ACEP Technical Report

Kake Heat Pump Rate Analysis for Inside Passage Electric Cooperative

Shivani Mathur, Steve Colt and Michelle Wilber

February 2021

Table of Contents

Table of Figures

Table of Tables

1 Introduction

Many utilities in Alaska, and elsewhere, have been experiencing decreasing energy sales over the last decade. Decreasing kilowatt hours (kWh)s sales mean that a utility selling fewer kWh with current rate structures must raise per kWh rates to cover fixed costs, leading to customer complaints, possible cross-subsidization, and a negative feedback loop. Building efficiency measures, behind-the-meter solar photovoltaic (PV), and other behind-the-meter generation can all cause decreasing kWh sales. One possible solution to this problem is beneficial electrification. Beneficial electrification is when the end use of electricity satisfies at least one of the following without adversely affecting another: saves consumers money, benefits the environment, improves consumers' quality of life, fosters a more resilient grid. Electric vehicles (EVs) and heat pumps (HPs) are commonly explored beneficial electrification technologies.

To address these challenges the utility, Inside Passage Electric Cooperative (IPEC), and Alaska Center for Energy and Power (ACEP) at the University of Alaska Fairbanks are interested in seeking technical and economic solutions that answer the following questions for the community of Kake in Southeast Alaska: 1) What rate structures are possible in Kake to encourage beneficial electrification, with an emphasis on HPs? 2) What are the benefits and costs of theserate structures?

This report provides an overview of possible rate structures that can encourage beneficial electrification, with an emphasis on HPs, in Kake, Alaska. The document overviews the background in section 2, methodology and calculations in section 3, the net present value (NPV) analysis in section 4, and the recommendations in section 5.

2 Background

This project focuses on Kake, a Tlingit community with a fishing, logging and subsistence lifestyle. Kake is located on the northwest coast of Kupreanof Island along Keku Strait and is part of Southeast Alaska. It experiences cool summers, mild winters and heavy rain throughout the year. It receives average rainfall of 54 inches a year and 44 inches of snow, which is less than the average for southeast Alaska. Kake is not connected to other communities by road, rail or electric transmission.

IPEC is a non-profit, independent electric utility which is consumer owned. It serves over 1,300 members in the rural Southeast Alaska communities of Hoonah, Kake, Chilkat Valley, Angoon, and Klukwan. Four of these service areas are not interconnected to each other. IPEC operates diesel generating units in all four areas and purchases hydroelectric power in the Klukwan/Chilkat Valley area. In 2015, IPEC completed construction of a run-of-river hydro project on Gartina Creek near Hoonah, which supplies roughly a third of the town's electrical needs when in operation. It also owns and operates the 10-Mile hydro project near Haines. A hydro run-of-river plant with a nameplate capacity of 850 kW at Thayer Creek is in the planning stages, and would supply all of Angoon's electricity needs.

A 500 kW run-of-river hydroelectric plant at Gunnuk Creek, serving the community of Kake, is in its final stages of completion. Kake currently uses four diesel generators rated at 450 kW each to meet its current electricity needs.[1] The new project would produce approximately 1,600 MWh annually, or over half of Kake's current average annual electric load requirements.[2]

IPEC operates on a not-for-profit basis and seeks to generate revenues to pay operating and maintenance costs, depreciation, and interest on indebtedness and to provide for the establishment of reasonable margins and reserves.[3] Currently, IPEC follows a postage stamp rate structure, whereby all customers in the five service regions pay the same rates, irrespective of the individual communities' generation costs. For the current analysis, this implies that the utility costs considered are from the most recent IPEC rate case,[4] which is IPEC-wide and not specific to Kake. Marginal costs considered are for Kake alone since these changes are applied only within Kake.

When marginal generation costs are lower than retail rates, additional electricity sales can reduce rates for all customers. Switching customer space heating from oil-based heating systems to electric heating systems adds to electricity sales. Additionally, switching to electric heat pumps for space heating, especially when there is hydro power or other low-carbon electricity generation, can reduce the greenhouse gas emissions of the community while increasing energy efficiency. Therefore, electric heat pumps could be a viable beneficial electrification technology in Kake, where hydro will soon provide over half of the electricity and customers commonly rely on oil-based space heating. Further, use of excess hydro from Gunnuk Creek to meet this additional HP electricity demand helps the utility have reduced marginal generation costs since this excess hydro does not come at additional cost to the utility.[5] Excess hydro is defined as the hydro potential after meeting Kake's current existing demand.

3 Methodology and calculations

This section gives an overview of the modeling methods and calculations used for the analysis. It is divided into five parts: demand calculations, modeling assumptions, adoption scenarios, cost calculations, and Net Present Value (NPV) calculations.

3.1 Demand calculations

Every household has heating and non-heating energy demand. Currently households use fuel heating systems which use no. 2 fuel oil to fulfill their heating demands in Kake. IPEC is interested in investigating beneficial electrification to replace the current fuel heating systems with HPs.

[1] These are four Caterpillar 3456 generator sets each of which are rated at 450 kW and operated at 80 percent efficiency - Source: Communication with IPEC's engineer Brandon.
[2] Gunnuk Creek Hydroelectric Project Reconnaissance Report
[3] IPEC rate case 2020
[4] IPEC rate case 2020
[5] Generation, operation, maintenance and distribution costs for the excess hydro are assumed to be negligible.

3.1.1 Household characteristics

Homes in Southeast Alaska are typically less energy efficient as compared to the rest of the state.[6] Table 1 shows the assumed characteristics of Kake residential households. Total heat requirements for a single household were estimated based on TMY3 hourly temperature data[7] available for Kake for the year 2018.

A household in Kake uses approximately 3,588 kWh annually (including electricity used for their fuel heating system and non-heating demand).[8] This value has been consistently decreasing over the past few years according to PCE reports. Almost 3,325 kWh[9] of this energy use is assumed to be for non-heating electricity demand while the remaining amount is used for operating fuel heating systems as per the assumptions in Table 2.

Table 1: Residential household characteristic assumptions

Item	Value
Home area	1,000 sqft[10]
Home heating index (HHI)	10.6 BTU/sqft/HDD[11]
Annual average electricity usage by a residential household in Kake	3,588 kWh[12]

3.1.2 Fuel heating system

The current heating needs of a residential household in Kake are met by using a fuel heating system which uses no. 2 fuel oil. Heating fuel needs are calculated based on the total heat requirement, the efficiency of the fuel heating system, and the heat content of the fuel. The model assumes a fuel heating system which uses fuel oil with a heat content of 137,452 BTUs/gallon and a heating system with an efficiency of 80 percent. The fuel oil retail price for customers is $4.12/gallon. This price has a markup when compared to the price paid by the utility for diesel due to local delivery costs. The assumptions used for these calculations are listed in Table 2.

[6] 2018 Alaska Housing Assessment: Statewide Housing Characteristics
[7] Weather data downloaded from EnergyPlus.
[8] Assumption based on annual average for residential households as per 2019 annual PCE data – Source: PCE Statistical Report FY 2019-Alaska Energy Authority.
[9] As per calculations of heating requirements of residential households made based on TMY3 Kake data.
[10] Source: Communication with IPEC representatives.
[11] The HHI is a measure of the energy used for space heating in a building normalized by square footage and climate. This value is for residential homes in Southeast Alaska – Source: 2018 Alaska Housing Assessment: Statewide Housing Characteristics
[12] Power Cost Equalization Program – Statistical Report - FY2019- Alaska Energy Authority

Table 2: Fuel heating system assumptions

Item	Value
Fuel oil price	$4.12/gallon[13]
Efficiency of heating system	80 %[14]
Fuel heat content	137,452 BTU/gallon
Electricity use of fuel heating system (fans/pumps/controls)	3 kWh/MMBTU[15]

3.1.3 Heat pump model

If HPs replace current fuel heating systems, we need to understand the additional HP electric demand per household. To calculate the HP power required we need the HP efficiency values. The efficiency of a HP varies across different models, indoor and outdoor temperatures, load level on the HP, and other factors. Predictions of fuel savings from a HP depend on the estimation of the seasonal average HP efficiency. While HP efficiency measures are available from manufacturers, they cannot be directly applied in the Alaska context, as Heating Seasonal Performance Factor (HSPF) testing procedures are focused on Climate Zone 4, while most Alaska communities lie in Zone 7 and Zone 8. Additionally, several studies show that HSPF testing protocols over-estimate HSPF. The HP efficiency model developed by Alan Mitchell, Analysis North, for a HP calculator used within the Alaska context is used in our modeling efforts.[16] That study combined HP data available from five different studies undertaken in cold climates, to create an efficiency model and estimate the Coefficient of Performance (COP) and outdoor temperature relationship applicable to Kake. This COP vs. temperature relationship was linearized to estimate the HP power requirement to meet the heating demands of a single household. Based on these calculations, the estimated HP demand is shown in Figure 1.

[13] Alaska Energy Data Gateway – Source: AHFC/DCRA Aug 2018
[14] Mini-Split Heat Pumps in Alaska Heat Pump Calculator Algorithms And Data – 2018
[15] Ibid.
[16] Mini-Split Heat Pumps in Alaska Heat Pump Calculator Algorithms And Data – 2018

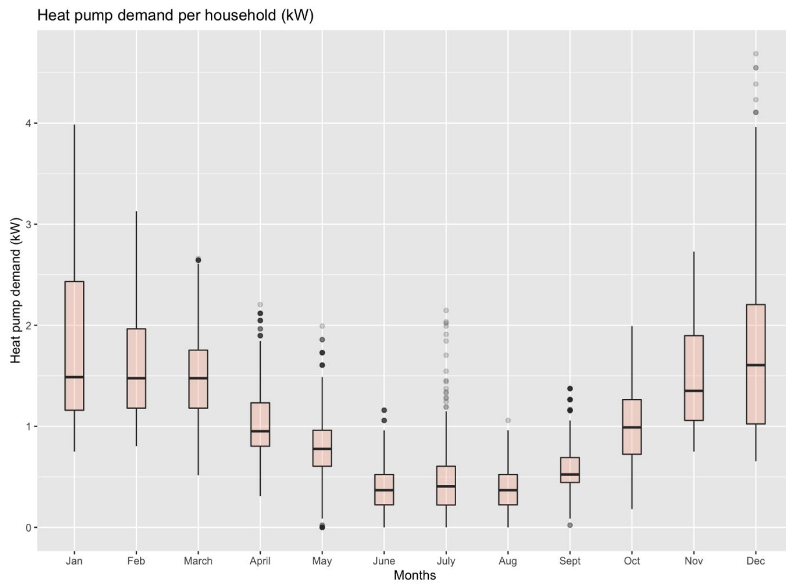


Figure 1: Box plot of hourly heat pump demand per household (average kW during each hour of the month) showing the median (center line of boxes), first and third quartiles (box), maximum and minimum (whiskers) and outliers (dots) for each month.

3.1.4 Existing community load

The existing community load profile for Kake was simulated starting with a standard HOMER Pro[17] community daily load shape modified by the monthly maximum and minimum readings available from a 2019 load profile graph provided by IPEC and normalized to the reported 2019 annual consumption of 2,232,150 kWh. This profile is shown in Figure 2.[18] It has high peaks in January and February of over 400 kW, and slightly higher than average loads in November and December.

[17] Homer Pro is a software developed originally by the National Renewable Energy Laboratory (NREL) and enhanced and distributed by HOMER Energy (Hybrid Optimization Model for Multiple Energy Resources). It is a global standard for optimizing microgrid design in all sectors, from village power and island utilities to grid-connected campuses and military bases. Homer Pro simplifies the task of evaluating designs for both off-grid and grid-connected power systems. HOMER examines all possible combinations of system types in a single run, and then sorts the systems according to the optimization variable of choice. It can simulate a viable system for all possible combinations of the equipment as specified. For more information please refer to https://www.homerenergy.com/products/pro/index.html.

[18] The generated kWh is higher i.e. 2,477,686 kWh and includes 11 percent line loss.

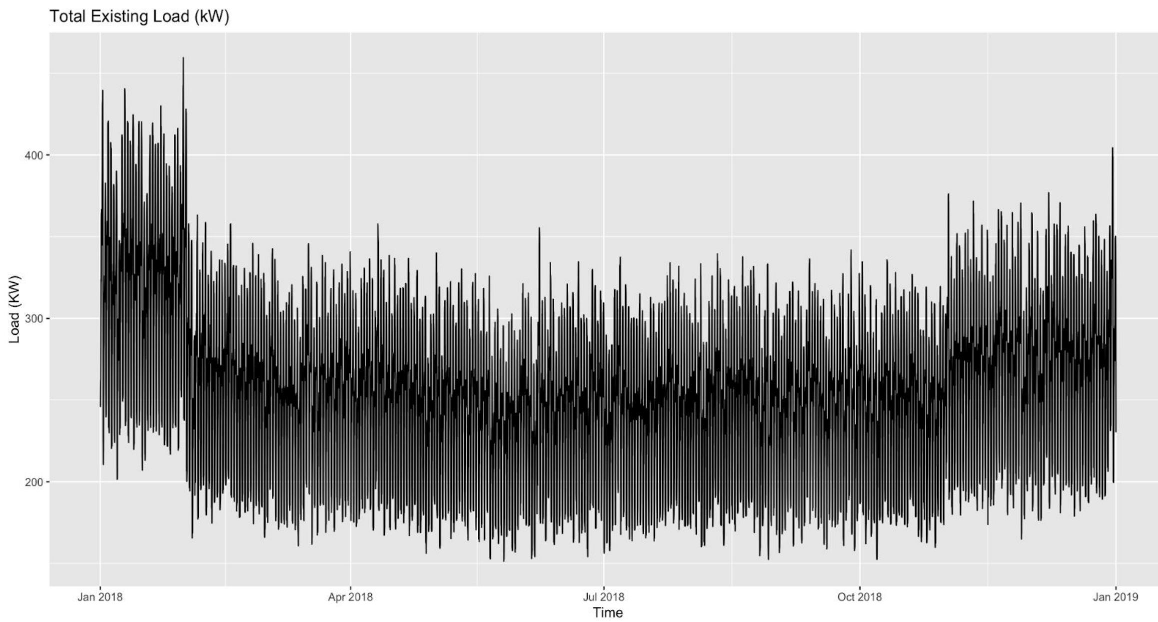


Figure 2: Kake existing load profile (based on HOMER Pro calculations)

3.1.5 Heat pump load

If HPs are used for space heating, the Kake load profile may change dramatically based on the HP adoption rate in the community. For example, if 50 percent of the existing residential households in Kake adopt HPs, the new Kake load profile would be as shown in Figure 3. The peaks in the winter months become more pronounced, and higher peaks can be seen in November, December, January and February.

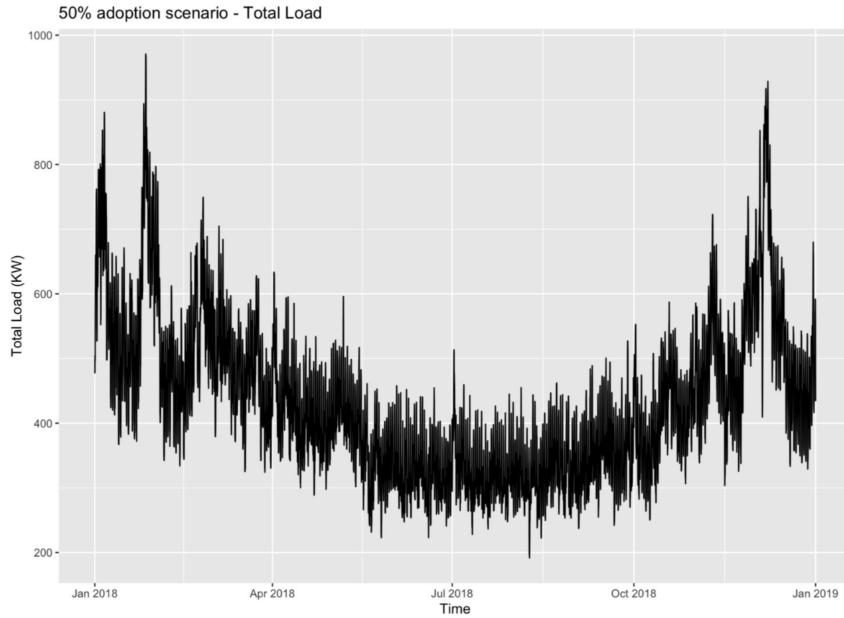


Figure 3: Total load in Kake - 50 percent adoption scenario[19]

3.1.6 Power Cost Equalization (PCE) eligible and non-eligible Load

The Power Cost Equalization (PCE) program provides economic assistance to residential customers based on their energy use. The residential rate for up to 500 kWh per household per month is reduced by a PCE payment which is decided by the Regulatory Commission of Alaska according to a formula established by state law. For energy used over 500 kWh per month, residential customers pay the regular utility rate.

The model assumes that all the non-heating load is under 500 kWh per month, while additional HP load (which replaces current fuel heating systems) would be partly under 500 kWh, but mostly over 500 kWh per month for an individual household.[20] HP load that fills any gap up to 500 kWh in a given month after considering the non-heating load (eligible for PCE rates) is referred to as ***PCE eligible*** additional HP load, while the additional HP load that puts the household energy use over 500 kWh is referred to as ***non PCE eligible*** load. An average Kake residential household would consume ~9,400 kWh of additional electricity to run a HP in this analysis, of which 28 percent is PCE eligible, and 72 percent is non PCE eligible. Residential customers pay the discounted "with PCE" rate for PCE eligible additional HP load, whereas they are required to pay a full (i.e., unsubsidized) rate (unless there is a special utility rate) for non PCE eligible HP load.

[19] This includes the total demand i.e. the existing community demand in Kake and the additional HP demand in a 50 percent adoption scenario. These are the kWh generated and include line losses of 11 percent.

[20] As described in section 2.1.1 a Kake household uses approximately 3,588 kWh annually of which 3,325 kWh is assumed to be for non-heating electricity demand. Thus, a residential household consumes ~277 kWh per month of non-heating load every month. The additional HP load under 500 kWh is ~223 kWh per month (This is the PCE eligible additional HP load). While there may be discrepancies in this, and some households may have higher consumption, which allows for less PCE eligible HP load, this is assumed to be true for the average residential customer.

3.1.7 Hydroelectric potential

IPEC is in the process of installing a run-of-river hydroelectric plant on Gunnuk Creek in Kake. This facility is not yet producing power, but is expected to be in the near future. To estimate potential electricity produced from this plant, 2006 and 2007 daily mean streamflow data for Gunnuk Creek from the U.S. Geological Survey (USGS) was used in a HOMER model. Due to lack of more recent data from USGS these estimates are used to model the existing hydroelectric potential to meet existing community demand and additional HP demand in Kake. Figure 4 and Figure 5 show the modeled hydroelectric potential (kWh and kW) based on the 2006 and 2007 streamflow data. The highly variable streamflow causes uncertain costs and benefits from HP s and thus uncertain effects on utility NPV.[21]

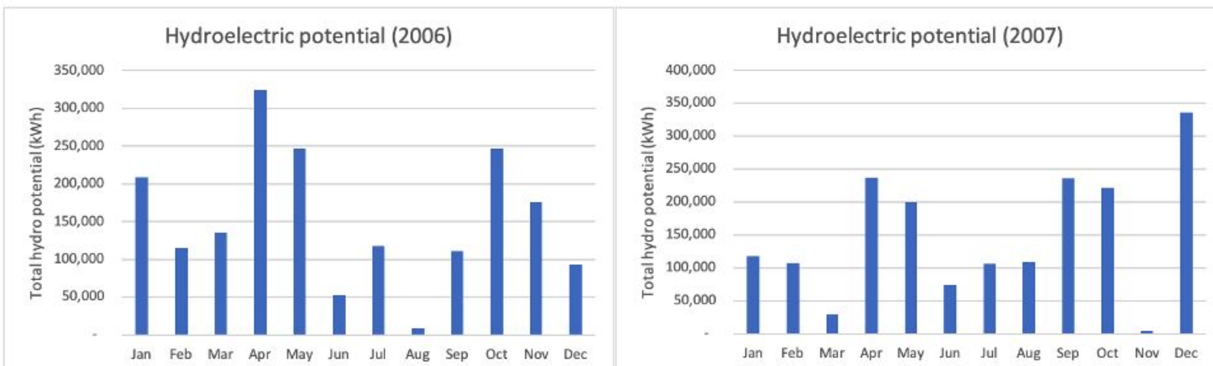


Figure 4: Hydroelectric potential (kWh)

[21] As calculated in the model, the utility NPV is the difference between the present value of cash inflows (marginal revenue) and cash outflows (marginal costs) for a utility over 15 years. For a more detailed explanation please refer to 3.5.1.

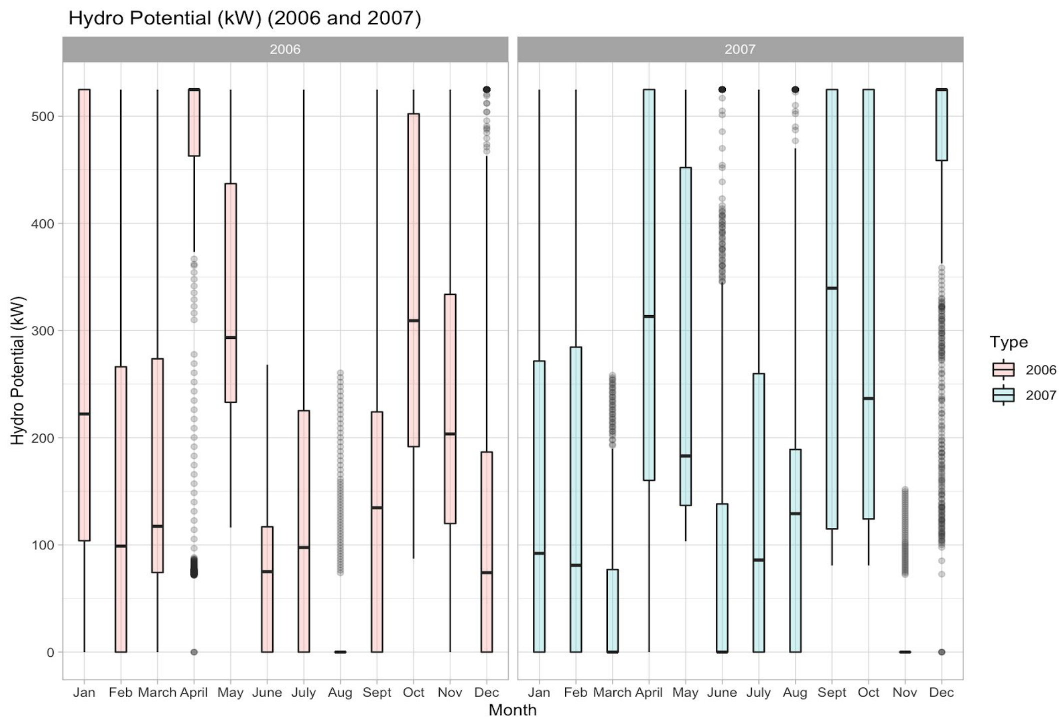


Figure 5: Daily mean hydroelectric potential (kW)

3.2 Key modeling assumptions

In any given hour:

- Available hydroelectric potential first meets existing community load.
- Hydroelectric potential in excess of the existing community demand (referred to as excess hydro) which meets the additional HP load in different adoption scenarios.
- Diesel meets any remaining load (existing community load and additional HP load).

Excess hydro available for meeting the additional HP demand for the two modeled years is shown in Figure 6. From Figure 5 and Figure 6 we can see that the high hydro availability and excess hydro months in each year are: January, April, May, October and November in 2006; and April, May, September, October and December in 2007.

The model assumes that over the fifteen years of the HP life, the hydroelectric potential remains the same during this time frame, and the additional HP demand and the existing community demand also remain the same, without any change in demand. Kake has seen a decrease in residential demand since 2015.[22] Yearly variation in hydroelectric potential is likely; however that has not been introduced in the model due to the limited data available.

[22] As per the annual Power Cost Equalization statistical reports by community for FY 2018-19 and 2015-16.

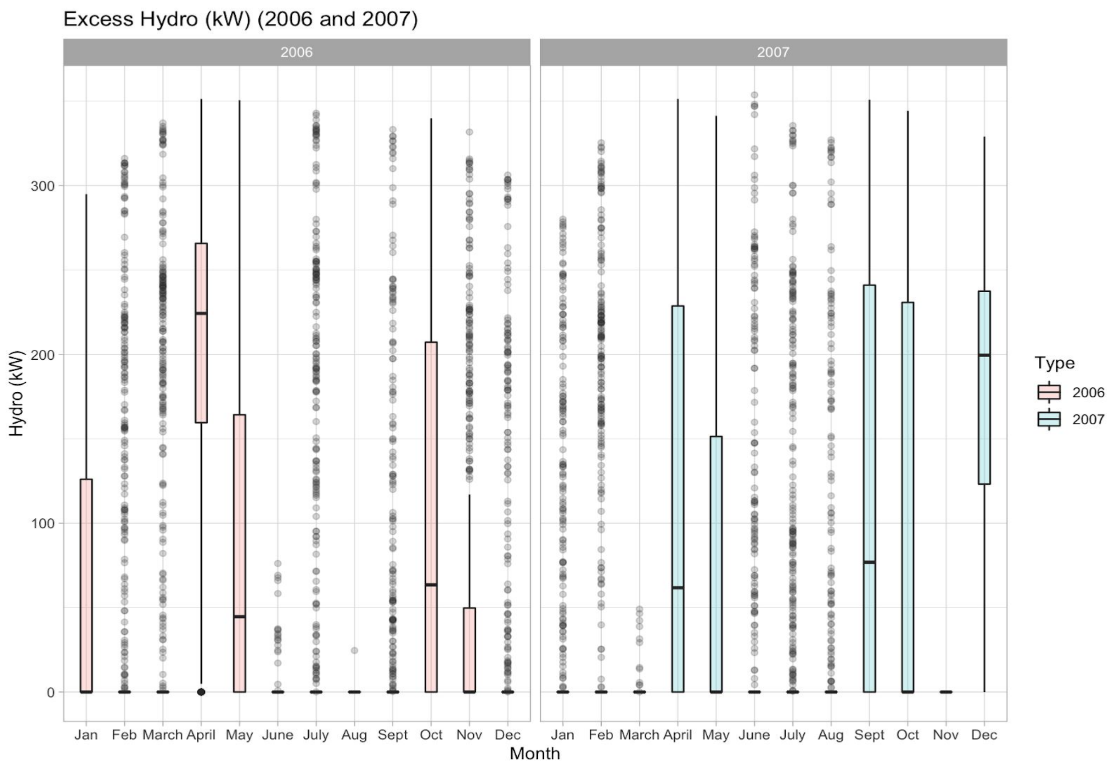


Figure 6: Hourly excess hydro (kW)

The model assumes a line loss of eleven percent of electricity generated in Kake. Line losses in Kake have fluctuated between seven to eleven percent over the last seven years, with a line loss of eleven percent in 2019.[23] Therefore the generated kWh are higher than the demand or load.

Financial assumptions used in the model are listed in Table 3.

Table 3: Financial assumptions

Item	Value
General inflation rate	2.50%
Heating Fuel Price Inflation Rate (percent per year)	3.00%
Electricity Price Inflation Rate (percent per year)	3.00%
Discount rate for utility (percent per year)[24]	2.00%
Life of HP (years)	15
Discount rate - for customer (percent per year)	6.00%

3.3 Heat pump adoption scenarios

In this analysis we considered five adoption scenarios in Kake. These scenarios vary with the number of customers participating in a potential HP program. The characteristics of the

[23] Power Cost Equalization Program – Statistical Report - FY2019- Alaska Energy Authority

[24] We have assumed that the utility enjoys a lower borrowing rate (2 percent) than the customer (6 percent).

scenarios are described in Table 4 and Table 5. The differences in the streamflow data of the two years do not change the generation mix dramatically for the additional HP demand. For each scenario, the additional HP demand is calculated based on the number of customers adopting HPs.

3.3.1 System boundaries

According to IPEC, their system boundaries allow use of two diesel generators at any given time for the community of Kake, while keeping two diesel generators for backup generation. These generators have a nameplate capacity of 450 kW each and are operated at 80 percent of capacity. This allows IPEC to accommodate maximum peak generation of approximately 720 kW without exceeding their system limits.[25] According to our analysis, the utility can accommodate up to a 25 percent adoption scenario i.e. about 62 customers, beyond which the generation system limits will be stressed. IPEC expects that additional HP demand will not likely stress the existing electrical distribution system.[26]

However, our analysis is based on hourly average electric demand, and a HP's peak power draw may be several times the average. From the limited data in Figure 7, peaks are approximately 3 times the average and occur for about 10 minutes of every 3 hours. If multiple HPs cycled through these peaks at random, uncoordinated times, the instantaneous total HP load might be up to about 10 percent higher than the hourly average HP load. It is expected that the peak will be smaller relative to the average the higher the average hourly load is, given that the HP has a maximum power draw. In this case, the total instantaneous load from all HPs should be even closer to the hourly average. Further investigation into this will be required to determine the number of HPs that may be installed without necessitating additional diesel generators or modified protocols.

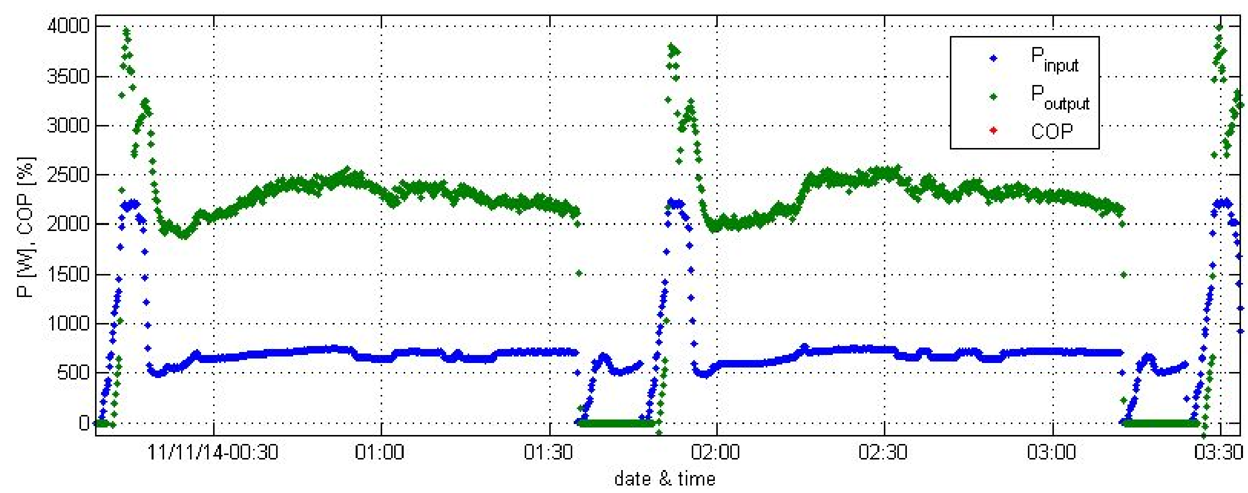


Figure 7: Heat Pump power draw example. Note that the power input spikes for about 10 minutes about every 3 hours. The spikes happen after each defrost. Source: Tom Marsik, Cold Climate Housing Research Center

[25] Source: Communication with IPEC's engineer Brandon.
[26] Ibid.

The current analysis assumes that no additional costs are imposed even when system limits are stressed. However, this may not be true. If Kake sees adoption at a rate greater than 25 percent, i.e. with an adoption rate of 50 percent or 124 customers, the utility may have to expand its existing capacity by adding generators to meet the total peak generation of 970 kW. More than 81 hours of the year have a demand that exceeds 720 kW per hour in the 50 percent adoption scenario. For an adoption rate of 75 percent of the households, the total required peak generation is approximately 1240 kW. Over 454 hours of the year have a demand exceeding720 kW per hour in the 75 percent adoption scenario. For an adoption rate of 100 percent of the households, the total peak generation is approximately 1514 kW. Over 1124 hours of the year have a demand exceeding 720 kW per hour in the 100 percent adoption scenario. The need to accommodate peak loads could increase costs for the utility which have not been included in this analysis.

Table 4: Adoption scenarios for additional HP demand (Hydro Potential based on 2006 Gunnuk Creek streamflow data)

Item	Scenario 1 10 percent adoption	Scenario 2 25 percent adoption	Scenario 3 50 percent adoption	Scenario 4 75 percent adoption	Scenario 5 100 percent adoption
Number of customers	24	62	124	185	247
Additional HP demand					
Generated kWh	79,150	186,819	316,260	395,455	438,278
Percent generated by diesel	68%	71%	76%	80%	83%
Percent generated by hydro	32%	29%	24%	20%	17%
Additional HP peak diesel generation (kW)	125	323	645	962	1,285
Total peak diesel generation (Kake) (kW)	523	674	**929**	**1,204**	**1,526**

Table 5: Adoption scenarios for additional HP demand (Hydro Potential based on 2007 Gunnuk Creek streamflow data)

Item	Scenario 1 10 percent adoption	Scenario 2 25 percent adoption	Scenario 3 50 percent adoption	Scenario 4 75 percent adoption	Scenario 5 100 percent adoption
Number of customers	24	62	124	185	247
Additional HP demand					
Generated kWh	250,289	646,580	1,293,160	1,929,312	2,575,892
Percent generated by diesel	68 %	70 %	75 %	78 %	82 %
Percent generated by hydro	32 %	30 %	25 %	22 %	18 %
Additional HP peak diesel generation (kW)	106	274	548	818	1,092
Total peak diesel generation (Kake) (kW)	544	696	**970**	**1,240**	**1,514**

3.4 Cost calculations

3.4.1 Fuel costs

With the current fuel price (paid by the utility for fuel for diesel generators) of $2.67/gallon[27] and the fuel efficiency value for the diesel generators used of 15.11 kWh/gallon,[28] we can calculate IPEC's average fuel costs of power from diesel generation for existing demand[29] at $0.1767/kWh. The marginal fuel cost of power from diesel generation for additional HP demand is assumed to be equal to the average fuel cost of power from diesel generation for existing demand.[30] The fuel cost of hydroelectric generation is modeled as $0/kWh. Power was purchased by IPEC from AP&T at $0.22/kWh in 2019.[31] Due to use of relatively inexpensive hydroelectric power with zero fuel cost, the average utility fuel costs are reduced, depending on the adoption scenario and the hydroelectric potential.

3.4.2 Non-fuel costs

The average non-fuel cost of power for existing demand met by diesel generation is $0.3742/kWh.[32] The calculated marginal non-fuel cost of power from diesel generation for additional HP demand is calculated as $0.1063/kWh, which includes generation operation and maintenance costs, customer engagement costs related to running this new program, and distribution system depreciation costs. The average non-fuel cost of power from hydroelectric

[27] IPEC rate case 2020
[28] Ibid.
[29] Existing demand - This includes any demand which is not the additional HP demand –it includes all the community demand prior to additional HPs. This value refers to the existing IPEC wide demand (including existing demand in Kake) which is met by diesel generation.
[30] While average fuel cost of power from diesel generation is derived from IPEC wide fuel prices and fuel efficiency values, and not for Kake specifically, they closely align with the diesel generation performance in Kake. Therefore, the average fuel cost of power from diesel generation and the marginal fuel cost of power from diesel generation in Kake are assumed to be equal.
[31] IPEC rate case 2020
[32] Ibid.

generation for existing demand is assumed to be the same as that of power from diesel generation, i.e. $0.3742/kWh. The marginal non-fuel cost of power from hydroelectric generation for additional HP demand is assumed to be $0.00/kWh.[33] Due to these assumptions of low marginal non-fuel costs, the overall average non-fuel cost of power is reduced when heat pumps are added and served partly by hydro. The amount of this reduction depends on the HP adoption scenario and the potential amount of excess hydroelectric energy.

Table 6: Marginal fuel and non-fuel cost of power from diesel generation (for additional HP kWh in Kake)

Item	Value
Generation O&M (for excess kWh)[34]	$0.0618/kWh
Distribution O&M (for excess kWh)[35]	$0/kWh
Customer service & sales (for excess kWh)[36]	$0.0278/kWh
Depreciation & amortization (for excess kWh)[37]	$0.0168/kWh
Marginal non-fuel cost of power from diesel generation (for excess kWh)	**$0.1063/kWh**
Cost of fuel – diesel[38]	$2.67/gallon
Fuel efficiency[39]	15.11 kWh/gallon
Marginal fuel cost of power from diesel generation (for excess kWh)	**$0.1767/kWh**

Table 7: Marginal and average costs of power from diesel and hydroelectric generation

<table>
<tr><th>Item</th><th>Marginal costs (for additional kWh) $/kWh</th><th>Average costs (for existing kWh) $/kWh</th></tr>
<tr><td>Non-fuel cost of power from diesel generation</td><td>0.1063</td><td rowspan="2">0.3742</td></tr>
<tr><td>Non-fuel cost of power from hydroelectric generation</td><td>0</td></tr>
<tr><td>Fuel cost of power from diesel generation</td><td>0.1767</td><td>0.1767</td></tr>
<tr><td>Fuel cost of hydroelectric generation</td><td>0</td><td>0</td></tr>
</table>

[33] It is assumed that using the otherwise spilled excess hydro will not cost the utility anything.

[34] These are per kWh generation O & M costs calculated from the IPEC rate case 2020. This includes generation, operation and maintenance costs such as maintenance of electric plant, miscellaneous power generation expenses, tool and inventory expenses, generator maintenance (for all 4 generators).

[35] We assume that there are no additional distribution operation and maintenance costs, however, since the distribution system will be stressed more than usual due to additional HP demand, we approximate this additional wear and tear from use by an increase in the depreciation. This has been included in the depreciation costs.

[36] While no costs for customer engagement and program management have been directly included, we used existing per kWh costs for customer services and sales and customer accounts expenses in the total non-fuel marginal costs to reflect that component - Source: IPEC rate case 2020.

[37] Only depreciation costs for distribution systems which are likely affected by additional HP demand i.e. depreciation costs of conductors, line transformers, and underground services are included - Source: IPEC rate case 2020.

[38] Source: IPEC rate case 2020

[39] Ibid.

3.4.3 PCE payment

PCE payments will be reduced due to the addition of Kake hydroelectric generation to IPEC's generation mix to meet the total demand (including any additional HP demand). The reduction in PCE payments is calculated from the following reduced costs:

1. Fuel cost of hydroelectric generation is $0/kWh.
2. Marginal non-fuel cost of any hydro that is used to meet additional HP demand is $0/kWh.
3. Marginal non-fuel cost of power from diesel generation for meeting the additional HP demand is $0.1063/kWh, which is less than the non-fuel cost of power from diesel generation for meeting the existing demand

3.5 Net present value (NPV) calculations

3.5.1 Utility NPV calculations

The NPV calculations in this analysis are based on the marginal costs to the utility to meet the additional HP demand, as well as the associated marginal revenues. Marginal fuel and non-fuel costs of diesel and hydroelectric power for additional HP demand[40] are calculated to give the total marginal costs for the utility. The marginal revenue collected by the utility for generated kWh to meet additional HP demand will be based on the rate paid by the customers. As described in 3.1.6 the customer will pay a different rate for PCE eligible and PCE non-eligible additional HP load. For the PCE eligible additional HP load, with the PCE payments included, the utility will receive its average total cost per kWh (a sum of the average utility fuel cost and the average utility non-fuel cost).

3.5.1.1 HP incentive rate

When customers are charged the full utility rate for HPs (for use over 500 kWh per month per household – non PCE eligible load) their NPV over 15 years of using HPs is substantially below zero. Therefore, customers have no incentive to switch from their current heating system to HPs. An analysis of the customer and utility NPV without a special rate is given in Appendix A.

In our analysis, we derive a potential special rate for non PCE eligible load that is lower than the regular utility rate, while being mutually beneficial to the customer and the utility. For the non-PCE eligible additional HP load, we assume the customers will pay a special HP rate which is lower than the standard (first 500kWh per month) residential rate. This special rate for total household power use over 500 kWh per month for those with a HP installed is called the '**HP incentive rate**' and is set by the utility. The customer will be charged an additional Cost of Power Adjustment (COPA) surcharge along with this rate.[41] In our model, this rate is set such that the utility breaks even and has $0 NPV over 15 years. This rate can be set at higher than the break even rate.

[40] These values are based on generated kWh to meet the additional HP demand in Kake and are dependent on the adoption scenario used and the hydroelectric potential.
[41] COPA is a line item on electric bills of customers which reflects the utility's fuel and purchased power costs.

3.5.2 Customer NPV calculations

For the customer NPV calculations, we consider the costs incurred for their current fuel heating system and the costs incurred by use of a HP, and compare the two to understand the net benefits for the customers when they use HPs. For the fuel heating system, the customer incurs two costs: The amount paid for purchasing heating fuel oil and the electricity costs for operating a heating fuel oil system (maintenance and replacement costs are not investigated in this study). The HP costs for the customer include electricity costs for PCE eligible additional HP load, electricity costs for PCE non eligible additional HP load, the annual operation and maintenance HP costs and the installation costs.[42] There is an additional benefit in the form of lower per kWh costs resulting from the utility's high kWh sales, which leads to a decreased cost for the non-heating load.[43] As mentioned in 3.5.1 for PCE eligible HP load, the customer will pay the standard low rate reflecting the PCE credit, while for the non PCE eligible load, the customer will be charged at the HP incentive rate described in 3.5.1.1.

In our model, the HP incentive rate is set such that the utility breaks even and has $0 NPV over 15 years. This rate can be set at higher than the break even rate. The decreased cost for non-heating load depends on the old and new residential rates, COPA surcharges and PCE payments for the customer. The annual operation and maintenance HP costs are estimated at $50 per year,[44] and the installation costs are estimated at $6,720 including taxes.[45]

4 NPV analysis

4.1 Break even analysis

To understand potential tariff rate structures for HPs we consider different adoption and hydroelectricity availability scenarios. We consider five adoption scenarios based on different percentages of uptake of HPs within the population of Kake. With these different adoption scenarios the increase in demand due to use of HPs varies, and the fuel mix used by the utility will also vary.[46]

We also consider different hydroelectricity availability scenarios. Using the 2007 hydrology data as the base,[47] we construct a low and high hydro scenario. In the ***low hydro*** scenario, we assume a decrease of 50 percent in the hourly hydro availability, i.e., streamflow is reduced by 50 percent as compared to the 2007 streamflow data. Similarly, in the ***high hydro*** case, we assume an increase of 50 percent in the hourly hydro availability. In the ***no hydro*** case, we assume all the load in Kake, including additional HP load, is only met by diesel generation, and there is no availability of hydroelectricity in Kake.

[42] A customer is charged only for sold kWh (does not include line losses), and not the generated kWh (includes line losses).
[43] Since average costs per kWh are reduced for the utility with beneficial electrification, the customer is charged lower electricity rates.
[44] Alaska heat pump study
[45] Installed cost for high cost city from the report "Mini-Split Heat Pumps in Alaska Heat Pump Calculator Algorithms and Data" with the additional sales tax for Kake from "DCRA Information portal".
[46] Table 5 and Table 6 show the adoption scenario details for the 2006 and 2007 streamflow data. They do not include details of the high hydro, low hydro and no hydro case.
[47] The 2007 hydrology data provides the most conservative options.

Table 8 shows the break even analysis. In this table, the “Break even rate for HPs” is the rate that must be charged for kWh in excess of 500 per month per household in order for the utility to have zero NPV from the HP program. This break even rate is lower than the “total marginal cost” because any kWh consumed by HPs that are under 500 kWh per month per household would be charged the existing tariff rate and thus generate some marginal revenue in excess of marginal cost.

From the table we can see that in each adoption scenario, as the contribution of hydroelectricity in the fuel mix increases, the costs (average and marginal) decrease. The no hydro case forms the ‘ceiling’ and the highest cost scenario. Customer NPV, as calculated based on the break even HP incentive rate, also decreases as the available hydroelectricity decreases.

Further, as the adoption rate increases, the break even HP incentive rate increases. This is because of fuel mix changes. For example, in the ten percent adoption scenario, using 2007 hydrology data, the fuel mix for the additional kWh is 32 percent hydro and 68 percent diesel generation. In the 50 percent adoption case, the hydro reduces to 25 percent and the diesel increases to 75 percent which increases the marginal costs and thus the break even HP incentive rate (Table 8).

4.2 Sensitivity analysis

We analyze the relationships between the utility and customer NPV and three variables: hydroelectric potential, fuel price of diesel, and marginal non-fuel cost of power from diesel generation. Year 2007 streamflow data, and the modelling calculations and assumptions detailed in Section 2 have been used to complete the sensitivity analysis. Figure 7 shows the sensitivity analysis results for the 50 percent adoption scenario case. For sensitivity analysis results for the remaining adoption scenarios please refer to Appendix B.

4.2.1 Hydroelectric potential

As the hydroelectric potential increases the utility and customer NPV increase, but nonlinearly. In Figure 7, we see that as the hydroelectric potential increases by 50 percent, there is a large increase in the utility NPV. However, this is not proportional to the decrease in the NPV as the hydroelectric potential decreases by 50 percent. This is because an increase in hydroelectric potential does not correspond to a proportional increase in hydroelectricity actually generated to meet the load, which would bring a proportional change in utility NPV or customer NPV. Hydroelectric potential has a large impact on utility NPV, and a small impact on customer NPV.

Table 8: Break even analysis

Hydro availability scenario	Utility non-fuel costs[48] ($/kWh)	Utility fuel costs[49] ($/kWh)	Total average utility costs[50] ($/kWh)	PCE Payment[51] ($/kWh)	Total marginal cost[52] ($/kWh)	**Break even HP incentive rate[53] ($/kWh)**	**Break even HP incentive rate + COPA[54] ($/kWh)**	Customer NPV($)
	10 percent adoption scenario							
High hydro	0.3662	0.1256	0.4918	0.2865	0.1693	**(0.0520)**	**0.0735**	11,759
2006 data	0.3664	0.1273	0.4937	0.2884	0.1935	**(0.0175)**	**0.1098**	9,507
2007 data	0.3664	0.1290	0.4954	0.2899	0.1919	**(0.0223)**	**0.1066**	9,698
Low hydro	0.3671	0.1364	0.5035	0.3129	0.2645	**0.0782**	**0.2145**	2,989
No Hydro	0.3673	0.1509[55]	0.5182	0.3116	0.2830	**0.0889**	**0.2398**	1,552
	25 percent adoption scenario							
High hydro	0.3544	0.1251	0.4795	0.2748	0.1938	**(0.0389)**	**0.0862**	11,011
2006 data	0.3551	0.1274	0.4824	0.2776	0.2234	**(0.0016)**	**0.1259**	8,548
2007 data	0.3550	0.1289	0.4839	0.2790	0.2197	**(0.0088)**	**0.1200**	8,899
Low hydro	0.3568	0.1377	0.4944	0.2890	0.3017	**0.0913**	**0.2290**	2,121
No Hydro	0.3570	0.1518	0.5089	0.3027	0.3142	**0.0886**	**0.2406**	1,369
	50 percent adoption scenario							
High hydro	0.3373	0.1247	0.4620	0.2582	0.2018	**(0.0211)**	**0.1035**	9,969
2006 data	0.3388	0.1281	0.4669	0.2629	0.2373	**0.0225**	**0.1151**	7,036
2007 data	0.3387	0.1295	0.4682	0.2641	0.2347	**0.0171**	**0.1466**	7,287
Low hydro	0.3417	0.1398	0.4815	0.2767	0.3075	**0.1019**	**0.2417**	1,357
No Hydro	0.3419	0.1532	0.4951	0.2897	0.3142	**0.0994**	**0.2526**	1,085
	75 percent adoption scenario							
High hydro	0.3229	0.1250	0.4478	0.2448	0.2117	**(0.0025)**	**0.1225**	8,828
2006 data	0.3251	0.1295	0.4546	0.2511	0.2498	**0.0428**	**0.1723**	5,717
2007 data	0.3249	0.1307	0.4555	0.2521	0.2643	**0.0365**	**0.1671**	6,035
Low hydro	0.3284	0.1416	0.4701	0.2659	0.3089	**0.1061**	**0.2477**	1,005
No Hydro	0.3288	0.1544	0.4832	0.2783	0.3142	**0.1024**	**0.2568**	838
	100 percent adoption scenario							
High hydro	0.3100	0.1257	0.4357	0.2332	0.2207	**0.0136**	**0.1393**	7,807
2006 data	0.3129	0.1313	0.4442	0.2413	0.2607	**0.0599**	**0.1911**	4,569
2007 data	0.3127	0.1323	0.4449	0.2420	0.2572	**0.0537**	**0.1860**	4,887
Low hydro	0.3165	0.1434	0.4600	0.2563	0.3108	**0.1106**	**0.2540**	631
No Hydro	0.3168	0.1555	0.4723	0.2680	0.3142	**0.0982**	**0.2538**	614

[48] These costs are calculated using all the utility generated kWh, which includes hydro in Kake as estimated by HOMER modelling, and as defined by the hydro availability scenarios (except the no hydro case).
[49] Ibid.
[50] Ibid.
[51] This is the PCE payment that will be received by the utility as hydro-electricity is added to the utility fuel mix in different adoption scenarios and hydro availability scenarios.
[52] This marginal cost is for additional HP kWh in Kake.
[53] For the utility to have a break even NPV of $0, this is the HP incentive rate they should charge their customers for any household kWh over 500kWh.
[54] Ibid.
[55] This value changes between adoption scenarios because the generation mix for IPEC-wide operations changes, as the percentage of generation from diesel increases and the percentage of generation from hydro decreases with increasing HP load in Kake met by diesel generation.

4.2.2 Fuel price – diesel

The fuel price for utility diesel is estimated at $2.67/gallon for the utility, and fuel efficiency for the diesel generators at 15.11 kWh/gallon which results in a fuel cost of $0.1767/kWh[56]. The price of heating fuel for customers in Kake is approximately $4.12/gallon, and is assumed to have a constant markup above the utility price for diesel.[57]

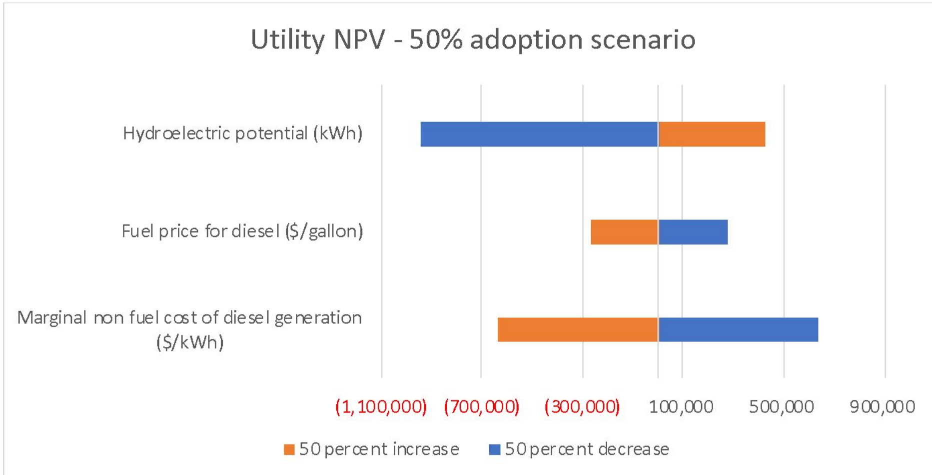
As the fuel price for utility diesel increases, the utility NPV decreases, while the customer NPV increases.The fuel price has the least impact on the utility NPV, when compared to the other two parameters considered. Price of diesel heating fuel has the most impact on customer NPV. A higher price of utility diesel increases the average and marginal fuel cost of power from diesel generation (average and marginal costs are equal in this case), which impacts the utility NPV. The diesel fuel price impacts the customer NPV in two ways. First, as the utility diesel price increases, it increases the COPA surcharge and thus the cost of using a HP. Second, as the heating fuel price increases it also increases the cost of using a fuel heating system. In the customer's case, the second effect is more prominent and makes HPs more cost effective for customers as the price of diesel increases.

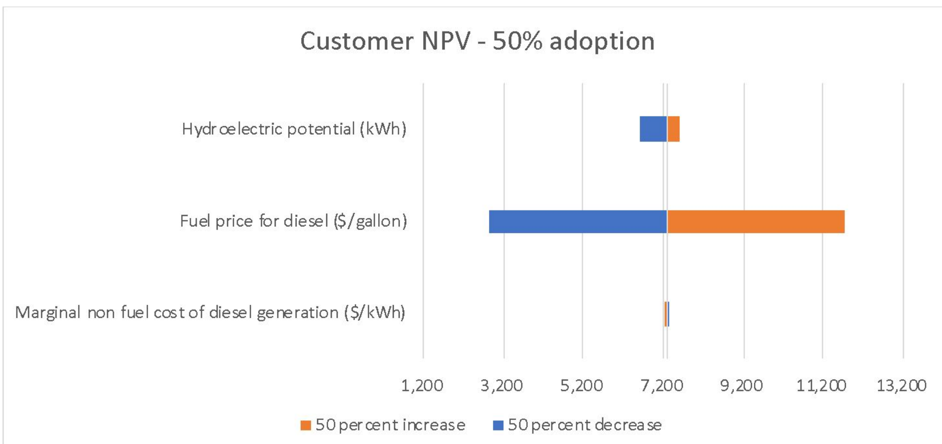
4.2.3 Marginal non-fuel cost of power from diesel generation

The marginal non-fuel cost of power from diesel generation consists of generation and distribution operation and maintenance cost, customer service costs, and depreciation costs for distribution assets. In our analysis, we have used a conservative estimate of the marginal non-fuel cost of power from diesel generation at $0.1063/kWh. This cost is seen to have a large impact on the utility NPV, but only a negligible impact on customer NPV.

[56] While these numbers are utility-wide and may differ slightly for diesel generation in Kake specifically, the difference is small. Source: IPEC rate case 2020

[57] AHFC/DCRA Aug 2018





Assumptions used for sensitivity analysis (50 percent adoption scenario)	**Value**
Break even HP incentive rate	$0.0171/kWh
COPA surcharge[58]	$0.1295/kWh
Fuel price for utility diesel	$2.67/gallon
Marginal non-fuel cost of power from diesel generation	$0.1063/kWh

Figure 8: Sensitivity analysis of utility and customer NPV the 50 percent adoption scenario

4.3 NPV Monte Carlo Simulations

To further analyze the relationship between these three variables (hydroelectric potential, fuel price of diesel and marginal non-fuel cost of power from diesel generation) and the utility and customer NPV, we performed Monte Carlo simulations. These simulations help to account for existing uncertainties within these variables and helps us understand their impact on the NPV.

[58] The COPA surcharge will vary with the fuel price for utility diesel, however it stays constant at this given rate while checking sensitivity of the other two parameters i.e. hydroelectric potential and marginal non-fuel cost of power from diesel generation.

A standard deviation of 3 and 2.5 percent, was introduced in the values of fuel price of utility diesel and marginal non-fuel cost of power from diesel generation, respectively. Hydroelectricity potential can also vary significantly over the years. To understand the impact of such variation, the values of the hydroelectricity generated in Kake were varied. The hydroelectricity potential was increased by 50 percent and decreased by 50 percent using the 2007 streamflow data. The high hydroelectric potential (50 percent increase) was used to calculate the maximum hydroelectricity generated kWh value in Kake, while the low hydroelectric potential (50 percent decrease) was used to calculate the minimum hydroelectricity generated kWh value in Kake. For the simulations, the hydroelectricity generated was randomly distributed and the max and min values encompassed ~75 percent of the probability mass. Each adoption scenario uses two values of hydroelectricity generated: 1) hydroelectricity generated to meet additional HP demand; and 2) hydroelectricity generated to meet existing demand. In each adoption scenario we used two components: 1) a different minimum and maximum value of hydroelectricity generated for additional HP kWh, since the hydroelectricity generated depends on the demand i.e. the HP adoption rate in our case; and 2) the same minimum and maximum value of hydroelectricity generated for existing demand which does not change across different adoption scenarios. The total hydroelectricity generated in the different adoption scenarios has a standard deviation of approximately 9 – 13 percent.[59]

In each adoption scenario, the simulations were performed twice. The first time, the simulations were performed at the break even HP incentive rate for HPs.[60] The second time, the simulations were performed at a HP incentive rate of about $0.12/kWh, which was found to ensure a higher probability of the utility making a positive profit while also ensuring high probability for a positive customer NPV. The complete results of the simulations with the utility and customer NPV distributions are given in Appendix C – Monte Carlo simulations. The results in the appendix show the standard deviation, average, minimum and maximum NPV values, along with the probability of a NPV being negative, for utilities and customers in each case for 1000 simulations. Note that in the break even rate case the utility has a distribution around zero utility NPV (lower probability of a positive utility NPV) while the customer always has a positive NPV (with a higher average customer NPV), while with the HP incentive rate at ~$0.12/kWh (refer to 6.3 Appendix C – Monte Carlo simulations) the utility has a higher probability of having a positive NPV while the customer NPV remains positive (but the average customer NPV is reduced). The utility and customer NPV results for the two cases are in Tables 9 through 12.

[59] This value is below the ~17 percent deviation seen in hydroelectricity generated within the IPEC communities when compared annually over the past four years as per the IPEC data on hydroelectricity generated within its territory – Source: IPEC rate case 2020.

[60] As calculated from values in Table 5 and shown in Table 8 in purple, using those for the 2007 hydro case for each adoption scenario.

Table 9: Monte Carlo simulation results showing utility NPV for break even HP incentive rate case

Adoption scenario	Average utility NPV ($) (percent of revenue)[61]	Minimum utility ($) (percent of revenue)[62]	Maximum utility NPV ($) (percent of revenue)[63]	Probability of positive utility NPV
10 percent	4,895 (0%)	-659,107 (-13%)	506,343 (10%)	52%
25 percent	93,278 (2%)	-1,289,951 (-25%)	1,432,403 (27%)	60%
50 percent	182,534 (3%)	-2,535,659 (-48%)	2,720,491 (52%)	60%
75 percent	212,791 (4%)	-3,205,347 (-61%)	3,510,649 (67%)	58%
100 percent	237,647 (5%)	-6,050,810 (-115%)	3,925,125 (75%)	58%

Table 10: Monte Carlo simulation results showing customer NPV for break even HP incentive rate case

Adoption scenario	Average customer NPV($)	Minimum customer NPV ($)	Maximum customer NPV ($)	Probability of positive customer NPV
10 percent	9,696	8,771	10,550	100%
25 percent	8,650	7,403	9,672	100%
50 percent	7,208	6,200	8,449	100%
75 percent	6,041	4,678	7,443	100%
100 percent	4,794	3,221	6,378	100%

Table 11: Monte Carlo simulation results showing utility NPV for ~$0.12/kWh – as the assumed HP incentive rate above 500 kWh ($/kWh)

Adoption scenario	Average utility NPV ($) (percent of revenue)[64]	Minimum utility NPV ($) (percent of revenue)[65]	Maximum utility NPV ($)(percent of revenue)[66]	Probability of positive utility NPV
10 percent	333,097 (6%)	-169,069 (-3%)	860,740 (16%)	97%
25 percent	789,131 (15%)	-818,418 (-16%)	2,276,064 (43%)	96%
50 percent	1,277,384 (24%)	-1,419,970 (-27%)	3,502,613 (67%)	93%
75 percent	1,587,991 (30%)	-2,504,256 (-48%)	4,750,075 (90%)	92%
100 percent	1,678,329 (32%)	-2,926,920 (-56%)	5,021,789 (96%)	88%

Table 12:Monte Carlo simulation results showing customer NPV for ~$0.12/kWh – as the assumed HP incentive rate above 500 kWh ($/kWh)

Adoption scenario	Average customer NPV($)	Minimum customer NPV ($)	Maximum customer NPV ($)	Probability of positive customer NPV
10 percent	798	-229	1,823	99%
25 percent	834	-246	1,991	99%
50 percent	829	-319	2,071	99%
75 percent	873	-693	2,126	98%
100 percent	1,015	-249	2,288	99%

[61] IPEC operating revenue for the FY2019 was $5,256,132 as per the IPEC rate case 2020, which is the revenue used for these calculations.
[62] Ibid.
[63] Ibid.
[64] IPEC operating revenue for the FY2019 was $5,256,132 as per the IPEC rate case 2020, which is the revenue used for these calculations.
[65] Ibid.
[66] Ibid.

5 Recommendations

To encourage beneficial electrification through implementation of heat pumps in Kake, utility rates for heat pumps should be mutually beneficial for the customer and utility. If the utility charges the customer the residential rate and COPA for additional heat pump kWhs that are non-PCE eligible, the customer does not benefit by switching from their current heating system (refer to Appendix A). To incentivize the customer, the utility can offer a special rate for total household power use over 500 kWh per month for those with a heat pump installed (the 'heat pump incentive rate'.)

The values listed in Table 13 represent the recommended heat pump incentive rate for usage above 500 kWh per household per month. These rates are based on NPV Monte Carlo simulations performed in section 4.3. This table shows a range of values which ensure a positive NPV for both the customer and the utility. The lower, minimum, values in Table 13 represent the break even values for the utility NPV of the heat pump incentive rate and the higher, maximum, values for the rate are about $0.12/kWh, which was found to ensure a high probability of a positive NPV for both the customer and the utility.

The minimum values result in a lower probability of having a positive utility NPV, and are associated with lower average utility NPV values; while they ensure a higher average customer NPV value, and always ensure a positive customer NPV. The maximum value tested of $0.12/kWh ensures a higher average utility NPV, and a higher probability of the utility having a positive utility NPV, while having a lower average customer NPV, but still ensuring a positive customer NPV. These averages and probabilities are given in detail in Tables 9 through 12.

The total rate charged by the utility for heat pump usage that brings the customer's monthly total over 500 kWh will include the heat pump incentive rate and a Cost of Power Adjustment (COPA). The heat pump incentive rate is fixed, whereas COPA is variable and dependent on the utility's fuel cost. Table 13 illustrates these values.

Table 13: Recommended HP incentive rate for consumption above 500 kWh per month

Scenario	HP incentive rate above 500 kWh ($/kWh)	HP incentive rate above 500 kWh + COPA[67] ($/kWh)
10 percent adoption	-0.0223 – 0.1200	~0.11 – 0.25
25 percent adoption	-0.0088 – 0.1200	~0.12 – 0.25
50 percent adoption	0.0171 - 0.1200	~0.15 - 0.25
75 percent adoption	0.0365 – 0.1200	~0.17 – 0.25
100 percent adoption	0.0537 – 0.1150	~0.19 – 0.25

From Table 4 and Table 5, we can see that the utility, based on its current diesel generation capacity, can only accommodate a 25 percent heatpump adoption scenario before reaching the generation limits of the current powerhouse in Kake and the imminent Gunnuk Creek

[67] Since COPA varies in the Monte Carlo simulations, these values are an average approximation of the recommended HP incentive rate + COPA.

Hydropower facility.. Therefore, the utility can accommodate approximately 62 customers in Kake switching from their current heating systems to electric heat pumps. In this scenario, approximately 30 percent of the total demand would be met by the new Gunnuk creek hydro project, while the remaining would be met by the existing diesel generation units in Kake. This number is dependent on the excess hydro available and the variability in the streamflow of Gunnuk creek. More excess hydro and favorable streamflow variability, which accommodates higher peak loads, would allow the utility to serve a larger number of customers. Similarly, lower availability of hydro would reduce the number of customers that could be served.

It is important to note that this analysis is based on average heat pump power draw based on the heating load, and does not consider the HP's peak power draw which may be several times the average heat pump hourly electric demand. As a result, the total instantaneous total heat pump load might be about 10 percent higher than the hourly average heat pump load. Further research is required to determine how many heat pumps may be installed without stretching existing system boundaries of IPEC.

The winter months (particularly November to February) have high space heating and electrical loads and low streamflow rates. The streamflow data from the year 2006 shows high streamflow rates in December, and low streamflow rates in January, while the year 2007 shows the opposite. Analysis results are based on hourly streamflow rates for the year 2007. Further, climate change may cause larger variations in existing average streamflow rates. Variability caused by dry vs wet years and climate change is partly captured through the Monte Carlo simulations analysis; however, a more detailed analysis with recent streamflow data is recommended. This would help the utility understand if there has been any further variation in the streamflow over the last decade.

When the utility exceeds the 25 percent adoption scenario, the analysis predicts a higher peak than the utility can currently accommodate (i.e. 720 kW). This demand is primarily in the winter months. The 50 percent adoption scenario (i.e. 124 customers) has a peak demand of 970 kW. There were 81 hours in the year for which peak demand was calculated to exceed 720 kW. These hours were all in the winter months. If the utility is able to manage this demand, a 50 percent adoption scenario could be accommodated. The utility could also encourage customers to maintain an alternate heating source such as their existing heating fuel oil systems, which they could be encouraged to use during times of peak demand which is over the existing utility generation capacity.

The model assumes that additional heat pump demand does not stress the existing transmission and distribution systems, and no major changes would be required for the distribution system with the additional heat pump demand. [68] Any changes in this assumption could increase utility costs considerably and change the utility and customer NPV simulations and analysis. Further, the model also assumes a constant consumer demand (besides the additional heat pump demand), however, if the consumer demand increases over the years, the

[68] The model does assume that part of the marginal non-fuel cost of diesel-fired power is due to depreciation of distribution equipment, so there is some built-in allowance for moderate wear-and-tear from additional heat pump demand.

utility may only be able to accommodate a smaller adoption scenario and fewer households with its current generation and distribution systems.

These model results can hold for other communities in Southeast Alaska within the IPEC territory that have space heating needs, existing community load patterns, excess hydro availability, and generation resources similar to those of Kake and IPEC. A community with at least as much excess hydro as that available in Kake, and similar space heating needs, can have a similar project implemented, though a more detailed analysis would help the utility understand its profits and costs in greater details for other similar projects.

For communities which do not have any available hydro, the “No hydro” case in Table 8 can provide a good baseline (depending on existing community load and additional space heating load). The break even rate (for utility NPV) for HPs above 500 kWh in the five different adoption scenarios for the “No hydro” case ranges between ~$0.23/kWh and $0.26/kWh (including COPA). These values would increase if the utility fuel cost or utility non-fuel cost increases, and can potentially cause the customer to have a lower NPV. The current model can be a potential starting point for analyses of other IPEC communities where similar assumptions are applicable.

6 Conclusion

Beneficial electrification implemented through heat pumps to meet customer heating needs has the potential to be advantageous for ratepayers, the utility, and the environment. In Kake, HPs can offer lower energy costs for customers than conventional fuel heating systems at current diesel and fuel oil prices, when electricity is charged at the “HP incentive rate” as discussed in the report. Further, heat pump use helps the utility, IPEC, spread its fixed costs over a larger number of kWhs, and helps use excess hydro from its newly implemented hydroelectricity project at Gunnuk Creek, which would otherwise be wasted and has lower marginal generation costs.

To incentivize customer adoption of heat pumps, IPEC needs to offer a “HP incentive rate”. This rate would be for use in excess of 500 kWh per month by a household with a heat pump. Until 500 kWh per month, a customer is charged the standard discounted “with PCE rate”, and over 500 kWh per month, the household is offered a HP incentive rate to make the use of HPs mutually beneficial for customers and the utility. If a customer is required to pay the regular residential electric rate for use over 500 kWh per month that is due to a HP, the customer will not benefit economically from the use of a HP.[69]

[69] Some other methods which can be considered to reduce the financial burden for the customers and for encouraging customers to switch to HPs include use of utility rebates and on-bill financing or on-bill repayment. A detailed cost and benefit analysis will be required to understand the impacts of these mechanisms as compared to the current “HP incentive rate” recommended here. For more information about different utility incentive mechanisms which can be applied please refer to Mini-Split Heat Pumps in Alaska: Analysis of Utility Incentives

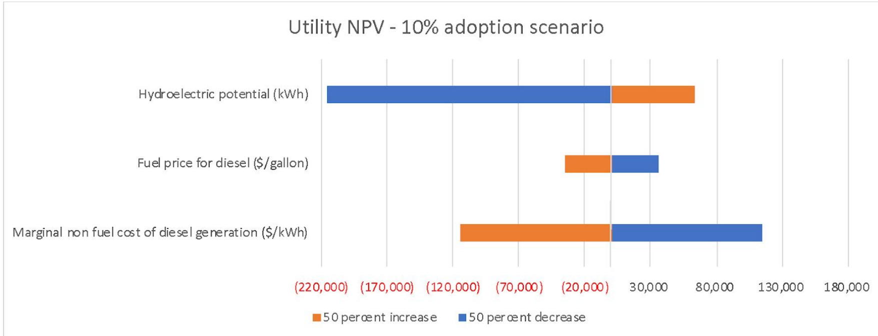
7 Appendix

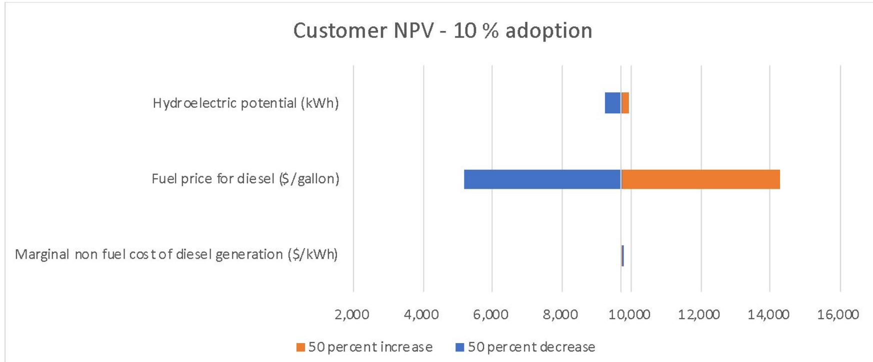
7.1 Appendix A – Utility and customer NPV without a HP incentive rate

In this case, we have calculated the utility and customer NPV, assuming that the customer is paying the utility the regular residential rate plus the COPA surcharge for all additional HP kWh (including additional HP kWh above the 500 kWh threshold beyond which no PCE credit is available). Paying these rates will increase costs for the customer substantially and make the HPs more expensive than their current heating systems, while increasing revenue for utilities. This would not be mutually beneficial for utilities and customers.

Adoption Scenario	Utility NPV ($)	Customer NPV
10 percent	805,887	-13,644
25 percent	1,471,925	-12,920
50 percent	2,595,708	-11,953
75 percent	4,575,759	-11,170
100 percent	5,468,634	-10,519

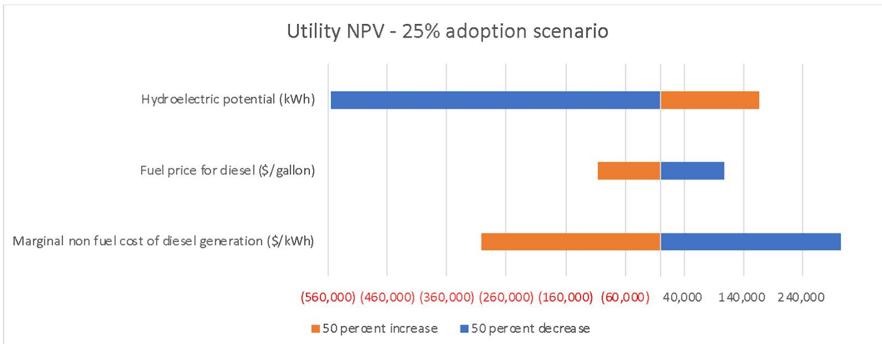
7.2 Appendix B – Sensitivity analysis (at break even HP incentive rate) for various adoption rates of heat pumps in the community

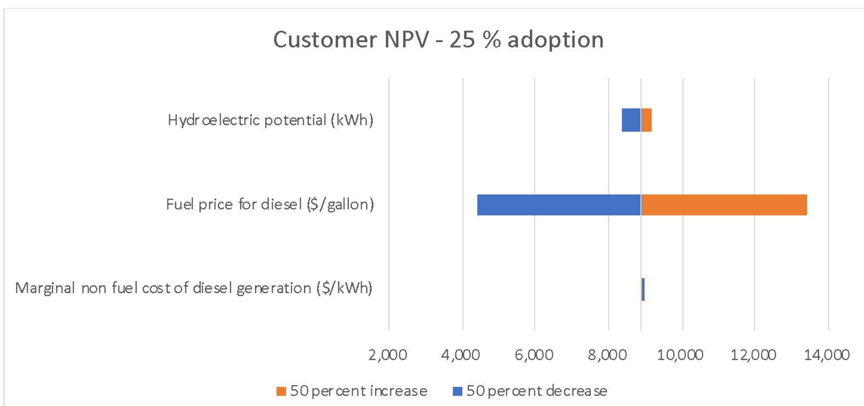




Assumptions used for sensitivity analysis (10 percent adoption scenario)	Value
Break even HP incentive rate	-$0.0223/kWh
COPA surcharge[70]	$0.12900/kWh
Fuel price for utility diesel	$2.67/gallon
Marginal non-fuel cost of power from diesel generation	$0.1063/kWh

Figure 10: Sensitivity analysis of utility and customer NPV the 10 percent adoption scenario

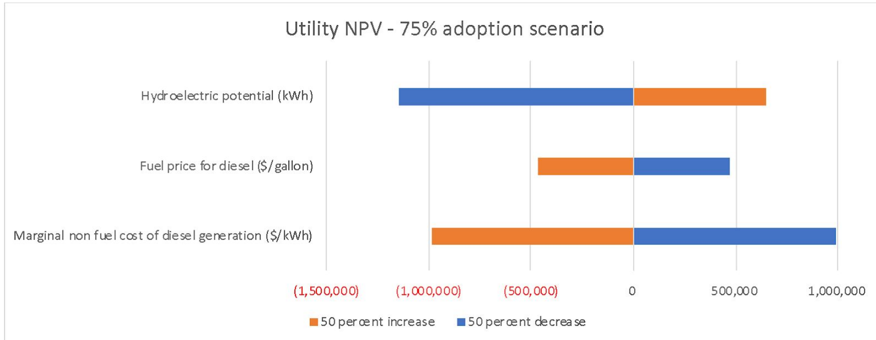


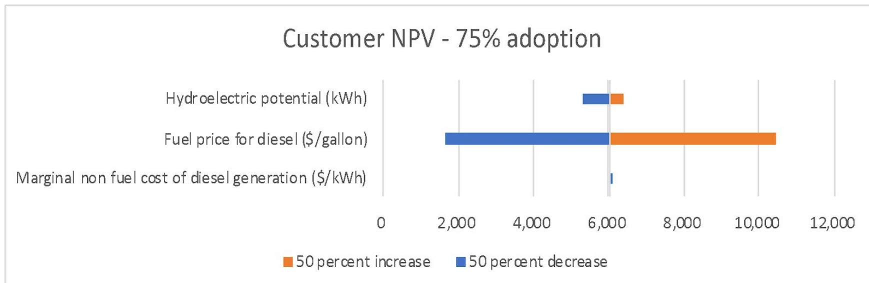


Assumptions used for sensitivity analysis (25 percent adoption scenario)	Value
Break even HP incentive rate	$-0.0088/kWh
COPA surcharge	$0.1289/kWh
Fuel price for utility diesel	$2.67/gallon
Marginal non-fuel cost of power from diesel generation	$0.1063/kWh

Figure 11: Sensitivity analysis of utility and customer NPV the 25 percent adoption scenario

[70] The COPA surcharge will vary with the fuel price for utility diesel, however it stays constant at this given rate while checking sensitivity of the other two parameters i.e. hydroelectric potential and marginal non-fuel cost of power from diesel generation.

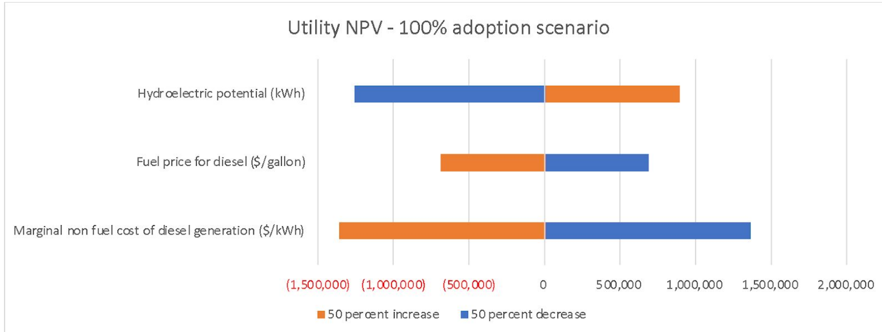


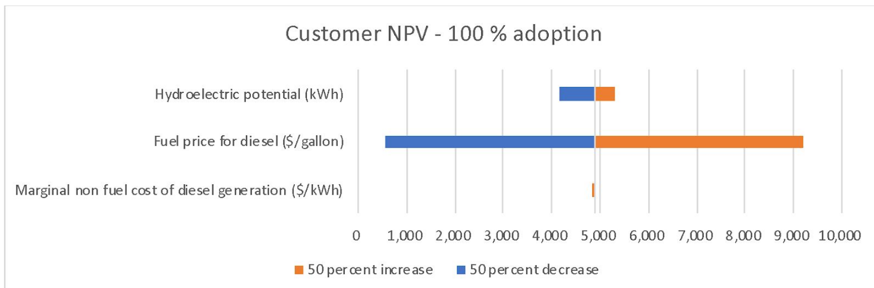


Assumptions used for sensitivity analysis (75 percent adoption scenario)	Value
Break even HP incentive rate	$0.0365/kWh
COPA surcharge[71]	$0.1307/kWh
Fuel price for utility diesel	$2.67/gallon
Marginal non-fuel cost of power from diesel generation	$0.1063/kWh

Figure 12: Sensitivity analysis of utility and customer NPV the 75 percent adoption scenario

[71] Ibid.





Assumptions used for sensitivity analysis (100 percent adoption scenario)	Value
Break even HP incentive rate	$0.0537/kWh
COPA Surcharge[72]	$0.1323/kWh
Fuel price for utility diesel	$2.67/gallon
Marginal non-fuel cost of power from diesel generation	$0.106/kWh

Figure 13: Sensitivity analysis of utility and customer NPV the 100 percent adoption scenario

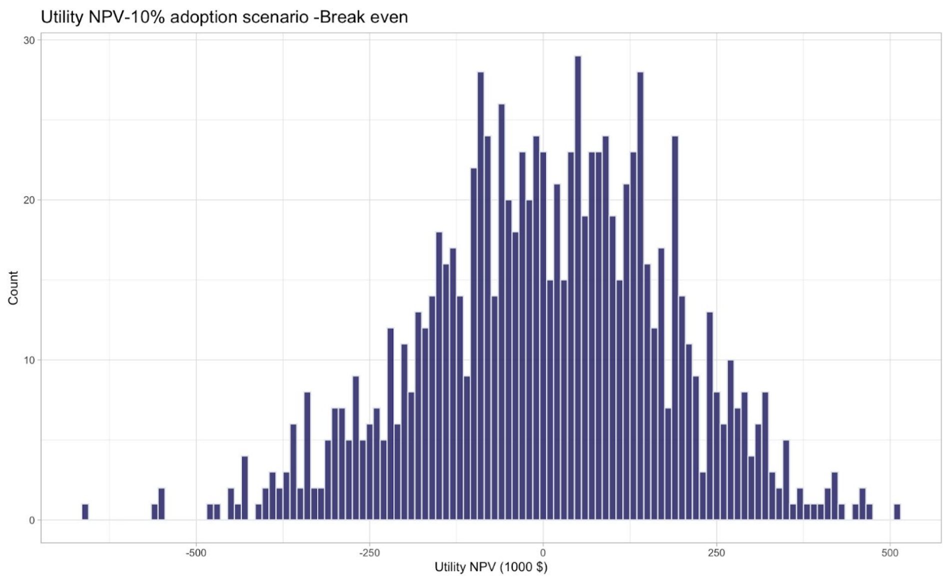
[72] Ibid.

7.3 Appendix C – Monte Carlo simulations

In each of the following sections there are two simulations. The first simulation – labeled "Break even" - was performed at the break even HP incentive rate.[73] The second simulation reflects a HP incentive rate that varies slightly among the adoption scenarios, but is approximately \$0.12/kWh. This rate ensures a higher probability of the utility making a positive profit while also ensuring high probability for a positive customer NPV (but reduced average customer NPV as compared to the break even case).

7.3.1 10 percent adoption

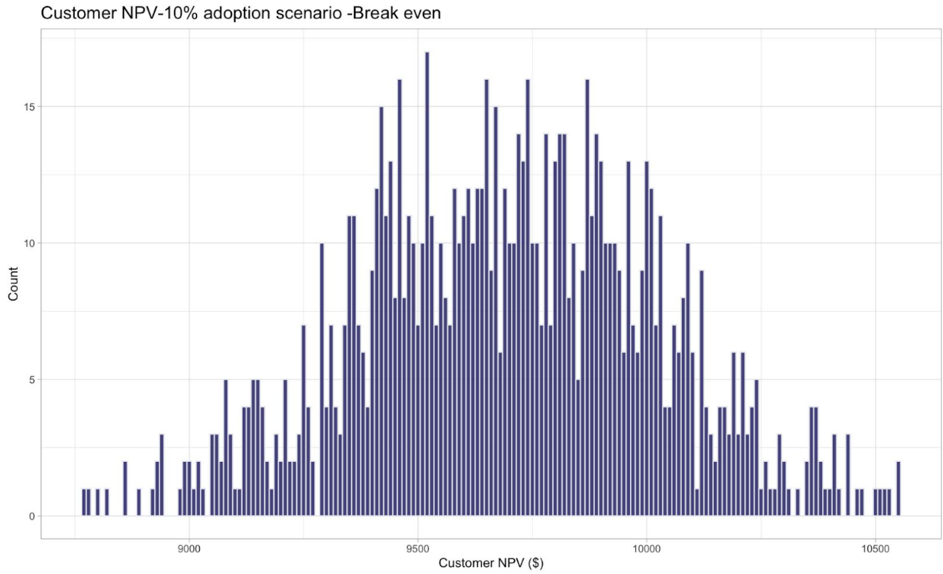
7.3.1.1 Utility NPV – Break even - HP incentive rate = \$-0.0223/kWh



Description	Utility NPV
Standard deviation	178,396
Average	4,895
Minimum	(659,107)
Maximum	506,343
Median	9,951
Probability of positive NPV	52%

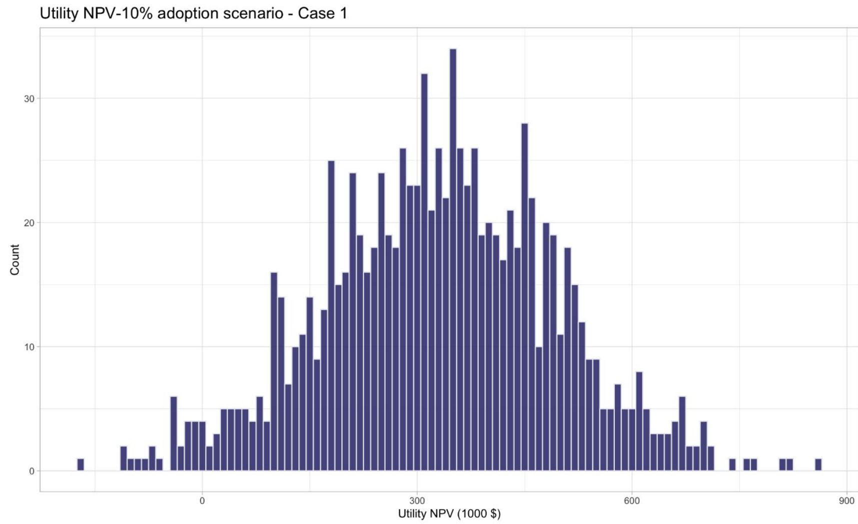
[73] This rate can be found as the break even HP incentive rate for HPs for the 2007 hydro case in Table 8. The customer pays a COPA surcharge in addition to this rate. In the Monte Carlo simulations the COPA surcharge varies with fuel price of utility diesel (which changes with a 3 percent deviation).

7.3.1.2 Customer NPV – Break even- HP incentive rate = $-0.0223/kWh



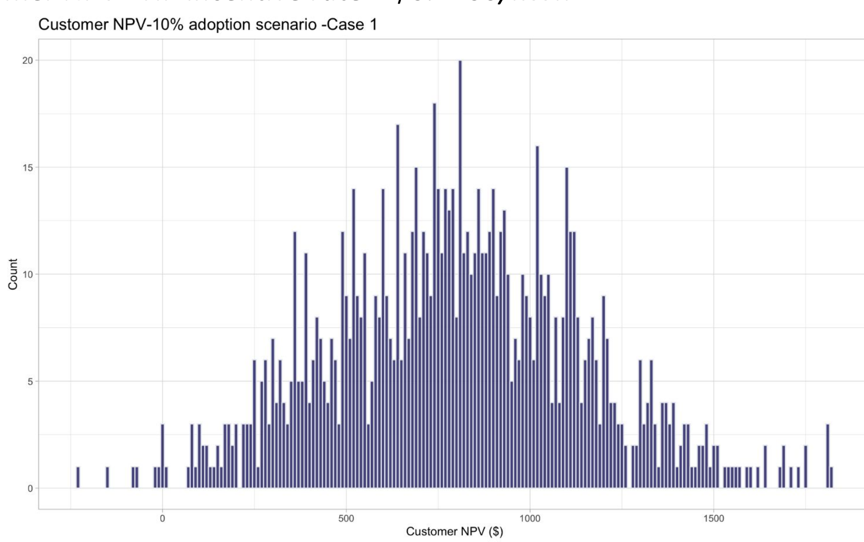
Description	Customer NPV
Standard deviation	326
Average	9,696
Minimum	8,771
Maximum	10,550
Median	9,699
Probability of positive NPV	100%

7.3.1.3 Utility NPV – HP incentive rate = $0.1200/kWh



Description	Utility NPV
Standard deviation	162,038
Average	330,097
Minimum	(169,069)
Maximum	860,740
Median	333,154
Probability of positive NPV	97%

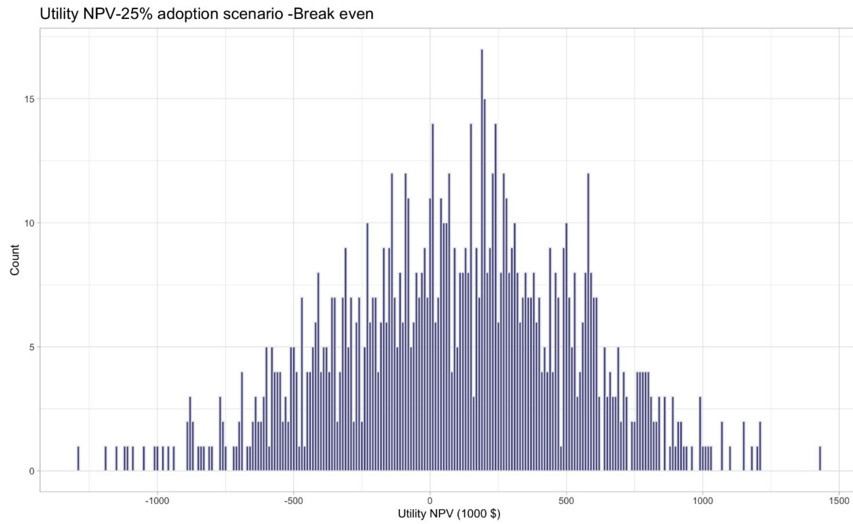
7.3.1.4 Customer NPV - HP incentive rate = $0.1200/kWh



Description	Customer NPV
Standard deviation	342.9145283
Average	798.47
Minimum	(229.87)
Maximum	1,823.28
Median	791.37
Probability of positive NPV	99%

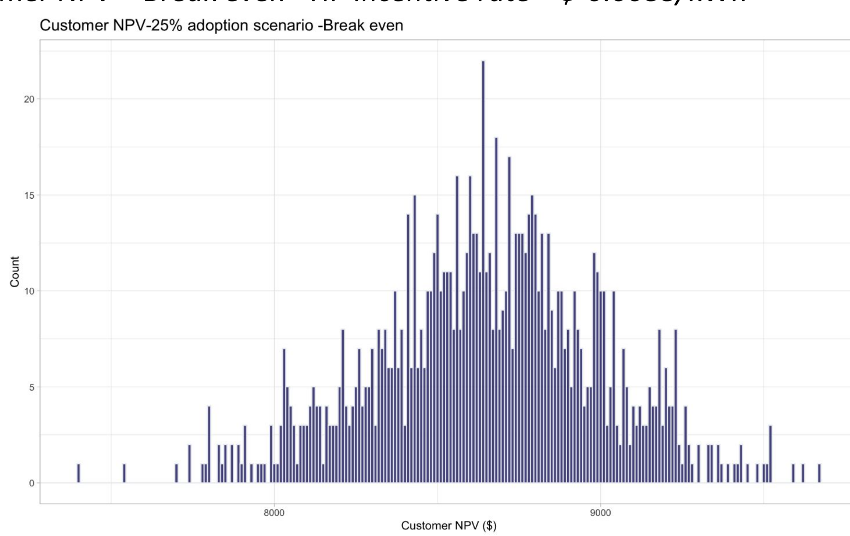
7.3.2 25 percent adoption

7.3.2.1 Utility NPV – Break even - HP incentive rate =$-0.0088/kWh



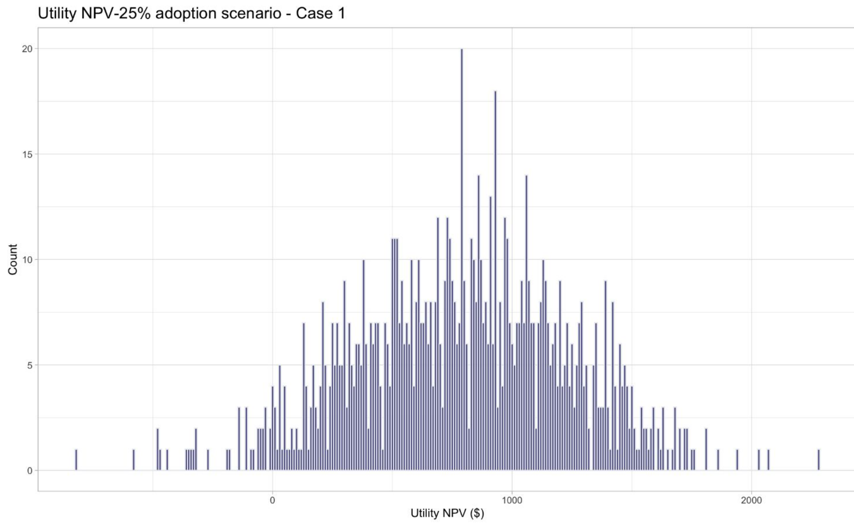
Description	Utility NPV
Standard deviation	430,656
Average	93,278
Minimum	(1,289,951)
Maximum	1,432,403
Median	109,402
Probability of positive NPV	60%

7.3.2.2 Customer NPV – Break even - HP incentive rate = $-0.0088/kWh



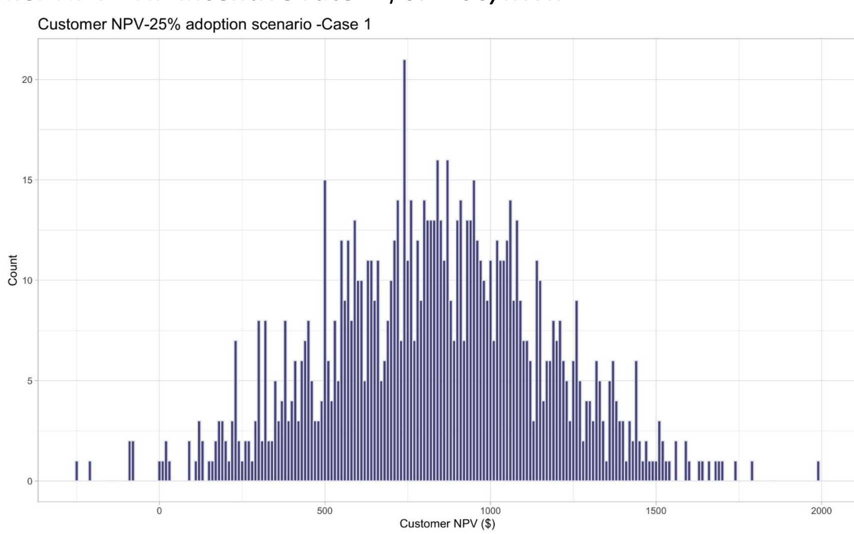
Description	Customer NPV
Standard deviation	342
Average	8,650
Minimum	7,403
Maximum	9,672
Median	8,651
Probability of positive NPV	100%

7.3.2.3 Utility NPV - HP incentive rate = $0.1200/kWh



Description	Utility NPV
Standard deviation	442,085
Average	789,131
Minimum	(818,418)
Maximum	2,276,064
Median	795,044
Probability of positive NPV	96%

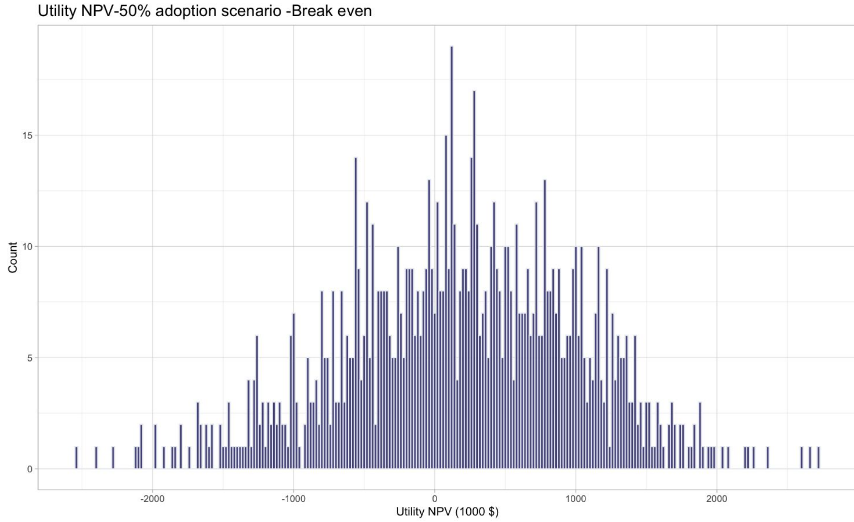
7.3.2.4 Customer NPV - HP incentive rate = $0.1200/kWh



Description	Customer NPV
Standard deviation	333
Average	834
Minimum	(246)
Maximum	1,991
Median	839
Probability of positive NPV	99%

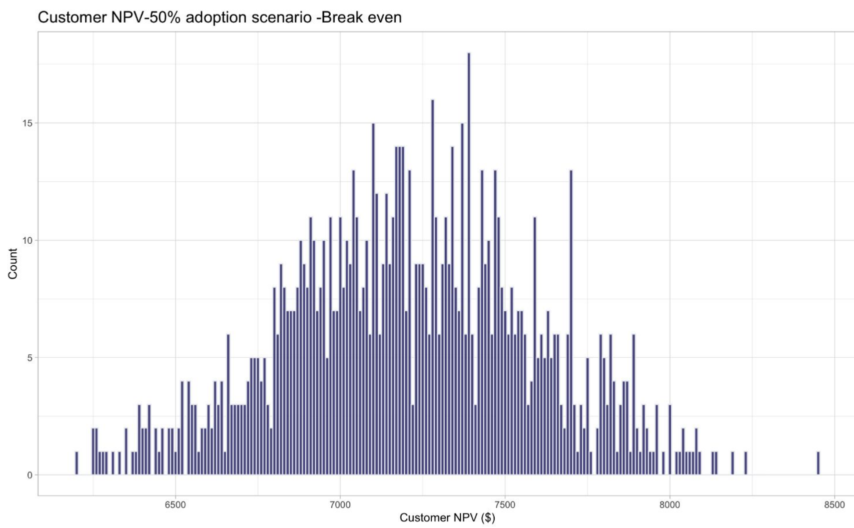
7.3.3 50 percent adoption

7.3.3.1 Utility NPV – Break even - HP incentive rate = $0.0171/kWh



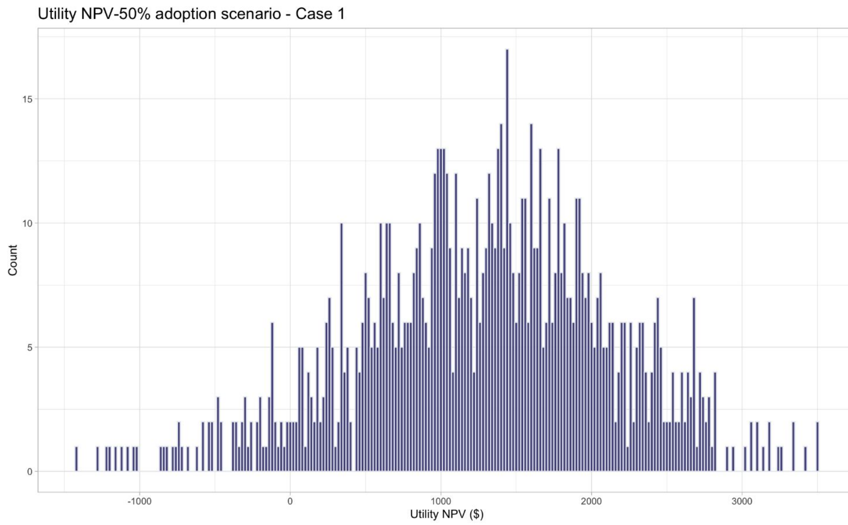
Description	Utility NPV
Standard deviation	832,614
Average	182,534
Minimum	(2,535,659)
Maximum	2,720,491
Median	203,636
Probability of positive NPV	60%

7.3.3.2 Customer NPV – Break even - HP incentive rate = $0.0171/kWh



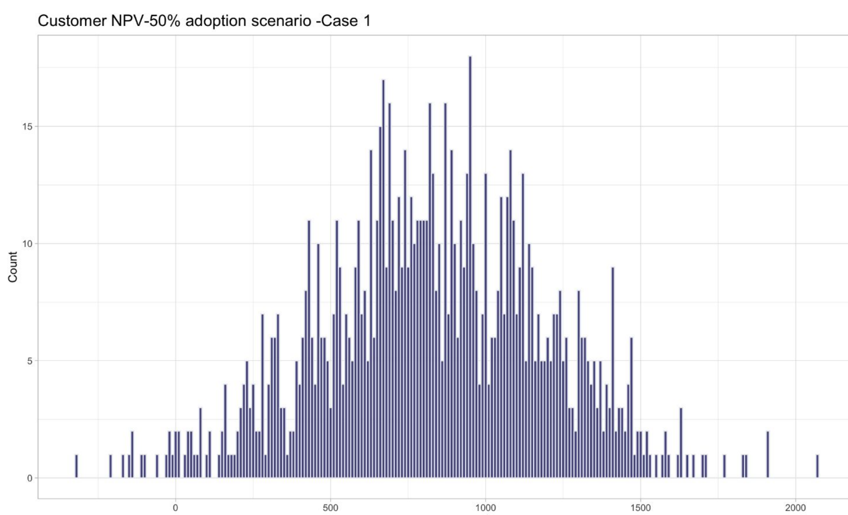
Description	Customer NPV
Standard deviation	377
Average	7,208
Minimum	6,200
Maximum	8,449
Median	7,200
Probability of positive NPV	100%

7.3.3.3 Utility NPV - HP incentive rate = $0.1200/kWh



Description	Utility NPV
Standard deviation	832,758
Average	1,277,384
Minimum	(1,419,970)
Maximum	3,502,613
Median	1,326,206
Probability of positive NPV	93%

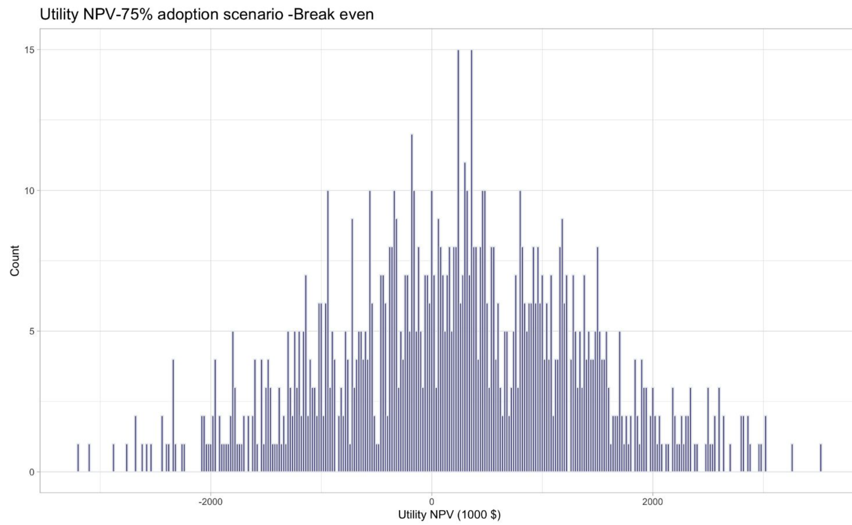
7.3.3.4 Customer NPV - HP incentive rate = $0.1200/kWh



Description	Customer NPV
Standard deviation	364
Average	829
Minimum	(319)
Maximum	2,071
Median	824
Probability of positive NPV	99%

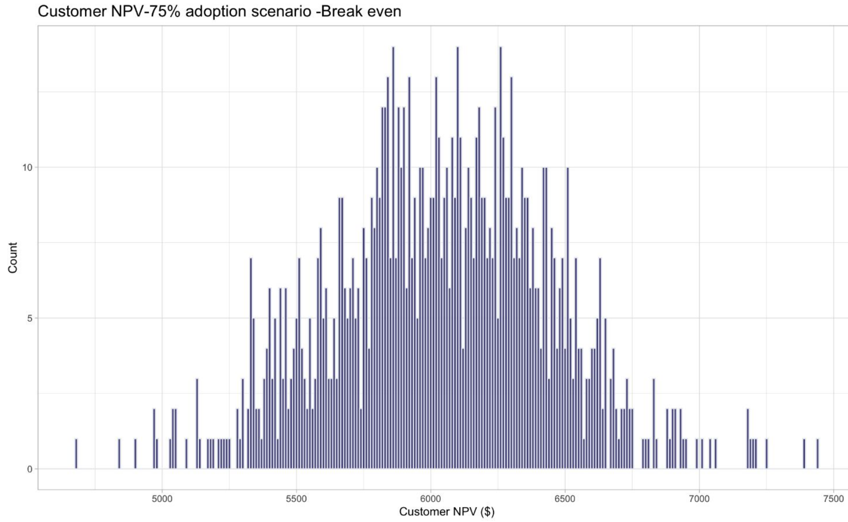
7.3.4 75 percent adoption

7.3.4.1 Utility NPV – Break even - HP incentive rate = $0.0365/kWh



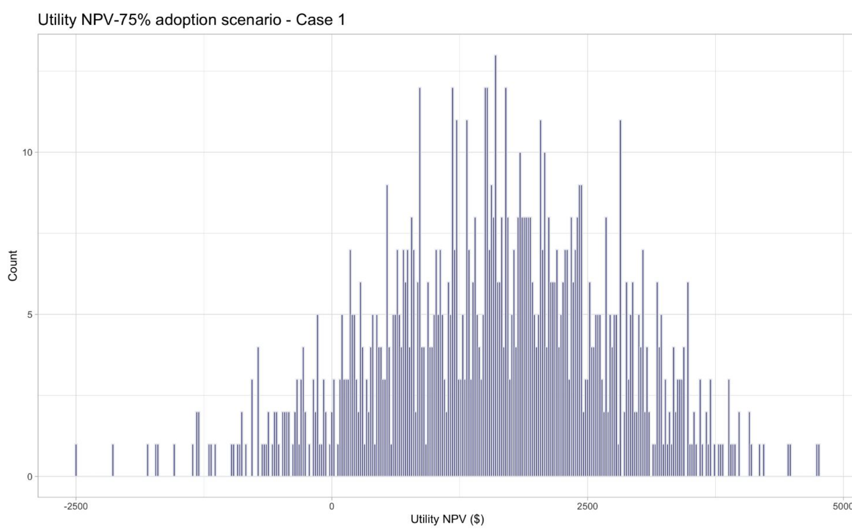
Description	Utility NPV
Standard deviation	1,129,956
Average	212,791
Minimum	(3,205,347)
Maximum	3,510,649
Median	244,475
Probability of positive NPV	58%

7.3.4.2 Customer NPV – Break even - HP incentive rate = $0.0365/kWh



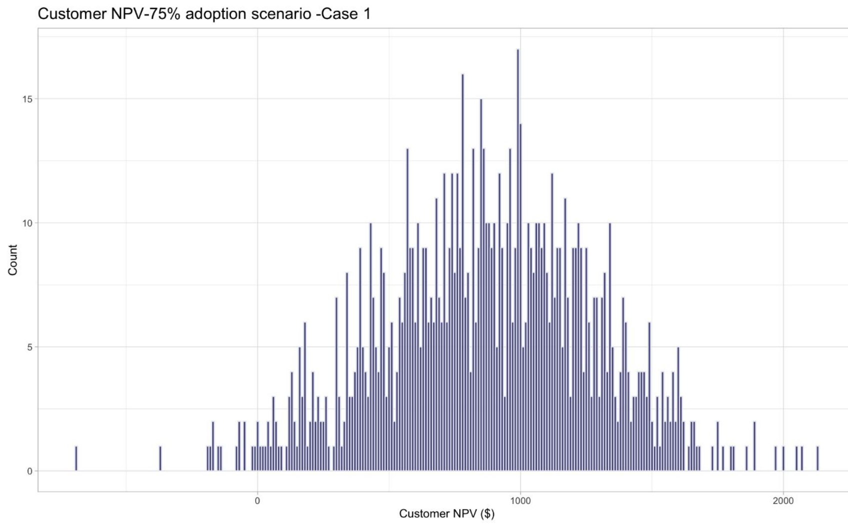
Description	Customer NPV
Standard deviation	405
Average	6,041
Minimum	4,678
Maximum	7,443
Median	6,045
Probability of positive NPV	100%

7.3.4.3 Utility NPV - HP incentive rate = $0.1200/kWh



Description	Utility NPV
Standard deviation	1,137,245
Average	1,587,991
Minimum	(2,504,256)
Maximum	4,750,075
Median	1,625,525
Probability of positive NPV	92%

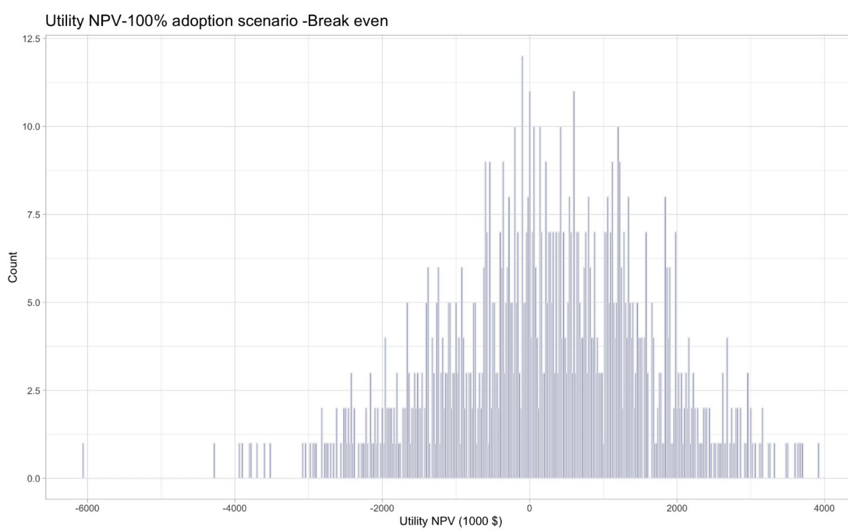
7.3.4.4 Customer NPV - HP incentive rate = $0.1200/kWh



Description	Customer NPV
Standard deviation	404
Average	873
Minimum	(693)
Maximum	2,126
Median	877
Probability of positive NPV	98%

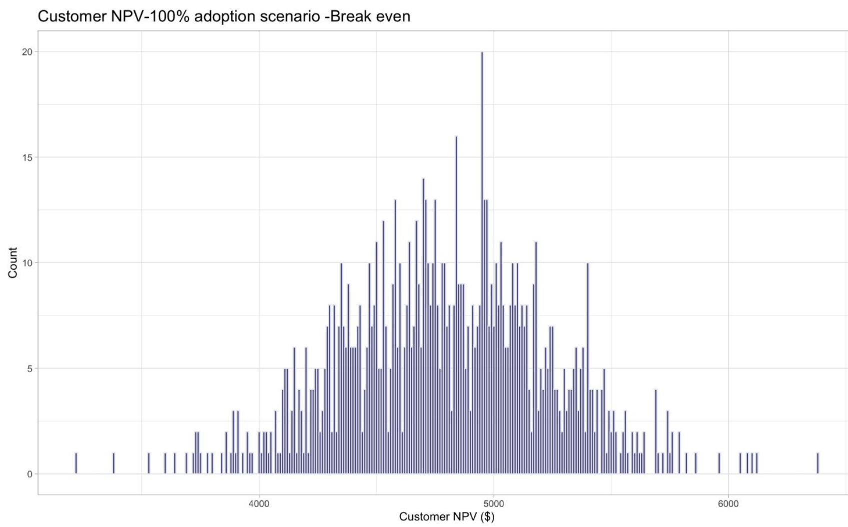
7.3.5 100 percent adoption

7.3.5.1 Utility NPV – Break even - HP incentive rate = $0.0537/kWh



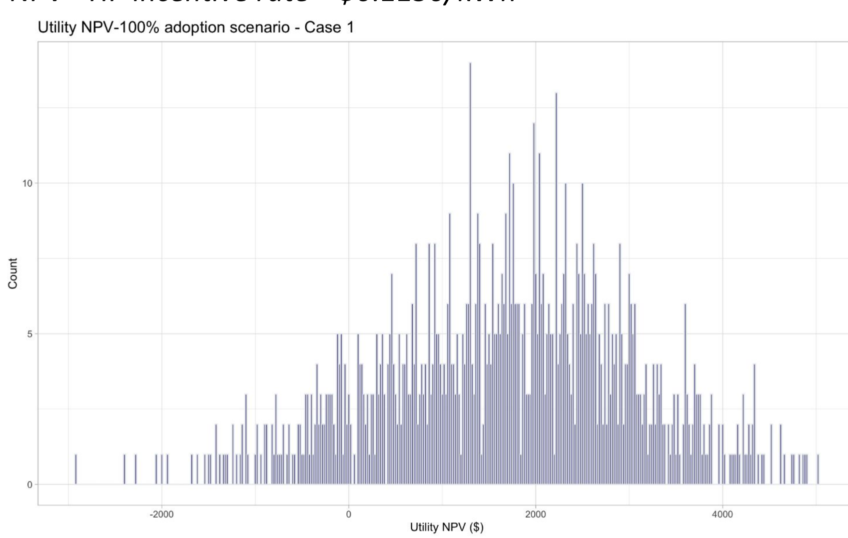
Description	Utility NPV
Standard deviation	1,382,489
Average	237,647
Minimum	(6,050,810)
Maximum	3,925,125
Median	266,908
Probability of positive NPV	58%

7.3.5.2 Customer NPV – Break even - HP incentive rate = $0.0537/kWh



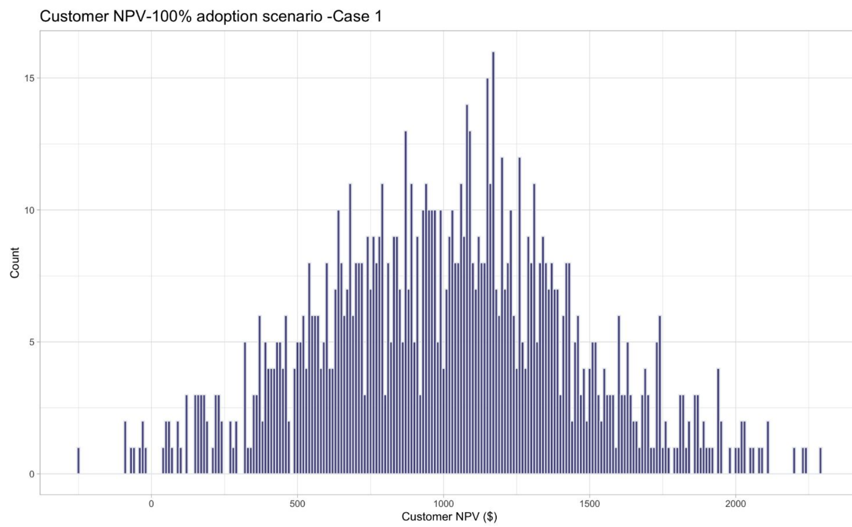
Description	Customer NPV
Standard deviation	433
Average	4,794
Minimum	3,221
Maximum	6,378
Median	4,794
Probability of positive NPV	100%

7.3.5.3 Utility NPV - HP incentive rate = $0.1150/kWh



Description	Utility NPV
Standard deviation	1,337,132
Average	1,678,329
Minimum	(2,926,920)
Maximum	5,021,789
Median	1,739,167
Probability of positive NPV	88%

7.3.5.4 Customer NPV - HP incentive rate = $0.1150/kWh



Description	Customer NPV
Standard deviation	435
Average	1,015
Minimum	(249)
Maximum	2,288
Median	1,027
Probability of positive NPV	99%