ADVANCED NUCLEAR POWER PROGRAM

The Value of Nuclear Microreactors in Providing Heat and Electricity to Alaskan Communities

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The Value of Nuclear Microreactors in Providing Heat and Electricity to Alaskan Communities[1]

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Summary

We evaluated the system cost of providing electricity and heat to serve the load profiles of two types of Alaskan communities, and calculated the cost efficiency of including a nuclear microreactor in the generation portfolio. We employed a capacity expansion and dispatch model augmented to co-optimize heat and electricity generation. Since microreactor designs are still in development and the eventual capital and O&M costs are speculative, our strategy was to explore the outcomes across a wide range of capital costs, and find the range in which a microreactor is included in the least-cost portfolio and the range in which it is not. We call the boundary between the two the capital cost ceiling.

We have identified the microreactor capital cost ceiling under a range of assumptions and scenarios. This includes two different load profiles—one reflective of demand across Alaska's Railbelt communities, and one reflective of demand at a remote Alaskan mine and neighbouring community. We assessed the impact of natural gas fuel availability, whether a community had a district heating network, future reductions in the capital cost of renewables, the price of fossil fuels, and, last-but-not-least, the need to reduce systemwide emissions.

Three factors appear to play a dominant role in setting the capital cost ceiling and answering whether a microreactor is likely to be a cost-efficient addition to the system. One of these is the availability of natural gas. Natural gas is a much cheaper source of energy than diesel fuel, and therefore the microreactor capital cost ceiling is significantly lower in communities where it is available. Most communities in the Alaskan Railbelt have access to natural gas, while few, if any, of the other communities do.

The second factor is the size of the heat load and the accessibility of a district heating network. In our results, the capital cost ceiling was much higher in scenarios where a microreactor's waste heat was highly utilized. Communities in the Alaskan Railbelt have higher heat loads and select ones have accessible district heating networks, which facilitated the use of microreactor waste heat, and set the capital cost ceiling high. In contrast, a remote community anchored by a mine has a relatively smaller heat load, which would set the capital cost ceiling lower.

The third, and overwhelmingly most important factor, is the goal of emission reductions. Any modest emissions reduction target dramatically raised the capital cost ceiling for a microreactor, reflecting that the microreactor is very cost-efficient among low carbon options when heat and electricity are considered together. This conclusion holds broadly across both load profiles. We focused on CO_2 emissions. However, we are aware that certain Railbelt communities face a critical need to reduce particulates and other criteria pollutants. Recognizing this would further boost the competitiveness of a microreactor.

[1] This research was funded by the Idaho National Laboratory as a part of the Emerging Energy Market Analysis (EMA) project. We received significant helpful input and direction from our colleagues in EMA, and especially from our several colleagues in Alaska, including Christi Bell, Steve Colt, Nolan Klouda, and Richelle Johnson at the University of Alaska-Anchorage and George Roe, Erin Whitney and Gwen Holdmann at the University of Alaska-Fairbanks; but we take responsibility for any errors. Thanks also to the participants of the Alaskan Nuclear Working Group seminar.

In the pages that follow, we report results from our full set of scenarios. However, to help convey the significance of these three factors, we display here the capital cost ceilings for select scenarios.

Community	Natural gas available?	CHP accessible?	No emission reduction target	25% emission reduction target
Railbelt community	Yes	No	$4,700/kWe	Not tested
		Yes	$8,300 /kWe	>$30,000/kWe
Mine & Remote community	No	No	$12,500/kWe	Not tested
		Yes	$12,500/kWe	>$30,000/kWe

Table 1. Summary results: microreactor capital cost ceiling for select scenarios. The capital cost ceiling is the highest overnight capital cost a microreactor can have while still being included in the least-cost generation portfolio. The microreactor variable cost was assumed to be $15/MWh-e. Diesel fuel was available in all scenarios for heating and electricity generation. Combined heat and power (CHP) accessibility refers to the whether waste and bypass heat from thermal electricity generators could be used to meet heat demand, and whether a district heating network existed to deliver that heat. The 25% emission reduction target considered emission from both electricity and heat generation.

Background

Nuclear microreactors, small containerized reactors producing 10MW of electricity or less, are intended as a new means of producing dispatchable zero-emission heat and electricity for the many industrial, agricultural, and other energy users beyond the electricity sector [1, 2]. These sectors constitute the majority of US GHG emissions, and have power, energy, and availability requirements which will be very challenging to meet at reasonable cost with variable renewable energy (VRE) and Li-ion storage alone [3].

Reactor developers aim to make microreactors cost competitive by avoiding the construction overruns and financing overhead which have plagued the massive GW-scale nuclear reactors built thus far. Designing a smaller reactor allows it and its power conversion unit to be mass-produced in factories, road-transported, and then installed very quickly. This approach trades diseconomies of engineering scale (i.e. more concrete and steel per kWe) for economies of volume. The smaller reactor will also permit greater use of passive safety systems and possibly remote operation of multiple reactors by a small staff [1].

Microreactors must be successfully field-demonstrated before mass-production facilities can be justified. Although based on well-established reactor technologies, microreactors are still an emerging product and many of the key outputs, capabilities, and viable cost ranges are yet to be determined. Demonstration reactors will reduce uncertainty about construction costs, remote operation, and plant reliability.

Alaska has been suggested by many as an ideal location for demonstration microreactors [2, 4, 5, 6]. First-to-market microreactors will face additional costs, so developers are seeking to operate them in locations with expensive heat and electricity, or where microreactors can bring additional value. Energy costs are 2-10x higher in Alaska than in the US lower 48 states [7, 8], and the state contains communities at a wide range of scales, from 200kWe to 200MWe [7, 8, 9, 10, 11]. Most Alaskan communities are microgrids systems, so may also value a reliable source of heat and electricity more highly.

Despite this enthusiasm, there has been limited assessment of microreactors in Alaska to understand where the first-to-market reactors should be operated and what level of reactor-costs are economically viable. Recent studies have suggested that microreactors will be viable in remote Alaskan communities if their overnight capital costs are less than $15,000/kWe [12, 13, 14, 15, 16], which is within the anticipated range of $10,000 – 35,000/kWe. Other studies have concluded that the microreactor capital costs will be prohibitively expensive and that the small total size of the remote-community energy market will not justify mass-production of microreactors [17, 18]. In both cases, the analyses either held the capital cost of microreactors fixed and compared it to a limited set of alternative technologies, or they varied the capital cost but assumed a fixed microreactor utilization factor.

In this study we extended the literature by assessing the viability of microreactors across a much wider range of capital costs and scenarios, in order to provide better understanding of where microreactors will succeed in Alaska and which reactor costs and outputs are most important. We simulated microreactors in two representative Alaskan communities: a mid-sized city, and a remote community and neighbouring mine. In each case, we assessed how microreactor installed capacity and utilization varied as a function of microreactor overnight capital cost against a range of competing technologies and carbon policies. We also explored the value of various microreactor capabilities, including ramp rate, minimum load, bypass heat, and waste-heat recovery.

Methods
GenX model

We used the GenX dispatch and capacity expansion model to simulate two representative communities with microreactors and a variety of other generation and storage technologies [19, 20]. GenX calculates the cheapest means of meeting the heat and electricity demand of an energy system for each hour of a representative year. As depicted in Figure 1, GenX utilizes mixed integer programming (MIP) to optimize the portfolio of generation and storage technologies included in the energy system, as well as hour-to-hour operational decisions. The model is subject to system-level constraints on emissions, capacity reserves, etc; as well as generator-level constraints on ramp-rates, VRE availability, downtime, etc.

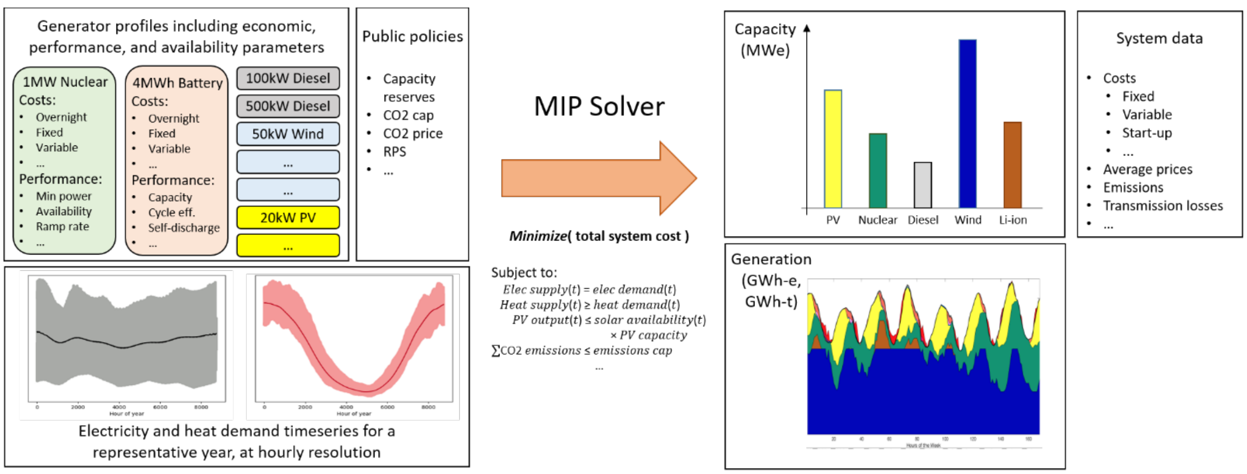

Figure 1. Overview of GenX model. GenX converts user-provided generator technology profiles, heat and electricity demand time series, and other constraints into a linear matrix problem. It then uses a MIP solver to find the solution to this problem which minimizes the total system cost. This solution simultaneously optimizes the portfolio of technologies constructed on the grid and the hour-to-hour operational decisions. GenX then returns the solved model to the user, as well as information on various system costs, emissions, and other factors.

In order to understand the value of microreactors which produce useable heat as well as electricity, we developed a heat module for GenX. This allowed heat and electricity production to be optimized simultaneously. Figure 2 shows how our heat module extends the original electricity-only GenX model. The heat module includes four sources of heat:

1. Electric resistance heaters. These were modelled as being 95% efficient, and the electricity consumed was reflected in increased electricity demand. We assumed that communities already owned the required heaters, so there was no associated capital cost.
2. Direct heating, where diesel or natural gas fuel (when available) are combusted to produce heat at the point of use. Based on the literature, we assumed direct heating was 80% efficient overall, to account for imperfect insulation and operation of the system [21]. We assumed that communities already owned the boilers and heaters required, so there was no associated capital cost, and that the variable cost of operation was incorporated in the efficiency-loss of the system.
3. Waste heat recovery (WHR) from thermal generators (diesel, natural gas, microreactor). Based on a literature review, it was assumed that 38%, 20%, 45%, and 66.5% of the initial energy could be recovered as waste heat from a diesel genset, large gas turbine, small gas turbine, and

microreactor respectively [22]. WHR units had $100/kWe overnight capital cost (annuitized to $12/kWe/yr), and zero fixed or variable O&M cost.

4. Bypass heating from a microreactor. This represents steam or air heated by the reactor being redirected away from the reactor's electricity-generating turbine and used for heating instead. This heat transfer was assumed to be 100% efficient. The overall power output of the microreactor at any time is the sum of the bypass and electric outputs, weighted by the thermal-to-electric efficiency of the microreactor turbine. Bypass heating incurs the same variable cost as electricity production, weighted by the same turbine efficiency to give units of $/kWh-t.

GenX found the cheapest combination of these four heat sources to meet the heat demand in each scenario. We could not find sufficient data on heat storage or heat demand curtailment used in Alaska, so disabled both options in our simulations.

Our model of heat generation and delivery included many assumptions. We assumed that communities already had the equipment required for direct heating and electric heating, so there was no associated capital cost. In practice, almost all Alaskan buildings today have direct heating equipment, in both the Railbelt and remote communities. However, our assumption gave direct heating a small advantage over waste and bypass heating from CHP generators. Electric heating equipment is much less common, with fewer than 1% of remote community buildings having electric space-heating systems [8]. However, the high variable cost of electric heating meant that it was rarely utilized despite the free equipment, so our assumption had little impact.

Our GenX model did include the cost of constructing and operating a heat distribution network, aka district heating system. While separate direct and electric heat can be installed in each building, CHP heat will require steam or air plumbing to deliver heat to residential, commercial, and industrial consumers. We simulated separate scenarios where CHP generators could only serve heat to a limited subset of these three heat demand segments, but we did not incorporate a cost for doing so. The omitted cost might be small if the district heating system must only serve a small remote community or a few industrial buildings, but could be very large if microreactors need to serve CHP heat to every residence in a Railbelt community in order to be successful.

Finally, we did not include propane or wood-burning generation in our model. While more Alaskan communities use these as their primary fuel for space and water heating than in other states, this constitutes less than 1% and 10% of remote communities respectively and less than 5% of Railbelt communities [8, 23]. This compares to 60-90% of Alaskan communities who use diesel or natural gas as their primary fuel. Given this lower utilization and the difficulty of finding consistent cost data for wood-burning heating, we omitted it. We do not believe this made a significant difference to our results, but it will be important to include in future work which looks at the health costs of pollution.

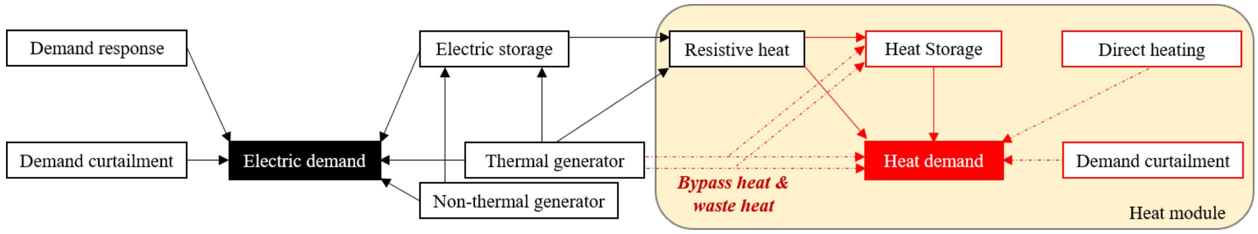

Figure 2. Overview of our new GenX heat module. The heat demand can be met by direct combustion of diesel and/or natural gas in boilers (aka direct heating), electric resistance heaters, or the use of co-generated heat from thermal electricity generators such as diesel gensets, natural gas turbines, and microreactors. The resistance heaters and co-generated heat link the electricity and heat energy subsystems. Our new GenX heat module allows both to be co-optimized to find the cheapest means of supplying both the heat and electricity demands.

Cost allocation

The GenX model's objective function was to minimize the total system costs, and all results presented use that criterion. In addition, we choose to show a particular allocation of those costs to units of electricity and heat. We used the cost allocation given in Equation 1. We allocated all electricity generation costs to electricity. The cost of direct heating, electric heating, the capital cost of WHR units, and the variable costs associated with bypass heating were allocated to heat production. The microreactor capital cost was prorated between bypass heating and electricity production based on the corresponding fractions of reactor thermal output used for each (η_{bypass} in Equation 1).

We reduced the cost of electricity from CHP generators which produced waste heat by the value of the direct heating that their waste heat displaced. We also increased the cost of heat by the same amount. Waste heat is a free byproduct of its associated electricity production, barring the small investment cost of the WHR unit. When the costs of heat and electricity generation were taken together, there were many circumstances in which GenX found the optimal portfolio included more forms of CHP generation which produced expensive electricity but also generated greater volumes of waste heat.

While the total cost of energy declined, under a straightforward cost allocation the increased use of these CHP generators increased the cost of electricity while decreasing the cost of heat. This did not reflect that the cheaper waste heat was contingent on the associated electricity generation, so we allocated the value (i.e. negative cost) of the direct heating displaced by waste heat to the associated electricity generation. This reversed the previous trend, with greater use of CHP generation now reducing the cost of electricity while the cost of heat remained approximately constant.

$$
\begin{aligned}
Elec\ cost\ [\$] = & \sum_{non-nuclear} \big((ann.fixed\ cost\ [\$/kWe])(cap\ [kWe]) + (var\ cost\ [\$/kWhe])(elec\ gen\ [kWhe]) + (startup\ [\$])(\#\ startup)\big) \\
& + \sum_{nuclear} \Big((ann.fixed\ cost\ [\$/kWe])(cap\ [kWe])(\eta_{bypass}) + (var\ cost\ [\$/kWhe])(elec\ gen\ [kWhe]) + (startup\ [\$])(\#\ startup)\Big) \\
& - (direct\ heat\ var\ cost\ [\$/kWht] \sum_{all\ gen} (WHR\ gen\ [kWht]) - \sum_{t \in electric\ heating} (mean\ cost\ of\ electricity\ in\ hour\ t\ [\$])
\end{aligned}
$$

$$Heat\ cost\ [\$] = (direct\ heat\ var\ cost\ [\$/kWht])(direct\ heat\ gen\ [kWht]) + \sum_{all\ generators}(ann.WHR\ unit\ cost\ [\$/kWe])(cap\ [kWe])$$
$$+ \sum_{nuclear}\Big((ann.fixed\ cost\ [\$/kWe])(cap\ [kWe])\left(1-\eta_{bypass}\right) + (var\ cost\ [\$/kWht])(bypass\ heat\ gen\ [kWht])\Big)$$
$$+ (direct\ heat\ var\ cost\ [\$/kWht]\sum_{all\ gen}(WHR\ gen\ [kWht]) + \sum_{t\in electric\ heating}(mean\ cost\ of\ electricity\ in\ hour\ t\ [\$])$$

$$\eta_{bypass} = \frac{elec\ gen\ [kWhe]}{(bypass\ heat\ gen\ [kWht])(thermal\ efficiency\ [kWhe/kWht])}$$

Equation 1. Cost allocation for the total cost of heat and electricity.

Case studies

Alaska is made up of six weakly-connected mid-sized grids (100-200MWe) in the Alaskan Railbelt region, and many remote communities (100kWe – 20MWe). Approximately 65% of the population live within the Railbelt [7, 8, 9, 10, 11]. Alaska is over twice the land size of Texas with an average of one person per square mile outside the cities, making a state-wide energy grid infeasible. The remote communities are microgrids with limited or seasonal access to fuel, materials, and maintenance expertise. They have unique energy demand patterns. The extreme cold weather means annual demand for heat is 6-8x that of electricity, compared to 4x in Boston or 0.75x in San Diego (where electric air-conditioning predominates) [7, 9]. Smaller diesel gensets (100kWe-2MWe) are the primary generation in most remote communities, and fuel prices are volatile year-to-year. Many remote communities have formed co-operatives or joint fuel purchasing programmes with one another and nearby ports, military bases and mines to reduce costs.

Smog and health effects from the use of community and domestic diesel generators and boilers are more common in Alaska than other states, especially in the Railbelt [8, 24]. Various levels of government are supporting efforts to utilise more variable renewable energy and battery storage, to reduce smog and reduce spending on diesel fuel. There are multiple successful projects, including some 10 – 20MWe wind farms, and more are being constructed [25, 26, 27, 28, 29, 30, 31]. The weather and high-latitude diurnal cycle can affect the operation and efficacy of VRE and storage but overall performance is good. One of the main hinderances is the higher upfront cost of construction in Alaska [27].

We modelled load profiles reflective of two different types of Alaskan communities: a mid-sized Railbelt community and a small remote community centred on a mining facility. We did not include stand-alone remote communities. They have very low peak electricity demand (400kWe – 10MWe), so are not a good match for the 10MWe microreactor we considered. Stand-alone remote communities may not agree to host first-of-a-kind microreactors as they are concerned about reactor reliability and the time required to fix any failures.

We created the hourly time series by combining seasonal and diurnal heat and electricity demand data from Alaskan and national lab sources [9, 32, 33, 34, 35, 36]. Appendix B describes the methods and data in more detail.

Figure 3 shows the heat and electricity demand time series of both case studies. The mid-sized grid demand is composed of residential, commercial, and industrial demand. The components make up 32% / 26% / 42% of annual electricity demand and 34% / 17% / 49% of annual heat demand respectively. The mine and community profiles only include residential and industrial (i.e. mining) components, each making up 22% / 78% of electricity demand and 79% / 21% and heat demand respectively.

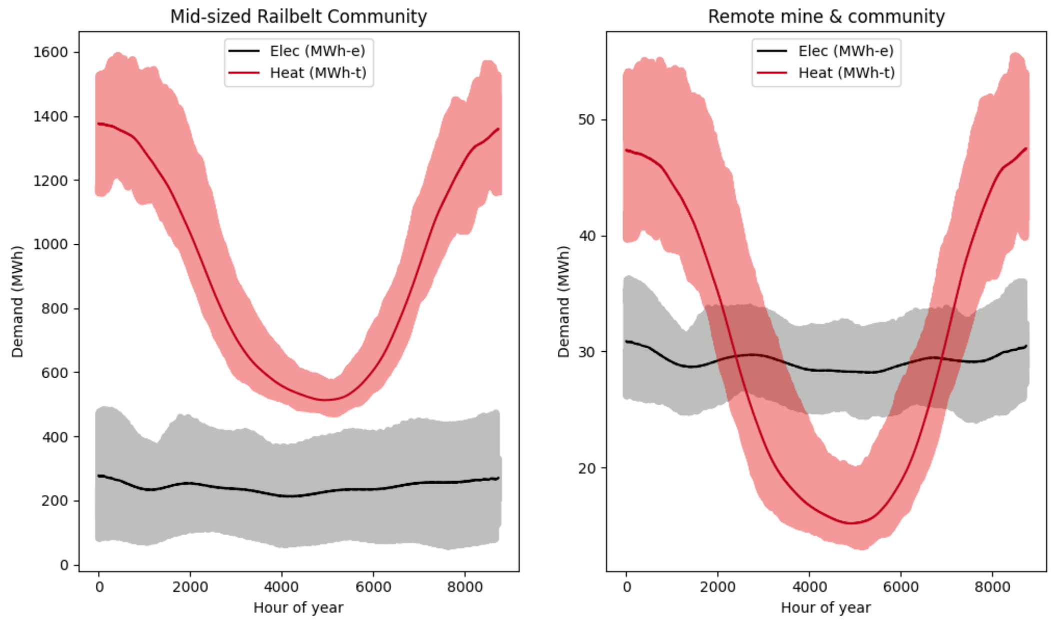

Figure 3. Electricity (black) and heat (red) demand timeseries for our two case study communities. The solid lines indicate the two-week moving average of each demand timeseries, and the shaded area is the extent of the hourly demand from this average.

We decided to simulate each case study with and without natural gas available as it is unclear how natural gas availability and prices will change in the future. While Alaska has significant natural gas resources, it is not widely used for power or heating outside of the cities due to the challenges involved in pumping and trucking it across the state [7]. In the scenarios where natural gas is not available, all direct heating and power generation used diesel-based or non-fossil generation. We assumed diesel and natural gas were priced at \$16/MMBtu and \$7.82/MMBtu respectively, based on surveys of diesel prices in Alaskan communities [37, 38, 39] and the pegged price of natural gas in the cities for industrial users [40]. These prices are somewhat low, as we were cautious about overstating the viability of microreactors based on high fossil fuel prices.

Microreactor model

Microreactor costs and design are still uncertain so we constructed a microreactor model which encompassed as wide range of designs as possible. Proposed microreactors range from 1-10MWe, with a variety of neutronic, heat removal, and electricity generation approaches under consideration [2, 41]. We used the 10MWe/33MWt microreactor described in Table 1 for our simulations. The reactor has a 300C outlet temperature and 30% efficient steam Rankine cycle for electricity generation. Waste heat recovery and a turbine bypass function were considered, and are described in more detail in the section on the GenX heat model. We assumed that the microreactor output could be scaled from 0-100% nameplate capacity between each one-hour time step. Conjectured fuel and operation and maintenance costs were taken from recent a study [1].

Analyst and vendor speculation of microreactor overnight capital costs range between $2,000-50,000/kWe for nth-of-a-kind (NOAK) reactors, with the majority of estimates falling between $5,000-35,000/kWe [12, 13, 14, 15, 16, 42, 43, 44, 45]. For comparison, the most recent large reactors constructed in the USA and Europe have cost $8,000-12,000/kWe [46]. Reactors constructed in the past twenty years in China, South Korea, and the UAE are reported to have cost between $2,000-$4,000/kWe [47, 48]. Future 300-1,500MWe reactors are forecast to cost $4,000-$6,000/kWe [49].

We varied the overnight capital costs of our model microreactor between $5,000 - $30,000/kWe. This range brackets the most common predictions in the literature. In calculating the capital cost annuity, we assumed microreactors will have a thirty-year life and 7% discount factor. All microreactor designs proposed thus far have the reactor being entirely replaced every 2-10 years. The reactor will be refuelled and refurbished at a central facility, rather than on-site, before being redeployed at another location. This cycle will be repeated as long as the reactor remains in good condition. A shorter total lifetime for each reactor will significantly increase the amortized annual cost of capital. A 7% discount factor is low for many Alaskan projects. Some smaller communities have a weighted average cost of capital as high as 21% [50], though it is likely that a larger entity or the government will own the first microreactors, making cheaper capital available.

Alaska vs Lower 48 capital costs

In this study, we evaluated microreactors alongside other technologies, based on the fixed and variable costs seen in Alaska. This means the capital cost ceiling we calculate assumes that we are constructing the reactor in Alaska. However, most microreactor capital cost estimates are based on lower 48 costs. We will have to reduce our capital cost ceiling accordingly to ensure an apples-to-apples comparison.

As an approximate rule based on the literature, small projects (<3MWe) cost twice as much to construct in the Alaskan Railbelt and larger projects were 50% more expensive. Costs can be significantly higher again for communities outside the Alaskan road network, shown in Figure 4. In some of those cases, small projects cost 2-3x more than in the lower 48. Comparing breakdowns of construction costs is challenging as methodologies are inconsistent, but the increase appears to be due to higher transport costs, inelastic costs such as the design of sites by experts, and the greater cost of overruns or errors [26, 27, 28, 37, 51, 52, 53].

In the rest of this report, we assumed microreactors will be 50% more expensive to construct in Alaska than in the lower 48. Therefore, any microreactor capital costs calculated in Alaska must be reduced by a third to give the equivalent lower 48 capital cost.

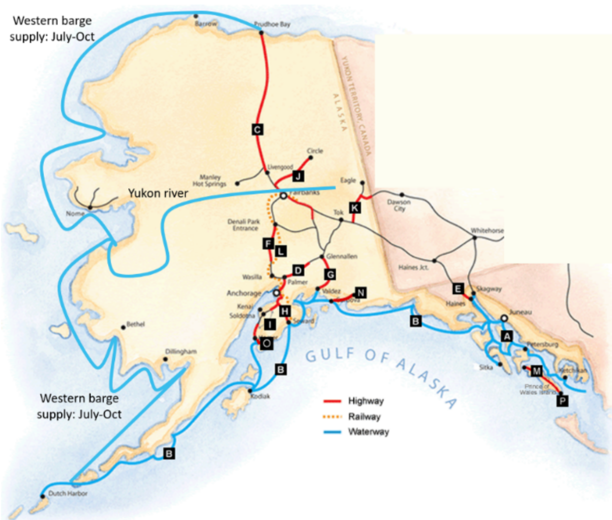

Figure 4. Map of road, railway, and waterway transport routes in Alaska. Air routes are not shown. The barge routes along the western coast are only open during the summer months, severely limiting the construction season [54].

Parameter	Units	Value
Electric Capacity	MWe	10
Thermal Capacity	MWt	33.3
Overnight capital cost	$/kWe	5,000 – 30,000
Lifetime	Years	30
Discount factor	%	7
Fixed O&M cost	$/kWe/yr	115
Variable O&M cost	$/MWh-e	15
Heat rate	MMBTU / MWh-e	11.373
Fuel cost	$/MMBTU	0.72
Start-up cost	$/kWe	0.12
Ramp rate	%/hr	100
Bypass heating efficiency	%	100
Waste-heat recovery fraction	%	66.5
Waste-heat recovery retrofit	$/kWe	100

Table 2. Microreactor design parameters

Alternative technologies

Table 2 lists the alternative generating and storage technologies we included in our simulations. Because of the small scale of our case study energy systems, we used an integer unit investment model and multiple versions of each technology with different unit capacities and costs. The unit capacities were chosen to reflect the most common gensets in the communities we surveyed [33].

We produced the hourly solar and wind availability timeseries which GenX requires by combining diurnal and monthly availability data from Alaskan sites. The method is described in more detail in Appendix A. The south-facing and east-west facing PV profiles drew on a capacity model created by U-AK and Sandia National Lab [29, 30], combined with insolation data from NREL [55, 56]. We used Alaskan and NREL reports on the efficacy of operational wind turbines for diurnal wind speed data and monthly average wind speeds in different regions [9, 57, 58, 59, 60].

The results presented here utilize wind speed and insolation data for Fairbanks Alaska. Wind speeds there peak in the summer months, in-sync with south-facing solar panel output. This reduced the opportunity for PV and wind generation to balance one-another across a year and may have reduced the inclusion of wind generation more generally. Future work should consider wind speed patterns in other parts of the state, for example the Southern and Western coasts where wind speeds are more uniform over the year or peak in winter [59]. However, we found that the impact of this is minimal in scenarios with combined heat and power (CHP) generators. In those cases, VRE capacity is replaced by thermal generators with waste heat recovery to reduce the cost of heat.

Technology	Unit capacity (kWe)	Annuitized investment ($/kWe/yr)	Lifetime (years)	Fixed O&M ($/kWe/yr)	Var O&M ($/MWh-e/yr)	Heat rate (MMBTU/MWh-e)
Diesel	2,000	179	20	82	121	9.91
	20,000	145	30	24	82	8.50
	50,000	145	30	15	82	8.50
Natural Gas	10,000	161	30	16.25	35	9.74
	25,000	110	30	16.25	35	5.70
Wind	1,000	566	20	88	0	-
	2,000	495	20	86	0	-
PV – Tilted, south-facing	20	283	20	50	0	-
PV – Bifacial, vertical, east-west facing	20	284	20	50	0	-
Li-ion, 4hr	1	449	10	32.5	0	-
Li-ion, 6hr	1	673	10	32.5	0	-
Pumped Hydro	1	97	30	3.25	0	-

Table 3. Alternative generating and storage technologies included in the GenX simulations. The pumped hydro was limited to 10MWe capacity, to more realistically represent how much of it can be constructed in the average location. Further details are given in Appendix A.

Reliability constraint

We applied a reliability constraint to our GenX simulations to reflect the additional installed generation and costs associated with ensuring a resilient energy system. GenX simulates representative, or average, years in an energy system, so does not directly simulate random generator failures. Instead, the user must add constraints which mandate back-up generation be available.

As our reliability constraint, we required that the two largest thermal generators in the system always have fully idle thermal back-up available. This reflected practices reported in remote communities in Alaska. Many remote Alaskan communities operate their diesel generators at 50% load with at least two back-up generators for the fleet. Some communities ensure each genset has back-up, in which case those generator fleets have at most a 25% annual utilization factor [37]. We believed a two-back-up generator requirement was an appropriate resiliency constraint across both our case studies.

This constraint created a trade-off for the optimization. Installing fewer large generators reduces costs during normal operation but also increases the size of the largest generators – making the resiliency constraint more expensive to meet. Installing a greater number of smaller generators had the opposite effect. Storage and VRE generation were not credited as back-up, but neither were they required to have dispatchable back-up available.

Further refinement could incorporate a probabilistic measure of energy system reliability into the set of GenX constraints. We knew of no tractable method for doing this using the mixed integer programming (MIP) methodology which underlies GenX. We have made some progress on incorporating a lower-bound probabilistic reliability constraint into GenX.

Results

We simulated a large set of scenarios to ascertain the conditions under which microreactors will be economically viable in our two representative communities. We have divided these results into a sequence of smaller comparisons of a few variables. We begin by presenting results focused exclusively on the electricity system, assuming there is no opportunity to use the microreactor or other thermal generators for heating. In a second section we present results incorporating the value of the microreactor as a source of heat and electricity. Both of these initial sections assume no constraint on emissions. Third, we consider how the results change if we assume cheaper renewable generation and Li-ion storage. Fourth, we re-evaluate all the previous results under the assumption of an emissions cap at various levels of stringency. Next, we show how a carbon price affects microreactor viability. Finally, we present the results of a sequence of sensitivity studies, showing how the value of a microreactor is impacted by changes in the price of diesel or natural gas fuel, the discount factor, microreactor lifetime, microreactor waste heat recovery efficiency, heat and electricity demand load factors, and microreactor minimum load.

Electricity-only microreactor in communities with no CHP

We began by simulating the microreactor in both representative communities assuming that heat and electricity supply were largely separate, and the microreactor could only produce electricity. Only direct heating and electric heating could be used to meet the heat demand, and there was no opportunity for any thermal generators to supply waste or bypass heat.

Figures 5 and 6 show the results of a series of GenX simulations under these assumptions. Figure 5 shows the results for the Railbelt community with natural gas available, and Figure 6 shows the equivalent results for the remote community with only diesel fuel. In each figure, the microreactor capital cost is varied between \$5,000 and \$30,000/kWe, allowing us to assess how the portfolio of installed technologies and the generation mix varied with the microreactor cost.

We can see the optimal generation portfolio without microreactors in the right-hand side of Figures 5a and 6a, where microreactors were too expensive to be installed. Without microreactors, the portfolio of installed generating technologies is dominated by large NGCC and diesel generators, depending on the fuels available, with smaller generators used to meet peak demand. Significant PV capacity is installed in the scenarios where only diesel fuel is available. This was true for both communities. All heat demand is supplied by direct heating.

If microreactors with lower capital costs are available, microreactors are included in the energy system as baseload electricity generation in both scenarios. Figures 5a-c and 6a-c show that the first microreactors displace large NGCC or diesel generations and have very high utilization. Microreactors in the Railbelt case had lower utilization, as seen by comparing Plots 5b and 6b, because fully stopping and restarting an NGCC plant was more expensive than partially reducing the output of a microreactor. If microreactors are very cheap, they displace all PV generation in the remote community, leading to a lower total installed capacity.

Microreactors reduce emissions in both scenarios, as shown in Figures 5f and 6f, but much more so for the remote community. Electricity demand made-up 50% of total demand in the remote community, compared to 25% in the Railbelt, so a larger fraction of emissions is available for microreactors to decarbonize. Direct heating is significantly cheaper than electric heating from microreactors, so electricity-only microreactors cannot reduce heating-related emissions.

Natural gas direct heating is cheaper than electric heating with a microreactor in all cases, not only in these scenarios. Even if a microreactor were free to construct (i.e. a $0/kWe capital cost and 100% utilization), the levelized cost of heat (LCOH) of electric heating from that microreactor would be $36/MWh-t, compared to $33/MWh-t for natural gas direct heating. The LCOH of diesel direct heating is $68/MWh-t, which is equalled by electric heating from a microreactor costing $3,500/kWe to construct.

Based on the GenX simulation series in Figures 5 and 6, we can see that there is a microreactor capital cost (the variable changing along the x-axis) above which no microreactors are included in the optimal generation portfolio for each scenario. We call this value the microreactor capital cost ceiling. The yellow-highlighted rows of Table 4 show the capital cost ceiling for the scenarios simulated in Figures 5 and 6, as well as the other no-CHP scenarios.

The greater the microreactor cost ceiling of a scenario, the more scope there is for microreactor designers to design a reactor which is economically viable in that scenario. We determined more specific capital cost ceilings by interpolating the installed microreactor capacity versus the microreactor capital cost.

With no emissions constraint, and without any ability to use a reactor's heat, the capital cost ceiling for a microreactor is extremely low in Alaskan communities with access to natural gas. The microreactor capital cost ceiling is $5,000 - 6000/kWe in those cases, which is at the very low end of capital cost estimates. Electric-only microreactors are more likely to be viable in communities using diesel fuel. This is most realistic for remote communities, as most of the Railbelt has access to natural gas.

Combined heat and power (CHP) microreactors

In the next set of experiments, we enabled WHR for all thermal technologies as well as bypass heating for the microreactor. As shown in Table 4, we first simulated scenarios where the district heating network and CHP generation only reached the industrial/mining and commercial heat segments, and then a second scenario where residential heat demand was also accessible. Direct and electric heating were still available in all scenarios. Figures 7 and 8 show the simulations results for the same scenarios as Figures 5 and 6, but with CHP allowed to serve all heat demand segments.

Adding CHP raises the microreactor capital cost ceiling by up to $5,000/kWe in scenarios with natural gas and up to $12,000/kWe in those with diesel (in Alaskan costs). The increase in the capital cost ceiling is greater for the Railbelt community than for the remote community.

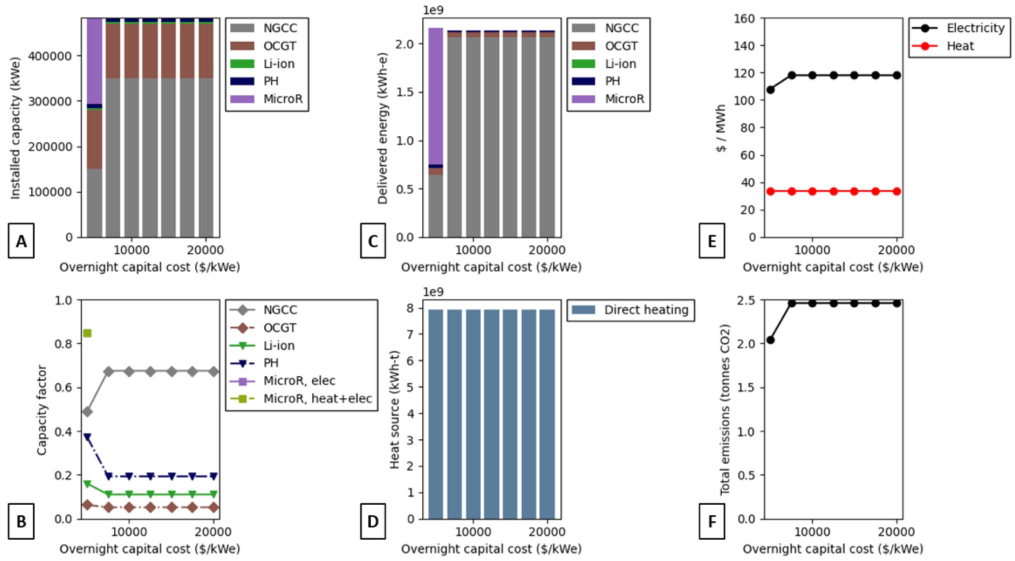

Figure 5. Railbelt grid case study with natural gas and diesel fuel, but no CHP available. The plot is truncated at \$20,000/kWe as there are no further changes at higher capital costs. [A] The installed capacity (kWe) of each generating and storage technology. [B] The capacity factor of each technology. The electric-only and combined bypass heating + electric capacity factors are shown for the microreactors. [C] Electricity generated (kWh-e) by each technology over the representative year. [D] Heat generated (kWh-t) by each technology over the representative year. [E] Costs of electricity (black - \$/MWh-e) and heat (red - \$/MWh-t). [F] The total emissions from the energy system (million tonnes CO2).

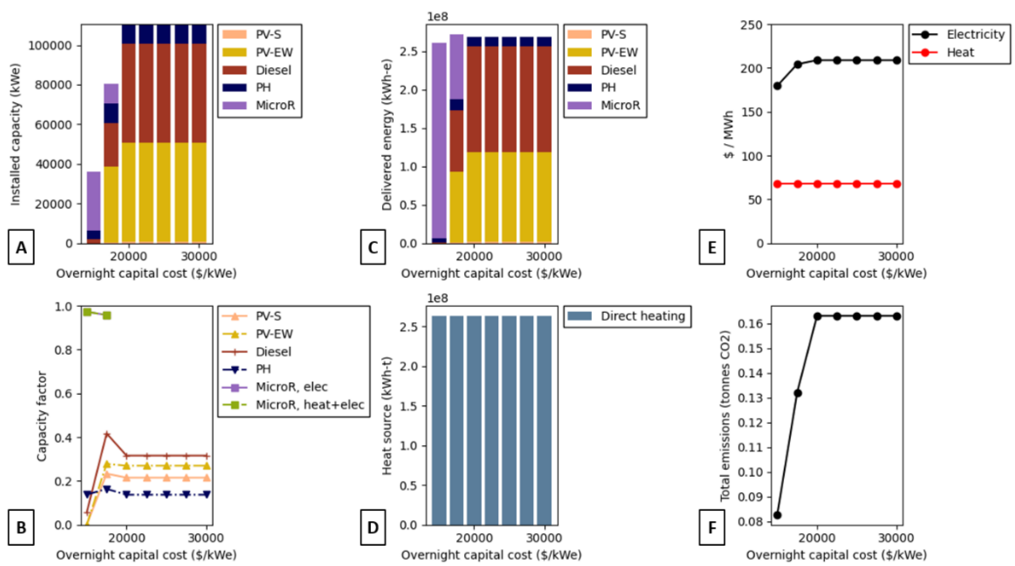

Figure 6. Remote community case study with only diesel fuel, and no CHP available. The plot is truncated at \$15,000/kWe as there are no significant changes at lower capital costs. [A] The installed capacity (kWe) of each generating and storage technology. [B] The capacity factor of each technology. The electric-only and combined bypass heating + electric capacity factors are shown for the microreactors. [C] Electricity generated (kWh-e) by each technology over the representative year. [D] Heat generated (kWh-t) by each technology over the representative year. [E] Costs of electricity (black - \$/MWh-e) and heat (red - \$/MWh-t). [F] The total emissions from the energy system (million tonnes CO2).

In both case studies, CHP significantly reduces the total cost of providing heat and electricity, as well as grid emissions. This is primarily due to the addition of WHR. Waste heat is very cheap and effectively emission free, as the costs and emissions are accrued in the process of generating electricity. Its low cost allows waste heat to displace direct heating, reducing costs as well as decarbonizing the energy supply.

Increased use of waste heat reduced the cost of electricity due to the cost allocation described in Equation 1 and the reasons given in the GenX model section. The cost of heat in remains approximately constant. At lower microreactor capital costs, the per-unit cost of heat decreased in scenarios where more bypass heat was utilized, as shown in Figure 7d and 7e.

Community	**Fuels available**	**Heat sources**	**Microreactor overnight capital cost ceiling**		**Mean cost of electricity ($/MWh-e)**	**Mean cost of heat ($/MWh-t)**	**Total cost (million $)**	**Total emissions (million tonnes CO2)**
			AK costs ($/kWe)	U.S. 48 cost ($/kWe)				
Railbelt community	Natural gas and diesel	Direct & electric	7,000	4,700	118	33	515.3	2.462
		Industrial and Commercial CHP	12,500	8,300	100	34	476.5	2.290
		Indust, Comm, & Residential CHP	13,750	9,200	99	34	476.9	2.289
	Diesel only	Direct & electric	16,250	10,800	220	68	1,005.5	3.222
		Industrial and Commercial CHP	28,750	19,200	175	68	914.0	3.058
		Indust, Comm, & Residential CHP	28,750	19,200	175	69	913.6	3.057
Mine & Remote community	Natural gas and diesel	Direct & electric	8,750	5,800	107	33	36.1	0.128
		Industrial and Commercial CHP	8,750	5,800	100	34	34.4	0.134
		Indust, Comm, & Residential CHP	11,250	7,500	91	34	32.2	0.118
	Diesel only	Direct & electric	18,750	12,500	210	68	71.4	0.163
		Industrial and Commercial CHP	18,750	12,500	196	69	68.0	0.130
		Indust, Comm, & Residential CHP	26,250	17,500	172	69	61.9	0.143

Table 4. Maximum viable microreactor capital costs for each scenario, as well as the cost of electricity, cost of heat, total cost of energy, and total emissions at which the first microreactor is added to the grid. These values were calculated by simulating each scenario in GenX and varying the microreactor capital cost between $5,000-30,000/kWe. Direct heating and electric heating were available in every scenario, but are only listed in those without CHP.

Waste heat has value equal to the cost of the heat it displaces, but is produced almost for free as a by-product of electricity generation. This means CHP technologies which produce more waste heat generate more value and are more economically competitive when the costs of heat and electricity are considered together. In our model, microreactors produced 2kWh-t of waste heat per kWh-e generated, compared to 1kWh-t/kWh-e for diesel generators, 0.35kWh-t/kWh-e for NGCC, and 1.25kWh-t/kWh-e for OCGT generators. The ratio is low for NGCC generation because it very efficiently converts fuel to electricity, leaving relatively little energy for WHR. This is why the electric-only Railbelt scenario in Figure 5 was mostly served by NGCC generators, while the same system with CHP, in Figure 7, made use of OCGTs and microreactors: it was cheaper to use technologies which produce more waste heat rather than generate electricity efficiently using NGCCs and then purchase additional direct heating.

For a technology to realize the value of its potential waste heat output there must also be enough heat demand for the available waste heat to be utilized. When there is insufficient demand less direct heating is displaced and the value of the waste heat is reduced. This occurred in our simulation of the remote community with industrial and commercial CHP. The mine (i.e. the industrial and commercial demand segment) required 6.3MWt of heat, on average, with demand varying between 0.8 – 15MWt. A fully utilized microreactor is capable of producing 20MWt of waste heat, so in this scenario only 31.5% of the available waste heat was utilized and its value to the microreactor and energy system was 68.5% smaller. The diminished value of the waste heat made little change to the combined cost of the microreactor heat and electricity, so the microreactor capital cost ceiling did not rise. Allowing CHP to serve residential demand increased the average heat demand to 30MWt. As a result, all of the microreactor waste heat could be utilized and the capital cost ceiling rose accordingly.

Microreactor bypass heating brings less value than microreactor waste heat as it is still relatively expensive compared to direct heating. The bypass heating utilization factor was approximately 10% in all Railbelt community scenarios, and less than 5% in the remote community. Bypass heating was primarily used at night when electricity demand fell enough that there was not sufficient waste heat available to meet the heat demand. Figure 9 shows an example of this for two weeks in the Railbelt community. In both case studies, heat demand rose relative to electricity demand during the winter, which often meant additional direct heating was also needed.

The LCOH of natural gas direct heating is $33/MWh-t, equal to the LCOH of bypass heating from a microreactor costing $250/kWe to construct and only producing bypass heat. Diesel direct heat costs $68/MWh-t, equal to the LCOH of bypass heat from a $4,000/kWe microreactor. These cost ceilings are very low, telling us that a heat-only microreactor, i.e. one which produces bypass heat only, is very unlikely to be economically viable in Alaska.

As mentioned above, the per-unit cost of heat decreased below the LCOH of direct heat in some scenarios with significant bypass heating. This occurred because our cost allocation pro-rated the microreactor capital costs between heat and electricity production based on how much of each was produced. Given that the bypass heat utilization was less than 10%, the LCOH of the bypass heat was lower than the cost of direct heating. For example, the first MWh-t of bypass heat cost only $17/MWh-t.

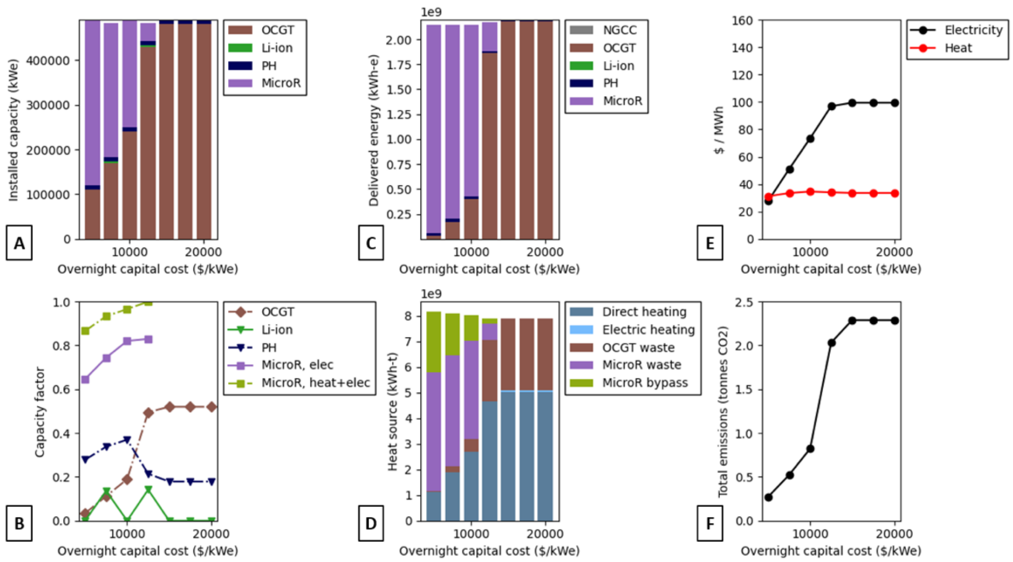

Figure 7. Railbelt grid case study with natural gas and diesel fuel, and CHP available to serve all heat demand. The plot is truncated at $20,000/kWe as there are no further changes at higher capital costs. [A] The installed capacity (kWe) of each generating and storage technology. [B] The capacity factor of each technology. The electric-only and combined bypass heating + electric capacity factors are shown for the microreactors. [C] Electricity generated (kWh-e) by each technology over the representative year. [D] Heat generated (kWh-t) by each technology over the representative year. [E] Costs of electricity (black - $/MWh-e) and heat (red - $/MWh-t). [F] The total emissions from the energy system (million tonnes CO2).

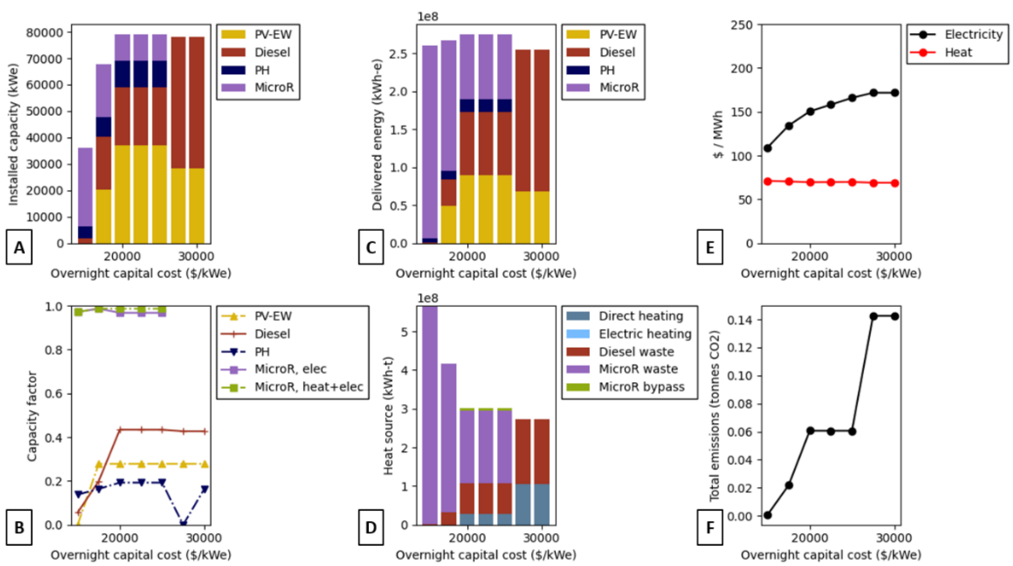

Figure 8. Remote community case study with only diesel fuel, but CHP available to serve all heat demand. The plot is truncated at $15,000/kWe as there are no significant changes at lower capital costs. [A] The installed capacity (kWe) of each generating and storage technology. [B] The capacity factor of each technology. The electric-only and combined bypass heating + electric capacity factors are shown for the microreactors. [C] Electricity generated (kWh-e) by each technology over the representative year. [D] Heat generated (kWh-t) by each technology over the representative year. [E] Costs of electricity (black - $/MWh-e) and heat (red - $/MWh-t). [F] The total emissions from the energy system (million tonnes CO2).

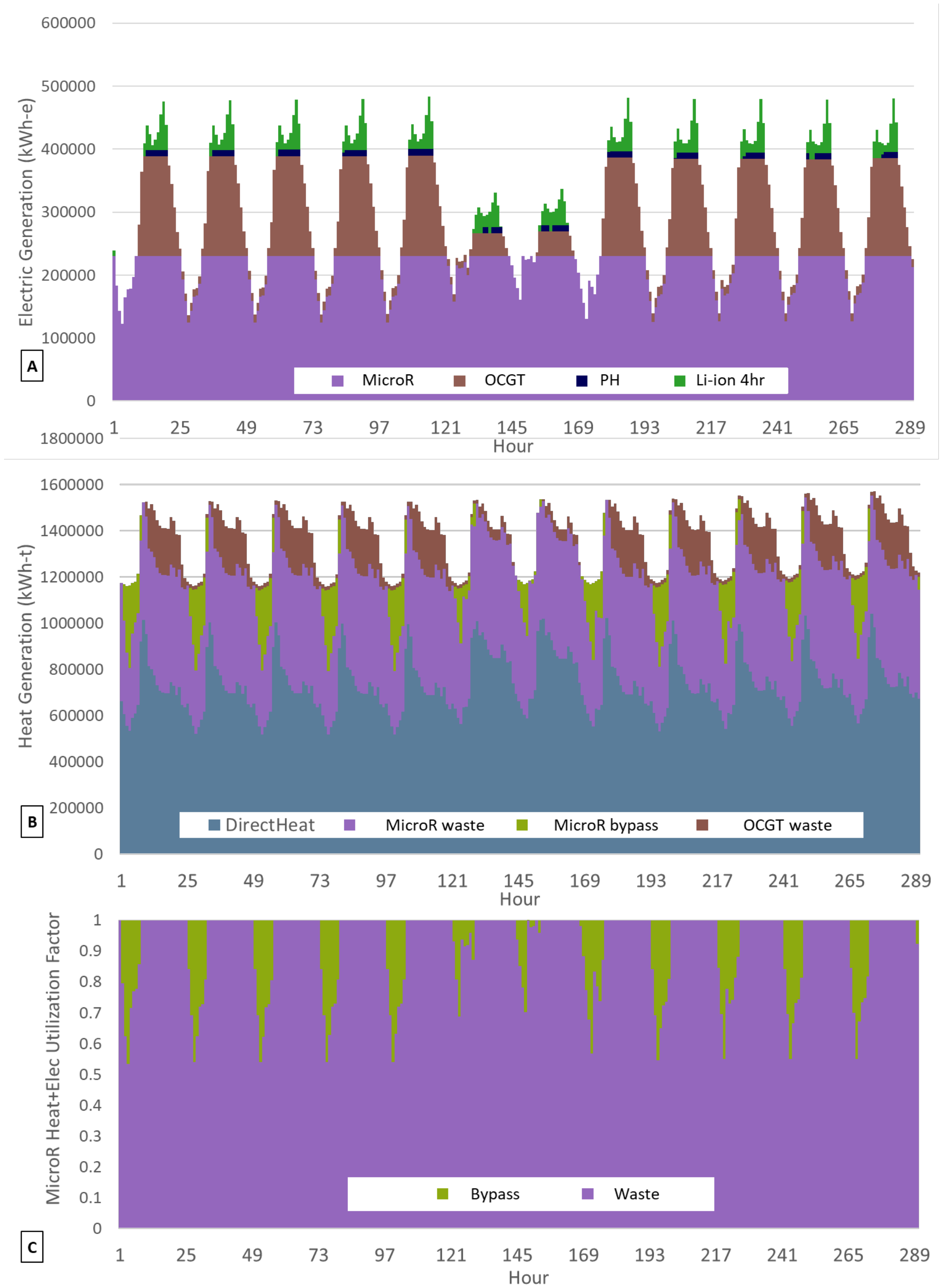

Figure 9. Hourly generation timeseries of the first two weeks of January from the Railbelt grid case study with natural gas and diesel fuel, and CHP available to serve all heat demand. [A] Electricity generation by source. The reduction in days 6 and 7 is due to the weekend. [B] Heat generation by source. [C] Total microreactor utilization factor.

Reductions in the price of VRE and Li-ion

There was less VRE installed capacity and utilization in the scenarios with CHP because thermal generation could provide heat and electricity while VRE generation required expensive electric heating. This can be seen most clearly when comparing Figures 6 and 8.

To test whether this outcome might change if VRE and Li-ion prices fall, we ran a series of GenX simulations where the capital costs of VRE generation and Li-ion storage were reduced to lower 48 prices, given in Table 5. CHP was allowed to serve all heat demand in all simulations.

The resulting microreactor capital cost ceilings are given in Table 6, under the column for no CO2 emission cap. The microreactor capital cost stayed the same for both representative communities when natural gas was available, and decreased by $2,000 – 3,000/kWe when only diesel was available.

Figures 10 and 11 show the simulations results for the same scenarios as Figures 7 and 8, but the reduced VRE and Li-ion costs. Comparing the Railbelt community results in Figures 7 and 10, we see that the cheaper VRE generation and electric heating is still not competitive with OCGT, so there is relatively little change in the grid installed portfolio or the microreactor capital cost ceiling. Lower cost VRE and Li-ion are cheap enough to displace diesel generation in the remote community, as seen by comparing Figures 8 and 10. This requires microreactors to be cheaper for them to be competitive, reducing their capital cost ceiling.

Technology	Unit capacity (kWe)	Annuitized investment ($/kWe/yr)	Lifetime (years)	Fixed O&M ($/kWe/yr)	Var O&M ($/MWh-e/yr)	Heat rate (MMBTU/MWh-e)
Wind	1,000	182	20	88	0	-
	2,000	158	20	86	0	-
PV – Tilted, south-facing	20	124	20	50	0	-
PV – Bifacial, vertical, east-west facing	20	125	20	50	0	-
Li-ion, 4hr	1	120	10	32.5	0	-
Li-ion, 6hr	1	200	10	32.5	0	-
Pumped Hydro	1	97	30	3.25	0	-

Table 5. Alternative generating and storage technologies assuming lower 48 costs.

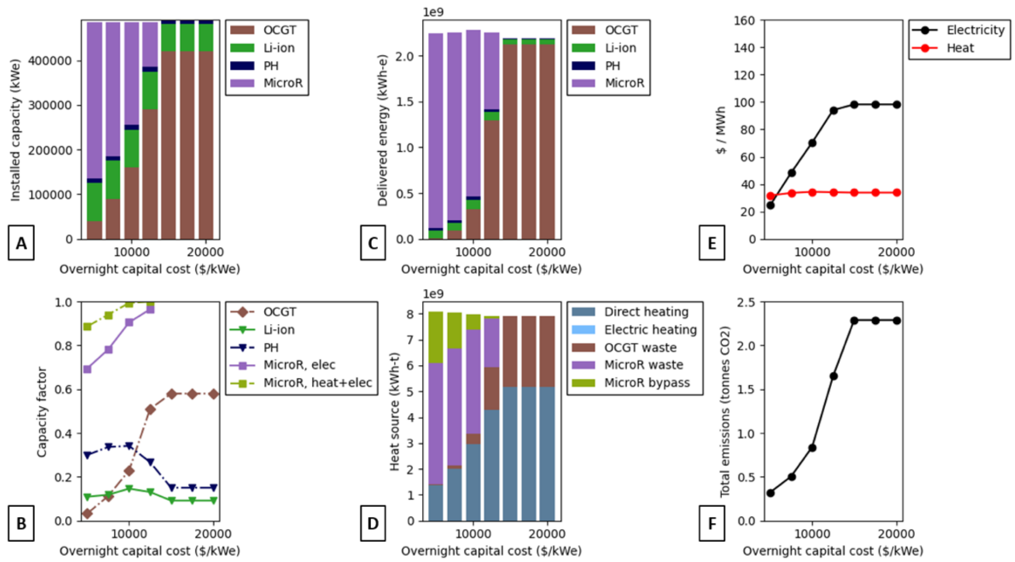

Figure 10. Railbelt grid case study with natural gas and diesel fuel, CHP available to serve all heat demand, and VRE and Li-ion costs reduced to lower 48 levels. The plot is truncated at \$20,000/kWe as there are no further changes at higher capital costs. [A] The installed capacity (kWe) of each generating and storage technology. [B] The capacity factor of each technology. The electric-only and combined bypass heating + electric capacity factors are shown for the microreactors. [C] Electricity generated (kWh-e) by each technology over the representative year. [D] Heat generated (kWh-t) by each technology over the representative year. [E] Costs of electricity (black - \$/MWh-e) and heat (red - \$/MWh-t). [F] The total emissions from the energy system (million tonnes CO2).

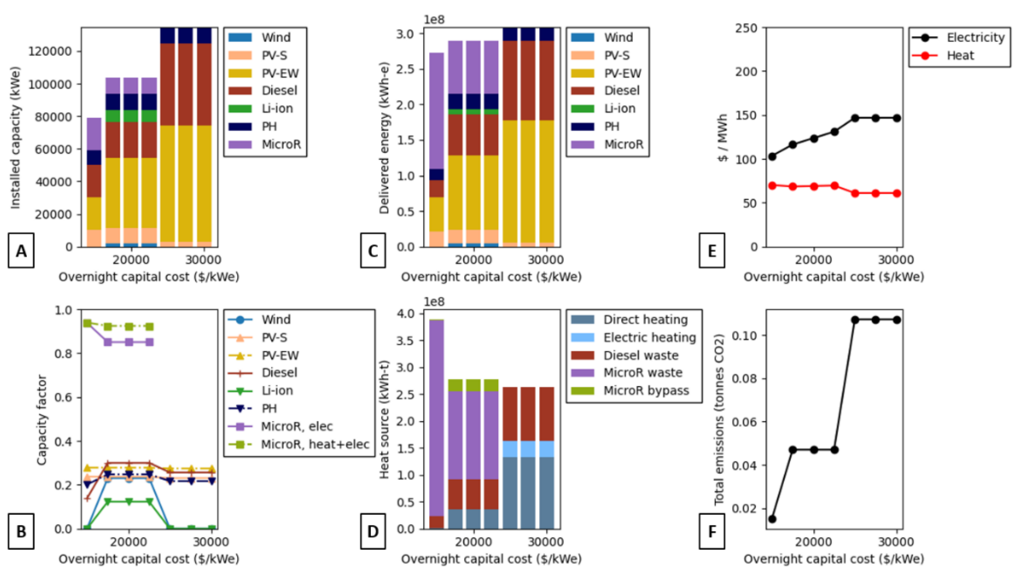

Figure 11. Remote community case study with diesel fuel, CHP available to serve all heat demand, and VRE and Li-ion costs reduced to lower 48 levels. The plot is truncated at \$15,000/kWe as there are no significant changes at lower capital costs. [A] The installed capacity (kWe) of each generating and storage technology. [B] The capacity factor of each technology. The electric-only and combined bypass heating + electric capacity factors are shown for the microreactors. [C] Electricity generated (kWh-e) by each technology over the representative year. [D] Heat generated (kWh-t) by each technology over the representative year. [E] Costs of electricity (black - \$/MWh-e) and heat (red - \$/MWh-t). [F] The total emissions from the energy system (million tonnes CO2).

System-level emissions cap

The next question we wished to answer was how emission reduction policies such as a carbon cap will change the microreactor capital cost ceiling. To explore these issues, we added an emission constraint to our GenX simulations, requiring that the total emissions from the production of heat and electricity, including direct heating, be less than a specified fraction of an emission baseline. The baseline for each scenario was the system emissions without any microreactors. We ran the same series of GenX simulations as before, varying the microreactor capital cost between $5,000-30,000/kWe each time, but with 25%, 50%, and 75% emission caps.

Figure 12 shows an example result for the Railbelt community with natural gas available and CHP serving all sectors. Plot 12a shows how the emission cap increased the cost of energy, and that cheaper microreactors brought down the total system cost significantly. Plot 12b shows how emissions fell in line with the emission caps, except when very cheap microreactors were available.

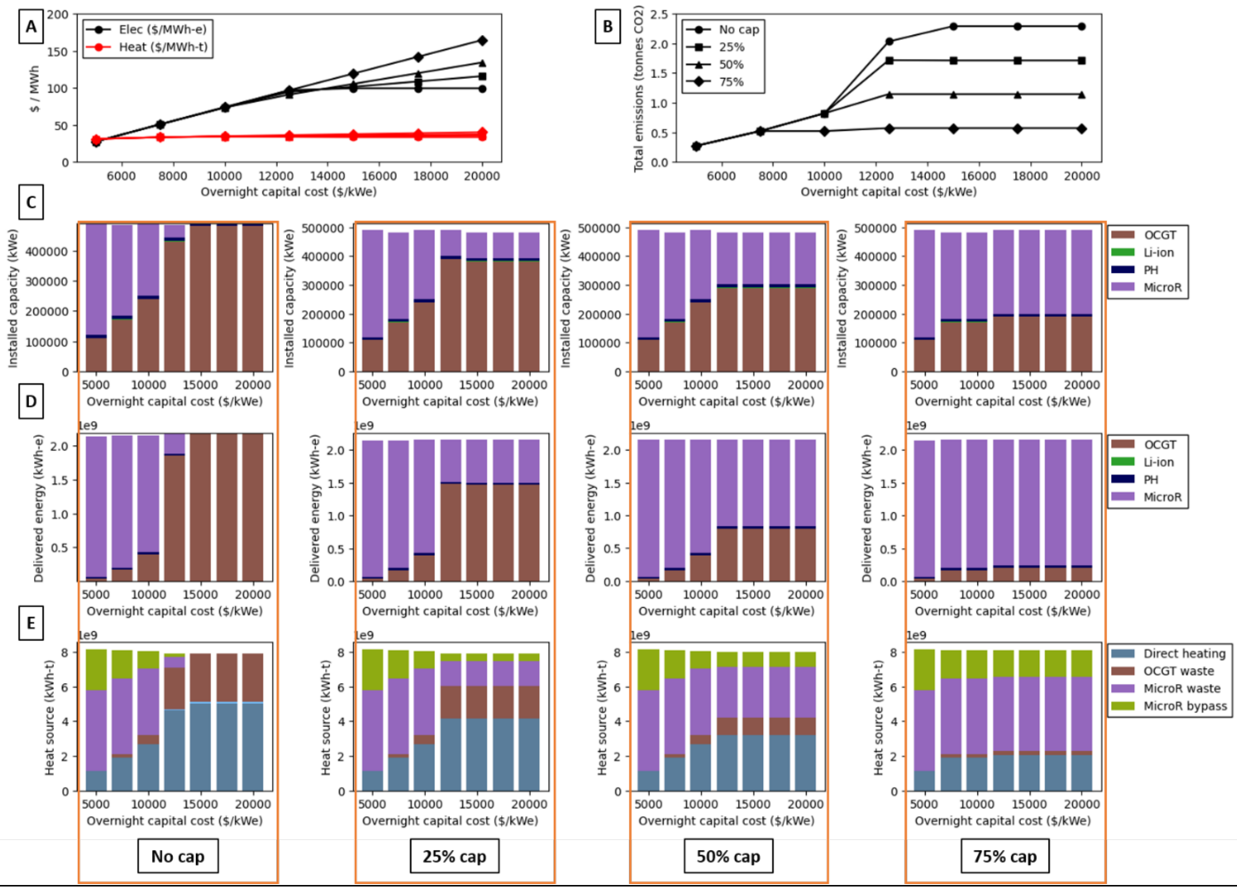

Figure 12. Result of applying a 25-75% emissions cap on the Railbelt community, with natural gas available, and industrial, commercial, and residential CHP. [A] The cost of heat (red - $/MWh-t) and electricity (black - $/MWh-e) for each level of emission cap. The line markers for each emission cap are denoted in the Figure 12b. [B] The total system emissions. [Row C] The installed generation portfolio (MWe) at 0%, 25%, 50%, 75% emission caps (left to right). [Row D] Electricity generation (GWh-e) at each level of emission cap. [Row E] Heat generation (GWh-t) at each level of emission cap.

Rows D and E of Figure 12 illustrate how increasing the emissions cap and/or reducing the microreactor cost affected the electricity and heat generation mixes. In all the scenarios, increasing the emissions cap causes more microreactors to be installed, decarbonizing electricity generation and making more emission-free waste heat available. Other generation is used to meet peak electricity demand. Under stricter emission caps these generators are gradually replaced by microreactors.

When electricity demand fell at night the volume of available waste heat also fell, requiring more heat demand to be met by direct or bypass heating. Under stricter emissions caps more of this shortfall must be met by bypass heating. Replacing direct heating in this manner is expensive, so the cost of energy begins to increase superlinearly, given a fixed microreactor capital cost, as seen in Figure 12a.

In almost every scenario we trialled, listed in Table 6, adding even a 25% emission cap raised the microreactor capital cost ceiling to more than $30,000/kWe. For each emission cap level, a minimum amount of nuclear capacity was required to ensure the limit was met, as seen in row C of Figure 12. This made the installed capacity of microreactors relatively inelastic to the microreactor capital cost, and raised the capital cost ceiling.

VRE and Li-ion storage with electric heating are the only emission-free alternatives to microreactors, and hence the main technologies which determine the microreactor capital cost ceiling. These technologies struggled to be economically viable because of the high heat demand in our representative community during winter. Winter heat demand was up to 18x greater than electricity demand in the Railbelt community, and 2x as much in the remote community. VRE availability is very low in winter, so seasonal Li-ion storage is required as well as overcapacity of VRE generation. Microreactors are a cheaper alternative, especially with waste heat recovery. Continuing our series of GenX runs to higher capital costs, we found that the microreactor capital cost ceiling was more than $100,000/kWe under our standard VRE and Li-ion cost assumptions. Allowing unlimited pumped hydro storage reduces this microreactor capital cost ceiling to $50,000-80,000/kWe. Reducing the VRE and Li-ion costs to lower 48 levels (with the 10MWe pumped hydro limit) reduced the capital ceiling below $30,000/kWe in the remote community.

Community	Fuels available	Heat sources and scenario details	Microreactor overnight capital cost ceiling, given a % emission cap (AK $/kWe)			
			0%	25%	50%	75%
Railbelt community	Natural gas and diesel	Indust, Comm, & Res CHP	13,750	>30,000	>30,000	>30,000
Railbelt community	Natural gas and diesel	Indust, Comm, & Res CHP VRE and stor @ L-48 costs	13,750	>30,000	>30,000	>30,000
Railbelt community	Diesel only	Indust, Comm, & Res CHP	28,750	>30,000	>30,000	>30,000
Railbelt community	Diesel only	Indust, Comm, & Res CHP VRE and stor @ L-48 costs	26,250	>30,000	>30,000	>30,000
Mine & Remote community	Natural gas and diesel	Indust, Comm, & Res CHP	11,250	>30,000	>30,000	>30,000
Mine & Remote community	Natural gas and diesel	Indust, Comm, & Res CHP VRE and stor @ L-48 costs	11,250	12,250	>30,000	>30,000
Mine & Remote community	Diesel only	Indust, Comm, & Res CHP	26,250	>30,000	>30,000	>30,000
Mine & Remote community	Diesel only	Indust, Comm, & Res CHP VRE and stor @ L-48 costs	23,750	28,750	>30,000	>30,000

Table 6. Microreactor capital cost ceiling in various scenarios after applying a 25 – 75% emissions cap. All costs are in terms of Alaskan costs

Carbon price

To test the effect of a carbon price on the microreactor capital cost ceiling, we repeated our GenX simulation series for each community, fuel option, and VRE cost level; with a carbon price between $0 - $100/tonne CO2, in $25 increments. Figure 13 shows the resulting capital cost ceiling for each scenario.

Table 7 shows the change in the microreactor capital cost per dollar of carbon price. This is the average of the non-zero gradients between the pairs of neighbouring points in Figure 13, for each scenario. Our use of a fixed 10MWe capacity microreactor introduced some error estimate, as the capital cost ceiling could not vary smoothly. This was especially the case for the remote community.

The microreactor capital cost ceiling increased with increasing carbon price in all scenarios. The slopes of the curves in Figure 13 are very similar, especially for carbon prices of $75/tonne CO2 or more. There is no clear difference between the case studies, other than the greater variability in the trend for the remote community. This is likely due to the use of fixed-capacity reactors. The average slope across all cases was $87.5/tonne CO2.

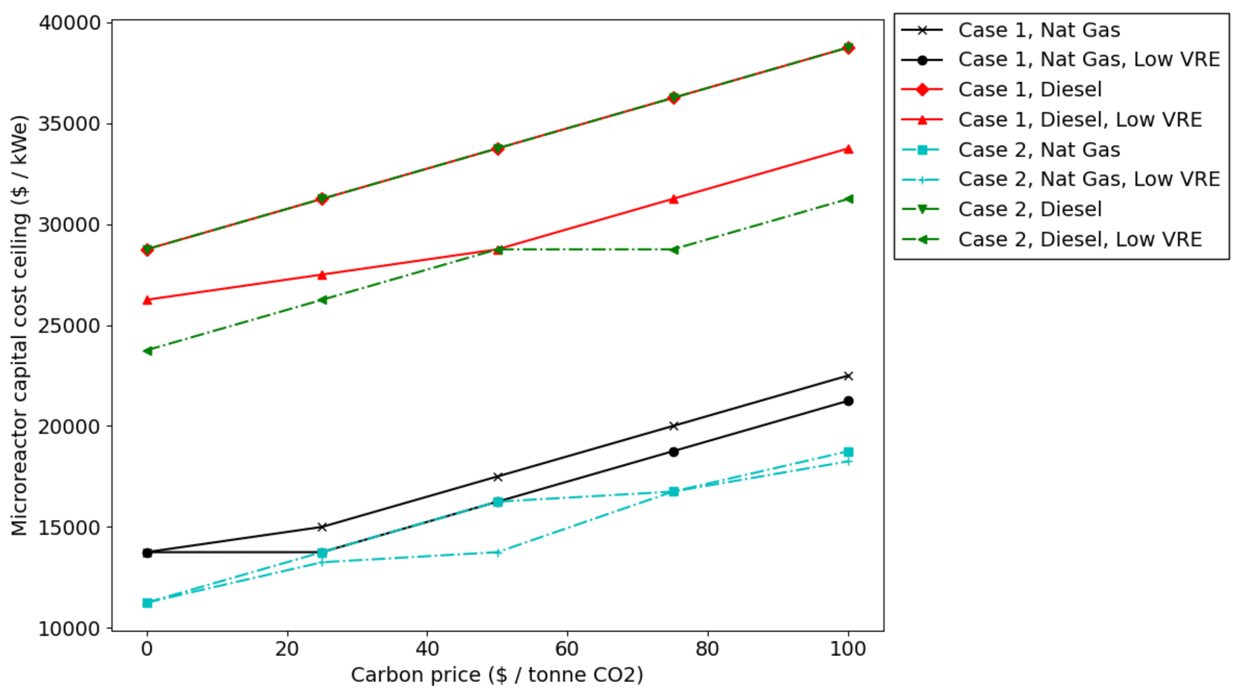

Figure 13. Change in the microreactor capital cost (Alaskan costs) versus a system-wide carbon price on all heat and electricity generation, for a variety of scenarios where CHP can serve all demand segments. Case 1 refers to the Railbelt community and Case 2 the Remote mine and neighboring community.

Sensitivity to change in diesel or natural gas price

We estimated the sensitivity of the microreactor capital cost ceiling to changes in the price of diesel or natural gas using the results from our carbon price sensitivity analysis. Diesel was seldom used in scenarios where natural gas was available because natural gas was half as expensive. The only exceptions where a few peak-load gensets making up 1-2% of generation, or as back-up generators which were not operated. This means the impact of the carbon price falls on one fuel or another depending on which fuels were available in the given scenario. We converted this carbon price result to a fuel price sensitivity based on the emissions per MMBTU of the fuel in question. Our model assumed natural gas fuel produced 0.054 tonnes CO_2/MMBTU, and diesel fuel 0.073 tonnes CO_2/MMBTU. The results are given in Table 7. Our method assumed that increasing the price of natural gas will not cause more diesel gensets to be included in the generation portfolio.

Community	Fuels available	Heat sources and scenario details	Change in microreactor overnight capital cost ceiling versus …		
			Carbon price (Δ$/kWe per $/t$CO_2$)	Nat gas fuel price (Δ$/kWe per $/MMBTU)	Diesel fuel price (Δ$/kWe per $/MMBTU)
Railbelt community	Natural gas and diesel	Indust, Comm, & Res CHP	88	1,600	
		Indust, Comm, & Res CHP VRE and stor @ L-48 costs	100	1,900	
	Diesel only	Indust, Comm, & Res CHP	100		1,400
		Indust, Comm, & Res CHP VRE and stor @ L-48 costs	75		1,000
Mine & Remote community	Natural gas and diesel	Indust, Comm, & Res CHP	75	1,400	
		Indust, Comm, & Res CHP VRE and stor @ L-48 costs	70	1,300	
	Diesel only	Indust, Comm, & Res CHP	100		1,400
		Indust, Comm, & Res CHP VRE and stor @ L-48 costs	100		1,400
Average			87.5	1,600	1,300

Table 7. Summary of results from applying carbon prices or changing the price of natural gas or diesel fuel. All costs are in terms of Alaskan costs.

Sensitivity to discount factor and reactor lifetime

The microreactor capital cost ceiling is very sensitive to the discount factor / cost of capital and reactor lifetime. While we have framed our analysis thus far as having calculated the overnight capital costs ceiling directly, our GenX simulations actually return a capital cost annuity ceiling, which we then converted to an overnight capital cost. This conversion assumed a thirty-year reactor lifetime and 7% discount factor.

A larger discount factor or shorter reactor lifetime will reduce the overnight capital cost ceiling. Figure 14 shows how the overnight capital cost varies with both factors, normalized to a 7% discount factor and thirty-year lifetime. If a microreactor has a 15% discount factor and only lasts ten years, the capital cost ceiling would fall by 60% (marked by the 0.4 contour on Figure 14). Equivalently, reducing the capital cost from 7% to 5% would increase the overnight capital cost ceiling by 25%. In general, the overnight capital cost ceiling will change more quickly with discount factor.

We assumed a 7% discount factor in our case studies as it is a common value for infrastructure projects, and is realistic for the largest Alaskan utilities and COOPs. Smaller associations have weighted costs of capital (WACC) between 10-15%, and some village utilities have a 21% WACC [50]. However, it is more likely that small Alaskan communities will host rather than own a microreactor, especially FOAK reactors. The reactor will be owned by a large public or private entity, with access to cheaper capital.

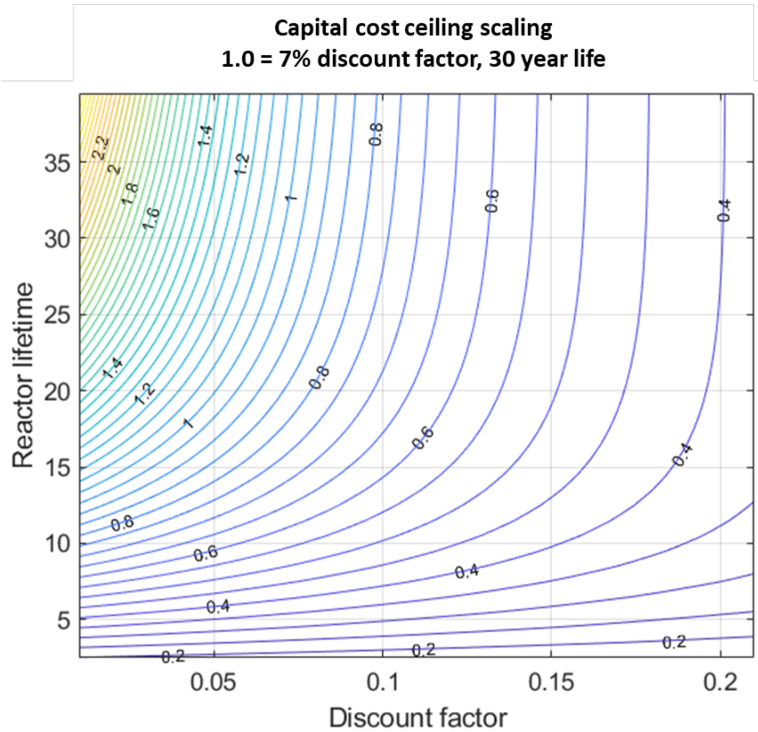

Figure 14. Change in the microreactor capital cost ceiling as a function of the discount factor and reactor lifetime, given a fixed annual capital cost payment.

Sensitivity to waste heat recovery fraction

Our results show that waste heat recovery will be an important factor in the viability of microreactors in Alaska. Our microreactor model assumed that almost all of the fuel energy not converted to electricity could be captured as waste heat. Under this assumption, the WHR fraction was 66.5% of the fuel energy, resulting in 2kWh-t of waste heat being produced per kWh-e of electricity generation.

Microreactors may not be able to recover this much of the available waste heat in practice, so we performed a sensitivity study in which we assessed the change in the microreactor capital cost ceiling as a function of the microreactor WHR fraction. Figure 15 shows the results for four scenarios where CHP could serve all demand segments. Figure 15a shows the absolute variation in the cost ceiling and Figure 15b shows the percent change in the cost ceiling relative to our initial 66.5% WHR fraction.

The microreactor capital cost ceiling fell by 0.63% per 1% change in the WHR, based on three of the four scenarios. Microreactors without WHR have a capital cost ceiling which is 42% lower than our base case. This is a considerable reduction in value. The Railbelt scenario with diesel fuel followed a different trend as low WHR fractions, due increased utilization of bypass heat. The installed capacity of microreactors changed slightly as a function of the WHR fraction between 0 – 30%, indicating a very small decrease in the microreactor capital cost ceiling.

When the WHR fraction is 0% we are comparing a microreactor capable of producing bypass heat and electricity against diesel and natural gas generators with WHR. In this comparison, the microreactor capital cost ceilings for the Railbelt community scenarios are slightly higher than in the no-CHP Railbelt scenarios, previously given in Table 3. This because small amounts of prorated microreactor bypass heat has value when the heat demand is much larger than the electricity demand and less WHR is available relative to demand. The heat demand load factor is smaller in the remote mine and community case, so the microreactor capital cost ceilings for the bypass heat and electricity reactor is lower in those scenarios due to competition from natural gas and diesel-based WHR.

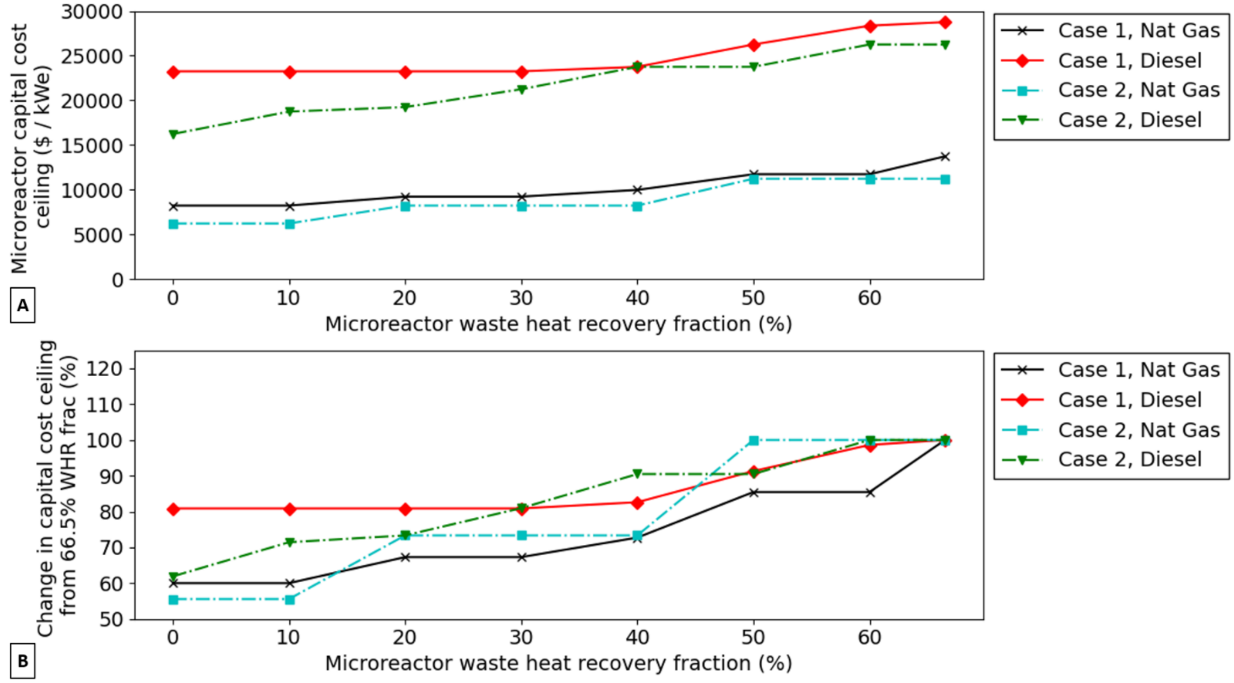

Figure 15. Microreactor capital cost ceiling (Alaskan costs) versus the fraction of fuel energy which the microreactor can recover as waste heat, for a variety of scenarios where CHP can serve all demand segments. Case 1 refers to the Railbelt community and Case 2 the Remote mine and neighboring community.

To complete this set of comparisons, we ran a series of GenX simulations where CHP was allowed to serve all demand segments but the microreactor could only produce electricity. The resulting capital cost ceilings are lower in all scenarios, as shown in Table 8.

Community	**Fuels available**	**Microreactor capital cost ceiling [AK $/kWe]**			
		No CHP	CHP serving all demand segments		
		Electric only microreactor	Electric only microreactor	Bypass heat (0% WHR) and electricity	Bypass heat, waste heat and electricity
Railbelt community	Natural gas and diesel	7,000	4,750	8,250	13,750
	Diesel only	16,250	13,000	23,250	28,750
Mine & Remote community	Natural gas and diesel	8,750	6,250	6,250	11,250
	Diesel only	18,750	13,750	16,250	26,250

Table 8. Microreactor **c**apital cost ceiling (in Alaskan costs) in a variety of scenarios, testing the value of the microreactor being able to produce bypass heat or waste heat, depending on whether of the diesel and natural gas-based generators could produce waste heat. When CHP was allowed, it could serve all demand segments.

Sensitivity to demand load factor

The seasonal and diurnal load factor of the heat and electricity demand in both our representative communities affects the competitiveness of each of the available generating technologies. A higher load factor encourages the deployment of cheaper diesel and OCGT gensets as peaking supply. A greater seasonal load factor (i.e. the peak winter demand for Alaskan communities) makes VRE less competitive, as the dispatchable generation required for the winter can also meet summer demand on its own.

We tested the degree to which the demand load factor of our representative communities had impacted the capital cost ceiling and utilization of our microreactor. We ran a series of GenX simulations for both representative communities and fuel availability options, increasing the electricity or heat demand load factors between 125% and 0% in increments of 25%. At a 0% load factor, the demand is constant throughout the year. Figure 16 shows the results for the Railbelt community.

Neither demand load factor affected the microreactor capital cost ceiling significantly. The installed capacity of microreactors with high capital costs was greater for the low load-factor cases indicating a slight increase in the capital cost ceiling, but the change was smaller than our capital cost increments. When the microreactor cost is low, the installed capacity is lower for small load factors as less peaking generation is needed and the total installed capacity of all technologies is smaller.

The remote mine and community showed even less variation with the load factor, primarily because the fixed 10MWe capacity of the reactor made the capital cost ceiling more insensitive to changes in conditions.

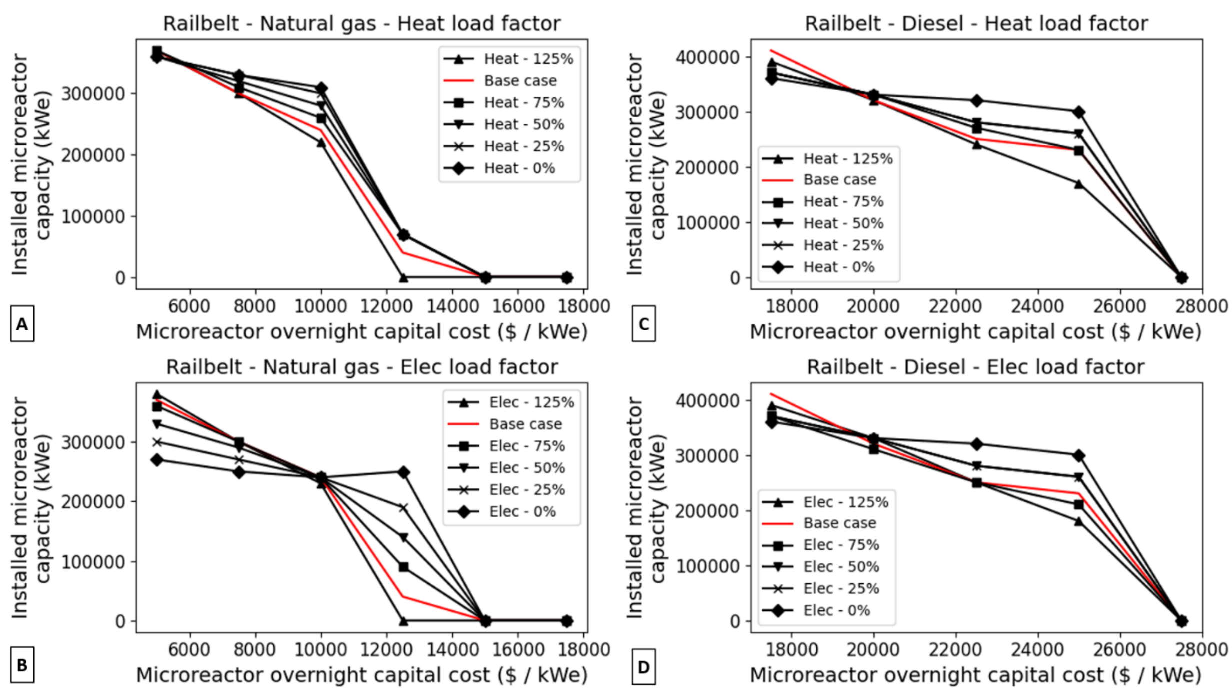

Figure 16. Variation in the installed microreactor capacity (and hence also the capital cost ceiling) with the microreactor capital cost and changes in the heat and electricity load factor. The heat or electricity load factors were varied in each case, as a percentage of the base case. [A] Railbelt community with natural gas and diesel available, where the heat load factor was varied. [B] Railbelt community with natural gas and diesel available,

where the electricity load factor was varied. [C] Railbelt community with only diesel available, where the heat load factor was varied. [D] Railbelt community with only diesel available, where the electricity load factor was varied.

Sensitivity to microreactor minimum load

We tested whether the minimum load of the microreactor (bypass heat and electricity combined) would affect the capital cost ceiling. We varied the minimum load between 0% (the base assumption used in the rest of the study) and 100% in 10% increments. GenX simulation series were run for both representative communities and fuel availability options.

Microreactors with higher minimum loads appeared to have a slightly lower capital cost ceiling across all scenarios, but the change was less than $1,000/kWe. The first microreactor installed on the grid always has very high utilization, 95% or more, so the minimum load was not an important factor. The installed capacity of microreactors at lower capital costs decreased, particularly for the Railbelt community.

Sensitivity to microreactor variable costs

While our focus in most of this study is on microreactor capital costs, there is also a need to understand how variable costs will affect the economic viability of reactors. Given their relatively small output, microreactor variable and fuel costs could constitute half of their levelized cost of energy, so we also tested their impact on the microreactor capital cost ceiling.

Our baseline cost assumptions are given in Table 9 alongside equivalent values from other recent microreactor studies. Each study accounted for microreactor costs differently, particularly in how they divided fixed and variable costs. For example, the INL and MIT studies assumed that the reactor refuelling schedule would be fixed, so fuel costs would not vary based on energy output. The MIT study accounted for the fuel as a fixed cost, while INL folded it into the overall capital cost. Both treated all O&M as fixed costs. We considered fuel and maintenance costs as variable costs to account for operators refining the reactor schedule as they learn best practices.

Our assumed costs are at the lower end of the range in Table 9, as our data was drawn from preliminary microreactor designs which scaled costs from existing large reactors. However, our results can be post-processed to consider alternative cost assumptions. We can consider greater fixed O&M and fixed fuel costs by subtracting those higher costs from the capital cost annuity which GenX calculates at the capital cost ceiling, and then convert the reduced annuity back to an overnight capital cost. The same can be done for variable costs by either converting them to fixed costs, assuming the microreactor capacity factor remains approximately the same, or by using the sensitivity study results in Figure 17.

To understand the impact of microreactor variable costs on the capital cost ceiling, we simulated all four case study and fuel availability combinations with CHP serving all demand segments, varying the combined fuel and O&M costs between $30 - 120/MWh-e, in steps of $10. We also included our previous result from Table 4, at $36/MWh-e. The results are given in Figure 17.

As shown in Figure 17, the microreactor capital cost ceiling changes at approximately the same rate for both the natural gas and diesel cases, as a function of the total variable cost. The capital cost ceiling falls by ($135/kWe) / ($/MWh-e) when natural gas is available, versus ($90/kWe) / ($/MWh-e) when only diesel is available. The difference between the two is relatively small, and can be accounted for by the inaccuracy in interpolating the capital cost ceiling, and the effect of microreactors only being available in discrete 10MWe units.

	This study	NEI – 2019 [15]	MIT – 2021 [1]	INL – 2021 [45]
Capacity (MWe)	10	10	10	1.8
Fixed O&M ($/kWe)	115	250 – 450	125	945
Var O&M ($/MWh-e)	15	-	-	-
Fixed Fuel ($/kWe)	-	-	225	-
Var Fuel ($/MWh-e)	8.20	9 – 21	-	-
Equivalent var fuel + O&M cost ($/MWh-e)	36.60	55.80	40.80	110.10

Table 9. O&M and fuel costs used to model microreactors in this and other recent studies. The equivalent variable fuel and O&M cost assumes a 98% capacity factor to convert fixed to variable costs.

Figure 17 also includes a contour plot of the levelized cost of energy for the microreactor. The capital cost ceiling approximately follow the lines of constant levelized cost as a function of variable cost. This means microreactor designers can trade-off fixed and variable costs while remaining viable, as long as their levelized cost of energy remains the same.

The total installed capacity of the microreactor fleet at lower costs did not show the same linear trade-off between fixed and variable cost, as the proportion of fixed to variable costs affected the economic viablilty of the microreactor as a non-baseload generator. However, this issue does not affect the capital cost ceiling and the economic viability of the first installed microreactor, which we observed always operates as baseload generation near 100% utilization

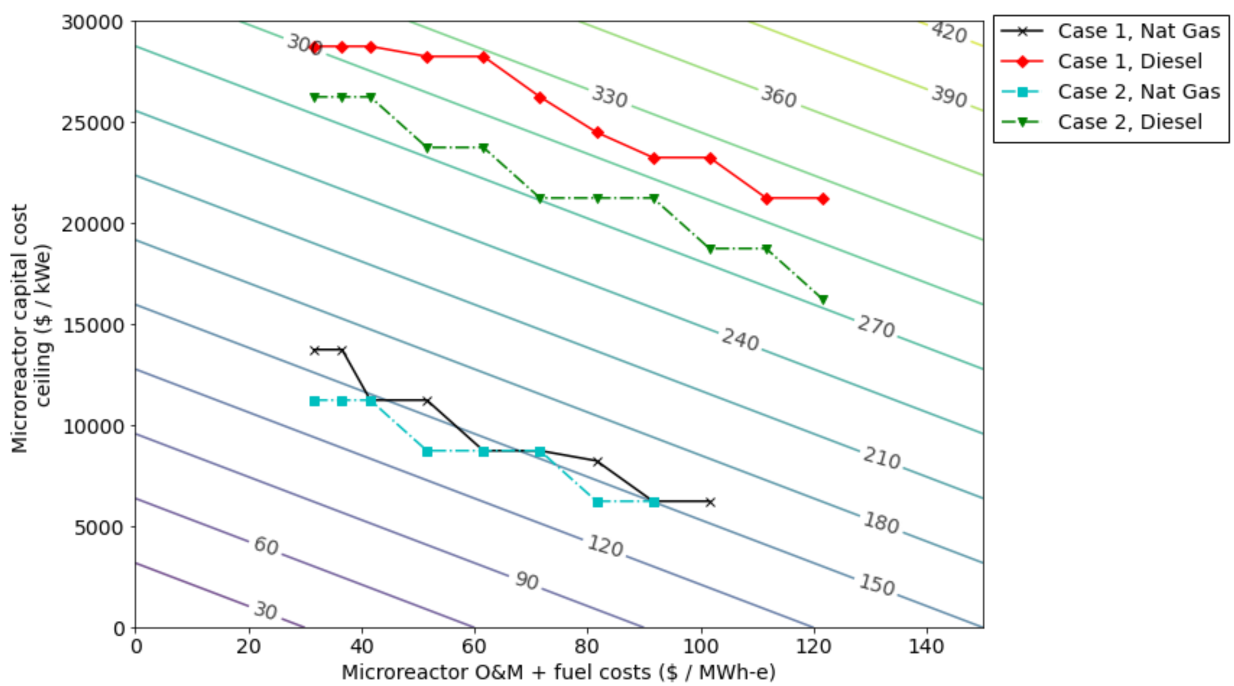

Figure 17. The four lines show the change in the microreactor capital cost ceiling (Alaskan costs) versus the microreactor fixed and O&M costs, for a variety of scenarios where CHP can serve all demand segments. Case 1 refers to the Railbelt community and Case 2 the Remote mine and neighboring community. The contour plot shows lines of constant levelized cost of energy for our simulated microreactor, assuming a 98% capacity factor. Because the microreactor was suppling heat and electricity, this is a combined levelized cost of heat and electricity.

The first installed microreactor in all four scenarios was able to supply all its available heat and electricity to the respective community: two MWh-t of waste heat per MWh-e of electricity. As such, this levelized cost of energy is per [1MWh-e electricity + 2MWh-t of waste heat]. The resulting LCOE is approximately equal to the mean cost of 1MWh-e + 2MWh-t for the respective scenarios in Table 4. The slight difference is likely due to interpolation error in the threshold cost of heat and electricity given in Table 4.

Discussion

In this study we explored the conditions under which microreactors are economically viable in two representative Alaskan communities: a Railbelt community and a remote mine with a small neighbouring community. We have determined microreactor overnight capital cost ceilings for both communities under various scenarios. Microreactors are only economically viable in a given scenario if they are less expensive than the respective capital cost ceiling.

We have demonstrated how the cost ceiling depends on the microreactor features and capabilities. Microreactor designers can use these capital cost ceilings as development targets and to decide on which microreactor features to prioritize.

The most valuable microreactor feature is the ability to recover a large fraction of waste heat. This raises the capital cost ceiling by \$2,000 – 9,000/kWe, as shown in Table 4. The heat load is greater than the electricity load in Alaskan communities, so high waste heat output may be more important than high thermal-electric efficiency. Bypass heat is less valuable, raising the capital cost ceiling by \$0 – 1,500/kWe, but we did not consider very high-temperature heat consumers who would have benefited most. A long reactor lifetime is preferable and may change the capital cost ceiling by 10%, though this matters most if future investors will have low costs of capital, as shown in Figure 14.

It will be important for microreactor designers to tailor the design and deployment protocols of microreactors to Alaskan requirements. Depending on the target community, this will include the duration of road and sea lane availability, additional excavation equipment, and other elements. Alternatively, designers may choose to focus on communities in the Railbelt or with access to the Alaskan road network. If these considerations are not made, construction in Alaska may cost 50 – 200% more than an equivalent project in the lower 48 states, jeopardizing its viability.

A Railbelt community with a district heating network serving at least industrial heat demand is the most promising site for the first microreactors. While Railbelt communities have access to natural gas, and hence the capital cost ceiling will be approximately half that of a remote community with access only to diesel fuel, other factors make up for this.

As shown in Table 4, microreactors need to produce waste heat and have access to sufficient heat demand through a district heating network for the capital cost ceiling to be within the \$5,000 - \$35,000/kWe cost range predicted by experts. We are most concerned with installing one microreactor, rather than an entire fleet, so a community only needs enough CHP-accessible heat demand to utilize the waste heat from one microreactor, in order for the capital cost ceiling to increase above \$5,000/kWe. Industrial and commercial heat demand in Railbelt communities is sufficiently large, and concentrated in a few consumers. Delivering heat to only a few customers, or possibly being co-located with them, will minimize the need to construct a large, expensive district heating system. Furthermore, some military and industrial facilities in Alaska already operate their own district heating networks.

Constructing the first microreactors in a Railbelt community will reduce operations and maintenance costs, and also reduce local concerns over reliability. Alaska is a sparsely populated state, and technical and financial experts are concentrated in the large towns and cities. Technicians and engineers must often fly to remote communities to service or repair equipment, which can be slow depending on the season and weather. Given this, leaders in small remote communities have expressed concern over having a large fraction or all of their heat and electricity produced by one microreactor before the reliability and repair-times of the reactor and power plant are well known. This is less of a concern for Railbelt communities, where a microreactor will constitute less than 10% of the grid, and other generators can make-up for any shortfall during microreactor outages. Maintenance, as well as initial construction and replacing the reactor, will also be cheaper in a Railbelt community, as costs are more similar to those in the lower 48.

Microreactors will certainly be economically viable in Railbelt communities if emission reduction policies are implemented. Even a modest carbon emissions cap raises the capital cost ceiling above $30,000/kWe, as shown in Table 6. This is due to the difficulty and high cost of decarbonizing heat without microreactors. Indeed, a carbon cap will make microreactors viable in both communities, but the other issues discussed above still favour Railbelt communities.

Three elements of this work could be extended to further explore the value of microreactors in Alaska: addition of more detail, consideration of more alternative scenarios, and incorporation of some non-monetary costs and benefits.

More detail could be added to our model. In particular, including the cost and practicalities of heat and electricity distribution networks would give insight into how the capacity of the microreactor might or might not be accommodated by representative communities of different sizes. As microreactor designs are developed, more details of their operation and cost can be incorporated as well as a greater understanding of how lower 48 and Alaskan construction and deployment costs compare.

A second extension would be to include more alternative scenarios. This study has used one set of VRE availability profiles. This could be expanded, particularly the wind availability profiles which vary significantly by region. We could also consider high temperature heat consumers, who may garner more value from high temperature bypass heat, which was neglected here.

Lastly, we could consider additional real-world elements in our model. We could perform a brownfield analysis, where microreactors must compete against existing, sunk-cost generators. This would be more representative of the competition faced by a real-world FOAK microreactor, and may see the capital cost ceiling fall significantly. Secondly, we could incorporate resilience and health effects into our model directly. This would allow us to determine capital cost ceilings considering all the factors, rather than having to caveat our results as we did here.

Appendix

A – Methodology for producing solar and wind availability timeseries

GenX requires hourly timeseries of resource availability for each generation and storage technology. We modelled dispatchable technologies, such as diesel generators and microreactors, as being fully available for the entire year. Wind and PV generation have limited availability based on seasonal and diurnal changes in wind speeds and insolation, so we developed availability timeseries for these technologies. We did so by combining detailed seasonal and diurnal data from the literature, parameterized to allow the timeseries to be adapted to different representative regions of Alaska.

Solar

A team at Sandia National Lab and the University of Alaska have produced detailed models of Alaskan insolation and the performance of South-facing tilted PV panels and East-West-facing vertical bifacial PV panels [29]. This performance is characterized by the kWe output per kWe nominal capacity. While the full model is not public, we had access to diurnal profiles for each technology for the summer and winter solstices and spring and fall equinoxes. We adapted these into an annual timeseries by interpolating between the profiles assuming a cosine seasonal insolation trend.

dates ← dates for which we have modelled performance data, of size 4
data ← array of four 24-hour modelled performance data, of size 24 x 4. Each 24-hour
timeseries corresponds to one of the entries in *dates*
insol*(x)* ← $0.5 * \left(1 - cos\left(2\pi \frac{(x - p)}{365}\right)\right)$: daily insolation estimate, where p is a phase shift to
ensure the maximum falls on the summer solstice date in *dates*
PV profile ← output array of size 365 x 24
For d ← 1 **to** 365 **do**
Find the two entries in *dates* closest to d*:* $dates_i$ and $dates_j$
$w_1 \leftarrow |\mathrm{insol}(dates_j) - \mathrm{insol}(d)|$
$w_2 \leftarrow |\mathrm{insol}(dates_i) - \mathrm{insol}(d)|$
For h ← 1 **to** 24 **do**
$(PV\ profile)_{d,h} \leftarrow \frac{data_{i,h} * w_1 + data_{j,h} * w_2}{w_1 + w_2}$

This produces a 365 x 24 array of daily profiles which can be reshaped into an 8760 x 1 timeseries. No smoothing was required between the daily profiles because the availability falls to zero each night.

Figure A.1 and A.2 show the process and example 1-week timeseries for the South-facing and East-West-facing panels. The higher Spring availability in both profiles is consistent with other data from Alaska [56]. Some data shows much less availability in Fall than seen in our timeseries. This discrepancy probably occurred because the Sandia-UAK model assumed clear skies throughout the year.

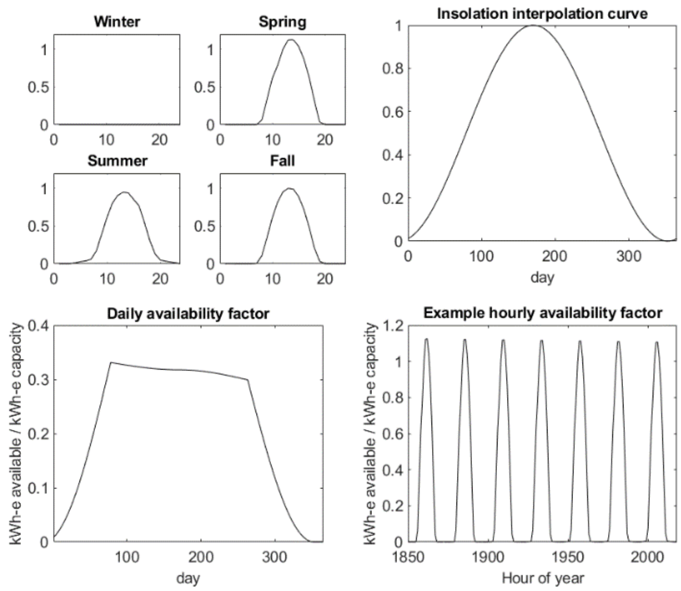

Figure A.1 Process for creating the South-facing PV availability profiles. [Upper-left] Four 24-hour timeseries of PV availability were taken from the Sandia-UAK model [29]. [Upper-right] We produced diurnal profiles for each day of the year by interpolating between these profiles according to a cosine weighting. [Lower-left] The average daily availability of the resulting profile. This assumes clear skies for the entire year, so is likely an overestimate of actual performance. [Lower-right] Example of the hourly profile for one week. The availability is sometimes greater than one as a result of the same being true in the modelled data – see the spring subplot in the upper-right.

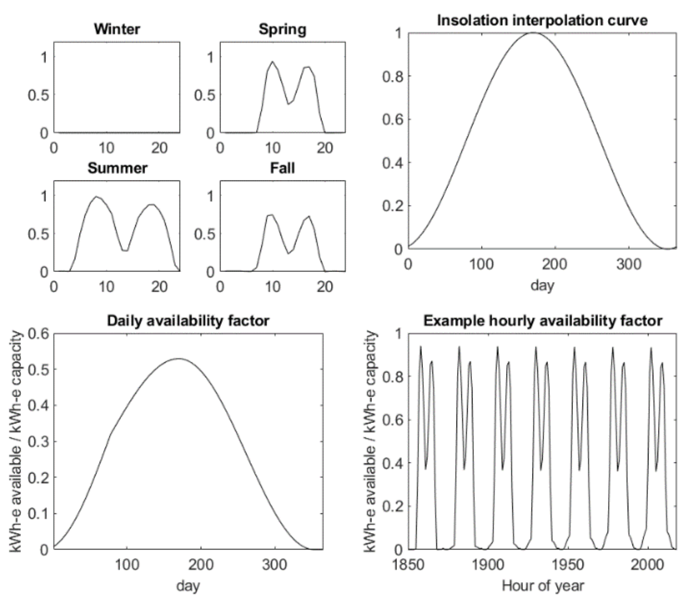

Figure A.2 Process for creating the East-West-facing PV availability profiles. [Upper-left] Four 24-hour timeseries of PV availability were taken from the Sandia-UAK model [29]. [Upper-right] We produced diurnal profiles for each day of the year by interpolating between these profiles according to a cosine weighting. [Lower-left] The average daily availability of the resulting profile. This assumes clear skies for the entire year, so is likely an overestimate of actual performance. [Lower-right] Example of the hourly profile for one week.

Wind

We produced wind power availability timeseries using a very similar method to the PV timeseries, combining seasonal and diurnal patterns to produce a one-year hourly timeseries. However, these timeseries also incorporated some stochastic elements and a wind speed-to-turbine output step.

The HOMER model contains a diurnal wind speed profile based on a cosine pattern. It is parameterized on the mean wind speed, diurnal pattern strength, and a cosine phase [61]. We found monthly mean wind speeds for various Alaskan communities [59] but rather than interpolate between these values to find daily mean wind speeds, we sampled them from a Weibull distribution, as suggested in the HOMER documentation [62]. The Weibull distribution is parameterized by a scale parameter and a shape parameter. Shape parameters have been measured at multiple sites in Alaska [35, 63, 64, 65]. We calculated the scale parameter from the shape parameter and monthly mean wind speed.

After the Weibull random variable was drawn and used to produce a 24-hour wind speed pattern, we then calculated the wind generation availability factors based on these wind speeds for 25m and 30m turbines, based on data collected in Alaska in the literature [57, 58].

dates ← dates for which we have monthly mean wind speed data, of size 12
data ← array of 12 monthly mean wind speed measurements
weibShape ← Weibull shape parameter
$\mathrm{WeibRV(a, b)}$ ← sampled Weibull random variable, given scale parameter *a* and shape parameter *b*
U_d ← mean wind speed for day *d*
$u_{d,h}$ ← wind speed for day d at hour h
ϕ ← hour of peak wind demand, between 1 and 24
δ ← diurnal pattern strength, between 0 and 1
$T(u)$ ← Turbine availability, between 0 and 1, as a function of the windspeed *u,* for 25m and 30m turbines
Wind profile ← output array of hourly wind availability factor, of size 365 x 24
For d ← 1 **to** 365 **do**
  Find the two entries in *dates* closest to d*:* $dates_i$ and $dates_j$
  $w_1 \leftarrow |dates_j - d|$
  $w_2 \leftarrow |d - dates_i|$
  $weibScale_d \leftarrow \frac{data_i * w_1 + data_j * w_2}{w_1 + w_2} \div \Gamma\left(1 + \frac{1}{weibShape}\right)$
$U_d \leftarrow \mathrm{WeibRV}(weibScale_d, weibShape)$
  For h ← 1 **to** 24 **do**

$$u_{d,h} = U_d\left(1 + \delta\cos\left(\frac{2\pi}{24}(h - \phi)\right)\right)$$

For d ← 1 **to** 365 **do**
  For first and last three hours of each day **do**
    $u_{d,h}$ ← average wind speed across the nearest 7 hours
For d ← 1 **to** 365 **do**
  For h ← 1 **to** 24 **do**

$$(Wind\ profile)_{d,h} = T(u_{d,h})$$

This produces a 365 x 24 array of daily profiles which can be reshaped into an 8760 x 1 timeseries. Unlike the PV, we performed some smoothing between the diurnal patterns to avoid large discontinuities between the days. This could also have been resolved by introducing an autocorrelation between the sampled daily mean wind speeds. Figure A.3 shows the process and an example output.

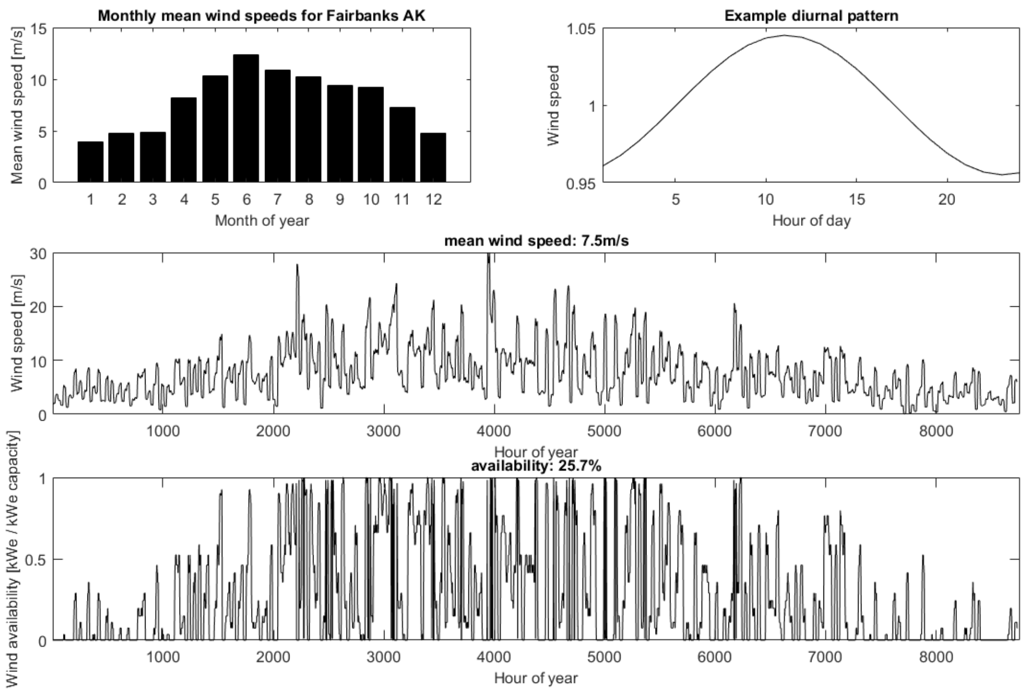

Figure A.3 Process for creating the wind availability profiles. [Upper-left] Monthly mean wind speeds for Fairbanks Alaska. Equivalent data for other regions also exists [59]. [Upper-right] Example diurnal wind pattern from the HOMER model, normalized to have mean wind speed equal to one. [Middle] Resulting hourly wind speed timeseries. [Lower-middle] Hourly wind generation availability based on the hourly wind speeds.

B – Methodology for producing heat and electricity demand timeseries

We created parameterized heat and electricity timeseries so that we could adapt the same model to multiple representative communities. As with the VRE availability timeseries in Appendix A, we did so by combining seasonal and diurnal data from Alaska to produce hourly one-year timeseries.

While we were able to find one-year hourly electricity demand for many small Alaskan communities [33], we were not able to find the same for larger communities. As such, we decided to develop a parameterized model which could be adapted to any community.

Our electricity demand timeseries can be adjusted based on at least four parameters:

1. Weekday load factor
2. Weekend load factor
3. Weekday to weekend mean demand ratio

4. Maximum and minimum load over the entire year. This can be supplemented with additional empirical data, defining quarterly, monthly, weekly, etc loads.

By default, we generated timeseries using a monthly mean demand timeseries taken from remote Alaskan communities [33] to determine the seasonal change in electricity demand. This profile was scaled to the maximum and minimum load given by the user, or could be replaced by alternative data with monthly or better resolution. In either case, this was then combined with empirical diurnal patterns to produce an hourly series. An Alaskan study measured diurnal electricity demand patterns for each month of the year in a remote Alaskan community [34]. We interpolated between these profiles to produce diurnal patterns for each day of a year, scaled by the user-defined weekday and weekend load factors, and the user-defined reduction in mean weekend demand. Finally, we applied some smoothing and integral checks to remove discontinuities and ensure the total demand was as expected.

dates ← the middle day of each month, for which we have measured diurnal timeseries, with 12 entries

data ← array of twelve 24-hour measured electricity demand timeseries, of size 24 x 12. Each 24-hour timeseries corresponds to one of the entries in *dates.* The timeseries are normalized to have mean 0 and peak demand equal to one.

M ← mean electricity demand for each month of the year, with 12 entries. The user can provide additional data at higher resolution

L_w ← weekday load factor, defined for the year or at greater resolution

L_k ← weekend load factor, defined for the year or at greater resolution

r_{wk} ← ratio of the weekday and weekend average load, defined for the year or at greater resolution

Elec demand ← output array of electricity demand timeseries, of time 365 x 24

For d ← 1 **to** 365 **do**

Interpolate mean daily demand, m_d, based on a cubic interpolation of *M*, or additional user-given data

Find the two entries in *dates* closest to d*:* $dates_i$ and $dates_j$

$w_1 \leftarrow \left|\mathrm{insol}\left(dates_j\right) - \mathrm{insol}(d)\right|$

$w_2 \leftarrow |\mathrm{insol}(dates_i) - \mathrm{insol}(d)|$

If d is a weekday **do**

For h ← 1 **to** 24 **do**

$$(Elec\ demand)_{d,h} \leftarrow \mathrm{m_d}\left(1 + (\mathrm{L_w} - 1)\frac{data_{i,h} * w_1 + data_{j,h} * w_2}{w_1 + w_2}\right)$$

If d is a weekend **do**

For h ← 1 **to** 24 **do**

$$(Elec\ demand)_{d,h} \leftarrow \mathrm{m_d r_{wk}}\left(1 + (L_k - 1)\frac{data_{i,h} * w_1 + data_{j,h} * w_2}{w_1 + w_2}\right)$$

For w ← 1 **to** 52 **do**

For d ← $7(\mathrm{w}-1)+1$ **to** $7w$ **do**

$$(Elec\ demand)_{d,1:24} \leftarrow \frac{\sum_{x=7(\mathrm{w}-1)+1}^{x=7w} m_x}{\sum_{x=7(\mathrm{w}-1)+1}^{x=7w}\sum_{h=1}^{h=24}(Elec\ demand)_{x,h}}(Elec\ demand)_{d,1:24}$$

For d ← 1 **to** 365 **do**

For first and last three hours of each day **do**

$(Elec\ demand)_{d,h}$ ← average wind speed across the nearest 7 hours

This produces a 365 x 24 array of daily electricity profiles which can be reshaped into an 8760 x 1 timeseries. Figure B.1 gives more details of the method.

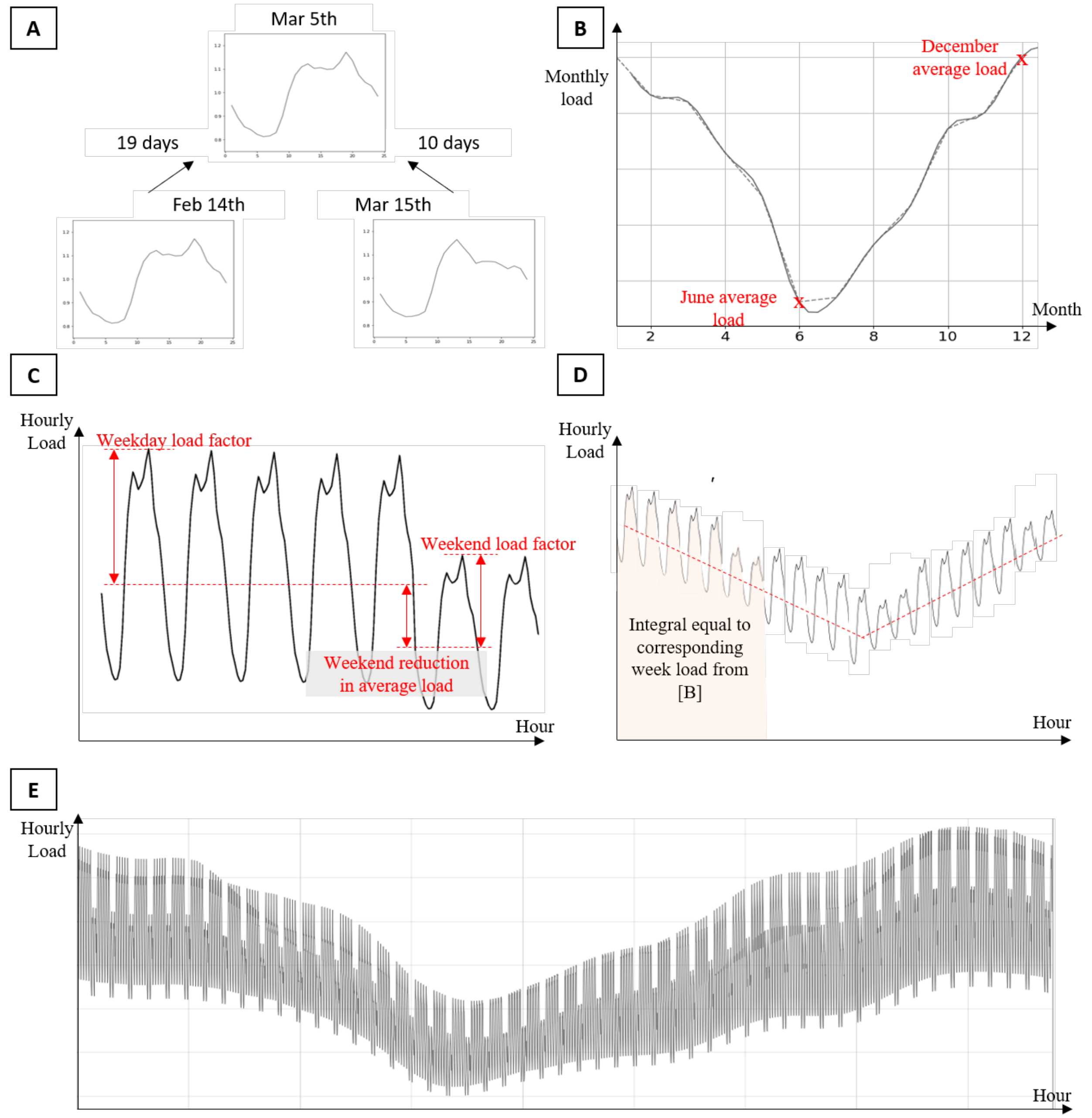

Figure B.1 [A] Diurnal profiles were created by linearly interpolating between twelve empirical profiles from remote Alaska communities [34]. [B] Monthly and seasonal trends were taken from empirical data [33] and scaled to a user-defined peak and minimum demands. This data could be replaced by the user. Daily average loads were then calculated using cubic interpolation. [C] Weekly profiles were created by scaling the interpolated diurnal profiles using weekday and weekend load factors as well as the interpolated daily load from B. The weekend loads were then reduced by a weekday to weekend factor. [D] The mean weekly loads were then scaled to match the weekly loads from [B], otherwise the reduced weekends would reduce the total demand. [E] Example one-year hourly electricity load.

Heat

We found much less empirical data on community heat demand in the literature. The best direct measurements were from NREL measurements [9] in cities and reported heating fuel consumption in small remote communities [33]. No diurnal patterns could be found for different times of the year. Because of this, we produced our heat demand timeseries using a much simpler method than for electricity demand.

We applied a smoothing function to average-out hourly variations of the most detailed heat and electricity demand timeseries available for the same community, in order to produce a representative average-demand timeseries. We then found the ratio of heat to electricity demand for each hour of the year, and multiplied them by our parameterized electricity demand timeseries produced in the previous subsection to determine the corresponding heat demand. We repeated this process separately using measured data for a Railbelt community and remote community.

> *E* ← measured electricity demand for the example community, with 8760 entries
> *H* ← measured electricity demand for the example community, with 8760 entries
> *Elec demand* ← *parameterized electricity demand timeseries* created, with 8760 entries
> *Heat demand* ← output array of hourly heat demand timeseries, with 8760 entries
> **For** h ← 1 **to** 8760 **do**
> E_h ← average electricity demand across the nearest 31 days
> H_h ← average heat demand across the nearest 31 days
> **For** h ← 1 **to** 8760 **do**
> $(Heat\ demand)_h \leftarrow (Elec\ demand)_h \frac{H_h}{E_h}$

Figure B.2 shows an example of this method in use for the Railbelt community.

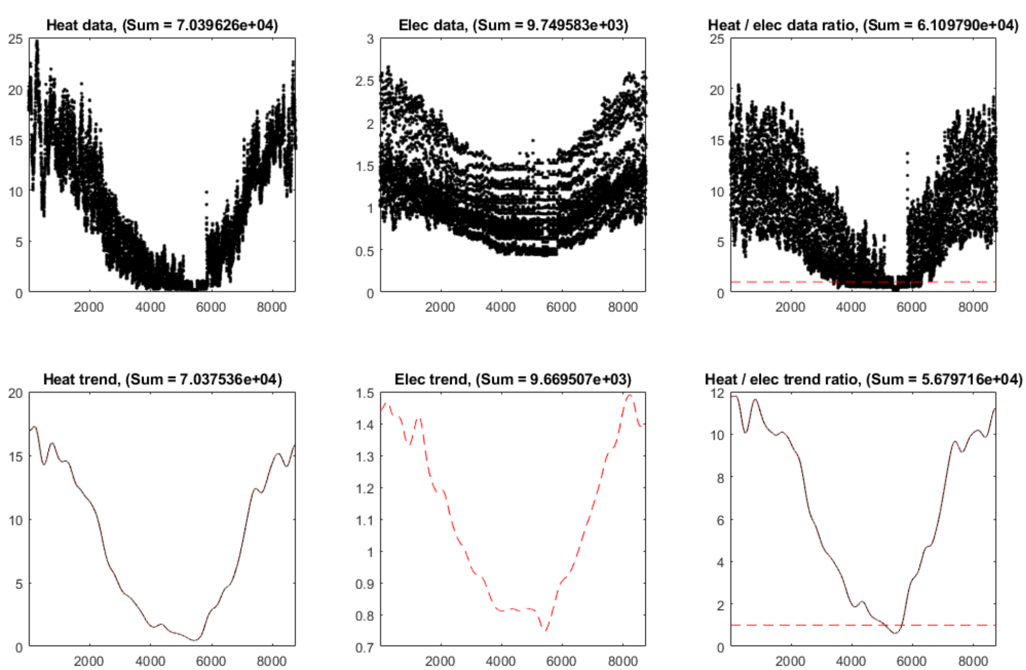

Figure B.2 The measured heat and electricity demands are smoothed out using 31 day averaging windows and then divided to find the hourly heat-to-electric ratio. The new heat demand timeseries is calculated by multiplying this ratio by the new computed electricity demand timeseries. This process was repeated with separate data for the remote community and mine.

Splitting heat demand into residential, commercial and industrial demand

Some of our scenarios required the heat demand to be categorized into residential, commercial and industrial timeseries so that only some of it could be served by CHP technologies. The TMY2 and TMY3 datasets report heat and electricity demand for these categories separately [9, 32]. For the Railbelt case study we compared the fraction of demand from each source, and used this to categorize our computed heat demand timeseries. We repeated the process for the remote community and mine, but only using the residential and industrial components.

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