cost estimates, which are then inflated to $2023 but then deflated to represent cost reductions since 2010, based on improvements tracked by the ATB. The last two rows are actual costs of the Southcentral CCGT and the Eklutna Generation Station, which is different generation technology but included for reference.

[116] 2010 Alaska Railbelt Regional Integrated Resource Plan (RIRP). https://www.akenergyauthority.org/Portals/0/Publications%20and%20Resources/2010.02.01%20Alaska%20Railbelt%20Integrated%20Resource%20Plan%20(RIRP)%20Study.pdf?ver=2022-03-22-115635-150

Table C-6. CT and CCGT Power Plant Cost Estimates

Technology	Source[117]	$ Year	Size (MW)	Cost ($Million)	Cost $/kW
CT	RIRP	2009	49.2	62.14	1,263
CT	RIRP	2009	99.2	100.54	1,014
CC	RIRP	2009	154.6	323.89	2,095
CC	RIRP	2009	312.3	511.5	1,638
CC	Southcentral (actual)	2013	204	369	1,809
ICE	Eklutna Generation Station (Actual)	2015	171	324	1,895

We assume a minimum size for new CTs of 50 MW and a minimum size of 100 MW for new CCGTs. We do not assume that the cost per unit capacity of the plant varies with size.

Costs are the sum of capital costs, fixed and variable O&M, fuel cost, and startup costs. Fuel costs depend on the cost of fuel (Section 5.4) and the plant efficiency (heat rate). We assume an average heat rate for new plants of 7,300 Btu/kWh for CCs and 9,720 Btu/kWh for CTs. We do not include part-load heat rate curves for new plants because there is very little new thermal capacity added, especially in cases that allow new renewables. Fixed O&M is assumed to be $29/kW-year and $39/kW-year, and variable O&M is assumed to be about $7/MWh and $3/MWh for CT and CCGTs, respectively.

An alternative to new gas turbines is the use of reciprocating internal combustion engines (RICEs). These plants are highly flexible and feature rapid start and ramping and low startup costs and are highly modular in scale and in operation. The Eklutna plant uses this technology and was completed in 2015 at a cost of about $1,895/kW. This technology was not included as a new build option.[118]

New coal plants may be constructed assuming a capital cost based on the Regional Integrated Resource Plant (RIRP) study with adjustments for inflation and technology improvements from the ATB.[119] Further cost trends follow the 2023 ATB, which result in a slight decline over time. We assume a minimum size of 50 MW. We assume a full load heat rate of 9,843 Btu/kWh based on the RIRP study.[120]

[117] The estimates do not include interest during construction and so are not the same as actual costs.
[118] Because very limited thermal capacity was built in any scenario, it is unlikely that including RICE would make a substantial change to the results. Costs and performance estimates used by EIA include a $2021 cost (Lower 48) of $2018/kW https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf.
[119] This cost is significantly higher than ATB costs, likely because of plant size assumptions and increased costs for Alaska construction. The ATB numbers are based on a coal plant size of 650 MW, which allows for significant economies of scale. See *Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity*. https://www.osti.gov/biblio/1893822.
[120] Because they have the lowest variable cost and are least likely to be cycled (and because they are not added in any of the scenarios that allow new renewable construction), we did not implement a part-load heat rate. A flat heat rate is a best-case scenario for new coal, so this assumption did not negatively impact the build choice.

Table C-7. Capital Cost and Fixed Charge Rate for CT, CC, and Coal Plants

	Capital Cost ($2023)			Fixed Charge Rate (%)		
	CT	CC	Coal	CT	CC	Coal
2024	1,250	2,016	7,799	8.83	8.83	9.82
2025	1,226	1,997	7,799	8.30	8.30	9.23
2026	1,214	1,984	7,799	8.30	8.30	9.31
2027	1,197	1,967	7,799	8.30	8.30	9.39
2028	1,187	1,956	7,799	8.30	8.30	9.47
2029	1,177	1,943	7,799	8.30	8.30	9.55
2030	1,170	1,936	7,799	8.30	8.30	9.23
2031	1,163	1,925	7,799	8.30	8.30	9.23
2032	1,156	1,917	7,799	8.30	8.30	9.23
2033	1,149	1,908	7,799	8.30	8.30	9.23
2034	1,145	1,902	7,799	8.30	8.30	9.23
2035	1,138	1,892	7,799	8.30	8.30	9.23
2036	1,131	1,885	7,799	8.30	8.30	9.23
2037	1,124	1,876	7,799	8.30	8.30	9.23
2038	1,120	1,869	7,799	8.30	8.30	9.23
2039	1,113	1,859	7,799	8.30	8.30	9.23
2040	1,107	1,852	7,799	8.30	8.30	9.23