THESIS

TECHNO-ECONOMIC ANALYSIS AND LIFE CYCLE ASSESSMENT OF A NOVEL AIR-SOURCED HIGH-TEMPERATURE HEAT PUMP WITH HOURLY RESOLUTION

Submitted by

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ABSTRACT

TECHNO-ECONOMIC ANALYSIS AND LIFE CYCLE ASSESSMENT OF A NOVEL AIR-SOURCED HIGH-TEMPERATURE HEAT PUMP WITH HOURLY RESOLUTION

As industrial decarbonization becomes increasingly relevant in the energy transition, electric technologies offer the potential to decarbonize industrial heat currently produced by natural gas. By upgrading heat, heat pumps offer a competitive solution with greater emissions reduction potential compared to resistance boilers. While current work on heat pumps typically focuses on waste heat, air-sourced systems offer higher flexibility and a wider range of applicability. A techno-economic analysis and life cycle assessment of a novel air-sourced heat pump was conducted, with a comparison to resistance and natural gas boilers. The impacts of time-of-use utility rates with hourly cost resolution and localized weather patterns are investigated. In addition, the potential decarbonization pathways of each technology are explored to further quantify future steam solutions as the grid trends towards renewable generation technologies. The study found that the electric resistance boiler is a generally unattractive option compared to heat pumping from both a cost and emissions standpoint. It was determined that, at the studied locations, the natural gas boiler generally offered a cheaper solution economically in the non-renewable case for the current studied time and locations. For the renewable technologies, the heat pump was found to be typically cheaper. When considering emissions reduction and decarbonization cost, the heat pump provided the best value across most scenarios.

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NOMENCLATURE

COP	Coefficient of Performance
TMY	Typical Meteorological Year
CAPEX	Capital Expenditures
OPEX	Operating Expenditures
TEA	Techo-Economic Analysis
LCA	Life Cycle Assessment
GWP	Global Warming Potential
EES	Engineering Equation Solver
SHP	Steam Heat Pump
HTHP	High-Temperature Heat Pump
ASHP	Air-Sourced Heat Pump
ERB	Electric Resistance Boiler
NGB	Natural Gas Boiler
rNGB	Renewable Natural Gas Boiler
Variables	
IRR	Internal Rate of Return [%]
n	Individual year [year #]
N	Total number of years [years]
NPV	Net Present Value [$]
LCoH	Levelized Cost of Heat [$/MWh]

CHAPTER 1: INTRODUCTION

1.1 Motivation

Since records of global temperature began in 1850, the average surface temperature of the Earth has increased, primarily driven by human activity beginning during the industrial revolution. Annual temperatures in the past 48 years have been higher than the 20th century average [1], shown in Figure 1. The Paris Agreement, signed in 2015 by 195 United Nations parties, aims to prevent the increase of global temperature past 1.5ºC above pre-industrial global temperatures. To meet this goal, efforts have been made to design technologies that utilize renewable or carbon-reduced energy sources to minimize the impact humans have on the greenhouse gas levels in the atmosphere while still meeting our global demand for energy.

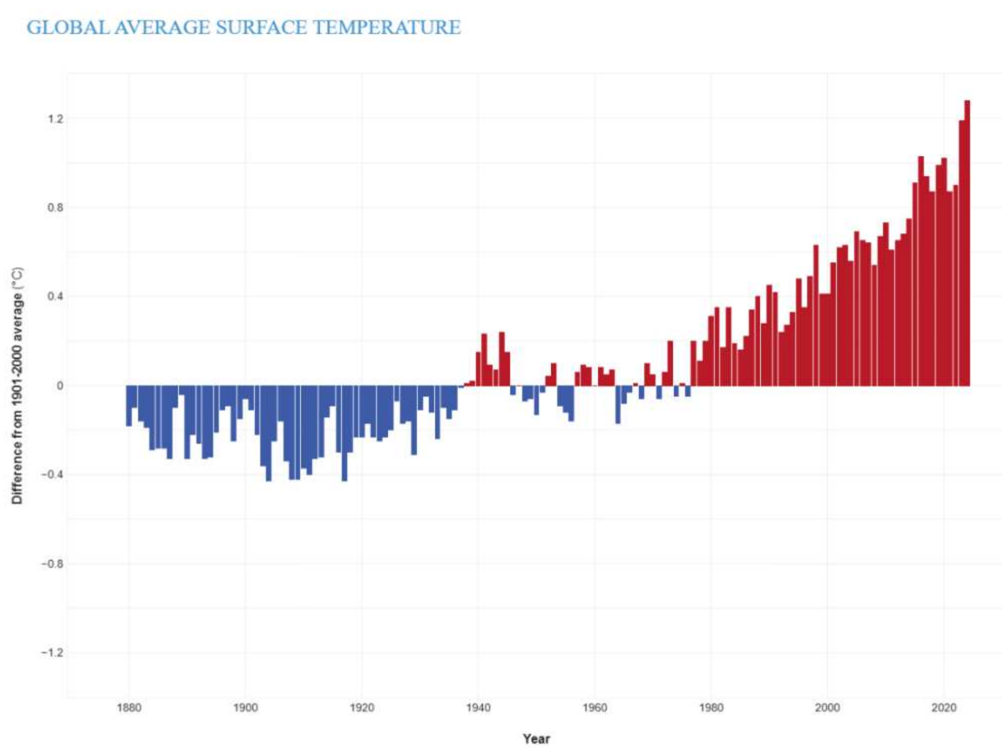

Figure 1: Global average temperature difference from 1901-2000 average [1]

1.2 Decarbonizing Industrial Heat

In 2016, industrial heat generation resulted in around 21% of global CO_2 emissions [2]. 25% of this heating demand in the US is for heat at the temperatures in the range of 100-200 ºC [3], which is typically delivered in the form of steam. Targeting industrial heating processes in this temperature range offers a strong decarbonization pathway in the US. While much of this current heat demand is met by natural gas boilers, electrified systems such as heat pumps and electric resistance boilers offer an alternative pathway towards the decarbonization of industrial heat as the grid trends towards electricity generation sourced from renewable technologies. Both electrically-driven technologies provide a potential to displace the greenhouse gas emissions in the industrial heat sector; however, heat pumping often has economic advantages over resistance boilers due to the ability to achieve higher efficiencies, therefore reducing energy consumption and its associated costs.

1.3 Heat Pump Technology

Waste heat and ambient air are two of the most common heat sources that provide thermal energy for heat pump applications. By upgrading this thermal energy source instead of generating heat directly, heat pumps can achieve a Coefficient of Performance (COP) greater than 1 [4]. As calculated in Equation 1, the power output from the system is greater than the electrical energy input required during operation. The COP of a heat pump is dependent on the source temperature of the input thermal energy: for a fixed output temperature, higher input temperatures result in higher COPs, meaning less electrical input is required. The Carnot COP, shown in Equation 2, is the maximum theoretical heat pump COP, where the denominator is the temperature lift of the system. Due to system losses, the real COP is less than the Carnot COP.

$$COP = \frac{Q_{out}}{W_{in.elec}} \tag{1}$$

$$COP_{Carnot} = \frac{T_H}{T_H - T_C} \tag{2}$$

While waste heat applications can provide higher source temperatures than ambient air, there are additional challenges associated with recovery of waste heat. A study conducted by Schlosser et al. discussed how waste-heat heat pumps are often custom-made and restricted to specific input temperatures [5]. In addition, they cite high costs associated with the recovery process of available waste heat, including lack of accessibility to customer-facing integration tools. Infrastructure and integration costs also act as barriers to the adoption of waste heat systems. Notably, waste heat streams are not available for use in all scenarios requiring high temperature industrial heat. The high costs associated with custom design and integration along with limited flexibility of usable source temperatures of waste-heat heat pumps motivate further investigation of ambient air-sourced heat pumps (ASHPs), which provide greater flexibility in applications for industrial heating processes [6]. This technology could displace both the natural gas boiler technology by reducing emissions, and the alternative electric resistance boiler by operating with less electrical input to lower operating costs for the customer for a given heat demand.

1.4 Necessity of Heat Pump Techno-Economic Modeling

To effectively deploy heat pump technology for industrial customers, a greater understanding of the lifetime system costs is required. CHAPTER 2: LITERATURE REVIEW will show that current literature examines the capital and operating costs of high-temperature heat pumps (HTHPs), but that investigation into the dynamics of air-sourced heat pumps is limited. Among the available literature, studies lack investigation into rigorous hourly performance and utility rate structures. Coupling TEA models with life cycle assessment results to understand the cost savings potential in the frame of emissions reduction is also vastly unexplored. This work will address the literature gap by presenting the coupled techno-economic analysis and life cycle assessment of the AtmosZero heat pump "Boiler 2.0", as further described in the subsequent sections.

CHAPTER 2: LITERATURE REVIEW

2.1 Techno-Economic Analysis Modeling

A significant roadblock to the wider adoption of heat pumps as an alternative technology is the economic viability as compared to other potential process heat solutions. While flat cost of materials and electricity rates can be used to provide a project estimate, a full economic analysis that is coupled to variable performance parameters allows for further understanding and improved accuracy of the lifetime costs of heat pump technology. Many studies have quantified this cost by conducting techno-economic analyses of high-temperature heat pumps [5], [7-21]. The total capital and operating expenditures of a heat pump are better understood in the context of similar "baseline" technologies, where a parallel techno-economic analysis employing the same parameters produces price data for each of the baselines.

Current studies in the open literature have examined a variety of parameters that impact the thermodynamic and techno-economic performance of high-temperature heat pumps. This includes variables such as the input temperature, refrigerant type, and location-specific effects like the cost of electricity and natural gas. Some of these studies have been conducted for steam production applications, while others are designed for process heat or generalized systems without specified application. Many consider the comparison to other methods for steam generation or process heat, such as the natural gas or electric resistance boiler baseline technologies. This literature review explores the current published work on the techno-economics of high-temperature heat pumps with steam (or process heat) at a temperature above 100°C. A gap in the literature for analysis on an hourly resolution with utility rate structures was identified. This gap is addressed in this work through the TEA and LCA modeling of a novel ambient air-sourced high-temperature heat pump, expanding preliminary work conducted by Siegel et al. [7].

A previous study conducted by Siegel et al. [7] examined the techno-economics of the AtmosZero heat pump at three locations. A model was developed for the thermodynamics of the air-sourced heat pump, which calculated the system COP as a percent of the Carnot heat pump efficiency, based on a fixed output temperature and an ambient temperature at each location from TMY data. The energy charge rates for electricity and natural gas at each location were modeled, and the impact of peak demand pricing was incorporated as well. The capital expenditures (CapEx) of the system were calculated from data found in the open literature, and fixed COP values were used for these calculations. In addition to the techno-economic analysis conducted, a life cycle assessment was completed to assess the CO_2 emissions during the operation of the system. The study found that heat pumps were cost competitive with electric boilers but not natural gas boilers. A carbon tax was quantified to equalize the economics of the gas boiler with the heat pump.

2.1.1 General Studies on High-Temperature Heat Pump Modeling

Literature was identified that examined the techno-economics of high-temperature heat pumps for topics of interest not identified as gaps in the current work. These cover a broad range of studies but primarily focus on the influence of operating parameters such as source temperature for non-air-sourced heat pump applications under constant operating conditions.

A study conducted by Hosseinnia et al. [12] researched the impact of refrigerants for a high-temperature heat pump, with a focus on a cascade system with variable low-stage refrigerants. An EES thermodynamic model was developed and validated with experimental data found in the literature. Cost correlations were used based on the calculated size to determine the equipment costs, and a total annual cost for varying temperature lifts was developed based on constant electricity prices per unit energy. It was concluded that additional information about the specific application, including capacity, was required to determine the optimal refrigerant for a heat pump.

Kosmadakis et al. [10] studied the techno-economics of a high-temperature heat pump coupled with an organic Rankine cycle for steam generation in marine applications. This analysis was based on a constant source temperature of water, which was an input to a thermodynamic EES model to calculate the required cost correlation inputs for equipment pricing. This model used an average global cost of fuel and quantified the net savings in fuel and the payback period for the proposed system. They concluded that the proposed alternate configuration did reduce consumption compared to the baseline technology for the application.

Trevisan et al. [13] compared the levelized cost of heat (LCoH) for steam production from a high-temperature heat pump to the cost for the current natural gas and electric boiler solutions. The impact of input and output temperatures, electricity, and the heat pump CapEx on the LCoH difference was analyzed. Cost correlations from the literature were employed to find the CapEx of the heat pump, and a flat energy rate of operational costs, including electricity or natural gas, was used. The COP of the heat pump was modeled as a percent of the Carnot COP based on the desired input and output temperatures. In addition, this study considered three different load profiles. These profiles included operation at either full or no capacity for different typical workday schedules. A reduction in energy consumption and total costs compared to a non-flexible electric boiler was identified.

Dumont et al. studied a waste-heat high-temperature heat pump for process heat applications in the food and beverage industry [15]. This techno-economic analysis found the levelized cost of heat based on a heat pump that operated at a fixed percent of its Carnot COP, which in turn was based on a variety of selected waste-heat temperatures for different analysis cases. The cost for electricity and natural gas used was from standard industry pricing at a constant energy rate. For the CapEx of the heat pump, a separate study from the literature was referenced for a cost per unit capacity of high-temperature heat pumps. The results for the heat pump were compared to a baseline natural gas boiler, and it was found that the different heat pump scenarios were cost competitive with the natural gas baseline scenario based on an implemented carbon tax.

Pihl et al. investigated the impact of the steam/hot water delivery temperature for steady-state operation of a steam-producing high-temperature heat pump [17]. This study calculated a specific total capital investment and sized components with Python. This sizing was used along with purchased equipment cost correlations from the literature to estimate the cost of the system given the input parameters, focusing on the variation from the delivery temperatures. To calculate the operating expenditures (OpEx) of the system, fixed prices were used for the fuel cost calculation. A percent of the Lorenz COP (the Carnot COP using mean high and low temperatures) was used as the system COP for these calculations. These results were used to find the annual lifetime cost, which could then be converted to the total capital investment as a cost per unit energy produced. This value was compared to results for boilers using natural gas, electricity, and biogas. The study found that lowering the delivery temperature decreased the operational cost of the HTHP studied.

2.1.2 Air-Sourced Heat Pump Performance Modeling

Some studies examined specific air-sourced applications for high-temperature heat pumps. While the variable temperature of the source was only dynamically considered by Siegel et al. [7], examination of air-sourced economics is relatively unexplored, and the following studies represent the literature identified on the subject.

Vannoni et al. [8] examined various refrigerants for heat pumps. The model maximized system COP in MATLAB based on selected typical temperatures of various heat sources (waste heat, water, and air) and calculated the net present value (NPV) difference between the heat pump model and a natural gas boiler under the same conditions. The CapEx of the heat pump was calculated using cost correlations from a separate study, and the costs of electricity and natural gas were set to a fixed average price per unit energy. Of the selected refrigerants, they concluded that only one could reach the temperature cutoff for classification as a high-temperature heat pump. They also found NPV trends across different temperature cases.

Liu et al. [18] studied steam production from coal, natural gas, and electric boilers, and both air and waste-heat-driven heat pumps. They primarily focused on an OpEx comparison across four different countries using constant fuel rates from each. When modeling the heat pump performance, they used rounded COP values with a fixed temperature input. This study quantified heat demand for the application and the potential decarbonization pathways associated with switching technologies. It was also found that heat pumps were cost competitive in many of the studied locations, and they outlined a roadmap for deployment of this technology.

Schlosser et al. [5] conducted a study on high temperature heat pumps for any heat application, mentioning steam as a potential use case. This study did not explicitly specify a heat source for the heat pump but did consider the temperature range that different sources, including air-source, could provide. A sensitivity to this constant temperature and the price of fuel was conducted. It was concluded that cost increases or taxes on fossil fuels for high temperature demand was necessary to achieve cost competitiveness for the heat pump. They also mentioned that quantifying cooling savings in future work could improve the economics of heat pumping.

2.1.3 Heat Pump Variable Location Studies

Some studies examined the influence of location on economics. This primarily was to establish different cost bases for capital or fuel costs. Each study considered constant fuel costs for each location rather than dynamic performance.

A separate study conducted by Vannoni et al. [9] focused on modeling for waste-heat-driven, high-temperature heat pumps. A MATLAB model was used to iteratively analyze the thermodynamics and size components for system design. A purchased equipment cost approach was used to obtain the price of the heat pump. This study more rigorously examined the cost of electricity, finding the average cost per unit energy for different system demand. In addition, this information was collected at different locations across the EU. However, this model assumed operation at constant load, meaning that individual heat pump results operated at a single given rate for electricity. They concluded that compressor cost, and therefore evaporator sizing, was critical in reducing overall costs, and that continuous operation was optimal for the economic viability of heat pump applications.

Kosmadakis et al. [11] examined the techno-economics of waste-heat-driven high-temperature heat pumps and the influence of low global warming potential (GWP) refrigerants. An EES thermodynamic model was built, with experimental validation from a 10kW lab-scale heat pump. The thermodynamic model was used to size heat exchangers based on literature cost correlations. To calculate the operational costs, fixed energy costs for electricity and natural gas were used based on average European prices. An optimal refrigerant was identified for a variety of sink and source temperatures across different European countries.

Saini et al. [14] conducted a techno-economic analysis of solar thermal collectors compared to a high-temperature heat pump for industrial steam. For the comparison, three different load profiles were considered. These profiles each alternated between peak load and zero load to reflect different real-world situations. For each profile, the peak load and outlet temperature was kept the same. In the heat pump analysis, the cost sensitivity to three different variables was considered. These variables were the CapEx, the cost of electricity (per unit energy at a flat rate for each case) and the load profiles. Based on the peak load and outlet temperature, a performance map for the COP of the heat pump was generated from a desired temperature lift. For specific case analysis, a fixed inlet temperature was used, resulting in constant operating COP during the run. They confirmed the expected trends of the heat pump LCoH with the studied variables and found that the solar collector was cheaper than the HTHP.

Lu et al. [16] examined the thermodynamics and techno-economics of a high-temperature steam-generating cascade heat pump driven by waste heat. This study incorporated different constant energy charges for the selected locations in China to calculate the heat pump payback period. Different combinations of top cycle and bottom cycle refrigerants were also considered. For this study, certain reference values were fixed, and boundary conditions were also provided for sensitivity analysis. These included the heat source and sink temperature, and the electricity and natural gas costs. In addition, the model used cost correlations developed by another study in the literature to determine the cost of the heat pump components. The COP was determined from the thermodynamic model. For both the COP and payback period, specific operating conditions were identified.

Rather than calculating the current cost of a heat pump, Ciambellotti et al. [19] determined the required CapEx of a waste-heat steam heat pump across multiple countries to achieve a desired payback period. In this study, the price of natural gas and electricity was held at a constant rate, and three different refrigerants, each with a unique fixed COP, were used. The results of this study showed that HTHPs were advantageous in both energy consumption and CO_2 emissions when compared with an electrified boiler, with fossil fuel systems as a baseline. While it was found that both electrified technologies were more expensive than the baseline, emissions reduction benefits were identified as motivation for the transition to electrified systems.

2.1.4 Heat Pump Variable Fuel Cost Studies

An important portion of the economic modeling results are the operation and maintenance costs. For the heat pump system, this is primarily the cost of the input electricity, which has a highly variable cost across different regions of the United States. For larger customers, electricity is typically charged on a time-of-use basis, usually consisting of three different types of charges: an energy charge, a demand charge, and a fixed billing charge (often charged monthly). Most of the open literature combines these three charges into an average constant energy charge, instead of examining the effects of a specific rate structure. While many did consider a sensitivity to the energy charge, they did not conduct a complex study of the influence of varying costs over a typical operating year. A study by Pilling et al. developed an equation based on seasonal variation of costs, but did not specify which charge types were included, nor did it reference a specific utility provider for the data [20]. A study by Vieren et al. referenced internal cost functions, without specification as to whether this included a rigorous structure or energy charge patterns [21]. The conference paper from Siegel et al. used a utility provider cost structure for a total of 3 locations [7].

Pilling et al. [20] examined the uses of wind power with a thermal energy storage system to power a HTHP with a steam generator. A model was developed to purchase electricity from the grid based on whether the wind power met the heat pump demand throughout operation. The setup assumed operation with a constant waste heat temperature from the wind system, and they aimed to minimize grid payments by controls optimization based on the wind and storage available. The electricity costs were based on a 15-minute average energy cost from multiple utilities across the operation time. Results were found for the stochastic control model to optimally reduce costs. This study was the only one identified that used a changing fuel cost structure during operation.

2.1.5 Heat Pump Variable Input Temperature Studies

To accurately represent the performance of a heat pump, the system COP is calculated based on the temperature lift. Many studies, both for air and waste-heat-sourced applications, did recognize the influence that source temperature has on system performance, but this was primarily quantified by conducting a sensitivity analysis with fixed source temperatures for a given case [5], [7-8], [11-13], [16-17], [21]. An exception to this for waste-heat application was a study by Vieren et al. [21] that used data from a specific installation site for the source temperature. As air-sourced heat pumps have fluctuating performance based on the ambient temperature, the performance characteristics from the source temperature can greatly impact the techno-economic results of the system even more than for waste heat applications, and thus it is critical to capture this effect for ASHPs. Among the literature on ASHPs, only Siegel et al. [7] used a varying temperature profile, which incorporated typical meteorological year (TMY) data for the temperature of the ambient air at the locations studied, then calculated the system COP as a percent of the ideal Carnot COP. The rest of the studies found in the literature for both waste-heat and air-source applications used fixed performance parameters for either the source temperature, lift, or COP directly.

Vieren et al. [21] conducted a study to meet heating demand with a waste-heat HTHP. This study focused on a large-scale, low-lift heat pump. A temperature and demand profile were available for the application to calculate the COP over time. A blend of literature correlations and unidentified internal cost functions were used to calculate the net present value and a discounted payback period. The sensitivity to a fixed fuel ratio was explored as well. A positive business case was identified for the application, but a large payback period was also found.

2.2 Life Cycle Assessments of High-Temperature Heat Pumps

In this work, a life cycle assessment and its results operate as a connection point between the techno-economic analysis conducted and the cost of CO_2 abatement, an additional metric for comparing economics of the heat pump with other systems (as calculated in 3.6 Contextualizing TEA Results with LCA Modeling). A review of heat pump LCA was conducted to benchmark common approaches and their results to validate the LCA methodology presented in this work.

A study by Zeilerbauer et al. [22] scaled up life-cycle data from residential heat pumps for industrial application. This study did a comprehensive review of different environmental impacts and found that greenhouse gas emissions were reduced with conversion to heat pumping. However, they found that other midpoint categories studied showed differing results as to whether heat pumping or the baseline technologies were better. A study by Violante et al. [23] compared ground-sourced and air-sourced heat pump impacts. They found that ground-sourced heat pumps had significant negative impact compared to air-sourced heat pumps for the manufacturing and installation process, but that air-sourced heat pumps had slightly higher negative impacts during operation. Tveit et al. [24] compared a Stirling heat pump with a natural gas boiler and an oil boiler in four impact categories and found the heat pump to have the lowest eco-indicator in each (a measure of impact on human and environmental health). Another study by Khan et al. [25] examined 13 different metrics for a Stirling heat pump for different lifetimes as compared to a natural gas and an oil boiler and found the heat pump to have the lowest environmental impact. Bonamente et al. measured 18 impact categories for ground-source heat pumps for industrial space heating and cooling with thermal storage [26]. Midpoint impact indicators were quantified for heat pump environmental impact, such as the equivalent CO_2 emissions and ecotoxicity measurements.

The presented literature on the life cycle assessment of heat pumps concluded that heat pumps can provide an emissions reduction pathway for large-scale applications when compared with alternative systems, such as natural gas and oil boilers. While heat pumps are not always cheaper than fossil fuel alternatives, customers invested in the decarbonization of steam may be interested in this technology nonetheless. Therefore, a combination of TEA and LCA results can better frame the opportunity cost of heat pumping.

2.3 Gaps in the Current Literature

Table 1 summarizes the literature on HTHPs. For each category studied, works that address the literature gap are highlighted in green, with studies using unspecified methods remaining unhighlighted. As discussed in the literature review above, multiple studies have been conducted to examine the techno-economic potential of heat pumps for industrial heat at high temperatures. While COP modeling varied, the current study was the only one to use experimental in-house calibration data with industrial scale testing. No study was found that conducted an analysis on an hourly basis to simultaneously model both performance and economics of running an air-sourced heat pump over a typical year across various locations. This is a critical component of quantifying the long-term economics of air-sourced heat pumps due to the varying source temperature both across locations in the United States and yearly fluctuations in temperature. This work further expands on concepts presented by Siegel et al. [7] and will address this gap in the current literature by presenting the techno-economic model of a heat pump while considering TMY data and specific utility rate structures at ten separate locations across the US. In addition to the techno-economic work, a life cycle assessment is conducted to quantify the decarbonization potential of using heat pumps for steam production.

Table 1: Literature on High-Temperature Heat Pumps

Source	**Air Source**	**Variable Location**	**Variable Input Temperature**	**Variable Fuel Costs**	**COP**
Hosseinnia et al. [12]	No	No	Fixed Sweep	Fixed Sweep	EES with validation
Kosmadakis et al. [10]	No	No	No	No	EES
Trevisan et al. [13]	No	No	Fixed Sweep	Fixed Sweep	% Carnot
Dumont et al. [15]	No	No	No	Fixed Sweep	% Carnot
Pihl et al. [17]	No	No	Fixed Sweep	No	% Lorenz
Pilling et al. [20]	No	No	No	Variable over Operation	Optimization function
Vieren et al. [21]	No	No	Variable over Operation	internal functions	Modeled
Vannoni et al. [9]	No	Yes	No	Fixed Sweep	MATLAB
Kosmadakis et al. [11]	No	Yes	Fixed Sweep	Fixed Sweep	EES with validation
Saini et al. [14]	No	Yes	No	Fixed Sweep	Performance map
Lu et al. [16]	No	Yes	Fixed Sweep	Fixed Sweep	Model with validation
Ciambellotti et al. [19]	No	Yes	No	No	Fixed values
Liu et al. [18]	Yes	Yes	No	Fixed Sweep	Fixed values
Schlosser et al. [5]	Yes	No	Fixed Sweep	Fixed Sweep	Case studies
Vannoni et al. [8]	Yes	No	Fixed Sweep	No	MATLAB
Siegel et al. [7]	Yes	Yes	Variable over Operation	Variable over Operation	% Carnot
Current Work	Yes	Yes	Variable over Operation	Variable over Operation	Experiment-ally modeled

CHAPTER 3: METHODOLOGY

3.1 General Techno-Economic Modeling Approach

This work presents a techno-economic analysis of a novel high-temperature, steam-generating heat pump driven by ambient air. A model that considers a variety of technical, economic, and geographical inputs was developed in the software MATLAB. The technical parameters of the system were modeled and experimentally informed by data collected from operation of the AtmosZero "Boiler 2.0" laboratory pilot machine housed at the Powerhouse Energy Campus at Colorado State University (CSU). Analytical models were employed to generate predictive performance curves for the market-ready design of the novel system and were then validated with pilot test data. In addition, target procurement prices of equipment from AtmosZero were used to determine capital costs of the heat pump based on the n^{th}-of-a-kind design. This model provides results for two baseline technologies, an electric resistance boiler and a natural gas boiler of the same heat capacity, to quantify the difference in the price of the technologies available to produce industrial steam.

The studied system is based on a novel high-temperature heat pump being developed by the startup company AtmosZero. "Boiler 2.0" is an air-sourced, cascade heat pump. It employs two different refrigerants to achieve greater lift from a range of ambient temperatures to a high steam temperature. More details on the system components and technical modeling can be found in Ryan et al. [27] and Ryan [28], and a high-level system diagram is shown in Figure 2.

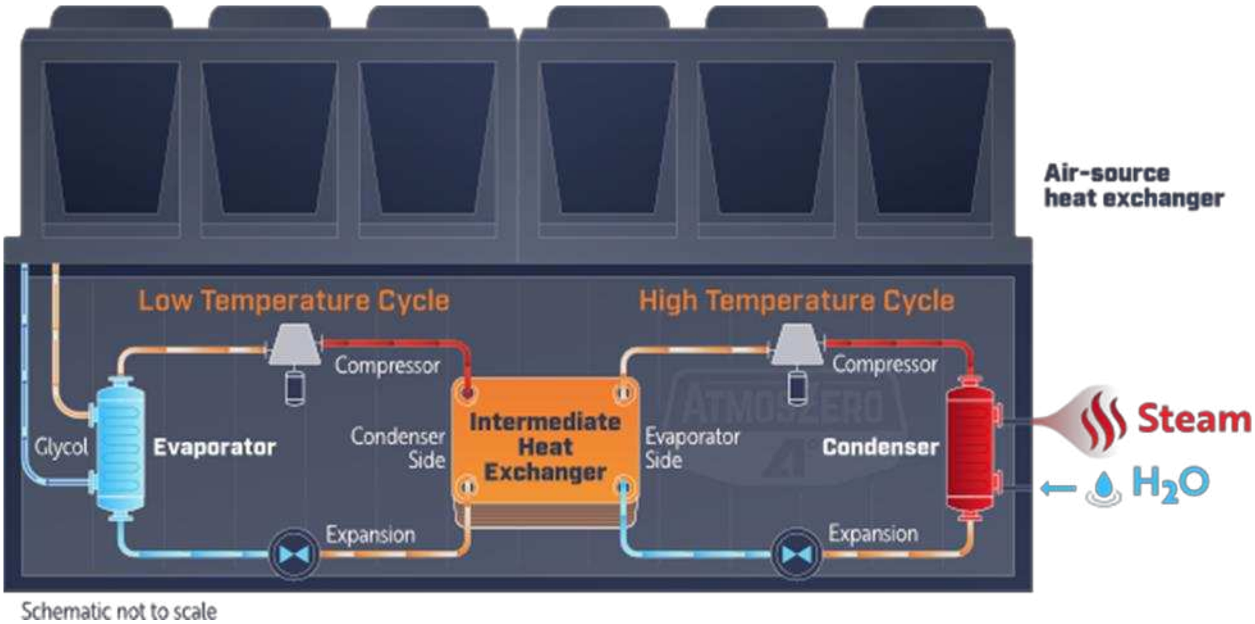

Figure 2: High-level diagram of the AtmosZero Heat Pump [27]

The MATLAB model was used to calculate the levelized cost of heat, the carbon intensity, and the cost of carbon abatement for the heat pump, a natural gas boiler, and an electric resistance boiler, as described in subsequent sections. In addition to looking at the base cost for

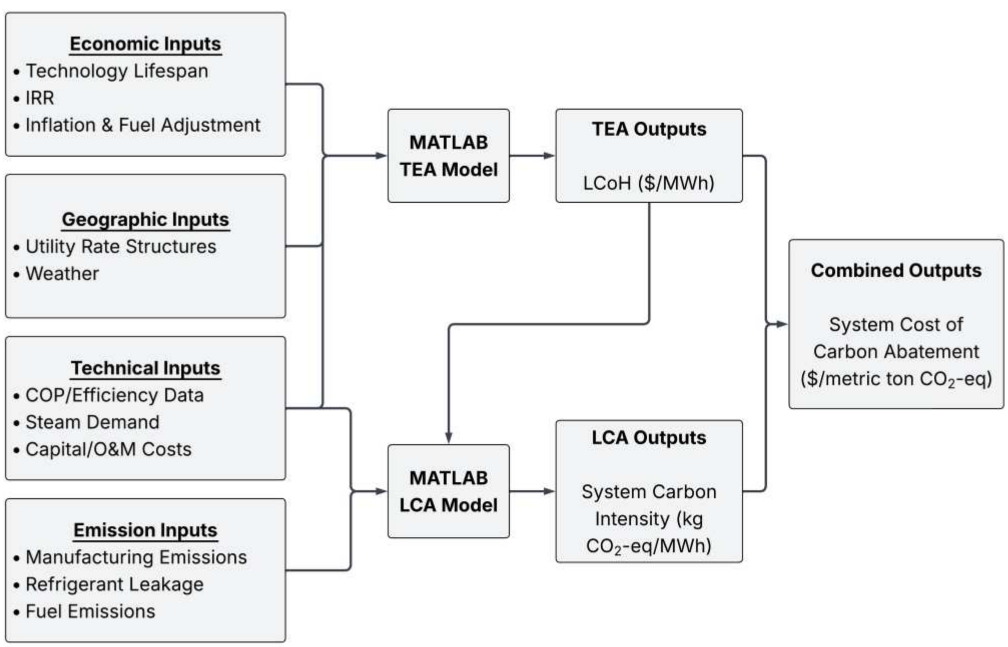

Figure 3: Flowchart of the MATLAB TEA/LCA model

each technology, a renewable-only grid and renewable natural gas were considered to understand the emissions reduction potential as renewable energy becomes more prevalent. The model inputs are split into four distinct categories: economic, geographic, technical, and emission inputs. Figure 3 shows a high-level flowchart of the model.

3.2 Heat Pump Technical Modeling

3.2.1 COP Modeling

The COP of the heat pump is dependent on both the ambient air temperature entering the bottom cycle evaporator and the total system steam demand. To capture the dynamic effect of variable temperature on heat pump performance, a COP curve-fit was developed in MATLAB. Performance data of equipment from the laboratory pilot test facility were used to calibrate a physics-based model in the GT-SUITE software tool. The developed model was built to predict various operating conditions of the industry-scale system producing a nominal 650 kW of steam at various ambient temperatures.

During operation at higher ambient temperatures, less energy is required to lift the refrigerant temperature to the desired level to match steam capacity. From the physics model, a cutoff point of ambient temperatures was determined, where temperatures below this cutoff require four stages of compression in the bottom cycle, and temperatures above the cutoff only require two stages of compression. Due to the different system thermodynamics in these operating conditions, two separate COP curve-fits were developed, where the fit used is dynamically chosen based on ambient temperature. By using the data points recorded and modeled in the GT-SUITE software, the curve-fits for the COP were created as two separate two-variable functions of input temperature and steam demand, as shown in Figure 4. In this work, a constant demand of 650 kW was assumed, based on the nominal scale of the laboratory pilot system.

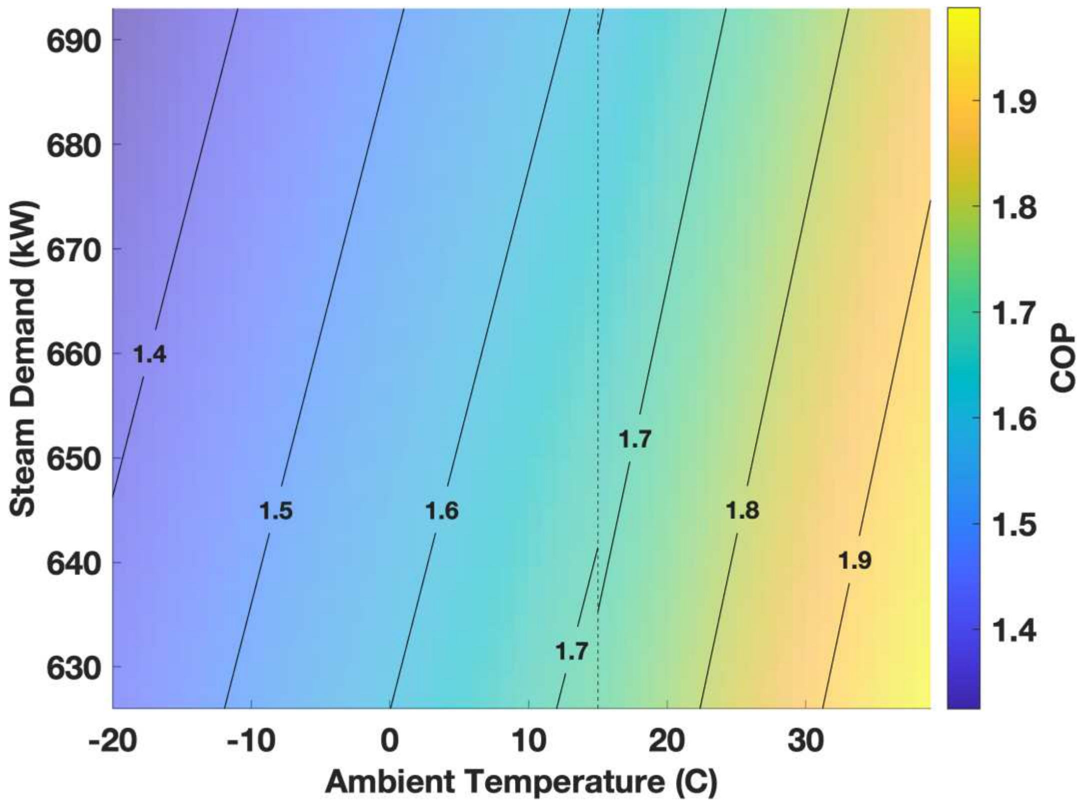

Figure 4: COP curve-fit model

3.2.2 Weather API Modeling

Integrated into the MATLAB model is a connection to the GOES Physical Solar Model v4.0.0 API developed by the National Renewable Energy Laboratory as part of the National Solar Radiation Database [29]. The API receives the latitude and longitude of locations of interest from the MATLAB model and returns a table of data with information about local weather. The data received includes typical meteorological year (TMY) data, which is a per-hour ambient temperature reading for a typical year at the chosen location, corrected for outliers found in each recorded year. For each location studied, the TMY-2024 database was used for the hourly ambient temperature to inform the heat pump performance calculation.

3.2.3 Techno-Economics of Heat Pump COP

To represent performance across the US, ten locations were selected for this study. Across a typical year, the COP varies based on the unique weather patterns of each location, creating a different COP curve for each studied location. In practice, the model architecture allowed for the determination of a COP at the same resolution as the available temperature data and steam demand data. To incorporate high resolution costs, the COP was calculated for each hour of a typical year, creating an 8760x1 array of performance data. As utility rate structures often have electricity charges varying down to the hourly level, this array allows for a more accurate cost model. The COPs for each studied location are shown in

Figure 5.

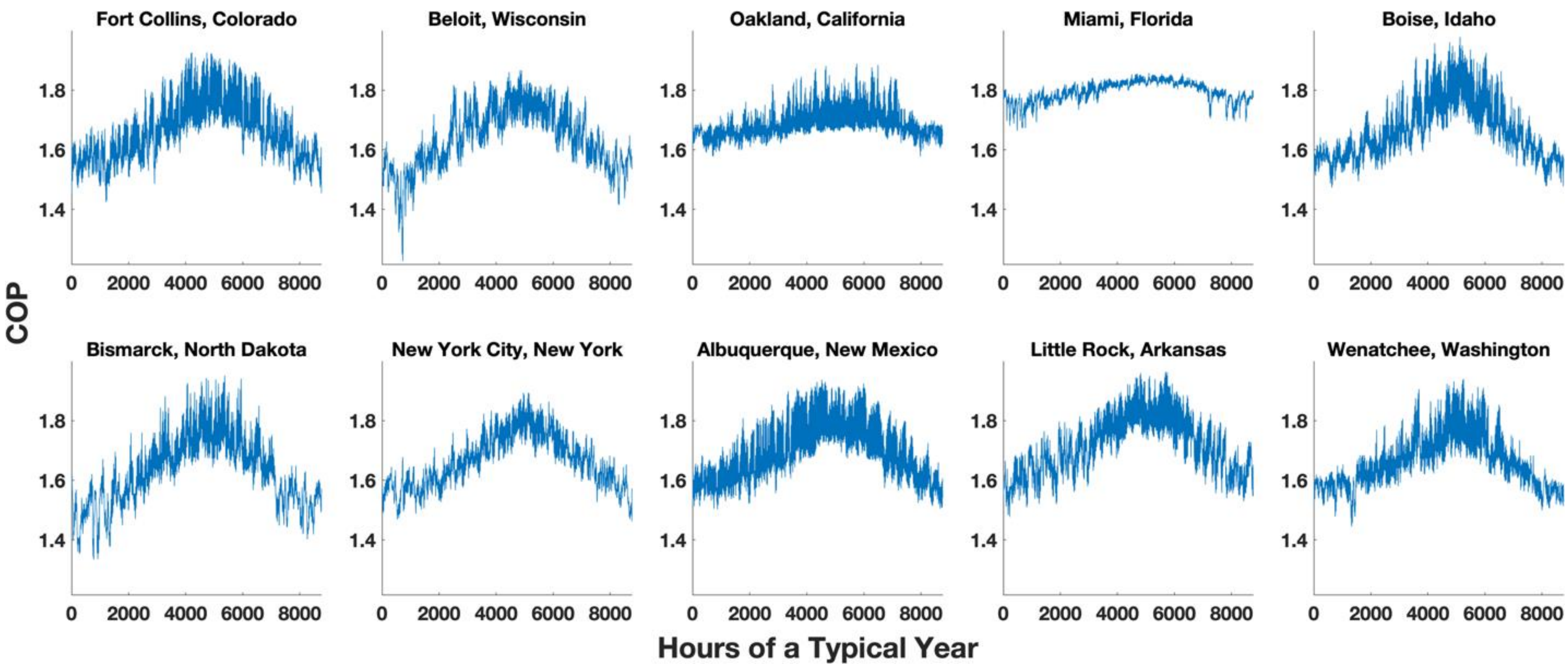

Figure 5: COP of the heat pump over the typical year at each location

3.3 Economic Modeling

3.3.1 Discounted Cash Flow, Net Present Value, and Levelized Cost of Heat

To calculate the NPV of each system, a discounted cash flow table was generated based on individual system parameters and fuel costs. The system inputs to the table were the fuel costs, operation and maintenance costs, and capital costs as described in subsequent sections. The parameters used for calculations were the internal rate of return, inflation rates, and inflation adjustments for fuel costs, with values shown in Table 2.

Table 2: Parameters of the discounted cash flow calculations

Variable	Value	Source
Internal Rate of Return (IRR)	10.5%	[30]
Inflation	2.5%	[31]
Electricity Inflation Adjustment	-0.6%	[32]
Natural Gas Inflation Adjustment	-0.6%	[32]

The technology life for each system was used to determine the total TEA length. A 25-year TEA calculation was selected based on the technology lifetimes presented in Table 3. As the resistance boiler has a shorter lifetime, a second boiler was purchased at the end of the first system lifetime. Since this second boiler ends its life in the 30th year, 5 years of residual value were credited to the techno-economics of the resistance boiler, assuming a linear decrease in capital value.

Table 3: Technology lifetime for TEA length determination

Technology	Technology Life (years)	Source
Heat Pump	25	AtmosZero
Electric Resistance Boiler	15	[33]
Natural Gas Boiler	25	[33]

From the technology inputs and model parameters, each annual cost was determined as the sum of the yearly payments of fuel and other O&M costs, as well as the capital cost in the first year of each new system purchase (year 0 for the heat pump and natural gas boiler, and years 0 and 15 for the resistance boiler). These numbers were adjusted for inflation, and the fuel costs were further adjusted due to their expected deviation from inflation. Next, the discount factor for each year was calculated based on the internal rate of return, as shown in Equation 3. The discount factor takes future cash flows and discounts them to present-day dollars. Each annual cost was discounted with this factor to an annual present value with Equation 4. Finally, the NPV was calculated as the sum of all annual present values in Equation 5 where N=24 (as payments were assumed to start in year n=0).

$$Discount\ Factor_n = \frac{1}{(1+IRR)^n} \tag{3}$$

$$Annual\ Present\ Value_n = Discount\ Factor_n * Annual\ Cost_n \tag{4}$$

$$NPV = \sum_{n=0}^{N} Annual\ Present\ Value_n \tag{5}$$

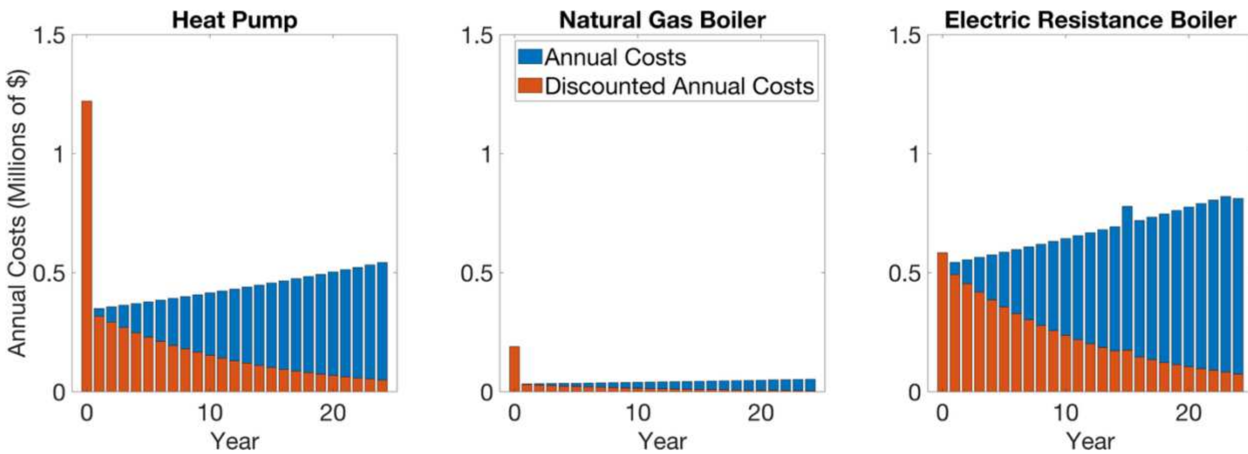

Figure 6: Annual costs for each system over the 25-year TEA length in Fort Collins, CO

Figure 6 shows the annual costs for each year of the techno-economic analysis for each system at the Fort Collins, Colorado location as an example. In blue is the annual cost from the right-hand side of Equation 4. After the discount factor is applied, the orange bars show the annual present value, the left-hand side of Equation 4. The first bar includes the CapEx investment for each system. For the resistance boiler, the 15th bar includes the additional CapEx investment, and the last bar includes the credit for residual value.

The NPV results were normalized using the levelized cost of heat (LCoH), a common metric used to normalize investments over the length of the TEA by finding an equivalent cost per unit energy produced, as calculated in Equation 6. This is the primary economic metric by which technologies are compared in this study.

$$LCoH = \frac{NPV}{\sum_{n=0}^{N} Heat\ Delivered_n * Discount\ Factor_n} \tag{6}$$

3.3.2 Heat Pump System Parameters

To determine the costs of the heat pump for the LCoH calculation, target prices for the nth-of-a-kind design of the 650-kW heat pump were used. First, the capital cost of the heat pump was determined based on the cost of the unit, as provided by AtmosZero. As the TEA is conducted from the customer perspective, CSU assumed a 20% cost of installation. Since the heat pump is a drop-in design, the installation cost is expected to be small. Needs for specific sites may vary, but this assumption includes foundation, piping, electrical, and other small components. For model flexibility, these were normalized to prices per kW, allowing for scaling of system capacity in modeling, as shown in Table 4. In addition to the capital costs of the heat pump, non-fuel operation and maintenance costs were included. For the heat pump, these were assumed to be an annual charge of 3% of the CapEx sale cost (without installation).

Table 4: Heat Pump System Parameters

Variable	**Value**
Cost of Unit per Megawatt	$ 1,125,000
Installation Factor	1.2
Normalized CapEx	$ 1350 / kW
Normalized Maintenance OpEx	$ 33.75 / kW-year
Efficiency/COP	Based on curve-fit

3.3.3 Other System Parameters

Equations 3-6 were also used to calculate the LCoH of both the natural gas and electric resistance boilers. As these technologies do not have the same weather dependence, data from EIA's technology forecast updates was used to find the economic and performance parameters necessary [33]. The natural gas boiler system parameters are shown in Table 5, using the 2022 typical costs, and the electric resistance boiler system parameters are shown in Table 6, using the

2022 typical costs. Each of these datasets were inflated to 2025 dollars for consistency. The listed costs were based on the total installed cost, so no additional factors to the CapEx were required.

Table 5: Natural Gas Boiler System Parameters [33]

Variable	Value
Normalized CapEx	$ 242.08 / kW
Normalized Maintenance OpEx	$ 11.02 / kW-year
Efficiency/COP	0.85

Table 6: Electric Resistance Boiler System Parameters [33]

Variable	Value
Normalized CapEx	$ 77.16 / kW
Normalized Maintenance OpEx	$ 0.85 / kW-year
Efficiency/COP	0.98

3.4 Localized Modeling

Coverage of multiple US locations was utilized to better understand cost variations based on both weather patterns and fuel price patterns across different regions. The weather patterns only affect the heat pump's performance, as described in 3.2.2 Weather API Modeling, however, the cost of fuel has large fluctuations in price and in charge structure depending on the provider, affecting all three technologies.

In this study, ten separate locations were examined. For each location, a specific high-volume utility provider was selected for modeling, and a publicly available rate structure from each was selected to match the scale of demand for the individual systems. When multiple options were provided for a given demand range and application, a time-of-use rate was chosen where available, allowing for hourly resolution of cost modeling, which matches an option that many customers will chose to reduce costs compared to flat rate structures.

3.4.1 Fort Collins, Colorado

For the Fort Collins, Colorado location, the electricity provider selected was the City of Fort Collins utilities [34]. The E300* series rate structure was used, which consisted of a fixed monthly charge, a constant energy charge, a facility demand charge, and a seasonal commercial peak demand charge. Monthly charges were broken down into an equivalent hourly charge. The energy charges were assigned to each hour of the year. The facility demand charge was based on the peak consumption from each month. As the resistance boiler and natural gas boilers were assumed to operate at a constant efficiency, MATLAB logic assigned this charge to the first hour of each month. For the heat pump, however, the 650-kW array was divided component-wise by the calculated localized-weather-dependent COP array for each hour to obtain the hourly electricity demand. The highest value each month was used to calculate the total facility demand charge.

In addition, a coincident peak charge in Fort Collins charges customers for their demand during the city's highest total demand. The utility information provided the most common times that this occurred each month in the past 10 years. For summer months, there was a higher rate than for the rest of the months in the year. For each month, the most common hour of coincident peak was selected, and this additional peak charge was added based on the system demand for that hour.

The natural gas provider for Fort Collins was Xcel Energy [35], with rate structure CLG: 5000+ Dth. Similarly to electricity pricing, a monthly charge, demand charge, and energy charge were considered. The monthly charge was broken down by hour. The demand charge was based on peak day consumption. The sum of each individual day's hourly consumption was calculated, and then the peak day for each month was identified and assigned this charge. Finally, the energy charge was modeled as a flat rate applied to each hour.

As each type of charge for both electricity and natural gas was broken down into the hour it applied to, a total equivalent cost array was generated, where the sum of this array was the yearly fuel cost for the system. This was conducted for each technology and was used as the input for fuel cost for the discounted cash flow table. This process was repeated at each location, but with changes to the rate structure, as described in the following sections.

3.4.2 Beloit, Wisconsin

The electricity provider for Beloit, Wisconsin was Alliant Energy, with rate structure Cg-2TOD (3-phase) [36]. In this structure, there was a daily fixed charge instead of a monthly charge, but for calculation purposes, this was still broken into hourly charges in the model. The demand charge was split into two parts: a customer demand charge and a firm demand charge. The customer demand charge was calculated based on the highest demand in the previous year. This was assumed to be the peak yearly demand from the steam demand profile divided by system efficiency for each technology. The firm demand was based on the peak demand during specified hours each day, so the demand profile was filtered, and a maximum was identified for each month. In addition to these charges, there were multiple energy charges. A high rate applied to summer and winter months during specific hours. A low rate applied to all weekends and holidays, as well as specific weeknight hours, however, the holidays were omitted for simplicity. All other hours used a regular rate. Finally, a demand energy limiter was compared to the total monthly result after all charges were calculated. This was a limit on the amount of money spent with this schedule based on an equivalent energy-only charge.

Alliant Energy was also the utility chosen for natural gas in Beloit [36]. The structure used was Gc-2. This structure was simply made up of three daily charges, which were summed and converted to hourly charges, and three energy charges, which were summed and applied to each hour of the year.

3.4.3 Oakland, California

For Oakland, California, Pacific Gas and Electric Company's electric schedule B-10 was selected for the electricity utility [37]. Similarly to Alliant, PG&E had a daily charge. The demand charge was broken down into summer and winter peak. However, the structure used applied the same charge to these periods. The energy charge had six different components: peak, part-peak, and off-peak for summer, and peak, super-off-peak, and off-peak for winter. For summer months (June-September for this location), the peak hours and partial peak hours were specified ranges for every day in the period, and off-peak was all other hours. For the winter months (all other months), the peak was the same range as summer. Super off-peak was a range of times for specifically March through May, and off-peak was all other non-summer times.

The natural gas supplier for Oakland was also PG&E, and G-NR2 was the structure used [38]. This schedule was split into a daily charge and energy charge. For the energy charge, procurement and transportation charges were added to get a total rate. The procurement charge was constant throughout the billing month, but the transportation charge was split into summer and winter charges, then divided again with a rate for energy consumed before and after a set cutoff. To model this tiered system, for each hour the total consumption from the start of the month up to the current hour was summed, and if it was less than the threshold, the first charge was applied. Otherwise, the second tier of charges was applied.

3.4.4 Miami, Florida

Florida Power and Light Company was selected for the Miami, Florida location for electricity prices, with GSDT-1 as the rate structure [39]. First, the monthly charge was applied. The demand charge was distributed into multiple parts. All but one were normal demand charges listed out differently but applicable to the same peak hours, which were added together. The final demand charge was an on-peak charge, which was added if the peak occurred during a set range of months and times. The energy charge was also broken into multiple components, but these were summarized as a peak and off-peak energy charge. The peak time for this location was dependent on the month, day of the week, and hour.

For the natural gas provider, Florida City Gas was selected [40]. General Service – 120K was the applicable rate. A monthly charge, demand charge, and energy charge were included. Both the monthly and energy charges were flat rates applied to each hour of the year. For the demand charge, the rate was based on the energy consumed in the peak day of operation, which was identified for each month individually.

3.4.5 Boise, Idaho

Idaho Power Company was used for Boise, Idaho, with Schedule 9 primary time-of-use rates [41]. This service was split into summer and non-summer structures. The monthly charge was the same for both summer and non-summer rates. Independent of month was the basic charge, a demand charge based on the basic load. This was calculated as the average of the two highest monthly demands in the previous year, which in the model is simply the average of the highest demand over the year, and the highest demand from all hours after that month was filtered out. A regular demand charge was included with a different rate for summer and non-summer months, based on the highest monthly demand for each monthly billing period. Finally, an on-peak demand charge for only summer months in a certain range of hours was included. The energy charge was broken down into on-peak, mid-peak, and off-peak charges for summer and non-summer as well, where on-peak and mid-peak were determined by the day of the week and the hour of the day, and off-peak for each season was the remaining times.

Intermountain Gas Company's GS-1 rate was used for Boise's natural gas supply [42]. This included a monthly charge and an energy charge. The energy charge was another tiered system, this time with three different cutoff points. To calculate the energy charge, the same modeling approach was used as in the natural gas rate in Oakland, where the sum of all previous monthly consumption was checked for each hour to determine the appropriate tier to apply to the hourly consumption.

3.4.6 Bismarck, North Dakota

Montana-Dakota Utilities Co. was the utility provider used for Bismark, North Dakota [43]. For this utility, the optional time-of-day general electric service Rate 31 was selected for hourly resolution of costs. A basic service monthly charge applied. In October through May, one on-peak demand rate was charged based on each month's highest demand, and June-September had the same structure with a different rate. In addition, an on-peak and off-peak energy charge was included in this schedule. The on-peak energy rate applied to weekdays during specified hours, and all other hours and weekends used the off-peak rate.

Montana-Dakota Utilities Co. was also used as the natural gas supplier in Bismark [44], with the firm general gas service Rate 70. Under this schedule, there were two tiers, but the tiers were dependent on total consumption, meaning only the higher tier was used in the model. This schedule was simple, with a daily charge and one constant energy charge.

3.4.7 New York City, New York

For New York City, New York, the utility Consolidated Edison Company of New York, Inc. was used [45]. The schedule selected was Rate I Schedule 9, General - large service, with the low-tension service selected. Under this service, a regular monthly charge and energy charge were applied constantly throughout the operation time. For the demand charge, there were two rates, one for June-September, and one for all other months. Each of these charges was based on the highest demand in the given month. In addition to these charges, a reactive power demand rate was included. This charge was calculated with power factor information provided by AtmosZero. Additional delivery charges and adjustments were not included in the model. These charges were based on allowable total revenue for the provider (as opposed to on a customer basis) where accurate data was not readily accessible.

Consolidated Edison was also the gas provider for the model [46]. The selected schedule was the Rider H Rate I b charges. This included a minimum charge (a monthly rate), and summer and winter period energy charges for consumption over the minimum energy consumed in the given month.

3.4.8 Albuquerque, New Mexico

For Albuquerque, New Mexico, the Public Service Company of New Mexico was used for the electricity utility, with the general power service time-of-use rate No. 3B [47]. This rate was split into summer and non-summer schedules. For each, there was a monthly charge, a demand charge based on highest monthly peak, and energy charges. The demand charge used was the rate for a customer-owned transformer. Energy charges were further divided into on-peak and off-peak charges.

New Mexico Gas Company's non-residential cost of gas was used for Albuquerque's natural gas supply [48]. While their rates specified different charges, such as distribution and transmission, these were both per unit energy and summarized to one energy cost specifically for non-residential application, which was used in the model.

3.4.9 Little Rock, Arkansas

Electricity rates in Little Rock, Arkansas were from Entergy Arkansas, LLC using the Large General Service- Time of Use Schedule 7 [49]. A monthly rate was included, with the same value for each month. For demand charges, there were summer period and other period rates. Each of these included on-peak demand and excess demand rates. The peak hours were different for the summer and other months. The energy charges for this rate structure were also separated into summer and other period months, with the same on-peak and off-peak hours.

The natural gas supplier in Little Rock was Summit Utilities, with the Small Commercial Firm Sales Service (SCS-1) [50]. A monthly charge was included, but no demand charge existed for this rate. The energy rates were on another tiered system, under the SSO option.

3.4.10 Wenatchee, Washington

The electricity rate for Wenatchee, Washington was Chelan County PUD's Rate Schedule 30 [51]. For this rate, a monthly charge and a monthly demand charge were included. The energy charge was a time-of-use structure, with one on-peak rate during the day (6am to 6pm) and a different off-peak rate during the night.

The natural gas provider for Wenatchee was Cascade Natural Gas Corporation, under Rate Schedule 104 [52]. For this schedule, there were two charges. The first was a monthly rate, and the second an energy charge. While the schedule broke down the energy charge into individual charges, the total sum per unit energy of natural gas was also provided, and no charges were variable throughout the year.

3.4.11 Rate Summaries

Table 7 and Table 8 show a summary of each utility rate structure modeled. The columns do not cover the comprehensive charges described in the previous sections but serve as a summary of the types of charges for each location. The electricity table specifies how the fixed charge is assigned from the real rate structure, whether the demand charge has a restriction in hours or days of peak charges, and how the energy charge is applied. The natural gas table also breaks down the fixed charge, whether the structure has a demand charge (which is less common for natural gas) and the type of energy charge structure.

Table 7: Electricity Rate Summary

Location	Fixed Charge	Timed-Restricted Peak	Energy Charge
Fort Collins, CO	Monthly	Yes	Constant
Beloit, WI	Daily	Yes	Time-of-Use
Oakland, CA	Daily	No	Time-of-Use
Miami, FL	Monthly	Yes	Time-of-Use
Boise, ID	Monthly	Yes	Time-of-Use
Bismarck, ND	Monthly	No	Time-of-Use
New York City, NY	Monthly	No	Constant
Albuquerque, NM	Monthly	No	Time-of-Use
Little Rock, AR	Monthly	Yes	Time-of-Use
Wenatchee, WA	Monthly	No	Time-of-Use

Table 8: Natural Gas Rate Summary

Location	Fixed Charge	Demand Charge	Energy Charge
Fort Collins, CO	Monthly	Peak Day	Constant
Beloit, WI	Daily	No	Constant
Oakland, CA	Daily	No	Tiered
Miami, FL	Monthly	Peak Day	Constant
Boise, ID	Monthly	No	Tiered
Bismarck, ND	Daily	No	Constant
New York City, NY	Monthly	No	Tiered
Albuquerque, NM	No	No	Constant
Little Rock, AR	Monthly	No	Tiered
Wenatchee, WA	Monthly	No	Constant

3.4.12 Average Energy Prices

For comparison with the ten locations using specific rate structures, the state average cost of electricity and natural gas were included in the model, which was a normalized energy charge. Data collected by EIA was used, with the commercial rates selected for this application. For electricity prices, the cost was specified as the average price to the end-use customer [53]. The natural gas prices modeled were general prices for commercial application [54].

3.4.13 Renewable Energy Cost Adjustment

Renewable energy can be bought as a premium from some utilities, but the structure of opting into these types of programs differs across the United States. However, not all the utility providers studied have green energy programs, and available data on location-specific additional charges is limited. Therefore, an average premium across the country was added to the energy charge of all rate structures when considering renewable technologies. This is often referred to as a renewable energy certificate (REC), which is a proof of opting in to renewable energy with a utility. The renewable cost of electricity was calculated based on the average of rates reported by Cleartrace (a carbon accounting platform) at 1.365 cents/kWh [55]. The renewable cost of natural gas was based on the average of two different renewable natural gas programs, with a value of 5.65 cents/kWh [56-57].

3.5 Life Cycle Assessment

In addition to the techno-economic model developed, a life-cycle assessment was conducted to explore the greenhouse gas impact of each system based on its techno-economic performance. This included emissions data of two different types: operating emissions and manufacturing emissions. The operating emissions consisted of emissions from purchased electricity, the emissions from the pipeline and combustion process of natural gas, and the refrigerant leakage rate of the heat pump. The manufacturing emissions were based on available production data for the construction of the systems. Together, these data cover cradle-to-gate plus use phase (excluding disposal) emissions of each system. Carbon dioxide emissions and carbon dioxide intensity were then calculated.

3.5.1 Heat Pump Refrigerant Leakage

To account for the emissions for refrigerant leakage, a 3% charge loss was assumed for each year of heat pump operation, which was validated with a study that reported a 3.8% charge leak annually [58]. It was assumed that leaked refrigerant was replenished, such that the leakage emissions is constant throughout the equipment lifetime. The leakage emissions were based on available data for the GWP-100 for each refrigerant [59]. The top cycle uses R-1233zd(E), a low-GWP refrigerant which acts as a replacement for R-123, and a 100-year GWP of 4. The bottom cycle uses R-513A, a substitute for R-134a, and a 100-year GWP of 630. As both the top and bottom cycle operate on different refrigerants with different charges, AtmosZero provided the individual refrigerant charges, which were used to calculate the leakage for each cycle separately.

3.5.2 Manufacturing Emissions

The emissions associated with the manufacturing process of each system were calculated using the EcoInvent Database available through the software OpenLCA [60]. For each system, the IPCC2021-GWP100 was the standard used. The database did not contain a similar heat pump for manufacturing emissions, so this was instead based on the emissions from the production of steel for a similar system, scaled by the heat pump weight provided by AtmosZero. The natural gas boiler manufacturing emissions were scaled up by capacity from a similar model available in OpenLCA, and the resistance boiler was assumed to have the same system emissions per unit for manufacturing, as the capacity is always identical for the systems. Since the resistance boiler has a shorter lifetime, in the context of the 25-year model, the total manufacturing emissions for the resistance boiler were higher (as more systems were purchased). The data used for manufacturing emissions is shown in Table 9.

Table 9: Manufacturing Emissions Data

Variable	**Value**
Heat Pump Weight	75,000 lbs
Steel Manufacturing Emissions	5.20702 kg CO_2-eq/kg steel
SHP Manufacturing Emissions	272.48 kg CO_2-eq/kW capacity
ERB/NGB Manufacturing Emissions	59.3510 kg CO_2-eq/kW capacity

3.5.3 Electricity CO_2 Emissions

To account for the emissions associated with the grid electricity consumed by the heat pump and resistance boiler, state-level grid intensity from eGRID 2023 was used [61]. The total equivalent CO_2 (CO_2-eq) emissions for electricity to the point of consumption in the system were considered. The data in the eGRID tables also provided the generation technologies for each state and showed that there was a large variation in grid generation resources. The type of generation resource has a large influence on the variation in specific grid intensities. A renewable-only grid was included based on data from NREL, with the assumption of generation from a blend of 50% wind power and 50% solar photovoltaics [62]. This was used as a comparison with state grid intensity for each location to understand the potential decarbonization by transitioning grid generation technologies. The state-level intensities and renewable intensity are shown in Table 10.

Table 10: Grid Intensity Data

Location	**Grid Intensity (kg CO_2-eq/kWh)**
Colorado	0.4948
Wisconsin	0.5277
California	0.1790
Florida	0.3579
Idaho	0.1424
North Dakota	0.5886
New York	0.2116
New Mexico	0.3508
Arkansas	0.4528
Washington	0.1209
Renewable Intensity	0.0280

3.5.4 Natural Gas CO_2 Emissions

The emissions for the consumption of natural gas were split into two components. The CO_2 emissions from burning natural gas was calculated from EPA data, which reported the carbon intensity of the combustion process of natural gas as 0.0053 metric tons CO_2/therm [63]. The pipeline emissions (including the CO_2-eq for methane leakage) based on a life cycle greenhouse gas report for cradle-to-delivery of US natural gas were also considered, with a value of 12.2 g CO_2-eq/MJ [64].

A report by O'Malley et al. provided the CO_2 intensities based on the CA-GREET model that were used for renewable natural gas emissions [65]. In the report, the carbon intensity of four different pathways, as well as their availability in the US, were calculated for renewable natural gas. The sources for each were livestock manure, sewage sludge, landfill gas, and organic waste. These carbon intensities and their makeup of availability in the US are listed in Table 11.

Table 11: Renewable Natural Gas Intensities

Pathway Type	**Carbon Intensity (g CO_2-eq/MJ)**	**Percent Availability (% of US Makeup)**
Livestock Manure	41	20%
Sewage Sludge	40	4%
Landfill Gas	51	71%
Organic Waste	-11	5%

For the livestock manure category, two different carbon intensities were listed in the report. The authors used the value reported in Table 11 for years past 2024, where credit for methane avoided was given to the livestock owner instead of the gas purchaser. From these four intensities and their respective availability in the US, a weighted average was calculated for the renewable natural gas intensity used for the model.

3.6 Contextualizing TEA Results with LCA Modeling

The primary purpose of the LCA results is to compare the cost of CO_2 abatement for each renewable technology. The baseline system for this analysis was the non-renewable natural gas boiler, which produced the reference values for the difference formulas below. The CO_2 abated for a given technology was calculated with Equation 7:

$$Cost\ of\ CO_2\ Abated = \frac{\Delta\ NPV}{\Delta\ CO_2\ emitted} \tag{7}$$

This result combines the economic tradeoff of each technology with the emissions reduction opportunity as a rate in \$/metric ton of CO_2-eq, where positive values indicate a cost incurred by the end user to avoid a unit of CO_2 by using an alternative to a natural gas boiler.

3.7 MATLAB Model Flowcharts

Figure 7 and Figure 8 show the detailed flow of the modeling methodology for the TEA and LCA models respectively. The diagrams further expand on the general flowchart presented in Figure 3 and serve to connect the specific inputs with the intermediate calculations conducted to compare technologies. In each diagram, the cost of carbon abatement is included, along with a black box input for the other model, as this metric combines the numerical results of the two.

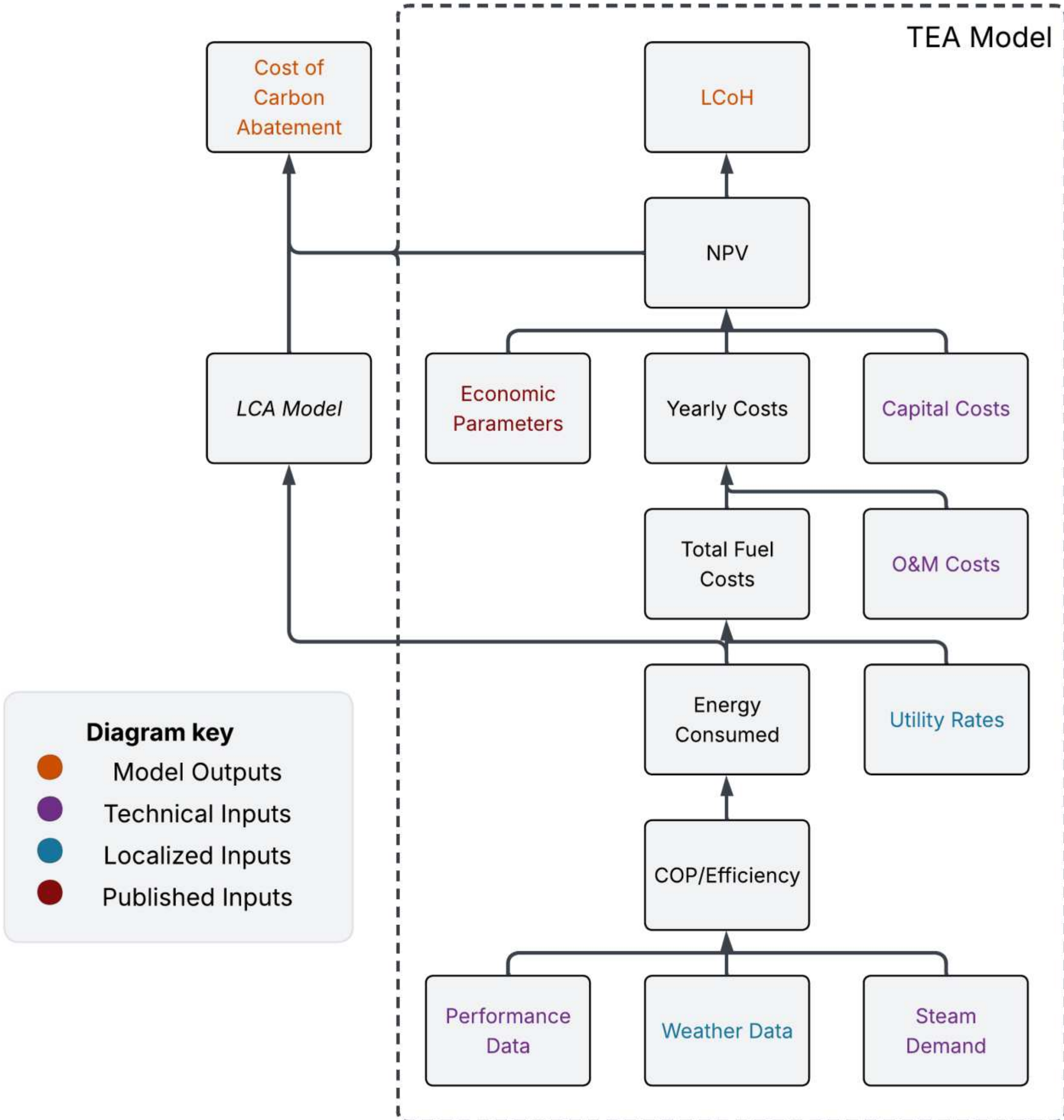

Figure 7: Detailed flowchart of the MATLAB TEA model

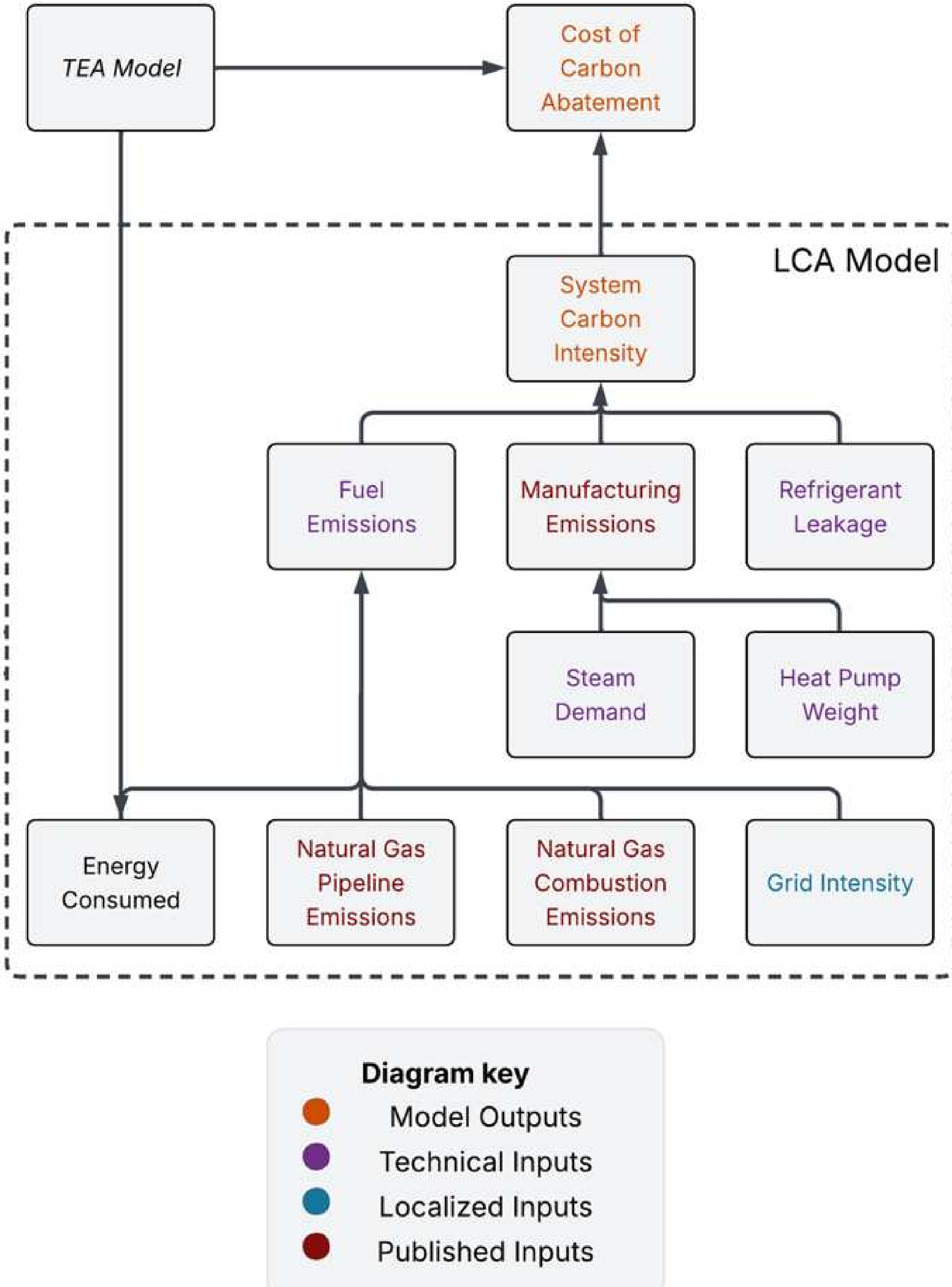

Figure 8: Detailed flowchart of the MATLAB LCA model

CHAPTER 4: RESULTS AND ANALYSIS

4.1 Levelized Cost of Heat

For each of the ten selected locations, the LCoH was calculated using utility rate structures. Figure 9 shows the results for each of the technologies; the steam heat pump (SHP), the electric resistance boiler (ERB), and the natural gas boiler (NGB). Across all locations except Wenatchee, the natural gas boiler was found to have the lowest LCoH, due to the cheaper cost of natural gas compared to electricity. Apart from Bismarck, Little Rock, and Wenatchee, where electricity had a lower price than at the other selected locations, the heat pump was cheaper than the resistance boiler. Both electricity and natural gas had notably high prices in Oakland.

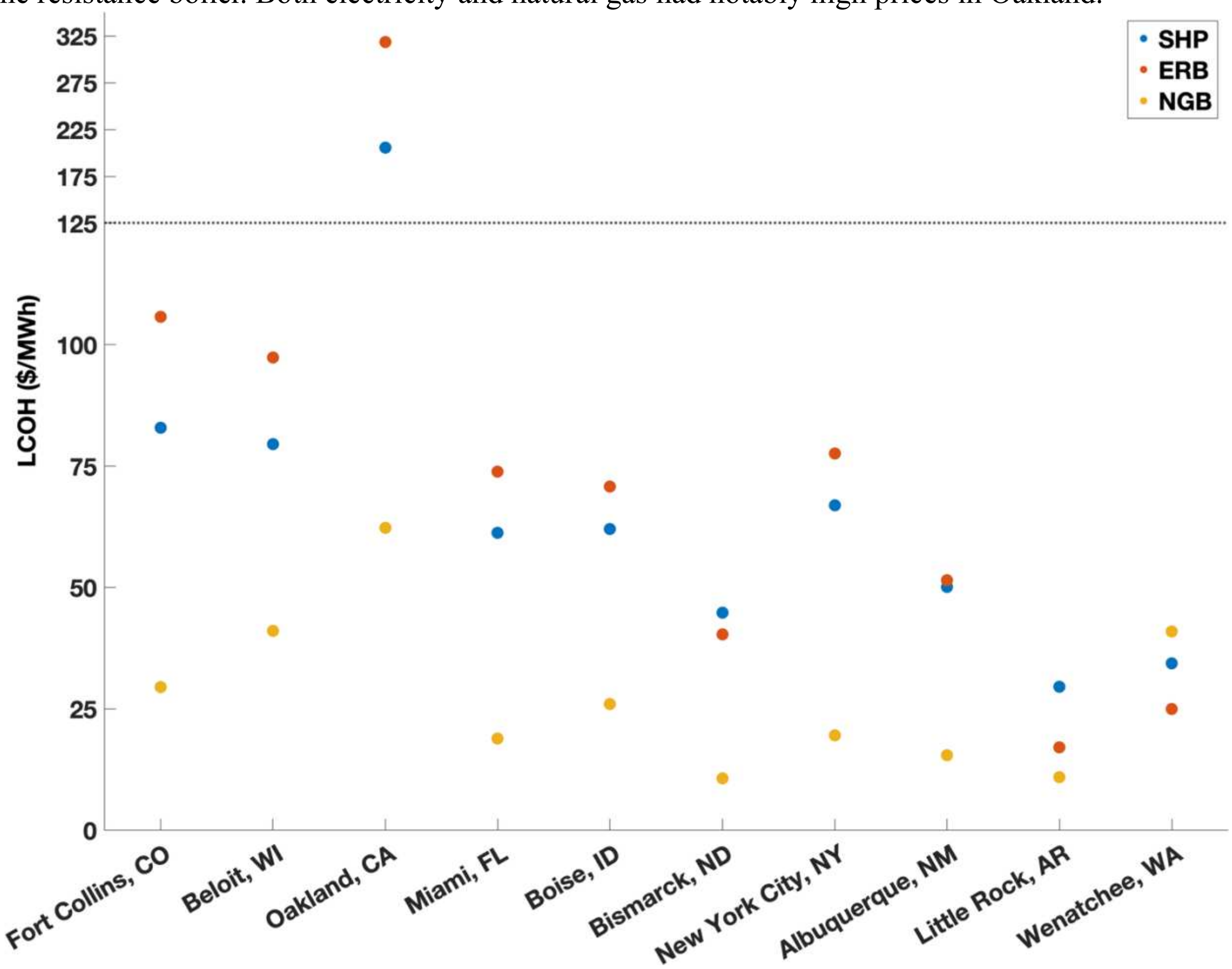

Figure 9: Levelized cost of heat for each technology using utility rate structures

Similar results were produced using renewable generation technologies for the electrically-driven systems and renewable natural gas for the natural gas boiler. As the price difference for the renewable technologies is modeled as an increased energy charge, this resulted in a shift of the LCoH for each technology, as shown in Figure 10 (where rNGB indicates the renewable natural gas boiler). When compared to the nonrenewable LCoH, the general trends by location are therefore similar. However, the natural gas boiler shifted to be the most expensive technology, except for at the two locations (Fort Collins and Oakland) where electricity prices were highest. The cost of the resistance boiler shifted to being more expensive than the heat

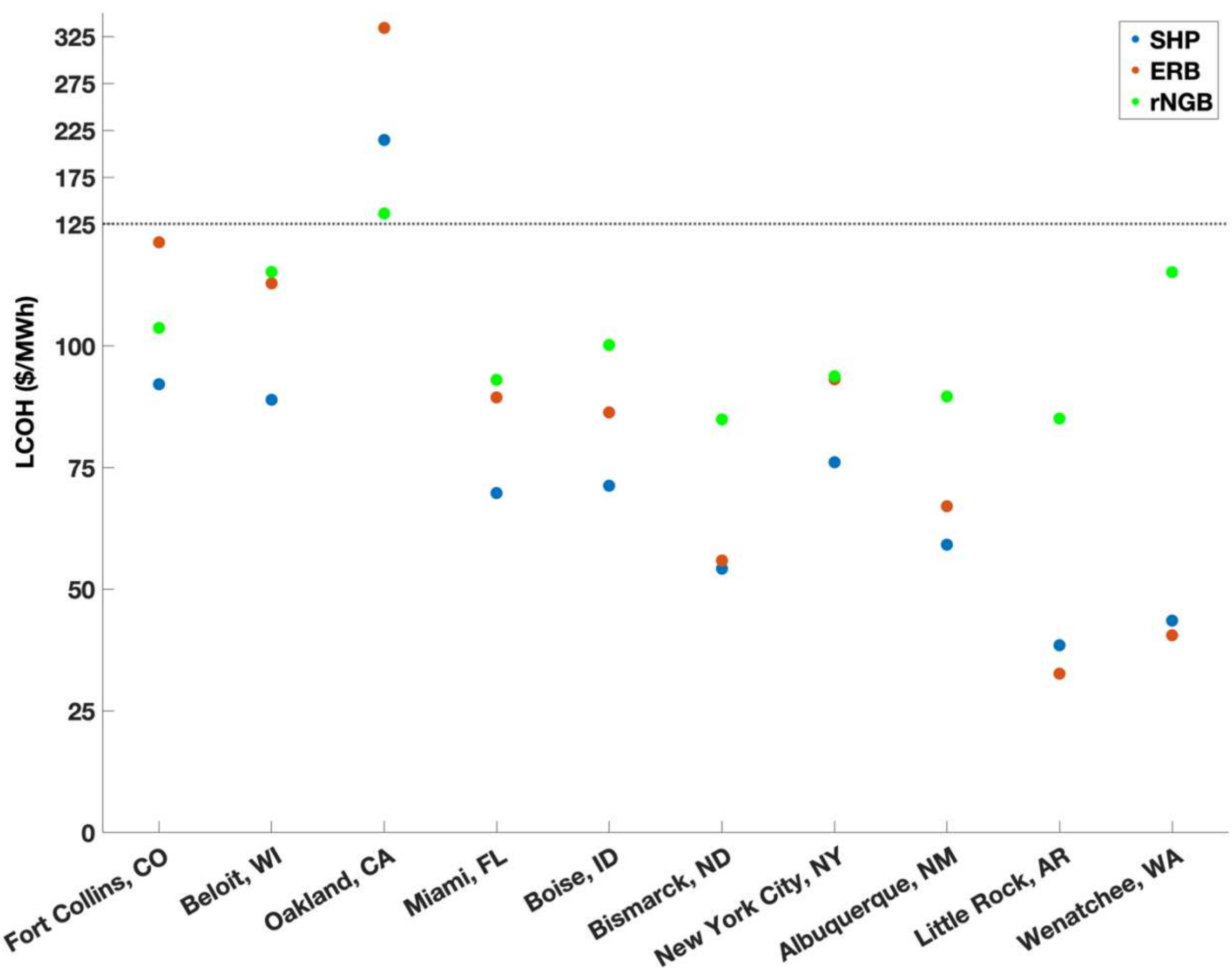

Figure 10: Levelized cost of heat for each technology using utility rate structures and renewable energy charges

pump at the Bismark location. As a result, the heat pump was only the most expensive of the electrified technologies in Little Rock and Wenatchee.

For nonrenewable systems, the natural gas boiler had the lowest levelized cost among the three technologies, with an average LCoH of $27.53/MWh. The heat pump had an average LCoH of $71.74/MWh, and the resistance boiler was the most expensive technology, with an average LCoH of $87.81/MWh. However, when adding in the cost of renewable electricity generation and renewable natural gas, the heat pump became the cheapest technology with an average LCoH of $80.86/MWh, followed by natural gas boilers with an average cost of $101.70/MWh, and resistance boilers with an average cost of $103.35/MWh. This indicates that natural gas boilers are generally the most attractive option for nonrenewable technologies currently due to the difference in current costs at the studied locations, but customers investing in decarbonized technology will save money by switching to heat pumping. It also shows that resistance boilers are not generally beneficial for electrified systems since the heat pumps offers efficiency gains to offset the capital increase.

4.1.1 Levelized Cost of Heat Category Breakdown

For each technology, the LCoH was broken down into three main categories: the capital costs, the fuel costs, and the operation & maintenance costs. The contribution of each component to the total LCoH was calculated to determine how different cost aspects influenced the total cost. Figure 11, Figure 12, and Figure 13 show the cost breakdowns of the heat pump, resistance boiler, and natural gas boiler, respectively. For each technology, the cost of electricity or natural gas was generally found to be the primary contributor to the total price. In addition, fuel was the only contributor that was variable based on location, due to both the cost of fuel from localized rate structures, and, in the heat pump case, the weather dependence based on localized data. This breakdown shows that the fuel costs examined in this study drive the difference in total LCoH, meaning the current snapshot of studied utility rates causes high variation in competitiveness between systems. This means that changing price trends, a carbon tax, or alternative solutions such as renewable energy create scenarios where heat pumps are more competitive with natural gas boilers, especially as interest in decarbonization grows in industry.

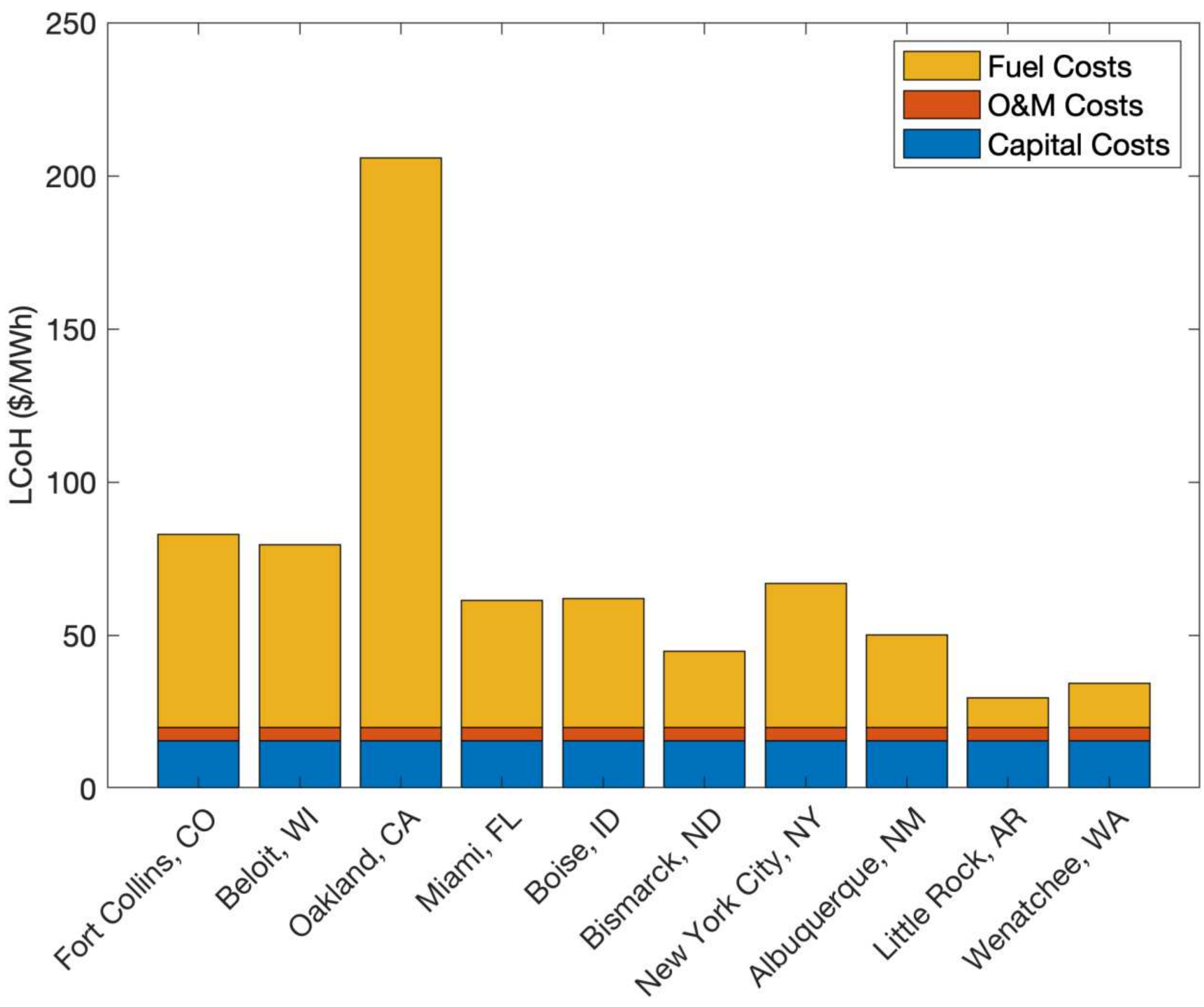

Figure 11: LCoH breakdown of the heat pump without renewable energy charges

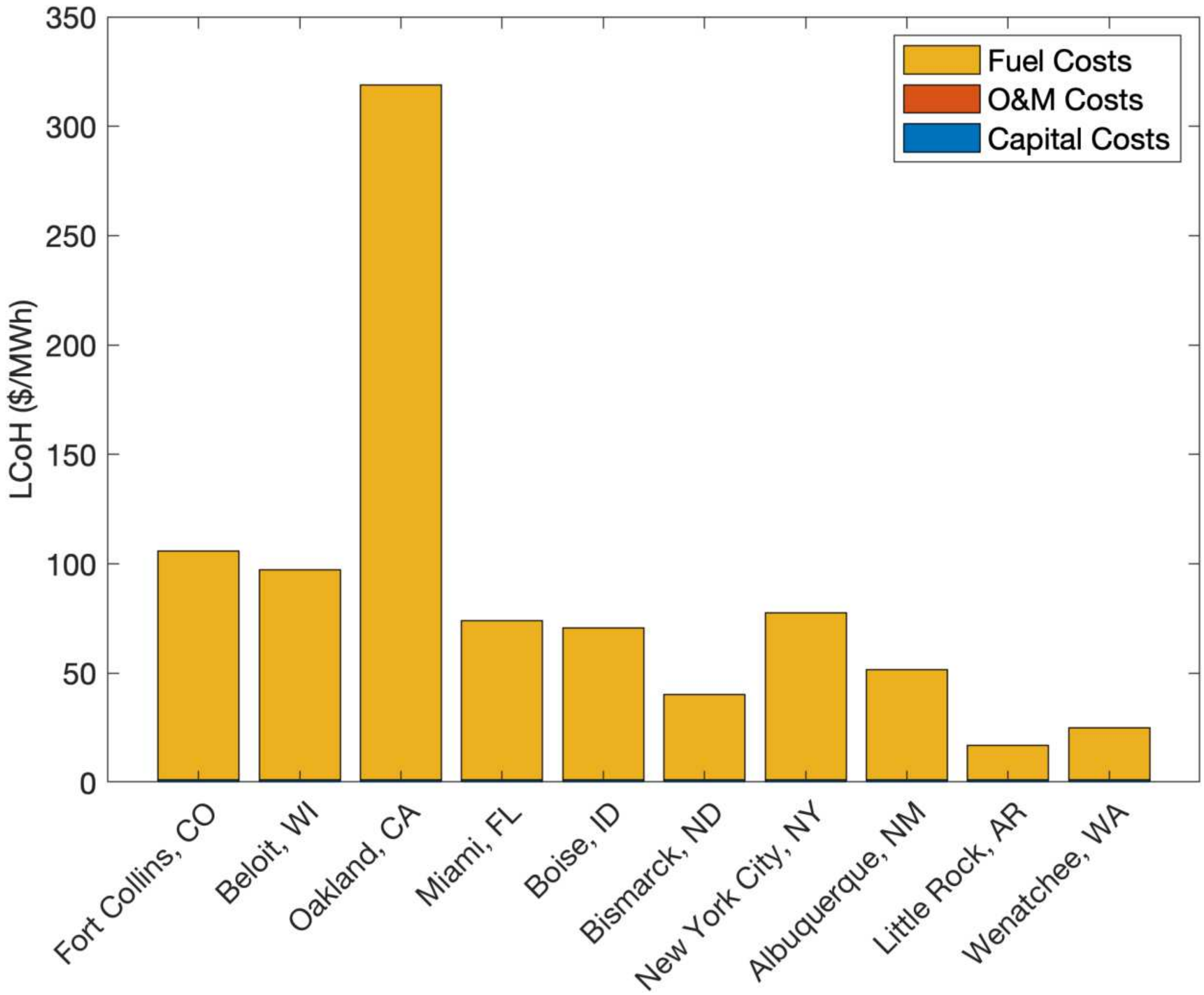

Figure 12: LCoH breakdown of the resistance boiler without renewable energy charges

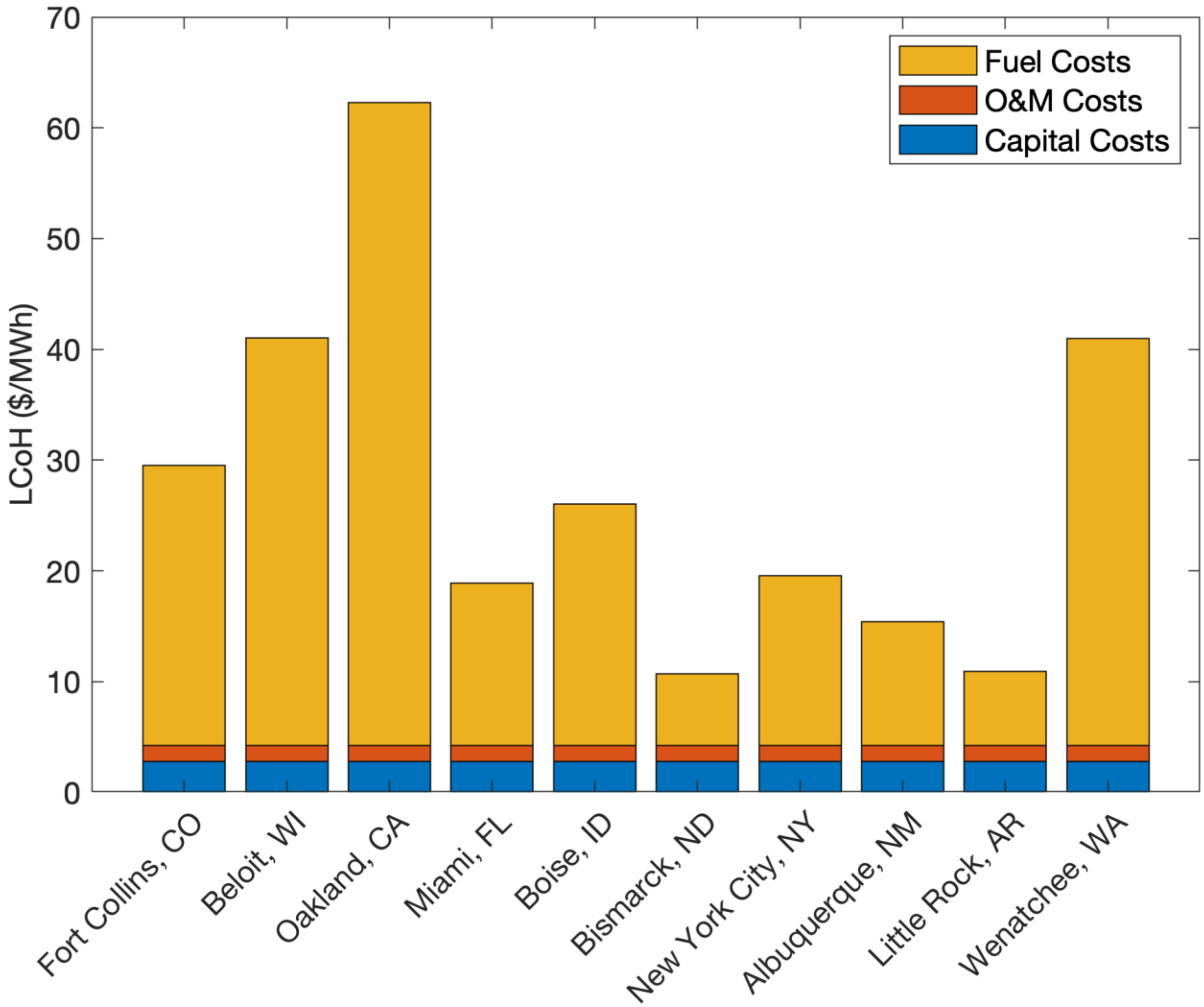

Figure 13: LCoH breakdown of the natural gas boiler without renewable energy charges

To further investigate the fuel cost, a breakdown of the components of the utility structures was assessed, calculated as the year one charges for the fuel cost shown in Figure 14, Figure 15, and Figure 16. These components include the fixed charge, the charge per unit energy, and the demand charge. This does not include charges that were not broken down into hourly rates (such as the basic charge in Boise). For natural gas, each cost was primarily driven by the energy charge. For electricity, it was found that the energy charge was the higher contributor for some locations, whereas others were driven by demand charges.

An overlaid scatterplot of the state-averaged energy prices is included in Figure 14, Figure 15, and Figure 16. As mentioned in the literature review, many heat pump TEAs consider an average energy charge by location. A state-level average energy price was identified and the year one charges were recalculated with this price. It was found that the state-averaged prices tend to have noticeably higher costs than when using utility rate structures. While some of this can be attributed to the aggregation of costs leading to scale mismatches in the average price structure used, the discrepancy highlights the importance of using specific charges over state-

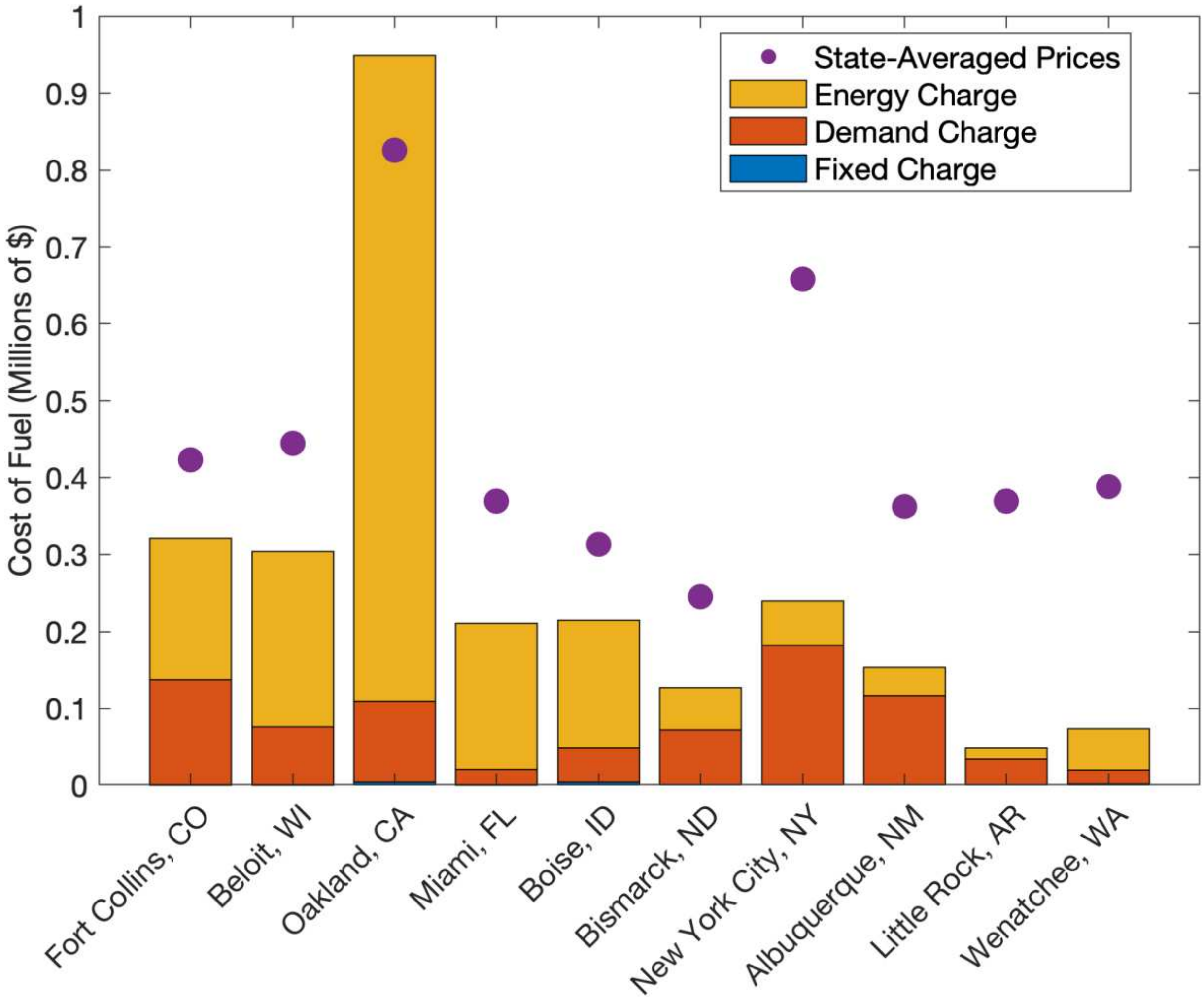

Figure 14: Year 1 fuel cost breakdown of the heat pump with utility rate structures and state-averaged energy prices without renewable energy charges

averaged data to predict costs. The average year one cost of fuel using utility rate structures was $264,000 for the heat pump, $442,000 for the resistance boiler, and $119,000 for the natural gas boiler. When using the state-averaged pricing data instead, the results were $440,000 for the heat pump, $751,000 for the resistance boiler, and $224,000 for the natural gas boiler.

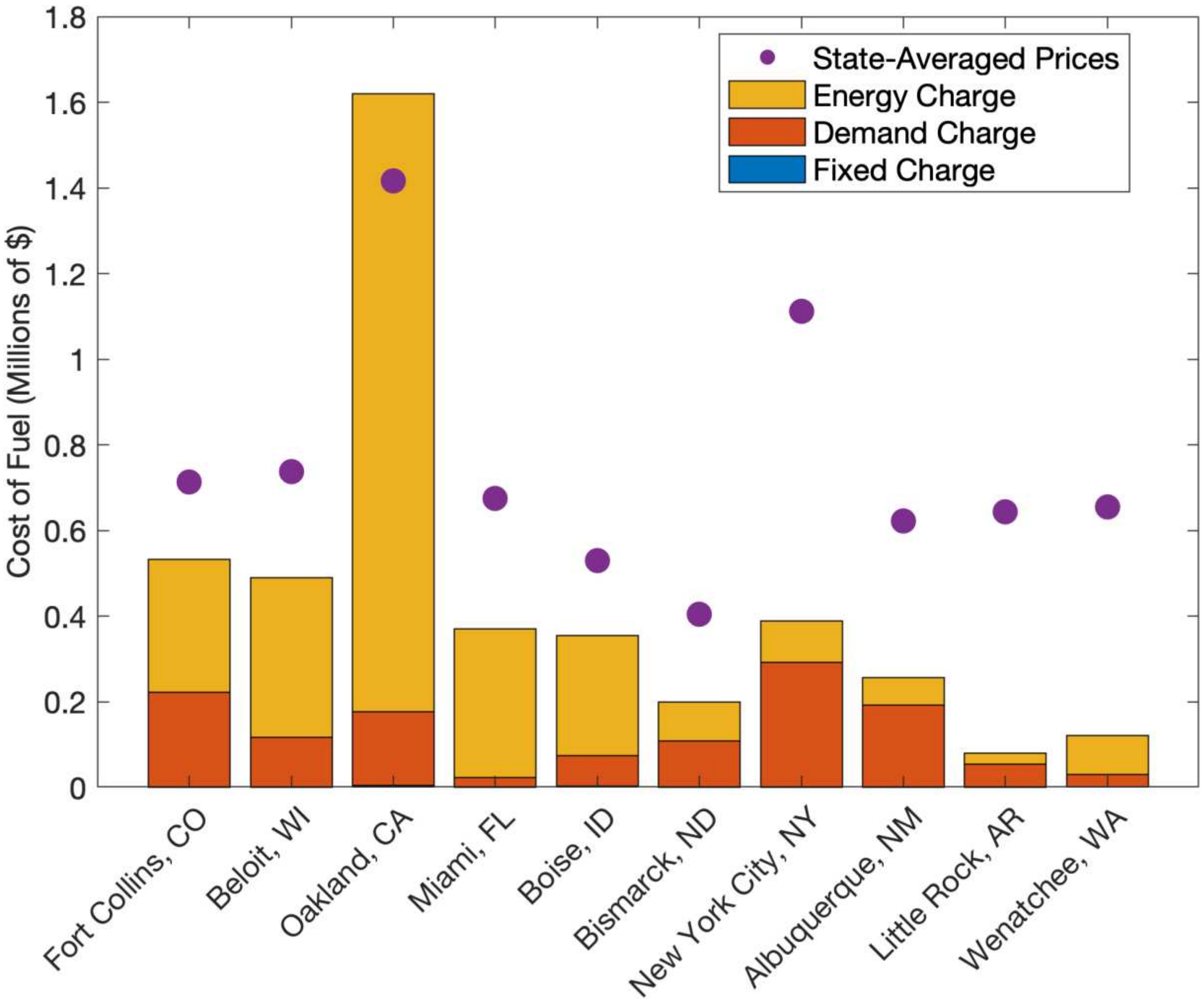

Figure 15: Year 1 fuel cost breakdown of the resistance boiler with utility rate structures and state-averaged energy prices without renewable energy charges

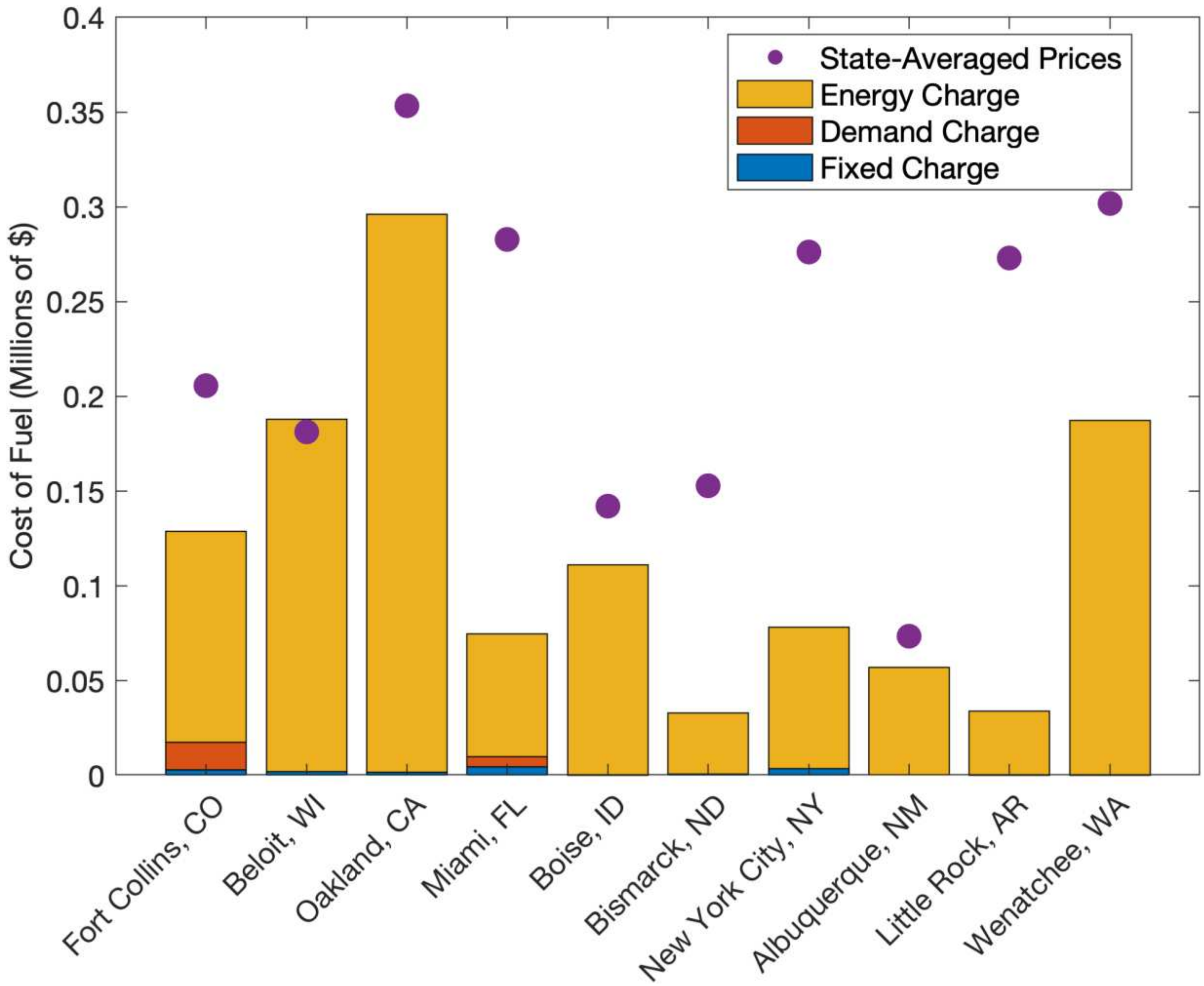

Figure 16: Year 1 fuel cost breakdown of the natural gas boiler with utility rate structures and state-averaged energy prices without renewable energy charges

Due to the difference in the component breakdown of electricity charges by location, different solutions are possible for cost reduction. Strategies such as fuel switching could have varying levels of cost benefit depending on whether energy or demand charges dominate cost. If time-of-use energy charges are high, optimizing fuel consumption with fuel switching could reduce operational cost. While it is difficult to avoid the demand charge altogether, some utilities incentivize avoiding operation during hours where the utility has the highest customer demand. Minimizing system runtime during these hours could reduce operational costs where demand charges are high.

4.2 Emissions

The carbon intensity of each technology was calculated based on fixed emissions data and varying intensity of the electricity grid. Across the United States, a variety of grid intensities exist due to the difference in energy resources used in the electricity generation process. As shown in Figure 17, the heat pump and resistance boiler have high sensitivity to the intensity of the grid. The intercept at zero grid intensity is slightly positive for each of these technologies due to the manufacturing emissions, as well as the refrigerant leakage associated with the heat pump. However, on the scale of the total intensity, these play a much smaller factor in total emissions.

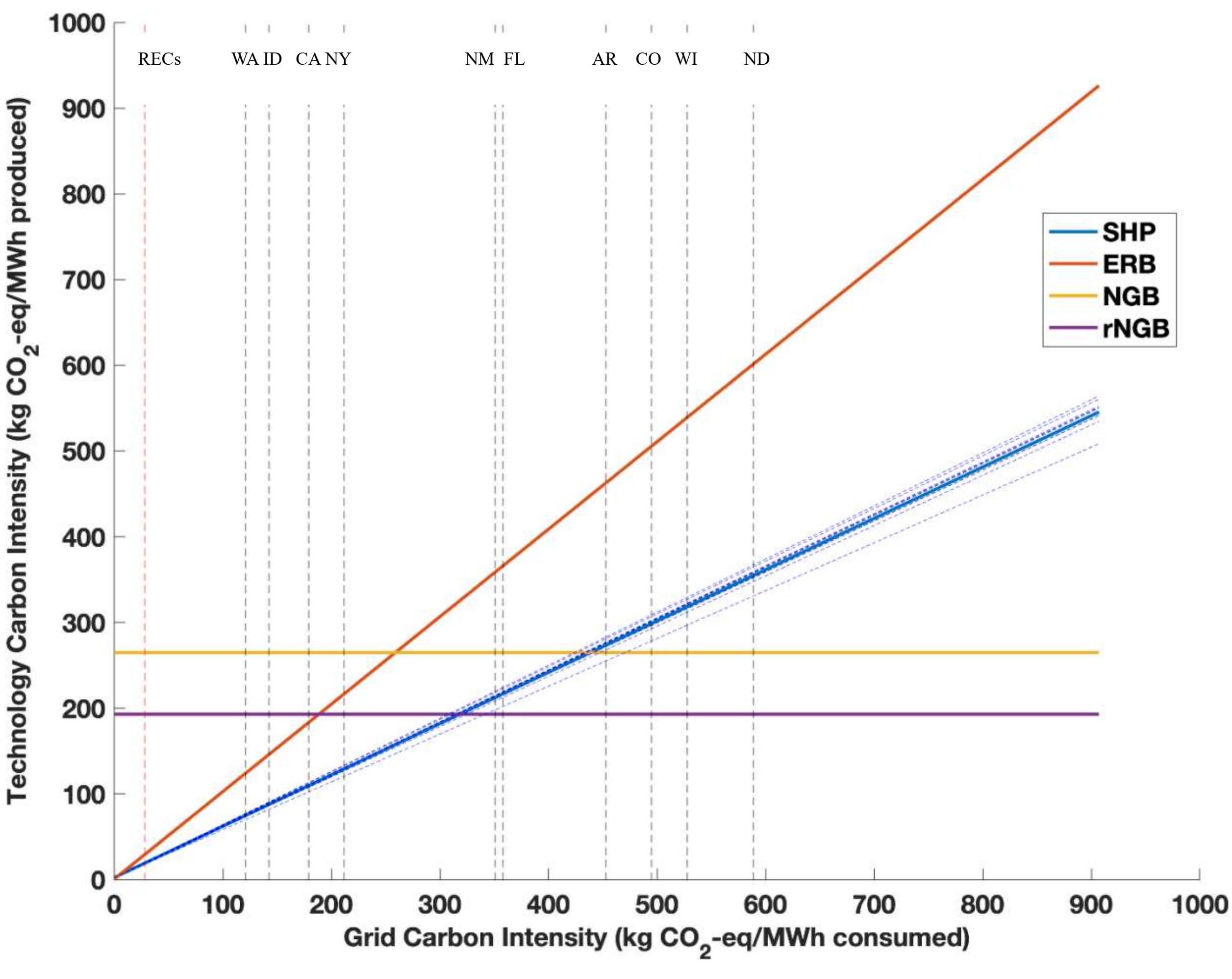

Figure 17: Carbon intensity of each technology across various grid intensities, with studied states and RECs as a reference. Dotted lines represent location-specific-weather COPs

Figure 17 includes the grid intensity references for each studied location, and for a grid from solely RECs generation (50-50 blend of wind and solar). In states that have a higher portion of coal usage for electricity generation, the electrically-driven systems have a higher intensity than the natural gas boiler. However, cleaner grids offer lower intensity than even the renewable natural gas boiler, and the RECs reference line highlights the significant drop-off in emissions for a decarbonized grid.

Since the COP of the heat pump is location-specific due to weather conditions, the total energy consumed varied slightly across the US. Each dotted blue line represents the technology intensity based on the COP of the studied locations, and the solid blue line is based on the average COP of all locations examined. Thus, the current carbon intensity of the heat pump occurs at the intersection of the dotted blue and black lines for a given location. However, as the makeup of electricity generation is expected to change as electricity providers look for cleaner and cheaper solutions, the entire range of grid intensity is critical in the consideration of the decarbonization potential of heat pumps. The results from the carbon intensity plot show that heat pumps have lower carbon intensities than electric resistance boilers, which is due to the increased efficiency of the system. In some locations, heat pumps are also less carbon-intense than natural gas boilers, but other studied locations showed a higher carbon intensity. This is due to the makeup of generation technologies of the grid, meaning that currently, heat pumps are not strictly better at reducing total emissions for steam generation. However, the results show that even without a shift to fully renewable generation, modern grids can supply reduced-carbon steam in heat pump applications, meaning shorter-term grid changes are plausible while fully renewable technologies are developed.

Based on the literature values identified for the natural gas boiler, it was found that renewable natural gas did not have a significant reduction in total emissions compared to the non-renewable baseline. While different pathways for renewable natural gas were identified with various carbon intensities, the real availability reported in the US indicated less scalability compared to decarbonizing the grid. This means that, while renewable natural gas can provide an emissions reduction, grid decarbonization could have a higher impact on reducing emissions for industrial heat.

To measure the total emissions reduction potential of each technology, the natural gas boiler was used as a reference point for total CO_2 emissions. Figure 18 shows the LCA-lifetime total CO_2 abated for each system. The black line represents the reference case of the natural gas boiler, with positive values indicating a quantity (in metric tons) of CO_2 reduction, and negative values indicating a relative increase in emissions.

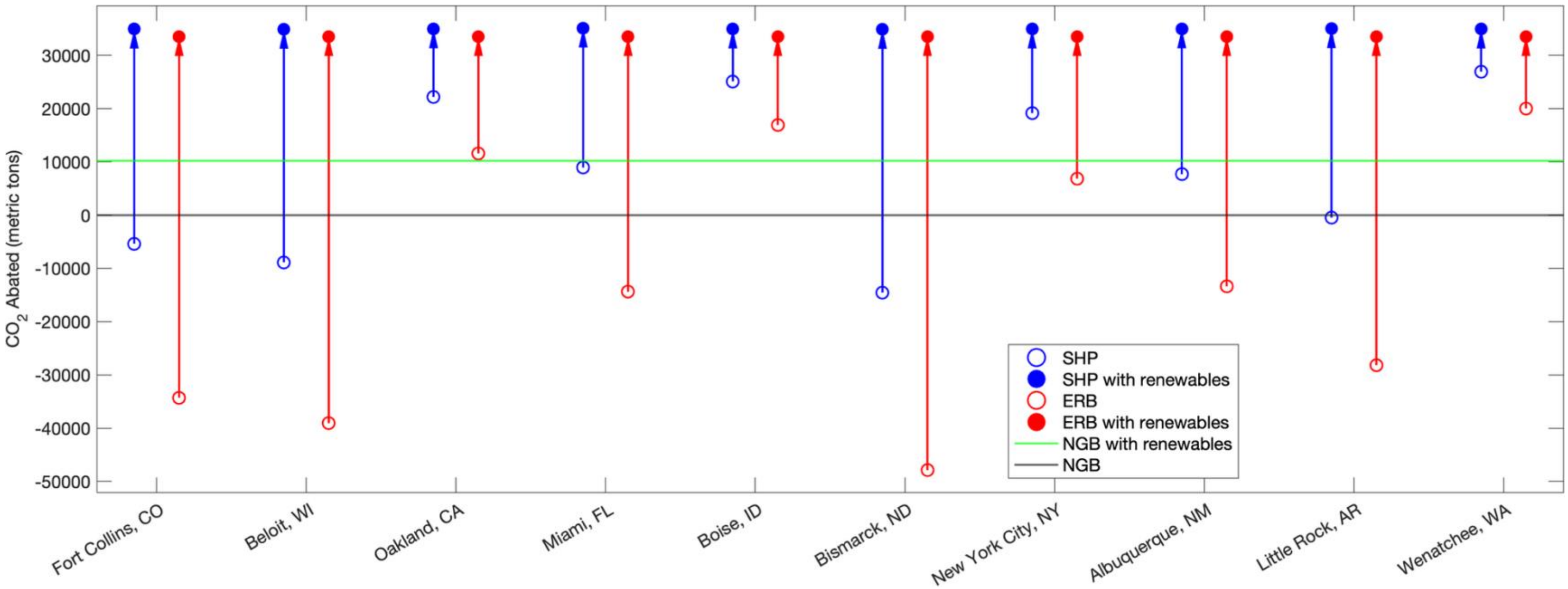

Figure 18: Total CO_2 abated for each technology, with a natural gas boiler as a reference

Each hollow circle represents the CO_2 abated based on the real grid intensity from the reference lines show in Figure 17. Due to the variation in grid intensity, as well as the COP variation for the heat pump, there was a difference in the total CO_2 abated across locations, with an average value of about 8,000 lifetime metric tons abated for the heat pump. There was an increase in total CO_2 from the resistance boiler, with an average value of -12,000 lifetime metric tons gained.

The filled circles represent the renewable electrically-driven technologies. Across each location, the renewable natural gas boiler has a constant CO_2 reduction because natural gas carbon intensity is not location-dependent. When comparing the renewable electric technologies, the heat pump still had the largest total CO_2 abated, with an average value of 35,000 lifetime metric tons abated. The resistance boiler and natural gas boilers both had constant abatement levels across all locations when using renewable technologies, with values of 33,500 lifetime metric tons abated and 10,000 lifetime metric tons abated, respectively.

The total abatement results mean that currently, on average, heat pumps stand to decrease emissions compared to natural gas boilers, as compared to resistance boilers which increase the total emissions. In general, this means that heat pumps are a good solution to decarbonize steam generation in industry. As the grid trends towards renewable resources, both the heat pump and resistance boiler stand to reduce emissions compared to the baseline natural gas boiler and renewable natural gas boiler. Due to the efficiency gains for heat pumping, however, heat pumps offer the greatest carbon reduction of the technologies at each location, offering a better pathway to decarbonization.

4.3 Cost of Carbon Abatement

The primary use of the LCA is to motivate an additional economic comparison, the cost per unit of CO_2 abated. While the total LCoH of each technology can be used for determination of the cheapest solution available to a customer, a cost of abatement incorporates the potential decarbonization of alternative solutions. As decarbonizing industrial heat is an attractive benefit of heat pump technologies, combining the economics with the emissions of potential solutions provides another method of comparison between systems.

Using the natural gas boiler again as a baseline for which to compare the renewable technologies against, it was found that the heat pump had the lowest cost of CO_2 abatement at each location, with a value of nearly \$87/metric ton CO_2-eq. The resistance boiler had a cost of \$129/metric ton CO_2-eq, and the natural gas boiler had a cost of \$412/metric ton CO_2-eq, with the trends by location shown in Figure 19. Notable locations include Oakland, where high electricity prices resulted in a higher cost of abatement for the resistance boiler than the natural gas boiler, and Little Rock and Wenatchee, where low electricity prices resulted in a lower cost of abatement for the resistance boiler than that of the heat pump.

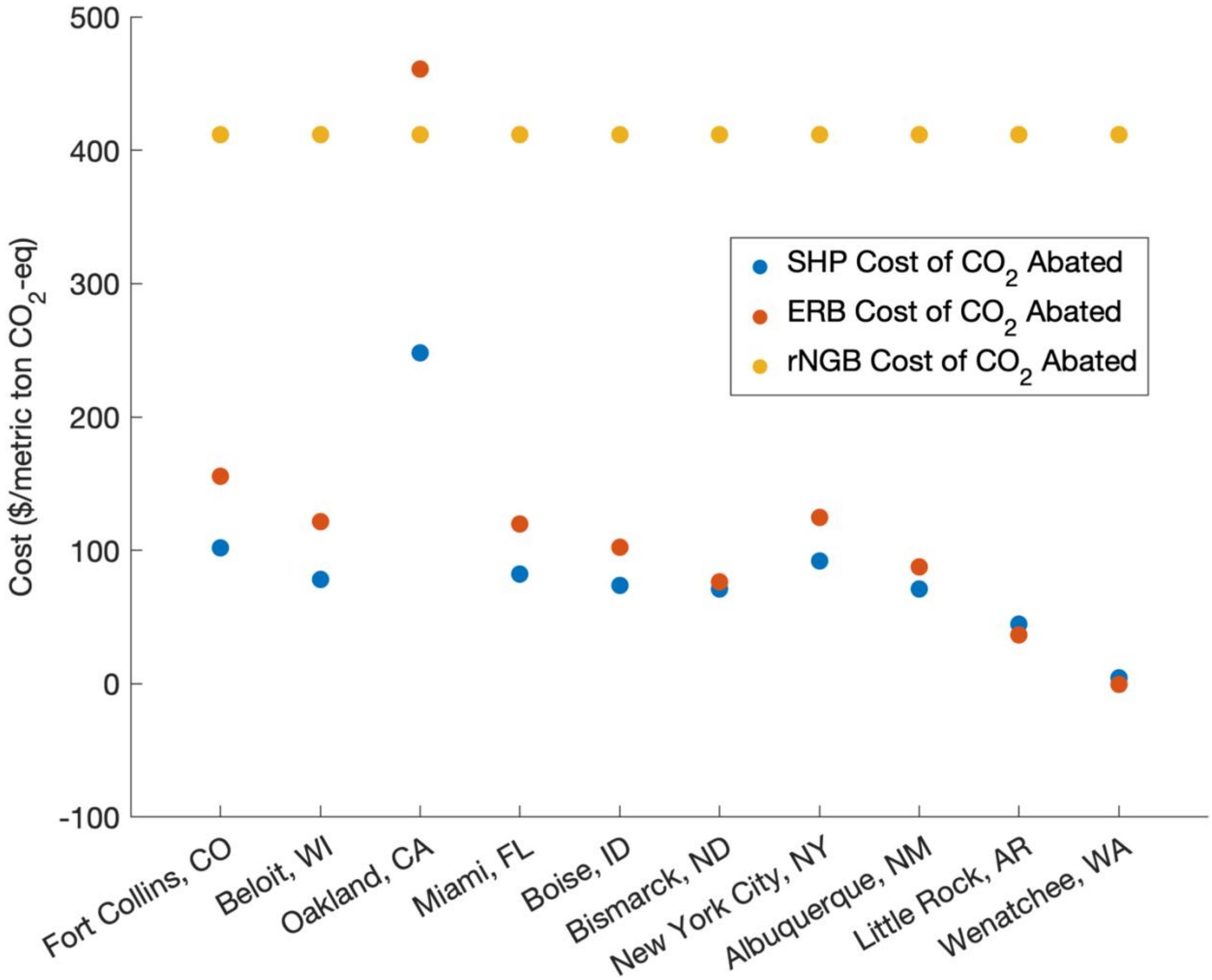

Figure 19: Cost of CO_2 abated for each technology, with a natural gas boiler as a reference

The results of the cost of CO_2 abated show that heat pumping offers the most economically efficient solution to the decarbonization of steam. While the total cost of the system was found to be larger than the natural gas boiler in the LCoH study, the study on total emissions showed the strong decarbonization case for heat pumping. Combining these metrics, customers aiming to decarbonize their current natural gas boiler will pay the least per unit of CO_2 abated by switching to a heat pump. While extremely low electricity prices can change this, other locations show a significant cost savings in heat pumping versus resistance boilers.

4.4 Sensitivity Analyses

A further understanding of the influence of inputs on the LCoH was explored in a sensitivity analysis. For each analysis conducted, a heat map for a two-variable sensitivity was created, with values being represented as a difference in LCoH between the heat pump and a chosen baseline technology. Each plot is on a red-blue color scale, where blue indicates a negative LCoH difference (meaning the heat pump is cheaper than the baseline) and red indicates the opposite. At the breakeven region, a black curve is added for readability. The center of each plot represents the current data for the respective plots in the LCoH results previously presented.

Figure 20 shows the heat maps for each location comparing the LCoH of the heat pump and natural gas boiler when simultaneously scaling the total cost of electricity and natural gas. As was seen in the raw LCoH numbers for each technology, the natural gas boiler is cheaper than the heat pump across nine locations for current pricing. Even at the extremes of these plots, there is not much room for competition due to natural gas being much cheaper than electricity. Volatility in energy prices and rate structures mean there is potential for customers to save money in the future, but generally, current price structures do not indicate a competitive advantage from economics alone. Therefore, renewable energy rates, a carbon tax, or fuel price changes would be necessary to create opportunity for heat pumps to be economically viable.

The same comparison was made to the renewable natural gas boiler in Figure 21. Here, the breakeven line is shifted closer to the nominal LCoH difference. For customers interested in decarbonizing heat, this shows that heat pumping is competitive economically. In addition, it means that rather than paying to make natural gas renewable, policies such as a carbon tax could also incentivize heat pumping. Assuming this equivalent cost, the increase in emissions reduction from heat pumping compared to renewable natural gas encourages further heat pump adoption.

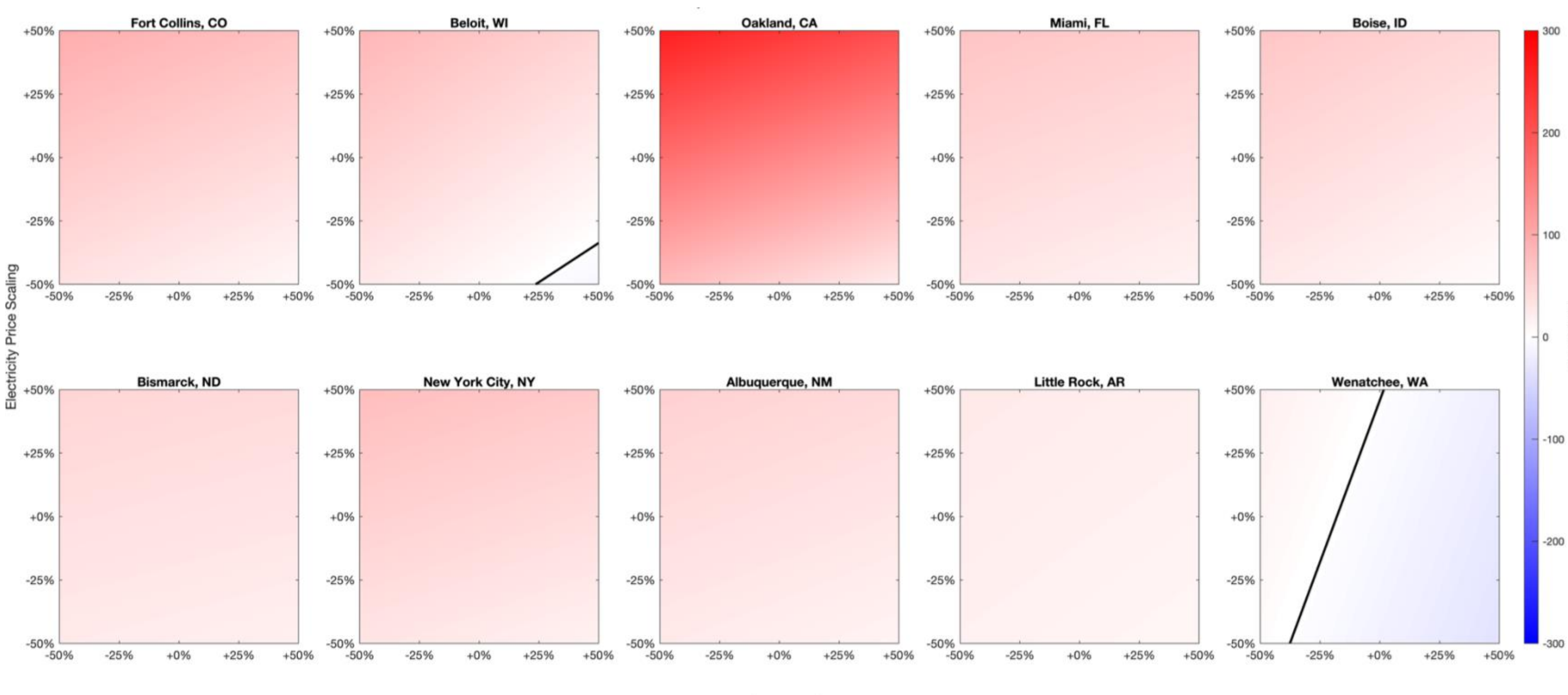

Figure 20: SHP versus NGB LCoH difference sensitivity analysis; electricity and natural gas simultaneous scaling

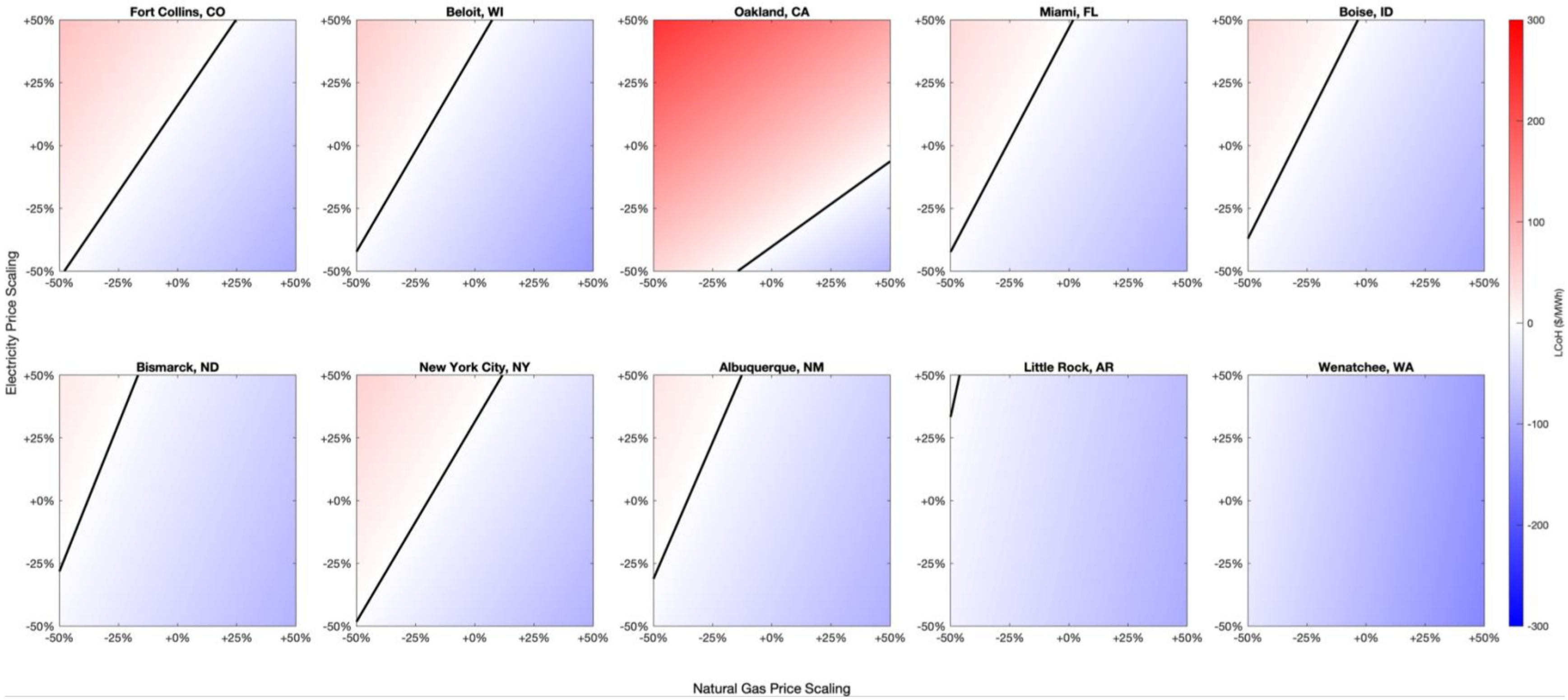

Figure 21: SHP versus rNGB LCoH difference sensitivity analysis; electricity and natural gas simultaneous scaling with renewable energy charges

Figure 22 shows the sensitivity analysis comparing the heat pump with the electric resistance boiler. As the price of natural gas is inconsequential in this comparison, the COP of the heat pump was varied on the x-axis. This plot showed a non-linear relationship in the scaling due to the smaller benefit of having higher performance in heat pumping at lower electricity prices. When electricity costs are lower, the COP advantage of heat pumps saves less money. As the CapEx makes up a larger portion of the total cost in this case, there is a larger range where resistance boilers are cheaper. In practice, notably, the COP of the heat pump is drastically varied only by a redesign of the system. The temperature variation does drive changes in the COP, but achieving a higher percent of a fixed Carnot COP is possible by redesigning components of the system. Therefore, the breakeven line is better interpreted as a reference for measuring potential concessions in the COP of future heat pump designs where taking a performance hit to reduce capital costs can still allow heat pumps to be competitive with resistance boilers.

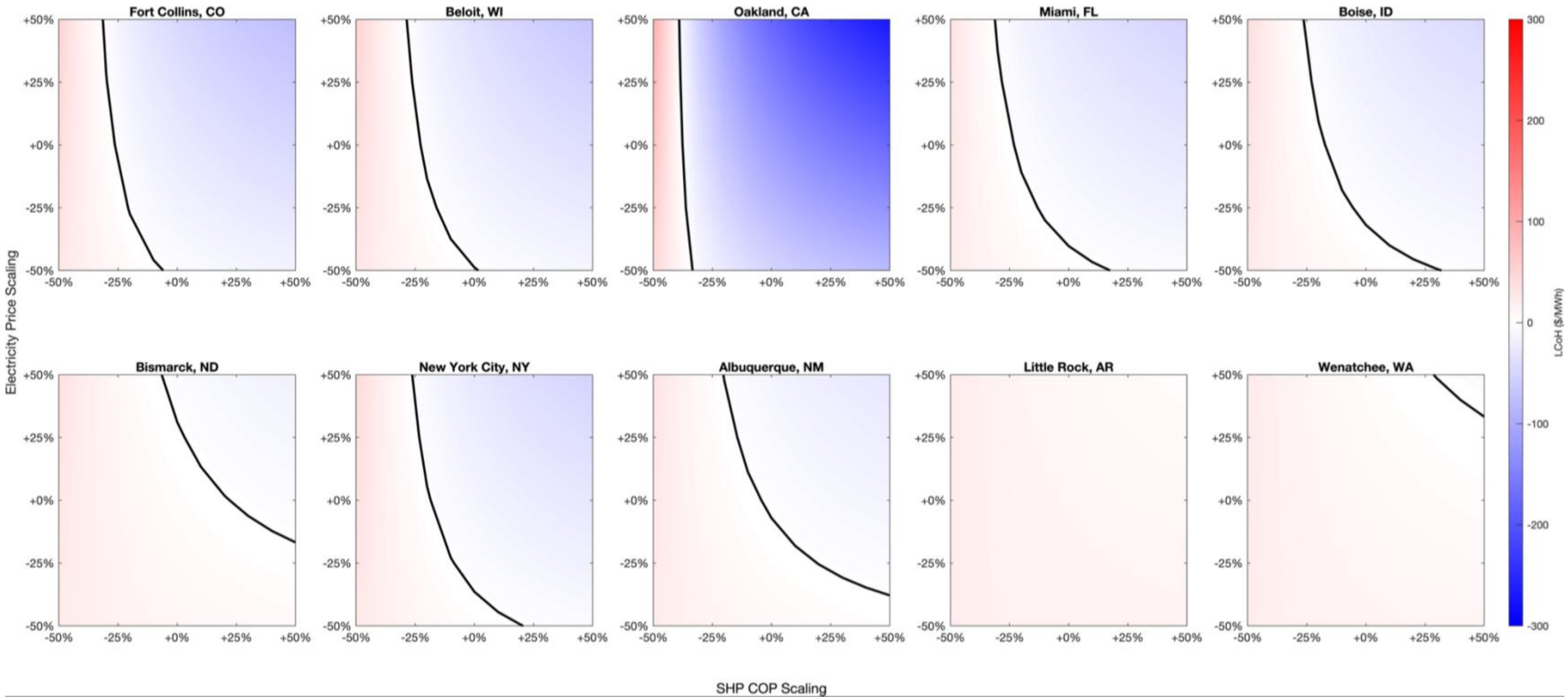

Figure 22: SHP versus ERB LCoH difference sensitivity analysis; electricity and heat pump COP simultaneous scaling

The next sensitivity analysis conducted was a comparison of the LCoH of the heat pump and resistance boiler when scaling the CapEx of the heat pump on the x-axis, as shown in Figure 23. For Oakland, where electricity prices are high, no breakeven line existed in the entire sensitivity range, indicating the heat pump is a much cheaper solution than the resistance boiler at this location. For many other locations, the resistance boiler was only competitive with the heat pump in the extremes of the study, apart from Bismark, Little Rock, and Wenatchee, where it was better in the original case, and Albuquerque, where the breakeven point was close to the center. This means that generally, the CapEx does not significantly affect the heat pump competitiveness except for in locations where fuel pricing already means the LCoH difference is closer.

Figure 24 is the final sensitivity analysis, where the heat pump CapEx remains on the x-axis and the heat load is plotted on the y-axis. For the heat load sensitivity, the same nominal capacity was used for the determination of CapEx costs, and the heat demand is assumed to only decrease from this nominal capacity so that total system sizing does not change. Because the heat pump is more competitive in situations where OpEx is high and CapEx is low, scaling down the heat load results in better relative costs for the resistance boiler. However, for many locations there was a large area in the sensitivity plots where the heat pump still outperformed the resistance boiler as less optimal performance and cost factors were applied.

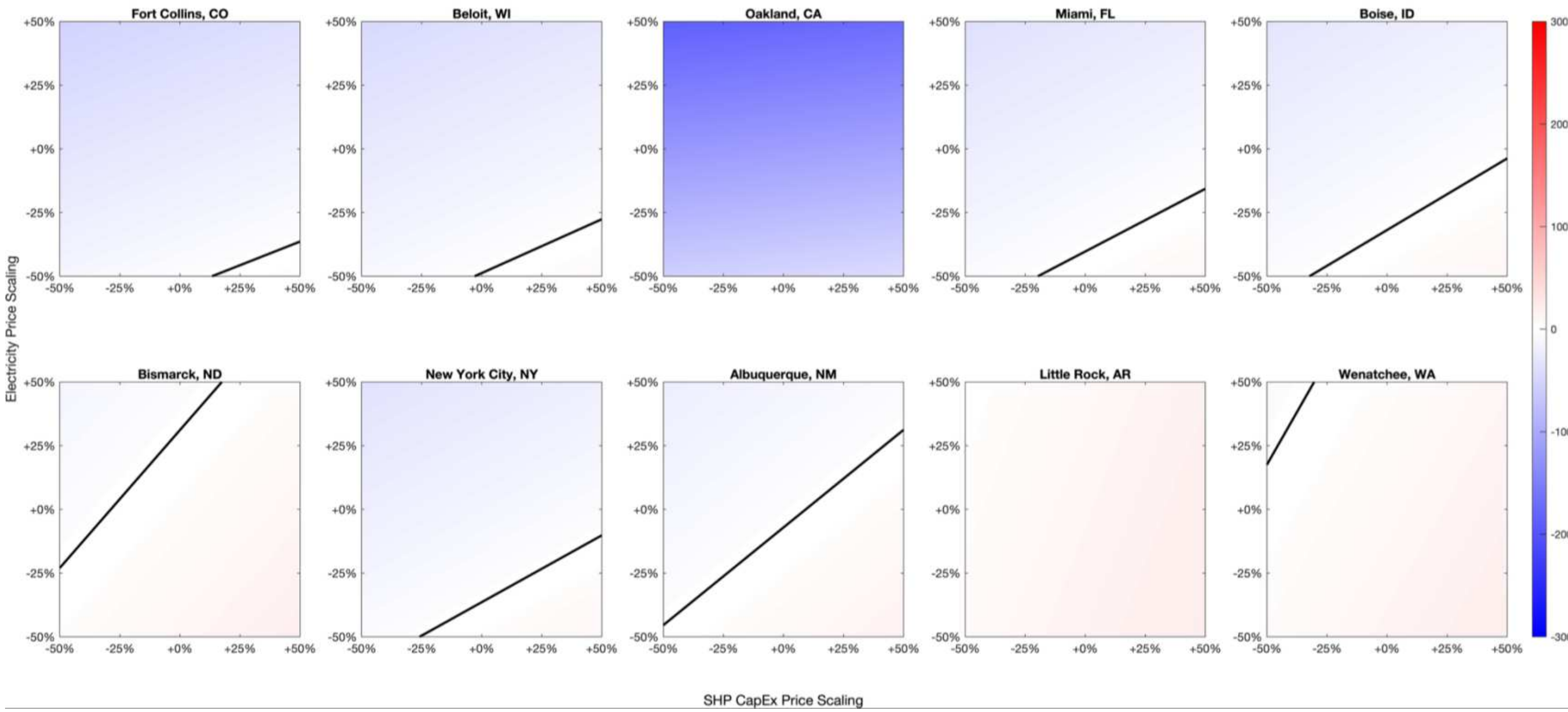

Figure 23: SHP versus ERB LCoH difference sensitivity analysis; electricity and heat pump CapEx simultaneous scaling

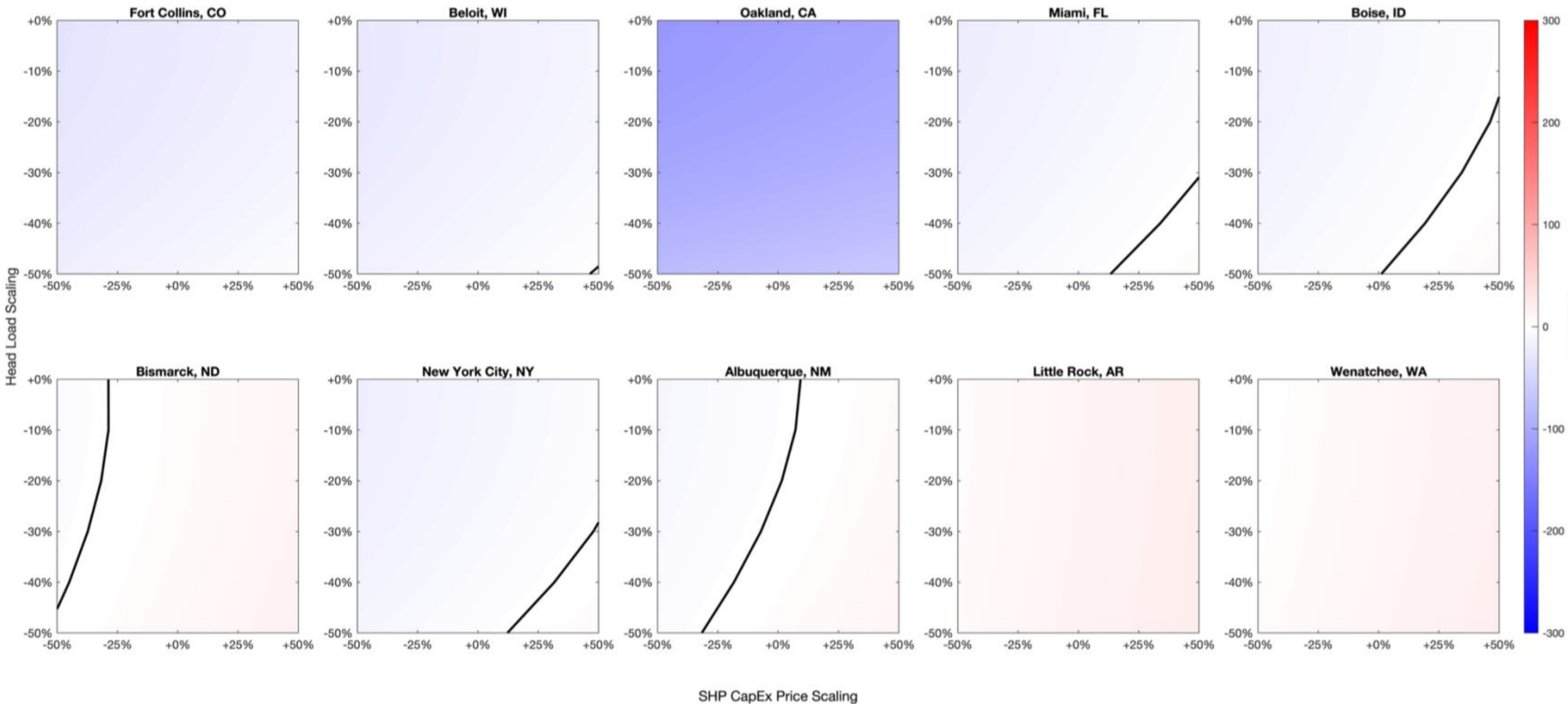

Figure 24: SHP versus ERB LCoH difference sensitivity analysis; heat load and heat pump CapEx simultaneous scaling

The sensitivity analyses all show that the difference in the technology costs is highly volatile to components such as the price of fuel and the COP and CapEx of the heat pump. The significantly lower cost of natural gas in the US means that the baseline natural gas boiler is cheaper than heat pumping, but when renewable costs are included, heat pumping shifts to being a better option, albeit close to the breakeven line in many locations. When comparing to the resistance boiler, the heat pump parameters have a large influence on how much savings potential exists at each location. However, there is a large region in many location graphs where COP could decrease or CapEx could increase, and the heat pump would still be cheaper than the resistance boiler. When scaling down the heat load for the electrified technologies, there was still competitive regions for heat pumping. These results mean that larger changes would be necessary for heat pumps to be cost competitive with natural gas boilers, but that heat pumps are generally cheaper than resistance boilers even in a range of performance and cost adjustments.

4.5 Results Summary

Three key findings were identified in this work from a cost analysis, an emissions analysis, and a combined metric. The first key finding was the total LCoH of each technology. The results indicate that natural gas boilers are still generally the cheapest solution in the United States, primarily driven by the cheaper cost of natural gas as compared to electricity, for the studied locations on the current market. However, the efficiency gains of heat pumping offset the increase in capital compared to electric resistance boilers, meaning that heat pumping is a more attractive electrified alternative. In locations where electricity is cheap, the electrified technologies stand to be economically competitive with natural gas, but efficiency gains from heat pumping no longer outweigh the capital investment, meaning resistance boilers become the cheapest option in these locations. When shifting to renewable natural gas and generation technologies, the electric resistance boiler is the most expensive of the technologies. The increase in cost for renewable natural gas, however, makes natural gas boilers more expensive than heat pumps. This means that, as renewable alternatives become more prevalent due to decarbonization efforts, heat pumping is an attractive option for steam generation economically.

The second key finding was the total emissions for cradle-to-gate plus use phase (excluding disposal). It was found that emissions for the electrically-driven technologies were highly dependent on grid intensity. In states that employ cleaner generation practices, heat pumping offers the lowest carbon intensity of the technologies, making it the most attractive solution in those locations. However, grids generating electricity largely from coal cause heat pumps and resistance boilers to increase emissions compared to the natural gas boiler, motivating further decarbonization of electricity. When factoring in fully renewable fuel, heat pumping is the best option for emissions reduction.

The electricity cost and grid intensity have been demonstrated to greatly influence whether heat pumps or natural gas boilers are the better of two steam generation technologies, motivating further decarbonization and cost reduction of electricity (or a potential carbon tax). In addition, the conflicting goals of cost and emissions reduction mean that customers with different interests may select a different solution in the same location. The third key finding combines these metrics as a cost of CO_2 abatement. It was found that, for customers interested in decarbonizing steam, heat pumps offer the most competitive cost per unit CO_2 abated. This is due to heat pumps both being the cheapest of the renewable technologies and offering the greatest emissions reduction. While the current natural gas boiler is cheaper typically, and at some locations has lower emissions, developments and greater interest in decarbonization motivate the adoption of heat pumping in modern and future steam generation applications.

CHAPTER 5: CONCLUSIONS AND RECOMMENDATIONS

A techno-economic analysis and life cycle assessment was conducted for a high-temperature, ambient air-sourced industrial heat pump, along with a parallel analysis for a natural gas boiler and an electric resistance boiler. Ten separate locations were examined, where the local weather was accounted for in the heat pump performance, and specific utility rate structures from each city were selected to model real customer payments in operation costs over the system lifetime. It was found that the natural gas boiler was the cheapest (on average) of the three options at producing a nominal 650 kW of heat over a 25-year period, with the heat pump being the next cheapest and the resistance boiler being the most expensive. However, the natural gas boiler also had higher emissions in some locations, depending on the generation technologies employed in that region. As the grid trends towards decarbonization, the emissions of the electrically-driven technologies become smaller relative to the constant emissions of the natural gas boiler. To combat this, renewable natural gas is one solution. A life cycle assessment quantified the emissions for both the non-renewable and renewable technologies based on a solar and wind blend for electricity generation, and a weighted average of four modern renewable natural gas pathways. When considering these carbon intensities, the heat pump had greater total carbon abatement than the resistance boiler, and both had a significant reduction in CO_2-eq versus the renewable natural gas when compared to the baseline natural gas boiler. In addition, the LCoH of the heat pump was the cheapest of the options, followed by the natural gas boiler and finally the resistance boiler. Combining the two metrics, the heat pump had the lowest cost of CO_2 abated in reference to the non-renewable natural gas boiler, with the resistance boiler following and the renewable natural gas boiler being the most expensive. Overall, it was found that the resistance boiler is generally an unattractive option when compared to heat pumping. It was also found that if a customer is strictly looking at current economics, the natural gas boiler is often the optimal choice for the generation of industrial heat at the studied locations. However, for those also considering their carbon footprint, the heat pump offers a cheaper alternative, especially as the grid becomes cleaner than natural gas. This motivates the adoption of heat pumps as a pathway towards both current and future decarbonization and cost savings.

5.1 Future Work

Future work on this model and analysis could include the study of additional locations, as the selected locations were not necessarily comprehensive of the range of grid intensities in the United States, or across the world in general. Part of the incorporation of locations could include quantifying the altitude system derating for specific locations, or looking into more weather pattern influence, such as whether humidity has a significant impact on the heat pump performance. A more rigorous examination on the LCA side of the results could also be conducted, as this work was primarily focused on the TEA. This includes looking further into the breakdown of generation technologies for the grid, examining the end-of-life disposal, and other impact categories such as NO_x emissions. In addition, since grid demand is calculated for each hour based on the COP curve, an hourly grid intensity could be included to capture dynamic generation changes throughout a typical day. Additional experimental data and finer technical modeling curves from AtmosZero, as well as from literature for the baseline technologies, could be used to increase the fidelity of the thermodynamic considerations in the model.

Larger-scale future work includes development of more metrics in the model and further examination of cost components. Since the model provided a breakdown of each individual fuel cost on an hourly resolution, examining fuel switching and demand charge avoidance could identify strategies to reduce the cost of heat pumping. Avoiding high energy charges with fuel switching or high demand charges with runtime optimization dynamically by location could make the heat pump more competitive with natural gas. Building an optimization model for balancing economic and emission benefits would provide another option to customers that want to reduce emissions but can’t justify increased costs of solely heat pumping. Another larger inclusion would be quantification of the value of chilling. Something mentioned but not quantified in the literature is the co-benefit of chilling that comes from heat pumps. For the baseline systems, a cost increase for the price of an external chiller that is capacity-matched to the heat pump chilling load would be required. However, the heat pump would not increase in cost, meaning it could be more economically viable in comparison. These larger changes to the model would increase the fidelity of the results and provide a wider range of application for the study.

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