Alaska Energy Technology Reports
Overview Document

Documentation of Alaska-Specific Technology Development Needs
in support of the Alaska Affordable Energy Strategy

Prepared by the Alaska Center for Energy and Power with funding from the Alaska Energy Authority

The passage of SB 138 by the Alaska State Legislature created an uncodified section of law defined as follows: "Plan and Recommendations to the Legislature on Infrastructure Needed to Deliver Affordable Energy of the State to Areas that do not have Direct Access to a [proposed] North Slope Natural Gas Pipeline." To support the Alaska Energy Authority (AEA) in its development of an Alaska Affordable Energy Strategy, the Alaska Center for Energy and Power (ACEP) contracted with AEA to document technology development needs specific to Alaska with regard to renewable and sustainable energy technologies. The intention was to determine what targeted, energy technology development solutions could be implemented in Alaska to make energy more affordable in the Alaska Affordable Energy Study area. While the focus was on technology research solutions, other factors such as logistics, labor, and training were also addressed.

The technologies addressed were decided in initial consultations to include wind power, energy storage, diesel engines, hydroelectric systems, biomass, solar photovoltaic, heat pump, and organic rankine cycle (ORC) technologies. Also included were the cross-cutting topics of electrical transmission and integration. Drafts of technology reports were vetted by expert roundtables in late February and early March of 2016. A short 1-2 page summary briefing also accompanies each longer technology report.

These reports are not meant to be exhaustive discussions of energy technologies in Alaska or proper designs for each technology, nor should they be used as guides for the choice and installation of specific systems. As such, not all possible issues with power production and each technology are addressed, in accordance with the scope of work for this project. Data for each technology were collected from surveys and publically available databases. Only completed projects, or projects with clearly reported data, could be included in each technology analysis. These distinctions and descriptions of data sources are included in each technology report.

Each briefing paper includes the following sections as a way to provide a standardized characterization of each technology for a varied audience, and to provide the necessary inputs for AEA's broader recommendations to the legislature.

Capital Costs – including fixed, on-time costs incurred on the purchase of land, buildings, construction, and equipment used to install an energy system. These costs are generally presented and analyzed as a function of installed capacity.

Operations and Maintenance (O&M) Costs – including ongoing costs associated with operations and maintenance of an energy system to maintain in good working condition per manufacturer requirements.

Expected Lifetime – when used per manufacturers' specifications and under constant use and maintenance schedules.

Capacity Factor – defined as the ratio of actual energy output over a period of time to its potential output at full nameplate capacity continuously over the same period of time. Other metrics are used as appropriate.

Diesel Offset – defined as the quantity of diesel in gallons displaced by the use of an energy system.

Conditions for Greatest Efficiency – including environmental and system integration conditions for maximum efficiency.

Levelized Cost of Energy (LCOE) – included as a standardized metric for the cost of electricity produced by a generator. It is calculated by accounting for all of a system's expected lifetime costs (including construction, financing, fuel, maintenance, taxes, insurance and incentives), which are then divided by the system's lifetime expected power output (kWh). All cost and benefit estimates are adjusted for inflation and discounted to account for the time-value of money. As a financial tool, LCOE is very valuable for the comparison of various generation options. A relatively low LCOE means that electricity is being produced at a low cost, with higher likely returns for the investor. If the cost for a renewable technology is as low as current traditional costs, it is said to have reached "grid parity."

Cost Curve Over Time – showing the trend in technology costs up to the current time period.

Installed Costs By Major Components – including a breakdown of costs into specific cost categories to gain insight into costs drivers and cost reduction opportunities.

Transportation Costs – defined as the average cost for delivery of an energy system to communities by the appropriate transportation method.

Technology Trends – including recent and projected trends in the technology over time.

Storage Systems – including required or commonly used energy storage types for each technology.

Refurbishment or Upgrade Market – including general comments on the likelihood of replacing or upgrading systems at the end of their lifetimes.

In addition, the summary reports for each technology include additional comments on **technology-specific gaps and barriers to successful project development and operations**, as well as **recommendations** for technology deployment in Alaska.

Biomass Technology Report

Summary

Prepared by the Alaska Center for Energy and Power for the Alaska Affordable Energy Strategy Effort with funding from the Alaska Energy Authority

Resource and Technology Description

Woody biomass that can be used as an energy fuel includes cordwood (round or split logs), chips (chipped or shredded wood), pellets (densified wood product), and hog-fuel (waste woodchips including bark). In Alaska, the most important and economical energy product from biomass is heat. In private homes, woody biomass usage tends to fuel direct radiant heat, burning wood in the space to be heated. In community buildings, it is more efficient (both in terms of energy and labor) to use biomass to heat a fluid, and then circulate the fluid throughout the space to be heated.

For larger scale usage (>500 MBTU), biomass is typically economical as an energy fuel only when it is a by-product of manufacturing or a result of forest management activities (e.g., wildfire risk reduction or forest health restoration). On a smaller scale, such as for residential use, some biomass can be grown or harvested specifically for energy generation.

This report summarizes data collected from a selection of commercial biomass boilers installed in institutional buildings around the State of Alaska.

Current Installations in Alaska

Region	Cordwood (MBTUh)	Pellet (MBTUh)	Large Pellet (MBTUh)	Small Chip (MBTUh)	Large Chip (MBTUh)
Interior	Tanana (2,940), Gulkana (650), Hughes (360), Koyukuk (325)			Mentasta (500)	Tok (5,500)
Western	Kobuk (180)				
Southeast	Coffman Cove (650) Thorne Bay (350), Kasaan (325)	Chilkoot Indian Association (Haines) (123) Haines Senior Center (109)	Sealaska (750) Ketchikan Library (510) Ketchikan GSA Building (1000)		Craig (4,000)

Key Performance Metrics

Capital costs, and operations and maintenance (O&M) costs, vary by boiler type and location around the state. Most boiler manufacturers claim system life expectancies of 20-30 years, assuming normal running conditions and adherence to maintenance schedules. System efficiencies vary with biomass system type, installation protocol, operation and maintenance protocols, piping distance, thermal storage, and wood moisture content. Sizing biomass units to meet 80% of peak required heat load ensures the boiler will run at the maximum heat output.

Biomass Technology Report

Summary

The boiler is one of the most substantial costs for each installation, along with the site foundation, the boiler building, and the integration of the system into the building. Fuel storage and construction management are also large expenses, though not reported in each project. Despite the large installed capacity of chip boilers in the Interior, their installation costs are higher than those of other boilers.

Technology Trends

Cordwood biomass systems involve intensive labor. One way to reduce O&M costs has been to move to an automated woodchip systems. In addition, the cost and the general availability of woodchips compared with cordwood and pellets make combustion technology more economical. Increasingly, schools and communities that are adopting biomass as a heating fuel are also installing greenhouses and incorporating biomass energy and food production synergies into their curriculum. Compared with cordwood systems, however, chip-fed combustion requires extra processing time and expense to manufacture chips.

Technology-Specific Gaps and Barriers to Successful Project Development and Operation

Technology must be matched to its location. Rural Alaska needs simple and robust systems that require less attention, tuning, or replacement parts. Locations along the road system (including the marine highway) can use more sensitive systems, including those that require specialists, unique parts, or technical input during operations. In addition, in locations with air quality concerns as a result of wood burning, there is more interest in improving those systems rather than in cultivating new biomass systems.

Cordwood systems have marginal paybacks, and none of the evaluation tools consider other community benefits of biomass systems such as local jobs and local fuel. The availability of local fuel supply is also a key component; as soon as fuel is shipped around, biomass systems are not economical.

Recommendations

Given the large number of potential applications, smaller chip systems could prove their value with an increased emphasis on installation and testing in Alaska. (Metasta has the only one right now.) On a larger scale, given communities' reluctance to finance biomass projects, education and encouragement could spur communities to take on debt burdens for projects with excellent economics, especially if coupled with establishment of a revolving loan fund. Regulations could also be changed so that bulk fuel loans could be used to purchase biomass.

Business models could also be explored which pair private ownership of a heating system or plant with heat sales agreements to facility operators and owner (like a heat utility). With such models, facility operators wouldn't save as much money but also wouldn't have to assume the risks.

Biomass Technology Report

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Woody biomass that can be used as an energy fuel includes cordwood (round or split logs), chips (chipped or shredded wood), pellets (densified wood product), and hog-fuel (waste woodchips including bark). For larger scale usage (>500 MBTU), biomass is typically economical as an energy fuel only when it is a by-product of manufacturing or a result of forest management activities (e.g., wildfire risk reduction or forest health restoration). On a smaller scale, such as for residential use, some biomass can be grown or harvested specifically for energy generation.

In Alaska, the most important and economical energy product from biomass is heat. This is a nontrivial contribution, since 80% of the stationary energy load in Alaska is heat. Only one system where electricity and heat are produced from biomass is operational in Alaska. The system is at Tok High School, and it is customized and not highly replicable.

In private homes, woody biomass usage tends to fuel direct radiant heat, burning wood in the space to be heated. In community buildings, it is more efficient (both in terms of energy and labor) to use biomass to heat a fluid, and then circulate the fluid throughout the space to be heated. Instead of controlling the heat output by controlling the air intake and/or venting, as one does with a home-scale wood stove, the heat output is modulated by controlling the fluid circulation rate. By decoupling the combustion process from the heat output, the burn rate and oxygen intake may be optimized for clean, efficient burning. Typically, a boiler heats water directly, and the heat is then transferred to a water/glycol mix for circulation throughout the building. The water and glycol loops also serve as thermal storage.

This report summarizes data, shown in Table 1, collected from a selection of commercial biomass boilers installed around the State of Alaska. The boilers were selected from ones installed in institutional buildings.

Table 1. Boiler installations around the state of Alaska

Region	Cordwood (MBTUh)	Pellet (MBTUh)	Large Pellet (MBTUh)	Small Chip (MBTUh)	Large Chip (MBTUh)
Interior	Tanana (2,940), Gulkana (650), Hughes (360), Koyukuk (325)			Mentasta (500)	Tok (5,500)
Western	Kobuk (180)				
Southeast	Coffman Cove (650) Thorne Bay (350), Kasaan (325)	Chilkoot Indian Association (Haines) (123) Haines Senior Center (109)	Sealaska (750) Ketchikan Library (510) Ketchikan GSA Building (1000)		Craig (4,000)

Boiler Models Selected For Analysis

Cordwood: Garn 2000 – 325 MBTUh (Dectra Corporation) (Tanana, Gulkana, Koyukuk, Coffman Cove, Thorne Bay, Kasaan)
Garn 1500 – 180 MBTUh (Dectra Corporation) (Installed in: Hughes, Kobuk)
Econoburn – 170 MBTUh (Econoburn) (Tanana)
Small pellet boiler: MESys – 109 MBTUh (Maine Energy Systems) (Haines)
Small chip boiler: EnviroChip – 500 MBTUh (Portage and Maine) (Mentasta)
Large chip boiler: 750 MBTUh – 5,500 MBTUh (Messersmith, Hurst) (Tok, Craig)
Large pellet boiler: 510 MBTUh – 1,000 MBTUh – (ACT, KÖB/Viessman) (Juneau)

Capital Costs/MBTUh[1]

Capital costs, which were calculated using nameplate output capacity for each installation, are shown in Figure 1. Performance heating power is not available at this time.

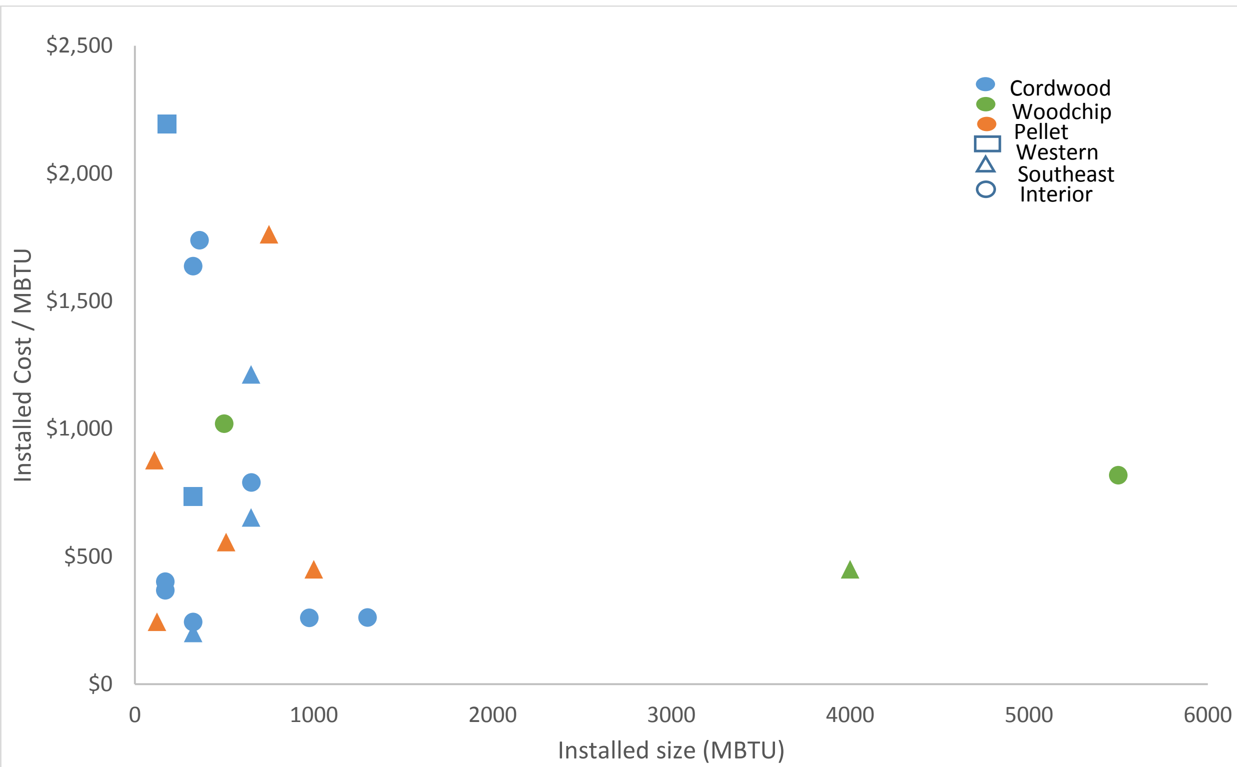

Figure 1. Capital costs of biomass systems as a function of installed capacity ($/MBTUh)[2]

Three cordwood boilers located in the remote communities of Kobuk, Koyukuk, and Hughes, and the Sealaska pellet boiler in Southeast show the highest cost per installed MBTUh, partly due to high costs of air transportation, extensive design, and construction-phase labor.

[1] See raw data on page XX
[2] Capital costs were obtained from project managers and funding agencies.

Thorne Bay shows a relatively high capital cost ($1213/MBTUh) because the project included two containerized boilers. Two large-scale woodchip boilers in Tok and Craig represent a relatively low ($500–$1000/MBTUh) installed cost per MBTUh.

The lowest cost cordwood systems are installed in Tanana and Kasaan (under $500/MBTUh). The pellet systems installed in Southeast (excluding the Sealaska boiler) are all priced below $1000/MBTUh, and the installed capital costs of the boiler at the Chilkoot Indian Association are below $500/MBTUh. The installation at the Ketchikan GSA Building is $450/MBTUh, and the installation at the Ketchikan Public Library is $556/MBTUh.

Operation and Maintenance Costs per MBTUh

Operations and maintenance (O&M) costs (Figure 2) reported for biomass systems generally include wood handling at the boiler and boiler firing; cleaning; and monthly, annual, and other scheduled maintenance. The reported figures may not include delivered (or purchased) costs of biomass feedstock.

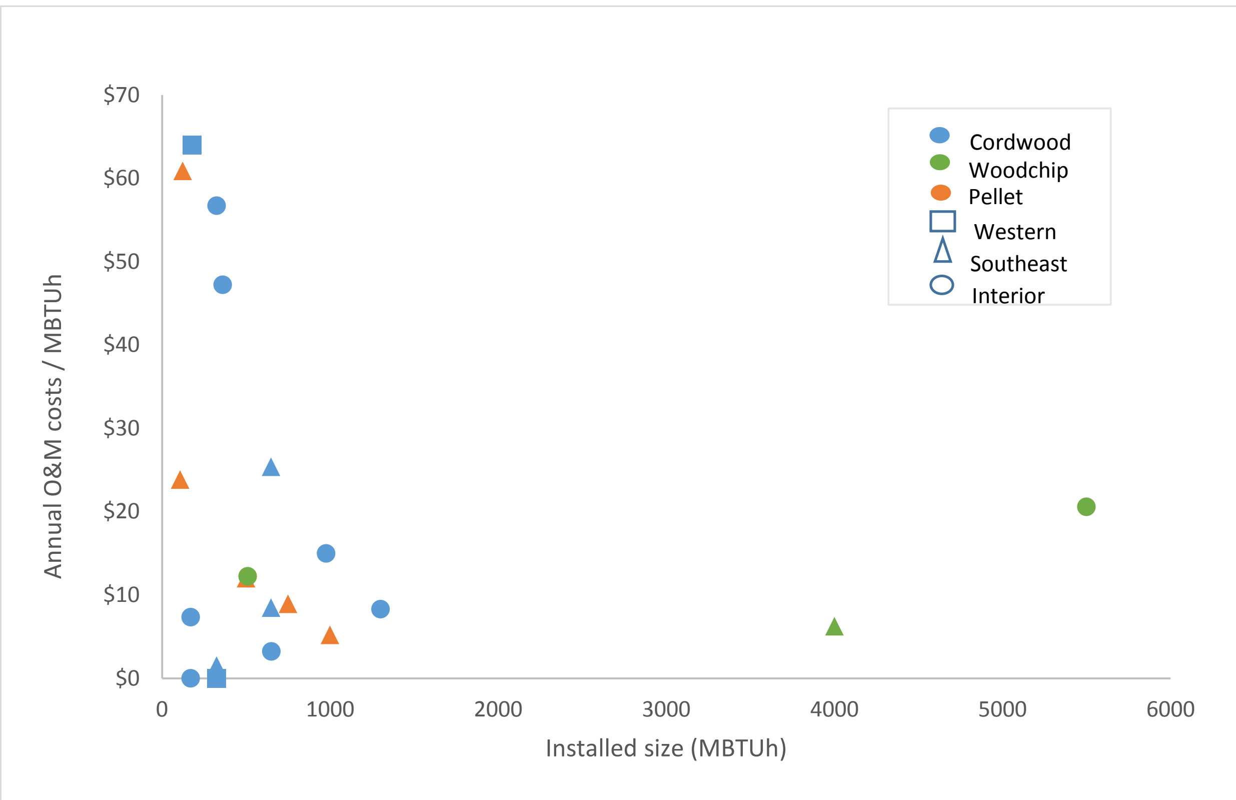

Figure 2. O&M costs as a function of installed capacity ($/MBTUh)[3]

The highest annual cost for O&M is for the boilers in Kobuk and Koyukuk, and at the Chilkoot Indian Association; all of these units have a cost of around $60 per MBTUh. Kobuk and Koyukuk have created

[3] O&M costs were obtained from project managers and funding agencies.

part-time boiler operator positions for their relatively small-capacity boilers, which increase the effective O&M costs.

All other O&M rates are under $30 per MBTUh. The Tanana Fire Hall and the Tanana Log Duplex both report a zero O&M cost, as the systems are operated and maintained by the residents in those buildings. Thorne Bay has a relatively high O&M cost of $25/MBTUh, and Mentasta and the Ketchikan Public Library both report $12/MBTUh. Gulkana has the lowest O&M rate at $3/MBTUh.

Expected Life of Unit
Most boiler manufacturers claim system life expectancies of 20–30 years.[4, 5] These estimates assume normal running conditions and adherence to all annual, semi-annual, and other maintenance schedules. Some units have failed much earlier due to little or no maintenance.

Overall System Efficiency[6]
System efficiency varies with biomass system type, installation protocol, operation and maintenance protocols, piping distance, and thermal storage. System efficiency is also dependent on the wood being burned, especially with regard to moisture content.

The U.S. Environmental Protection Agency (EPA) has reported tested efficiencies for units, though these numbers are often reported using a standardized, uniform wood product (crib wood) not normally used in communities in Alaska. The EPA efficiencies reported are:

Cordwood: Garn 2000 – 74%
Pellet boiler: MESys – 85%
Chip boiler: Portage and Main – 73%; Other – 65%

Some companies, including Garn and Advanced Climate Technologies (ACT), have had their boiler efficiencies tested by independent third-party testing facilities. Garn boilers are independently tested by Intertek using the ASTM (American Standard Test Method). Garn system efficiencies are reported as follows: Garn 2000 – 88.4%;[7] Garn 1500 – 80%.[8] Tested efficiencies for ACT range between 85% and 92%.[9] These numbers only account for the boiler itself, not the overall system efficiency.

Annual Displaced Diesel (Gallons/MBTUh)
The quantity of displaced diesel fuel, in gallons, as a function of boiler installed capacity is shown in Figure 3.

[4] Maine Energy Systems and Garn warranty their units for 30 years.
[5] Portage and Main - 20 years, Viessman Pyrot - 25 years
[6] EPA tested hydronic heater report was used for Garn, MESys.
[7] http://www.garn.com///wp-content/uploads/2011/07/G100463637MID-005R2-WHS2000-EPA-report-Revised-signed.pdf
[8] http://www.garn.com///wp-content/uploads/2011/07/G100248857MID-006R-REVISED-06232011-signed.pdf
[9] http://www.actbioenergy.com/faq.html

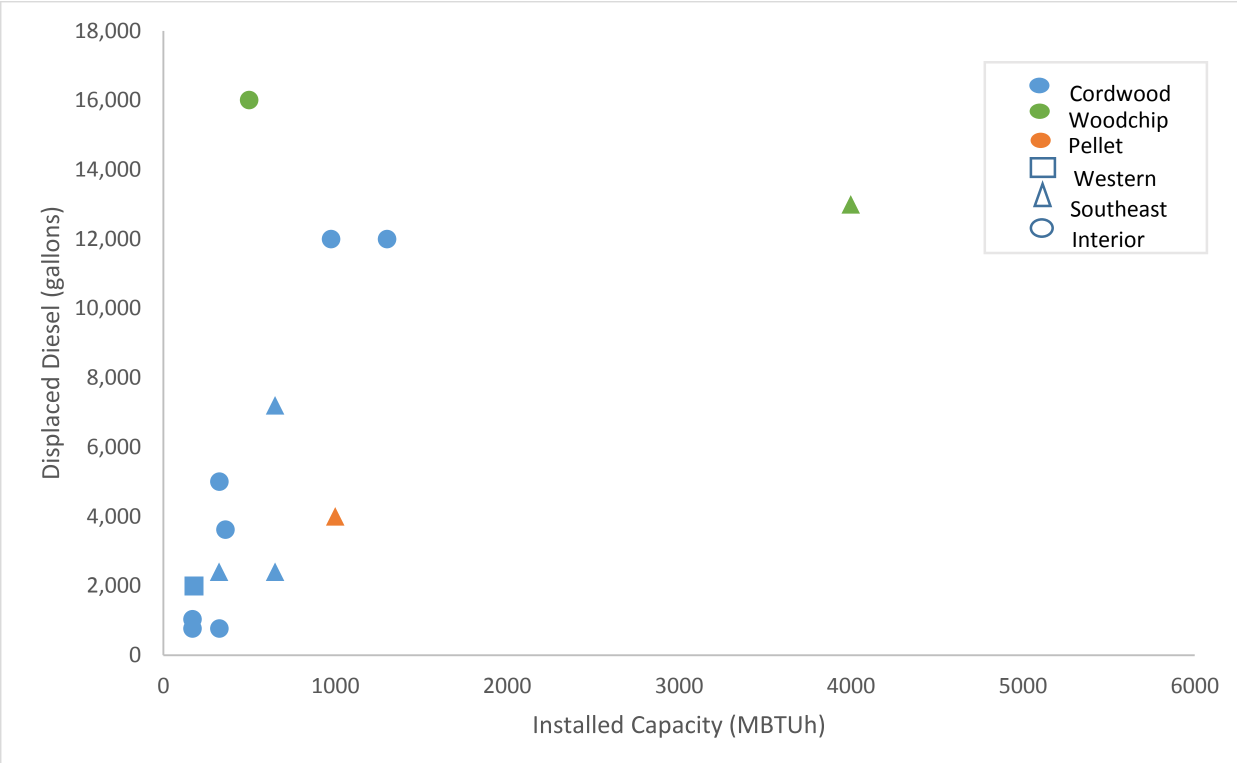

Figure 3. Avoided diesel as a function of biomass boiler installed capacity[10]

The Tok woodchip boiler data point of 55,000 gallons displaced annually has been omitted from this plot, as the data point strongly skews the scale for the other points, and the displaced or avoided diesel in Tok is uniquely used to generate electricity as well as heat.

Mentasta has the highest displaced diesel quantity (16,000 gallons), followed by the Tanana Water Plant and the Tanana School, each at 12,000 gallons, and the Craig School boiler with 13,000 gallons. Coffman Cove was the only other system displacing over 7,000 gallons.

The Tok, Mentasta, and Craig systems are automated woodchip systems that offer more constant heating output due to uniform and constant metered feedstock delivery. The Ketchikan GSA Building originally displaced only 4,000 of its potential 9,000 gallons at the time that data were collected. The Tanana Shop, Fire Hall, and Log Duplex recorded the lowest avoided fuel quantity.

Conditions for Greatest Efficiency

Biomass systems are designed to burn at their maximum capacity: hot and fast. Sizing the unit to meet 80% of the required peak heat load ensures the boiler will run at the maximum heat output. Additional heating sources such as diesel fuel are often used to meet the final 20% during peak loads.

[10] Avoided diesel numbers were obtained from project managers and operators and may be best estimates rather than inventory reconciliations.

Thermal storage can add more efficiency to a system by heating with circulating hot water, heated from the boiler and connected storage. A larger thermal storage volume can reduce the number of daily firings a boiler requires to maintain a building's heat, although decreasing the number of firings too drastically can result in unintended consequences such as water quality issues that can affect the life of the boiler. Burning wood with a moisture content of less than 25% increases the burn efficiency of the system.

Cost over Time

Figure 4 shows installed capital costs for installed systems, for the years 2007 to 2015. The costs shown in the figure have been corrected for inflation in the United States over time.[11] Note the slight trending increase in capital costs per installed MBTUh over time. This trend takes into account all types and locations of installed systems.

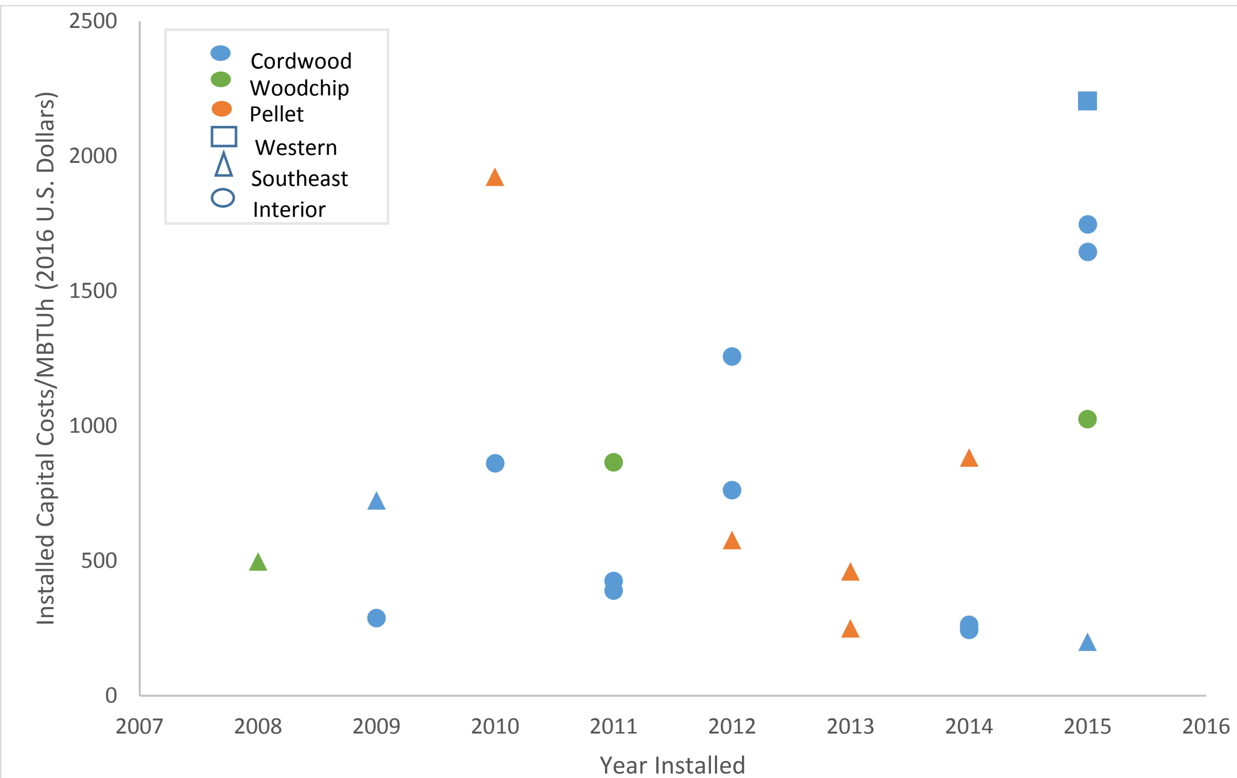

Figure 4. Installed capital costs ($/MBTUh) of biomass boilers versus year of installation

The most recent cordwood boiler installations in Kobuk, Hughes, and Koyukuk have the highest capital cost, though Kasaan (built during the same years) was significantly cheaper to install. Air transport was required for two of the three village systems, with waterborne delivery for Koyukuk and Kasaan. In 2012, Thorne Bay had the highest capital cost of any prior installation, likely due to installation of two containerized boilers.

[11] Costs were made constant to 2016 values using http://www.usinflationcalculator.com/

The Sealaska installation served as the first commercial-scale pellet boiler installation in the state; its relatively high costs may have been the result of little prior experience with these systems.

Installed Costs by Major Component

Figure 5 shows the installed biomass technology costs by major component. Component descriptions are as follows:

- Boiler: The boiler unit
- Site foundation: The preparation of the area to place the boilers
- Pellet silo: Pellet fuel storage
- Distribution piping: The piping required to move water heated by the boiler to the building being heated
- Distribution pumps: Pumps required to move water through piping
- Boiler installation: Costs for installing the boiler, including labor
- Boiler building: The building housing the boiler (if it is not being housed in the heated building)
- Boiler building mechanical: The mechanical requirements for the boiler in the building
- Integration: The integration of the boiler into the heating system
- Design and permits: The system design plans and permits required for the boiler system
- Stack and install: The boiler emissions stack and the installation of the stack on the boiler unit
- Construction management: Overseeing the project's construction, including management labor
- Fuel building: The building, other than a silo, required for storing biomass fuel
- Heavy equipment rental: Equipment that may not have been available in the community for installation
- Shipping: The costs associated with shipping the boiler, and other construction materials

The boiler is one of the most substantial costs for each installation, along with the site foundation, the boiler building, and the integration of the system into the building. Fuel storage and construction management are also large expenses, though not reported in each project. Despite the large installed capacity of chip boilers in the Interior, their installation costs are higher than those of other boilers.

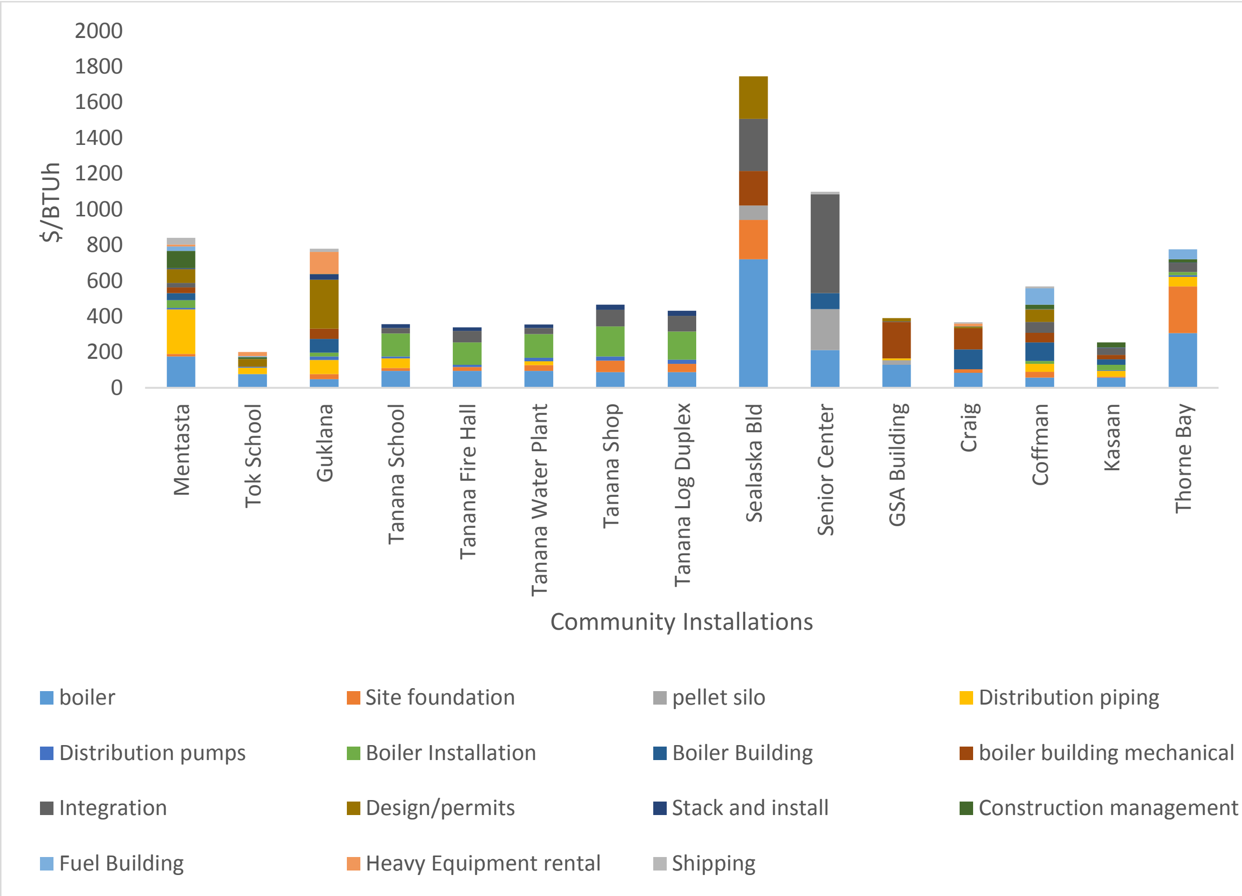

Figure 5. Installed biomass technology costs by major component ($/MBTUh).

Transportation Costs

Transportation costs by system type and installed capacity are shown in Figure 6.

Unfortunately, shipping costs were not reported for all projects. Of the shipping costs available, the cordwood boilers of Kobuk, Hughes, and Koyukuk experienced the highest shipping costs. Kobuk and Hughes are located on rivers that are not accessible by barge; the shipping method was by air. Koyukuk is accessible by barge on the Yukon River.

Mentasta and Gulkana are located on the road system and use shipping methods that may include rail, road, and ocean barge from Seattle.

Southeast communities have lower shipping costs due to barge and ferry service from Seattle. As such, they do not incur the added costs of transporting equipment inland.

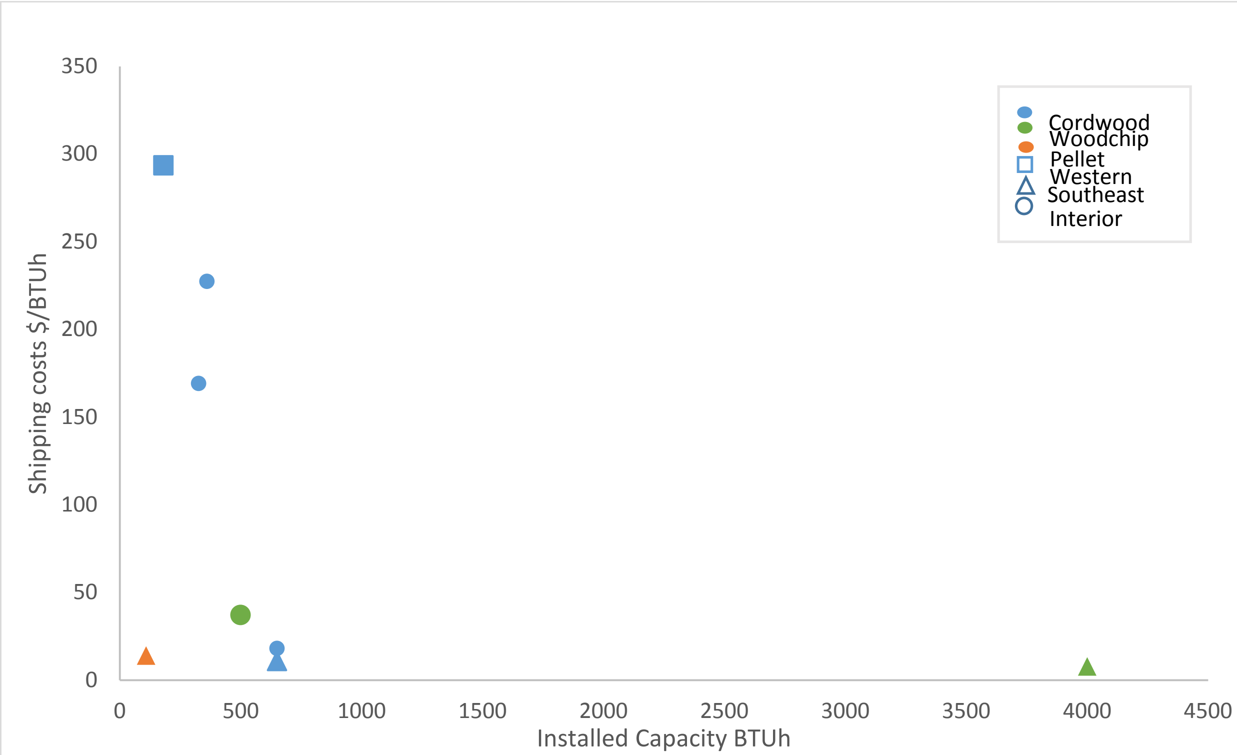

Figure 6. Shipping costs as a function of installed capacity

Technology Trends

Cordwood biomass systems involve intensive labor. One way to reduce the O&M costs has been to move to an automated woodchip system, which as seen in Figure 2, have relatively low O&M costs. In addition, the cost and the general availability of woodchips compared with cordwood and pellets make combustion technology more economical. Increasingly, schools and communities that are adopting biomass as a heating fuel are also installing greenhouses and incorporating biomass energy and food production into their curriculum. Compared with cordwood systems, however, chip-fed combustion requires extra processing time (and expense) to manufacture chips.

Technology-Specific Storage

Information here is specified by the New York State Energy Research and Development Authority (NYSERDA). Several demonstration projects, being funded by the NYSERDA, will show that thermal storage is "system dependent" rather than just a fixed ratio of gallons/BTUh. The first results are expected by late spring or summer 2016.

The Biomass Thermal Energy Council (BTEC) is forming an action group on thermal storage, and the Clean Energy State Alliance (CESA) has commissioned consultants to develop a white paper on thermal storage. John Siegenthaler, an industry specialist, says the following on this topic:

> My pitch on thermal storage is that it is highly system dependent. A pellet fired boiler supplying a very high mass heated concrete floor slab with only one zone could likely work fine without any water-side thermal storage. However, a low thermal mass distribution system (like fin-tube

baseboard), that's divided into several zones would definitely benefit from the 2 gallons per 1000 Btu/hr storage requirement. Ultimately these scenarios can be simulated by high end software ..

Pellet systems: 20 gallons water / 10,000 BTU/hr Thermal storage
Cordwood Systems: 130 gallons of storage per cubic foot of combustion chamber volume minus the water volume of the boiler
Chip Boiler: No specific volume suggested

Cost of Biomass Fuel

Biomass fuel prices across the state are often tied to fuel costs for harvesting, and vary both regionally and seasonally. Regionally, available wood species is a determinant of price. Figure 7 shows the varying cordwood costs for eight regions of Alaska. Interestingly, while the price of gasoline has recently decreased, the price of wood has not. This may be due to high costs of harvest equipment and the labor needed to harvest, transport, and store roundwood biomass.

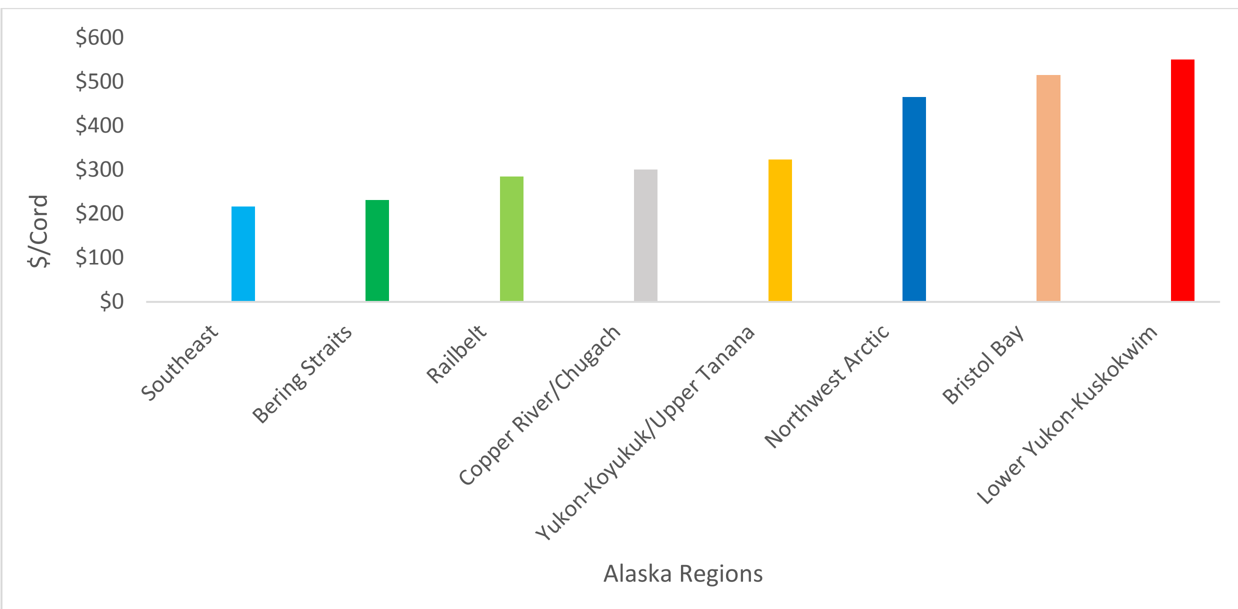

Figure 7. Average delivered firewood costs per region in Alaska (data courtesy of AEA)[12]

[12] Data collected from LiHEAP wood collectors and from Cal Kerr, forester and analyst with Northern Economics, Inc. (Anchorage).

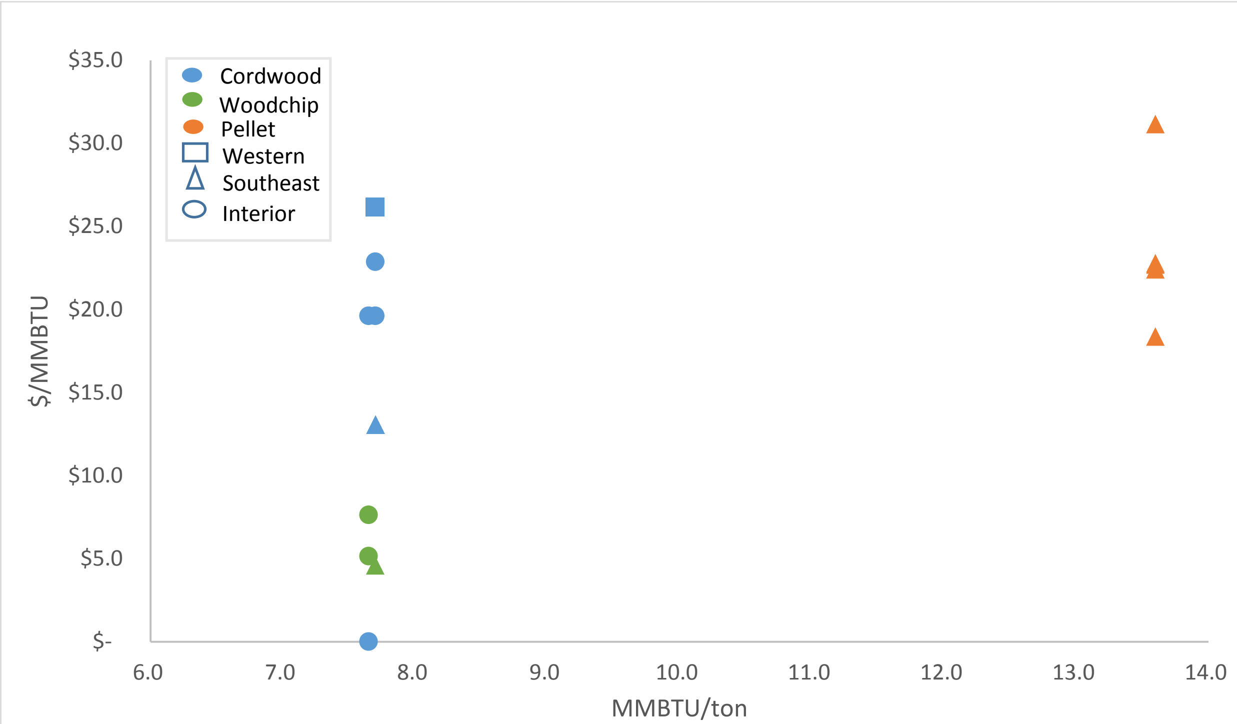

Figure 8. Cost of delivered biomass per ton as a function of the energy content per ton[13]

Pellets have a higher MMBTU per ton; however, their cost per MMBTU is similar to that of cordwood in Interior Alaska. Woodchips, while yielding the same MMBTU per ton as cordwood, may be delivered at a lower cost overall than cordwood. For example, Gulkana reports zero cost for delivered wood, as their feedstock is provided free as part of a fire-prevention program.

In Tanana, while biomass feedstock costs are around $20/MMBTU, the community recently received approximately 6-years-worth of feedstock from a road construction project. The wood still needs to be processed and brought to the boilers, however, and current calculated costs for processing and delivering the wood is now around $50 per cord. These numbers have not been fully reflected in this study, as they have not been confirmed. In addition, it is unlikely that zero cost feedstock will be available over the economic life of the biomass system.

References

All costs and numbers were collected by survey from the following individuals:

Communities	References
Coffman Cove	Jonathon Fitzpatrick: jfitzpatrick@sisd.org
Craig	Jon Bolling: jbolling@aptalaska.net
Gulkana	Sandra Tsinnie: stsinnie@gulkanacouncil.org
Haines Chilkoot Indian Association	Harriette Brouillette: hbrouillette@chilkoot-nsn.gov
Haines Senior Center	Ed Bryant: ebryant@haines.ak.us

[13] Cordwood cost and energy content was converted to weight using the USDA Forest Service calculator.

Hughes	Eric Hanssen: echanssen@anthc.org
Juneau Sealaska Building	Shawn Blumenshine: shawn.blumenshine@sealaska.com
Kasaan	Jonathon Fitzpatrick: jfitzpatrick@sisd.org
Ketchikan GSA	NREL Report
Ketchikan Public Library	Linda Lyshol: lindal@firstcitylibraries.org
Kobuk	Eric Hanssen: echanssen@anthc.org
Kokhanok	Nathan Hill: manager@lakeandpen.com
Koyukuk	Eric Hanssen: echanssen@anthc.org
Mentasta	Rex Goolsby: rex.goolsby@gmail.com
Tanana	Jeff Weltzin: jeffreyweltzin@gmail.com
Thorne Bay	Jonathon Fitzpatrick: jfitzpatrick@sisd.org
Tok	Scott MacManus: smacmanus@agsd.us

Diesel Generator Technology Report

Summary

Resource and Technology Description

Diesel generators are the main source of electrical generation in remote Alaska communities; they also help maintain grid frequency and voltage. The nameplate outputs of individual generators installed in rural Alaska vary from about 30 kW to over 1 MW. The best diesel generator systems convert roughly 40% of diesel fuel energy content into electricity. The remaining fuel energy is converted to heat.

Current Installations in Alaska

The data in this briefing report were collected from public sources. Installation costs were gathered from project Financial Close-Out Reports on the Denali Commission project database. Operations and maintenance cost data were collected from the Regulatory Commission of Alaska. The numbers for kWh generated were collected from Power Cost Equalization data on the Alaska Energy Data Gateway website.

Key Performance Metrics

The scale of the installed system directly affects capital costs; that is, larger systems are more cost-effective per kW. However, appropriately sizing a system for a community is more cost-effective overall than significantly oversizing the system.

Capacity factors range from under 5% to over 25%. The low values are typically for diesel-hydroelectric hybrid systems, for which this measure is not entirely accurate. In addition, rural diesel plants may have low capacity factors, since typically there are three to four generators in-house. These generators are sized so that one to two generators provide power at any given time; the remaining generators are available as backup.

Generators of this size can expect to operate approximately 60,000–100,000 hours, with larger engine blocks tending to have longer lifespans. An appropriately maintained generator operating for 60,000 hours 35% of the time will last approximately 20 years.

Technology Trends

The technology continues to see advances in power output, efficiency, noise reduction, and emissions control. The shapes of combustion chambers in newer engines are designed to maximize the combustion rate of fuel, thus increasing output power and fuel efficiency. The common-rail fuel (CRF) system can maintain high pressure from the fuel tank to injection, which allows for finer vaporization of fuel and more complete combustion. Nitrous oxide can be reduced through exhaust gas recirculation and selective catalytic reduction.

Control systems have also seen advancement. Mechanical control systems have been slowly phased out in favor of electronic control systems, which allow for offsite monitoring of a system and reduction in the number of necessary service calls.

Technology-Specific Gaps and Barriers to Successful Project Development and Operation

Diesel generators in rural Alaska communities remain difficult to maintain to the degree necessary for smooth operation. Additionally, Supervisory Control and Data Acquisition (SCADA) systems with remote

Summary

control capabilities require continuous Internet connection, which is not always available in rural communities

From 2007 to 2014, the Environmental Protection Agency phased in mandates for non-road diesel engines to use low-sulfur then ultra-low-sulfur diesel in most of the United States. Additionally, new stationary diesel engines are required to meet certain emissions standards. Small facilities in rural Alaska have been given some exemptions due to the high cost and difficulty of operations in remote areas, but meeting these mandates is still an area of concern.

Recommendations

Ensuring proper and continuous maintenance of diesel generators in rural Alaska communities needs to be a high priority, whether through in-person visits, telecommunications upgrades for remotely controlled systems, or further advances in SCADA systems.

Diesel Generator Technology Report

Prepared by the Alaska Center for Energy and Power for the Alaska Affordable Energy Strategy Effort with funding from the Alaska Energy Authority

In much of rural Alaska, as with other remote microgrids, diesel generators are often used as the grid prime mover, meaning they are responsible for maintaining grid frequency and voltage. Due to the cost of diesel fuel, significant energy cost savings revolve around reducing fuel consumption.

The data in this briefing report were collected from public sources. Installation costs were gathered from project Financial Close-Out Reports on the Denali Commission Project Database (2016). Operations and maintenance cost data were collected from the Regulatory Commission of Alaska (RCA). The numbers for kilowatt-hours (kWh) generated were collected from Power Cost Equalization (PCE) data on the Alaska Energy Data Gateway (2016) website. When relevant, costs were adjusted for inflation using Consumer Price Index data listed on the Alaska Department of Labor and Workforce Development (2016) website.

Capital Costs

Each of the projects evaluated in this briefing received a Rural Power System Upgrade (RPSU) grant. Many, but not all, of the grants included a heat recovery system, an intermediate fuel tank, and/or a distribution upgrade, but the RPSU reports do not provide a cost breakdown to discern those costs. Some projects were built in parallel with others, thereby reducing costs compared with scenarios that have separate project completions. The cost categories include freight, labor, materials, planning and design, administration and overhead, and other. A list of communities examined, along with installed capacities and comments about the scope of the RPSU projects, is shown in Table A-1 of Appendix A. The scale of the installed system directly affects capital costs, as shown in Figure 1. Larger systems are more cost-effective per kilowatt (kW). However, appropriately sizing a system for a community is more cost-effective overall than significantly oversizing the system.

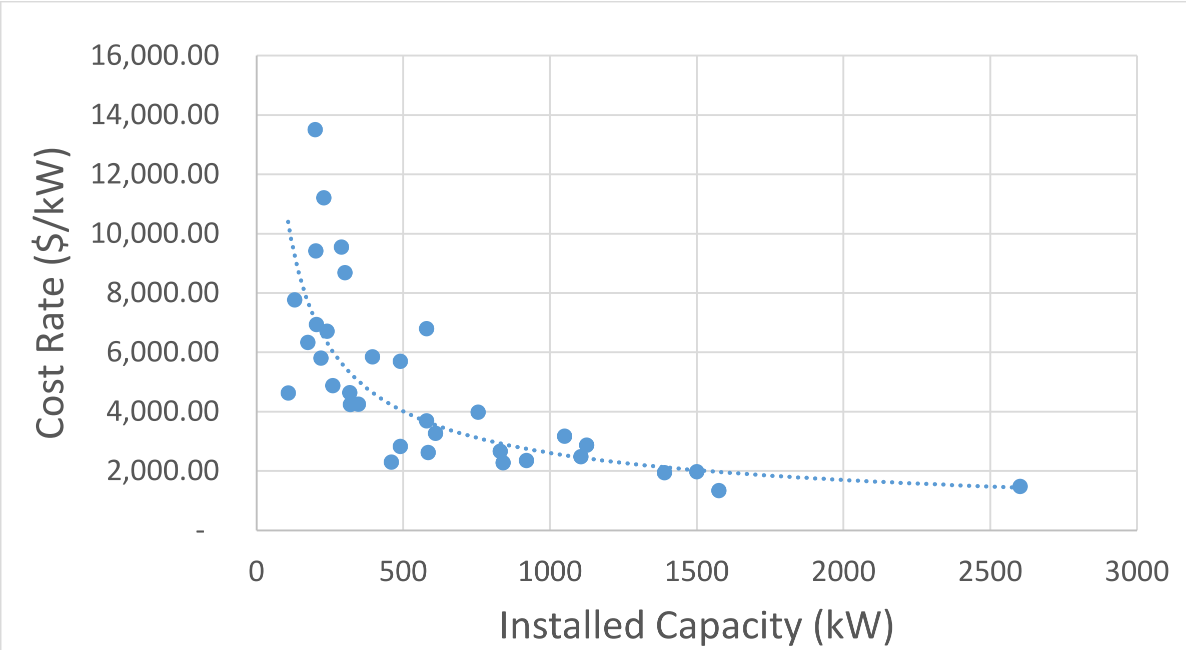

Figure 1. Capital costs (2014 $) of RPSU diesel systems normalized by installed capacity. Larger systems are more cost-effective per kW; however, appropriately sizing a system for a community is more cost-effective overall than significantly oversizing the system.

Operations and Maintenance

Operations and maintenance (O&M) represent the cost to keep a generator operational throughout its expected life. Such costs include labor and materials for inspections, repairs, and other tasks. A model was developed by the Alaska Energy Authority (AEA) and modified by the Alaska Center for Energy and Power (ACEP) to approximate O&M costs for three generator classes: 4 cylinders, 6 cylinders, and 8–16 cylinders. These categories generally correspond to rated power outputs of 60–150 kW, 151–600 kW, and 601–1300 kW, respectively, although there is overlap. The three cost models are shown in Figure 2. The assumed maintenance intervals used in the model are shown in Table B-1 of Appendix B. The duration of each maintenance task is shown in Table B-2 of Appendix B. In-house labor, which was assumed at $60/hour, includes wages, benefits, and overhead. Contracted labor was assumed at $120/hour plus travel and per diem. Price escalation was not taken into account in these calculations. Daily inspections and oil changes were the dominant cost factors of O&M because these tasks must be done frequently. The total O&M costs for each size category were normalized by the assumed number of operating hours over the life of the engine: 60,000 hours for 4- and 6-cylinder engines and 100,000 hours for 8- to 16-cylinder engines. It was assumed that the generators were operating with a load factor that was 55% of nameplate capacity on average.

The cost per kWh, shown in Figure 2, decreases as the size of installed capacity increases because the load factor remains constant. However, for a given load, larger machines are more costly to operate (overall and per kWh), which illustrates the importance of right-sizing generators for the expected demand.

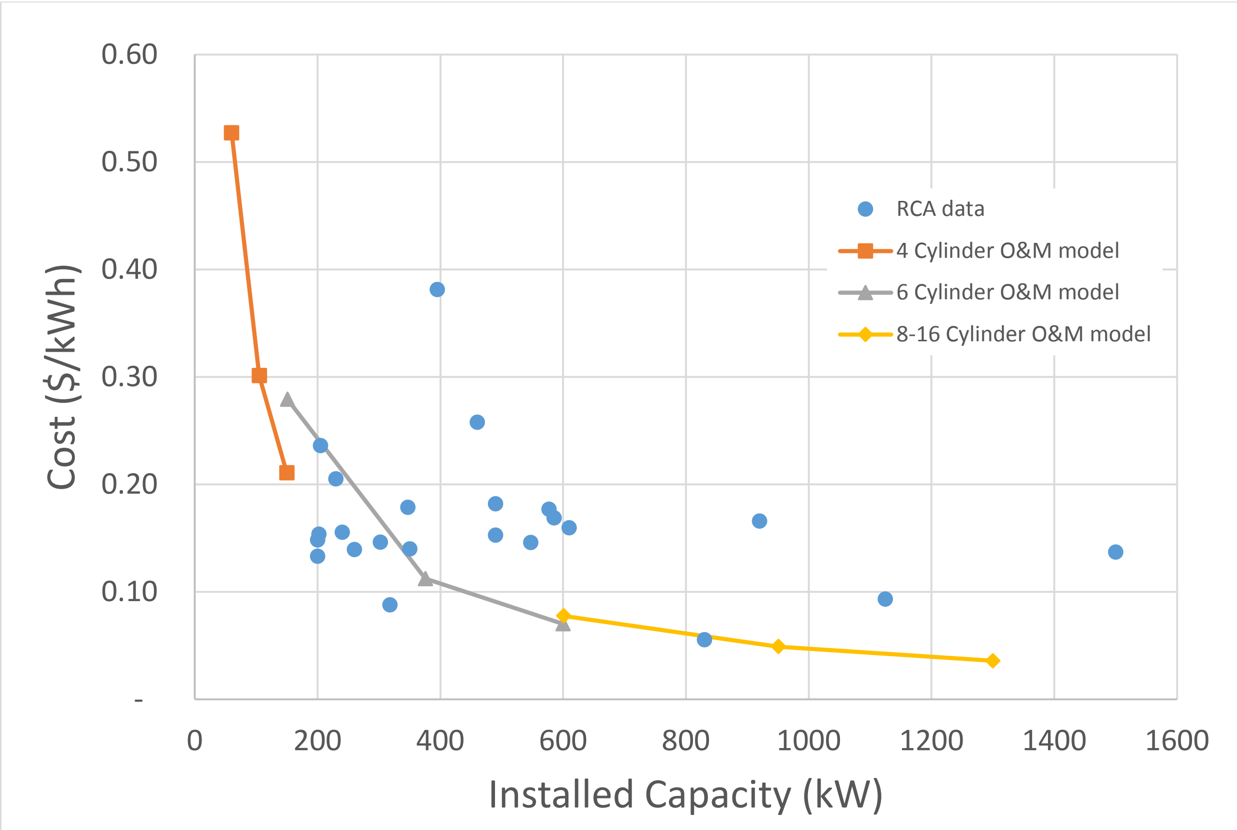

Figure 2. Operations and maintenance costs per kWh from calculated models and RCA data. According to the model, O&M costs per kWh decreases as generator size increases for a constant load factor (not a constant load). According to RCA data, O&M costs per kWh are nearly flat for power plants ranging from 200–1500 kW.

The cost to operate a single generator does not necessarily scale with the cost to operate an entire powerhouse. Operations and maintenance cost data were collected from the Regulatory Commission of Alaska (RCA) for the communities seen in Table B-3 in Appendix B. The values include personnel costs, routine O&M, generator repairs, and other operating expenses; they do not include offices expenses, debt, insurance, depreciation, interest, and other administrative costs. The values are plotted in Figure 2 along with the O&M cost model. The RCA data indicate that O&M costs are relatively flat across different sized plants as opposed to the O&M model, which indicates an inverse relationship. There may be factors that could not be fully understood from the available dataset which contribute to power plant level O&M, causing the costs to differ from generator level O&M.

Levelized Cost of Electricity

Levelized cost of electricity (LCOE) was determined by dividing the expected total cost of a system over its lifetime by the expected total kWh. To calculate lifetime kWh generated, it was assumed that the generators in each community operated for 60,000 hours with an average load factor of 55% of nameplate capacity. The costs for a diesel powerhouse included fuel, O&M, and initial capital costs.

Administrative costs were not included, as they were not tracked at the level of detail necessary to separate general utility administration from specific diesel-related costs. Capital cost data were gathered from the Denali Commission and the Alaska Energy Authority RPSU projects. Regulatory Commission of Alaska (RCA) data were used for O&M costs, because the model discussed in the previous section broke down when scaled from an individual generator to an entire powerhouse. The fuel costs were calculated by assuming an efficiency of 12 kWh/gallon of diesel and lower and upper cost boundaries of $3/gallon and $7/gallon. These assumptions yielded fuel costs ranging from 0.25 to 0.58 $/kWh.

In reality, fuel costs vary significantly by community and over time. A full economic analysis and projection of diesel fuel prices is beyond the scope of this report. The range of calculated LCOE values is shown in Figure 3. Fuel represents about 30–50% of total LCOE under the $3/gallon assumption and 50–80% of total LCOE under the $7/gallon assumption. Fuel represents a significant portion of LCOE and is the most variable, which makes cost projections over the lifetime of a project difficult without specifying a range of potential fuel prices.

Calculated LCOE values are similar to but not the same as residential rates (before Power Cost Equalization adjustment) in these communities, because the residential rates are calculated based on administrative, O&M, and fuel costs. Generally, RPSU project capital expenses are paid for by the Denali Commission and other grants rather than by the community or local utility. Levelized cost of electricity calculations represent the full cost of generation, not the cost of delivery for the utility.

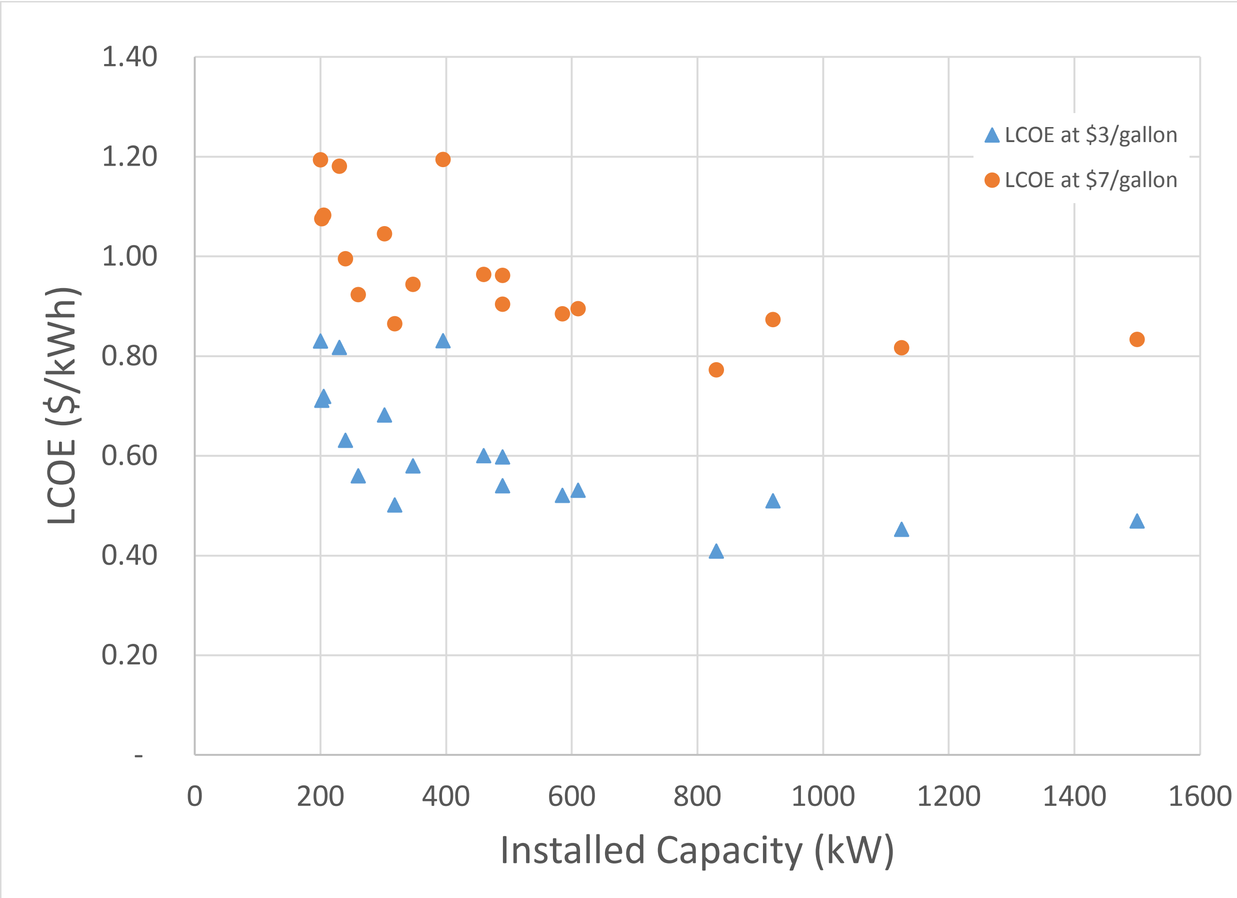

Figure 3. Levelized cost of electricity by installed capacity for two different fuel cost assumptions. Fuel represents a significant portion of LCOE, and its cost is highly variable, making it difficult to accurately predict lifetime costs of generating diesel electricity without accurate fuel cost models.

Conditions for Greatest Efficiency

The efficiency of diesel generators is often reported as the number of kWh generated per gallon of fuel. Typical values for generators used in Alaska are 11–15 kWh/gallon. Generators tend to have poor efficiency when lightly loaded, but efficiency plateaus at around half the rated load and above. The steady-state efficiency of a diesel generator can be deduced from fuel consumption (gal/hr) curves. Unfortunately, not all generators in a powerhouse can maintain a fixed output due to varying loads. Control schemes are often employed within power plants to provide the most cost-efficient combination of generators for a given load.

Installation of auxiliary equipment can also affect efficiency. After-coolers help remove heat created in the combustion process, which allows fuel to combust more completely. Poor fuel quality can lead to incomplete combustion and decreased efficiency. Filters and other emissions-control devices reduce the output of nitrogen oxide (NO_x) and particulates, but typically decrease overall efficiency.

Diesel Generator Technology Report

Cost over Time

In order to track the change in installation costs over time, the effect of power plant size must be taken into account. The installation cost ratio of each project was calculated relative to the cost curve. A value of 1 indicates that the project cost lies directly on the cost curve. A value of 2 indicates that the project cost is double the curve. Installation cost ratios are plotted over time in Figure 4. There is no noticeable trend over the time for which installation cost data are available. However, it is expected that costs increase over a longer timeframe due to increased emissions standards and other regulatory drivers.

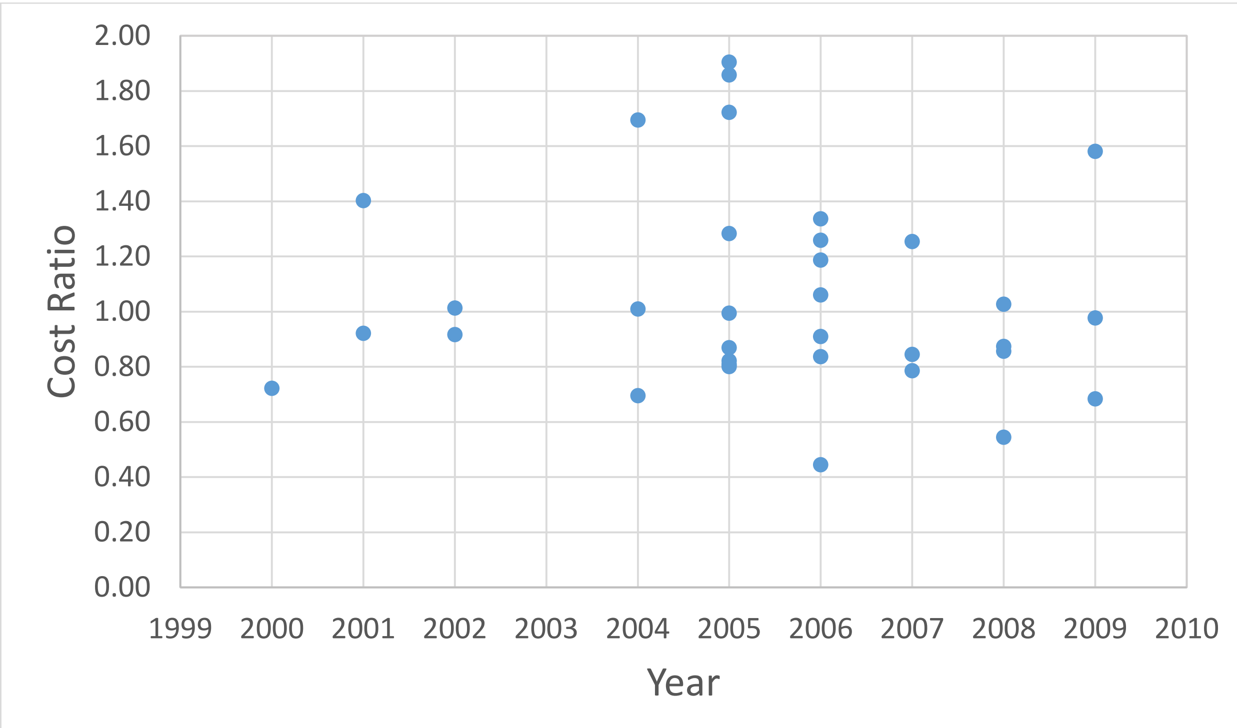

Figure 4. Installation cost ratio relative to cost curve of Figure 1 by year. There is no significant trend over the time for which installation cost data are available.

Transportation

Project materials must be transported through Anchorage. Locations closer to Anchorage and barge routes tend to have lower costs associated with transportation. Communities that require equipment to be delivered via ice road or air have much higher freight costs.

Expected Life

The nameplate outputs of individual generators installed in rural Alaska vary from about 30 kW to over a megawatt. Generators of this size can expect to operate 60,000–100,000 hours, with larger engine blocks tending to have longer lifespans. An appropriately maintained generator operating for 60,000 hours 35% of the time will last approximately 20 years. However, the lifetime of an individual generator does not necessarily match the lifetime of the powerhouse, because generators and other components can be replaced without rebuilding the powerhouse.

Capacity Factor

The capacity factor of a diesel powerhouse is calculated by dividing the number of kWh generated, by the number of kWh it would generate if each of its generators were running at full capacity. The number of kWh generated was collected from Power Cost Equalization (PCE) data on the Alaska Energy Data Gateway website. The capacity factors for the RPSU projects are shown in Figure 5. Systems with a mixture of diesel and other sources are differentiated from systems that only use diesel generators.

Rural diesel plants typically have three to four generators in house. The diesel plants are sized so that one or two generators provide power at any given time; the remaining generators are available as backup. The operating generators are not necessarily running at full rated load.

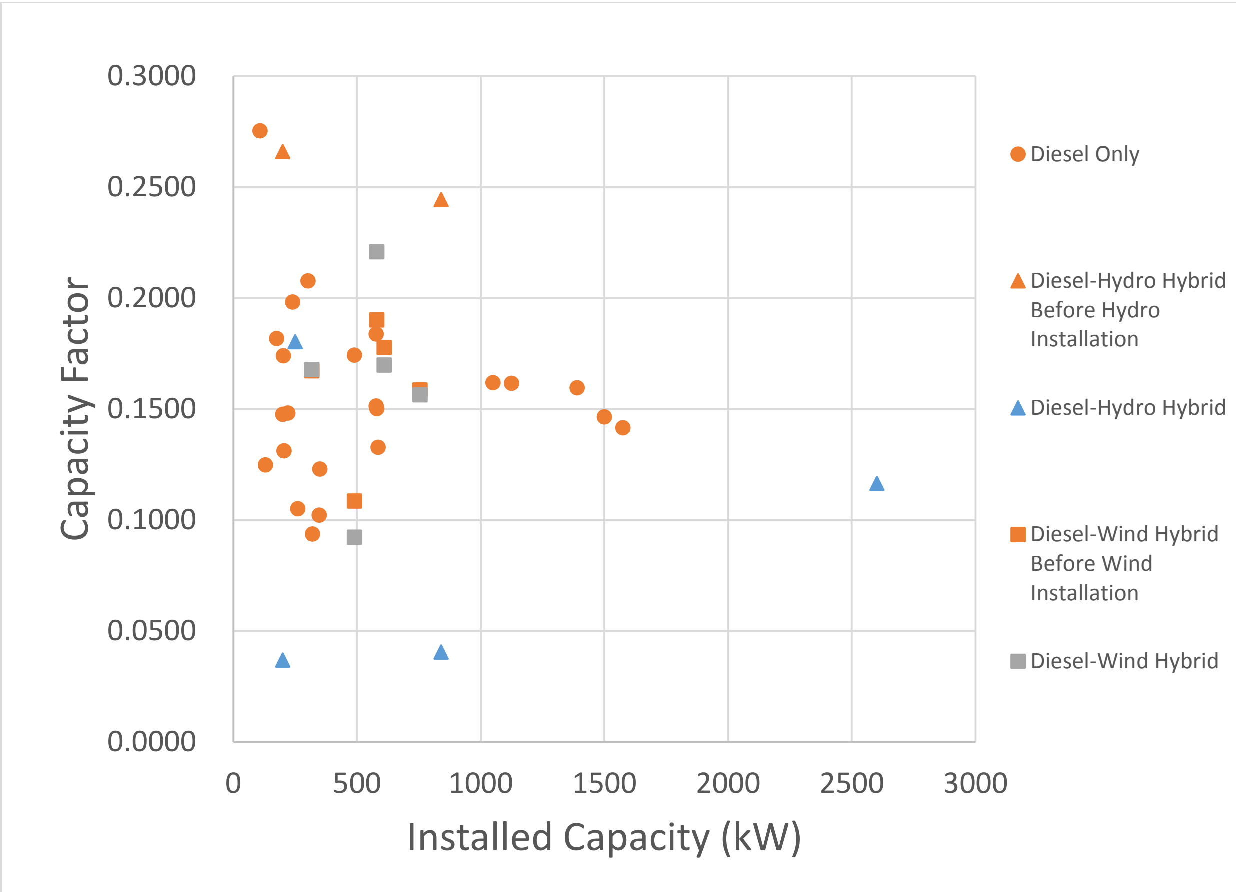

Figure 5. Capacity factor of diesel power plants by installed capacity. Rural power plants have low capacity factors, because at any given time, most generators are not running. Additionally, the generator that is operating is not necessarily running at full rated load.

Technology and Regulatory Trends

Diesel engines have been in use for over a hundred years, and yet the technology continues to see advances in power output, efficiency, noise reduction, and emissions control. The shapes of combustion chambers in newer engines are designed to maximize the combustion rate of fuel, thus increasing output power and fuel efficiency. Common-rail fuel (CRF) systems can maintain high pressure from the fuel tank to injection. High pressure consequently allows for finer vaporization of the fuel, thus more complete combustion.

Nitrous oxide (NO_x) is caused by high combustion temperatures in an oxygen-rich environment; NO_x can be reduced through exhaust gas recirculation (EGR). This process lowers the adiabatic flame temperature and increases the heat capacity of the air mixture in the combustion chambers, allowing for combustion at a much lower temperature. Another method of NO_x reduction, selective catalytic reduction (SCR), passes the exhaust through a reducing catalyst such as ammonia or urea to convert NO_x into diatomic nitrogen and water.

Control systems have also seen advancement. Mechanical control systems have been slowly phased out in favor of electronic control systems. Electronic control systems allow for offsite monitoring of a system, reducing the number of necessary service calls.

From 2007 to 2014, the Environmental Protection Agency phased in mandates for non-road diesel engines to use low-sulfur then ultra-low-sulfur diesel in most of the United States. Additionally, new stationary diesel engines are required to meet certain emission standards. However, small facilities in rural Alaska have been given some exemptions due to the high cost and difficulty of operations in remote areas (ADEC, 2016). Pre-2014 model year engines are exempt from diesel fuel sulfur requirements. Engines may be certified to marine engine standards, rather than land-based non-road engine standards. After-treatment devices for NO_x reduction, such as SCR, are not required. After-treatment devices for particulate matter are not required for pre-2014 model year engines.

References

ADEC (Alaska Department of Environmental Conservation), Internal Combustion Engine Requirements, [https://dec.alaska.gov/air/anpms/ulsd/ulsdnsps.htm], accessed April 2016.

Alaska Energy Data Gateway, Power Cost Equalization Data, [akenergygateway.alaska.edu], accessed January 2016.

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Acknowledgments

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Appendix A

Table A-1. List of communities examined in installation costs with some description of the RPSU grant.

Community	Installed Capacity (kW)	Notes (all grants include the powerhouse, generators, and controls)
Akiachak	1500	Grant also includes a 15,000 gal intermediate tank and a waste heat recovery loop
Angoon	1575	Grant also includes a waste heat recovery system
Arctic Village	395	Grant also includes a distribution upgrade and a waste heat recovery system
Buckland	1125	Grant also includes a 12,000 gal intermediate tank, a distribution upgrade, and a heat exchanger for existing waste heat recovery loop
Chefornak	1050	Grant also includes a 22,000 gal intermediate tank and a heat exchanger for existing waste heat system
Chitina	302	
Chuathbaluk	175	Grant shared with other middle Kuskokwim projects. Grant also includes tank farms for the powerhouse, school, and village
Crooked Creek	220	Grant shared with other middle Kuskokwim projects. Grant also includes tank farms for the powerhouse, school, and village
Deering	585	Grant also includes a 5,000 gal intermediate tank and a heat exchanger for existing waste heat recovery system
Diomede	460	Grant also includes a distribution upgrade and a heat exchanger for existing waste heat loop
Elfin Cove	347	Built in parallel with a distribution upgrade project on a separate grant
Elim	1105	
Golovin	580	Grant also includes a 12,000 gal intermediate tank and a heat exchanger for existing waste heat system
Gustavus	840	Built in parallel with a Hydro system on a separate grant
Hughes	230	Grant also includes a 6,000 gal intermediate tank
Karluk	108	Grant also includes a distribution upgrade
King Cove	2602	Hydro and diesel system
Kokhanok	490	Built in parallel with bulk fuel project but on separate grant
Kongiganak	755	Grant also includes a 12,000 gal intermediate tank, a distribution upgrade, and a heat exchanger for existing waste heat loop
Kotlik	1390	Grant also includes a 12,000 gal intermediate tank, a distribution upgrade, and a heat exchanger for existing waste heat loop
Koyukuk	202	Grant also includes a 12,000 gal intermediate tank, a distribution upgrade, and a heat exchanger for existing waste heat loop
Kwigillingok	580	Grant also includes three 22,000 gal bulk fuel tanks, a 12,000 gal intermediate tank, a distribution upgrade, and a heat exchanger for existing waste heat loop
Manokotak	830	Grant also includes a 12,000 gal intermediate tank and a heat exchanger for existing waste heat loop
Nikolski	200	Grant also includes re-plumbing for existing intermediate tank
Pedro Bay	260	Grant also includes a distribution upgrade and a waste heat recovery system
Pelican	920	Project was done in parallel with a bulk fuel storage project and preceded a hydro system upgrade
Pilot Point	318	Built in parallel with a bulk fuel project on a separate grant
Sleetmute	320	Grant shared with other middle Kuskokwim projects. Grant also includes tank farms for powerhouse and school

Community	Installed Capacity (kW)	Notes (all grants include the powerhouse, generators, and controls)
Stevens Village	290	Grant also includes a distribution upgrade
Stony River	130	Grant shared with other middle Kuskokwim projects. Grant also includes tank farms for powerhouse, school, and village
Takotna	205	Grant shared with other middle Kuskokwim projects. Grant also includes tank farms for powerhouse, school, and village
Tenakee Springs	240	Grant also includes a distribution upgrade and some equipment for waste heat recovery was installed but no heat loop was close enough to utilize it
Tuluksak	490	Grant also includes a 12,000 gal intermediate tank, a road upgrade, and a distribution upgrade
Tuntutuliak	610	Grant also includes a 4,000 gal intermediate tank and a heat exchanger for future waste heat recovery system

Appendix B

Table B-1. Assumed Intervals of maintenance tasks. Note that each manufacturer specifies different maintenance intervals for machines. The assumed intervals are simply approximations.

Maintenance Category		60-150 kW Interval (hr)	151-600 kW Interval (hr)	601-1300 kW Interval (hr)
Repeating maintenance tasks: contracted	Replace oil cooler and injectors	15,000	10,000	15,000
	Replace generator bearings	6,000	6,000	6,000
	Unscheduled maintenance/repair	15,000	15,000	15,000
Repeating maintenance tasks: in-house labor	Daily inspection	14	14	14
	Check battery electrolyte level, adjust belts, clean radiator	250	250	250
	Change oil and filter	250	250	500
	Clean crankcase breather	250	250	500
	Check/lubricate fuel control linkage	1,000	1,000	1,000
	Drain fuel tank water and sediment	250	250	1000
	Replace fuel filters and glycol filter	500	500	1000
	Replace air filter, hoses and belts	2,000	2,000	2,000
	Adjust valve lash	3,000	3,000	2,000
	Inspect turbocharger	2,000	2,000	2,000
	Inspect generator including bearings	2,000	2,000	2,000
	Replace coolant	6,000	6,000	6,000
	Inspect engine speed sensor, starting motor, water pump	6,000	6,000	6,000
One-time maintenance tasks	Initial 250 service hours inspection and valve lash adjustment	250	250	250
	First top end rebuild	15,000	15,000	15,000
	Second top end rebuild	30,000	30,000	30,000
	In-frame rebuild	45,000	45,000	45,000
	Third top end rebuild	-	60,000	60,000
	Fourth top end rebuild	-	75,000	75,000
	Fifth top end rebuild	-	-	90,000

Table B-2. Labor duration of maintenance tasks.

	Maintenance Category	60-150 kW Labor (hr)	151-600 kW Labor (hr)	601-1300 kW Labor (hr)
Repeating maintenance tasks: contracted	Replace oil cooler and injectors	30.0	30.0	30.0
	Replace generator bearings	30.0	30.0	30.0
	Unscheduled maintenance/repair	30.0	40.0	40.0
Repeating maintenance tasks: in-house labor	Daily inspection	1.0	1.0	2.0
	Check battery electrolyte level, adjust belts, clean radiator	2.0	2.0	2.0
	Change oil and filter	2.0	2.0	2.0
	Clean crankcase breather	1.0	1.0	1.0
	Check/lubricate fuel control linkage	1.0	1.0	1.0

		60-150 kW	151-600 kW	601-1300 kW
	Maintenance Category	**Labor (hr)**	**Labor (hr)**	**Labor (hr)**
	Drain fuel tank water and sediment	2.0	2.0	2.0
	Replace fuel filters and glycol filter	2.0	2.0	2.0
	Replace air filter, hoses and belts	4.0	4.0	4.0
	Adjust valve lash	4.0	4.0	4.0
	Inspect turbocharger	1.0	1.0	1.0
	Inspect generator including bearings	1.0	1.0	1.0
	Replace coolant	4.0	4.0	4.0
	Inspect engine speed sensor, starting motor, water pump	2.0	2.0	2.0
One-time maintenance tasks	Initial 250 service hours inspection and valve lash adjustment	6.0	6.0	6.0
	First top end rebuild	40.0	60.0	80.0
	Second top end rebuild	40.0	60.0	80.0
	In-frame rebuild	150.0	300.0	400.0
	Third top end rebuild	-	60.0	80.0
	Fourth top end rebuild	-	60.0	80.0
	Fifth top end rebuild	-	-	80.0

Table B-3. List of O&M costs reported to RCA and the installed capacity for respective community.

Community	Installed Capacity (kW)	O&M Cost ($/kWh)
Akiachak	1500	0.14
Atka	200	0.13
Arctic Village	395	0.38
Atmautluak	547	0.15
Buckland	1125	0.09
Chignik	577	0.18
Chitina	302	0.15
Deering	585	0.17
Diomede	460	0.26
Elfin Cove	347	0.18
Hughes	230	0.21
Kokhanok	490	0.18
Koyukuk	202	0.15
Manokotak	830	0.06
Nikolski	200	0.15
Ouzinkie	350	0.14
Pedro Bay	260	0.14
Pelican	920	0.17
Pilot Point	318	0.09
Takotna	205	0.24

Diesel Generator Technology Report

Community	Installed Capacity (kW)	O&M Cost ($/kWh)
Tenakee Springs	240	0.16
Tuluksak	490	0.15
Tuntutuliak	610	0.16

Energy Storage Technology Report

Summary

Prepared by the Alaska Center for Energy and Power for the Alaska Affordable Energy Strategy Effort with funding from the Alaska Energy Authority

Resource and Technology Description

Since the discovery of electricity, we have sought effective methods to store that energy for use on demand. Energy storage systems provide a technological approach to managing power supply in order to create a more resilient energy infrastructure. Energy storage systems can be divided into the energy storage unit and the power conditioning system. The energy storage unit determines how much energy can be stored, or the capacity, in kWh. The power conditioning system is the interface between the grid and the energy storage unit, and controls the charging and discharging. Thus, the power conditioning system is largely responsible for the power in kW of the energy storage system.

Lead-acid (Xtreme Power), lithium-ion, flow (vanadium redox and zinc-bromine), nickel-based (nickel cadmium) batteries, and flywheel, compressed air, and closed-loop pumped hydro and open loop pumped hydro energy storage are the technologies represented by data available for this report. Demonstration projects were removed from this analysis, since many of them had unexplainably high costs.

Current Installations in Alaska

Deployment of energy storage systems (ESS) is still nascent in Alaska, with a few exceptions. Thus, the dataset provided in the Alaska Energy Authority Renewable Energy Fund applications has been supplemented by data from the Department of Energy Global Energy Storage Database, which captures installations worldwide by data from Sandia National Laboratory's energy storage reports (several editions) and by data collected by the Alaska Center for Energy and Power through personal communication with energy storage developers, and utilities.

Key Performance Metrics

Energy storage is hard to quantify in terms of performance, cost, and economic value. Costs and performance in the overall energy storage market have been evolving sporadically, and it is not easy to discern any clear trend. The most significant trend in the data considered here is the increased variance in costs with time. Thus, there are now more options for energy storage systems with "low cost per kW"/"high costs per kWh" and vice versa, indicating a greater variety of specialized energy storage systems for targeted applications.

It is often still difficult to justify energy storage economically based on fuel savings alone. There remains significant work in quantifying other possible cost savings afforded by energy storage, such as reduced fuel consumption and stress on a diesel generator by smoothing out the load.

The data analyzed for this briefing paper do not show any difference in the cost of energy storage in Alaska compared with the rest of the nation or globally. Alaska has had relatively few energy storage technology failures. Most of the failures have been due to improper operation.

Technology Trends

Material advances, especially in nanotechnology, have been significant recently in the development of energy storage systems: low-cost, long-life electrodes and membranes for flow batteries, flywheel designs, and increased surface area supercapacitors and superconducting materials. New chemistries are also a focus of research with regard to different oxidation-reduction reactions and electrolyte solutions for lower costs, higher performance, higher safety, and longer life for batteries and flow batteries. Inverters and converters have been improving in performance and decreasing in price, with improving power electronics and new topologies. The electric vehicle market is a major driver of energy storage system development, resulting in home and grid-connected battery development.

Technology-Specific Gaps and Barriers to Successful Project Development and Operation

Lack of standardization and quantification of costs and benefits is the main barrier to determining the economic potential for implementation of energy storage in Alaska. In addition, communities in Alaska often wish to avoid energy storage systems that use hazardous materials, since they will eventually have to deal with disposal issues.

Recommendations

Energy efficiency grants could be leveraged for energy storage systems. The development of standardized use case scenarios for the operation of energy storage systems would maximize their economic benefits in Alaska. These scenarios would ideally include quantification of economic savings, performance specifications for energy storage systems manufacturers, and calculation of comparison metrics based on performance specifications. Guidance documents would be extremely helpful with regard to information on need, required specifications, and selection procedures for energy storage systems. These documents should include information on how to protect an investment from technical failures by agreeing on performance and lifetime guarantees as well as responsibility for failure.

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Deployment of energy storage systems (ESS) is still nascent in Alaska, with a few exceptions. Thus, the dataset provided in the Alaska Energy Authority Renewable Energy Fund (REF) applications has been supplemented with data from the U.S. Department of Energy (DOE) Global Energy Storage Database. The DOE database captures installations worldwide by data from Sandia National Laboratory's energy storage reports (several editions) and by data collected by the Alaska Center for Energy and Power through personal communication with energy storage developers and utilities. Data sources are detailed in Appendix B.

Lead-acid, advanced lead-acid (Xtreme Power), lithium-ion, flow (vanadium redox and zinc-bromine), nickel-based (nickel cadmium) batteries, flywheels, compressed air, and closed-loop pumped hydro and open-loop pumped hydro energy storage are the technologies represented by the available data. Demonstration projects were removed from this paper, since many of them had unexplainably high costs.

Note that none of the flow battery projects reported in this paper is currently operational, including the vanadium redox flow battery that Kotzebue had received a quote on from VRB before the company went out of business, the zinc-bromine flow battery purchased by Kotzebue from Premium Power, which was decommissioned, and two other batteries that are contracted/under construction. It is not certain, therefore, that the prices presented here accurately reflect the cost of functioning systems.

All costs have been converted to 2015 dollars based on the Consumer Price Index (CPI) (U.S. Bureau of Labor Statistics, 2016).

Capital Costs by Power and Energy Capacity

Energy storage systems generally consist of the actual storage device (e.g., a battery or flywheel), which defines the energy capacity and theoretical maximum power available, and power conversion systems, which determine the actual maximum power available for both charging and discharging. As the two systems—storage device and power conversion system—are separate units selected depending on a particular application, it makes sense to examine the capital cost of systems in relation to both the energy storage capacity and the power capacity, referred to in this paper as the Capacity and Power of an ESS.

Figure 1 and Figure 2 show the cost per capacity ($/kWh) and rated power ($/kW) plotted against capacity and rated power for global and Alaska projects. There is wide variation and no obvious trends in CAPEX/capacity and CAPEX/power with respect to capacity and power, both overall and within particular technologies.

The wide variation can be partly explained by different amounts of infrastructure included in CAPEX. For example, one project simply involved replacing the batteries in an existing installation, while other projects required varying amounts of infrastructure such as a building and interconnection. For most of the data, cost breakdowns were not given, and it was not always clear what was included in CAPEX. All costs from REF applications for projects in Alaska (labeled AK on the plots) include transport, hardware, and installation.

The variation can also be partly explained by the ratio of capacity to rated power (or the duration in hours). CAPEX/power tends to be higher for energy storage systems with a longer duration, while CAPEX/capacity tends to be lower. The plots of CAPEX/capacity and CAPEX/power versus duration can be seen in Figures A1 to A4 in Appendix A.

The costs presented in Figure 1 and Figure 2 are best understood in the context of what each data point represents. A short description of the different projects represented in these figures is given in Appendix B and helps explain the variation seen in costs.

Note that the cost data on flow batteries are for installations that are not currently operational.

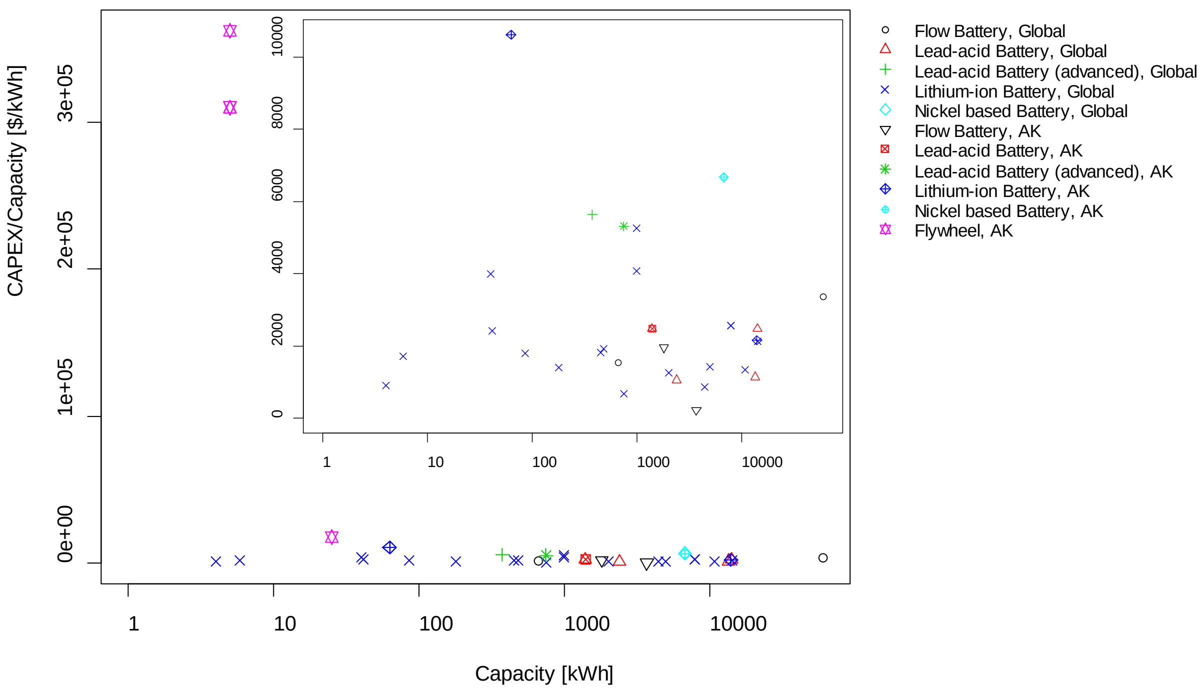

Figure 1. The plot of CAPEX/capacity versus capacity for non-hydro energy storage. The inset shows a scaled view of the *y*-axis for easier viewing of lower CAPEX/capacity values. Data are shown for both global and Alaska installations. Flywheels tend to be more expensive per capacity (kWh) than other forms of energy storage; they tend to be cheaper per rated power (see Figure 2).

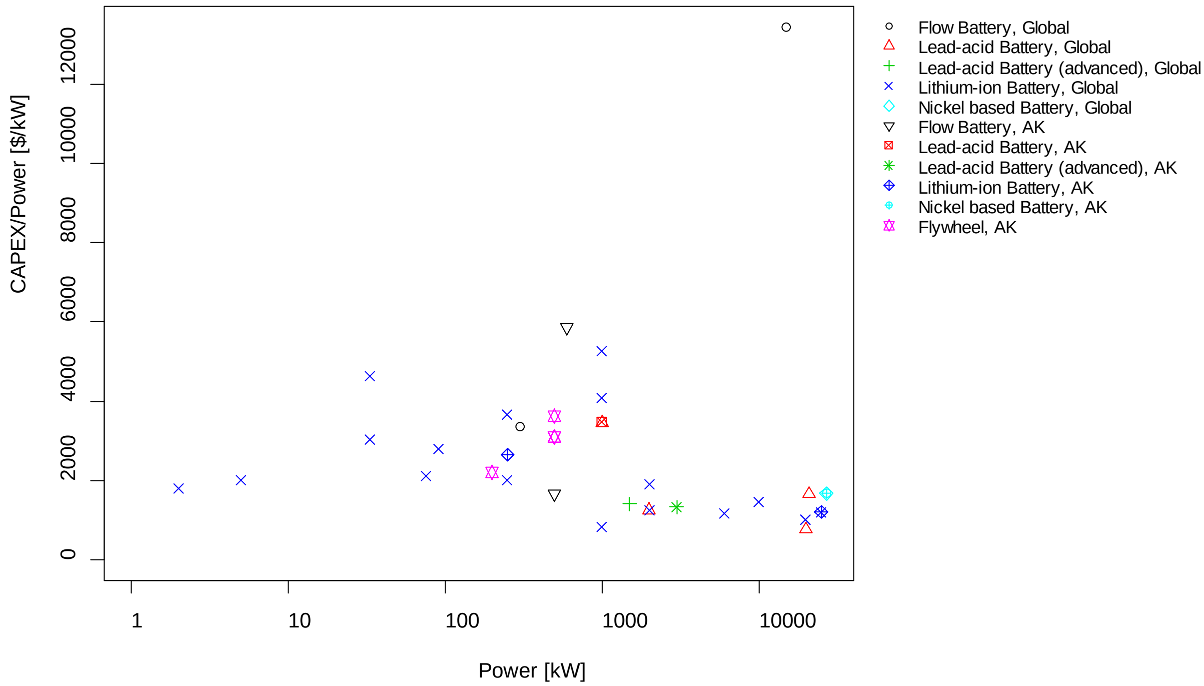

Figure 2. The plot of CAPEX/power versus power for non-hydro energy storage. Data are shown for both global and Alaska installations.

Table 1 shows mean values of CAPEX/power and CAPEX/capacity for global and Alaska data. Similar to Figures 1 and 2, these values are best understood in the context of the projects they represent. See Appendix B for an overview of the different projects.

Table 1. Mean CAPEX/power and CAPEX/capacity for global and Alaska data.

	Global		Alaska	
Technology	**Mean CAPEX/Power ($/kW)**	**Mean CAPEX/Capacity ($/kWh)**	**Mean CAPEX/Power ($/kW)**	**Mean CAPEX/Capacity ($/kWh)**
Flow Battery	8,401	2,444	3,758	1,089
Lead-Acid Battery	1,785	1,785	3,472	2,480
Lead-Acid Battery (advanced)	1,408	5,634	1,328	5,311

Lithium-Ion Battery	2,292	2,115	2,172	7,797
Nickel-Based Battery	1,668	6,674	979	2,650
Closed Loop Pumped Hydro	1,438	141		
Open Loop Pumped Hydro	995	77		
CAES	1,120	80		
Flywheel			3,026	261,978

Operations and Maintenance ($/kW)

Data for global and Alaska operations and maintenance (O&M) costs were minimal. The 2003 Sandia report (Schoenung and Hassanzahl, 2003) gives the estimates shown in Table 2. The O&M values given for flow batteries are low, based on the experience and knowledge of the authors.

Table 2:. O&M costs for different energy storage technologies, from Sandia's 2003 report (Schoenung and Hassanzahl, 2003); O&M is reported in $/kW*yr

Name	**O&M ($/[kW*yr])**
Lead-Acid Battery (flooded cell)	19.5
Lead-Acid Battery (advanced)	6.5
Lithium-Ion Battery	32.5
Nickel Cadmium Battery	32.5
Zinc Bromine Flow Battery	26
Vanadium Redox Flow Battery	26
Flywheels (high speed)	6.5
Compressed Air Energy Storage (surface)	13
Pumped Hydro	3.25

Note: Costs have been increased by 30% to update them to 2015 dollars based on the CPI.
For power generation, O&M would be reported in $/kWh. However, the costs for power generation are not as straightforward as the costs for energy storage, as O&M is influenced by more variables.

Expected Life and Efficiency

The energy efficiency and expected number of cycles before replacement/overhaul, from a 2011 Sandia report (Schoenung, 2011), are shown in Table 3. Electro-mechanical systems, like pumped hydro and flywheels, typically can be overhauled at minimal cost, while electrochemical systems typically need to be replaced. The replacement period in years is used for levelized cost of energy (LCOE) and levelized cost per cycle power (LCCP) calculations and corresponds with the end of the cycle life. The performance metrics listed for Flow Batteries are much higher than what the authors have experienced or are aware of in actual installations.

Table 3. Performance characteristics of ESS technologies (Schoenung, 2011; Schoenung and Hassanzahl, 2003; Divya and Ostergaard, 2009; Butler et al., 2000; Viswanathan et al., 2013).

Technology	Round Trip Efficiency %	Depth of Discharge %	Cycle Life	Replacement Period (yr)
Lead-Acid Battery (flooded cell)	75	50	2000	6
Lead-Acid Battery (advanced)	80	50	2000	6
Lithium-Ion Battery	85	80	4000	10
Nickel Cadmium Battery	65	100	3000	10
Zinc Bromine Flow Battery	70	100	3000	8
Vanadium Redox Flow Battery	65	100	5000	10
Flywheels (high speed)	95	100	25000	20
Compressed Air Energy Storage (surface)	70	100	25000	30
Pumped Hydro	85	100	25000	30

Capacity Factor

The capacity factor for energy storage technology is not applicable.

Diesel Offset

General uses for energy storage systems are peak shifting (charging during low load/high generation events and discharging during high load/low generation events), power quality support (balancing high ramp rates in the load or renewable generation), and supplying spinning reserve capacity (SRC; this allows smaller generators or no diesel generators to run online). Peak shifting generally saves diesel by increasing the utilization of renewable energy. Providing power quality support reduces stress on diesel generators, which increases their lifespan and efficiency. Providing SRC saves diesel by allowing a smaller or no diesel generator to run online, enabling a much higher use of renewable energy.

Schaede et al. (2015) give an example of the possible diesel savings with energy storage. They modelled Nome's grid with 959 kW/58 kWh flywheel energy storage supplying SRC. Nome's grid has an average load of 4 MW and 2.7 MW of installed wind power capacity. The flywheels supplied SRC (as well as load leveling), which allowed smaller diesels to run online and let wind power supply a higher fraction of the load when wind power was available, reducing diesel consumption. The energy storage reduced diesel consumption by 850 gal/week during periods with high levels of wind power, and by 450 gal/week during periods with low levels of wind power.

Cost per kWh

For energy storage, the levelized cost of energy (LCOE) is defined as the levelized cost of storing energy ($/kWh stored). However, this metric does not give the whole picture, since it does not take into account the power at which energy storage is able to charge and discharge. A second metric called levelized cost per cycle power (LCCP) is used for this. The LCCP, which provides levelized cost per cycle per kW ($/[cycle*kW]), does not take into account the duration of the discharge (charge) and is more relevant for applications, such as power quality, that need high power and not necessarily long duration.

The equations for LCOE and LCCP are in Appendix C. Both LCOE and LCCP were calculated assuming an inflation rate of 2%, interest rate of 5%, and typical depth of discharge (DOD), cycle life, year life, and efficiency from Table 3. These values can vary widely depending on the system and how it is operated. Different energy storage technologies have different replacement costs, which would affect LCOE and LCCP but are not considered here. Figure 3 and Figure 4 give a more detailed analysis on the cost of different ESS technologies and show the LCOE and LCCP for global and Alaska energy storage system installations. The mean values of LCOE and LCCP for global and Alaska data are shown in Table 4. Certain technologies have a lower LCOE, while others have a lower LCCP, indicating their feasibility for high energy or high power applications. Again, these values are best understood in the context of the projects they are representing, described in Appendix B. Note that the values for flow batteries have been calculated with cost data from non-operational projects and performance data from literature that seems high based on the authors' experience. Thus, these values may offer overly optimistic figures.

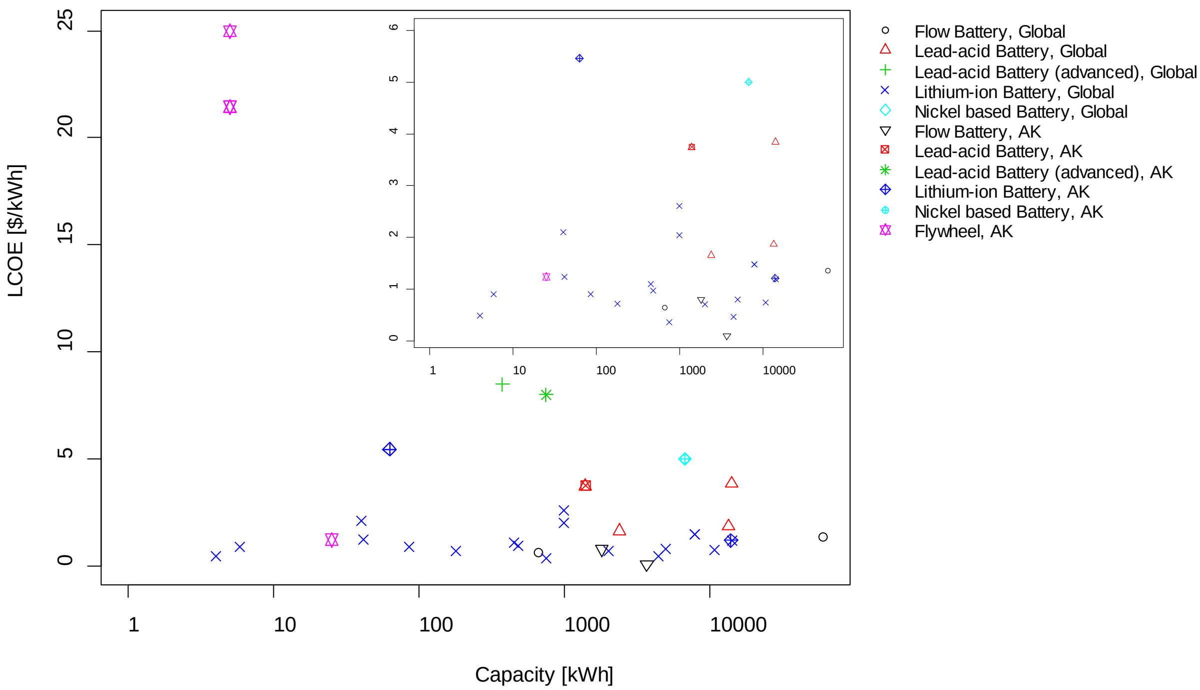

Figure 3. LCOE for energy storage applications. The inset shows a scaled view of the *y*-axis for easier viewing of lower LCOE values. LCOE values for energy storage only show the energy throughput of the storage device and not the increase in energy production from cheaper sources, such as renewable energy, that it enables. The LCOE and LCCP of energy storage must be understood in terms of how they affect cost of energy in the entire system. Certain technologies have a lower LCOE, while others have a lower LCCP, indicating their feasibility for high energy or high power applications. Note that the values for flow batteries have been calculated with cost data from non-operational projects and performance data from literature that seems high based on the authors' experience. Thus, these values may offer overly optimistic figures.

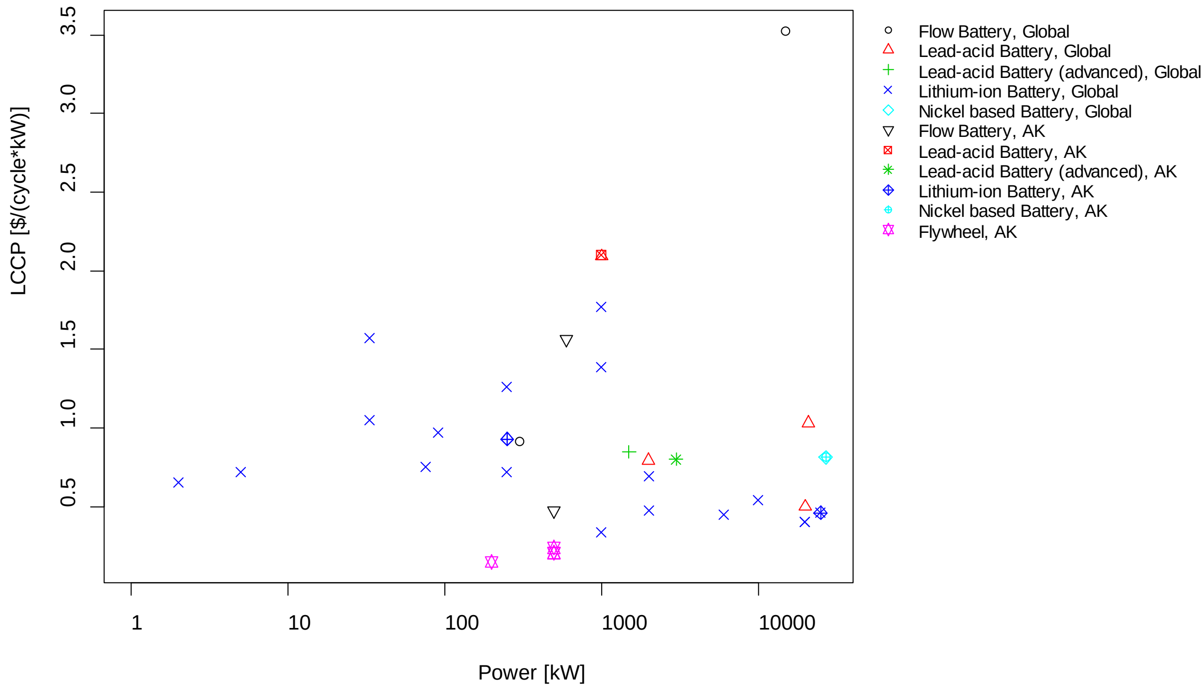

Figure 4. LCCP for energy storage applications. Certain technologies have a lower LCOE, while others have a lower LCCP, indicating their feasibility for high energy or high power applications. Again, these values are best understood in the context of the projects they are representing, described in Appendix B. Note that the values for flow batteries have been calculated with cost data from non-operational projects and performance data from literature that seems high based on the authors' experience. Thus, these values may offer overly optimistic figures.

Table 4. Mean LCOE and LCCP for global and Alaska data. Note that all data used in this paper for flow batteries are from systems that are not currently operational.

	Global		Alaska	
Technology	**Mean LCOE ($/kWh)**	**Mean LCCP ($/[cycle*kW])**	**Mean LCOE ($/kWh)**	**Mean LCCP ($/[cycle*kW])**
Flow Battery	1.0	2.2	0.45	1.0
Lead-Acid Battery	2.8	1.1	3.8	2.1
Lead-Acid Battery (advanced)	8.5	0.85	8.0	0.80
Lithium-Ion Battery	1.1	0.81	4.0	0.77
Nickel-based Battery	5.0	0.81	5.0	0.81

Closed Loop Pumped Hydro	0.013	0.12		
Open Loop Pumped Hydro	0.0075	0.081		
CAES	0.010	0.10		
Flywheel			18	0.20

Conditions for Greatest Efficiency

The efficiencies of energy storage systems are largely influenced by the technology type (see Expected Life and Efficiency section) and usage. There are three main forms of energy loss: charge/discharge (losses in energy storage medium and power electronics), storage (self-discharge), and parasitic losses due to balance of plant (e.g., cooling systems). An inefficiency is always associated with converting electrical energy into chemical or mechanical energy. Between technologies, levels of self-discharge vary, which results in losses during storage, with more losses the longer the storage. Other factors such as temperature can play a significant role as well. Thus, the conditions for greatest efficiency are technology-dependent.

Cost Curve over Time

The U.S. DOE, together with industry, has developed the near-term (present–2018) goals of under $250 per kWh of installed capacity for storage technologies and under $1750 per kW of rated power for power conditioning technologies. Their long-term (2018–2023) goals are under $150/kWh for storage systems and under $1250/kW for power conditioning technologies (U.S. DOE, 2013). These numbers need to be converted into CAPEX for the entire energy storage system and divided by capacity and power for comparison with the costs of the energy storage systems presented in this paper. The total energy storage system costs (CAPEX) presented in this paper average $591/kW, $6.6/kWh higher than the short-term goal (2018) and an average of $1213/kW and $860/kWh higher than the long-term goal (2023).

Installed Costs by Major Components

Sandia's reports include energy storage system costs by technology (Schoenung and Hassanzahl, 2003; Schoenung, 2011). The authors split the costs into the power conditioning system, listed in $/kW, and the energy storage system, listed in $/kWh. The costs, updated to 2015 dollars, are shown in Table 5. Sandia's cost estimates have been converted to total CAPEX/capacity and CAPEX/power using the average duration of the different technologies. These costs have then been compared with the global and Alaska data. The difference between Sandia's calculated costs and costs from the data is shown in Table 5. The data show on average significantly higher costs except for pumped hydro storage, which is cheaper than Sandia's costs.

Table 5. Comparison of Sandia cost estimates with costs from Global and Alaska data (2015 dollars) shows on average significantly higher costs for Alaska.

	Sandia		Global and Alaska	Calculated from Sandia		Global		Alaska	
Tech1	**Power Conditioning Cost ($/kW)**	**Energy Storage Cost ($/kWh)**	**Mean Duration (hr)**	**Mean CAPEX/ Power ($/kW)**	**Mean CAPEX/ Capacity ($/kWh)**	**CAPEX/ Power Difference ($/kW)**	**CAPEX/ Capacity Difference ($/kWh)**	**CAPEX/ Power Difference ($/kW)**	**CAPEX/ Capacity Difference ($/kWh)**
Flow Battery	420	525	4.2	2625	625	5776	1819	1133	464
Lead-Acid Battery	420	346.5	1	766.5	766.5	1018.5	1018.5	2705.5	1713.5
Lead-Acid Battery (advanced)	420	346.5	0.25	506.625	2026.5	901.375	3607.5	821.375	3284.5
Lithium-Ion Battery	420	630	1.2	1176	980	1116	1135	996	6817
Nickel-based Battery	292.5	780	0.31	534.3	1723.548	1133.7	4950.452	444.7	926.4516
Closed-Loop Pumped Hydro Storage	1260	78.75	10	2047.5	204.75	-609.5	-63.75		
Open-Loop Pumped Hydro Storage	1260	78.75	13	2283.75	175.6731	-1288.75	-98.6731		
Compressed Air Storage	735	5.25	18	829.5	46.08333	290.5	33.91667		
Flywheel	630	1680	0.033	685.44	20770.91			2340.56	241207.1

Transportation

Only one data entry had an estimate for transportation costs: Kotzebue budgeted $40,000 for the transport of a vanadium redox flow battery from VRB (the project did not go through). Transportation costs are highly dependent on the weight, size, and shipping restrictions of the energy storage unit as well as the distance and available means of transportation to the end destination.

Technology Trends

Materials advances, especially in nanotechnology, have been significant recently in the development of ESS systems: low-cost, long-life electrodes and membranes for flow batteries, flywheel design, increased surface area supercapacitors, and superconducting materials. New chemistries are also the focus of research: different ox-redox equations and electrolyte solutions for lower cost, higher performance, higher safety, and longer life for batteries and flow batteries. Inverters and converters have been improving in performance and decreasing in price with improving power electronics and new topologies. System design is a major part of bringing a technology out of the lab and into a product that is easy to use and maintain in the field. The electric vehicle market is a major driver of energy storage systems development, resulting in home and grid-connected batteries.

Tech-Specific Storage Systems (i.e., ultra-capacitors with wind)

Tech-specific storage systems are not applicable to energy storage technology.

Refurbishment/Upgrade Market

For electro-mechanical energy storage systems such as pumped hydro and flywheels, refurbishment is often a cost-effective way to extend the life of the system. An example of a growing refurbishment market is old electric vehicle (EV) batteries. After the battery drops to 70–80% of its initial capacity, it becomes insufficient for automotive use. However, the battery is still useful for stationary energy storage. Nissan is the first EV manufacturer to launch a startup—Green Charge Networks—which resells old Nissan Leaf batteries as part of stationary storage systems (Neubauer and Pesaran, 2010; St. John, 2015).

Realized Cost Savings

Cost savings from integrating renewable power are difficult to gauge due to technical and incentive impacts at the entire power systems level. At the technical level, for example, effects of diminished losses of secondary services such as recovered waste heat and reductions in fuel efficiency are hard to gauge, as they depend not only on average reductions in load, but also on specific operating schemes regarding minimum allowable load on diesels and the spinning reserve kept.

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Appendix A

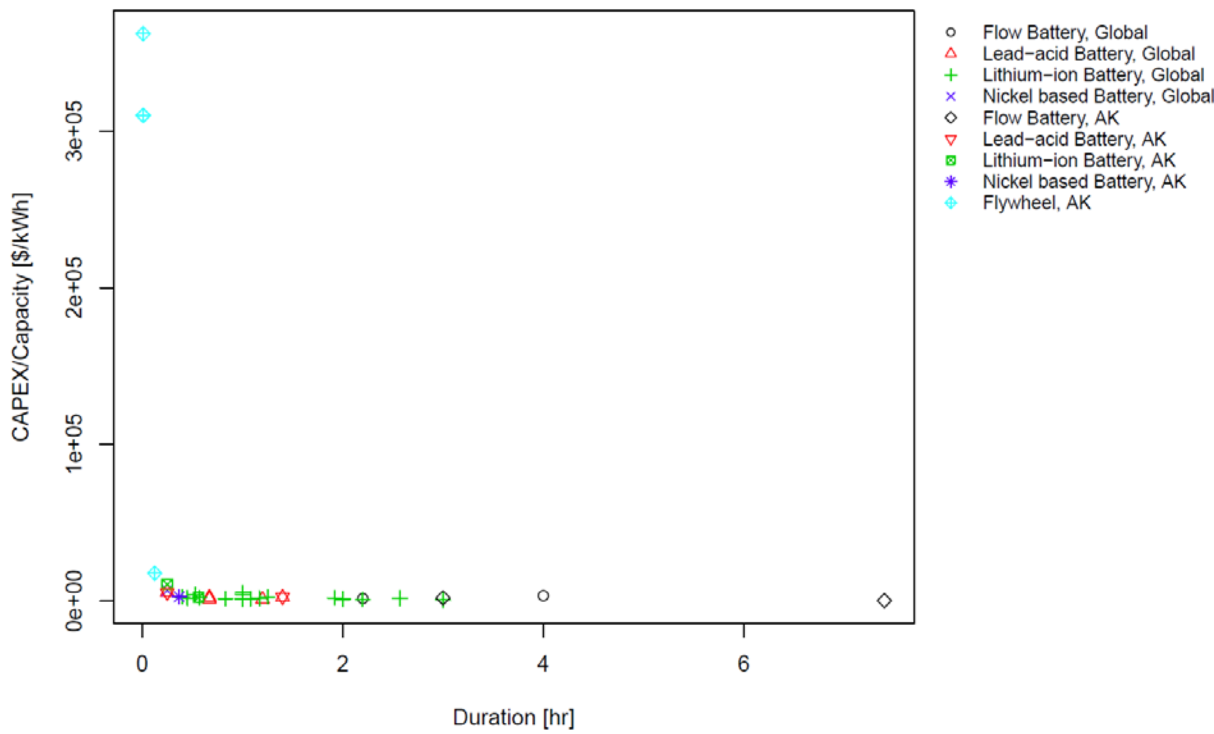

Figure A1: Plot of CAPEX/capacity versus duration. The high cost per capacity of flywheels and high duration of flow batteries make this plot hard to read.

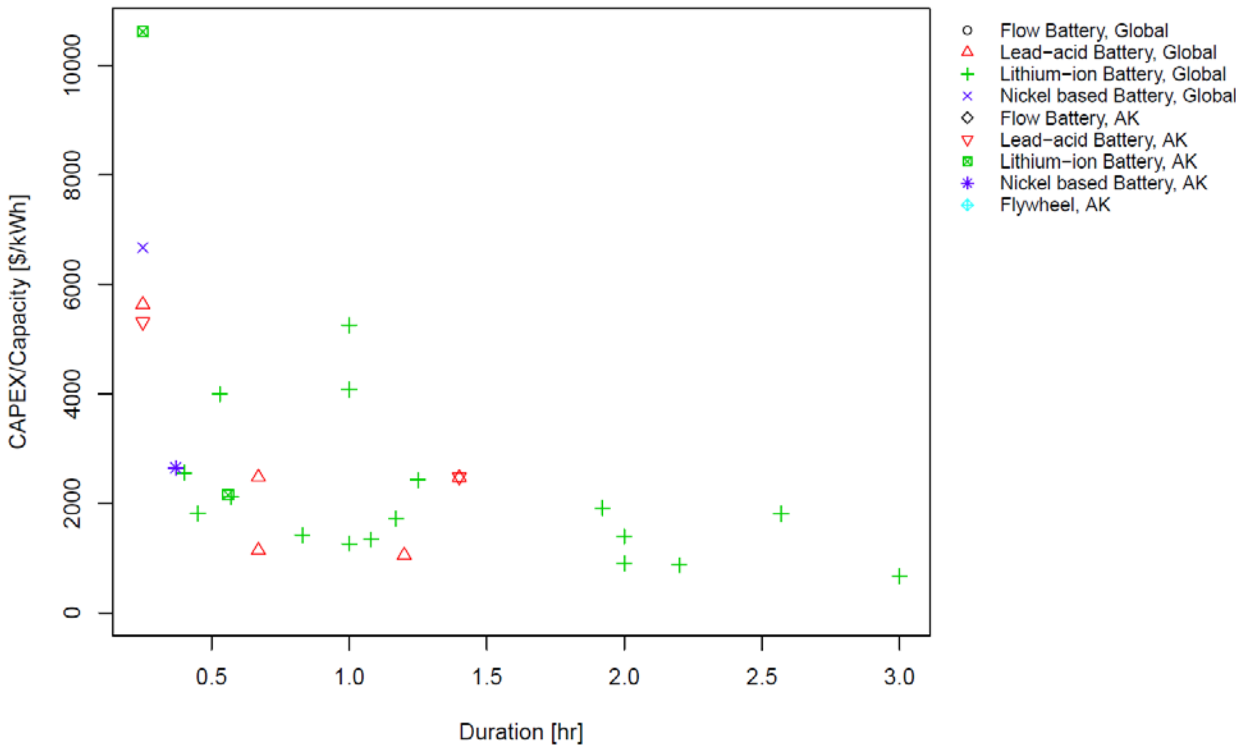

Figure A2: Plot of CAPEX/capacity versus duration with flywheels and flow batteries removed.

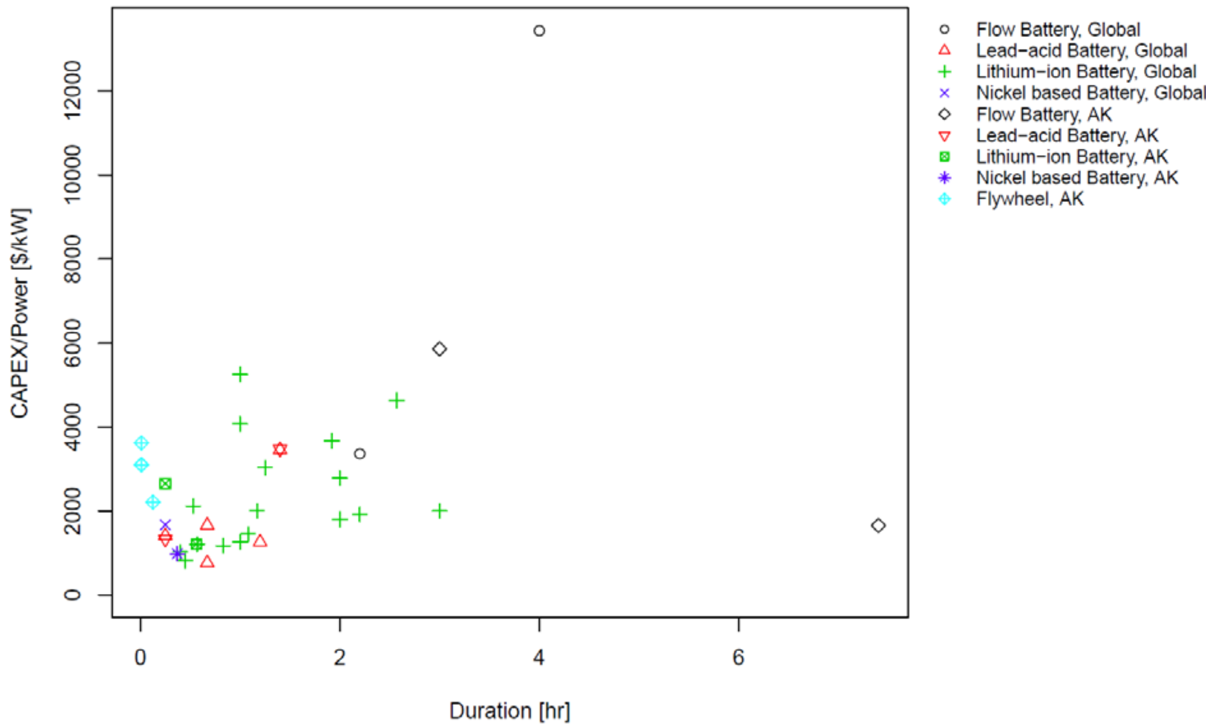

Figure A3: Plot of CAPEX/power versus duration. The high duration of flow batteries make this plot hard to read.

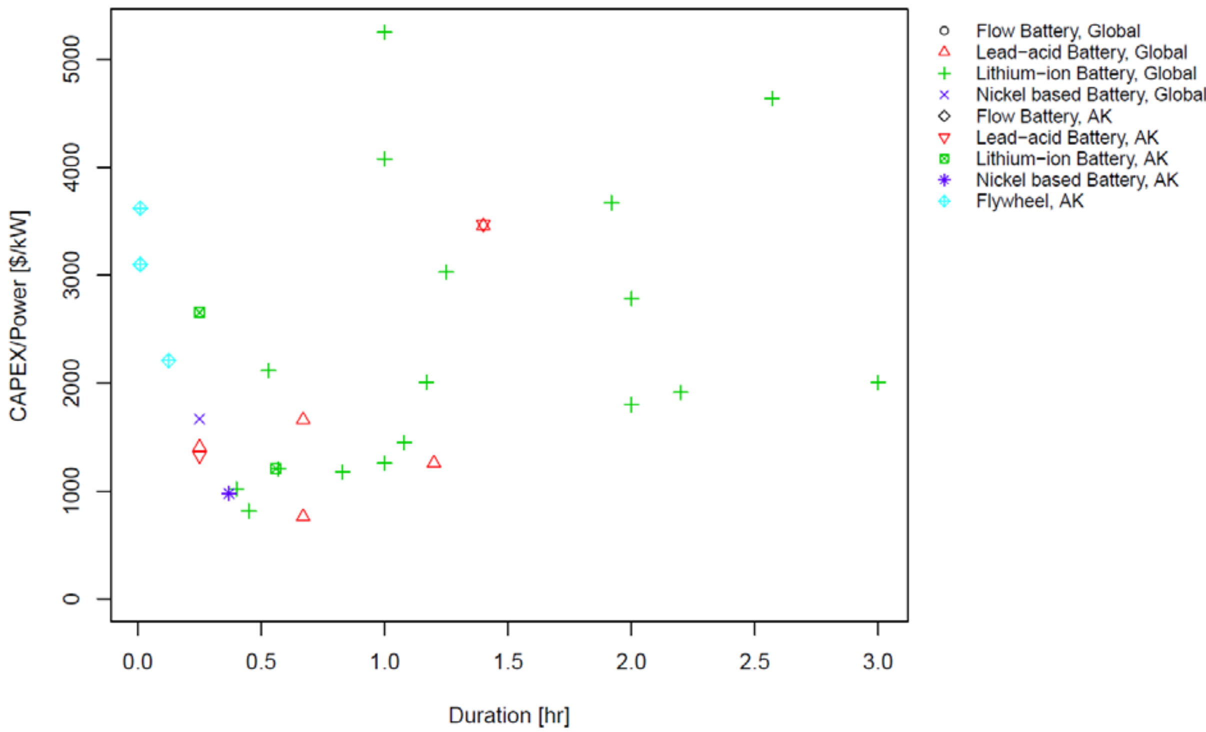

Figure A4: Plot of CAPEX/power versus duration with flow batteries removed.

Appendix B

Tables B1 to B5 list the energy storage projects studied in this paper and where they are sourced. *REF* refers to the Renewable Energy Fund, *DOE* refers to the DOE global energy storage database, *EETF* refers to the emerging energy technology fund, *ACEP* refers to the Alaska Center for Energy and Power, and *ARTEC* refers to Alaska Railbelt Cooperative Transmission & Electrical Company.

Table B1: Lithium-ion Battery

Project Name	Source	Date	State	Country	Power [kW]	Capacity [kWh]	CAPEX/Power [$/kW]	CAPEX/Capacity [$/kWh]	Notes
NICE GRID project in Carros (Southern France): Primary Substation Battery (PSB)	DOE	7/31/2013	Provence-Alpes-Côte dAzur	France	1000	450	817.62	1816.93	There are 3 'NICE GRID' data points, consistent CAPEX/capacity with varying CAPEX/Power.
Jake Energy Storage Center: RES Americas	DOE	2/25/2015	Illinois	United States	19800	7920	1022.66	2556.66	Relatively low CAPEX/Power and high CAPEX/Capacity.
Elwood Energy Storage Center: RES Americas	DOE	2/25/2015	Illinois	United States	19800	7920	1022.66	2556.66	Relatively low CAPEX/Power and high CAPEX/Capacity.
KIUC Anahola Solar Array and Battery	DOE	12/29/2014	Hawaii	United States	6000	4980	1175.69	1416.49	
Anchorage Area Battery Energy Storage System	DOE and ARTEC	1/1/2016	Alaska	United States	25000	14250	1208.00	2119.30	Data is from ARCTEC '2013 Railbelt Energy Priorities'.
Stafford Hill Solar Farm & Microgrid: Lithium Ion	DOE	12/18/2014	Vermont	United States	2000	2000	1259.67	1259.67	
10 MW / 10 MWh - Feldheim Regional Regulating Power Station (RRKW)	DOE	2/14/2015	Brandenburg	Germany	10000	10800	1447.78	1340.54	
5kWh LiFePO4 DIY ESS	DOE	11/3/2012	Ile de France	France	2	4	1802.30	901.15	
2 MW/ 4.4 MWh Puget Sound Energy - Glacier WA	DOE	12/17/2014	Washington	United States	2000	4400	1914.69	870.31	
Oncor Battery Storage	DOE	6/23/2014	Texas	United States	250	750	2006.43	668.81	

JuiceBox Residential solar energy storage - AC-coupled peak-shifting and backup	DOE	5/10/2015	California	United States	5	5.85	2009.11	1717.19	
Landing Mall DR	DOE	5/21/2011	Washing-ton	United States	75	39.75	2117.78	3995.80	Remotely controlled by Utility for demand response.
Tuntutuliak	REF	1/1/2011	Alaska	United States	250	62.5	2654.00	10,617	Tuntutuliak and Kwigillingok are identical REF applications. Both were declined funding due to control and integration issues. Kwigillingok ended up installing Chevy-volt batteries with ABB PCS-100 inverter, same specs and price. The very high CAPEX/Capacity is likely partly due to very low Duration.
Kwigillingok	REF	1/1/2011	Alaska	United States	250	62.5	2654.00	10,617	
90 kW / 180 kWh Santa Cruz County Building GCN	DOE	9/28/2015	California	United States	90	180	2784.15	1392.08	
ZECO Energy	DOE	#N/A	Victoria	Australia	33	41.25	3030.30	2424.24	This installation is off-grid, which is likely the cause for the relatively high cost.

Energy Storage Technology Report

NICE GRID project in Carros (Southern France): Secondary Substation Battery (SSB)	DOE	8/24/2013	Provence-Alpes-Côte dAzur	France	250	480	3672.46	1912.74	There are 3 'NICE GRID' data points, consistent CAPEX/capacity with varying CAPEX/Power.
Fort Hunter Liggett Battery Storage Project	DOE	10/1/2013	California	United States	1000	1000	4074.23	4074.23	This installation is on a military base. Perhaps higher building standards result in high cost.
NICE GRID project in Carros (Southern France): Low Voltage Grid Batteries (LVGB)	DOE	8/23/2013	Provence-Alpes-Côte dAzur	France	33	84.81	4636.94	1804.26	There are 3 'NICE GRID' data points, consistent CAPEX/capacity with varying CAPEX/Power.
UBC Electrochemical Energy Storage Project	DOE	11/6/2012	British Columbia	Canada	1000	1000	5252.40	5252.40	This was installed on a university campus and intended for research as well as grid support, which possibly led to high costs.

Table B2: Lead-acid Battery									
Project Name	**Source**	**Date**	**State**	**Country**	**Power [kW]**	**Capacity [kWh]**	**CAPEX/Power [$/kW]**	**CAPEX/Capacity [$/kWh]**	**Notes**
PREPA BESS 2	DOE	4/21/2002	Puerto Rico	United States	20000	13400	763.6019	1139.704	This is the cost of replacing the existing installation 'PREPA BESS 1'. Having existing infrastructure results in the lowest CAPEX/Power.
Stafford Hill Solar Farm & Microgrid: Lead Acid	DOE	12/18/2014	Vermont	United States	2000	2400	1259.665	1049.721	
Kodiak-Pillar Mountain	REF	1/1/2012	Alaska	United States	3000	750	1327.818	5311.273	This is an 'advanced' lead acid battery, which results in a higher CAPEX/capacity.
KIUC Koloa - Xtreme Power DPR	DOE	7/15/2011	Hawaii	United States	1500	375	1408.405	5633.622	This is an 'advanced' lead acid battery, which results in a higher CAPEX/capacity.
PREPA BESS 1	DOE	2/10/1992	Puerto Rico	United States	21000	14070	1660.707	2478.667	The higher cost is likely due to the early installation date.

Metlakatla BESS	DOE	2/3/1997	Alaska	United States	1000	1400	3459.063	2470.759	The higher cost is likely due to the early installation date as well as being installed in a remote microgrid.

Table B3: Flow Battery

Project Name	Source	Date	State	Country	Power [kW]	Capacity [kWh]	CAPEX/ [$/kW]	CAPEX/ Capacity [$/kWh]	Notes
Kotzebue Premium Power	REF	1/1/2010	Alaska	Unite States of America	500	3700	1655.345	223.6953	The cost of purchasing, transporting, and installing a Zinc-Bromine Flow Battery from Premium Power. It did not perform to required specs and was decommissioned.
RedFlow 300 kW Adelaide	DOE	4/17/2015	South Australia	Australia	300	660	3363.406	1528.821	The cost of purchasing and transporting a Zinc-Bromine Flow Battery from RedFlow. Under construction.

Kotzebue VRB	REF	1/1/2008	Alaska	Unite States of America	600	1800	5860.927	1953.642	The price quoted to Kotzebue for a Vanadium Redox Flow Battery before VRB went out of business.
Minami Hayakita Substation Vanadium Redox Flow Battery	DOE	4/17/2014	Hokkaido	Japan	15000	60000	13438.93	3359.733	Project cost of installing Vanadium Redox Flow Batteries. These costs are much higher possibly due to higher infrastructure costs. Contracted/under construction.

Table B4: Flywheel

Project Name	Source	Date	State	Country	Power [kW]	Capacity [kWh]	CAPEX/ Power [$/kW]	CAPEX/C apacity [$/kWh]	Notes
Chugach FESS	EETF	5/26/2015	Alaska	United States of America	200	25	2210	17680	The installed cost of Flywheel energy storage for Chugach's announced project.
Kwigillingok FESS	REF	1/1/2010	Alaska	United States of America	500	5	3100	310010	Kwigillingok, Tuntutuliak and Kongiganak

Tuntutuliak FESS	REF	1/1/2010	Alaska	United States of America	500	5	3100	310010	submitteds identical REF applications which were not funded. Kipnuk also was not granted funding through REF. Kwigillingok installed Lithium-ion Batteries instead. The high CAPEX/Capacity is due to the low Capacity.
Kongiganak FESS	REF	1/1/2010	Alaska	United States of America	500	5	3100	310010	
Kipnuk high penetration	REF	1/1/2010	Alaska	United States of America	500	5	3622	362183	

Table B5: Pumped Storage and Compressed Air Energy Storage

Project Name	Source	Date	State	Country	Power [MW]	Capacity [MWh]	CAPEX/ Power [$/kW]	CAPEX/C apacity [$/kWh]	Notes
Yards Creek Pumped Storage	DOE	#N/A	New Jersey	United States	400	2400	38	6	Open-loop Pumped Hydro
Blenheim-Gilboa Pumped Storage Power Project	DOE	7/1/1973	New York	United States	1160	17400	659	44	Open-loop Pumped Hydro
Northfield Mountain Pumped Storage Hydroelectricity Facility	DOE	12/31/1969	Massachuse tts	United States	1119	8482	790	104	Open-loop Pumped Hydro
Raccoon Mountain Pumped Storage Plant	DOE	1/1/1974	Tennessee	United States	1652	36344	934	42	Open-loop Pumped Hydro
Silver Creek Pumped Storage Project	DOE	5/15/2012	Pennsylvani a	United States	300	2400	1041	130	Closed-loop Pumped Hydro

McIntosh CAES Plant	DOE	1/1/1991	Alabama	United States	110	2860	1048	40	Compressed Air Energy Storage
Pacific Gas and Electric Company Advanced Underground Compressed Air Energy Storage	DOE	1/1/2015	California	United States	300	3000	1192	119	Compressed Air Energy Storage
Bath County Pumped Storage Station	DOE	1/12/1985	Virginia	United States	3003	30930.9	1200	117	Open-loop Pumped Hydro
Lake Elsinore Advanced Pumped Storage	DOE	8/6/2007	California	United States	500	6000	1835	153	Closed-loop Pumped Hydro
Ingula Pumped Storage Scheme	DOE	11/1/2007	Kwa-Zulu Natal	South Africa	1332	21312	2350	147	Open-loop Pumped Hydro Open-loop Pumped Hydro

Appendix C

Equations for LCOE:

$$LCOE = \frac{NPV_c \cdot CRF}{Annual\ Energy\ Stored}$$

$$NPV_c = CAPEX + \sum_{j=1}^{N} \left(\frac{1+i}{1+r}\right)^j \cdot OM$$

$$CRF = \frac{r}{1-(1+r)^{-N}}$$

$$Annual\ Energy\ Stored = \frac{Cap \cdot DOD \cdot \eta \cdot Cycles}{Years}$$

Where $NPVc$ is the net present value of the annual cost of the system, CRF is the capitol recovery factor (the ratio of a constant annual cost to the present value of that cost), $CAPEX$ is the capital expenditure, i is the inflation rate, r is the interest rate, N is the system lifetime in years, Cap is the capacity of the installation, DOD is the depth of discharge, η is the efficiency, $Cycles$ is the number of cycles the system is rated for and $Years$ is the number of years the system is rated for.

Equations for LCCP:

$$LCCP = \frac{NPV_c \cdot CRF}{Cycles \cdot Power / Years}$$

Where $Power$ is the rated power of the energy storage system.

Heat Pump Technology Report

Summary

Prepared by the Alaska Center for Energy and Power for the Alaska Affordable Energy Strategy Effort with funding from the Alaska Energy Authority

Resource and Technology Description

Heat pumps are space conditioning appliances that can provide both heating and cooling of indoor areas by moving heat using a refrigeration cycle. These heat pumps draw heat from a variety of sources including air, ground, and seawater.

Heat pumps take advantage of the phase change properties of a refrigerant to transport heat between spaces. When used for cooling, heat pumps extract heat from the indoors and pump it outside. In heating mode, heat pumps extract heat from the outdoors and pump it inside. Heat pumps do not use resistance electric heaters, but rather use electricity to power fans, pumps, and compressors, which run the refrigeration cycle to transfer heat. The ratio of the amount of electrical energy used to power the process, to the amount of heat transported is known as the coefficient of performance, which in the right conditions can be well over 3, indicating that for every 1 unit of electrical energy input, 3 units of heat energy are transported.

The performance of heat pumps in cold climates continues to improve, and several studies have been done in recent years to learn more about the options for heat pumps in Alaska. However, there are limits to the use of heat pumps, and the economics depend on the price of grid electricity and the competing fuel. In general, when air temperatures approach 0°F, air source heat pumps are nearing the limits of their operating parameters.

Current Installations in Alaska

Data from 17 heat pump projects were used in this report. While several hundred heat pumps are operating around the state in both residential and commercial settings, most data used in this report are from projects involved with various state and academic studies or from projects funded through public money that thus have more transparent cost and performance data available. Heat pumps generally produce lower temperature heat (130°F) than conventional fuel oil boilers (180°F). Consequently, cost information in this analysis often includes HVAC modifications in many of the systems, although it should be noted that heat pumps have been installed without replacing a building's entire hydronic (HVAC) system when weatherization and energy efficiency have first been optimized.

Key Performance Metrics

The data show that ground source systems have the widest range for installed cost per kW, ranging from less than $2,000/kW to over $12,000/kW. The same range is found for air source heat pumps, which tend to be used for smaller projects. The smallest range of installed cost/kW was found for seawater source heat pumps. These systems are typically installed where a reliable intake of seawater is already in place, which helps reduce costs. All systems over 200 kW were either seawater heat pumps or ground source heat pumps. The mean cost per kW of the systems studied was $4,248 with a standard deviation of $4,202.

Heat Pump Technology Report

Summary

The life expectancy of newer heat pumps is still not entirely known, but is probably 20 to 25 years. For smaller mini split style air source heat pumps, life expectancy is probably closer to 15 years. Compressor replacement is typically needed sometime during the lifetime of the heat pump.

Technology Trends

Heat pump technology is improving as companies develop more efficient heat pumps that function better in colder climates. In addition, advances with alternate natural refrigerants such as carbon dioxide and ammonia are being made, which enable water to rise to higher temperatures.

Technology-Specific Gaps and Barriers to Successful Project Development and Operation

Technological advances are still needed for heat pump applications in colder climates. There is also a challenge in Alaska with regard to the Power Cost Equalization (PCE) program subsidies and unused heat pump capacities, especially in colder months. If a utility could sell more electricity for heating purposes, a community might save diesel, but utilities in PCE communities are hesitant to sell electricity at different costs because of the potential dilution of the PCE subsidy.

Recommendations

As with other renewable energy technologies for heating purposes, the PCE formula may need to be addressed.

Heat Pump Technology Report

Prepared by the Alaska Center for Energy and Power for the Alaska Affordable Energy Strategy Effort with funding from the Alaska Energy Authority

Several hundred heat pumps are operating in the State of Alaska in both residential and commercial settings (Stevens et al., 2013; Meyer et al., 2011). Heat pumps are space conditioning appliances that can provide both heating and cooling of indoor areas by moving heat using a refrigeration cycle. These heat pumps draw heat from a variety of sources including the air, ground, and seawater.

Heat pumps take advantage of the phase change properties of a refrigerant to transport heat between spaces. When used for cooling, heat pumps extract heat from the indoors and pump it outside. In heating mode, heat pumps extract heat from the outdoors and pump it inside. Heat pumps do not use resistance electric heaters, but rather use electricity to power fans, pumps, and compressors, which run the refrigeration cycle to transfer heat. The ratio of the amount of heat transported to the amount of electrical energy used to power the process is known as the coefficient of performance (COP), which in the right conditions can be well over 3, indicating that for every 1 unit of electrical energy input, 3 units of heat energy are transported. Put another way, the process is 300% efficient where electrical resistance heating is 100% efficient.

The performance of heat pumps in cold climates continues to improve, and several studies have been done in recent years to learn more about the options for heat pumps in Alaska (Stevens et al., 2015). There are limits to the use of heat pumps, and the economics depend on the price of electricity and the competing fuel. In general, when air temperatures approach 0°F, air source heat pumps are nearing the limits of their operating parameters.

Data Sources

Data from 17 heat pump projects were used for this report. While many more heat pumps are installed around the state, most data used in this report are from projects involved with various state and academic studies or projects funded through public money that thus have more transparent cost and performance data available. Cost data came from engineering studies, State of Alaska grant applications, actual install and maintenance records, and interviews with installers, owners, and facility staff members.

The majority of the heat pumps described are from larger systems used in sizeable public buildings. However, some smaller systems are described as well. In Alaska, the opportunity is significant to use off-the-shelf heat pump technology, typically found in residential settings, for buildings of simple design. Examples of such buildings are rural government offices. In Wrangell, for example, small residential air-to-air mini split heat pumps are used in the utility and city offices. The division between residential and commercial applications is fuzzy, and this report attempts to describe a variety of sizes and styles.

Heat pumps generally produce lower temperature heat (130°F) than conventional fuel oil boilers (180°F). While technology is changing, the lower temperatures may require differently designed heating, ventilation, and air conditioning (HVAC) systems to efficiently use the low temperature heat produced by heat pumps (Alaska Sea Life Center, 2013). Some building retrofits that are a change from fuel oil boilers to heat pumps can require significant indoor HVAC modifications. In other cases, building envelope modifications can allow the integration of a heat pump into the existing hydronic system. An example is the integration of new ground source heat pumps in the existing 17,000 ft^2 Senior House in Seldovia in 2013, which used existing hydronic heating appliances because the insulation value of the roof, walls, windows, and doors was first upgraded in a weatherization effort. The improved envelope performance allowed lower temperature (130°F–140°F) heat pumps to meet 90% of the annual building heat load when one oil boiler was retained as backup for the coldest days (A. Baker, personal communication, 2016).

For heat pump retrofits, HVAC modifications are part of the necessary cost. Initially, we intended to separate costs for indoor HVAC work from the heat pump work performed outdoors and in the mechanical room. It quickly became clear that this would be overly difficult and subjective. As such, cost information for many of the systems in this analysis often includes HVAC modifications. Readers should keep this in mind when observing the high costs of some systems. These high costs often occur because of necessary modifications to the existing building HVAC systems. While not ideal, this approach was thought to be the best method, given the time and data available for this study.

As an additional caveat about costs, figures are approximate, and many come from feasibility reports. Discussions with installers in the interior region of the state indicate that installed system costs are typically lower than some of costs reported here (A. Roe, personal communication, 2016).

No discounting of installation or operations and maintenance costs occurs in this report. All heat pumps discussed have been installed since 2010. The systems described range in size considerably. Some systems can be purchased off Amazon and shipped to the consumer; others are large custom units.

Installed Costs

The data in Figure 1 show that ground source systems have the widest range for installed cost per kW_{th} (thermal), ranging from less than \$2,000/kW_{th} to over \$12,000/kW_{th}. The same range is found for air source heat pumps. In general, air source heat pumps are better suited for smaller projects. The smallest range of installed costs/kW_{th} was found for seawater source heat pumps. These systems are typically installed where a reliable intake of seawater is already in place, which helps to reduce costs. All systems over 200 kW_{th} are either seawater heat pumps or ground source heat pumps. When calculated on a non-weighted per heat pump basis, the mean cost per kW_{th} of the systems studied is \$4,248. When a weighted average is calculated based on system size, the average cost per kW_{th} is \$5,579. The cost breakdown of components is addressed in a later section of the report. Table 1 shows the weighted average cost per kW_{th} of the different types of heat pumps studied. Note that the study size was rather small, and some categories only have a couple of data points. This small sample size is demonstrated by the high cost of air source heat pumps, where the high cost of larger systems masks the relatively low cost of smaller systems.

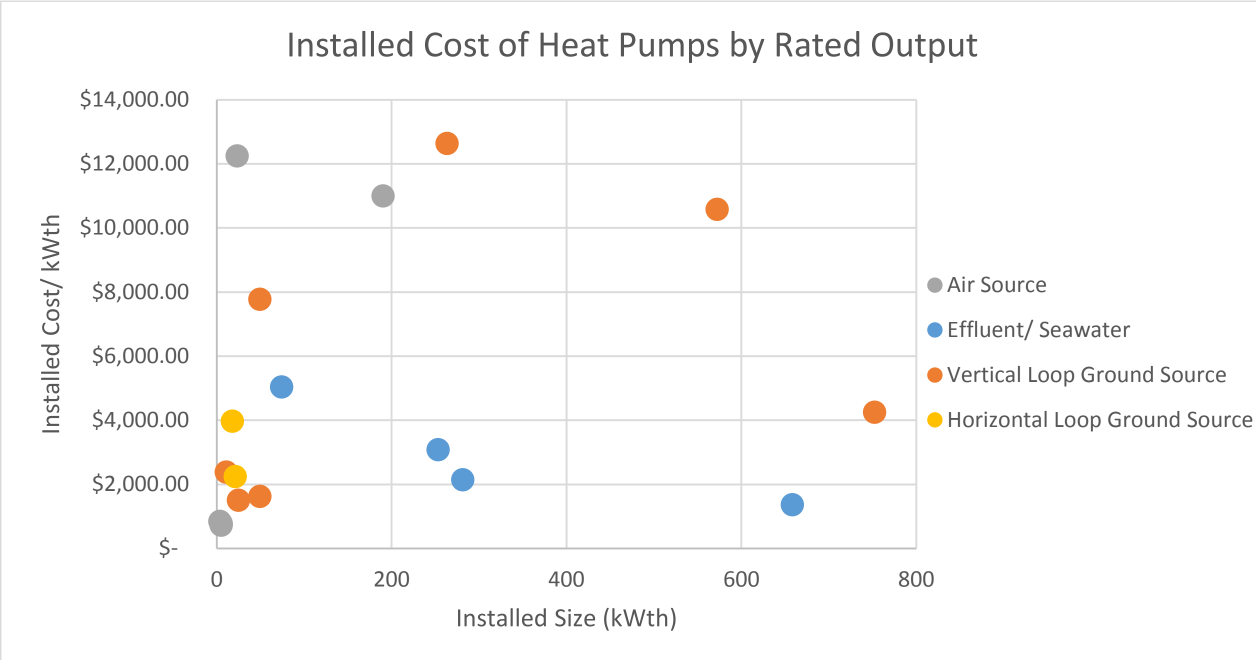

Figure 1. The installed cost per kW_{th} (thermal) of rated output is compared with the rated output of 20 heat pumps of varying sizes and designs around Alaska.

Table 1. Weighted average costs of different heat pump types.

Heat Pump Type	**Weighted Average of Installed Cost/kW_{th}**
Effluent/Seawater	$2,096.91
Vertical Ground Loop	$7,613.90
Horizontal Ground Loop	$3,036.35
Air Source	$10,359.88

Installed Costs by Component

A broad range of heat pump installations are described in this report, and generalizing the cost of components from one system to another is challenging. The costs of major components for some example projects are as follows:

Juneau Airport Ground Source Heat Pump

Installation of the heat pump was part of a renovation and expansion of the airport terminal. The old HVAC system was removed, and everything was replaced. Major heat pump component costs were:

- Ground loops – 108 vertical wells @ 305 feet deep: ~$1 million
- Water source heat pumps – 28: ~$460,000

  Total Project Cost: $6 million[1]

[1] Building controls, ventilation, commissioning, mechanical room replacement, etc., are all additional significant expenses not broken out in this report.

Cold Climate Housing Research Center Ground Source Heat Pump

This system replaced an oil-fired condensing boiler in an existing building, and no interior renovations were necessary. Costs include outdoor components and those in the mechanical room:

- Ground loop design: $1,026
- Ground loop parts and installation: $26,491
- Heat pump parts and installation: $19,686

Total Project Cost: $47,000[2]

Alaska Sea Life Center Seawater Source Heat Pump

This system was a retrofit and required modification to the building mechanical room and HVAC system.

- Two 90-ton water-to-water heat pumps: $190,000
- Corrosion-resistant heat exchangers: $36,000
- Design: $100,000
- Labor: $150,000

Total Project Cost: $897,000[3]

Other Considerations

For vertical ground source heat pumps, drilling is required. Drilling costs vary significantly around the state. Andy Roe of Alaska Geothermal indicated that his company entered the drilling business several years ago due to the high cost of drilling for their systems. In many areas of the state, a drill rig would need to be shipped in for projects, elevating costs.

Maintenance and Repair Costs

Figure 2 shows the annual cost of maintenance and repairs associated with different heat pumps around Alaska. *These costs include the approximate cost of system replacement in 20–25 years*. These figures do not include the electricity needed to run these systems (this is addressed in later sections). In most cases, these data were compiled from actual system cost and feasibility assessments developed as part of system planning.

Since the systems discussed in this analysis are relatively new, detailed long-term operation and maintenance (O&M) cost information does not exist. Andy Roe reports that maintenance on systems is minimal. All systems from Alaska Geothermal are sold with a 5-year warranty. Owners can expect a compressor replacement after approximately 12 years, which costs approximately $1,000 and requires 5 hours of labor. Tom Marsik and Clay Hammer, in Dillingham and Wrangell, respectively, report that the only maintenance their small mini split air source heat pumps require is vacuuming the filter. Tom reports that he spends about 20 minutes per year on maintenance. In these circumstances, it was assumed a cost of $50 per year and a 15-year replacement life. Actual costs are likely less.

[2] Discussions with the installer indicate that prices for this system were higher due to the wage requirements associated with the grant funding. An installed 6-ton system usually costs about $33,000 in Fairbanks.

[3] The seawater intake was already installed, which otherwise would represent a significant expense.

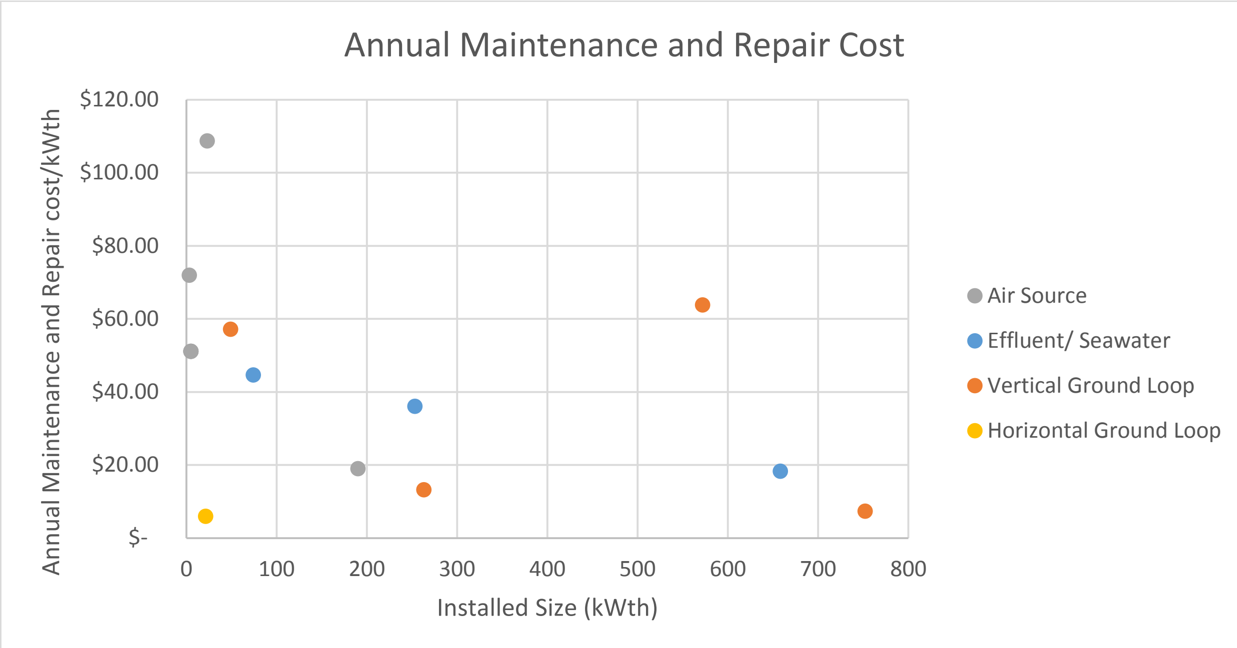

Figure 2. Maintenance and repair costs per kW_{th} along with system installation size are shown for 14 heat pumps around Alaska. These cost figures include the estimated cost of eventual replacement or refurbishment of the system, and the approximate cost of system replacement in 20–25 years. These cost figures do not include the electricity needed to run the systems (this is addressed in later sections).

The Alaska Sea Life Center is one of the few systems that have actual O&M cost information available. Their biggest challenge is the lack of local heat pump and refrigeration technicians, so any time maintenance is required from the manufacturer, travel costs tend to be high, as more time is spent by technicians traveling to and from Seward than actually working on the system.

Expected Life

The life expectancy of newer heat pumps is still not entirely known, but it is safe to assume that for larger heat pumps, it is probably 20 to 25 years. For smaller mini split style air source heat pumps, life expectancy is probably closer to 15 years. Compressor replacement will likely be necessary after approximately 12 years in ground source heat pumps, according to Andy Roe. Trane, the manufacturer of the large 90-ton heat pumps at the Alaska Sea Life Center, reports that the compressor bearing lifespan of the units is 20 years based on 40,000 total hours of operation at 2,000 hours per year. Compressor overhaul will likely be necessary at 12–15 years at a cost of $30,000–$50,000.

Conditions for Greatest Efficiency and Coefficient of Performance

Heat pump efficiency is dependent on input temperature on the cold side of the unit, that is, the outside air temperature for an air source heat pump, or the seawater temperature for a seawater heat pump. The compressors in the heat pumps must work harder to extract heat from colder fluids, as shown in Figure 3. Warmer input temperatures lead to higher coefficients of performance.

A recent report from the Cold Climate Housing Research Center (CCHRC) on air source heat pump performance around Alaska found that performance varied widely based on the heat pump model as well as on regional location (Stevens et al., 2015). Air source heat pumps have reported operating ranges as low as -18°F; however, below 0°F, current technology is likely to be problematic. Cold weather heat pump technology continues to advance. Many participants in the study from the CCHRC reported that air source heat pumps did not work on the coldest days. Authors of the study recommended that in Alaska, air source heat pumps be paired with a backup appliance.

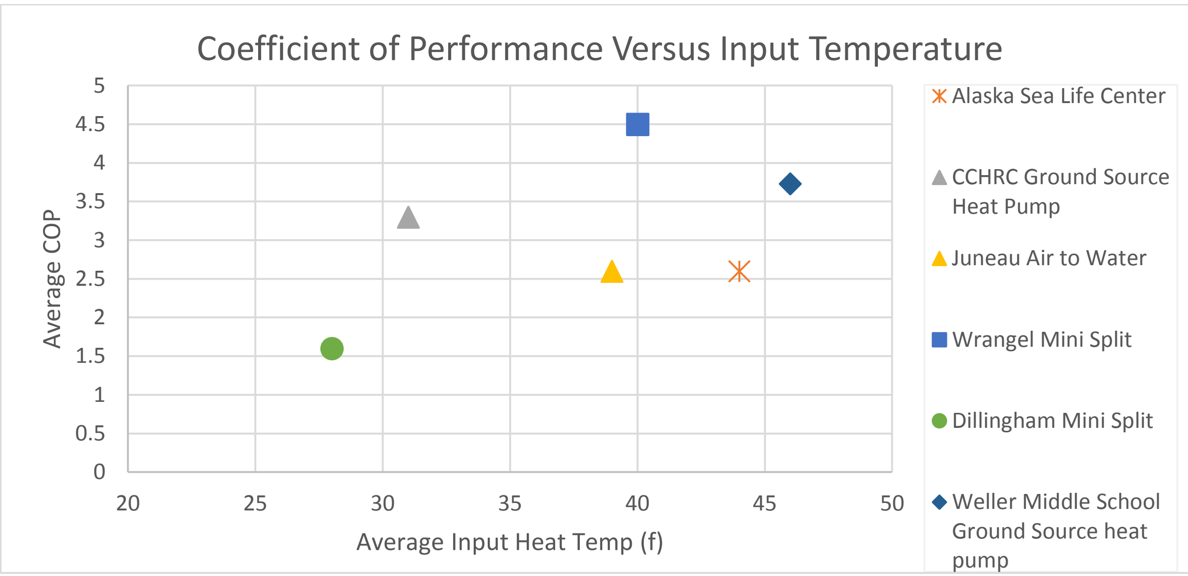

Figure 3. Average coefficient of performance is plotted according to input temperatures for a variety of heat pumps in Alaska. Warmer input temperatures lead to higher coefficients of performance.

Ultimately, the economics of a heat pump are largely dependent on the cost of electricity and the cost of an alternate fuel source such as natural gas or heating oil. Heat pumps will be most economical in places with cheap electricity, expensive fuel oil, and conditions that lead to high coefficients of performance. In 2015, the CCHRC produced a two-page handout entitled "Could a ground source heat pump work for you?" This document explains that forced air—or in-floor hydronic heating paired with south-facing slopes and cheap electricity, relative to the cost of the alternate fuel type—could make a ground source heat pump an economical heating option (Garber-Slaght and Rettig, 2015).

Diesel Offsets

Using annual electrical energy consumption and the coefficients of performance reported in Figure 3, an estimated diesel offset was calculated for these systems (see Table 2). The following assumptions were used:

- Alternate heating source is a fuel oil powered boiler
- One gallon of heating oil = 138,000 Btu
- Boiler operates at 85% efficiency

Table 2. Approximate fuel offsets of heat pumps in Alaska

Heat Pump Installations	Annual Fuel Oil Offset (gallons)
Alaska Sea Life Center Seawater Heat Pump	41,534
CCHRC Ground Source Heat Pump	746
Juneau Residential Air to Water	858
Wrangell Utility Office Air Source Heat Pump	276
Dillingham Air Source Heat Pump	26
Weller Elementary School Ground Source Heat Pump	575

Levelized Cost of Energy

Using the levelized cost of energy (LCOE) calculator from the National Renewable Energy Lab (http://www.nrel.gov/analysis/tech_lcoe), we used a set of assumptions to calculate the LCOE for a range of conditions. Capital costs, capacity factor, and O&M costs were kept constant, while the coefficient of performance (COP) values were changed to demonstrate the effect that changing COP values have on LCOE. Cost assumptions are shown in Table 3. These costs are middle-of-the-road costs, as observed in the systems reviewed in this report. Some systems such as the Alaska Sea Life Center system had lower costs, and other systems had higher costs. The LCOE values ranged from $.083/kWh$_{th}$, with a COP of 3.5 and electricity at $.08/kWh$_e$, to $.221/kWh$_{th}$ with a COP of 1.5 and an electric rate of $.24/kWh$_e$ (Figure 4). These LCOE values are equivalent to $2.85/gallon and $7.59/gallon of fuel oil, respectively, when consumed in a furnace with 85% efficiency (Figure 5).

Table 3. LCOE calculation assumptions

Capital Cost ($/kW$_{th}$)	$2000
Capacity Factor (%)	30
Fixed O&M ($/kW$_{th}$-Yr)	$20
Variable O&M ($/kWh)	$0.002
Heat Rate/ COP (Btu/kWh)	2274 (for COP of 1.5)
Fuel Cost ($/MMBtu)	Varies with electric rate

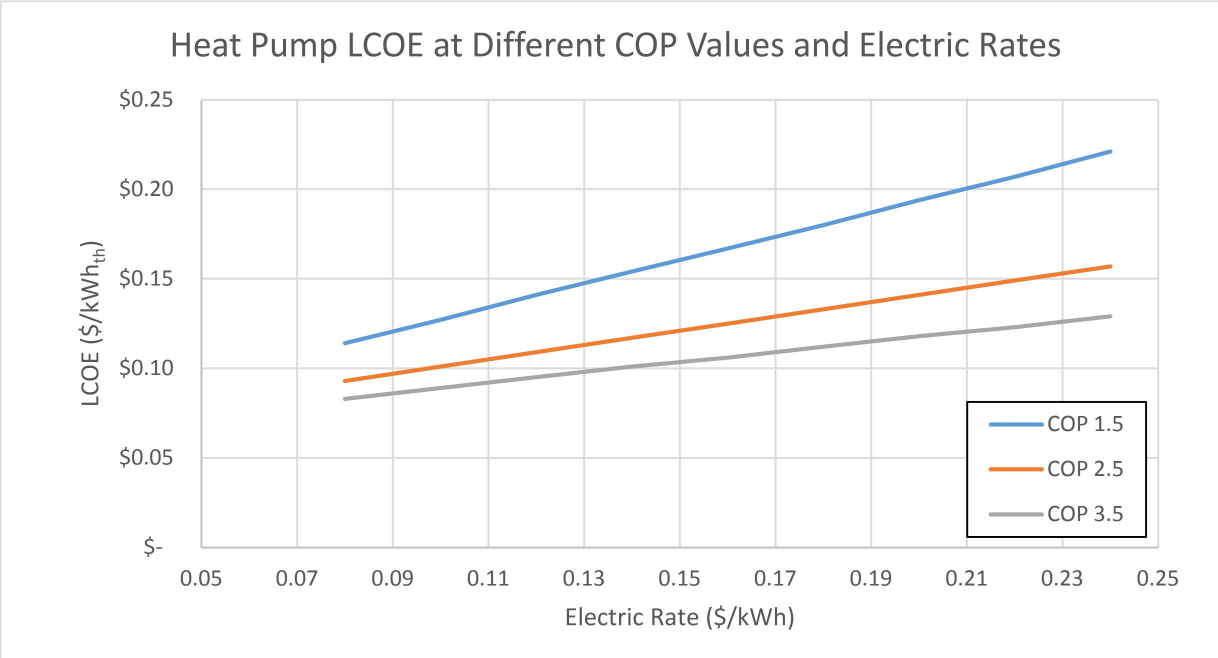

Figure 4. Heat pump LCOE is plotted at different electric rates and different COP values using a constant set of assumed capital and O&M costs.

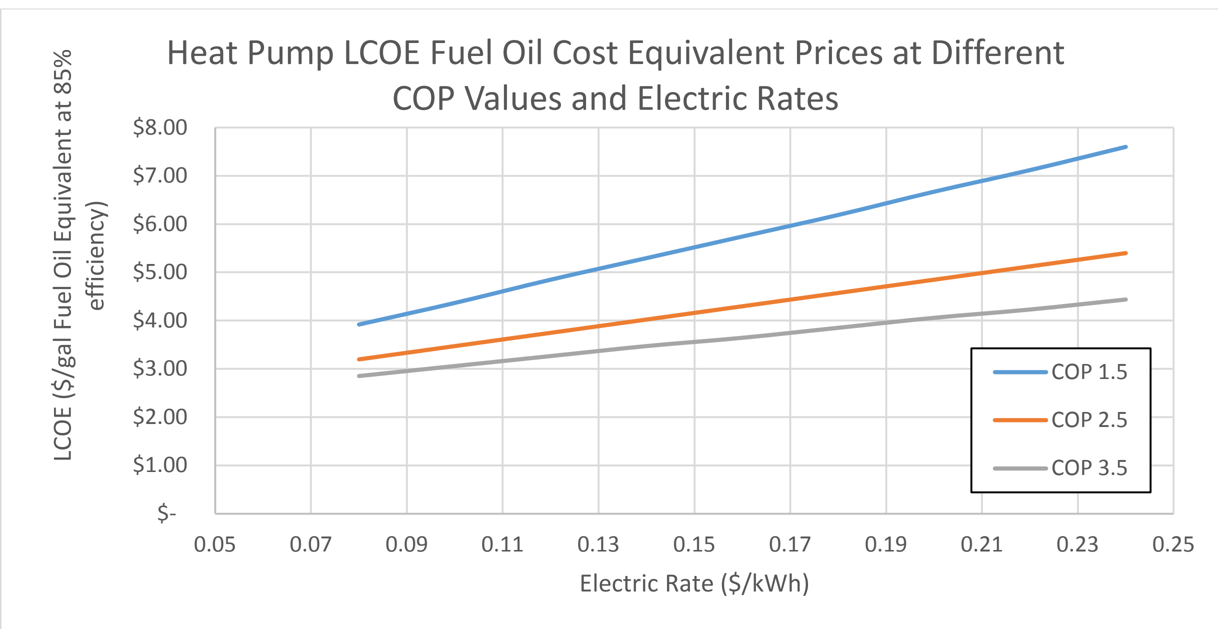

Figure 5. This graph uses the same input data as Figure 4. However, LCOE is shown as the equivalent cost of fuel oil when consumed in an 85% efficient boiler.

Cost Curve over Time

There is not enough data in Alaska to show a change in installed cost over time. The number of different units installed varies in size, type, and location. Comparisons of price over time are difficult.

Transportation Average

Heat pumps do not require any special transportation and can be shipped around the state as any other piece of equipment would be shipped; they are shipped to Alaska from the Lower 48, and sometimes from outside the United States. Small mini split air source heat pumps, like those described in this report installed in Wrangell and Dillingham, weigh about 100 pounds.

Technology Trends

Heat pump technology is improving as companies strive to develop more efficient heat pumps that can function better in colder climates. In addition, advances with alternate natural refrigerants such as carbon dioxide and ammonia are enabling water to rise to higher temperatures. In December 2015, the Alaska Sea Life Center installed four water-to-water heat pumps that use carbon dioxide as a refrigerant. This design compresses the carbon dioxide to a transcritical state at 2,000 psi and enables hydronic fluid to be heated as high as 194°F. The project demonstrates the integration of transcritical carbon dioxide heat pumps into an existing medium temperature (160°F) hydronic heating system in a large facility with both heating and cooling loads. The challenge of this emerging technology is that it requires higher refrigerant pressures, and the price of packaged units is still significantly higher than conventional R-134a heat pumps. Data from this project are currently being collected, and preliminary results should be available by the end of 2016.

Acknowledgments

Many people have contributed information and insight to this report. For their review and comments, we wish to thank Tom Marsik of the University of Alaska Fairbanks Bristol Bay Campus; Catherine Fritz, Juneau Airport architect; Dan Smith at the Alaska Energy Authority; Eric Hansen from the Alaska Native Tribal Health Consortium; Clay Hammer from Wrangell Municipal Light and Power; Roger Smith with Murray and Associates; Darryl Schaefermeyer with the Alaska Sea Life Center; Andy Baker of YourCleanEnergy LLC; Bruno Grunau with the Cold Climate Housing Research Center; and Dan Hertrich and Neil McMahon of the Alaska Energy Authority. In addition, the staff at the Cold Climate Housing Research Center has researched heat pumps and their role in Alaska extensively, and they were an invaluable resource during the writing of this report. The authors especially wish to thank Vanessa Stevens and Robbin Garber-Slaght. In addition, Andy Roe, owner of Alaska Geothermal LLC, provided valuable insight on his experience with ground source heat pumps in Interior Alaska.

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Hydroelectric Power Technology Report

Summary

Prepared by the Alaska Center for Energy and Power for the Alaska Affordable Energy Strategy Effort with funding from the Alaska Energy Authority

Resource and Technology Description

A hydroelectric power plant produces electricity by the force of water moving through a hydro turbine that spins a generator. Hydroelectric plants are typically constructed one of two ways: either via a conventional dam reservoir, which regulates the flow of water through the drawing down of reservoir levels, or via smaller “run-of-river” plants, which rely on the seasonally dependent rate and fall of natural streamflow to produce power. According to the U.S. Department of Energy, the state of Alaska contains 87,000 MW (annual mean power) of hydropower resources, of which less than 1% has been developed. Hydroelectric power is Alaska’s largest source of renewable energy, supplying more than 20% of the state’s electricity in an average water year.

Current Installations in Alaska

The data for this report were compiled from 22 applications submitted by utility companies and local governments across the state, for funding from the Alaska Energy Authority (AEA), Rounds 1 through 9 (2008–2016) of the Renewable Energy Fund (REF). For the comprehensive cost breakdowns shown in this paper, only applications submitted in the “Construction/Commissioning” phase were considered due to inclusion of the most complete information.

Key Performance Metrics

Gauging the actual capital costs of hydroelectric projects is difficult, as there is large variability in the logistical permitting, design, and other preconstruction aspects of any project (including access roads, transmission lines, switchgear, controls, etc.). However, increased capacity of the facility results in decreased capital costs on a per kW basis.

For all AEA REF applications, an assumed 50-year life is standard for hydroelectric power plants (under normal daily stress and with continued proper maintenance), although some projects are estimated to last approximately 100 years.

Technology Trends

Hydroelectric power technology is mature. Nationally, growth in hydropower projects is occurring from unit additions and upgrades at existing facilities, conduit projects to which hydropower generation equipment is added, and low-impact new stream-reach developments. In addition, flow sensors are rapidly decreasing in size and cost, and increasing in resolution.

Technology-Specific Gaps and Barriers to Successful Project Development and Operation

A significant obstacle to improving the cost and performance of hydroelectric power generation in Alaska is the maintenance of existing hydropower facilities across the state. Another challenge in Alaska is the risk of disturbing rivers that provide vital fish and game habitat to support local subsistence needs. Additionally, a significant portion of the undeveloped hydroelectric potential in Alaska is not likely to be accessible for many social and geographic reasons. Climate change may also bring long-term hydrologic changes with consequences for existing and future hydropower installations.

Summary

Recommendations

More study and further research on local fisheries, wildlife habitats, and local indigenous uses of natural resources could help identify low-impact hydropower opportunities. Future hydropower generation may need to be considered in the context of climate change and long-term hydrologic system changes.

Hydroelectric Power Technology Report

Prepared by the Alaska Center for Energy and Power for the Alaska Affordable Energy Strategy Effort with funding from the Alaska Energy Authority

A hydroelectric power plant produces electricity by the force of water moving through a hydro turbine that spins a generator. Hydroelectric plants are typically constructed one of two ways: either via a conventional dam reservoir, which regulates the flow of water through the drawing down of reservoir levels, or via smaller "run-of-river" plants, which rely on the rate and fall of natural streamflow to produce power. To be an economically viable source of power production, hydroelectric resources require a number of attributes: (1) flowing water of sufficient quantity, (2) elevation drop in the waterway, (3) proximity to load (power sales), and (4) minimal environmental risks from project development (AEA, 2015).

Reliable hydropower also supports the use of smaller, more efficient diesel generators to augment hydroelectric capacity, providing improved fuel efficiencies over operating a larger diesel genset. The high cost of energy in rural Alaska is among the most significant obstacles to community sustainability. Access to reliable, lower-cost, efficient hydro energy will benefit residential and commercial customers. Hydroelectric power is Alaska's largest source of renewable energy, supplying more than 20% of the state's electricity in an average water year (NREL, 2001)

The data used in this paper are compiled from 22 applications submitted by utility companies and local governments across Alaska—7 different regions—for funding from the Alaska Energy Authority (AEA), Rounds 1 through 9 (2008–2016) of the Renewable Energy Fund (REF). For the following comprehensive breakdowns, only applications submitted in the "Construction/Commissioning" phase were considered due to inclusion of the most complete information.

Selected Turbine Models

The following section highlights turbine models included in the REF applications. Note that other types of reactive turbines are on the market (such as the cross-flow and the Kaplan turbine models); however, they are not considered for this document.

As turbine manufacturing, engineering, and technology improve, cost reductions help to make projects more affordable.

- Impulse turbines: A horizontal or vertical wheel that uses the kinetic energy of water striking its buckets or blades to cause rotation. Least complex design, most commonly used for micro-hydro systems.
    - *Pelton wheel*: Operates best under low-flow and high-head conditions. Water is funneled into a pressurized pipeline with a narrow nozzle at one end. The water sprays out of the nozzle and strikes the double-cupped buckets attached to the wheel. The resulting force rotates the wheel at high efficiency rates of 70–90% (NREL, 2001).
    - *Turgo wheel*: Upgraded version of the Pelton wheel. Also uses the jet spray concept, but the Turgo jet is half the size of the Pelton jet, and is angled so that the spray hits three buckets at once. Therefore, the Turgo wheel moves twice as fast. Can operate under low-flow conditions, but requires a medium to high head.

- Reaction turbines: A horizontal or vertical wheel that operates with the wheel completely submerged, a feature that reduces turbulence, developing power from the combined action of pressure and moving water. Generally used for sites with lower head and higher flows compared with impulse turbines.
    - *Francis wheel*: Usually has nine or more buckets. Water is introduced just above the runner and all around it, and then falls through, causing the wheel to spin.

Outside of reservoir and run-of-river systems, there are Lake Tap systems. Lake Tap systems use the natural impoundment of an existing lake to create kinetic energy potential without the use of a dam. Of course, these systems can only exist where the topography allows. Regions with naturally occurring high-elevation lakes may utilize this feature quite easily. Lake Taps essentially eliminate the costs of dam construction and possible environmental consequences.

Capital Costs and Operations and Maintenance Costs

Gauging the actual capital cost of hydroelectric projects is difficult, as there is significant variability in logistical permitting, design, and other preconstruction aspects of any project (including access roads, transmission lines, switchgear, controls, etc.). Operation and maintenance (O&M) costs are fixed, meaning that they remain constant regardless of the size of the project. These costs are often seemingly high, especially for small projects. In Alaska, costs are high usually due to the unique, site-specific, and remote nature of many projects. The only things affected by the size of a project are site-specific items such as intake structure, penstock, turbine generators, etc. As Figure 1 illustrates, increased capacity of the facility results in decreasing capital costs on a per kW basis.

Run-of-river hydroelectric generators in Alaska do not provide the same seasonally consistent electric supply that larger hydroelectric projects do because of seasonal changes in flow, with diminished flows during the winter months. Dams and reservoirs of larger projects provide energy storage, holding water to be used for energy generation when flows are low. Smaller run-of-river systems sometimes require the installation of diesel generators for backup energy generation when seasonal flows are low and electric loads are high. Any expected fuel costs for these projects are included in O&M costs in Figure 2.

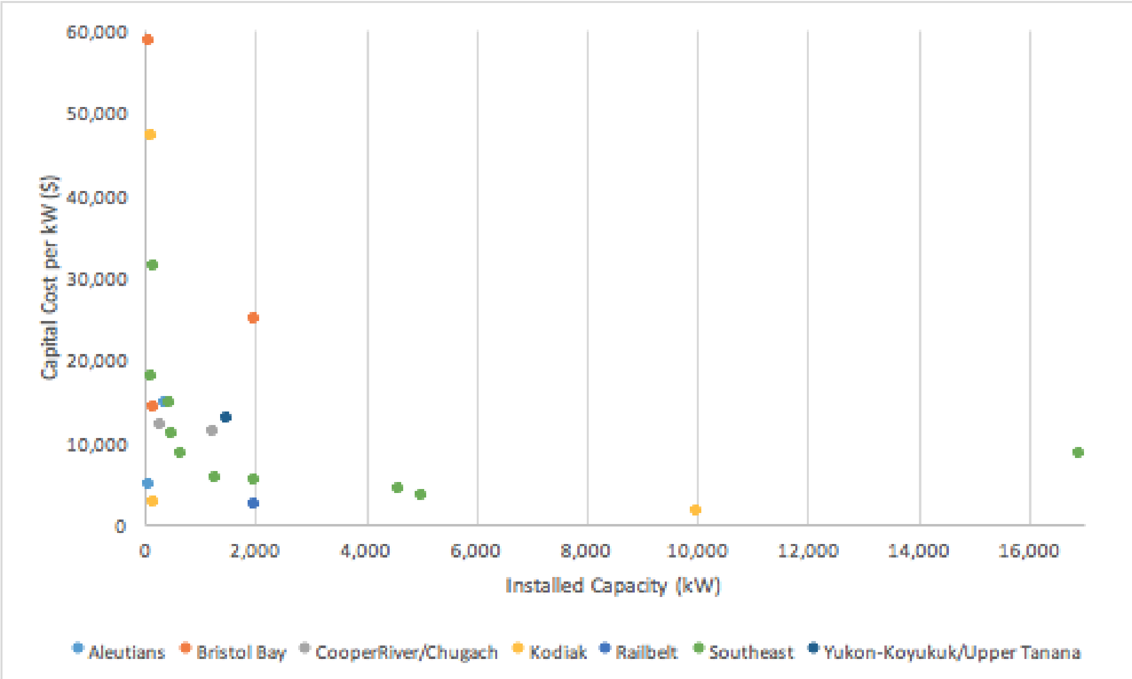

Figure 1. Capital cost per kW ($) by region. In general, costs decrease with increasing capacity.

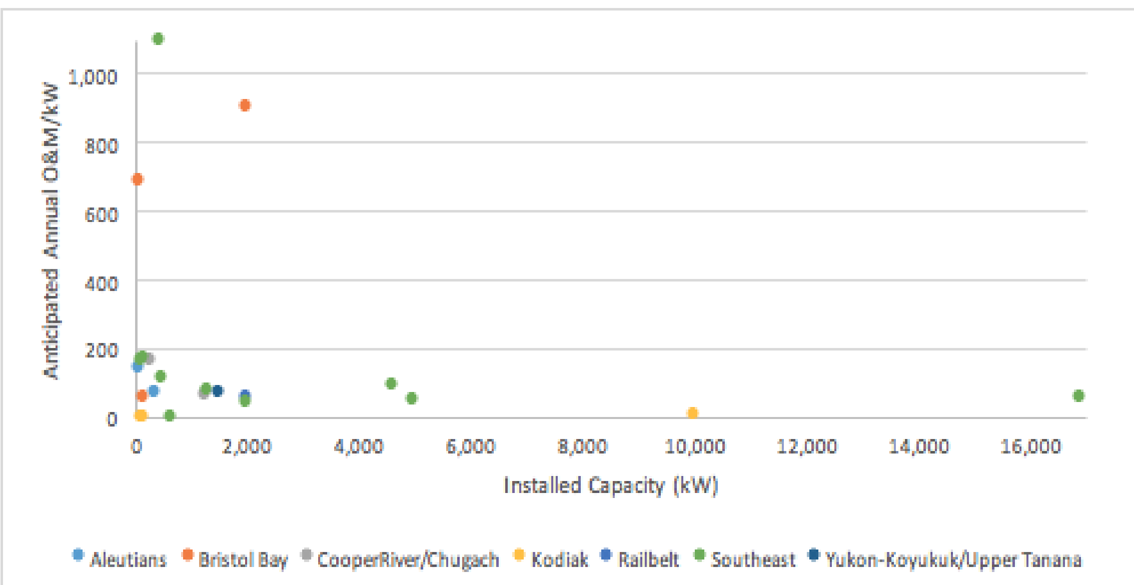

Figure 2. Anticipated annual O&M costs ($/kW-year) by region. These costs are fixed, regardless of the size of the project.

Expected Lifetime of Project

The expected lifespan of a hydroelectric project is influenced by the project's characteristics themselves, including sedimentation in the water (which can limit the lifetime of working components), and high O&M costs. All hydroelectric projects are specialized and customized to the unique and site-specific locations for which they are designed, making expected lifetimes quite variable. Exceptionally high O&M costs have the power to end projects; projects may be abandoned because they are not producing adequate power. However, in more cases than not, projects require upgrades, replacement, or reconstruction if necessary O&M has been neglected.

For all AEA REF applications, an assumed 50-year life is standard for hydroelectric power plants (under normal daily stress and with continued proper maintenance). A lifespan of 50 years is used for the following calculations. Some projects are estimated to last approximately 100 years.

Anticipated Generation

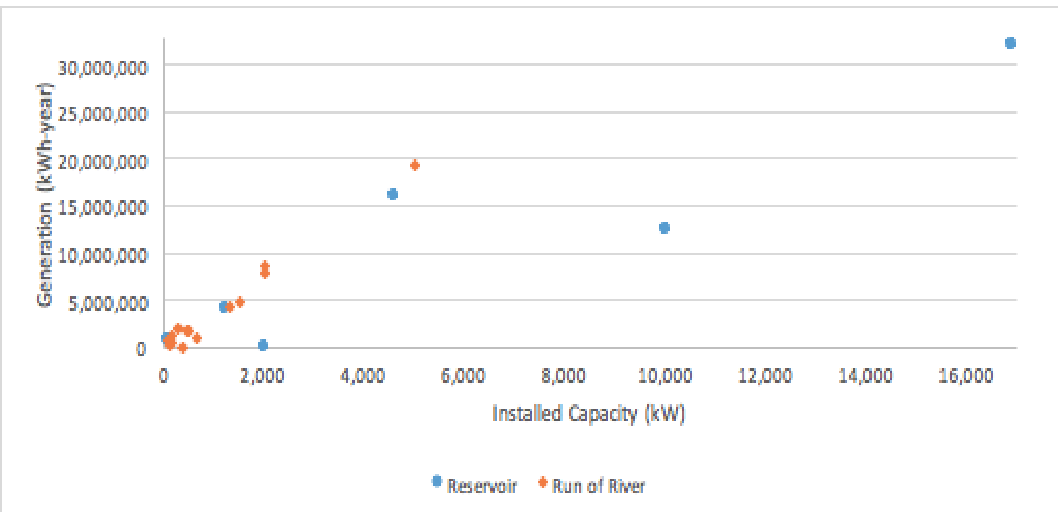

Figure 3. Anticipated annual generation (kWh-year) by type. In general, annual generation increases by capacity for both reservoir and run-of-river installations.

Capacity Factor

Capacity factor essentially represents a project's potential energy. Though a guidelines form was provided by AEA for applicants, many applications were inconsistent and varied from the form, resulting in missing or inaccurate information. Additionally, it seems that no clear indication was given in the application process as to how capacity factor is defined. Note that capacity factor calculations can be skewed due to seasonal variability (spill in the summer, and diesel supplement in the winter).

For the purposes of this document, capacity factor is defined as a percentage between 0 and 100% representing the portion of a year that the power plant is generating power, although power generation is not always time-dependent in this manner (see Table 1).

Capacity factor = (anticipated annual generation in kWh)/(8,760 hr X unit size (kW))

Hydroelectric Power Technology Report

Table 1. Capacity factor (%), installed capacity (kW), annual diesel offset (gal), and anticipated annual generation (kWh)

Region	Project	Type	Capacity Factor	Annual Diesel Offset (gal)	Installed Capacity (kW)	Anticipated Annual Generation (kWh)
Aleutians	Hydro Power Generator ADAK	Reservoir	100%	16,500	89	779,640
	Waterfall Creek	Run of River	3.0%	77,000	375	1,000
Bristol Bay	Packer's Creek	Run of River	35.7%	43,425	177	553,900
	Nushagak Area	Reservoir	11.0%	850,000	2,000	20,000
	Tanalian River_AGE	Run of River	95.0%	N/A	70	582,728
Copper River/ Chugach	Humpback Creek	Reservoir	36.5%	293,040	1,250	4,000,000
	Fivemile Creek	Run of River	77.6%	33,789	300	2,040,000
Kodiak	Ouzinkie	Reservoir	36.2%	36,068	150	475,750
	Mahoona	Reservoir	68.5%	30,000	125	759,000
	Terror Lake	Reservoir	14.2%	827,076	10,000	12,406,150
Railbelt	Fishhook	Run of River	44.6%	N/A	2,000	7,820,000
Southeast	Gunnuk Creek	Run of River	36.5%	124,000	500	1,600,000
	Indian River	Run of River	74.1%	30,000	180	1,169,000
	Blue Lake	Reservoir	21.6%	2,285,714	16,900	32,000,000
	Gartina Falls	Run of River	45.4%	100,000	455	1,810,000
	Thayer Lake	Run of River	48.5%	184,400	2,000	8,500,000
	Pelican	Run of River	17.6%	75,000	659	1,000,000
	Whitman Lake	Reservoir	39.7%	1,103,000	4,600	16,000,000
	Hoonah	Run of River	38.2%	250,000	1,300	4,344,000
	Neck Lake	Run of River	27.6%	25,000	124	300,000

Region	Project	Type	Capacity Factor	Annual Diesel Offset (gal)	Installed Capacity (kW)	Anticipated Annual Generation (kWh)
	Reynolds Creek	Run of River	44.1%	1,600,000	5,000	19,300,000
Yukon-Koyukuk/ Upper Tanana	Yerrick Creek	Run of River	37.3%	375,000	1,500	4,900,000

Diesel Fuel Offset

Some proposed systems were designed for excess electricity to be used for heat in community buildings (i.e., schools, clinics). As this was not the case in all applications, Figure 4 only illustrates annual diesel offset for electrical use (not heat).

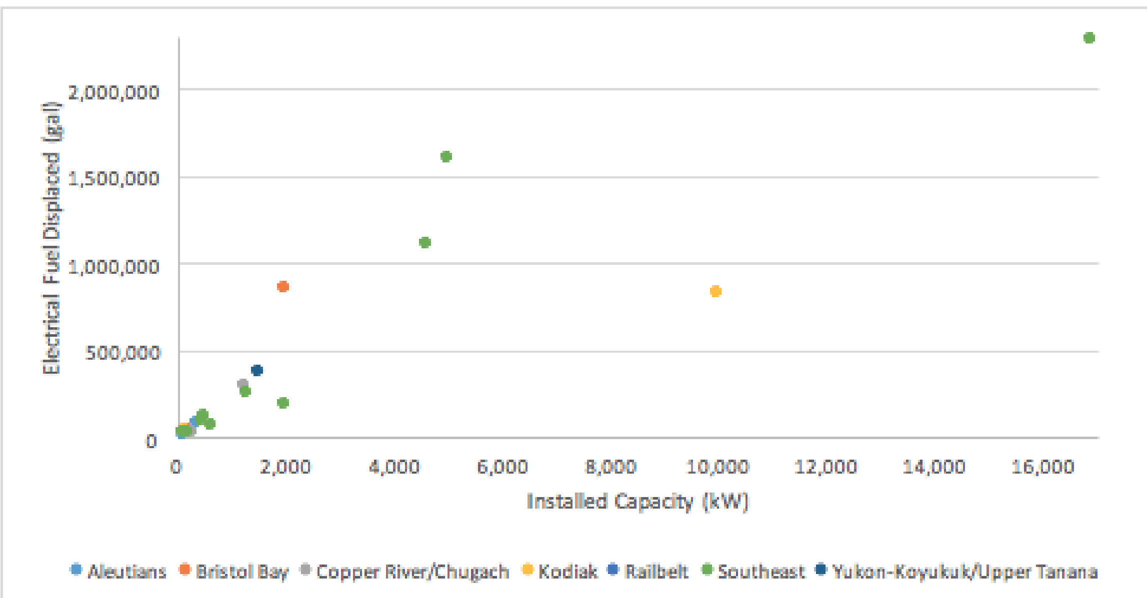

Figure 4. Anticipated annual electrical fuel offset (gal) by region, showing more diesel fuel offset with increasing installation capacity for all regions.

Levelized Cost of Energy[1]

By calculating the levelized cost of energy (LCOE), it is possible to compare the combination of capital costs, O&M, performance, and fuel costs. This calculation is one of the utility industry's primary metrics for the cost of electricity produced by a generator, and is used as a means of best comparing different types of technology. The LCOE is calculated by dividing the total expected lifetime costs by the system's expected lifetime power output. Note that Figure 5 does not include environmental costs, financing

[1] Levelized Cost of Energy Calculator. National Renewable Energy Laboratory, Energy Analysis. August 2015. http://www.nrel.gov/analysis/tech_lcoe.html.

issues, future replacement, and/or degradation costs. A relatively low LCOE indicates that electricity is being produced at a low cost with higher likely returns for the investor.

*LCOE = {(initial capital cost * capital recovery factor + fixed O&M cost)/(8,760 hr * capacity factor)} + (fuel cost * heat rate) + variable O&M cost*

Assumptions

- Financial:
    - Periods (years) = 50 (assumed lifetime of hydropower units)
    - Discount Rate (%) = 2.00
- System Cost and Performance:
    - Capital Cost ($/kW) = varies on a per project basis
    - Capacity Factor (%) = varies on a per project basis
    - Fixed O&M Cost ($/kW-yr) = varies on a per project basis
    - Variable O&M Cost ($/kWh) = 00.00, hydropower plant O&M is reported in annual (fixed) costs
    - Heat Rate (Btu/kWh) = 00.00, no heat is produced in hydropower systems
    - Fuel Cost ($/MMBtu) = 00.00
- Today's Utility Electricity Cost:
    - Electricity Price ($/kWh) = varies on a per project basis, commercial rates calculated by the utility company (or geographic area) in which the project falls
    - Cost Escalation Rate (%) = 2.00

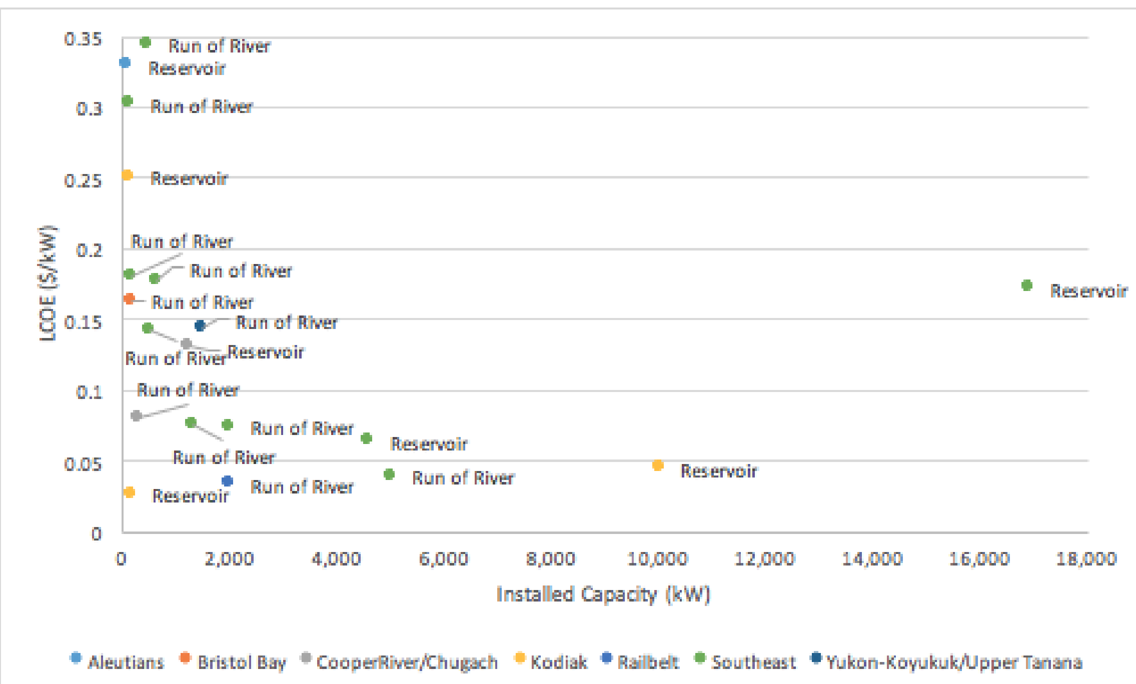

Figure 5. LCOE ($/kW) by region and type.

Conditions for Greatest Efficiency

This section is meant to address how to get hydroelectric projects to perform as well as possible. Conditions for greatest efficiency include having low O&M costs, high capacity, and minimal spill requirements, issues that are all a result of design and permitting.

Depending on water availability and annual precipitation, hydroelectricity has provided 5.8–7.8% of the electricity used in the United States in the last dozen years, and it is the largest renewable source of electricity in the United States (EIA, 2011). If a particular section of river lies in the right terrain to form a reservoir, it may be suitable for dam construction. Smaller rivers may be suitable for run-of-river hydro plants. The earth's hydrologic cycle naturally replenishes the "fuel" supply, and no fossil fuels are required to produce the electricity.

Unfortunately, most electric loads in Alaska are highest during the winter, the same time that river flow is at its lowest. Low river flow lowers the amount of run-of-river hydro capacity that can be installed without significant amounts of excess capacity in the summer.

Cost Curve of Technology

The high capital cost of hydroelectric power (both absolute and especially on a per kW basis for smaller projects) is the chief impediment to the economic feasibility of this power source. Capital cost tends to decrease over time, as the original capital costs are paid down from power sales revenue and the low O&M cost features of hydropower prevail. However, higher fuel prices in a 2007 analysis, relative to those considered in 1996, were sufficient to propel several possible projects in Alaska into the ranks of potentially feasible projects (AEA and ACEP, 2009).

Installed Costs by Major Component

Average installation costs are shown in Figure 6 through Figure 11. Absent from this document are costs associated with development, including licensing, permitting, and planning. Another major component of project development is the amount of time required for hydroelectric projects to come to fruition. This is not a tangible cost, but it has considerable impact on all hydroelectric projects.

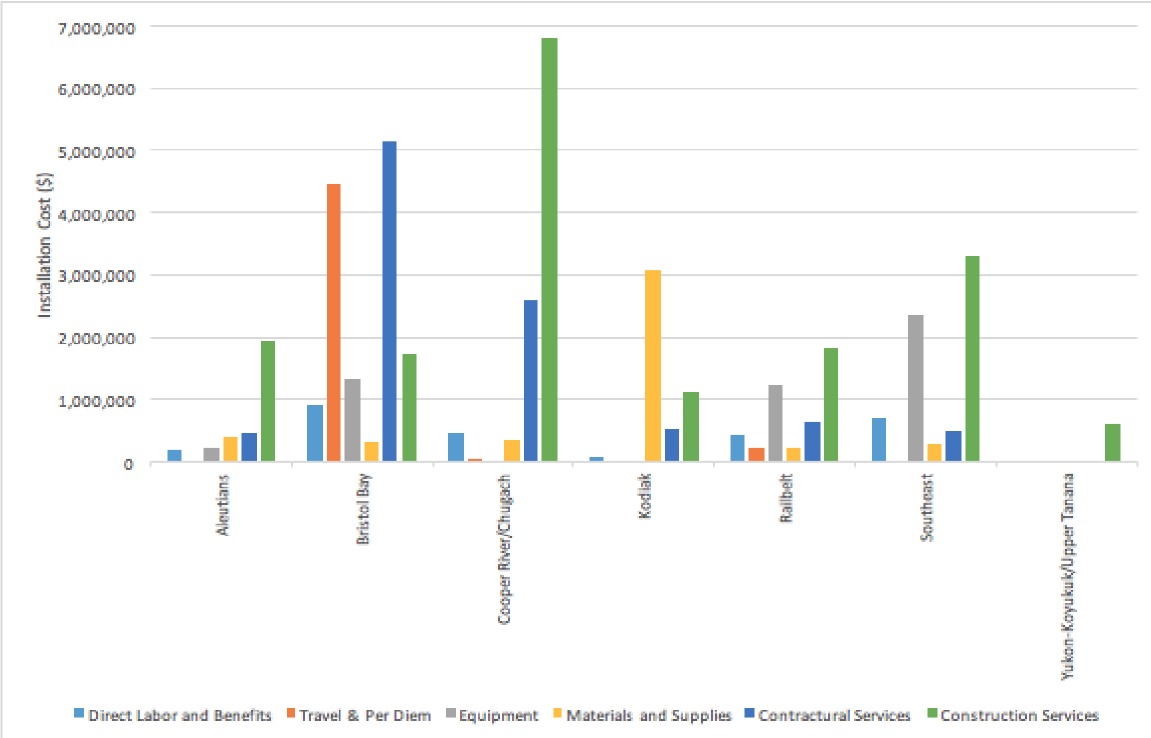

Figure 6. Average installation cost ($) by FERC budget category by region.

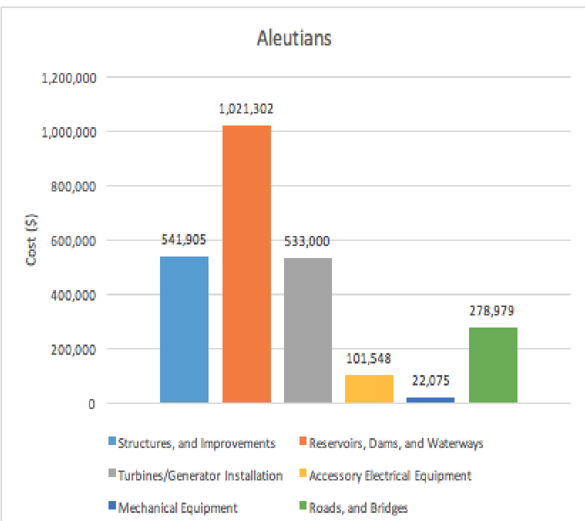

Figure 7. Average installation cost ($) by major component, Aleutians region.

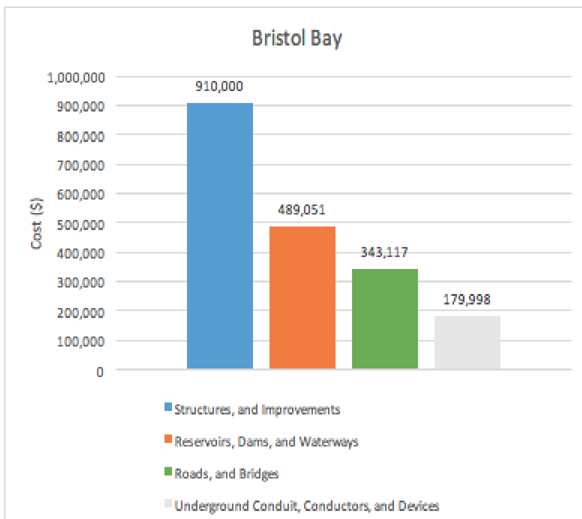

Figure 8. Average installation cost ($) by major component, Bristol Bay region.

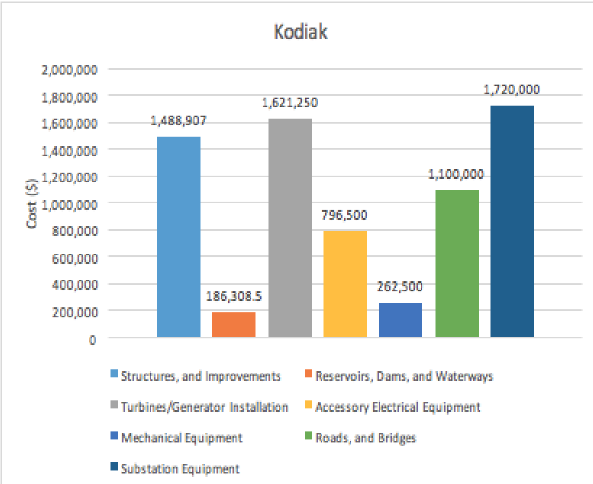

Figure 9. Average installation cost ($) by major component, Kodiak region.

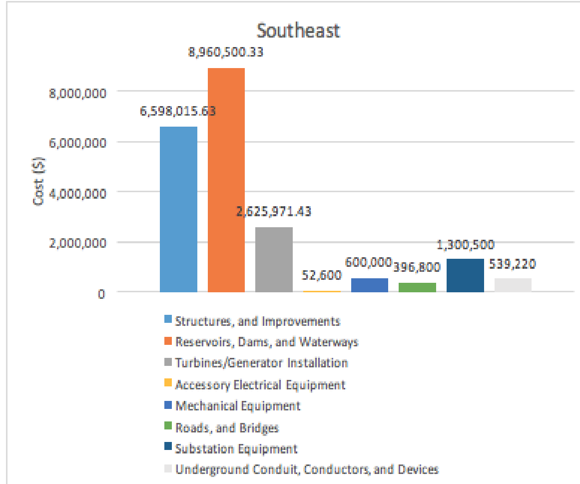

Figure 10. Average installation cost ($) by major component, Southeast region.

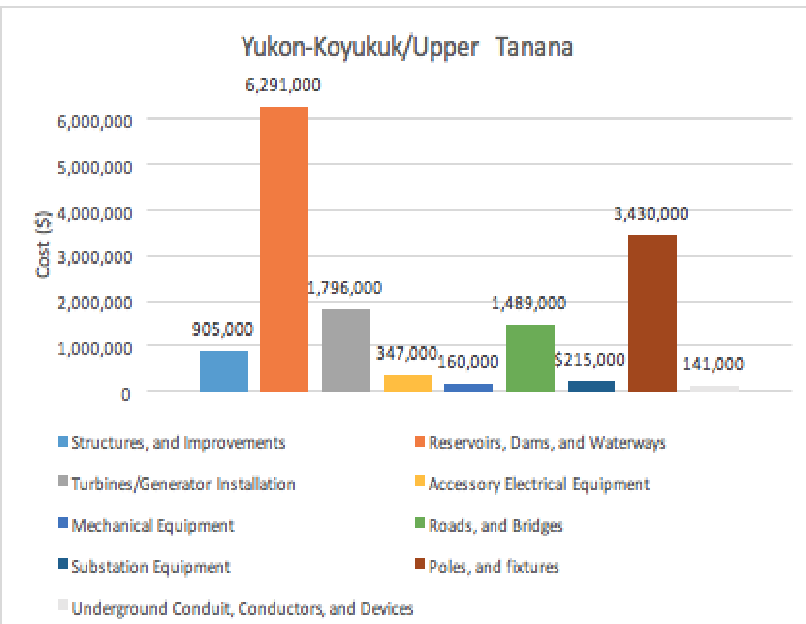

Figure 11. Average installation cost ($) by major component, Yukon-Koyukuk/Upper Tanana region.

Technology Trends

Hydroelectric power technology is mature; by the late 19th century, the newly developed electrical generator coupled with hydraulic machines gave way to tremendous development in the world of hydropower (DOE, 2016). Nationally, growth in hydropower projects is occurring from three different kinds of projects: (1) unit additions and upgrades at existing facilities; (2) conduit projects to which hydropower generation equipment is added; and (3) low-impact new stream-reach developments (DOE, 2014).

In Alaska, adoption issues concerning hydroelectric power generation are primarily social. However, limitations of technological feasibility (transmission, batteries, and storage systems), current political direction, and economic status are also possible hindrances to the advancement of hydropower.

Alaska's vast water energy resources and remote population centers are prime areas for development of low-power hydropower plants. Low environmental impact coupled with virtually no fuel costs and high performance make hydropower plants in Alaska a prime example of the potential benefits of low-power hydropower generation. According to the U.S. Department of Energy, the state of Alaska contains 87,000 MW (total water energy resource potential) of resources, of which less than 1% has been developed (DOE, 2004) (see Figures 12 and 13).

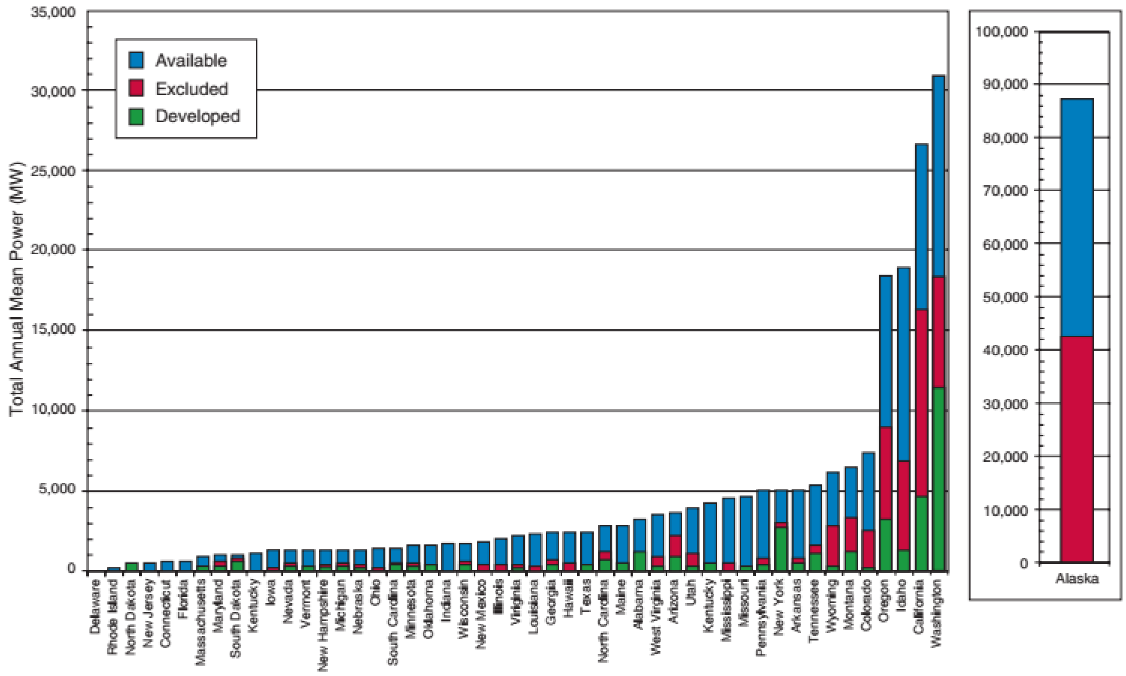

Figure 12. Total power potential of water energy resources in the 50 United States. The blue bar segments represent the amount of available potential in each state. Green bar segments represent the amount of developed potential, and red bar segments represent the amount of potential excluded from development (DOE, 2004).

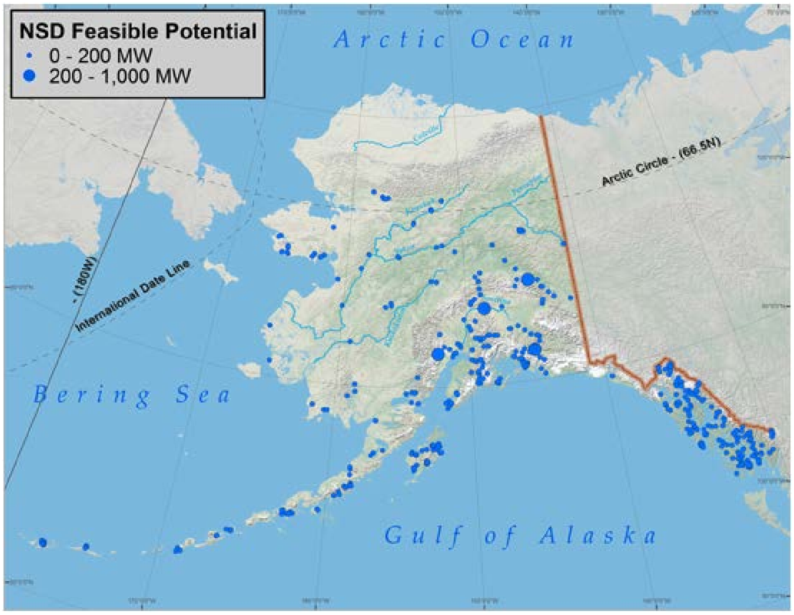

Figure 13. Total estimated hydropower potential feasible for development in Alaska (ORNL, 2014).

Storage Systems

Used for load balancing, pump-storage hydroelectricity is a type of hydroelectric energy storage system. It uses stored energy in the form of gravitational potential energy of water, pumped from a lower elevation reservoir to a higher elevation. During periods of high electrical demand, the stored water is released back through a series of turbines to produce power.

- Stand-alone hydropower systems require additional equipment to condition and safely transmit electricity to the load that will use it.
- Run-of-river hydroelectric systems do not have large storage reservoirs.
- Streamflows and water levels can be variable over time, so determining the system's lowest average flow of the year is the first step to designing a storage reservoir.

Realized Cost Savings

Cost savings from integrating renewable power are difficult to gauge due to technical and incentive impacts at the entire power systems level. At the technical level, for example, effects of diminished losses of secondary services such as recovered waste heat, and reductions in fuel efficiency are hard to measure, as they depend not only on average reductions in load, but also on specific operating schemes regarding minimum allowable load on diesel.

Positive cost savings occur when annual O&M costs are subtracted from the total savings of annual diesel fuel offset. Several of the larger Southeast Alaska hydroelectric projects have the largest savings. The majority of projects across the state see annual cost savings of under $1,000,000, no matter the type of hydro plant (Figure 14).

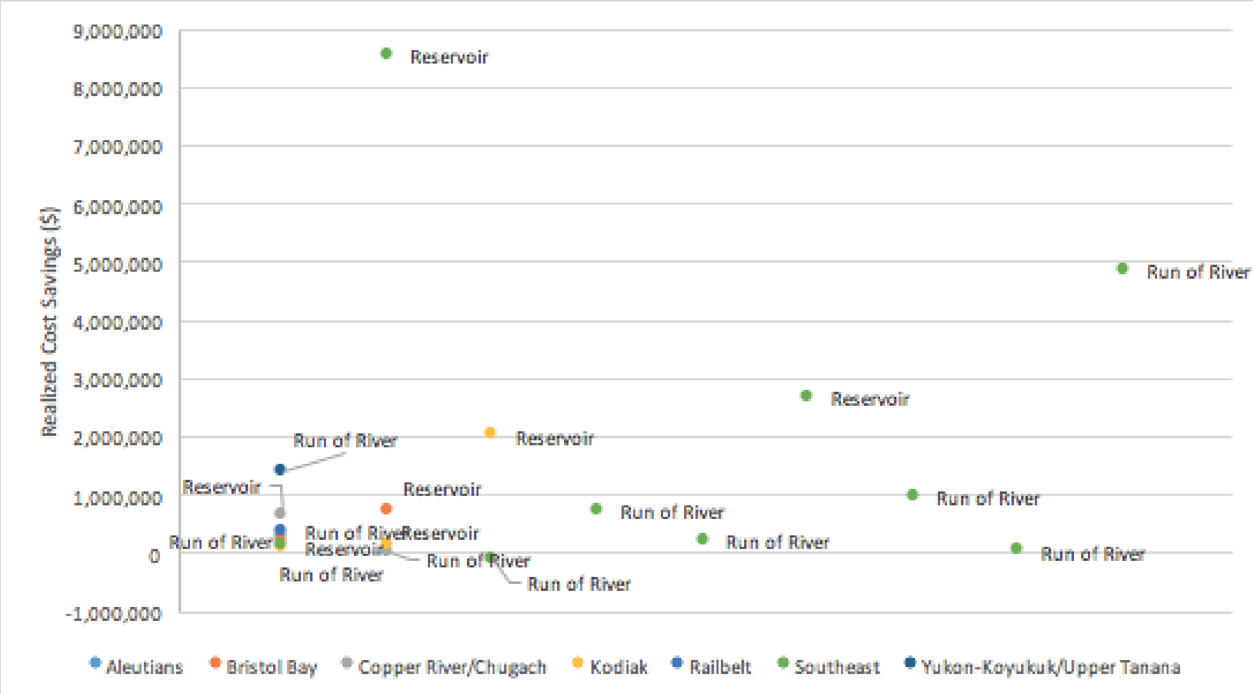

Figure 14. Annual realized cost savings ($) by region and type.

Refurbishment/Market Upgrades

- Hydroelectric power generation systems are rarely completely replaced, due to high initial costs. Rather, parts are replaced over long timelines to minimize the likelihood of multiple parts failing at once.
- Run-of-river hydropower systems consist of these basic components, which are the most common reason for necessary upgrades and refurbishment:
  - Water conveyance: Channel, pipeline, or pressurized pipeline (penstock) that delivers the water
  - Turbine, pump, or waterwheel: Transforms the energy of flowing water into rotational energy
  - Alternator or generator: Transforms the rotational energy into electricity
  - Regulator: Controls the generator
  - Wiring: Delivers the electricity

Acknowledgments

Many people have contributed information and insight to this report. For their review and comments, we wish to thank Ben Beste of Alaska Power and Telephone; Joel Groves of Polar Consulting; Clay Koplin, Chief Executive Office of Cordova Electric Cooperative, Inc.; and Dan Hertrich and Neil McMahon of the Alaska Energy Authority.

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Integration Technology Report

Summary

Prepared by the Alaska Center for Energy and Power for the Alaska Affordable Energy Strategy Effort with funding from the Alaska Energy Authority

Resource and Technology Description

For the purposes of this analysis, integration refers to the modifications and additions made to a microgrid in order to incorporate a new energy source, not including transmission/distribution. The goal of integration is to maintain a stable grid while maximizing economic benefit. Energy sources can be categorized by whether they are dispatchable (can generate power according to a schedule, and follow demand within its operating range) and if they have a synchronous front end (able to control real and reactive power flow, either with a synchronous generator or a grid-forming inverter).

Energy sources that are both dispatchable and have a synchronous front end do not need any special integration beyond dispatch control, which is fairly straightforward and part of any modern powerhouse. Energy sources that do not have a synchronous front end require other components in the grid to supply reactive power to maintain an acceptable power factor and to provide voltage and frequency reference. Energy sources that are not dispatchable require available spinning reserve capacity (SRC) and standby generation for times when the energy source can no longer meet the load. Spinning reserve capacity can supply instantaneous power while standby generation is brought online.

Diesel generators, and usually hydropower, are dispatchable and have a synchronous front end. Biomass and geothermal power generation systems are dispatchable, but often do not have a synchronous front end. Wind and solar photovoltaic (PV) power are not dispatchable and generally do not have a synchronous front end.

Integration costs for nondispatchable, variable energy sources such as wind and solar PV power also depend on the nature of their variability. Solar PV power can be more variable than wind, with higher ramp rates, which may result in higher integration costs per installed capacity ($/kW) for solar PV power compared with modern wind turbines.

Current Installations in Alaska

The analysis in this report largely relies on data extracted from applications to the Alaska Energy Authority Renewable Energy Fund, Rounds 1 through 8, and thus may not always represent actual as-built costs. However, the data provide an indication of integration costs.

Key Performance Metrics

Analysis shows a statistically significant increase of around $27/kW in the total integration cost per percent increase in wind energy penetration. Higher integration costs can be offset by lower CAPEX per kW installed for larger renewable energy systems.

For integration systems incorporating thermal or electrical storage, the average control integration cost is around 66% of the total cost, and storage is 34%. Control integration equipment includes SCADA, hardware, integration, and testing costs.

Different components used in integration have their own energy efficiency or consumption. A significant example is energy storage, which has losses while charging and discharging and during storage (see the energy storage paper for more information). Other components such as switchgear and inverters represent smaller energy losses, typically in the mid and high 90% efficiency, respectively. A well-designed integration scheme will result in much higher energy savings than losses.

Technology Trends

Trends that are being used to integrate higher penetrations of renewable energy in grids include demand side management, excess generation to heat, energy storage with grid-forming inverters, and advanced control systems. Demand side management allows electrical loads to be turned on and off, depending on the presence of excess electrical generation. Excess generation can be stored in thermal and electrical energy storage. Electrical energy storage and grid-forming inverters can be used to maintain grid stability and allow diesel generators to be turned off with sufficiently high penetration of renewable energy. Advanced control systems are being developed for microgrids. However, they are often designed for grid-connected microgrids, and it is uncertain how well they will work for remote microgrids.

Integration Technology Report

Prepared by the Alaska Center for Energy and Power for the Alaska Affordable Energy Strategy Effort with funding from the Alaska Energy Authority

For the purposes of this analysis, integration refers to the modifications and additions made to a microgrid in order to incorporate a new energy source, not including transmission/distribution. This analysis looks specifically at the costs of integrating wind power, since most available data are for wind, but it is relevant to other energy sources as well. A qualitative description and comparison of the integration requirements of different energy sources are given in Table 1.

The goal of integration is to maintain a stable grid while maximizing economic benefit. Table 1 provides an overview of the integration requirements for energy sources, depending on their capabilities. Energy sources can be categorized by whether they are dispatchable (can generate power according to a schedule, and follow demand within the operating range of the energy source) and whether they have a synchronous front end (able to control real and reactive power flow, either with a synchronous generator or a grid-forming inverter[1]).

Energy sources that are both dispatchable and have a synchronous front end do not need any special integration beyond dispatch control, which is fairly straightforward and part of any modern powerhouse. Energy sources that do not have a synchronous front end require other components in the grid to supply reactive power to maintain an acceptable power factor and provide voltage and frequency reference. Energy sources that are not dispatchable require available spinning reserve capacity (SRC) and standby generation for times when the energy source can no longer meet the load. Spinning reserve capacity can supply instantaneous power while standby generation is brought online.

Diesel generators and usually hydroelectric sources are dispatchable and have a synchronous front end. Biomass and geothermal power generation systems are dispatchable, but often do not have a synchronous front end. Wind and solar photovoltaic (PV) power are not dispatchable and generally do not have a synchronous front end.

Integration costs for nondispatchable variable energy sources such as wind and solar PV power also depend on the nature of their variability. Solar PV can be more variable than wind, with higher ramp rates, which may result in higher integration costs per installed capacity ($/kW) compared with modern wind turbines.

[1] A grid-forming inverter is a voltage source and can operate in 4 quadrants, meaning it can output and absorb real and reactive power.

Table 1. General power integration requirements depending on the capability of the energy source.

	Dispatchable power generation	Synchronous front end
Definition	Real power output can be controlled and generated according to a schedule or demand.	The power factor (ratio of real to apparent power), used to supply loads that consume reactive power, can be controlled. Frequency and voltage references are provided to all other sources of generation and those sinks that require it.
Energy sources that commonly have this capability	Hydroelectricity, biomass, geothermal, diesel	Hydroelectricity, diesel
Integration needs for energy sources that do not have this capability	• There must be sufficient spinning reserve capacity (SRC) to cover possible short-term inadequate generation. • There must be standby generation/stored energy to cover long-term inadequate generation. • If the source can overgenerate (generate more power than is demanded) “negative-SRC” in form if diversion loads may also be necessary.	• The voltage and frequency of the grid need to be maintained. • The grid power factor needs to be maintained.
Available integration hardware	• Dispatchable and synchronous generators such as diesel and hydroelectric power are able to supply SRC when sufficient capacity is running online. They can supply standby generation when online and offline.[2] • Electrical energy storage and inverters can supply SRC and/or stored energy • Demand response or secondary loads can be used together with excess generation from the energy source to supply some of the SRC. This depends on the variability of the energy source and the size and granularity (available load steps) of the secondary load.	• Dispatchable and synchronous generators such as diesel and hydro are able to maintain voltage, frequency, and power factor when sufficient capacity is online. • Capacitor banks and synchronous condensers can be used to correct the grid power factor. Synchronous condensers can be used to maintain voltage and frequency. • A grid-forming inverter (also known as a voltage source inverter), placed between the energy source and the grid, can maintain voltage, frequency, and power factor, but may not be able to follow demand. • Electric energy storage with a grid-forming inverter can maintain voltage, frequency, and power factor.
Integration options to increase the energy harvested from high penetrations of energy sources that do not have this capability	• Diversion loads • Secondary loads • Demand response • Energy storage	• Synchronous condensers • Energy storage with grid-forming inverter

[2] Different diesel generators require different amounts of time to be brought online. Some can be brought online as quickly as 30 seconds, while others require over 30 minutes. The amount of time largely depends on the size of the generator (the larger it is, the longer it takes) and standby practices. Cold engines require more time than engines kept in “hot” standby.

The following analysis largely relies on data extracted from applications to the Alaska Energy Authority Renewable Energy Fund (REF), Rounds 1 through 8, and thus may not always represent actual as-built costs. In this analysis, integration is broken down into the categories of SCADA and hardware, integration and testing, thermal storage,[3] and electrical storage.[4]

Controllable loads is another integration category, but it was not included in the REF applications used for this paper. There is some overlap between the definition of controllable loads and energy storage. Electrical and thermal energy storage could be considered a controllable load since it can be charged with excess generation. Electrical storage could also be considered a generating source when discharging. Energy storage is a subset of controllable loads, and many controllable loads do not have a significant storage component. Distributed masonry heaters in homes were considered thermal energy storage since they include a thermal storage component. However, they have also been classified as a controllable load.

In the data, SCADA and hardware costs included "low load diesel modifications," "power factor correction," "upgraded transfer trip scheme," "SCADA/communications," and "power plant improvements." Thermal storage included large centralized boilers in power stations and community centers, and distributed masonry heaters in residences. Electrical energy storage included a flow battery and an advanced lead-acid battery. Integration projects usually only include a subset of the above integration categories. For example, many projects do not include electrical or thermal storage.

Capital Costs

The capital costs (capital expenditure or CAPEX) of wind integration per kW of installed wind capacity can be seen plotted against grid wind energy penetration in Figure 1. Wind energy penetration was calculated as the total predicted wind generation in 1 year (existing capacity and additional capacity from project) divided by the grid electrical consumption for 1 year. A dashed line connects the individual integration costs with the total cost for projects with more than one type of integration.

In Figure 1, the data show a statistically significant increase of around $27/kW in the total integration cost per percent increase in wind energy penetration.[5] With increasing penetration of a variable energy resource, integration becomes increasingly complex. Thus, it is expected that costs will increase as seen in Figure 1. Higher integration costs can be offset by lower CAPEX per kW installed for larger renewable energy systems. See the wind power briefing paper for average wind CAPEX for different sized systems.

[3] In this paper, thermal storage refers to converting electrical energy to thermal energy, which is later used to supply thermal loads.
[4] In this paper, electrical storage refers to electrical energy being converted and stored (usually as mechanical or chemical energy), which is later reconverted to electrical energy to supply electrical loads.
[5] Note that these are predicted values from applications, not as-built costs.

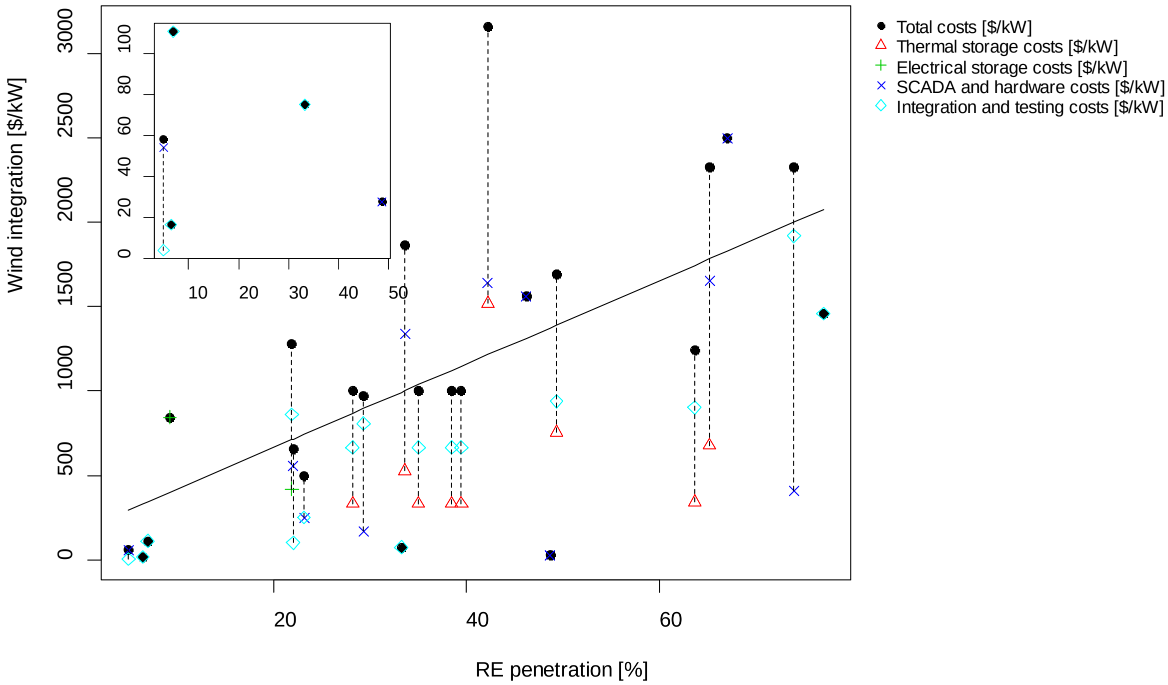

Figure 1. Capital costs per kW of installed wind capacity plotted against wind energy penetration. The inset shows low values that are difficult to see in the main plot. Wind energy penetration was calculated as the total predicted wind generation in 1 year (existing capacity and additional capacity from project) divided by the grid electrical consumption for 1 year. A dashed line connects the individual integration costs with the total cost for projects with more than one type of integration.

Operations and Maintenance $/kW

Operations and maintenance (O&M) cost data are only available for electrical energy storage. Other O&M costs are needed for SCADA and hardware and thermal storage. See the briefing paper on energy storage for electrical storage O&M costs.

Expected Life

Expected life data are only available for electrical energy storage. The expected life of SCADA and hardware and thermal storage are also relevant. See the briefing paper on energy storage for electrical storage expected life.

Capacity Factor

Capacity factor is not applicable.

Diesel Offset

Proper integration of a variable energy resource into a grid is important for grid stability and power quality. For low energy penetrations (< ~8% for wind), all the energy from the resource can be used, and the diesel generators can account for its fluctuations. At higher penetrations, excess generation begins and cannot be directly fed into firm demand while maintaining grid stability. Different integration schemes allow the use of excess generation to supply electrical or thermal storage or controllable loads.

Upgrades to diesel generators (such as low-load diesels), controllable loads, and electrical energy storage can allow more energy onto the grid to supply electric loads. Electrical energy storage accomplishes this by providing SRC or by storing energy during excess generation and releasing it during low generation. See the energy storage paper for more information. Controllable loads can be turned on when there is excess generation.

Thermal loads can be supplied with excess generation. In the applications included in this analysis, this process was done by converting electrical energy to thermal energy and storing it in thermal storage, including centralized boilers and distributed masonry heaters.

Using excess generation to supply electric loads displaces more diesel than supplying thermal loads, because diesel is much more efficient at supplying thermal loads than electric loads. For example, if a diesel generator generates 13 kWh and a boiler generates 30 kWh of heat with 1 gallon of diesel, then it will take around 13 kWh and 30 kWh of renewable energy to displace 1 gallon of diesel while supplying electric and thermal loads, respectively. However, the integration costs to supply thermal loads with excess generation are often less than the integration costs to supply electric loads.

Cost per kW

Cost per kW or levelized cost of energy (LCOE) data are only available for electrical energy storage. The LCOE for SCADA and hardware and thermal storage is also needed. See the briefing paper on energy storage for electrical storage LCOE and levelized cost of cycle power (LCCP).

Conditions for Greatest Efficiency

Integration is not a form of energy generation, thus does not necessarily have its own energy efficiency. Integration does help increase the energy efficiency of a grid by increasing the utilization of renewable energy generation and reducing diesel consumption. See the *Diesel Offset* section for more information.

Different components used in integration have their own energy efficiency or consumption. A significant example is energy storage, which has losses while charging and discharging and during storage (see the energy storage paper for more information). Other components such as switchgear and inverters represent smaller energy losses, typically in the mid and high 90% efficiency ranges, respectively. A well-designed integration scheme will result in much higher energy savings than losses.

Cost Curve over Time

The cost curve over time is only available for electrical energy storage, but is also needed for SCADA and hardware and thermal storage. For electrical energy storage, see the briefing paper for cost curve over time.

Installed Costs by Major Components

Figure 2 shows the maximum, upper quartile, median, lower quartile, minimum, and outliers for the breakdown of total costs for control integration equipment relative to storage for integration systems incorporating thermal or electrical storage. Control integration equipment includes SCADA, hardware, integration, and testing costs. For both electrical and thermal energy storage the average control integration cost is around 66% of the total cost, and storage is 34%.

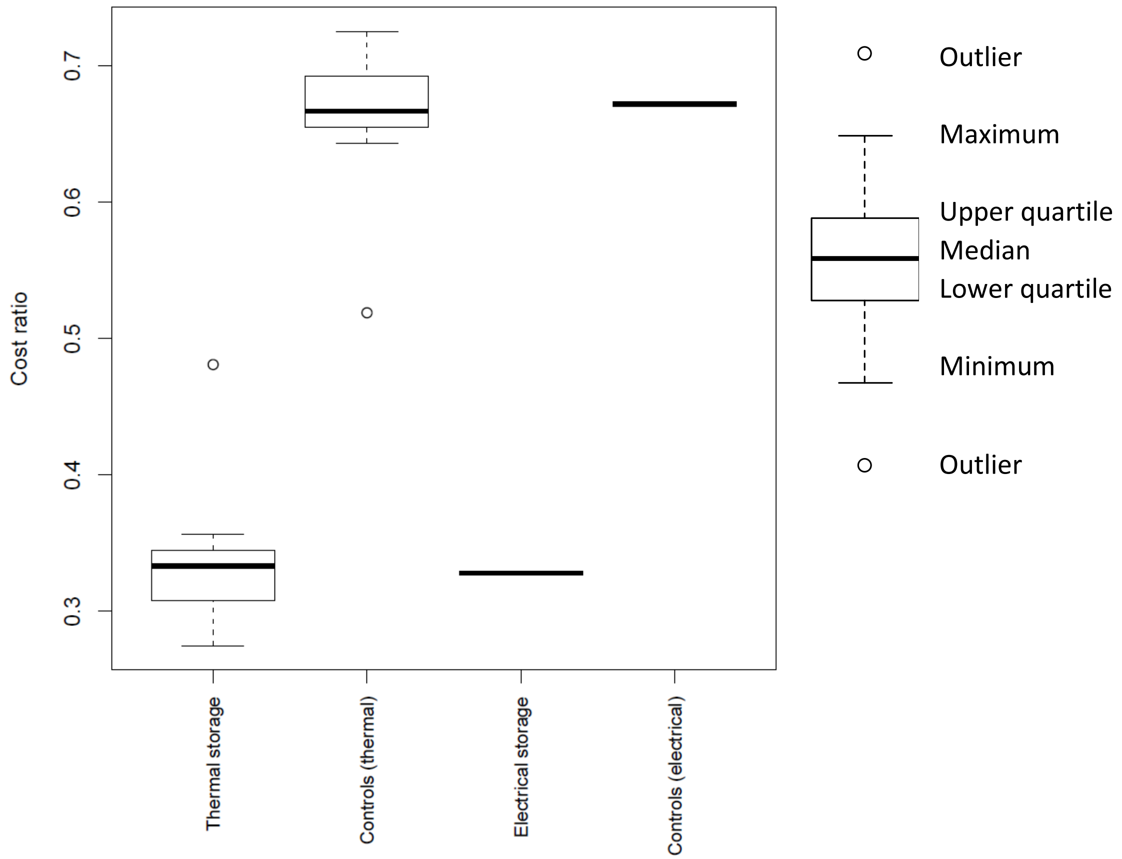

Figure 2. Ratio of individual to total cost for integration systems including thermal and electrical storage. Controls (thermal) represent the SCADA and hardware and the integration and testing cost ratio for systems including energy storage, and controls (electrical) represent the same for systems including electrical storage.

Transportation

Transportation costs depend on the weight, size, and shipping restrictions of the integration hardware as well as the distance and available means of transportation to the end destination. Energy storage units can be quite large and can fill several sea containers, depending on the containers' capacity and on the technology. Integration hardware such as switchgear generally can be broken down and transported in small planes, if necessary. An entire electrical cabinet is more difficult to transport. Some forms of energy storage have hazardous materials that need to be disposed of at the end of their life, which often involves transporting them somewhere for safe extinction.

Technology trends

Trends that are being used to integrate higher penetrations of renewable energy in grids include demand side management, excess generation to heat, energy storage with grid-forming inverters, and advanced control systems. Demand side management allows electrical loads to be turned on and off, depending on the presence of excess electrical generation. Excess generation can be stored in thermal and electrical energy storage. Electrical energy storage and grid-forming inverters can be used to maintain grid stability and allow diesel generators to be turned off with sufficiently high penetration of renewable energy. Advanced control systems are being developed for microgrids; however, they are often designed for grid-connected microgrids and it is uncertain how well they will work for remote microgrids.

Tech specific storage systems

Various electrical or thermal storage systems can be part of integrating an energy source into a grid, as discussed previously.

Refurbishment/Upgrade market

Refurbishment/upgrade market data are only available for electrical energy storage. These data are also relevant to SCADA and hardware and thermal storage. For the electrical energy storage refurbishment/upgrade market, see the respective briefing paper.

Realized Cost Savings

Cost savings from integrating renewable power are difficult to gauge due to technical and incentive impacts at the entire power systems level. At the technical level, for example, the effects of diminished losses of secondary services such as recovered waste heat and reductions in fuel efficiency are hard to gauge, as they depend not only on average reductions in load, but also on specific operating schemes regarding minimum allowable load on diesels and on available spinning reserve.

Acknowledgments

Many people have contributed information and insight to this report. For their review and comments, we wish to thank John Cameron from Marsh Creek, LLC; Martin Miller from Coffman Engineers; Ingemar Mathiasson, Energy Manager of the Northwest Arctic Borough; David Burlingame of Electric Power Systems; Jason Custer of Alaska Power and Telephone; Cal Kerr and Dave Weiss of Northern Economics; Dave Messier, Rural Energy Coordinator at the Tanana Chiefs Conference; and Josh Craft, Neil McMahon, and Dan Hertrich of the Alaska Energy Authority.

Appendix A

Table A1: Individual project costs. "Wind Power" refers to the wind capacity installed with the current project. "Existing Wind Power" refers to the wind capacity already existing in the grid before the current project. Total and incremental RE penetration refer to the respective penetration of total and newly installed wind capacity.

Names	Year	Wind Power [kW]	Existing Wind Power [kW]	Average Load [kW]	SCADA and Communi-cations [$/kW]	Integration Hardware [$/kW]	Integration and Testing [$/kW]	Electrical Energy Storage [$/kW]	Thermal Storage [$/kW]	Total [$/kW]
Nome Phase 3 and 4	2012	900	900	4200	0	0	17	0	0	17
Nikiski Wind Farm Construction	2008	18000	0	10976	0	28	0	0	0	28
Kenai Winds	2009	18000	0	10976	0	28	0	0	0	28
Eva Creek Wind Farm Construction	2008	24000	0	157000	54	0	4	0	0	58
St. Mary's / Pitkas Point	2011	400	0	356	0	0	75	0	0	75
Bethel	2011	1000	0	5000	0	0	111	0	0	111
St. Mary's	2012	300	0	414	0	250	250	0	0	500
Teller	2010	300	0	217	0	558	100	0	0	658
Kongiganak Wind Farm Construction	2008	450	90	210	0	1651	0	0	678	2329
Pillar Mountain	2012	4500	4500	17000	0	0	0	844	0	844
Nome / Newton Peak Wind Farm Construction	2008	3000	0	3487	168	0	807	0	0	974
Kaktovik	2011	300	0	420	0	0	667	0	333	1000
Point Hope	2011	300	0	620	0	0	667	0	333	1000
Point Lay	2011	300	0	310	0	0	667	0	333	1000
Wainwright	2011	300	0	525	0	0	667	0	333	1000
Sand Point Wind	2009	1000	0	461	0	0	903	0	342	1245
Kotzebue	2010	1800	0	2500	0	0	860	420	0	1280
St. Mary's / Pitkas	2013	900	0	368	0	0	1458	0	0	1458

Integration Technology Report

Names	Year	Wind Power [kW]	Existing Wind Power [kW]	Average Load [kW]	SCADA and Communi-cations [$/kW]	Integration Hardware [$/kW]	Integration and Testing [$/kW]	Electrical Energy Storage [$/kW]	Thermal Storage [$/kW]	Total [$/kW]
Emmonak / Alakanuk Wind & Trans	2009	800	0	489	0	1563	0	0	0	1563
Unalakleet Wind Farm Construction	2008	1200	800	458	411	0	1918	0	0	2329
St. Mary's / Pitkas	2015	380	0	367	0	1338	0	0	526	1865
Tuntutuliak High-Penetration Wind Diesel	2009	475	0	150	0	0	939	0	754	1693
Shaktoolik Wind	2009	200	0	92	0	2500	0	0	0	2500
Pilot Point	2010	100	0	60	0	1640	0	0	1520	3160

Organic Rankine Cycle Technology Report

Summary

Resource and Technology Description

Diesel generators are the main source of electricity in remote Alaska communities. The best diesel generator systems convert roughly 40% of diesel fuel energy content into electricity, with the rest of the fuel energy converted to heat. This heat, if not captured by heat recovery devices, is lost into the atmosphere through the exhaust and cooling systems. When direct use of engine waste heat for space or domestic water heating is not practical, this heat energy can be used to generate additional electricity through organic Rankine cycle (ORC) technology.

An ORC uses an organic fluid with a boiling point lower than that of water to convert the waste heat from the cooling jackets and exhaust stacks of generators into mechanical work and, ultimately, electricity. Exhaust stack gases can be high temperature (over 1000°F), while cooling jacket water is lower temperature (as low as 165°F). The ORC is utilized as a waste heat to power (WHP) system to generate electricity that is supplied to the grid.

Current Installations in Alaska

Four different models of ORC generators have been or are being installed in different parts of Alaska, as summarized in the following table:

Installation Location	Manufacturer	Model	Heat Source	Cold Source	Nameplate Capacity (kW)	Number Units	Total Capacity (kW)
Cordova	Pratt & Whitney	PureCycle 280	Cooling Jacket	Air Coil	260 kW	1	260 kW
Kotzebue	Energy Concepts	Ammonia Power Cycle	Exhaust Stack	City Water and Air Cooler	162 kW	1	162 kW
Unalaska	ElectraTherm	Green Machine	Cooling Jacket	Sea Water	50 kW	3	150 kW
Tok	ElectraTherm	Green Machine Block 1	Cooling Jacket	Well Water	50kW	1	50kW

Key Performance Metrics

Capacity factors range from 33% to 52% for installations that have already been installed; Kotzebue's ORC installation is still in progress. Low utilization levels are a result of insufficient waste heat rather than inefficient ORC operation (in Unalaska), as well as the use of a prototype pre-commercial model (Tok). While operation and maintenance (O&M) costs vary, significant annual fuel savings have been realized for each installation, with annual demonstrated savings of $70,000 in Unalaska and projected annual savings of over $300,000 for the Cordova installation.

Organic Rankine Cycle Technology Report

Summary

The ORC unit itself accounts for a third to a half of total capital costs, indicating that Alaska projects should expect total capital expenditures to be two to three times the cost of the ORC unit itself. Shipping is less than 10% of the cost in all installations.

A 20-year design life is the industry standard for commercial ORC generators, although of the installations in Alaska, only the Unalaska Green Machines have achieved reliable operation beyond a few weeks.

Organic Rankine cycle generators are most efficient with higher temperature waste heat sources. Choice of working fluid is also a factor in efficiency. The ORC units in Alaska all use either R-245fa (pentafluoropropane) or ammonia.

Technology Trends

New ORC systems are being developed to utilize more efficient working fluids that are better suited to particular waste heat source temperatures. An ORC offers the potential to combine multiple waste heat sources of different qualities or to incorporate solar thermal and biomass heat sources.

Technology-Specific Gaps and Barriers to Successful Project Development and Operation

Some systems have been highly reliable and cost-effective, while other installations have not been. An entire ORC project can be expected to run 200–300% of the ORC system cost to cover shipping, infrastructure, and labor. Modifying existing generation for an ORC system can be highly challenging, and in some cases, the ORC system may be best implemented with a ground-up new generator design and install. The smallest reliable system, which operates in Unalaska, has a 50 kW nameplate capacity. The ORC systems of this size require 500 kW of heat, meaning the diesel generator needs to have a 700 kW nameplate at bare minimum. Based on current demonstrated ORC performance, this technology is best suited for communities with waste heat streams of 1 MW or more of diesel generation.

Exhaust heat capture from diesel generators allows elevated cycle temperatures, but may conflict with tightening emissions restrictions, as heat exchangers can interfere with exhaust composition. There is also difficulty in receiving performance guarantees from ORC manufacturers. Installations that are more efficient require approved rate adjustments to recover debt and cost; however, rate proceedings are very expensive and time-consuming.

Recommendations

With the state's power cost equalization (PCE) formula relying on gallons of diesel burned, it can create a disincentive for offsetting diesel consumption. Uncertainty over the effect of exhaust stream heat recovery on emissions and the progression of EPA emissions requirements pertaining to rural diesel generators further discourages investment in ORC projects. The State of Alaska or AEDC could insist that the EPA provides clarity and accommodations on emissions for this type of technology to create an environment conducive to such investments. Current powerhouses are trying to make engines more efficient, with decreased emissions and rates for customers; however, as emissions laws are toughened, utilities are not seeing real returns on their capital investments in these projects. An incentive is recommended, along with a simplification in the rate-making process.

Organic Rankine Cycle Technology Report

Prepared by the Alaska Center for Energy and Power for the Alaska Affordable Energy Strategy Effort with funding from the Alaska Energy Authority

Diesel generators are the main source of electrical generation in remote Alaska communities. The best diesel generator systems convert roughly 40% of the diesel fuel energy content into electricity, with the rest of the fuel energy converted to heat. This heat, if not captured by heat recovery devices, is lost into the atmosphere through the exhaust and cooling systems. The most efficient use of waste heat is for direct heating of adjacent building spaces or domestic water. When such direct use of engine waste heat is precluded by geographic or infrastructure constraints, this heat energy can be used to generate additional electricity through organic Rankine cycle (ORC) technology.

An ORC uses an organic fluid with a boiling point lower than that of water to convert waste heat from the cooling jackets and exhaust stacks of generators into mechanical work and, ultimately, electricity. Exhaust stack gases can reach high temperatures (over 1000°F), while cooling jacket water is a lower temperature (as low as 165°F). The ORC is utilized as a waste heat to power (WHP) system to generate electricity that is supplied to the grid. This report evaluates four ORC units implemented in communities in Alaska.

ORC Models

Four different models of ORC generators have been or are being installed in different parts of Alaska. A summary of the installations is shown in Table 1.

Table 1. Summary of Alaska ORC installations.

Installation Location	Manufacturer	Model	Heat Source	Cold Source	Nameplate Capacity (kW)	Number Units	Total Capacity (kW)
Cordova	Pratt & Whitney	PureCycle 280	Cooling Jacket	Air Coil	260 kW	1	260 kW
Kotzebue[1]	Energy Concepts[2]	Ammonia Power Cycle	Exhaust Stack	City Water and Air Cooler	162 kW	1	162 kW
Unalaska	ElectraTherm	Green Machine	Cooling Jacket	Sea Water	50 kW	3	150 kW
Tok	ElectraTherm	Green Machine Block 1[3]	Cooling Jacket	Well Water	50kW	1	50kW

In Cordova, a Renewable Energy Fund (REF) grant enabled the installation of a new 3.6 MW diesel generator and dedicated ORC waste heat recovery system. The project, which was completed in March 2013, ran for approximately 2 months before being shut down for economic reasons. The diesel

[1] Kotzebue ORC installation is in progress. System expected to commission summer 2016.
[2] Kotzebue REF application data are for an Energy Concepts ORC, but a GE brand system was actually purchased.
[3] Block 1 machine was a prototype, pre-commercial model.

generator is too often supplanted by hydroelectric generation, and the air coil cooling tower design for the ORC has proved insufficient.

In Unalaska, three ElectraTherm 4200 50 kW stand-alone ORC modules were installed to capture waste heat off three of the powerhouse's diesel generators. The city considered the ORC systems of more than a dozen manufacturers before selecting the ElectraTherm units. The Unalaska ORC installation was completed in October 2014, and the units are still in operation, requiring only routine maintenance. As of March 2016, the system has offset 44,501 gallons of fuel usage, saving the city $101,686.

Kotzebue is currently working to complete the installation of a waste heat recovery system to use waste heat from the exhaust stack of their largest generator. The system is being installed simultaneously with district heating upgrades and a new absorption chiller system that produces ice for the local fishing industry.

The ORC system in Tok was initially installed at the ACEP Power Systems Integration (PSI) Laboratory for testing. The system was then moved to the Tok power plant, where it ran continuously from October 2, 2013, to November 19, 2013, when an expander failure shut down the system. The manufacturer stated that it was aware of the problem, and it has implemented design and lubricant changes in subsequent models. In Tok, the ORC expander was not rebuilt, and the system was bypassed.

Every system is expected to perform below peak capacity in the real world. The capacity factor is the actual ORC output as a percentage of the nameplate capacity. The Kotzebue application assumes a capacity factor of 96%, but the real-world performance of the other three systems indicates that 30–50% is a more realistic expectation. Table 2 contains the demonstrated power, energy output, run time, and capacity factor of the ORC systems in Alaska. Estimated values are in italics.

Table 2. Summary of ORC power output and energy production in Alaska (estimated values in italics)

	Power Output			**Energy Production**		
	Name-plate (kW)	**Average Demonstrated (kW)**	**Total Demonstrated Runtime (hr)**	**Name-plate (kWh/yr)**	**Average Demonstrated (kWh/yr)**	**Capacity Factor**
Cordova[4]	260	134.0	382	2,265,120	*1,167,408*	52%
Kotzebue[5]	162	*154.7*	-	1,411,344	*1,348,164*	*96%*
Unalaska[6]	150	57.4	30,000	1,306,800	500,064	38%
Tok[7]	50	16.6	1138	435,600	*144,619*	33%

Capital Costs and Operation and Maintenance Costs

The capital costs for each installation were calculated for both nameplate and demonstrated power outputs. Capital costs represent the total "overnight" expenses incurred prior to the first production of

[4] Cordova performance from 2013 ACEP case study.
[5] Kotzebue performance based on 2008 REF application estimates.
[6] Unalaska performance data submitted through March 2016 by City of Unalaska.
[7] Tok performance data from 2013 ACEP report field data.

electricity. The annual operations and maintenance (O&M) costs were calculated based on nameplate and demonstrated annual energy output. The Cordova installation coincided with a new diesel generator installation, and the Kotzebue installation coincided with a new absorption chiller and district heating loop installation. To the extent possible, the ORC system costs were isolated from the total project costs for Cordova and Kotzebue. The nameplate figure represents the system running at nameplate capacity 363 days a year (2 days offline for maintenance). Estimated and projected figures in Table 3 are in italics.

Table 3. Capital costs and O&M costs of ORC systems installed in Alaska (estimated values in italics).

	Capital Cost			O&M Costs		
	Capital Cost (USD)	**Nameplate ($/kW)**	**Actual ($/kW)**	**Annual O&M ($/yr)**	**Nameplate ($/kWh)**	**Actual ($/kWh)**
Cordova[8]	$1,934,376	$7,440	$14,436	$17,555	$0.00775	$0.01504
Kotzebue[9]	$1,056,042	$6,519	$6,824	$20,222	$0.01433	$0.01500
Unalaska[10]	$1,889,381	$12,596	$32,916	$1,200	$0.00092	$0.00240
Tok[11]	$280,500	$5,610	$16,898	$7,600	$0.01745	$0.05255

The data from Table 3 are plotted in Figure 1 for comparison. The nameplate quantities are represented with triangles, and the demonstrated quantities are represented with circles. The quantities for each installation are connected by color-coded lines.

[8] Cordova capital costs from REF application cost worksheet; O&M costs projected based on ACEP case study.
[9] Kotzebue costs from REF application estimates.
[10] Unalaska capital costs from REF application. Unalaska O&M actual costs reported by City of Unalaska.
[11] Tok capital costs based on installation of pre-production module at ACEP PSI laboratory; O&M costs estimated by ACEP study.

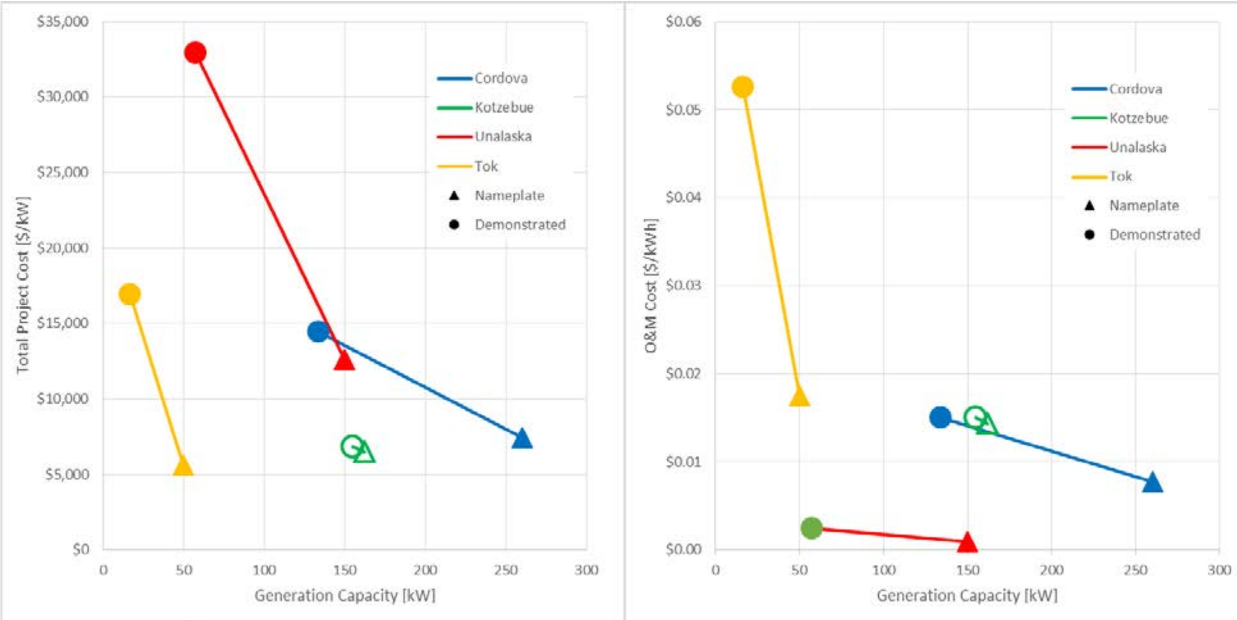

Figure 1. Alaska ORC capital and O&M costs. The nameplate quantities are represented with triangles, and the demonstrated quantities are represented with circles. The quantities for each installation are connected by color-coded lines.

A 2015 report from Oak Ridge National Labs (ORNL) (Elson et al., 2015) predicts the installed cost of 4,500 $/kW for ORC systems between 50 and 500 kW capacity. ElectraTherm quotes turnkey prices for three of their ORC modules ranging from 35 kW to 110 kW. In Figure 2, the capital costs of the Alaska installations are plotted with the ORNL and ElectraTherm values for comparison.

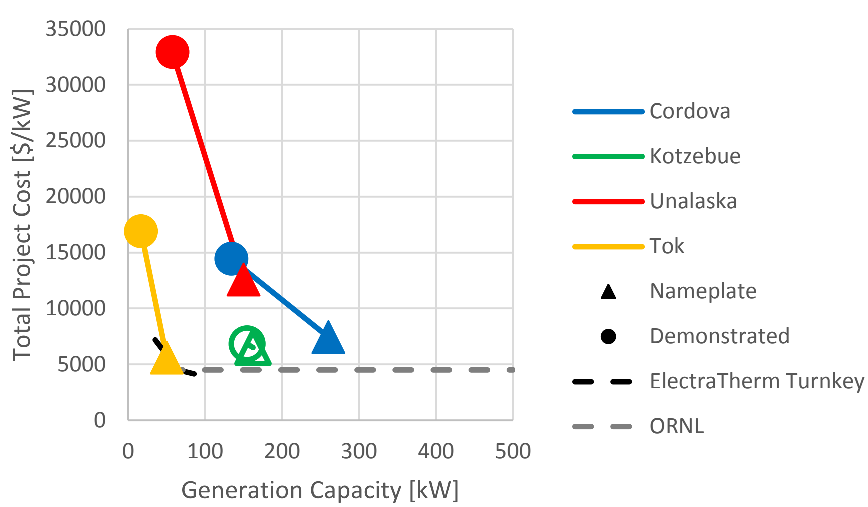

Figure 2. Alaska ORC capital costs compared with commercial expectations in the Lower 48. Elevated nameplate costs can be attributed to higher costs of shipping, labor, and materials in Alaska's remote areas.

The nameplate capital cost for the Alaska projects fall much closer to expected than demonstrated costs. Elevated nameplate costs can be attributed to higher costs of shipping, labor, and materials in Alaska's remote areas. Demonstrated capital costs in Alaska are up to seven times greater than expected capital costs in the Lower 48. This difference can be attributed to the Alaska installations operating with relatively low capacity factors. Low capacity factors are likely to be the result of either maintenance/reliability-related downtime or improper system sizing. Improper sizing can result in an ORC that requires more heat than can be supplied, or inefficient performance due to ineffective cooling on the cold side of the ORC.

Expected Life of Unit

A 20-year design life (Venables, 2014; ElectraTherm, 2015) is the industry standard for commercial ORC generators. Of the installations in Alaska to date, only the Green Machines located in Unalaska have achieved reliable operation beyond a few weeks. The City of Unalaska reports their ORC modules have required only normal maintenance.

Capacity Factor

The capacity factor is the ratio of the actual energy generated to the nameplate capacity of the installed unit. As shown in Table 2:

- The Cordova PureCycle briefly demonstrated 52% capacity.
- The Kotzebue Ammonia Power Cycle is billed to achieve 96% capacity.
- The Unalaska ElectraTherm units are achieving 38% capacity.
- The Tok ElectraTherm unit demonstrated 33% capacity.

It was noted in the Green Machine report (Lin, 2014) that the amount of waste heat available in most communities may not be enough to run an ORC unit at full capacity year-round, as waste heat availability in summer in some communities may decrease, reducing the operational period of the ORC to 7.5 months, or less, a year.

Diesel Offset

The magnitude of diesel offset is dependent on the generating efficiency of the existing diesels, the ORC capacity factor, and the efficiency of the ORC system, which is dependent on the temperature of the waste heat and the proper sizing of the system. Total annual savings is the cost savings from diesel offset minus the ORC O&M expenses. The estimated and projected figures in Table 4 are in italics.

Table 4. Alaska ORC annual diesel offset and cost savings.[12] Estimated and projected figures in italics.

		Cordova	Kotzebue	Unalaska	Tok
Annual Diesel Generation[13]	Diesel Cost ($/gal)	$3.87	$5.20	$2.28	$5.00
	Annual Generation (kWh)	11,490,065	20,300,000	45,719,844	9,776,160
	Diesel Consumption (gal/yr)	841,763	1,400,000	2,921,748	698,297

[12] Fuel prices and savings calculated utilizing costs reported for period of evaluation.

[13] Annual generation information from REF applications.

		Cordova	Kotzebue	Unalaska	Tok
	Diesel Efficiency (kWh/gal)	13.82	14.5	15.69	14
ORC Output	Average Power (kW)	134	*155*	57	17
	Annual Energy (kWh)	*1,167,408*	*1,348,164*	500,064	*144,619*
ORC Annual Impact	Diesel Offset (gal/yr)	*84,472*	*92,977*	31,872	*10,330*
	Fuel Savings ($/yr)	*$326,908*	*$483,480*	$72,667	*$51,650*
	Combined Efficiency (kWh/gal)	*15.04*	*15.46*	15.82	*14.21*
	Annual Savings (Fuel - O&M) ($/yr)	*$309,353*	*$463,258*	$71,467	*$44,050*

Conditions for Greatest Efficiency

The percentage of waste heat that can be converted into mechanical work for electricity generation is limited by the thermodynamic availability of the energy in the system, as defined by the Carnot efficiency equation:

$$\eta = 1 - (T_c/T_h)$$

Maximum possible ORC system efficiency, η, is dependent on both the waste heat temperature, T_h, and the available cold temperature resource, T_c (generally the ambient air temperature or natural cold-water source), where the temperature units are in Kelvin. Typical waste heat to power systems achieve around 1/3 of Carnot efficiency (Elson et al., 2015). The waste heat temperatures and operating efficiencies achieved by the three ORC installations in Alaska are shown in Figure 3, along with a curve of 1/3 Carnot efficiency.[14] The efficiency of the ORC in Unalaska indicates that its low capacity factor is a result of insufficient waste heat, rather than inefficient ORC operation.

[14] Carnot efficiency assuming 40°F cold source temperature.

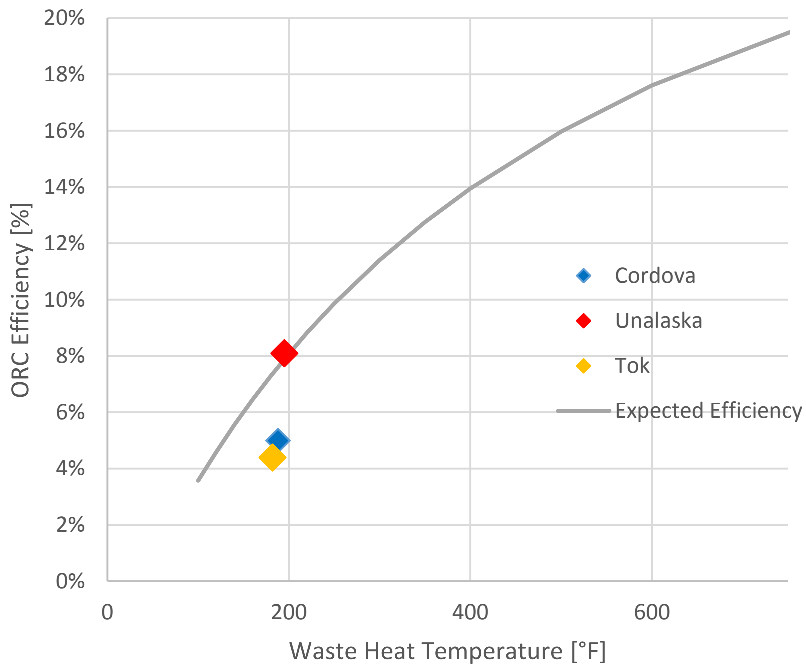

Figure 3. ORC efficiency as a function of waste heat temperature. Expected efficiency assumes 40°F cold source temperature and achievement of 1/3 Carnot efficiency.

Cooling jacket water is an appealing waste heat source, as an ORC can often be plumbed with the engine's existing coolant lines. The jacket heat is limited in temperature to the designed operating temperature of the engine (typically 160–200°F). Exhaust stack heat recovery offers the potential for higher temperatures (300°F or more) and increased ORC efficiencies, but requires the additional capital costs of adding a heat exchanger to the engine's exhaust system. In addition, the presence of the exhaust heat exchanger can change the exhaust gas composition and may not be compatible with emissions controls.

Working fluid choices can affect the operating efficiency of the ORC unit. The ORC units in Alaska all use either R-245fa (pentafluoropropane) or ammonia as the working fluid. Other proven working fluids include pentane, propane, CO_2, benzene, toluene, and *p*-Xylene. Polar molecules such as water, ammonia, and ethanol (due to strong hydrogen bonds) are not the most appropriate working fluids due to larger vaporizing enthalpy (Liu et al., 2004). Organic Rankine cycle working fluids should also have high decomposition temperatures and high critical and condensing temperatures, and be chosen to work within the temperature range of available waste heat and cold resources (Bourji et al., 2010). Organic Rankine cycle manufacturers select working fluids based on anticipated waste heat temperatures and hardware compatibility.

Cost Curve over Time

There is not sufficient ORC presence in Alaska to comment on cost changes over time. The installation in Unalaska, which is a newer version of the ElectraTherm pre-production ORC system in Tok, has exhibited improved reliability and decreased O&M costs.

Installed Costs by Major Components

Capital costs were compared on a per-kilowatt nameplate basis and broken into categories of ORC unit, materials, labor, shipping, and other costs. Table 5 compiles the nameplate capital costs of each project category. The ORC unit itself accounted for 34–47% of the total capital costs, indicating that projects in Alaska should expect total capital expenditures to be two to three times the cost of the ORC unit itself. Capital costs are graphed in Figure 4. Kotzebue's numbers are based on expected costs and performance from its REF application, with actual installed costs expected to be higher and actual performance expected to be lower.

Table 5. Capital costs breakdown based on nameplate capacity. Kotzebue's numbers are based on expected costs and performance from its REF application, with actual installed costs expected to be higher and actual performance expected to be lower.

		Cordova	Kotzebue[15]	Unalaska	Tok
ORC Unit	$/kW	$3,961	$2,932	$4,256	$2,388
	% Total	53%	45%	34%	43%
Materials	$/kW	$0[16]	$1,533	$4,615	$1,439
	% Total	0%	24%	37%	26%
Labor	$/kW	$3,452	$1,080	$2,089	$1,780
	% Total	46%	17%	17%	32%
Shipping	$/kW	$28[17]	$753	$500	$0
	% Total	0%	12%	4%	0%
Other	$/kW	$0	$220	$1,135	$3
Total	$/kW	$7,440	$6,519	$12,596	$5,610

[15] Based on expected costs and performance.
[16] ORC unit costs not separated from other materials.
[17] Shipping from Whittier to Cordova only.

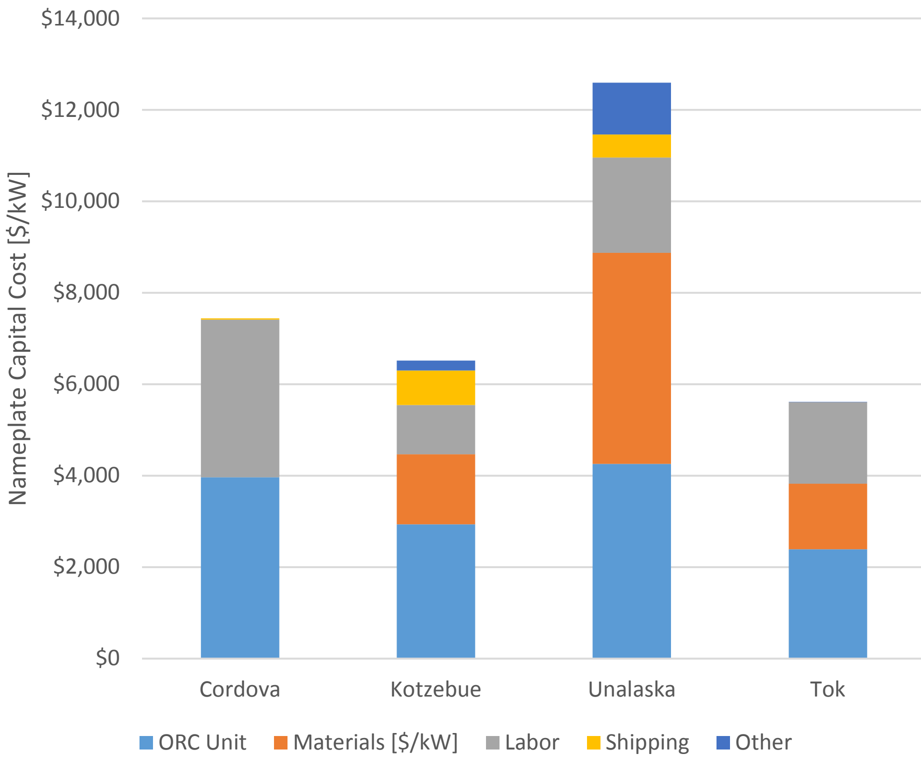

Figure 4. ORC nameplate capital cost per kilowatt by cost category.

Average Transportation Costs

From the Unalaska and Kotzebue estimates, it appears shipping constitutes 4–12% of the capital costs of an ORC installation in Alaska. Available shipping information is shown in Table 6.

Table 6. Transportation costs for systems to communities in Alaska

Cordova	$7,220	Barge: Whittier to Cordova
Unalaska	$75,053	Land: Reno to Seattle (706 mi) Barge: Seattle to Unalaska (1951 mi)
Kotzebue	$122,000	Unknown
Tok	Costs were not separated out	Land/Barge: Reno to Tok (2700 mi)

Technology Trends

Organic Rankine cycle system performance is highly dependent on the quantity and temperature of available waste heat, the availability of a low-temperature heat sink, and the properties of the working fluid. New systems are being developed to utilize more efficient working fluids that are better suited to particular waste heat source temperatures. Exhaust heat captured from diesel generators allows elevated cycle temperatures, but may conflict with tightening emissions restrictions, as the heat exchangers can interfere with exhaust composition. The ORC offers the potential to combine multiple waste heat sources of different qualities or to incorporate solar thermal and biomass heat sources.

Tech-Specific Storage Systems

The energy generated by the ORC unit is integrated into the main power plant electric generation grid. The heat used to generate power through the ORC comes from the power plant directly as waste heat. Some systems use thermal storage when combined with other renewable energy sources such as solar photovoltaic power.

Levelized Cost of Energy

The estimated cost of energy of each system over a 20-year life was calculated using the National Renewable Energy Laboratory's Energy Analysis Calculator.[18] The simple levelized cost of renewable energy (sLCOE) reflects the average cost of energy over 20 years from a renewable system and is calculated assuming a 3% discount rate. Table 7 presents the specific capital and O&M costs along with capacity factor and 20-year sLCOE.

Table 7. Alaska ORC specific costs and 20-year sLCOE

	Nameplate Capacity (kW)	Capital Costs ($/kW)	O&M Costs ($/kWh)	Capacity Factor	20-yr sLCOE ($/kWh)
Cordova	260	$7,440	$0.00775	52%	$0.117
Kotzebue	162	$6,519	$0.01433	96%	$0.066
Unalaska	150	$12,596	$0.00092	38%	$0.254
Tok	50	$5,610	$0.01745	33%	$0.130

Acknowledgments

Many people have contributed insight and information to this report. For their review and comments, we wish to thank Bob Grimm and Ben Beste of Alaska Power and Telephone; Earl George and David Burlingame from Electric Power Systems; Bob Deering, Renewable Energy Coordinator for the United State Forest Service Alaska Region; Dan Winters, Director of Public Utilities for the City of Unalaska; Dave Messier, Rural Energy Coordinator at the Tanana Chiefs Conference; and Devany Plentovich and Neil McMahon of the Alaska Energy Authority.

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Unalaska	http://www.ci.unalaska.ak.us/sites/default/files/fileattachments/Public%20Utilities/page/1007/waste_heat_to_energy_feasibility_study.pdf
Kotzebue	ftp://www.aidea.org/REFund/Round%202/Applications/235_Kotzebue%20HR%20and%20Ammonia%20Power%20Cycle/AEA-REF-WasteHeat.pdf

[18] http://www.nrel.gov/analysis/tech_lcoe.html

Tok	http://acep.uaf.edu/media/112531/Green-Machine-Final-Report-12-9-2014.pdf

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Solar Photovoltaic Technology Report

Summary

Prepared by the Alaska Center for Energy and Power for the Alaska Affordable Energy Strategy Effort with funding from the Alaska Energy Authority

Resource and Technology Description

The installation of solar photovoltaic (PV) arrays has increased in Alaska in the last 5 years as the price of systems has dropped. A number of factors support the prospects for solar PV power in Alaska energy systems. Detailed computer simulations by the National Renewable Energy Laboratory (NREL) show significant solar potential on par with or greater than Germany, the largest market for solar power in the world. (To be fair, it should be noted that the large penetration of solar PV power in Germany is due to government policies and incentives.) Alaska's cold temperatures increase solar PV system voltage, reduce electrical resistance, yield higher-than-rated outputs associated with reflected light and albedo effect, and may affect long-term degradation of solar panels differently.

Current Installations in Alaska

This briefing paper covers community installations, ranging in size from 2.2 kW in Ambler to 50 kW in Galena, of which there are about 20 in the state of Alaska. Some of the systems installed in communities around the state are currently being monitored, and data are available via online portals. Cost information is harder to come by. State-funded project cost information is available from the Alaska Energy Authority, but few projects have been funded by the state. Cost information is sometimes available via community development staff. Significant data collection is still needed for specific details such as module technology type, mounting types, and other characteristics that can further refine this analysis.

Key Performance Metrics

With the exception of several outliers, total installed costs arguably show a trend towards lower values with larger installation sizes. However, prices in Alaska are still significantly higher than prices in the rest of the United States. Operation and maintenance costs vary due to limited data and the short time that solar PV systems have been installed in Alaska. Anecdotally, many solar PV arrays installed around the state have not needed any maintenance since installation. In general, cost data for solar installations in rural Alaska are difficult to obtain. Often a job is bid on by a contractor as a lump sum, and separating labor from equipment and materials is difficult to do accurately.

Capacity factors for selected installations around Alaska range from 6%–15%. Note that many of the systems installed in the Northwest Arctic Borough were installed in a semicircular fashion with the goal of a broad production curve rather than maximum power production. Additional systems are installed around the state, but do not have sufficient data available to obtain capacity factor information.

Most installers assume a system life of 25 years, although individual components may need replacement sooner.

Solar Photovoltaic Technology Report

Summary

Technology Trends

In Alaska, options in solar PV systems include micro-invertors, which are attached to each panel and prevent an entire string of panels from going offline if just one panel is damaged. Concentrated solar PV technology is a candidate for generating heat as well as electricity.

Technology-Specific Gaps and Barriers to Successful Project Development and Operation

A current paradox for utilities is that renewable energy installations can displace diesel, but fixed costs remain, and utilities end up raising rates for the rest of the community to cover their fixed costs. In addition, Alaska's installations are smaller and mainly comprise monocrystalline silicon panels. Tracking systems, which may yield additional output, have been successfully demonstrated but require regular inspection, which may not always be available in remote communities. Even then, the extra cost of tracking systems makes them not nearly as cost-effective as nontracking systems, especially with the decreasing cost of modules in general.

Recommendations

Statewide purchasing of panels could provide larger economies of scale, and providing help with navigating tax credits for solar PV installations would be useful, especially for those parties without tax liabilities.

Solar Photovoltaic Technology Report

Prepared by the Alaska Center for Energy and Power for the Alaska Affordable Energy Strategy Effort with funding from the Alaska Energy Authority

The installation of photovoltaic solar arrays has increased in Alaska in the last 5 years as the price of the systems has dropped. Photovoltaic modules can be purchased in Fairbanks at prices between $1 and $2 per watt. To obtain information regarding the current state of the solar industry in Alaska, we consulted installers, community development staff, and Alaska Energy Authority staff. Many of the systems installed in communities around the state are currently being monitored, and data are available via online portals. Cost information is harder to come by. Cost information for state-funded projects is available from the Alaska Energy Authority, but few projects have been funded by the state. Cost information is sometimes available via community development staff. This briefing paper covers community installations, ranging in size from 2.2 kW in Ambler to 50 kW in Galena. Significant data collection is still needed for specific details such as module technology type, mounting types, and other characteristics that can help further refine the analysis.

This paper is not meant to be an exhaustive discussion of solar photovoltaic installations in Alaska or a discussion on the proper design of solar photovoltaic systems. As such, not all possible issues related to solar photovoltaic power production are addressed, which is in accordance with the scope of work for this project.

Total Installed Costs

Total installed costs in $/W plotted as a function of installation size arguably show a trend towards lower costs with larger installation sizes, as seen in Figure 1. The 6.7 kW installation in Galena ($3.19/W) and the 18 kW installation in Fort Yukon ($3.89/W) were accomplished with creative means to cuts costs. In Fort Yukon, these factors included volunteer labor and a shipping deal. For a number of other installations, figures are based on verbal estimates from batched purchases and are not public record. The inconsistency of information is indicative of the nascent solar photovoltaic industry in Alaska. In general, however, prices in Alaska are still higher than prices in the rest of the United States. According to the Lawrence Berkeley National Laboratory (LBNL) report “Tracking the Sun VII,” in the Lower 48, “Installed prices exhibit significant economies of scale, with a median installed price of $4.8/W [$4,800/kW] for systems ≤ 2 kW completed in 2013, compared to $3.1/W [$3,100/kW] for commercial systems > 1,000 kW” (Barbose et al., 2014, page 2)

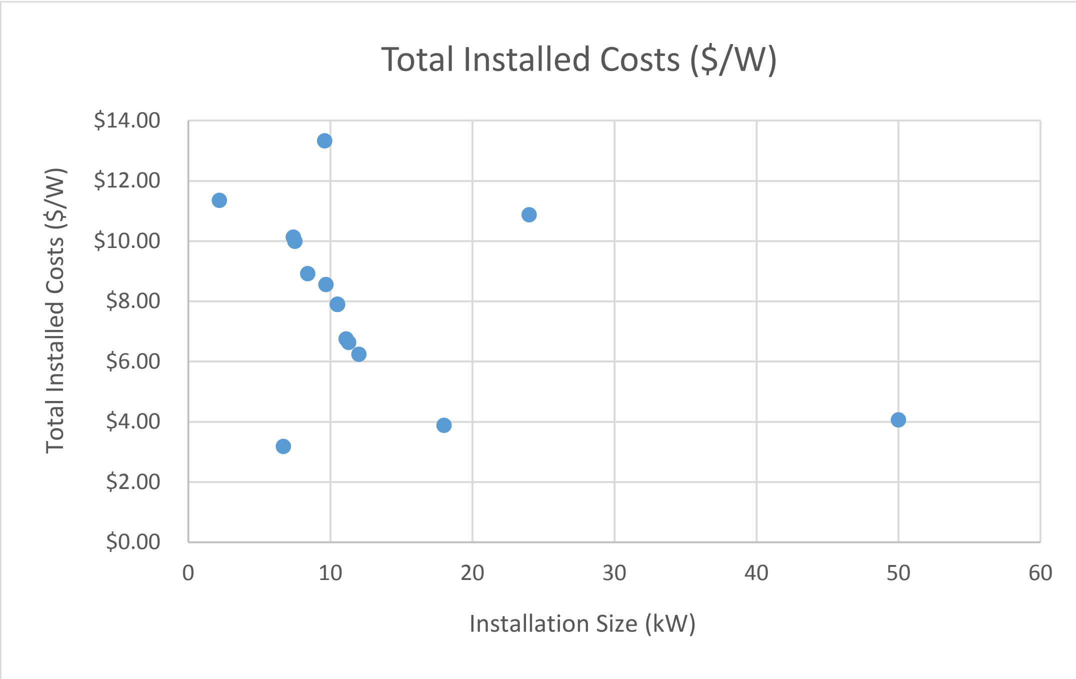

Figure 1. Total installed costs ($/kW) as a function of installation size (kW) arguably show a trend towards lower costs with larger installation sizes.

Operation and Maintenance Costs

Photovoltaic (PV) system operation and maintenance (O&M) cost calculation is an area of increasing interest. Most systems installed around the United States have been installed within the last 8 years and limited O&M cost data exist (Enbar et al., 2015). In Alaska, most grid-tied PV systems were installed less than 5 years ago. According to the Electric Power Research Institute, O&M costs include scheduled maintenance and cleaning, unscheduled maintenance, and inverter replacement reserves, with costs up to $47/kW/yr for nontracking systems (Enbar et al., 2010). The O&M figures from a report by Black and Veatch (2012) and the LBNL (Bolinger et al., 2015) are $20–$50/kW/yr for nontracking PV systems. Obviously, this range is wide due to limited data and the short amount of time that grid-tied PV systems have been installed. In addition, industry's best practices are just beginning to emerge.

The Cold Climate Housing Research Center (CCHRC) has some of the oldest grid-tied solar installations in Alaska; it maintains three pole-mounted PV systems on two-axis tracking systems with a total installed size of 8 kW. A relay has needed replacement, but otherwise very little maintenance has been required. Staff at the CCHRC report that 4 hours of maintenance are devoted to the systems per year (2 hours twice each year). Assuming $60/hour, yearly maintenance costs equal $30/year/kW, without taking inverter replacement into account. The trackers are locked at a fixed angle of 80 degrees azimuth facing due south between November and February, when solar insolation is at a minimum and temperatures are coldest; they are set to track the rest of the year.

One aspect of O&M in Alaska that deserves special mention is that of snow clearing. A study by students at the University of Alaska Fairbanks involved simulating the cost and benefit of clearing snow from a hypothetical 1 MW solar installation that faced south at a panel angle of 70 degrees. The study plainly demonstrated that the cost savings from increased generation of electricity due to snow having been cleared from the panels did not justify the cost of labor to perform the task of clearing snow. This study was performed in Fairbanks, where winds are light and extended cold temperatures cause snow that occurs in fall and winter to stay on the ground into springtime. The results would likely be the same, if not more exaggerated, in Western Alaska where high winds blow and mid-winter warm-ups melt snow from roofs (Vilagi and Brown, 2015).

During discussions with a number of individuals involved in the solar industry in Alaska, it was generally agreed that O&M costs might be approximately $100 per installed kW of PV power on the high side.[1] Note that many of the PV arrays installed around the state have not needed any maintenance since installation. Given all of the documents reviewed to date, for PV systems less than 20 kW in Alaska, O&M likely ranges from $50/kW/yr on the road system or in hub communities and up to $100/kW/yr in more remote areas. Operation and maintenance costs are a function of the level of local expertise available for repairs and the cost of travel to the site, and are not completely dependent on system size. These figures include items such as occasional cleaning and inspection, unscheduled warranty work, inverter replacement reserves, and travel to and from the site.

Expected Life

Most installers assume a system life of 25 years, although it is useful to consider expected lifetimes of individual components. Panels are typically warrantied for 10 years on materials and 25 years for power output, and inverters can be warrantied from 10–20 years. No failure has been reported to date.

Capacity Factors and Diesel Offset

Capacity factor is a function of weather, system design, system installation location, angle, and azimuth. Note that many of the systems installed in the Northwest Arctic Borough were installed in a semicircular fashion with the goal of a broad production curve rather than maximum power production in the middle of the day. More systems are installed around the state than the ones reported here; however, insufficient data were available to obtain capacity factor information on the systems not listed.

In Table 1, diesel offset was calculated by dividing the community diesel power plant efficiency, found in reports by the Alaska Energy Authority (AEA) Power Cost Equalization (PCE), into the system's annual solar production. While additional factors contribute to the amount of diesel fuel offset by a renewable energy system, this method provides a rough approximation.

[1] Most solar systems within Alaska have been installed in the last 5 years, and little maintenance has been needed. The figure of $100/kW was reached after discussions with Ingemar Mathiasson (NWAB), Robert Bensin (BSDC), Jeremy Osborne (Yuut Elitnuarviat), and David Pelunis-Messier (TCC).

Table 1. Capacity factors and diesel offsets for selected solar installations in Alaska.

Village	Rated Size (kW)	PV Capacity Factor	2013 Community Diesel Efficiency (kWh/gal)[2]	Average Daily Solar Performance Since Installation (kWh)	Annual Diesel Offset (gallons)
Ambler	8.4	9%	14.1	17.5	453
Ambler IRA	2.2	12%	14.1	6.1	157
Kobuk	7.4	6%	14.3	10.8	275
BSNC		9%	16.2	37.3	840
Shungnak	7.5	7%	14.3	12.4	316
Noorvik	12	6%	12.4	17.6	518
Noatak	11.3	8%	14.1	21.1	546
Deering	11.1	10%	13.6	26.9	721
Selawik	9.7	11%	13.9	25	656
Yuut Elitnuarviat (Bethel)	10	14%	13.7	33.6	895
Kaltag	9.6	9%	13	21.7	609
Galena	6.7	12%	13.1	18.6	518
Ruby Washeteria	5.4	10%	13.4	12.8	348
Ruby Health Clinic	5.5	8%	13.4	10.8	294
Manley	6	9%	12.5	12.3	359
Nenana	4.4	12%	GVEA[3]	12.5	
CCHRC[4]	8	15%	GVEA	29.7	

Levelized Cost per kW

The simple levelized cost of renewable energy (cents/kWh) was calculated at 70.5 cents/kWh based on the following inputs into the NREL (National Renewable Energy Laboratory) LCOE (levelized cost of electricity) calculator:

Period: 25 years
Discount Rate: 3%
Capital Cost (average): 8,000 $/kW
Capacity Factor (average): 9%
Fixed O&M Cost: $100/kW/yr
Variable O&M Cost: none
Heat Rate: none
Fuel Cost: none

Factoring in the range of capacity factors seen in installations in Alaska, the LCOE ranges from 42.3–105.8 cents/kWh over a capacity factor range of 6–16%, all other variables remaining constant. Similarly, factoring in the range of capital costs seen in installations in Alaska, which are assumed equal to the

[2] From AK Energy Data Gateway.

[3] Nenana is on the Golden Valley Electric Association grid, which receives power from a number of generation sources including hydro, coal, natural gas, fuel oil, and wind. Due to this variety, no diesel efficiency is given, and no diesel offset is calculated.

[4] There are three tracking PV systems at CCHRC. Their performances were averaged to determine capacity factors and summed to calculate the average daily performance.

total installed costs for our purposes since solar PV costs are predominantly capital costs, the LCOE ranges from \$0.40–\$1.22/kWh over a capital cost range of \$3,190–\$13,300/kW.

Conditions for Greatest Efficiency

Photovoltaics work best under clear, cold sunny conditions. Photovoltaic panels are more efficient and produce more power at colder temperatures, and high springtime snow albedo can reflect more solar radiation towards steeply angled panels. These cold, clear conditions and long days with high albedo ground cover usually make April the highest production solar month in most locations around Alaska.

Figure 2 from LG Solar[5] shows the maximum power point (in red) as a function of temperature for an LG Solar module. It is not known whether these plots are based on actual data or extrapolations. The figure shows that at cold temperatures, short-circuit current decreases slightly, while open-current voltage increases rapidly. The important point of this figure, however, is the power output, which at -25°C can be approximately 25% higher than output at the standard test condition cell temperature of 25°C given the same irradiance. Note that this temperature dependence has been best characterized at temperatures higher than standard test conditions, and that this temperature-power correlation needs further independent research and field characterization in Alaska's below-freezing environments.

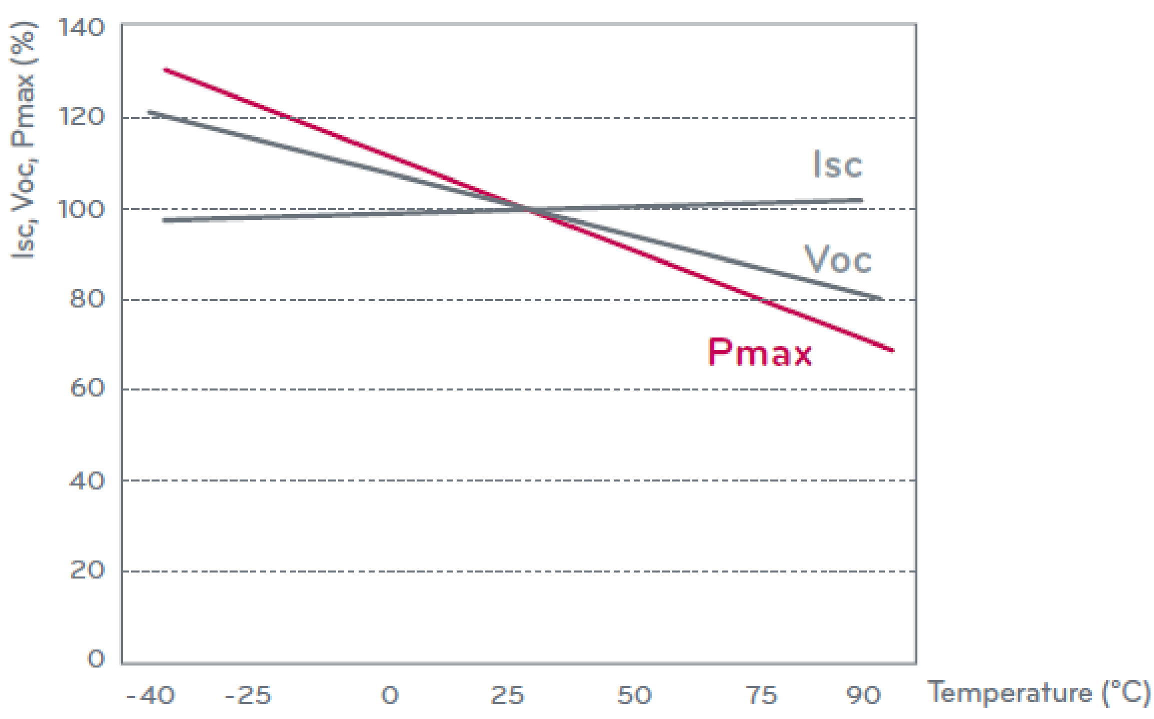

Figure 2. Short circuit current (I_{sc}), open circuit voltage (V_{oc}), and maximum power output (P_{max}) as a function of temperature for an LG Solar module (www.lg-solar.com).

[5] www.lg-solar.com

Cost Curve over Time

The cost curve for solar PV technology in Alaska over time is virtually impossible to establish given the nascent nature of such installations in Alaska, inconsistencies in data, and differences in installation approaches (i.e., some are bid out, other use volunteer labor, and still others find ways to cover shipping, etc.) As a point of reference, we can look to national trends showing a steady decline in the last two decades, as illustrated in Figure 3, from LBNL's "Tracking the Sun VIII Report" (Barbose and Darghouth, 2015).

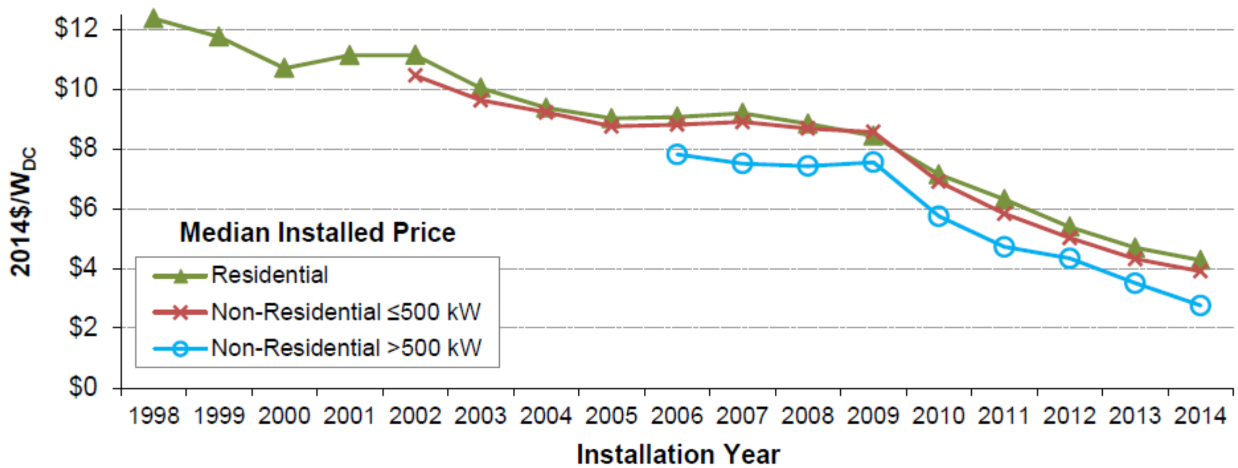

Figure 3. Installed price trends as a function of year (Barbose and Darghouth, 2015).

According to Barbose and Darghouth (2015, p. 15),

> Starting in 2009, installed prices resumed their descent and have fallen steeply and steadily since, with average annual declines of 13% to 18% per year across the three customer segments. As discussed in a later section, these recent price declines are the result of reductions in global PV module prices, as well as declines in other hardware costs and 'soft' costs. Within the last year of the analysis period, from 2013-2014, median installed prices fell by \$0.4/W (9%) for residential systems, by \$0.4/W (10%) for non-residential systems <500 kW, and by \$0.7/W (21%) for non-residential systems <500 kW.

Anecdotal evidence suggests that solar module prices and equipment prices have dropped in Alaska, as they have done in the Lower 48. The costs of shipping and installation remain above those seen in the rest of the country.

Cost Data

Cost data for solar installations in rural Alaska (Table 2) are difficult to obtain. Often the job is bid on by a contractor as a lump sum, and separating labor from equipment and materials is difficult to do accurately. Of note, the 6.7 kW installation in Galena (\$3.19/W) and 18 kW installation in Fort Yukon (\$3.89/W) were accomplished with creative means to cuts costs. In Fort Yukon, these factors included volunteer labor and a shipping deal. For a number of other installations, figures are based on verbal estimates from batched purchases and are not public record.

Table 2. Cost data for selected solar installations in Alaska.

Location	System Size (kW)	Installation Date	Installed Cost by Major Components[6]				Cost/Watt	Total Cost
			Hardware	Support Structure	Labor/Travel	Shipping		
Installed systems. Costs were based on percentages of estimated total system cost[7]								
Ambler	8.4	3/2013	41,250	included in hardware	11,250	22,500.00	$ 8.93	$ 75,000.00
Ambler IRA	2.2	3/2013	13,750	included in hardware	3,750	7,500.00	$ 11.36	$ 25,000.00
Kobuk	7.4	3/2013	41,250	included in hardware	11,250	22,500.00	$ 10.14	$ 75,000.00
Shungnak	7.5	10/2013	41,250	included in hardware	11,250	22,500.00	$ 10.00	$ 75,000.00
Noorvik	12	10/2013	41,250	included in hardware	11,250	22,500.00	$ 6.25	$ 75,000.00
Noatak	11.3	11/2013	41,250	included in hardware	11,250	22,500.00	$ 6.64	$ 75,000.00
Deering	11.1	11/2013	41,250	included in hardware	11,250	22,500.00	$ 6.76	$ 75,000.00
Kotzebue-1	10.5	10/2014	45,650	included in hardware	12,450	24,900.00	$ 7.90	$ 83,000.00
Kotzebue-2	10.5	11/2014	45,650	included in hardware	12,450	24,900.00	$ 7.90	$ 83,000.00
Selawik	9.7	11/2014	45,650	included in hardware	12,450	24,900.00	$ 8.56	$ 83,000.00
Kiana	10.5	8/2015	45,650	included in hardware	12,450	24,900.00	$ 7.90	$ 83,000.00
Buckland	10.5	2015	45,650	included in hardware	12,450	24,900.00	$ 7.90	$ 83,000.00

[6] Systems in Ambler, Kobuk, Shungnak, Noorvik, Noatak, Deering, Kotzebue, Selawik, Kiana, Buckland, and Kivalina (shaded) were installed by Bering Straits Development Company through coordination with the Northwest Arctic Borough. Costs for these systems were difficult to separate from the main lump sum bid. Based on the input from Rob Bensin, costs were separated using 30% for logistics, 15% for labor, and the remainder for racking, hardware, and materials. Systems in Eagle and Kaltag were installed by the utilities using funding from the Renewable Energy Fund. Systems in Galena and Fort Yukon were installed with assistance from the Tanana Chiefs Conference.

[7] Systems were bid as a group. From Rob Bensin, personal communication

Location	System Size (kW)	Installation Date	Installed Cost by Major Components[6]				Cost/Watt	Total Cost
			Hardware	Support Structure	Labor/Travel	Shipping		
Installed systems. Costs were based on percentages of estimated total system cost[7]								
Kivalina	10.5	2015	45,650	included in hardware	12,450	24,900.00	$ 7.90	$ 83,000.00
Installed systems with detailed costs records								
Location	System Size (kW)	Installation Date	Hardware Cost[8]	Support Structure Cost	Labor/Travel Cost	Shipping Cost	Cost/Watt	Total Cost
Eagle	24	7/2015	115,552	included in hardware	94,632		$ 10.88	$261,000.00
Kaltag	9.6	2012	78,657	included in hardware	15,946	6465	$ 13.33	$128,000.00
Galena	6.7	11/2012	14,400	$2000	5,000	City covered shipping cost	$ 3.19	$ 21,400.00
Fort Yukon	18	7/2015	45,000	Included in Hardware	20,000	5000	$ 3.89	$ 70,000.00
Galena	50	Dec 2015 Estimate Only	Lumped together in bid			30000[9]	$ 4.07	$203,613.00

[8] Systems in Ambler, Kobuk, Shungnak, Noorvik, Noatak, Deering, Kotzebue, Selawik, Kiana, Buckland, and Kivalina (shaded) were installed by Bering Straits Development Company through coordination with the Northwest Arctic Borough. Costs for these systems were difficult to separate from the main lump sum bid. Based on the input from Rob Bensin, costs were separated using 30% for logistics, 15% for labor, and the remainder for racking, hardware, and materials. Systems in Eagle and Kaltag were installed by the utilities, using funding from the Renewable Energy Fund. Systems in Galena and Fort Yukon were installed with assistance from the Tanana Chiefs Conference.

[9] This system was only bid, and not installed. Per price quote, "Heavy equipment to be provided for trenching/anchors/material handling." In addition, shipping was not included, but was estimated after discussions with the energy manager at TCC. Shipping from Fairbanks to location not included." Shipping is estimated here at $30,000 per Dave Pelunis-Messier, based on other similar systems in the Interior.

Transportation
Further data collection is needed for this category.

Technology Trends
In Alaska, options in solar PV systems include micro-invertors, which are attached to each panel and prevent an entire string of panels from going offline if just one panel is damaged. Module costs continue to drop, and efficiencies continue to increase, especially for nonsilicon technologies. Other technologies may lend advantages for use in Alaska. Finally, concentrated solar PV technology is a candidate for generating heat as well as electricity, but may not be suitable for Alaska.

Storage Systems
Currently, energy storage is not a significant component of solar PV systems in Alaska. An off-grid utility-scale example outside Alaska that may provide guidance in this direction is the 600 kWh AGM battery bank in the Star Island solar installation in Maine. In addition, Tesla's 7 kWh Powerwall batteries may provide promising storage solutions for smaller installations.

Refurbishment/Upgrade Market
Systems are generally replaced rather than upgraded. Both used and surplus panels are available. However, purchasing used panels introduces the possibility that the panels may not work properly. Surplus panels are left-over or older models that the manufacturer sells at a greatly discounted rate. Since these panels are usually older, they may not be quite as efficient as brand new panels, but can still be a reasonable value.

Realized Cost Savings
Cost savings from integrating renewable power are difficult to gauge due to technical and incentive impacts at the entire power systems level.

At the technical level, for example, the effects of diminished losses of secondary services such as recovered waste heat, and reductions in fuel efficiency are hard to gauge, as they depend not only on average reductions in load, but also on specific operating schemes regarding minimum allowable load on diesels and on spinning reserve kept.

Acknowledgments
Many people have contributed information and insight to this report. For their review and comments, we wish to thank Rob Bensin, Energy Efficiency and Renewable Energy Division Manager at Bering Straits Development Company; Ingemar Mathiasson, Energy Manager for the Northwest Arctic Borough, Paul Schwabe of the National Renewable Energy Laboratory; Dave Messier, Rural Energy Coordinator for the Tanana Chiefs Conference; Bob Deering of the United State Forest Service; Bruno Grunau of the Cold Climate Housing Research Center; Alan Mitchell of Analysis North; and Dave Lockard, Sam Tappen, and Neil McMahon of the Alaska Energy Authority.

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Electrical Transmission Technology Report

Summary

Resource and Technology Description

Electrical transmission is a good example of the unique challenges within the state of Alaska. Numerous relatively small villages are isolated from each other sometimes by hundreds of miles without crossing any other settlement. The electrical grids for these villages are often disconnected from other communities. These conditions mean that connecting two communities may force work crews to go further and further away from each community, with minimal infrastructure at best. In addition, work crews must construct and maintain purposely built access roads in severe weather conditions such as extreme cold and wind, and across permafrost in sometimes rugged terrain.

This document contains a brief statistical analysis based exclusively on the data of applications to the State of Alaska's Renewable Energy Fund (REF), Rounds 1 through 8. The variability in application styles and total project scope causes a disparate dataset, which results in significant uncertainty. Budget items cannot be compared with exhaustive detail. Thus, the applications considered included those that contained both a budget for a transmission project and the corresponding distance. Furthermore, in some parts of this analysis, only projects exclusively proposing transmission are considered, meaning that data from applications containing both transmission and generation could not be considered. Comparisons with high voltage direct current (HVDC) transmission cost estimates are included at the end of this report.

Current Installations in Alaska

Only 18 projects in the REF applications, Rounds 1 through 8, were found to meet the required data specifications detailed in the preceding resource and technology description.

Key Performance Metrics

Transmission lines vary from overhead to submarine to underground installations. Analysis indicates that overhead transmission lines are the least expensive to build, ranging from $100,000 to $400,000 per mile. Cost variability is influenced by pole spacing, pole heights, line ratings, river crossings, and the amount of work on energized power lines. Submarine lines and underground lines are substantially more expensive than overhead lines, ranging from less than $3,000,000 to more than $4,500,000 per mile, although there is some uncertainty in the datasets.

When broken down by major cost components, the cost category including materials, construction, and installation comprises just over half of total costs, with remaining costs distributed among control system, substation, switchyard, road clearance, indirect costs, and contingencies. Operation and maintenance (O&M) costs range from $2,800/mile to $4,200/mile, with an average of $3,560/mile. Expected lifetimes are 20–30 years.

Technology Trends

In general, the transmission technology market is not as dynamic as other energy markets. The techniques used have been on the market for the last half-century, with updates only to 24-strand fiber optic cable for communication infrastructure.

Electrical Transmission Technology Report

Summary

Technology-Specific Gaps and Barriers to Successful Project Development and Operation

Private investment and cost decreases in transmission projects are not likely to occur unless individual community loads are linked together to make bigger loads and create economies of scale. With regard to technological advances, further development of conductors will also slightly cut costs, but these advances would be small improvements relative to overall construction costs.

Recommendations

Financing and initiatives to encourage interties are recommended, to create bigger loads and economies of scale.

Electrical Transmission Technology Report

Prepared by the Alaska Center for Energy and Power for the Alaska Affordable Energy Strategy Effort with funding from the Alaska Energy Authority

Electrical transmission[1] is a good example of the unique challenges within the state of Alaska. The state is by far the least densely populated of all states in the U.S. with fewer than two people per square mile (1.3 in 2015) according to the U. S. Census, distant from the second least densely populated state, Wyoming (6.0 in 2015). Numerous relatively small villages are isolated from each other, sometimes by hundreds of miles without crossing any other settlement. The electrical grids for these villages are often disconnected from other communities. These conditions mean that connecting two communities may force work crews to go further and further away from each community, with minimal infrastructure at best. In addition, work crews must construct and maintain purposely built access roads in severe weather conditions such as extreme cold and wind, and across permafrost in sometimes rugged terrain.

This document contains a brief statistical analysis based exclusively on the data of applications to the State of Alaska's Renewable Energy Fund (REF), Rounds 1 through 8. Variability in application styles and total project scope caused a disparate dataset, which resulted in significant uncertainty. Budget items could not be compared in exhaustive detail. Thus, the applications considered include those that contained both a budget for a transmission project as well as the corresponding distance. Furthermore, in some parts of this analysis, only projects exclusively proposing transmission were considered, meaning that data from applications containing both transmission and generation could not be considered.

Note that only 18 projects were found to specify the required data. All of these projects are referenced at the Appendix along with an active web link to the respective sources of data. Comparisons with high-voltage direct current (HVDC) transmission cost estimates are included at the end of this report.

Capital Costs

Figure 1 distinguishes transmission costs by line type (overhead, submarine, and underground). To calculate the costs shown in Figure 1, the control system, indirect costs (engineering, survey, permitting, etc.), substation, switchyard, road clearance, and contingencies are excluded and therefore not mixed with transmission construction costs. The objective is to provide some abstraction from the specific terrain conditions. Not all projects give detailed budget breakdowns, making it impossible to separate the abovementioned budget items from the total cost of the project.

[1] The term *transmission line* is used loosely in the context of this paper, not with the typical distinction made between transmission (>138 kV) and distribution (<138 kV) line, because many "transmission" projects in remote Alaska operate at voltages typically attributed to distribution systems due to the low power levels transmitted.

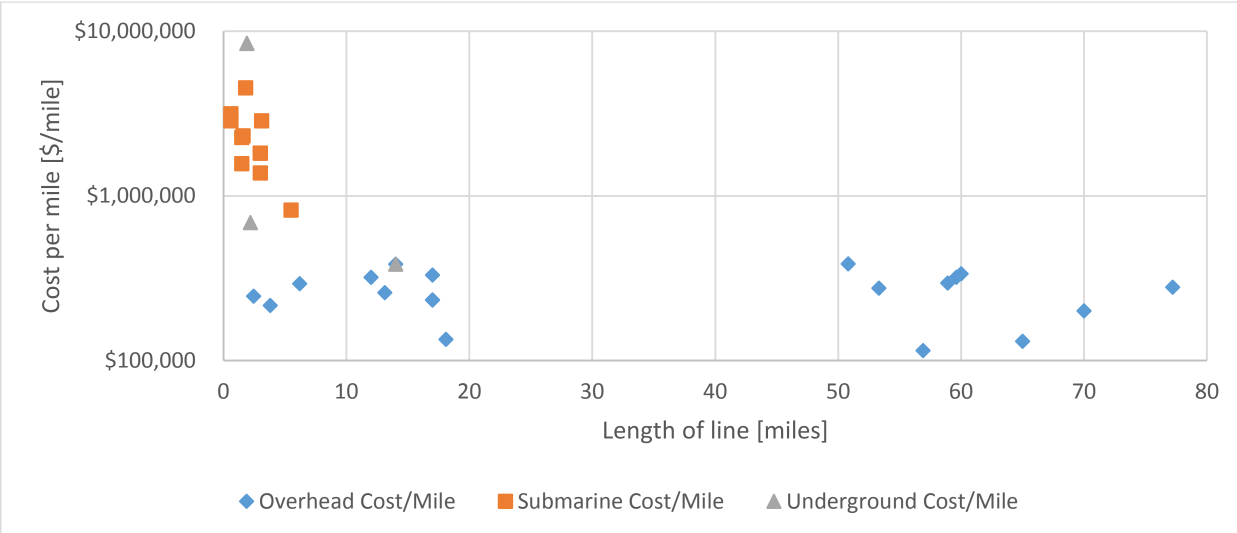

Figure 1. Simplified direct cost of different types of transmission line. Cost includes only that of the materials, installation, and construction. The *y*-axis is presented in a logarithmic scale. Overhead transmission line is the least expensive type to build, and most widely used.

Overhead Line Transmission Cost

An overhead line installation is typically a single pole line, frequently including a 24-strand fiber optic cable mounted on a wooden pole. Figure 1 illustrates that an overhead transmission line is the least expensive line to build. It comes as no surprise, therefore, that almost all of the projects use an overhead transmission line.

Differences in costs by line type are accentuated in Alaska due to the remoteness of job sites, lack of connecting infrastructure, extreme weather conditions, poor terrain conditions, extended permitting, and a harsh competing environment for the reduced specialized labor available. These differences are indicated in NANA Pacific (2008) by identifying two distinct scenarios: one that is more closely related to the Lower 48 or the Railbelt region, and another that indicates the case of rural Alaska.

According to the North Slope Borough (2010), which cites several contractors, the cost for an overhead line per mile can range from $150,000 to $500,000, which is consistent with plotted data in Figure 2.

On the other hand, City and Borough of Sitka (2009) and City and Borough of Sitka (2010) state a cost of $2,000,000 per mile. Since these specified data points as well as Borough and Municipality of Skagway (2008) are more than 1.5 interquartile ranges above the third quartile, they were considered outliers and therefore removed. No other outliers were present in the dataset.

Figure 2 does not show a clear relationship between the length of the transmission line and cost per mile. In fact, North Slope Borough (2010) states that longer lengths can result in higher cost mostly due to the time lost to get the crews to the job sites. To overcome this, the North Slope Borough suggests a travelling construction camp.

Another factor that could greatly influence the cost is the line path terrain. Pole spacing, pole heights, line rating, number of river crossings, and amount of any "hot work," that is, work on energized power lines, also give rise to cost variability within the dataset.

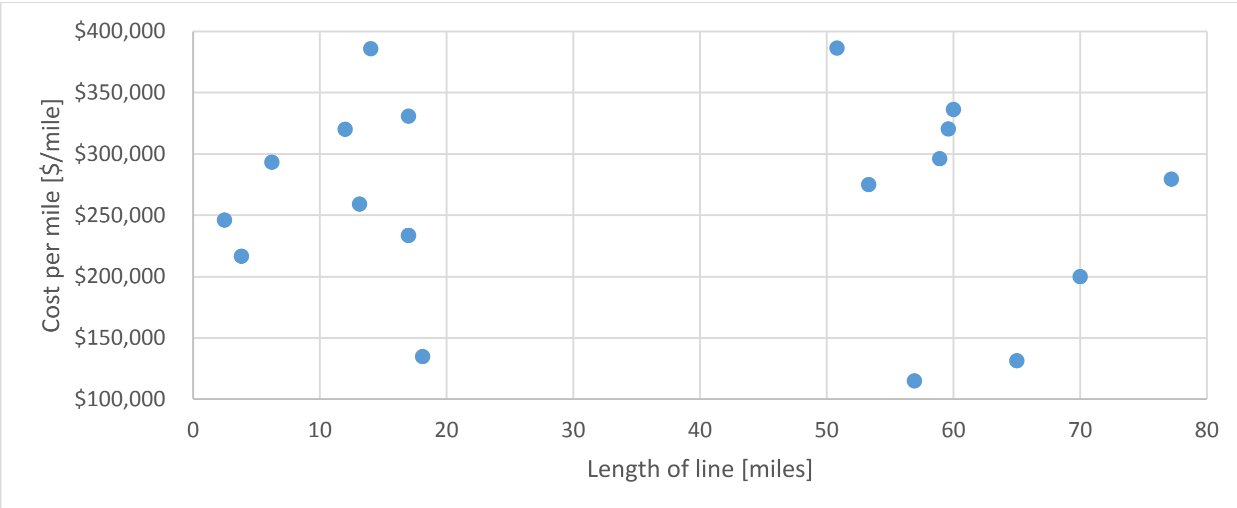

Figure 2. Simplified direct cost of overhead transmission line. Cost includes only that of materials, installation, and construction. Costs for Sitka are excluded because of its outlier status, but are addressed in the text. No clear relationship between length of transmission line and cost per mile emerges for overhead transmission lines.

Comparison of Cost per Mile Estimates

Black and Veatch (2011) report sufficiently detailed cost breakdowns for 69 kV lines to allow comparison of the values against the REF project applications dataset. The general estimate by Black and Veatch increases by $2,000,000 per mile for roadless areas, due to the use of helicopter constructed self-supported steel poles with micropile foundations.

Despite the reduced REF sample size, the corresponding estimate by Black and Veatch (2011) is close to the average of the REF dataset (Figure 3), which demonstrates that the process of separation of costs as a means to achieving a better estimate removes some of the components that are subject to specific conditions, such as terrain.

Estimates given by NANA Pacific (2008) are more difficult to compare with the available REF dataset because these estimates are relative to the total project cost, while the total values given by Black and Veatch (2011) exclude any road construction. The total project costs for the REF proposals dataset are calculated based on total project cost in the case of overhead transmission projects. In the case of joint transmission and generation or transmission projects that include submarine or underground cable, the total cost is estimated using the average budget proportions for the budget sub items shown in Table 1. Figure 4 shows this comparison with NANA Pacific estimates.

In considering Figure 4, note that the range estimated by NANA Pacific (2008) is a gradient between two cost scenarios, where the first is the lower-cost scenario around the Alaska Railbelt and the second is in rural Alaska where installation and construction conditions are far from ideal and generally more costly. As most project applications in the REF dataset cover rural situations, the range is displayed with a gradient, the rural scenario in a darker tone. Considering the same line voltage of 69 kV as before, the Railbelt scenario has a cost of around $200,000/mile, while the rural scenario costs roughly $500,000/mile.

Despite the fact that only the estimates including road construction are from Black and Veatch (2011), the two general estimates do not contradict each other. They enerally point to a smaller range between $450,000 and $500,000.

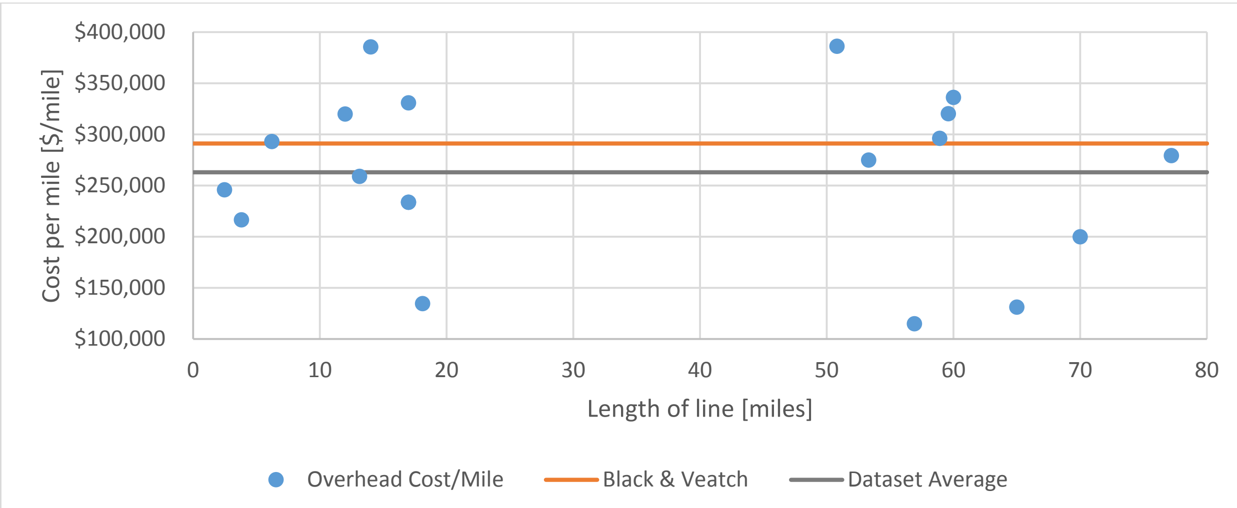

Figure 3. Simplified direct cost comparison for overhead line between the dataset and Black and Veatch (2011). Cost includes only that of materials, installation, and construction.

Table 1. Major components of transmission line cost (includes labor and materials)

	Average among the Dataset	**Black and Veatch (2011) 69 kV Adjacent to Existing Road**
Transmission Line(Materials, Construction and Installation)	51.6%	69.0%
Control System	6.9%	-
Indirect Costs(Engineering, Surveys, Staking, Permitting, Admin)	9.8%	12.6%
Substation	2.9%	-
Switchyard	1.9%	-
Road Clearance (roads and bridges)	13.8%	1.7%
Contingency	13.1%	16.7%

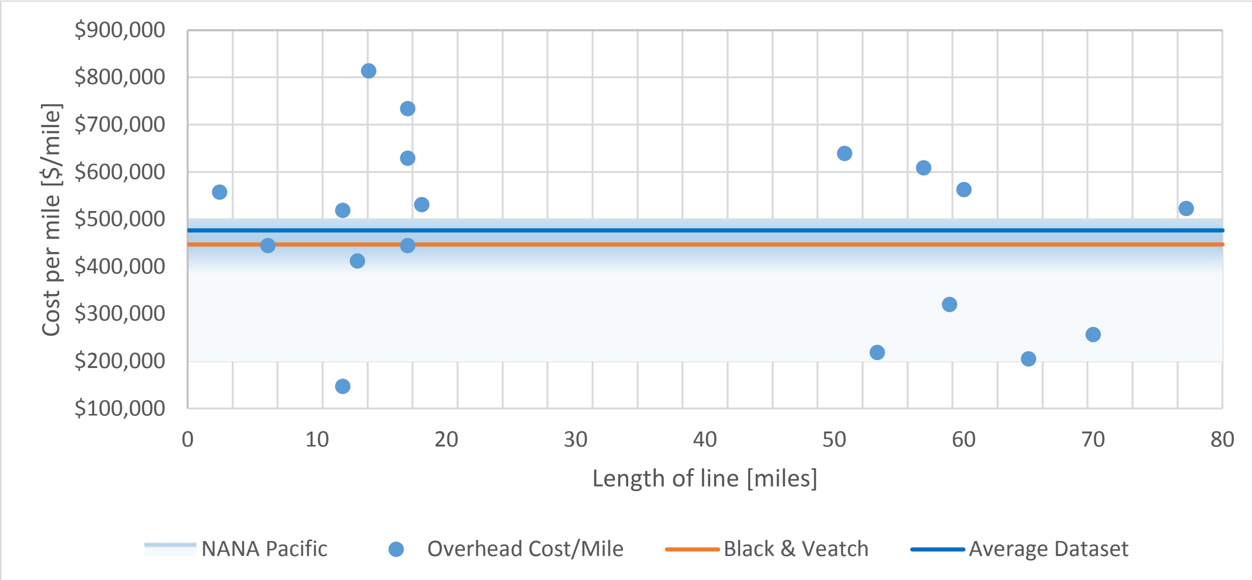

Figure 4. Comparison of total $/mile cost for the construction of an overhead transmission line. These costs are not the same as displayed in Figure 3, which only include materials, installation, and construction. The shaded area representing NANA Pacific estimates is a range between the extremes of rural and Railbelt construction.

Geographical Distribution of the Overhead Line Transmission Dataset

The geographical distribution of the REF projects dataset within Alaska is represented in Figure 5. The map represents the approximate physical location, the line rating in kV, the total projected mileage, as well as the overall cost by thousands of dollars per mile. As it is clearly shown, not only does the dataset have a reduced sample size, the data points are predominately within one region, Southeast Alaska. This region is known to have rather irregular terrain that could account for some of the high variability in overall cost per mile.

Figure 5. Geographic distribution of REF overhead line dataset. Costs are in thousands of dollars/mile. Line ratings are indicated by color (see legend).

Submarine Line Transmission Cost

Submarine line transmission is typically a three-phase line bundled with a 24-strand fiber optic cable, for communication purposes. Figure 6 plots these costs as a function of line length. The cost for submarine line transmission does appear to decrease as the total installed length increases. Linear regression does not yield statistically significant results. However, note that the cost for submarine line transmission is considerably higher than that for overhead line transmission.

One of the most curious cases is in D Hittle & Associates, Inc. (2009), where even in the same project with two different routes, the cost for submarine line transmission ranges from less than $3,000,000 to more than $4,500,000 per mile. There are concerns about the accuracy of the budget for this project.

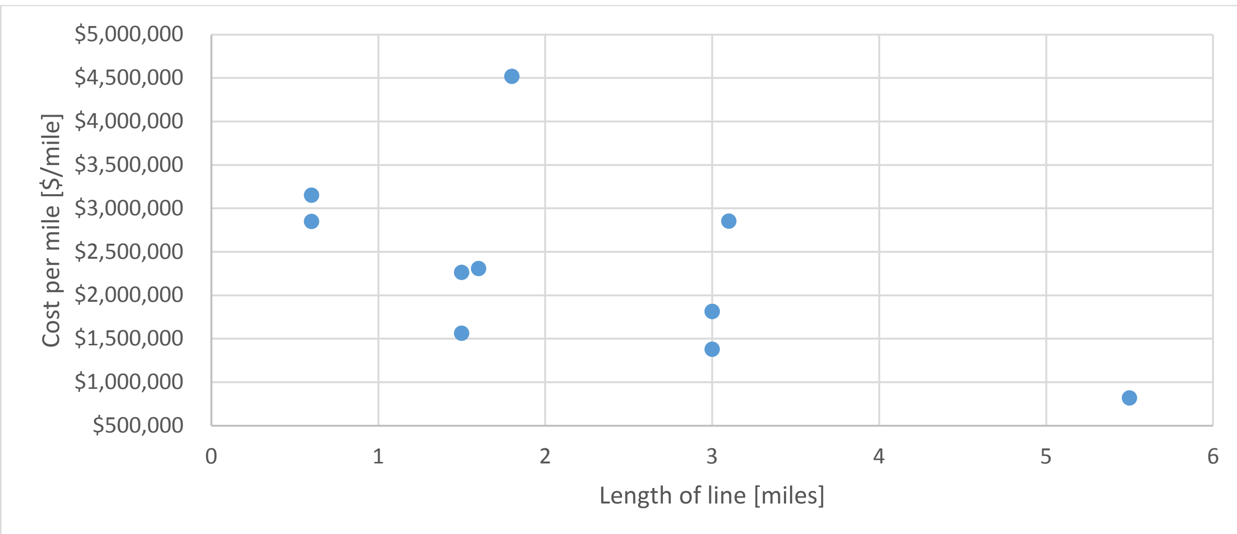

Figure 6. Simplified direct cost of submarine transmission line. Cost includes only that of materials, installation, and construction. Note the overall higher costs than for overhead line transmission.

Underground Line Transmission Cost

The underground line transmission dataset includes the data point with the highest overall cost/mile across all line types, at almost $9,000,000 per mile. Note that these high values are from some of the projects that were considered outliers for overhead transmission, namely City and Borough of Sitka (2009) and City and Borough of Sitka (2010).

Apart from the costs in Southeast Alaska, the construction cost of underground transmission line can be even higher due to construction in permafrost conditions. However, the underground transmission line sample size is too small to draw any substantial conclusions, as shown in Figure 7, with only three data points.

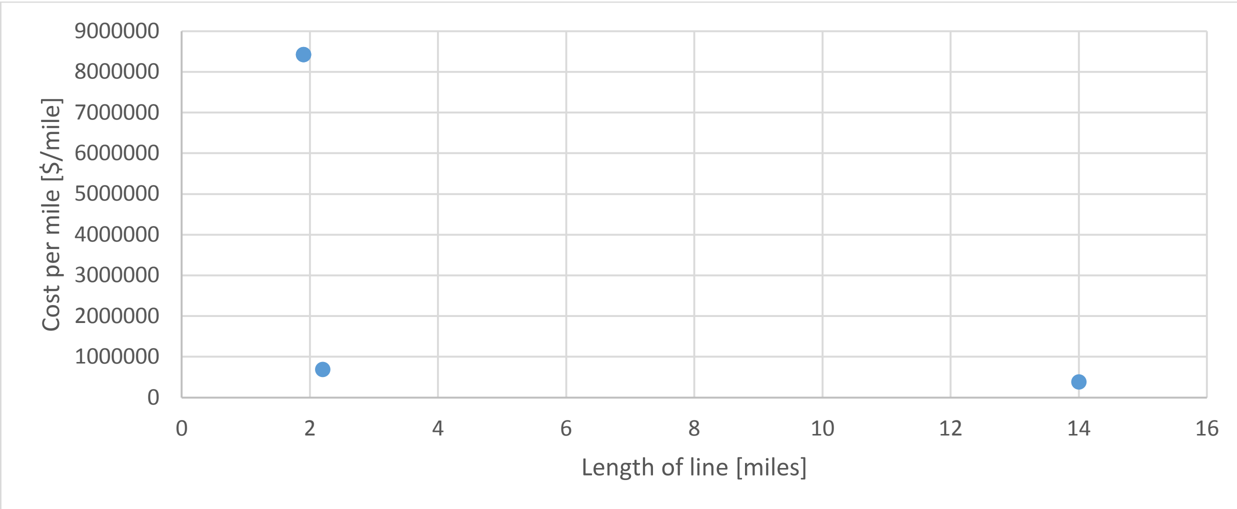

Figure 7. Simplified direct cost of underground line. Cost includes only that of materials, installation, and construction.

Operations and Maintenance Cost

For consideration of the operation and maintenance (O&M) cost, only pure transmission projects are considered, with no cases of joint transmission and generation. Otherwise, the O&M for generation would introduce unnecessary noise into the dataset. The relative proportions of overhead, submarine, and underground lines do not seem to influence the cost for O&M. The majority of projects (8 out of 11) point to a narrow region, ranging from $2,800 to $4,200/mile and averaging $3,560/mile

Expected Life

To consider the expected life of transmission lines, we must filter the exclusively transmission projects, similar to what was done in previous sections. Expected lifetimes have an almost binary distribution, with an equal number of projects (4) estimated at 20 and 30 years. The exception is the Alaska Power Company (2011) which estimates a 50-year expected life.

Installed Costs by Major Components

Using data exclusively from transmission-only projects, we show calculations of the average proportion of each project component relative to the overall project budget in Table 2. Average proportions among the REF dataset are compared with the estimate given by Black and Veatch (2011). It is unclear if Black and Veatch included the control system, substation, and switchyard in the transmission line cost estimate; however, the indirect costs and the contingency costs are comparable to those of the REF dataset, a primary difference being the category of "road clearance," since the Black and Veatch estimate assumes that an adjacent road already exists.

Table 2: Major components of transmission line cost (includes labor and materials)

	Average among the Dataset	(Black and Veatch, 2011) 69 kV Adjacent to existing road

Transmission Line(Materials, Construction and Installation)	51.6%	69.0%
Control System	6.9%	-
Indirect Costs(Engineering, Surveys, Staking, Permitting, Admin)	9.8%	12.6%
Substation	2.9%	-
Switchyard	1.9%	-
Road Clearance (roads and bridges)	13.8%	1.7%
Contingency	13.1%	16.7%

Technology Trends

In general, the transmission technology market is not as dynamic as other energy markets. The techniques used have been on the market for the last half-century, with updates only to 24-strand fiber optic cable for communication infrastructure.

Refurbishment/Upgrade Market

Since the life expectancy of transmission lines is from 20 to 30 years, the lines are usually replaced after that amount of time.

Typically, by upgrading a line, the cost of clearing and building an access road is eliminated. According to D Hittle & Associates, Inc. (2009), road and clearing costs can be $200,000/mile for forested areas and $230,000/mile across muskeg. Based on these estimates, even if the cost to remove old line and poles is added, there could still be significant cost savings by upgrading the old line instead of building a new route.

HVDC Comments and Cost Estimate Comparisons

Lowering the cost of power transmission via HVDC has been suggested as an option for reducing and stabilizing the cost of delivering power to Alaska’s rural villages. Alternating current (AC) transmission is limited by high costs and line losses that increase with transmission distance. Direct current (DC) transmission, in contrast, has fewer infrastructure requirements and lower line losses, and can be economical over long distances. Because AC power has been the dominant worldwide standard for generation and transmission, the use of DC for power transmission requires conversion from and to AC in order to integrate it into the existing AC infrastructure. Large-scale HVDC systems, on the order of hundreds to thousands of megawatts and designed to transmit large amounts of power across long distances, have been in use since the mid-twentieth century. However, the electrical demand of rural villages in Alaska is much smaller, typically less than 1 MW. At this scale, existing HVDC technology is not available. Therefore, the development of small-scale HVDC systems, power converters, and multi-terminal networks is of critical need if HVDC technology is to be applied in rural Alaska (Alaska Center for Energy and Power, 2013).

Life-cycle cost analysis indicates that 60 miles is about the intertie length at which HVDC becomes an economically attractive option (Alaska Center for Energy and Power, 2013). However, more empirical data for a small-scale HVDC intertie are needed for a more rigorous economic analysis. The following tables, which compare AC with HVDC transmission costs, are taken from the 2013 Alaska Center for Energy and Power report that contains a review of small-scale HVDC applications in Alaska.

8.1 Overhead AC Intertie Cost Estimates

Cost Items for Intertie	Per Mile Cost from 0 - 25 Miles	Total Cost from 0 - 25 Miles	Per Mile Cost from 25 - 50 Miles	Total Cost from 25 - 50 Miles	Per Mile Cost from 50 - 60 Miles	Total Cost from 50 - 60 Miles	Total Cost
Pre-construction	$39,000	$975,000	$36,000	$900,000	$33,000	$329,000	$2,204,000
Administration/ Management	$18,000	$450,000	$18,000	$450,000	$18,000	$180,000	$1,080,000
Materials	$71,000	$1,775,000	$71,000	$1,775,000	$71,000	$710,000	$4,260,000
Shipping	$33,000	$825,000	$31,000	$783,000	$30,000	$295,000	$1,903,000
Mobilization/ Demobilization	$125,000	$3,125,000	$118,000	$2,958,000	$112,000	$1,115,000	$7,198,000
Labor	$111,000	$2,775,000	$111,000	$2,775,000	$111,000	$1,110,000	$6,660,000
TOTAL	**$397,000**	**$9,925,000**	**$386,000**	**$9,641,000**	**$374,000**	**$3,740,000**	**$23,306,000**

8.1.1: Estimated Cost Items for Overhead AC Intertie in Normal Terrain (author's estimate)

Intertie Estimated Cost in Difficult Terrain	Cost
Project Cost	$23,306,000
per mile without contingency	$388,000
for 21 miles of normal terrain	$8,157,000
for 21 miles of difficult terrain	$9,788,000
for rest of the 39 miles normal terrain	$15,149,000
cost for 60-mile intertie	**$24,937,000**

8.1.2: Estimated Cost for Overhead AC Intertie in Difficult Terrain (author's estimate)

Notes: Table 8.1.2**Error! Reference source not found.** assumes that 21 miles have difficult terrain and that costs will rise by 20% compared with normal terrain to construct an intertie in that terrain. The cost does not include the cost of the substations and contingency costs.

Intertie Estimated Cost with Substations and Contingency	Cost
Pre-construction Activities	$3,400,000
Administration/Management	$1,300,000
Substations and Switchyards	$3,000,000
Overhead Intertie Construction	$24,937,000
Contingency (20%)	$6,527,000
Total Cost for the Intertie and Substations	**$39,164,000**

8.1.3: Estimated Cost Items for Overhead AC Intertie in Difficult Terrain with Substations (author's estimate)

8.2 Overhead HVDC Monopolar 2-wire Intertie Cost Estimates

Cost Items for Intertie	Per Mile Cost from 0 - 25 Miles	Total Cost from 0 - 25 Miles	Per Mile Cost from 25 - 50 Miles	Total Cost from 25 - 50 Miles	Per Mile Cost from 50 - 60 Miles	Total Cost from 50 - 60 Miles	Project Cost
Preconstruction	$56,000	$1,400,000	$33,000	$826,000	$30,000	$302,000	$2,528,000
Administration / Management	$17,000	$425,000	$17,000	$425,000	$17,000	$170,000	$1,020,000
Materials (intertie only)	$47,000	$1,175,000	$47,000	$1,175,000	$47,000	$470,000	$2,820,000
Shipping	$25,000	$625,000	$22,000	$544,000	$21,000	$205,000	$1,374,000
Mobilization/ Demobilization	$94,000	$2,350,000	$82,000	$2,045,000	$77,000	$771,000	$5,165,000
Labor	$71,000	$1,775,000	$71,000	$1,775,000	$71,000	$710,000	$4,260,000
TOTAL	**$310,000**	**$7,750,000**	**$272,000**	**$6,789,000**	**$263,000**	**$2,628,000**	**$17,167,000**

8.2.1: Estimated Cost Items for Overhead HVDC Monopolar 2-Wire Intertie in Normal Terrain (author's estimate)

Estimated Cost in Difficult Terrain	
per mile cost	$286,000
for 21 miles of normal terrain	$6,009,000
for 21 miles of difficult terrain	$7,210,000
for rest of the 39 miles normal terrain	$11,159,000
cost for 60-mile intertie	**$18,369,000**

8.2.2: Estimated Cost for Overhead HVDC Monopolar 2-Wire Intertie in Difficult Terrain (author's estimate)

Notes: For difficult terrain the additional cost is ($7,210,000 - $6,009,000) = $1,201,000. The cost does not include the cost of the converter stations and contingency costs.

8.3 Overhead HVDC Monopolar SWER Intertie Cost Estimates

Per Mile Cost Item for Intertie	Per Mile Cost from 0 - 25 Miles	Total Cost from 0 - 25 Miles	Per Mile Cost from 25 - 50 Miles	Total Cost from 25 - 50 Miles	Per Mile Cost from 50 - 60 Miles	Total Cost from 50 - 60 Miles	Total Cost for 60-mile Intertie
Preconstruction	$58,000	$1,450,000	$34,000	$856,000	$31,000	$313,000	$2,619,000
Administration/ Management	$13,000	$325,000	$13,000	$325,000	$13,000	$130,000	$780,000
Materials (intertie only)	$48,000	$1,200,000	$48,000	$1,200,000	$48,000	$480,000	$2,880,000
Shipping	$15,000	$375,000	$13,000	$326,000	$12,000	$120,000	$824,000
Mobilization/ Demobilization	$37,000	$925,000	$32,000	$805,000	$30,000	$303,000	$2,033,000
Labor	$67,000	$1,675,000	$67,000	$1,675,000	$67,000	$670,000	$4,020,000
TOTAL	**$238,000**	**$5,950,000**	**$207,000**	**$5,187,000**	**$201,000**	**$2,019,000**	**$13,156,000**

8.3.1: Estimated Cost Items for Overhead HVDC Monopolar SWER Intertie in Normal Terrain (author's estimate)

Estimated Cost in Difficult Terrain	
per mile cost	$219,000
for 21 miles of normal terrain	$4,605,000
for 21 miles of difficult terrain	$5,526,000
for rest of the 39 miles normal terrain	$8,551,000
cost for 60-mile intertie	**$14,077,000**

8.3.2: Estimated Cost for Overhead HVDC Monopolar SWER Intertie in Difficult Terrain (author's estimate)

Notes: For difficult terrain, the additional cost is ($5,526,000 - $4,605,000) = $921,000. The cost does not include the cost of the converter stations and contingency costs.

Acknowledgments

Many people have contributed information and insight to this report. For their review and comments, we wish to thank Joel Groves of Polar Consulting, David Burlingame of Electric Power Systems, Tom Lovas, Brent Petrie (AVEC, retired), Steve Gilbert of AVEC, and Kirk Warren and Neil McMahon of the Alaska Energy Authority.

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Wind Power Technology Report

Summary

Prepared by the Alaska Center for Energy and Power for the Alaska Affordable Energy Strategy Effort with funding from the Alaska Energy Authority

Resource and Technology Description

Wind power systems have been installed in locations in Alaska, both in remote areas and along the road system. Total installed capacity exceeds 60 MW, with installations ranging from 40 kW to 24 MW.

Current Installations in Alaska

This analysis of wind power in Alaska largely relies on data extracted from approximately 40 applications to the Alaska Energy Authority (AEA) Renewable Energy Fund (REF), Rounds 1 through 8.

Key Performance Metrics

The costs per kilowatt for the different components of wind turbine installations were found to decrease with increasing size of installation. Exceptions were the costs for transmission and integration, which did not vary significantly with the capacity of the installed system. Individual costs were tested for correlations with region and year, but in most cases, the relationship was not significant.

The minimum design lifetime for wind turbines must be 20 years, and for planning purposes, this figure is typically used.

Capacity factors ranged from approximately 10% to 40%. Factors affecting the variance of capacity factors at wind power classes include the rated wind speed and height of the wind turbines and the resolution of the wind power class map. A turbine rated for low wind speeds will have a higher capacity factor at low wind speeds than a turbine rated for high wind speeds. At high wind speeds, a turbine rated for high wind speeds may have a higher capacity factor due to a higher cutoff wind speed. Taller wind turbines experience higher wind speeds, which generally result in higher capacity factors.

Technology Trends

Wind power technology is relatively mature internationally, nationally, and in Alaska. Turbines typically function at a high availability often for their entire design life, and sometimes longer. The wind market in Alaska, in general, is moving towards larger and more powerful wind turbines, often with gearless direct-drive generators. Due to the size of communities in Alaska as well as other factors, turbines installed in Alaska have been smaller than the trend in the larger market. There is evidence that installing overcapacity wind farms together with energy storage, and significant diversion into thermal loads, would allow communities to achieve diesel-off and least-cost energy when considering displacement of diesel fuel for both electricity and heat. Robust direct drive turbines (such as NPS 100 and EWT 900) are currently popular in Alaska due to their high availability rates.

Technology-Specific Gaps and Barriers to Successful Project Development and Operation

The remoteness of communities in Alaska leads to higher transportation, infrastructure, and maintenance costs. There are significant economies of scale to be gained with larger wind turbines. The size of wind turbines that can be installed in Alaska is limited by the small size of the state's communities and the challenges of integrating high penetrations of wind power into microgrids. Excess wind generation and the need for more complex integration equipment increase with higher penetrations of wind power.

Wind Power Technology Report

Summary

Recommendations

Demonstrations of different high penetration wind power integration techniques are need, including demand side management and wind to heat. Improvements and reduction in costs of integration equipment such as energy storage systems will help achieve higher penetrations of wind power.

An integrated approach is needed that includes analysis to understand low-hanging fruit and mechanisms to allow collaboration between government and industry. Funding is a major issue in implementing grid improvements, and state, federal, and private funds could help with this implementation.

Wind Power Technology Report

Prepared by the Alaska Center for Energy and Power for the Alaska Affordable Energy Strategy Effort with funding from the Alaska Energy Authority

Wind power systems have been installed in several locations in Alaska, both in remote areas and along the road system. Total installed capacity exceeds 60 MW, with installations ranging from 40 kW to 24 MW. This analysis of wind power technology in Alaska largely relies on data extracted from applications to the Alaska Energy Authority's (AEA) Renewable Energy Fund (REF), Rounds 1 through 8. Wind power costs were broken down into the categories of Energy Analysis, Conceptual Design, Final Design, Hardware, Transportation, Foundation and Infrastructure, Turbine Installation, Transmission, and Integration. These categories were necessary since individual applications often only included a subset of the above costs. Linear regressions were run on the data for capital expenditure (CAPEX) per installed capacity ($/kW) for each individual cost with respect to installed capacity. The regressions were added together to get the total cost. A regression was considered significant if its *P*-value[1] was less than 0.05. The results have been compared with as-built costs from AEA in Appendix C and are a good prediction of as-built costs. Costs are in 2015 dollars.

Capital Costs

From the REF application data, the costs per kilowatt for the different components of wind turbine installations were found to decrease with the increased size of the installation. Exceptions were the costs for transmission and integration, which did not vary significantly with the capacity of the installed system. Individual costs were tested for correlations with region and year, but in most cases, the relationship was not significant or did not significantly improve the fit of installed capacity without taking these relationships into consideration. Figure 1 shows the incremental costs of each individual category for different installed capacity systems. Each line is added to the line below and represents the sum of all costs below it. Thus, the top line (integration) represents the total cost. Note that the *x*-axis is plotted on a log scale. The equations for the individual cost fits along their scatter plots are shown in Appendix A. Table 1 shows the cost per installed capacity for several system sizes, which have been calculated based on the regression analysis. The costs are grouped as *analysis and design* (energy analysis and conceptual and final design), *hardware and transport* (turbine hardware and transport), and *balance of system* (foundations and infrastructure, turbine installation, transmission, and integration).

[1] *P*-value is the probability of there being no relationship between the dependent variable and regressors compared with the given regression.

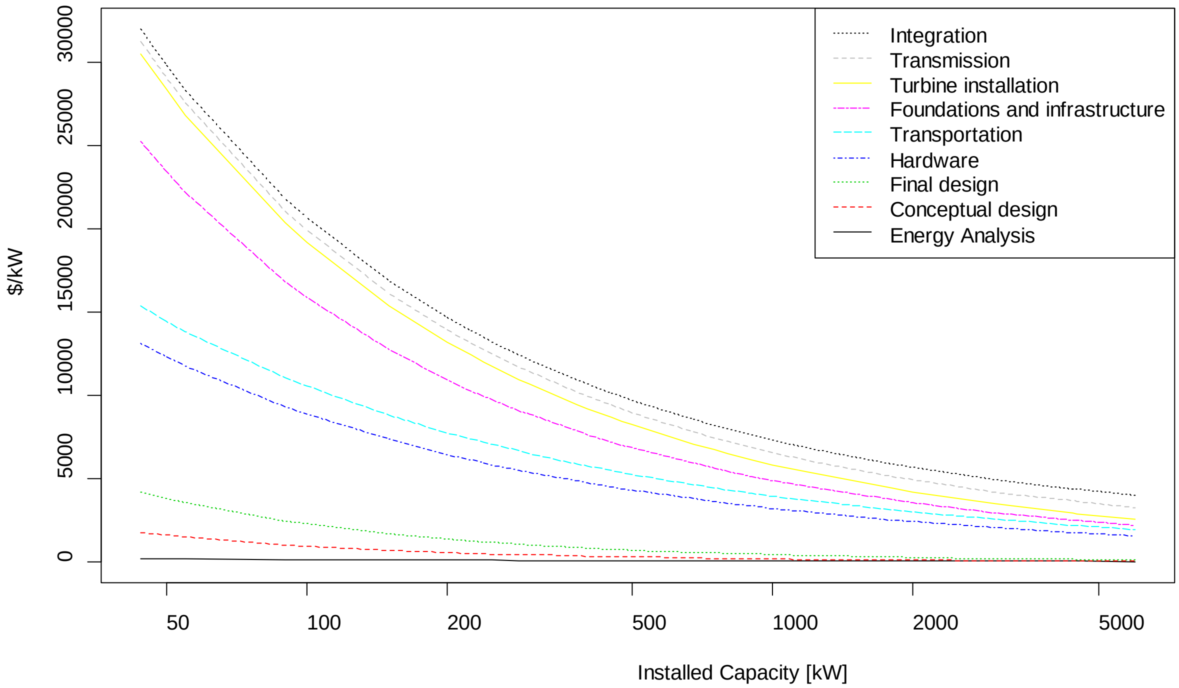

Figure 1. Cumulative cost ($/kW) of a wind power system. Each line is added to the line below it, with the top line representing the total cost per kilowatt of installed capacity. These costs are regressions based on REF applications, shown with the data and equations in Appendix A. Very few applications included all cost categories, thus regressions were found for each category and added to get an estimate for total project cost. Costs are in 2015 dollars.

Table 1. Costs per installed capacity taken from the regressions shown in Figure 1 (costs in 2015 dollars).

Size (kW)	Analysis and Design ($/kW)	Hardware and Transport ($/kW)	Balance of System ($/kW)	Total ($/kW)
50	3805	10661	15353	29819
100	2284	8251	10145	20680
500	715	4552	4438	9705
1000	439	3523	3357	7319
2000	273	2728	2676	5676
5000	148	1945	2143	4236

Wind Power Technology Report

Operations and Maintenance $/kW

Many communities in Alaska have performance-based operations and maintenance (O&M) contracts with the turbine supplier. The supplier performs O&M (often in collaboration with the utility) while guaranteeing a certain level of availability. Operations and maintenance does not include repairs and replacements. Figure 2 shows the predicted maintenance costs from REF applications, with an average of $0.036/kWh. This tends to be lower than O&M calculations from other sources. The points are plotted against the annual wind generation and sorted by the annual electric consumption of the grid. No clear trends are indicated in the data.

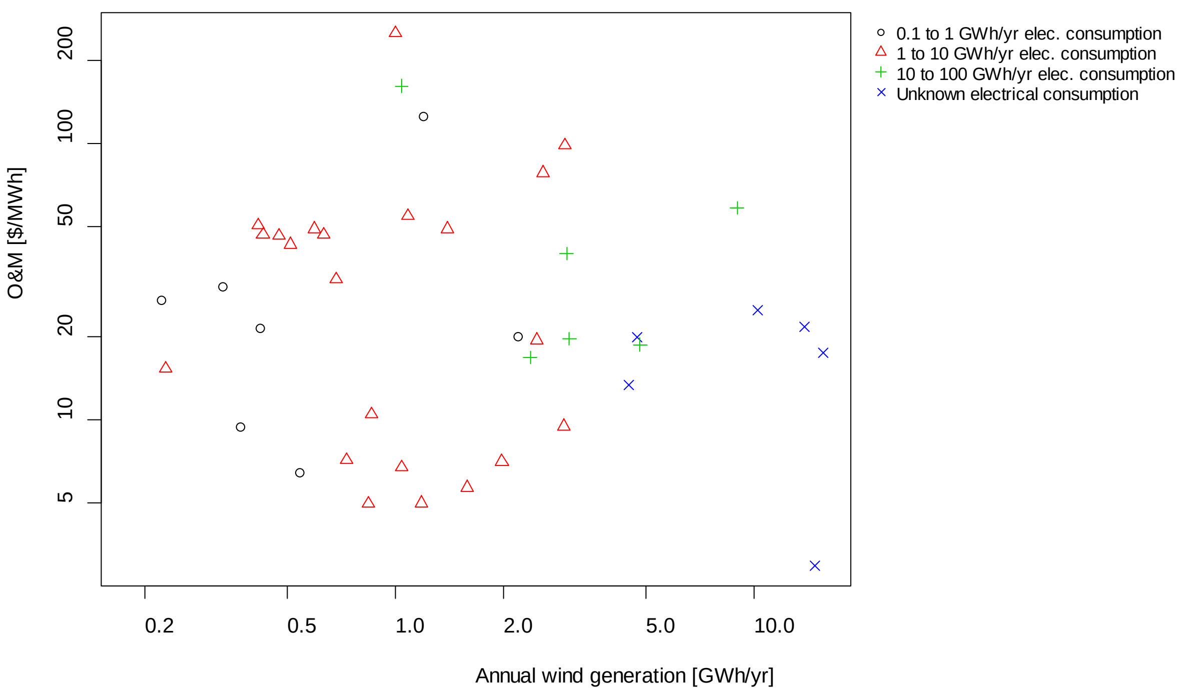

Figure 2. O&M costs per kWh of wind energy production. The points are sorted by the annual electricity demand of the grid. This data are from REF applications.

Expected Life

The minimum design lifetime for wind turbines must be 20 years.[2] Table 2 shows average wind turbine lifetimes as reported by the National Renewable Energy Laboratory (NREL, 2013). For planning purposes 20 years is typically used. However, considering that many wind turbines installed in Alaska fall in the 10 to 1000 kW range, it might be prudent to revise the values given in Table 2, or work with the vendor on sufficient warranties.

[2] IEC 61400-1, *Wind Turbines-Part 1: Design requirements*.

Table 2. Wind turbine lifetime (NREL, 2013).

Wind Turbine Size (kW)	Lifetime (yr)	Lifetime Standard Deviation (yr)
<10	14	9
10 – 100	19	5
100 – 1000	16	0
1000 – 10,000	20	7

Capacity Factor

Figure 3 shows predicted capacity factors from REF applications. Capacity factors above 40% were removed since they are possible but unlikely. Capacity factor was calculated as the total wind energy used to supply electrical loads (excluding diversion loads) in 1 year, divided by the energy that would be harvested from the wind if the turbines were outputting their rated (maximum) power the entire year. In general, capacity factor should depend primarily on the wind power class of the installation site for low and medium penetration hybrid-diesel systems. Wind power class refers to the available energy from the wind as outlined by the U.S. Department of Energy (DOE).

At high wind power penetrations, it might not be possible to use all the energy from wind for electrical loads. In such cases, thermal loads can be supplied, but this is not reflected in the capacity factor. Thus, capacity factor might not be as good of a metric as reduction in diesel consumption, and even then, a distinction will have to be made between displacement of diesel fuel slated for electricity production and heat production.

Factors affecting the variance of capacity factors at wind power classes include the rated wind speed and height of the wind turbines and the resolution of the wind power class map. A turbine rated for low wind speeds will have a higher capacity factor at low wind speeds than a turbine rated for high wind speeds. At high wind speeds, a turbine rated for high wind speeds may have a higher capacity factor due to a higher cutoff wind speed. Taller wind turbines experience higher wind speeds, which generally result in higher capacity factors.

The wind power classes in Figure 3 are from the Alaska Energy Data Inventory (AEDI) wind power class map.[3] Localized wind speeds can be higher than what is shown by the resolution of the wind power class map, resulting in higher capacity factors used in the REF applications than what is shown in Figure 3.

[3] http://www.arcgis.com/home/item.html?id=6aaef4ce5821459cad757bf9adda3079

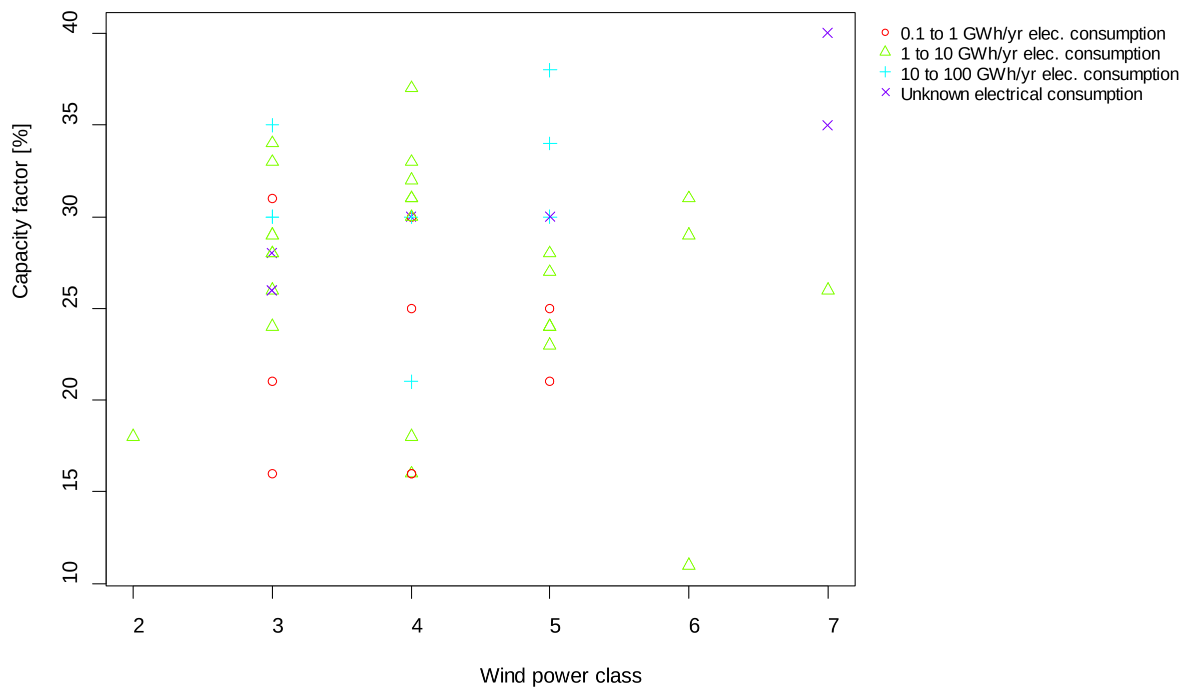

Figure 3. Capacity factor plotted against the wind power class. Capacity factors above 40% were removed since they are possible but unlikely. Capacity factor was calculated as the total wind energy used to supply electrical loads (excluding diversion loads) in 1 year, divided by the energy that would be harvested from the wind if the turbines were outputting their rated (maximum) power the entire year. In general, capacity factor should depend primarily on the wind power class of the installation site for low and medium penetration hybrid-diesel systems. Wind power class refers to the available energy from the wind as outlined by DOE.

Diesel Offset

Figure 4 shows the predicted improvement in grid diesel electric efficiency from REF applications. This improvement is calculated as the total electric consumption divided by the diesel consumed. Wind power supplies some of the electric load, reducing diesel consumption. At higher penetrations, not all wind energy can be used for electric loads. This "excess" generation can be used to supply thermal loads. Figure 4 only accounts for electric loads.

Wind energy displaces more diesel by supplying electric loads than thermal loads. Thirty-three kilowatt-hours of wind energy will displace around 1 gallon of diesel being used to supply a heating load, assuming a boiler diesel efficiency of 110,000 Btu/gal. Thirty-three kilowatt-hours will displace around 2.5 gallons of diesel to supply an electrical load, assuming the diesel generator has an efficiency of 13 kWh/gal. Thus, since diesel is more efficient at supplying thermal loads than electric loads, wind energy displaces more diesel by supplying electric loads.

Figure 5 shows the predicted ratio of diesel offset for thermal loads to electric loads supplied by wind energy at different energy penetrations. These ratios simply show what the project plan was for using thermal and electric loads and do not necessarily reflect what is feasible or optimal. For example, a project may plan to install a boiler or several masonry thermoelectric heaters that use some but not all of the excess wind generation. One project below 20% wind energy penetration included a plan to use a large portion of the wind energy to supply thermal loads. This plan is generally not economical due to the amount of wind energy required to displace diesel for thermal loads. In general, only projects above around 25% energy penetration included a plan to supply thermal loads with wind energy.

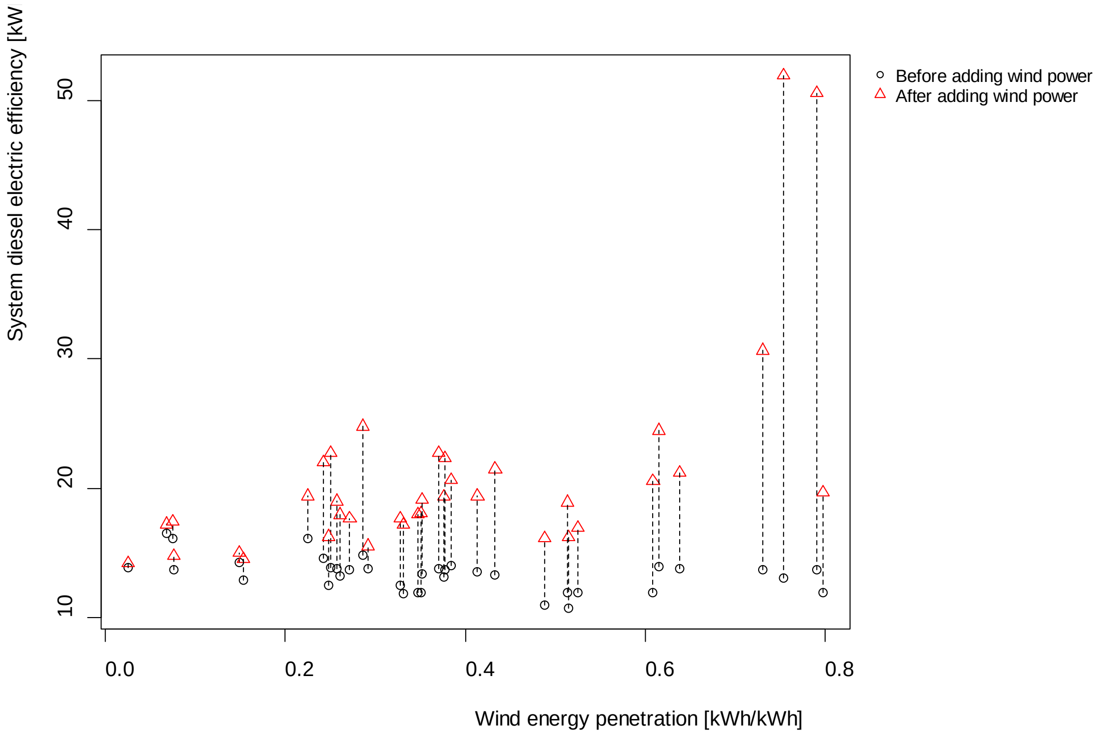

Figure 4. System diesel electric efficiency before and after installing wind turbines, plotted against wind energy penetration. Corresponding before-and-after values are connected by a dashed line. Wind energy penetration is the amount of wind energy in kilowatt-hours that can be generated (assuming no diversion), divided by grid electrical consumption.

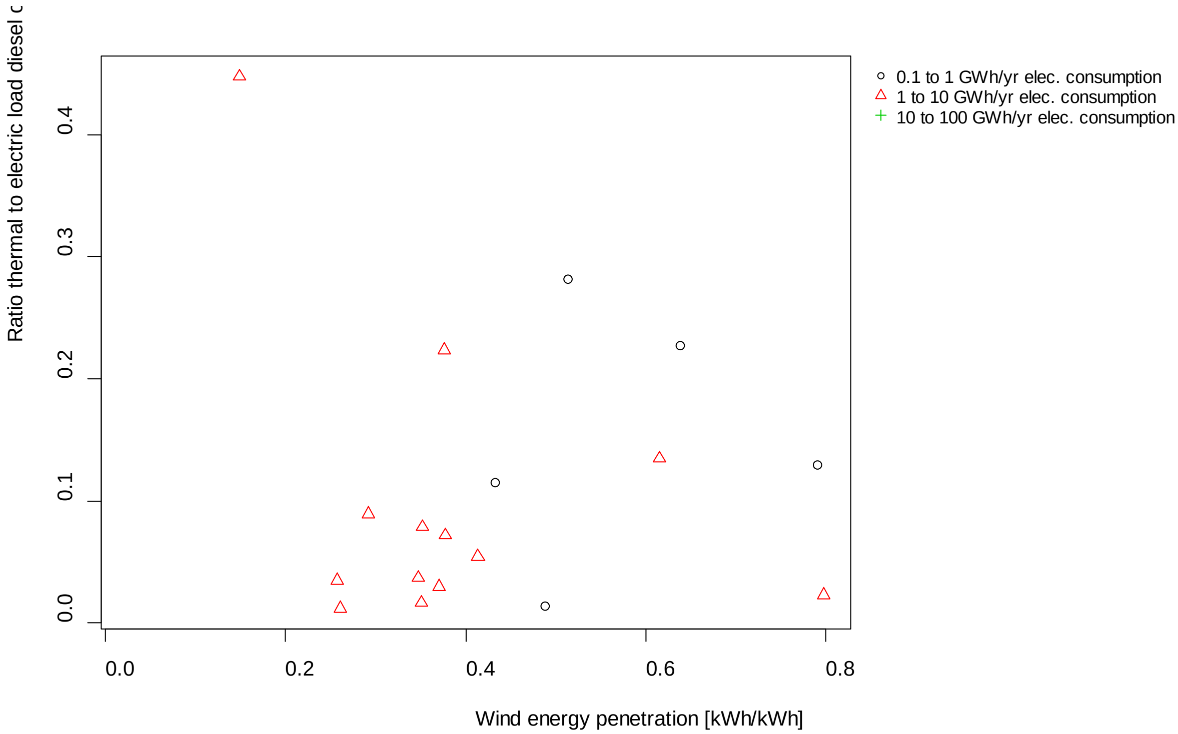

Figure 5. The predicted ratio of diesel offset for thermal loads to electric loads supplied by wind energy. Wind energy penetration is the amount of wind energy in kilowatt-hours that can be generated (assuming no diversion), divided by the grid electrical consumption.

Cost per Kilowatt-Hour

Figure 6 shows the resulting levelized cost of electricity (LCOE), assuming yearly O&M costs of \$0.036/kWh of wind energy generation that increase with an inflation rate of 2%, an interest rate of 5%, a lifetime of 20 years, and different average capacity factors; LCOE equations are in Appendix B. These costs do not take into account subsidies; thus, they are higher than the actual cost to the utility and not directly comparable to subsidized diesel generating costs. Table 3 gives LCOE values for various installed wind capacities and average capacity factors.

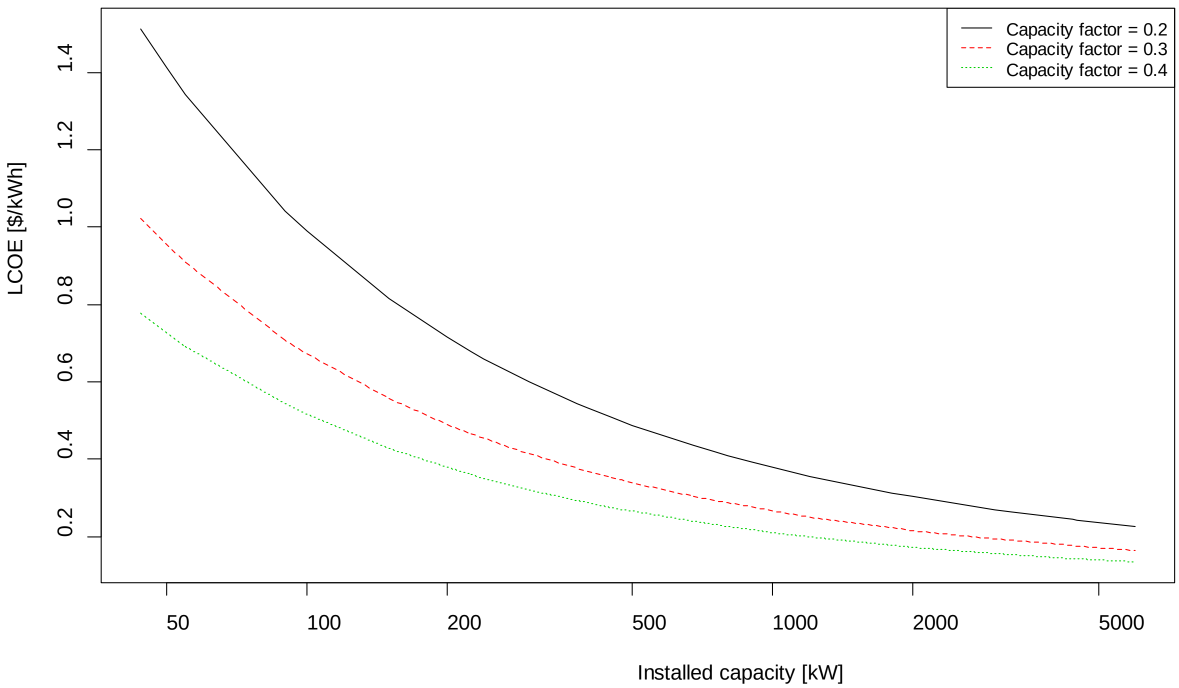

Figure 6. Levelized cost of energy for different installed capacities and capacity factors, assuming yearly O&M costs of $0.036/kWh of wind energy generation that increase with an inflation rate of 2%, an interest rate of 5%, and a lifetime of 20 years.

Table 3. LCOE values for various installed wind capacities and average capacity factors.

Installed Wind Capacity (kW)	20% Average Capacity Factor	30% Average Capacity Factor	40% Average Capacity Factor
50	1.41	0.96	0.73
100	0.99	0.67	0.52
200	0.71	0.49	0.38
500	0.49	0.34	0.27
1000	0.38	0.27	0.21
2000	0.30	0.22	0.17
5000	0.24	0.17	0.14

Conditions for Greatest Efficiency

Consistent, high-speed, non-turbulent winds result in the best wind farm performance. Turbines are rated for average wind speed, extreme 50-year gust, and turbulence by IEC 61400-1. The wind power at 10 m and 50 m height is classified by DOE using “Wind Power Class 1–7,” with Class 3 and above generally suitable for utility wind power (Elliot et al., 1986). A grid’s ability to accept power from a wind farm at a given moment may result in having to divert or curtail excess generation. Excess generation can be used for either energy storage or controllable loads.

Cost Curve over Time

The REF applications did not show any statistically significant change in costs over time. As-built costs from Alaska (outlined in Appendix C) did not show a significant change in cost over time either. In Figure 7, as-built costs for projects in Alaska are plotted in 2015 dollars against the year the projects were installed.

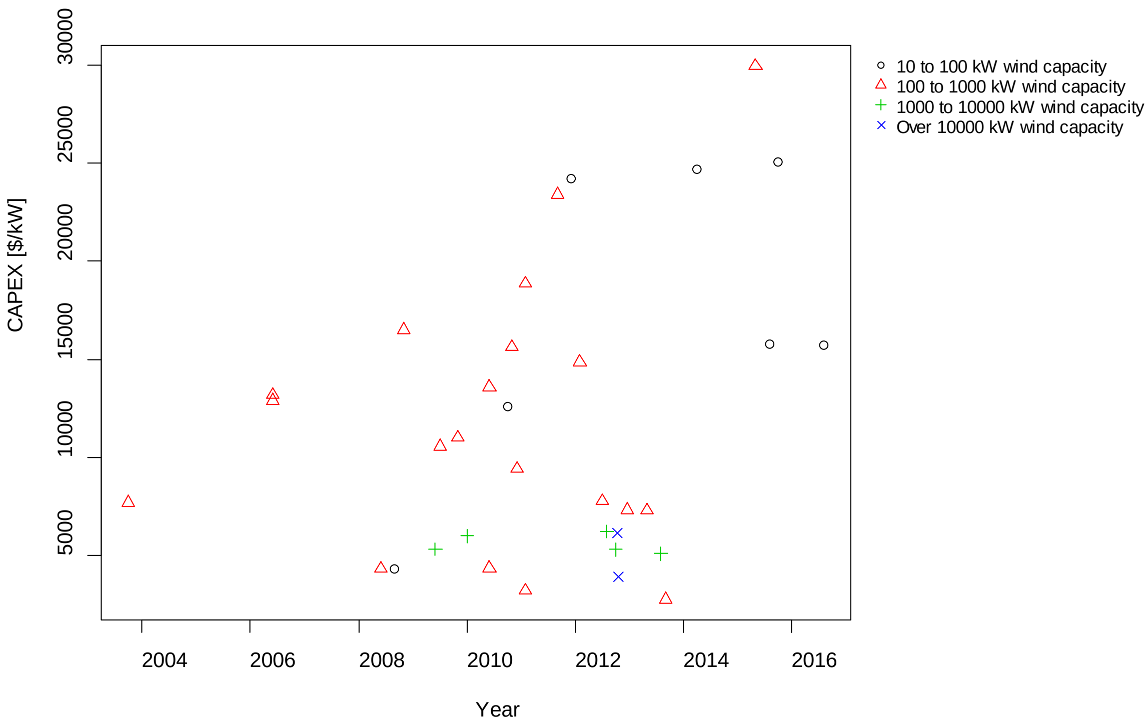

Figure 7. As-built costs for projects in Alaska plotted against the year of installation. Costs are converted to 2015 dollars.

Installed Costs by Major Components

See section on Capital Costs and Appendix A.

Transportation

See section on Capital Costs and Appendix A.

Technology Trends

The wind market in general is moving towards larger and more powerful wind turbines, often with gearless direct-drive generators. Due to the size of communities in Alaska as well as other factors, turbines installed in Alaska have been smaller than the trend in the larger market. There is evidence that installing overcapacity wind farms together with energy storage, and significant diversion into thermal loads, would allow communities to achieve diesel-off and least-cost energy when considering displacement of diesel fuel for both electricity and heat (Simpkins et al., 2015). Robust direct drive turbines (such as NPS 100 and EWT 900) are currently popular in Alaska due to their high availability rates.

Refurbishment/Upgrade Market

The refurbished wind turbine market is significant. As wind farms upgrade to larger wind turbines, companies such as Windmatic purchase the old wind turbines to refurbish and resell them. Upgrades in new and refurbished models that are popular for Alaska include marine-grade paint on the tower and black Teflon paint and heaters on the blades. Modifications to turbines, such as hub extensions, and control and drive upgrades are considered at times.

Realized Cost Savings

Cost savings from integrating renewable power are difficult to gauge due to technical and incentive impacts at the entire power systems level. At the technical level, for example, effects of diminished losses of secondary services such as recovered waste heat and reductions in fuel efficiency are hard to gauge, as they depend not only on average reductions in load, but also on specific operating schemes regarding minimum allowable load on diesels and spinning reserve kept.

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Many people have contributed information and insight to this report. For their review and comments, we wish to thank David Burlingame of Electric Power Systems, Inc.; Rob Bensin, Energy Efficiency and Renewable Energy Division Manager at Bering Straits Development Company; Ian Baring-Gould of the National Renewable Energy Laboratory; Steve Gilbert of the Alaska Village Electric Cooperative, Inc.; and Dan Smith, Josh Craft, and Neil McMahon of the Alaska Energy Authority.

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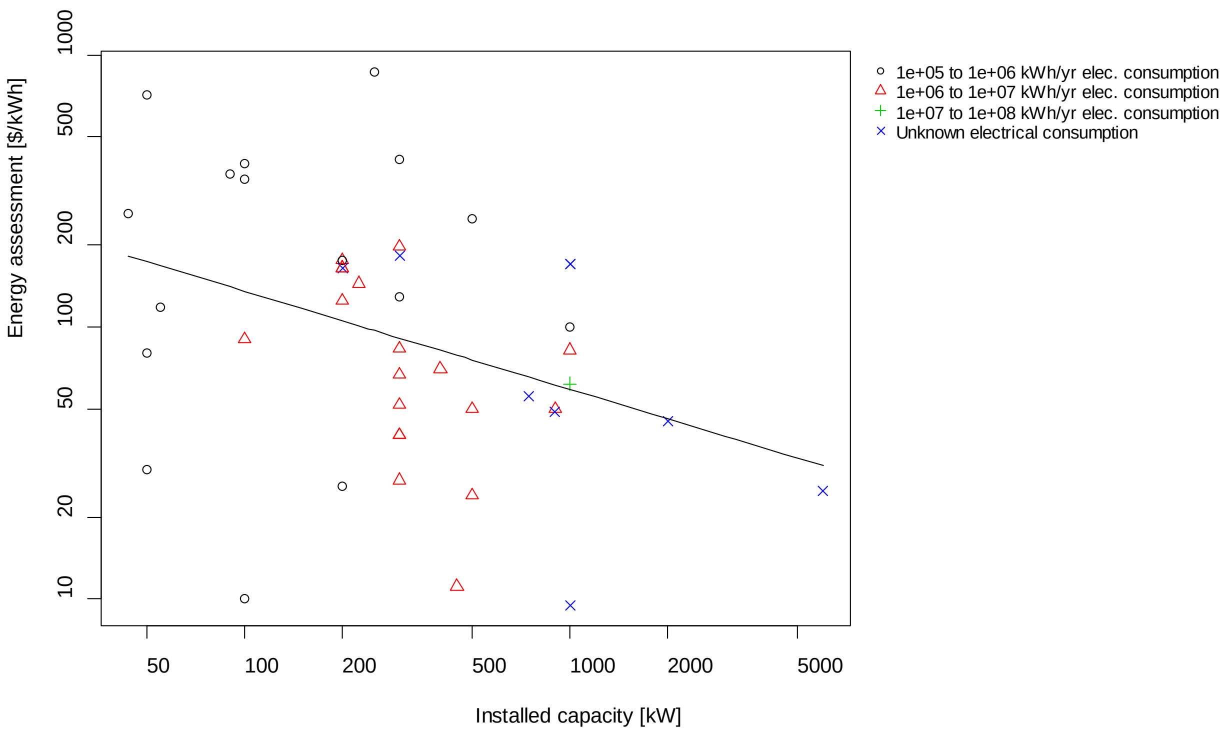
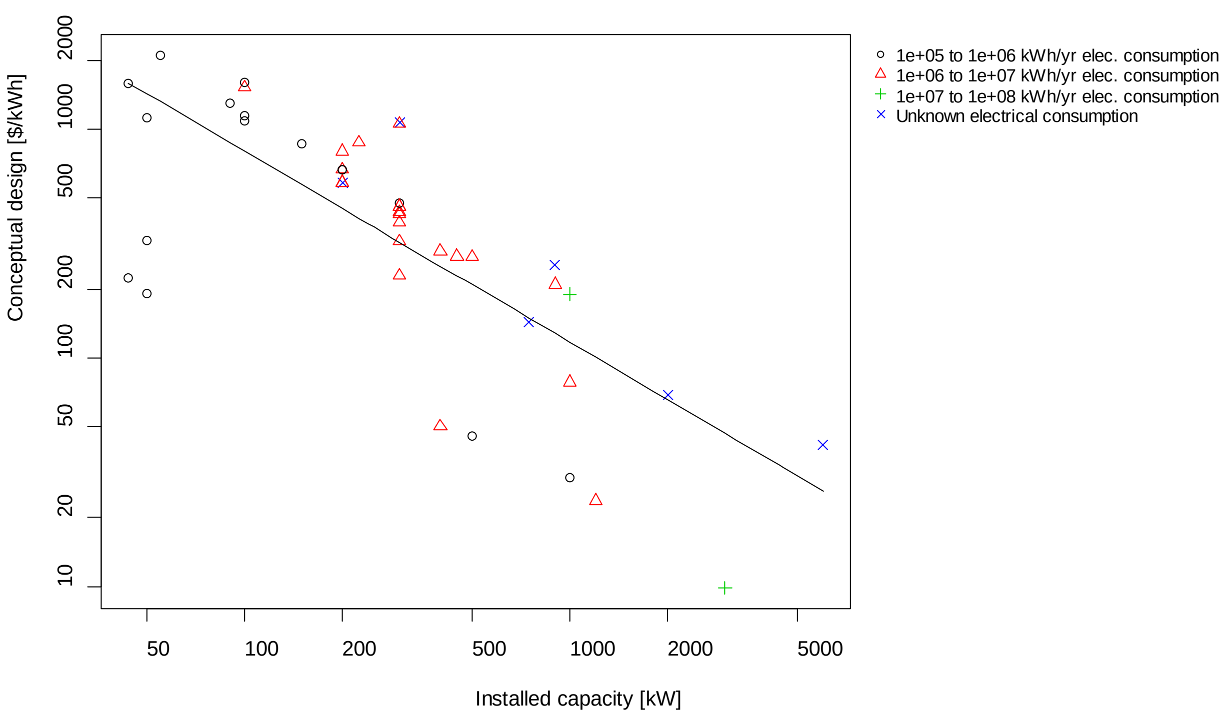
Appendix A

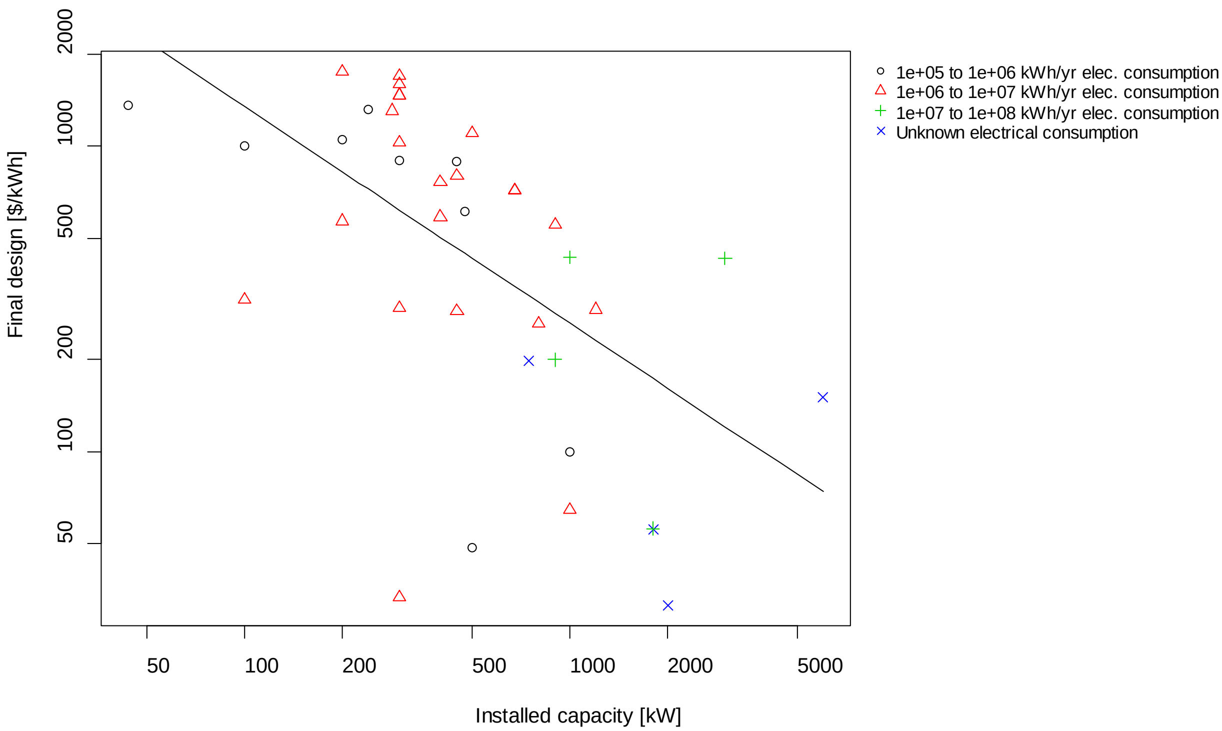
Following are the best fit equations for the individual costs of installing wind power from the REF data and the R^2 of their fit. The following figures show the data with their best fits.

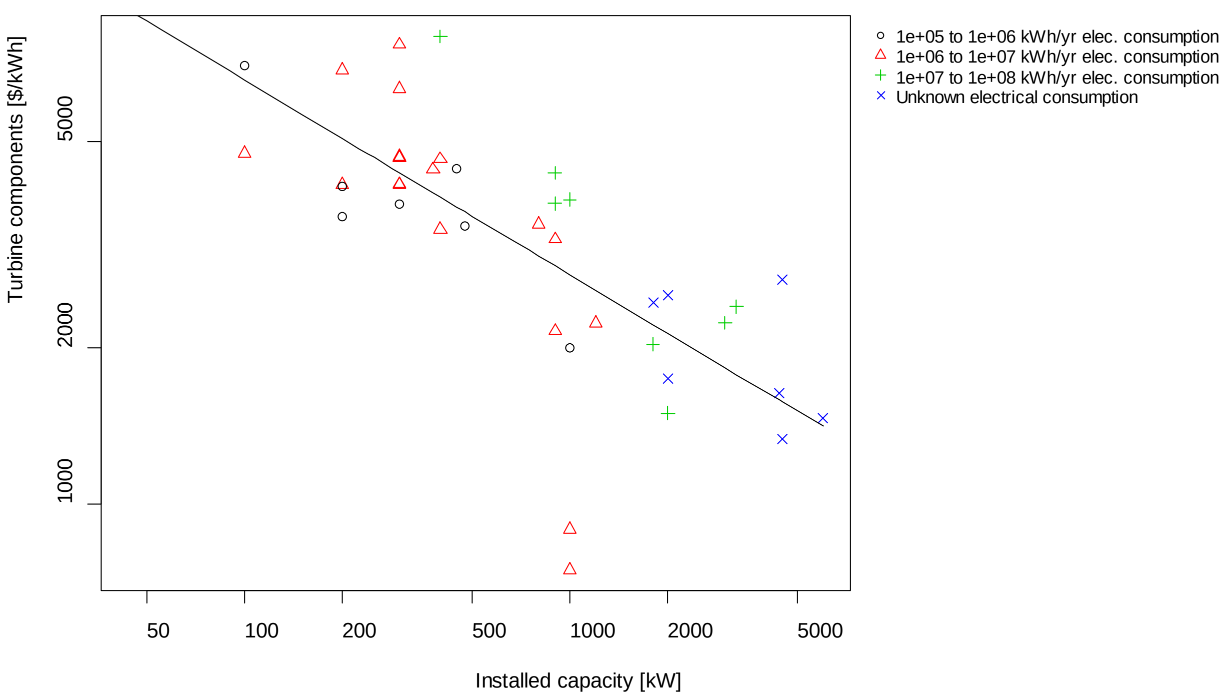
Energy analysis:	$E(\log(EA)\,\vert\,\log(X_1)) = 6.6 - 0.36 \cdot \log(X_1)$,	$R^2 = 0.11$
Conceptual design:	$E(\log(D1)\,\vert\,\log(X_1)) = 10.5 - 0.63 \cdot \log(X_1)$,	$R^2 = 0.56$
Final design:	$E(\log(D2)\,\vert\,\log(X_1)) = 10.5 - 0.71 \cdot \log(X_1)$,	$R^2 = 0.30$
Hardware:	$E(\log(H)\,\vert\,\log(X_1)) = 10.5 - 0.38 \cdot \log(X_1)$,	$R^2 = 0.53$
Transportation:	$E(\log(TP)\,\vert\,\log(X_1)) = 9.0 - 0.35 \cdot \log(X_1)$,	$R^2 = 0.27$
Foundations and infrastructure:	$E(\log(FI)\,\vert\,\log(X_1)) = 12.1 - 0.75 \cdot \log(X_1)$,	$R^2 = 0.69$
Turbine installation:	$E(\log(TI)\,\vert\,\log(X_1)) = 10.6 - 0.55 \cdot \log(X_1)$,	$R^2 = 0.29$
Transmission:	$E(\log(TM)\,\vert\,\log(X_1)) = 6.6$	
Integration:	$E(\log(I)\,\vert\,\log(X_1)) = 6.6$	

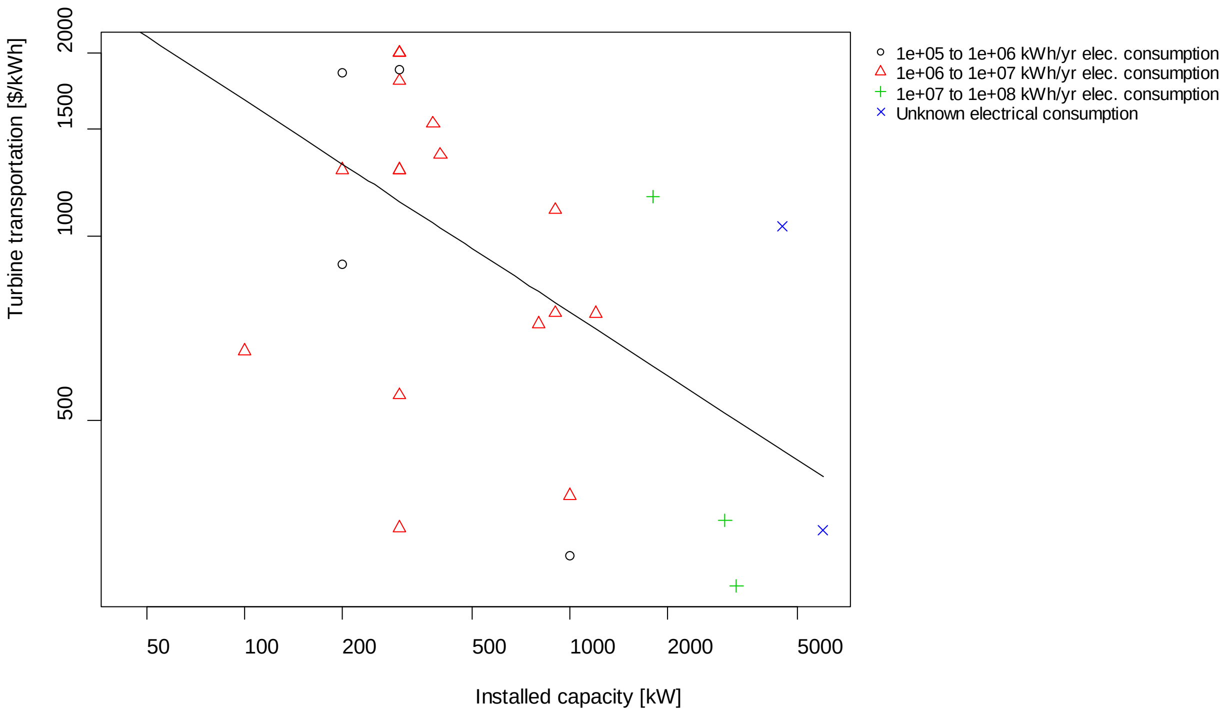
Total installed cost: $E(\log(TOT)\,|\,\log(X_1)) = 12.9 - 0.77 \cdot \log(X_1) + 0.028 \cdot \log(X_1)^2$

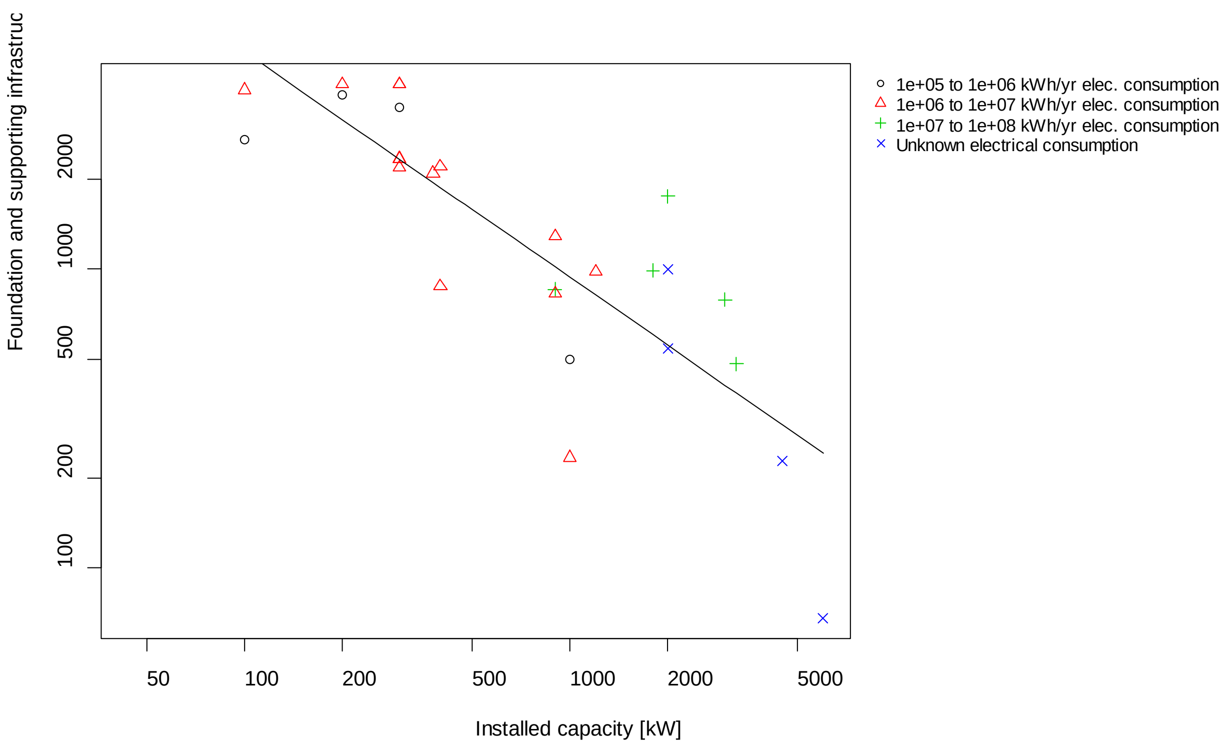

1e+05 to 1e+06 kWh/yr elec. consumption
1e+06 to 1e+07 kWh/yr elec. consumption
1e+07 to 1e+08 kWh/yr elec. consumption
Unknown electrical consumption
Energy assessment [$/kWh]
Installed capacity [kW]

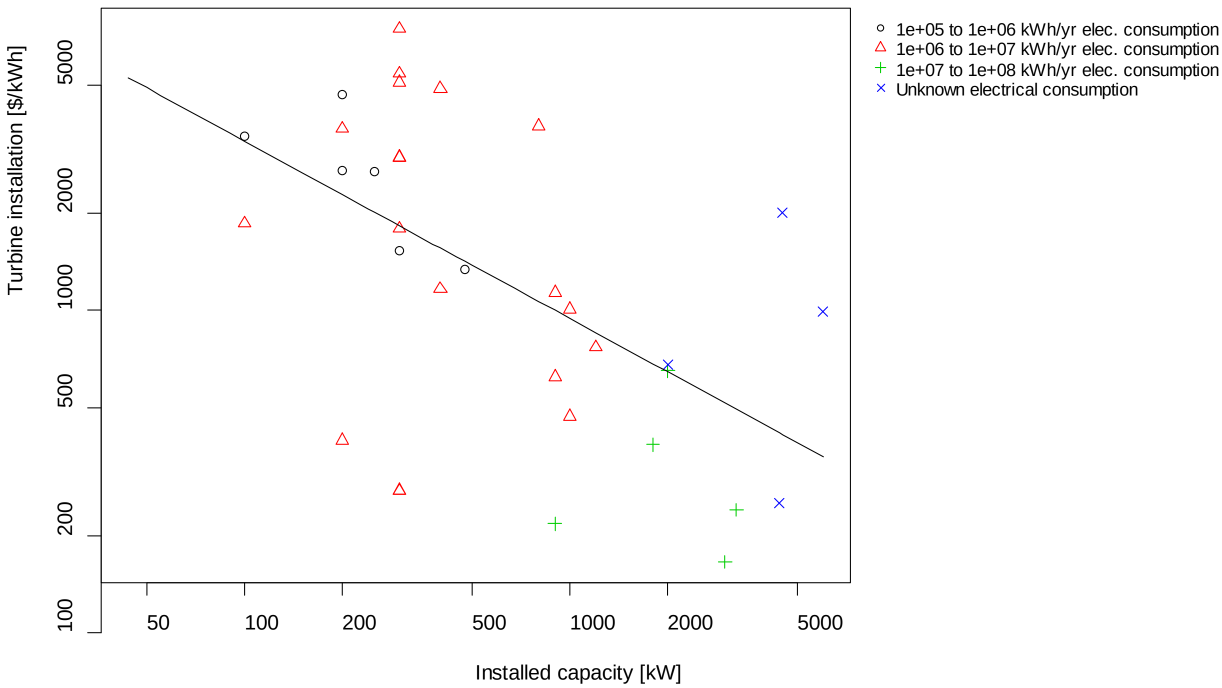

1e+05 to 1e+06 kWh/yr elec. consumption
1e+06 to 1e+07 kWh/yr elec. consumption
1e+07 to 1e+08 kWh/yr elec. consumption
Unknown electrical consumption
Conceptual design [$/kWh]
Installed capacity [kW]

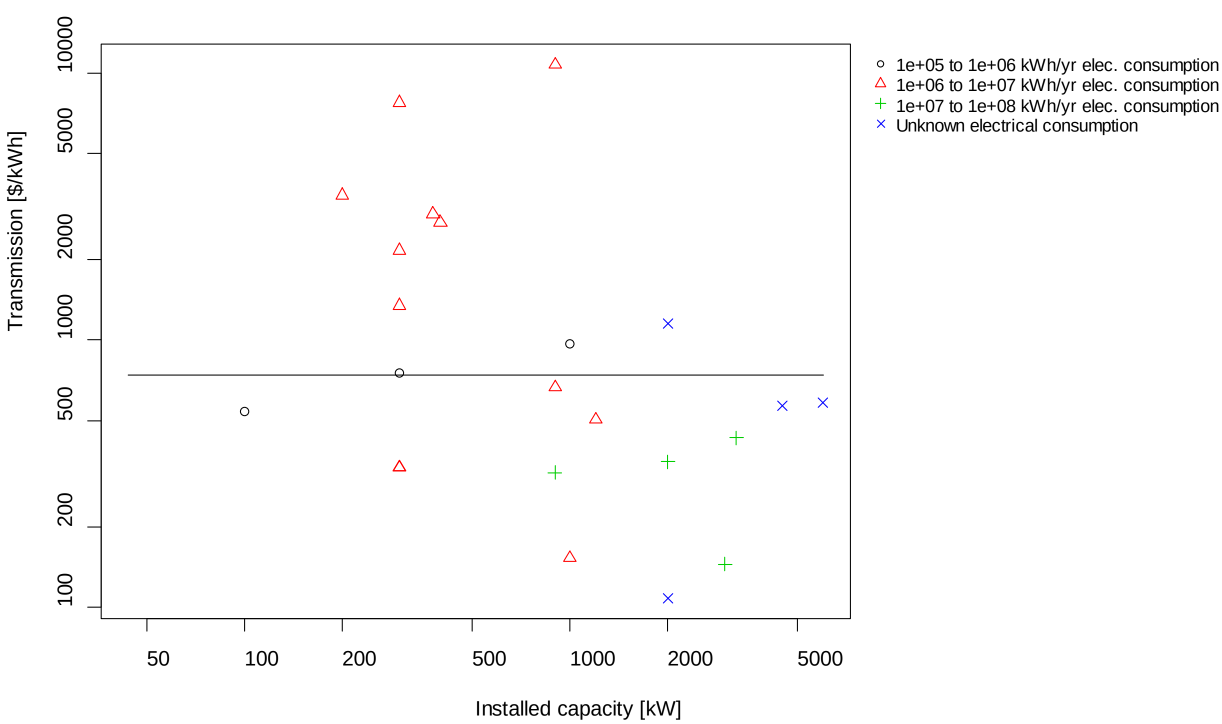

Final design [$/kWh]
2000
1000
500
200
100
50
50
100
200
500
1000
2000
5000
Installed capacity [kW]
1e+05 to 1e+06 kWh/yr elec. consumption
1e+06 to 1e+07 kWh/yr elec. consumption
1e+07 to 1e+08 kWh/yr elec. consumption
Unknown electrical consumption

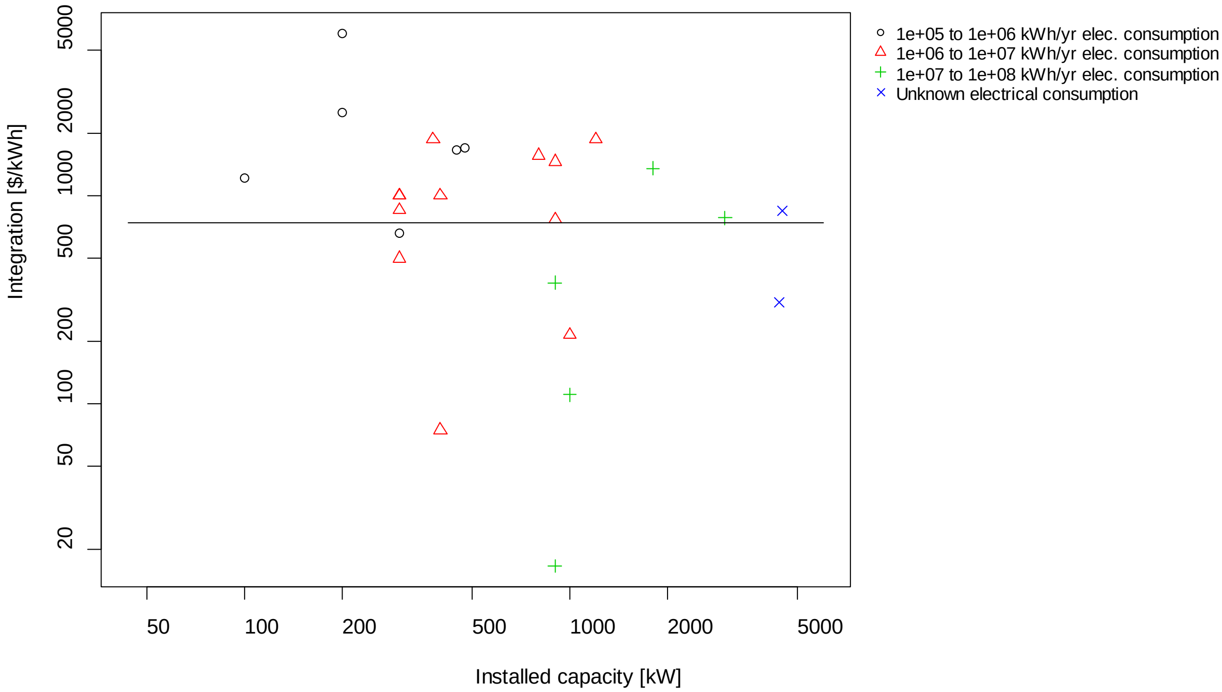

Turbine components [$/kWh]
5000
2000
1000
50
100
200
500
1000
2000
5000
Installed capacity [kW]
1e+05 to 1e+06 kWh/yr elec. consumption
1e+06 to 1e+07 kWh/yr elec. consumption
1e+07 to 1e+08 kWh/yr elec. consumption
Unknown electrical consumption


Turbine transportation [$/kWh]
500
1000
1500
2000
50
100
200
500
1000
2000
5000
Installed capacity [kW]
1e+05 to 1e+06 kWh/yr elec. consumption
1e+06 to 1e+07 kWh/yr elec. consumption
1e+07 to 1e+08 kWh/yr elec. consumption
Unknown electrical consumption


Foundation and supporting infrastruc
100
200
500
1000
2000
50
100
200
500
1000
2000
5000
Installed capacity [kW]
1e+05 to 1e+06 kWh/yr elec. consumption
1e+06 to 1e+07 kWh/yr elec. consumption
1e+07 to 1e+08 kWh/yr elec. consumption
Unknown electrical consumption


Turbine installation [$/kWh]
100
200
500
1000
2000
5000
50
100
200
500
1000
2000
5000
Installed capacity [kW]
1e+05 to 1e+06 kWh/yr elec. consumption
1e+06 to 1e+07 kWh/yr elec. consumption
1e+07 to 1e+08 kWh/yr elec. consumption
Unknown electrical consumption


Transmission [$/kWh]
100
200
500
1000
2000
5000
10000
50
100
200
500
1000
2000
5000
Installed capacity [kW]
1e+05 to 1e+06 kWh/yr elec. consumption
1e+06 to 1e+07 kWh/yr elec. consumption
1e+07 to 1e+08 kWh/yr elec. consumption
Unknown electrical consumption


1e+05 to 1e+06 kWh/yr elec. consumption
1e+06 to 1e+07 kWh/yr elec. consumption
1e+07 to 1e+08 kWh/yr elec. consumption
Unknown electrical consumption
Integration [$/kWh]
Installed capacity [kW]
20
50
100
200
500
1000
2000
5000

Appendix B

Equations for LCOE:

$$LCOE = \frac{NPV_c \cdot CRF}{Annual\ Energy\ Production}$$

$$NPV_c = CAPEX + \sum_{j=1}^{N} \left(\frac{1+i}{1+r}\right)^j \cdot OM$$

$$CRF = \frac{r}{1-(1+r)^{-N}}$$

where NPV_c is the net present value of the annual cost of the system, $CAPEX$ is the capital expenditure, i is the inflation rate, r is the interest rate and N is the system lifetime in years.

Appendix C

Figure C1 shows the total project costs and installed capacity predicted by REF applications compared to future as-built costs and installed capacity from the same community. The projects can be seen in Table C1. Note that the REF data does not necessarily represent all costs. For example, many projects do not include the engineering and energy assessment. Other projects do not include transport, foundation, installation, integration and/or transmission costs. It is not always clear whether these costs are included with other costs. It is also not known what exactly the as-built costs cover. That being said, there seems to be a trend of lower power and higher CAPEX/Power for as-built projects compared to the associated REF application.

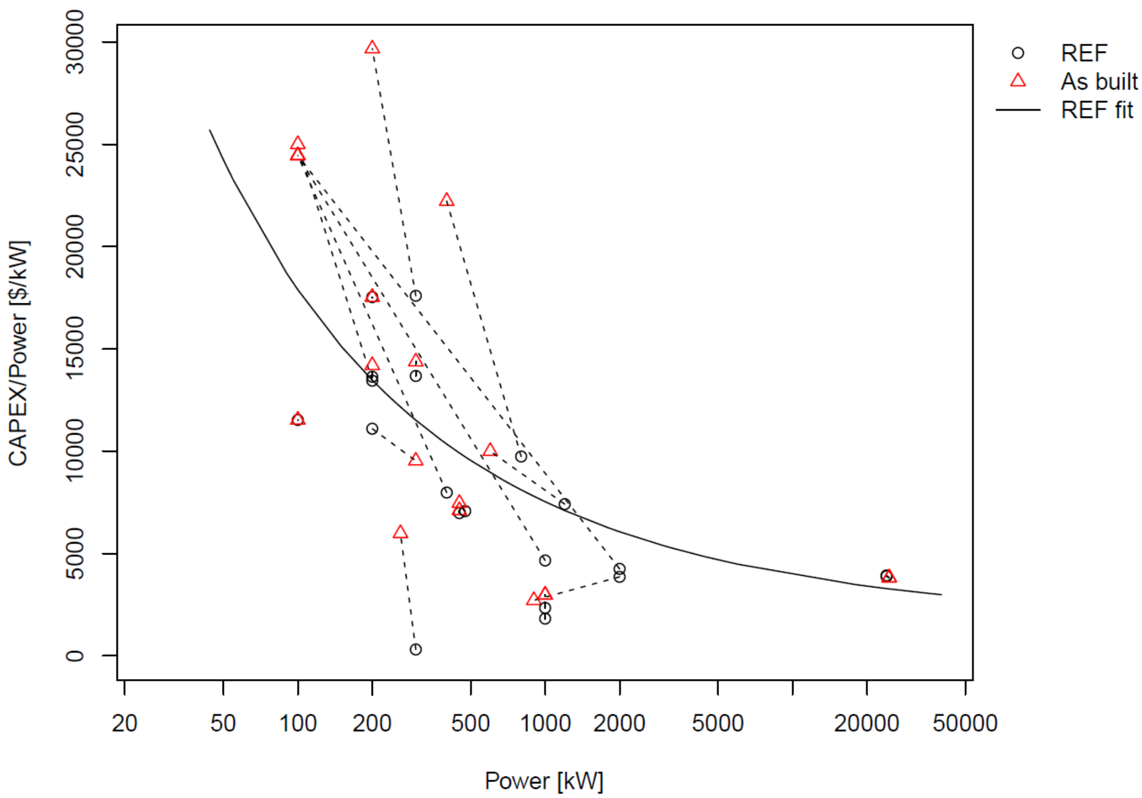


Figure C1: REF costs and associated as-built costs and power are connected with dashed lines. The projects can be seen in Table C1. The fit to the REF data is the solid line.

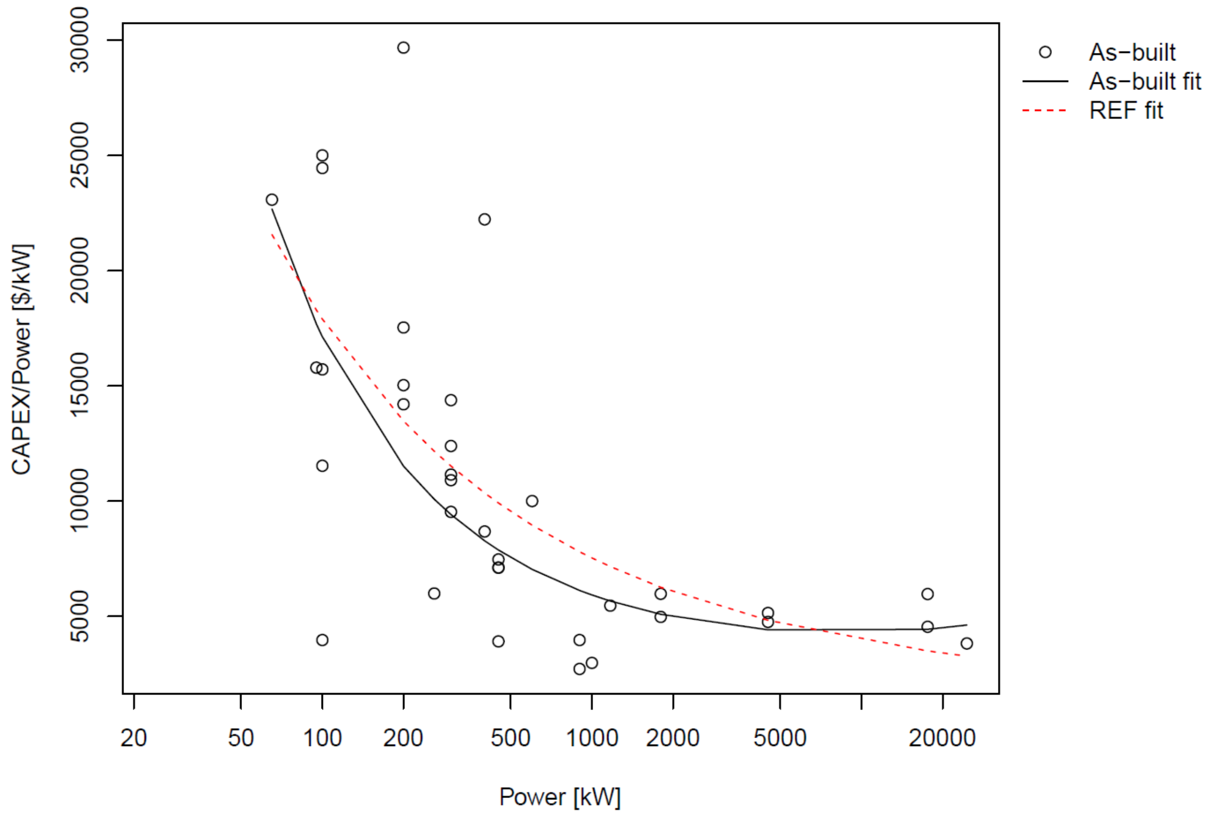


Figure C2: As-built costs with the as-built fit and REF fit. The fit for both data sets are similar. This indicates that the costs calculated from the REF applications and used in this paper are representative of actual costs. The as-built show a more dramatic curvature but for absolute values they are relatively similar.

Wind Power Technology Report

Table C1: Comparison of REF application costs and as built costs for the same location. Not all as-built costs are for the same project as the REF application. The ones with a dark grey background were built before the REF application.

REF Applications													As built costs				
Names	**Year**	**Size [kW]**	**Assessment [$/kW]**	**Design conceptual [$/kW]**	**Design final [$/kW]**	**Hardware [$/kW]**	**Transportation [$/kW]**	**Foundation [$/kW]**	**Installation [$/kW]**	**Transmission [$/kW]**	**Integration [$/kW]**	**Total [$/kW]**	**Size [kW]**	**Date**	**CAPEX [$/kW]**	**Power ratio [kW/kW]**	**CAPEX ratio [$/$]**
Unalakleet Wind Farm Construction	2008	1200	0	24	291	2238	748	980	770	504	1858	7414	600	11/1/2009	10000	0.50	1.35
Bethel Wind Power Project Times 4	2008	400	0	0	0	7980	0	0	0	0	0	7980	100	4/1/2014	24450	0.25	3.06
Bethel Wind Farm Construction (BNC land)	2008	2000	0	0	0	1500	0	1750	650	350	0	4250	100	4/1/2014	24450	0.05	5.75
Bethel	2011	1000	62	190	433	3865	0	0	0	0	111	4661	100	4/1/2014	24450	0.10	5.25
Kongiganak Wind Farm Construction	2008	450	0	0	889	4436	0	0	0	0	1652	6977	450	12/15/2012	7111	1.00	1.02
Quinhagak Wind Farm Construction	2008	300	0	0	0	7707	550	0	5422	0	0	13679	300	11/1/2010	14379	1.00	1.05
Mekoryuk Wind Farm Construction	2008	200	0	0	0	4097	900	3816	2720	0	6000	17532	200	2/1/2011	17532	1.00	1.00
Toksook Bay Wind Farm Expansion Construction	2008	100	0	0	315	4750	650	3959	1856	0	0	11531	100	10/1/2010	11531	1.00	1.00

Wind Power Technology Report

													300	6/1/2006	11149	3.00	0.97
Hooper Bay Wind Farm Construction	2008	200	0	0	569	6876	0	0	3655	0	0	11101	300	7/1/2009	9530	1.50	0.86
Kotzebue Wind Farm Expansion Construction	2008	3250	0	0	0	2407	268	481	241	431	0	3828	195	7/1/1997	#N/A	0.06	#N/A
													455	5/1/1999	#N/A	0.14	#N/A
													100	5/1/2002	#N/A	0.03	#N/A
													130	5/1/2005	#N/A	0.04	#N/A
													65	5/1/2006	#N/A	0.02	#N/A
													195	10/1/2006	#N/A	0.06	#N/A
													1800	8/1/2012	5975	0.55	1.56
													25	5/1/2014	#N/A	0.01	#N/A
Kotzebue	2010	1800	0	0	56	2033	1163	987	384	0	1352	5975	195	7/1/1997	#N/A	0.11	#N/A
													455	5/1/1999	#N/A	0.25	#N/A

Wind Power Technology Report

													100	5/1/2002	#N/A	0.06	#N/A
													130	5/1/2005	#N/A	0.07	#N/A
													65	5/1/2006	#N/A	0.04	#N/A
													195	10/1/2006	#N/A	0.11	#N/A
													1800	8/1/2012	5975	1.00	1.00
													25	5/1/2014	#N/A	0.01	#N/A
Buckland Wind Farm Construction	2008	300	0	0	0	4138	1287	4136	275	7758	0	17596	200	5/1/2015	29674	0.67	1.69
Deering Wind Farm Construction	2008	200	0	0	0	4138	1287	4136	396	3491	0	13449	100	10/1/2015	25000	0.50	1.86
Eva Creek Wind Farm Construction	2008	24000	39	125	40	1633	500	719	334	479	58	3928	24600	10/20/2012	3821	1.03	0.97
Eva Creek	2011	24000	0	0	125	1571	0	0	2192	0	0	3888	24600	10/20/2012	3821	1.03	0.98
Delta Junction Wind Farm Construction	2008	2000	0	0	0	2532	0	541	681	108	0	3862	100	9/1/2008	3970	0.05	1.03
													900	6/1/2010	3970	0.45	1.03

Wind Power Technology Report

													900	9/1/2013	2717	0.45	0.70
Sand Point Wind	2009	1000	0	0	0	896	377	234	469	153	214	2341	1000	2/1/2011	2978	1.00	1.27
Sand Point	2016	1000	0	0	65	748	0	0	1007	0	0	1820	1000	2/1/2011	2978	1.00	1.64
Tuntutuliak High Penetration Wind Diesel	2009	475	0	0	611	3436	0	0	1335	0	1693	7074	450	7/1/2012	7467	0.95	1.06
Shaktoolik Wind	2009	200	0	0	1050	3591	1853	0	4645	0	2500	13640	200	2/1/2012	14200	1.00	1.04
Emmonak / Alakanuk Wind & Trans	2009	800	0	0	263	3470	720	0	3727	0	1563	9741	400	9/1/2011	22222	0.50	2.28
Selawik turbine upgrade	2011	300	83	228	0	0	0	0	0	0	0	312	260	10/1/2003	5990	0.87	19.22
Wales	2013	100	400	1600	0	0	0	0	0	0	0	2000	130	7/1/1998	#N/A	1.30	#N/A

Appendix D

The total electrical energy produced in a year by a wind farm is $E_e = 8760hr \cdot X_3 \cdot P$, where X_3 is the average capacity factor and P is the nameplate capacity of the windfarm.

Assuming the energy content of diesel is 38 kWh/gal and an average diesel efficiency of η, this will displace $E_e/(38 \cdot \eta)$ gallons of diesel.

Thus, the offset per installed capacity in gal/kW is $OFF\ = \frac{230}{\eta}X_3$.