Colorado Residential Retrofit Energy District (CoRRED) Phase I

Final Modeling Results

Lieko Earle, Jeff Maguire, Prateek Munankarmi, and Dave Roberts

National Renewable Energy Laboratory

Prepared on behalf of the Colorado Energy Office by the National Renewable Energy Laboratory (NREL) under TSA-19-01206 (in collaboration with RMI and Xcel Energy). This work was funded by the U.S. Department of Energy.

NREL is a national laboratory of the U.S. Department of Energy
Office of Energy Efficiency & Renewable Energy
Operated by the Alliance for Sustainable Energy, LLC

This report is available at no cost from the National Renewable Energy Laboratory (NREL) at www.nrel.gov/publications.

Contract No. DE-AC36-08GO28308

Strategic Partnership Project Report
NREL/TP-5500-82325
April 2022

Colorado Residential Retrofit Energy District (CoRRED) Phase I

Final Modeling Results

Lieko Earle, Jeff Maguire, Prateek Munankarmi, and Dave Roberts

National Renewable Energy Laboratory

Suggested Citation
Earle, Lieko, Jeff Maguire, Prateek Munankarmi, and Dave Roberts. 2022. *Colorado Residential Retrofit Energy District (CoRRED) Phase I: Final Modeling Results*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-5500-82325. https://www.nrel.gov/docs/fy22osti/82325.pdf.

NREL is a national laboratory of the U.S. Department of Energy
Office of Energy Efficiency & Renewable Energy
Operated by the Alliance for Sustainable Energy, LLC

This report is available at no cost from the National Renewable Energy Laboratory (NREL) at www.nrel.gov/publications.

Contract No. DE-AC36-08GO28308

Strategic Partnership Project Report
NREL/TP-5500-82325
April 2022

National Renewable Energy Laboratory
15013 Denver West Parkway
Golden, CO 80401
303-275-3000 • www.nrel.gov

Cover Photos by Dennis Schroeder: (clockwise, left to right) NREL 51934, NREL 45897, NREL 42160, NREL 45891, NREL 48097, NREL 46526.

NREL prints on paper that contains recycled content.

Acknowledgments

The authors acknowledge Virginia Castro of the Weatherization and Intergovernmental Programs Office at the U.S. Department of Energy for her support of this research.

List of Acronyms

ACH_{50}	air changes per hour at 50 pascals
AFUE	annual fuel utilization efficiency
ANSI	American National Standards Institute
ASHP	air-source heat pump
BEV	battery electric vehicle
CO_2	carbon dioxide
CoRRED	Colorado Residential Retrofit Energy District
DER	distributed energy resource
EV	electric vehicle
EVI-Pro	Electric Vehicle Infrastructure Projection
HELICS	Hierarchical Engine for Large-scale Infrastructure Co-Simulation
HEMS	home energy management system
HPWH	heat pump water heater
HSPF	heating seasonal performance factor
HVAC	heating, ventilation, and air-conditioning
MOER	marginal operating emission rate
NREL	National Renewable Energy Laboratory
OCHRE	Object-oriented Controllable High-resolution Residential Energy Model
PHEV	plug-in hybrid electric vehicle
PSCo	Public Service Company of Colorado
PV	photovoltaics
SEER	seasonal energy efficiency ratio
TOU	time of use
UEF	uniform energy factor

Executive Summary

The Colorado Residential Retrofit Energy District (CoRRED) project team was formed in 2018 in response to a U.S. Department of Energy State Energy Program Competitive solicitation. Led by the Colorado Energy Office, the collaboration comprises the National Renewable Energy Laboratory (NREL), RMI (formerly Rocky Mountain Institute), and Colorado's largest utility, Xcel Energy. The team was awarded funding for a three-year project to establish an experimental plan to answer a growing list of technical, regulatory, and financial questions regarding how existing building and utility infrastructures can be enhanced with energy-efficiency retrofit measures, renewable energy, and electrification to provide greater affordability, resilience, and reliability.

NREL's role in this project was to conduct a simulation study using building and grid modeling tools and to develop an experimental plan based on the results. We modeled a community of existing single-family homes to assess the performance of various technology packages that include efficiency measures, electrification, photovoltaics (PV), energy storage, electric vehicle (EV) charging, and controls in terms of cost-effectiveness and benefits to both residents and the utility grid. Instead of choosing between traditional energy-efficiency upgrades of existing buildings and cost-effective integration of PV and other distributed energy resource (DER) technologies, this project investigated the most promising combinations of both conventional energy-efficiency retrofits and more advanced DER technologies that provide concrete value to both residents and utilities as well as greater system-level benefits such as demand flexibility for utility planning and operation.

We developed a model of a mixed-fuel community of 30 homes based on neighborhood and distribution grid characteristics found in the Central Park community of Denver, Colorado. We explored six different retrofit scenarios, ranging from conventional energy-efficiency upgrades only, to full electrification with and without efficiency measures, as well as with and without advanced DER technologies such as PV and batteries. We applied Xcel Energy's year-round time-of-use (TOU) rate structure, which was recently approved and is being implemented in limited trials. Using NREL-developed buildings-to-grid co-simulation tools we studied the impacts of retrofit scenarios on energy consumption, utility bills, community load profiles during peak price periods, voltage profiles, and secondary transformer loading. We also calculated the carbon emissions associated with energy use in the community.

One important conclusion is that electrification can be achieved without negatively impacting the monthly utility bill. Our simulations show that the efficient electrification scenario, which combines energy-efficiency measures such as air sealing and infiltration with advanced DER technologies, would result in the lowest source energy consumption and carbon emissions of the six scenarios studied. Even with the addition of an EV in one-third of the homes, the average homeowner would see a utility bill decrease. Furthermore, while the homes that have EVs would likely see their utility bills increase, the incremental cost is much less than the equivalent cost of gasoline for the same miles driven. This community would be a net producer of electricity during much of the year thanks to on-site PV generation. The controls and home battery enable substantial load shifting and arbitrage, where electricity is stored when the price is low and discharged when the price is high, so these homes can avoid purchasing electricity during peak periods, especially during the summer. In contrast, the electrification scenarios that do not include energy-efficiency retrofits but instead replace natural gas appliances with electric alternatives with the lowest first cost fare poorly in terms of source energy consumption, utility bills, and carbon emissions. PV, controls, and batteries play a crucial role in this case because of the added load created by inefficient equipment.

Our results highlight a number of challenges that require further research. The energy bill savings achievable through efficient electrification tell only part of the story because the upgrades require upfront costs, and modest utility bill savings result in long payback periods that are not appealing to most homeowners. Looking forward, we anticipate that the problem of peak load management will grow in both complexity and importance because widespread electrification would subject the entire distribution system to winter peaks that occur primarily in the early mornings, and PV would not be able to shift the load in a meaningful way. This type of scenario would have implications for the relative value of different DER technologies and their implementation.

In this work we developed and demonstrated an analysis framework and a functional co-simulation platform that can be broadly applied to community-scale beneficial electrification studies in other regions, climates, utility infrastructures, and building typologies. Using techniques developed here we can make specific, targeted recommendations based on quantified projections of energy demand in any given community. Our approach of creating a synthetic neighborhood inspired by Central Park is well suited to produce scenario studies that are perhaps more generally applicable to other neighborhoods of similar vintage, but to obtain more detailed and nuanced results that realistically predict electrification scenarios it is necessary to model the actual buildings and the electrical infrastructure that serves those buildings. This is precisely how we would begin a future field demonstration. We are pursuing field opportunities using an experimental plan that we developed based on the work presented in this report.

Table of Contents

List of Figures

List of Tables

1 Introduction

The Colorado Residential Retrofit Energy District (CoRRED) project team was formed in 2018 in response to a U.S. Department of Energy State Energy Program Competitive solicitation. Led by the Colorado Energy Office, the collaboration comprises the National Renewable Energy Laboratory (NREL), RMI (formerly Rocky Mountain Institute), and Colorado's largest utility, Xcel Energy. The team was awarded funding for a three-year project to test new approaches to demand-side management, demand response, and renewable integration in existing residential buildings in a way that ensures customer affordability, grid resiliency, and reliability. Dubbed "Phase I," the scope of this project is to conduct preliminary research toward design of a retrofit energy district,[1] with particular attention to developing a replicable, collaborative model that can be broadly applied to future innovative energy districts. Phase I outcomes will inform future state intervention in regulatory and utility demand-side management and generation resource planning.

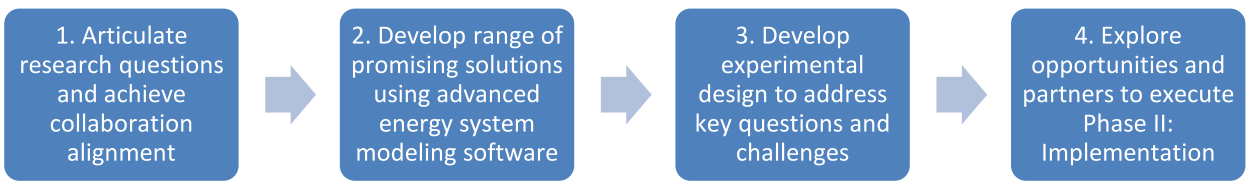

Figure 1. Project objectives flowchart

The four sequential high-level objectives in CoRRED Phase I are shown in Figure 1. To kick off the project, the Colorado Energy Office convened and RMI facilitated a series of initial workshops for the collaboration to define clearly the key research questions that address affordability, resilience, and grid reliability challenges and reach alignment on the premise and analysis approach. The desired outcome was to establish an experimental plan to answer a growing list of technical, regulatory, and financial questions regarding how existing building and utility infrastructures can be enhanced with energy efficiency retrofit measures, renewable energy, and electrification to provide greater affordability, resilience, and reliability. Instead of choosing between traditional energy-efficiency upgrades of existing buildings and cost-effective integration of photovoltaics (PV) and other distributed energy resource (DER) technologies, this project investigated the most promising combinations of *both* conventional energy-efficiency retrofits *and* more advanced DER technologies that provide greater system-level benefits, including:

- Demand flexibility for utility planning and operation
- Value identification and optimization for utilities and residents
- Resident and utility satisfaction and engagement.

[1] An energy district is a system of grid-interactive efficient buildings that incorporates distributed energy resources, energy-efficiency technologies, energy storage, and advanced building controls to optimize energy load and performance. Energy districts have the opportunity to provide greater system benefits than individual measures, such as distributing load across an extended time period, mitigating grid constraints, and increasing system reliability and resiliency.

NREL's role in this project was to conduct the simulation study using building and grid modeling tools and to develop an experimental plan based on the results. We modeled a community of existing single-family homes to assess the performance of various technology packages that include efficiency measures, electrification, PV, energy storage, electric vehicle (EV) charging, and controls in terms of cost-effectiveness and benefits to both residents and the utility grid.

The objectives of the modeling effort were twofold. First, we aimed to characterize the grid flexibility potential and limitations for a range of retrofit scenarios incorporating conventional energy efficiency and more advanced DER technologies. Second, we sought to build out a functional and robust co-simulation platform that can accommodate additional technologies and scenario studies. This report describes our work to meet these objectives. Section 2 details the analysis approach, including the co-simulation framework and modeling tools employed. Section 3 outlines the results and key findings. Section 4 concludes with high-level takeaways and a discussion of future work.

2 Analysis Approach

2.1 Neighborhood Selection and House Characterization

Our first task was to select a neighborhood in the Denver metropolitan area that is representative of a candidate neighborhood for a future field demonstration. We chose Central Park,[2] which is currently Denver's largest residential neighborhood. It is located east of downtown Denver and at the former site of the Stapleton International Airport, which was decommissioned in 1995. The Central Park community was a good candidate on which to base our modeling assumptions because the majority of its homes were constructed in the early 2000s, which means that the major equipment such as heating, ventilation, and air-conditioning (HVAC) systems and water heaters are just approaching end of life. This first equipment replacement timing is a unique window of opportunity for a community retrofit strategy because it may be the only time when the replacement cycle is synchronized across many homes. The master-planned community model found in Central Park is representative of housing stock commonly found in the Denver metropolitan area and across the Front Range. Also, because it is a relatively new neighborhood, there is a higher likelihood that the distribution infrastructure could accommodate electrification upgrades.

Based on the characteristics of Central Park homes, we created a synthetic neighborhood using ResStock™, an NREL-developed analysis tool that generates a statistical sampling of the U.S. single-family housing stock at high spatial resolution.[3] We sampled for 30 single-family buildings using typology consistent with the geographic location (e.g., 2000s vintage, mixed fuel, 2- to 4-bedroom homes). The goal was not to model the same houses that exist in Central Park, but rather to create a statistically representative synthetic neighborhood that we can use for our simulation study. The distribution of key house characteristics is given in Figure 2.

Based on firsthand knowledge of the neighborhood being studied and engineering judgement, we adjusted certain parameters to be more representative of the actual neighborhood. For example, some of the sampled homes did not have a dishwasher, but we were confident that every home in this neighborhood would have a dishwasher. The distribution of house sizes was adjusted slightly to account for a higher fraction of larger homes, and we forced all the homes to have cooling equipment; we knew these were reasonable assumptions to make for Central Park. We also increased the fraction of LED lighting in the home to be higher than indicated by the sample statistics and increased the miscellaneous loads power consumption to better match the increasing number of devices in homes today.

One of the key parameters for this community is the thermostat setpoint. ResStock can generate distributions of both nominal setpoints and setup and setback periods. Including setup and setback has a substantial impact on the timing of power consumption in the home as well as the overall energy consumption. While our simulations do allow a home energy management system (HEMS) to control the thermostat setpoint, it is also highly likely that many homes in this neighborhood would employ some type of setup/setback schedule. Therefore, we decided to

[2] Central Park was formerly called the Stapleton neighborhood. Its name was changed in August 2020.
[3] For more information, see https://www.nrel.gov/buildings/resstock.html.

incorporate setpoint schedules from ResStock that include setup and setback as the starting point in each home, then allow the HEMS to control around this preset schedule.

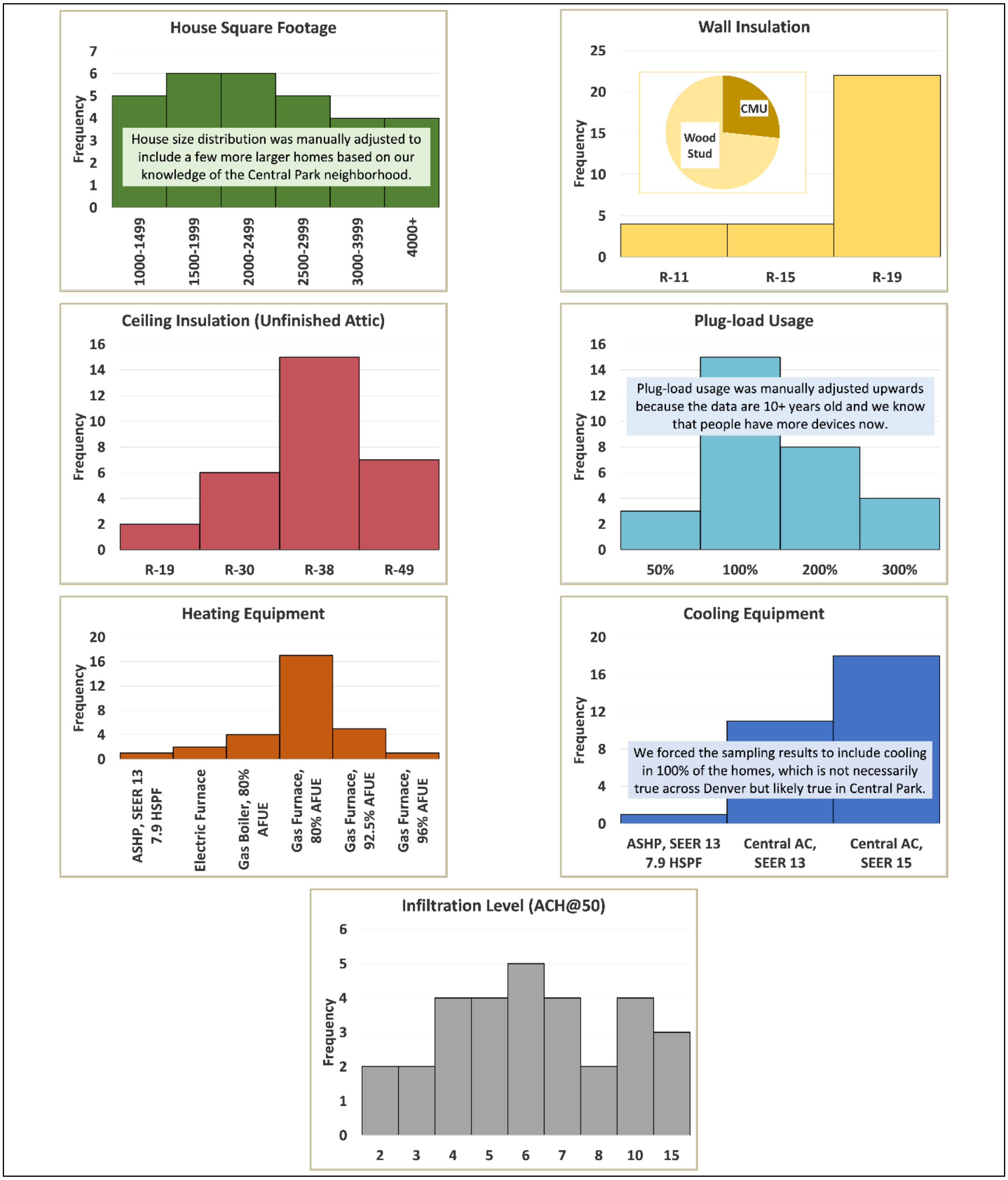

Figure 2. Distribution of house characteristics used to model synthetic neighborhood

2.2 Secondary Feeder Model

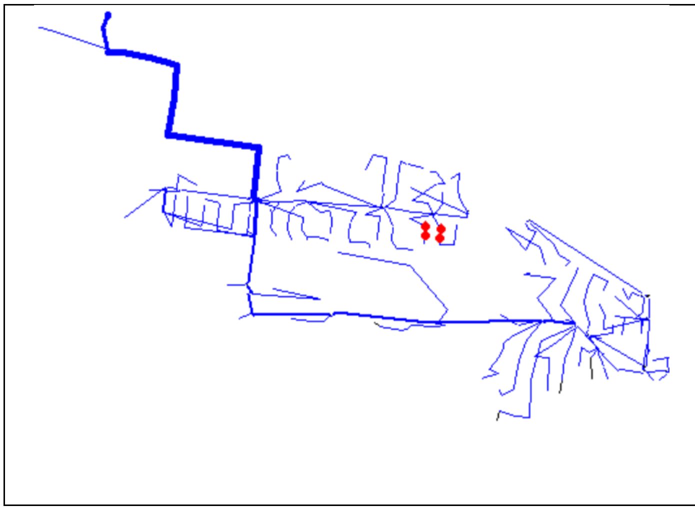

Figure 3. Primary distribution feeder layout

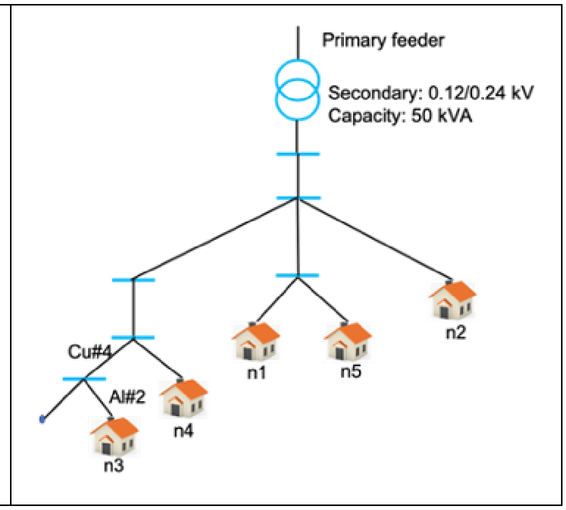

Figure 4. Generic secondary feeder model layout

To study distribution system impacts, we first obtained a suitable primary feeder model and hourly substation meter data from Xcel Energy under a nondisclosure agreement. However, residential homes connect with the grid at a much lower voltage level (120V/240V), so the impact of our measures is difficult to see at the primary distribution level. A detailed model of the secondary feeder could not readily be obtained for this project. Understanding that the broader goal of this work is to build the co-simulation framework and demonstrate how a smart electrification retrofit may be designed for communities *like* Central Park, we decided to develop generic secondary feeder models for our analysis. The 30 homes are connected to the primary feeder via four distribution transformers, as shown by red dots in Figure 3. The synthetic secondary distribution feeder models connect the distribution transformers to the houses. The parameters used to model the secondary feeder are summarized in Table 1. Following Xcel Energy's standard practice, the service lines that run from each house to the common point are modeled to be 2-gauge aluminum and the rest of the secondary feeder lines to be 4-gauge copper. Realistic impedance values corresponding to the lines were considered in the feeder models. The line length from the transformer to individual homes are in range of 30–200 ft, and all secondary lines are overhead. While lines in Central Park are actually underground, our generic model assumes overhead lines because we did not update this parameter in the tool that we used to generate the model. A layout of one of the secondary models is shown in Figure 4.

Table 1. Distribution Feeder Parameters

Transformer ID	Number of Houses	Transformer Size	Voltage Level	Line Configuration	
91129481	5	50 kVA	120/240 V	Overhead	Service wire: Al #2 Other wires: Cu #4
91129201	10	100 kVA			
418232014	6	50 kVA			
117977518	9	100 kVA			

2.3 Co-Simulation Tools and Framework

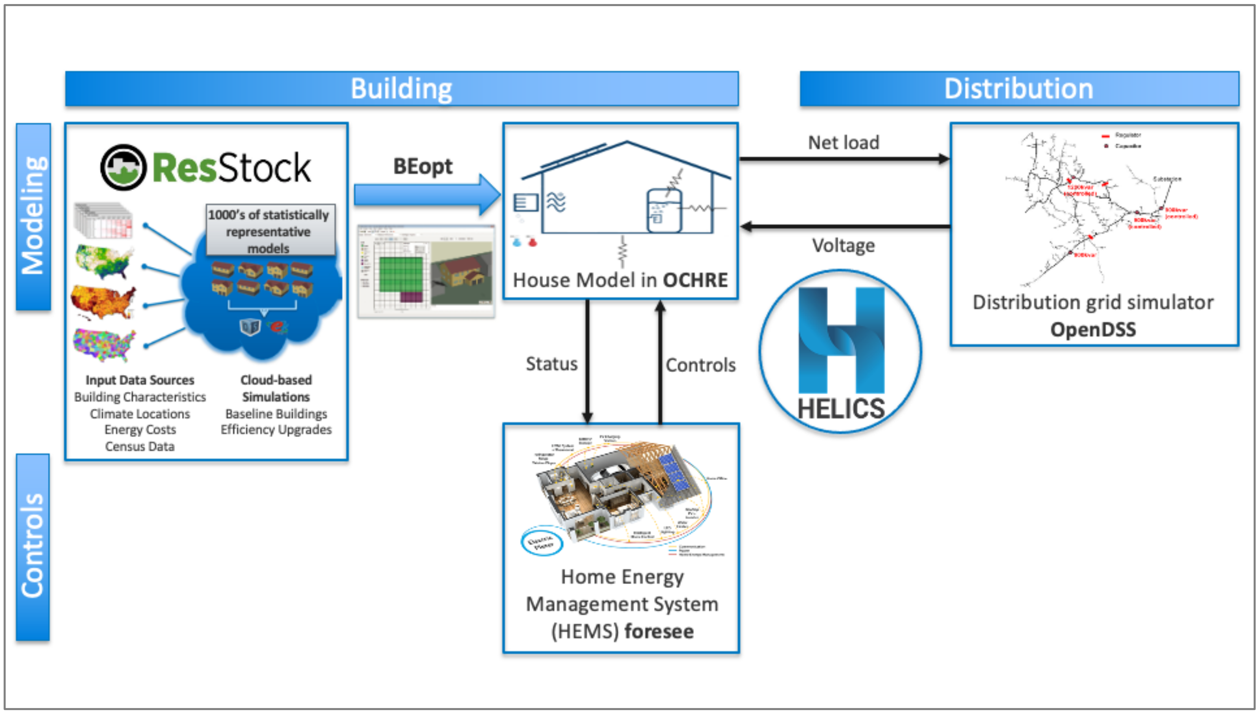

Figure 5. Overview of co-simulation framework

An overview of the co-simulation framework is shown in Figure 5. Based on the ResStock sampling we created a BEopt™ model for each of the 30 homes. BEopt[4] is an optimization tool that runs on EnergyPlus™ and enables evaluation of residential building design to compare the costs and benefits of different measures and identify cost-optimal energy efficiency packages.

Next, we generated OCHRE[5] (Object-oriented Controllable High-resolution Residential Energy Model) input files from the BEopt models. OCHRE is a reduced-order residential building model that is designed to be used in building-grid co-simulation framework. We applied combinations of **foresee™** HEMS and other DERs in these homes (per scenarios outlined in the following section) to conduct power grid co-simulation to explore the flexibility potential and limitations of each case, including operational characteristics of the homes and their impact on the distribution

[4] For more information on BEopt, see https://www.nrel.gov/buildings/beopt.html.
[5] For more information on OCHRE, see https://www.sciencedirect.com/science/article/pii/S0306261921002464.

system. OpenDSS, an electric power distribution system simulator, was used for modeling and simulation of the distribution system.

The distribution feeder, HEMS, and residential building were co-simulated using the Hierarchical Engine for Large-scale Infrastructure Co-Simulation (HELICS)[6] framework. HELICS enables us to develop a highly scalable, modular, and cross-platform operable co-simulation framework. Our co-simulation framework is modularized so that each component can be enabled or disabled according to various scenarios considered in Section 2.4. The co-simulation framework manages the information exchange between various components in the closed-loop co-simulation. The overall flow of the simulation is described as follows:

- At time *t*, OCHRE calculates the current status of each end device (including state of charge of battery and EV), indoor air temperature, and water temperature. At the beginning of the simulation the current statuses are initialized in the OCHRE model. OCHRE then sends the current status to **foresee**. In the scenarios without **foresee**, default controllers (traditional thermostat control for HVAC and water heater) are implemented. The OCHRE models run every 1 minute.
- At time *t*, **foresee** receives the status of each device, indoor air temperature, and water temperature from OCHRE. The received information from OCHRE is used as initial conditions for the optimization in **foresee**. **foresee** computes the optimal control signals for each device and sends control actions to OCHRE. **foresee** runs every 15 minutes and the control actions are implemented for each subsequent 15 minutes.
- OCHRE receives and implements the control actions from **foresee** and computes the total house active and reactive power. OCHRE then sends the total house power data to OpenDSS for distribution system analysis.
- After receiving the net house loads from all the houses, OpenDSS computes the power flow and determines the voltage of each node. The distribution feeder model runs every 1 minute.

In the co-simulation framework, which is deployed using NREL's supercomputer, there are a total of 30 agents (or instances) of the OCHRE model, 30 agents of **foresee** (when running scenarios that include HEMS), and one agent of OpenDSS. We utilize the parallel-processing feature in the supercomputer to increase the scalability and minimize the total runtime of the simulations.

2.4 Cases and Retrofit Options

Starting with the baseline scenario (the existing mixed-fuel neighborhood) obtained from ResStock sampling, we selected three cases that outline the boundaries of our problem space. They are illustrated in Figure 6 and described below.

Scenario 1: Using BEopt we determined the cost-optimal package of conventional energy-efficiency upgrades to apply to the entire neighborhood. This scenario assumes that there are no

[6] For more information on HELICS, see https://helics.org.

additional DER technologies, including controls, beyond a smart thermostat. This can be seen as a kind of a lower limit, to show how much load flexibility is possible in a business-as-usual case.

Scenario 2: Here we eliminated natural gas appliances and electrified each home. Instead of seeking the cost-optimal package (from a simple payback standpoint) we chose the most energy-efficient retrofit measures that minimize the annual kWh per home. We explored this scenario without (2A) and with DERs and controls (2B).

Scenario 3: This is a different electrification scenario, where we simply replaced natural gas equipment with electric counterparts without kWh efficiency improvements. Load shifting is the sole energy management strategy. This scenario was analyzed without (3A) and with DERs and controls (3B, 3C), and also without (3B) and with rooftop PV (3C).

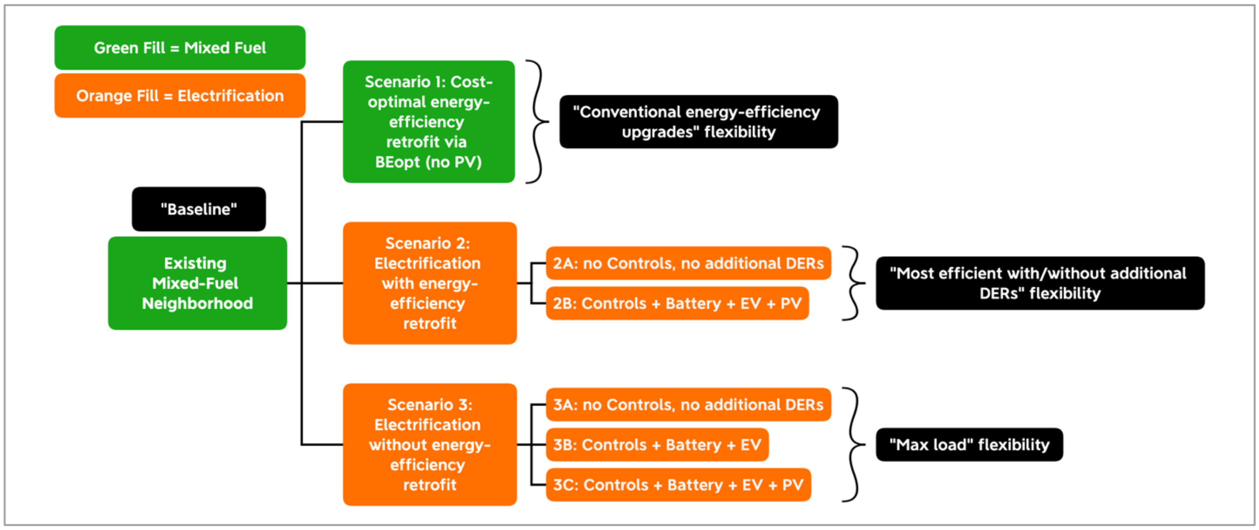

Figure 6. Summary of scenarios studied

To select energy efficiency retrofit measures, we ran BEopt optimizations on a handful of buildings that are likely to produce the most different solution packages, then selected a combination of measures to apply to the entire community. Rather than customizing a cost-optimal retrofit package for each individual home, implementing similar packages across all homes more realistically simulates a district retrofit rollout strategy, one where "one size fits most." Conventional retrofit measures considered in the optimization include wall and ceiling insulation, lighting, HVAC, hot water, infiltration, and PV. The measure packages for each scenario are summarized in Table 2.

In scenarios that employ a home battery, a battery size of 6 kWh was selected based on earlier analysis of the economics of residential batteries (Xin et al. 2018) and by surveying current battery size offerings from leading manufacturers. The batteries were sized primarily to allow for arbitrage and to maximize utilization of solar energy produced on site rather than for resilience in the event of an outage. (The former requires only a modest battery capacity because the charging and discharging occur on relatively short timescales, whereas the latter would require a much larger battery in order to meet the electric needs of a home during an extended outage.) The EV model combines a standard battery model and a random parking event generator, which uses data obtained from Electric Vehicle Infrastructure Projection (EVI-Pro) ("Alternative Fuels Data

Center" N.D.) The parking event consists of three parameters: (1) arrival time, (2) departure time, and (3) arrival state of charge.

To set up simulations for the scenarios with EVs (2B, 3B, 3C), we assumed that one-third of the homes in the community (i.e., 10 out of 30 houses) are each equipped with one EV. We also considered various types and charge capacities of EVs with different charging levels. We assumed that 50% of the EVs are battery EVs (BEV) and the remaining 50% are plug-in hybrid EVs (PHEV) based on current market penetrations in Colorado of BEVs and PHEVs ("Colorado Electric Vehicle Plan" 2020). The battery capacity of PHEVs ranges from 20 to 50 miles, whereas the battery capacity of BEVs ranges from 100 to 250 miles. We assumed that the homes with PHEVs are equipped with Level-1 chargers (1.4 kW) and that the homes with BEVs are equipped with Level-2 chargers (9 kW) ("Alternative Fuels Data Center" N.D.)

Table 2. Comparison of Retrofit Measures Employed

	Scenario 1: Conventional Energy Efficiency Retrofit	Scenario 2: Electrification With Conventional Energy-Efficiency Upgrades		Scenario 3: Electrification Without Conventional Energy-Efficiency Upgrades		
	1	**2A**	**2B**	**3A**	**3B**	**3C**
Attic Insulation	R-49			-		
Basement Insulation	R-30			-		
Air Sealing	Reduce infiltration by 30% (each home starting at different ACH_{50} level)			-		
Heating	98% AFUE gas furnace	Air-source heat pump (ASHP), SEER 22 HSPF 10.0		ASHP, SEER 13 HSPF 8.2		
Cooling	SEER 17 central AC					
Domestic Hot Water	Gas standard, UEF = 0.60	Heat pump water heater (HPWH), UEF = 3.54		Electric resistance standard, UEF = 0.90		
Lighting	Replace with 100% LED			-		
Major Appliances	Replace with ENERGY STAR®			Replace gas appliances with standard electric		
PV	-		Maximized, limited by roof area or 120% rule	-		Maximized, limited by roof area or 120% rule
Battery	-		6 kWh	-	6 kWh	
Electric Vehicle	-		5 homes with PHEVs, charging at Level-1 (L1); 5 homes with BEVs, charging at Level-2 (L2)	-	5 homes with PHEV, charging at L1; 5 homes with BEV, charging at L2	
Controls	-		**foresee**™ HEMS	-	**foresee** HEMS	

2.5 Utility Rates

Our simulations used Xcel Energy's time-of-use (TOU) rates (Xcel Energy N.D.), the filing for which was approved by the Colorado Public Utilities Commission in September 2020 (Table 3). Over the next several years Xcel Energy will roll out TOU across Colorado residences along with new advanced metering infrastructure meter (aka "smart meter") installations; a trial is already underway. The year-round TOU rates will largely replace the tiered pricing structure that is currently employed during the summer months, although customers can opt out of TOU.

For the gas utility rate, we used Xcel Energy's residential natural gas rate, also approved by the Colorado Public Utilities Commission in September 2020. Xcel Energy implements a flat gas utility rate at $0.52 per therm (total gas rate including the surcharges) for residential customers (Xcel Energy 2020).

Table 3. Xcel Energy Residential Electricity TOU Rates Used in Our Simulations

		Summer Jun 1–Sep 30 [$/kWh]	Winter Oct 1–May 31 [$/kWh]
On-peak	3–7 p.m. weekdays (except holidays)	0.13861	0.08727
Shoulder	1–3 p.m. weekdays (except holidays)	0.09497	0.06930
Off-peak	7 p.m.–1 p.m. the next day, plus weekends and holidays	0.05134	0.05134

In addition, our simulations employed net metering in a manner consistent with Xcel's Energy's net metering implementation in Colorado. Residents receive credit on their energy bills when their solar panels produce more electricity than is needed. The excess generation is added back to the grid, and the dollar value of that energy is determined based on the rate for the same time period as when the excess energy was generated. Our simulations were structured in such a way that utility bills receive credit in the same month as the excess generation; in practice the bill credits are given in each subsequent billing month for the previous month's generation.

3 Results and Discussion

3.1 Baseline Scenario Results

Energy use characteristics of the baseline homes are shown in Figure 7 and Figure 8. Figure 7 shows the source energy consumption[7] across the entire community before any retrofits are implemented. The loads are clearly dominated by heating in the winter and cooling in the summer. There is some seasonality in water heating energy use: During the summer months the incoming mains temperature is higher, so less energy is needed to heat the water to the desired setpoint. While most homes in the baseline use natural gas for space and water heating, three of the homes use electricity, which is why these end uses are shown as contributing to both electric and gas consumption at the community level.

The other major load is labeled "uncontrollable." Represented by the brown bars, the uncontrollable load refers to a collection of end uses that will not be affected by load-shifting tools and techniques because they do not have the ability to be controlled by our HEMS. The uncontrollable load comprises large appliances, lighting, and miscellaneous electric loads. The total energy use in this category varies slightly from month to month due to some seasonal differences in usage, as outlined in the Building America House Simulation Protocols (Building America 2013). Across scenarios, the end uses that contribute to the uncontrollable load change when energy efficiency is added or end uses are electrified, but the load is unaffected by the inclusion of a HEMS, PV, battery, or EV.

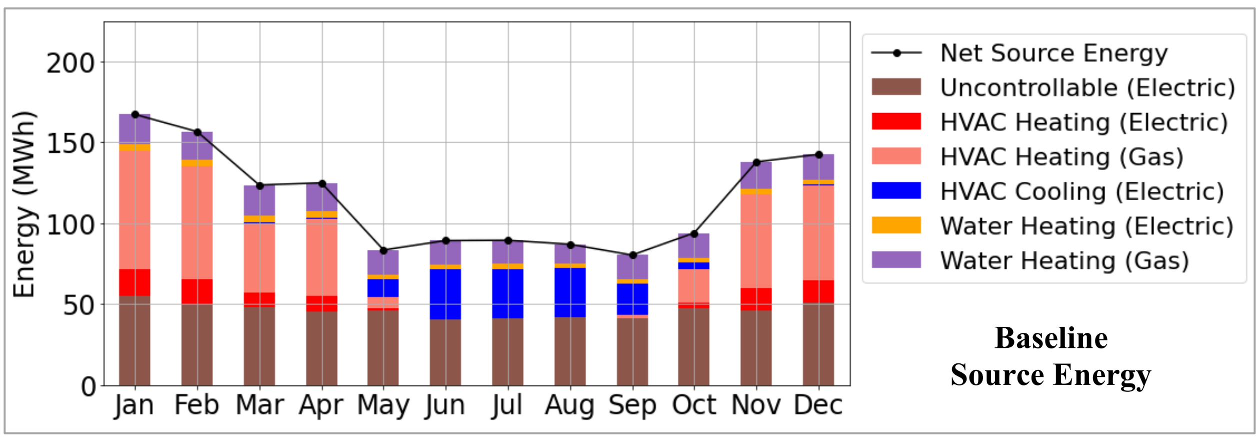

Figure 7. Baseline monthly source energy consumption by end use (for entire community)

The average monthly utility bills by end use and fuel type are shown in Figure 8. Average bills are the sum of all homes' utility bills divided by the number of homes (30), and individual homes may pay substantially more or less depending on their energy usage habits, installed equipment, envelope insulation, or other factors. It is also worth noting that there are some end uses that

[7] In order to compare energy use across the scenarios studied, we needed to decide on a consistent convention for how energy is reported. Because we looked at both mixed-fuel and all-electric cases, we chose to use source energy as the primary figure of merit. In a nod to the electrification themes in this project and to simplify the inclusion of PV generation, we chose to use watt-hours as the standard unit of energy. Source energy multipliers are based on national average numbers, 2.8 for electricity and 1.05 for natural gas (see https://portfoliomanager.energystar.gov/pdf/reference/Source%20Energy.pdf).

appear in some homes but not all (e.g., homes in our sample have either electric or gas heating but not both). Because the utility costs are summed and divided over the entire sample of 30 homes, individual utility bills for any single home will look different from the community average. As expected, the electric end uses cost the homeowners more money than the natural gas end uses relative to how much energy they consume. The utility bills largely reflect the source energy consumption in their shapes and trends because the difference between on- and off-peak TOU rates is not sufficiently large to cause deviations between them, and the peak periods are relatively short in duration.

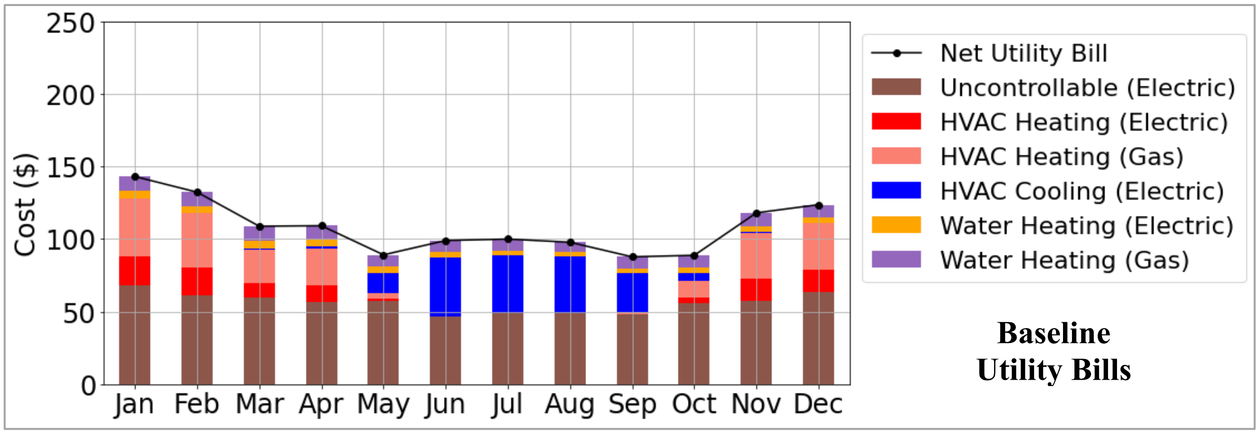

Figure 8. Baseline average monthly utility bills by end use (averaged across community for one house)

3.2 Scenario 1 Results

The first scenario is the case of the cost-optimal energy-efficient retrofit (see Figure 6 for an overview of scenarios, and Table 2 for a summary of retrofit measures). There is no electrification in this scenario, only energy efficiency, so equipment is upgraded with cost-optimal replacements (i.e., more efficient versions that use the same fuel type). The community-wide energy use and average monthly utility bills are shown in Figure 9 and Figure 10, respectively. The notable difference from the pre-retrofit baseline in Figure 7 is the roughly 15% decrease in energy use over the winter months, largely due to more efficient heating equipment. The average monthly utility bills likewise decrease during the winter months as a result of the retrofits, while the summer bills are much less affected. There is some modest cooling savings due to upgrading the air conditioner from seasonal energy efficiency ratio (SEER) 15 to SEER 17 and the envelope to reduce infiltration. (While code minimum is SEER 13, our ResStock sample based on 2010s-era construction practices indicates that SEER 15 is more prevalent. See distribution in Figure 2.)

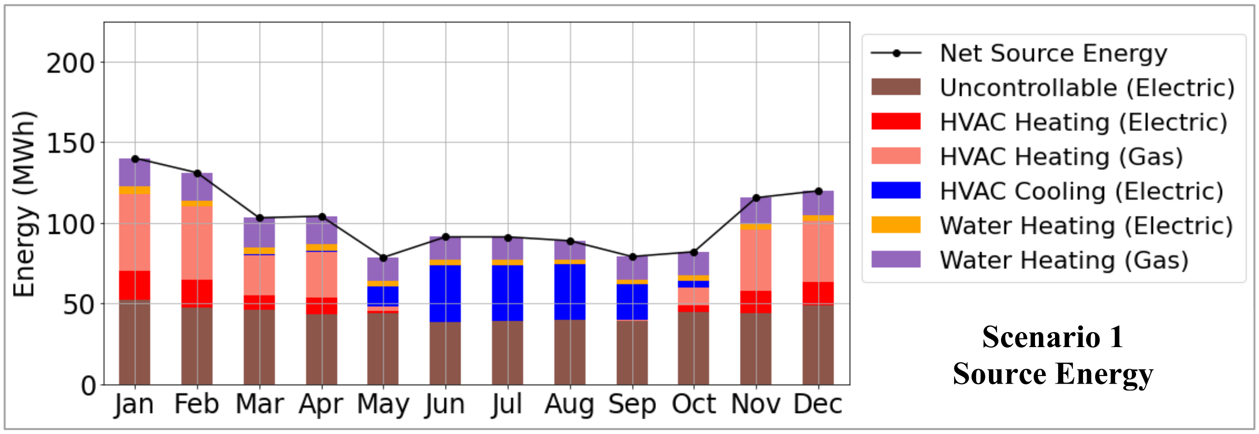

Figure 9. Scenario 1 monthly source energy consumption by end use (for entire community)

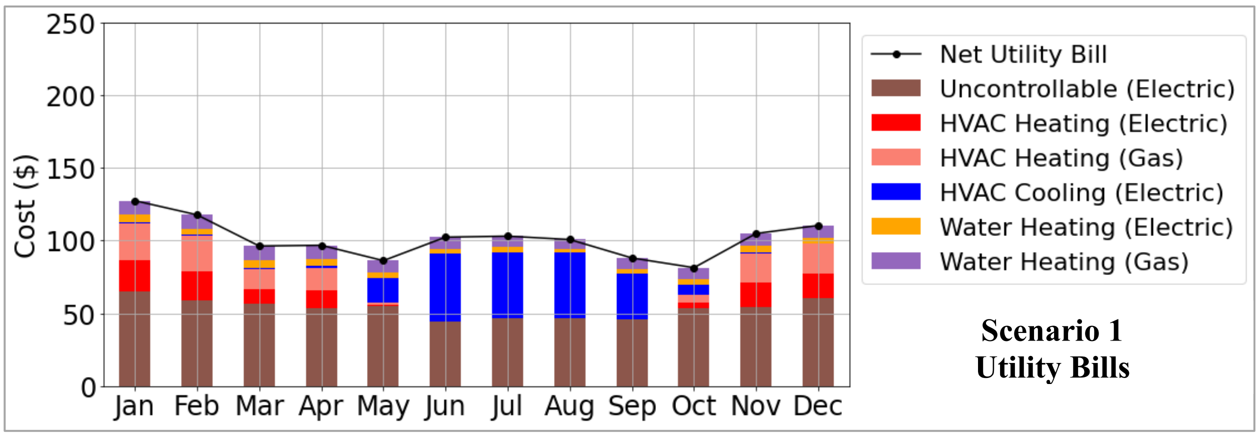

Figure 10. Scenario 1 monthly utility bills by end use (averaged across community for one house)

3.3 Scenario 2 Results

The second scenario includes full electrification in an energy-efficient way, including all of the upgrades in scenario 1 but also installing a heat pump water heater (HPWH) and air source heat pump (ASHP). Source energy consumption is shown in Figure 11, and monthly utility bills are shown in Figure 12. Compared to the baseline, source energy use is lower because of all the efficiency improvements, despite electrification.

Switching from a largely natural gas baseline to electricity yields 30% source energy savings in both space heating and water heating. Although the site-to-source energy conversion factor for electricity is 2.8 (which is much higher than for natural gas, at 1.05), the upgrade in efficiency more than compensates for this difference. For space heating, a baseline composed of mostly 80% annual fuel utilization efficiency (AFUE) furnaces is replaced with ASHPs with a heating seasonal performance factor (HSPF) of 10, or a nominal coefficient of performance (COP) of about 2.9. While the ASHP does rely on backup electric resistance elements (which operate at lower efficiencies) during the coldest hours when its capacity is insufficient to meet the load, the overall annual efficiency improvement for space heating is substantial enough to still reduce source energy consumption. It is important to point out that the backup elements, which only turn on during the coldest hours of the year but use much more power, could lead to new winter morning peaks for the utility if a substantial portion of the housing stock were to electrify and use electric resistance as the backup. Likewise, water heaters improve in efficiency, from a uniform energy factor (UEF) of about 0.6 in the baseline to a HPWH with a UEF of 3.45. The high-efficiency cooling equipment also substantially decreases the cooling energy consumption during the summer months.

This efficient electrification scenario uses slightly less source energy than even the conventional efficiency retrofit in scenario 1. However, on an annual basis the utility costs to homeowners are nearly identical to the baseline because the higher cost of electric heating in the winter offsets the cooling savings in the summer. In other words, because electricity is more expensive per unit energy than natural gas under current rates, a conventional retrofit (scenario 1) can save money on monthly utility bills relative the baseline, while an efficient electrification (scenario 2A) is approximately cost neutral in terms of energy bills.

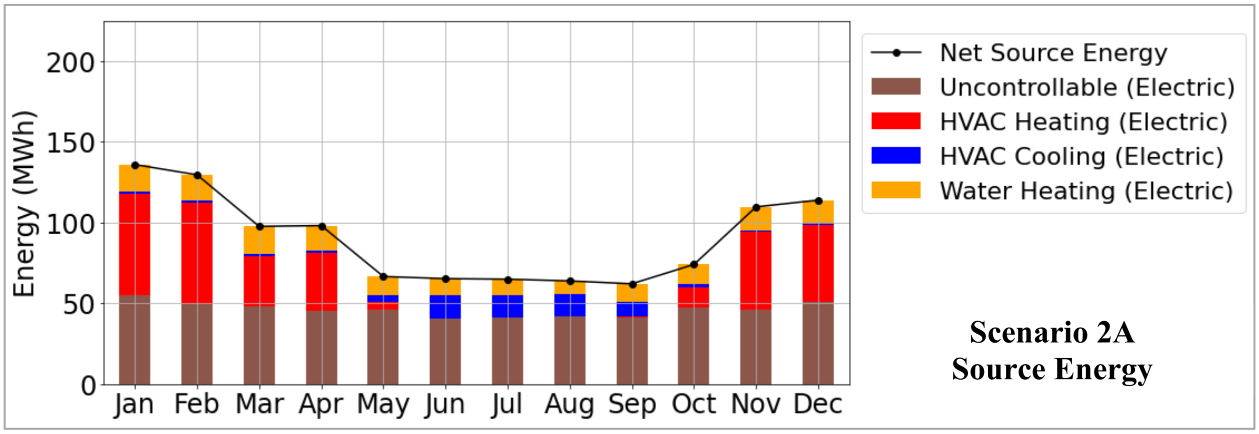

Figure 11. Scenario 2A monthly source energy consumption by end use (for entire community)

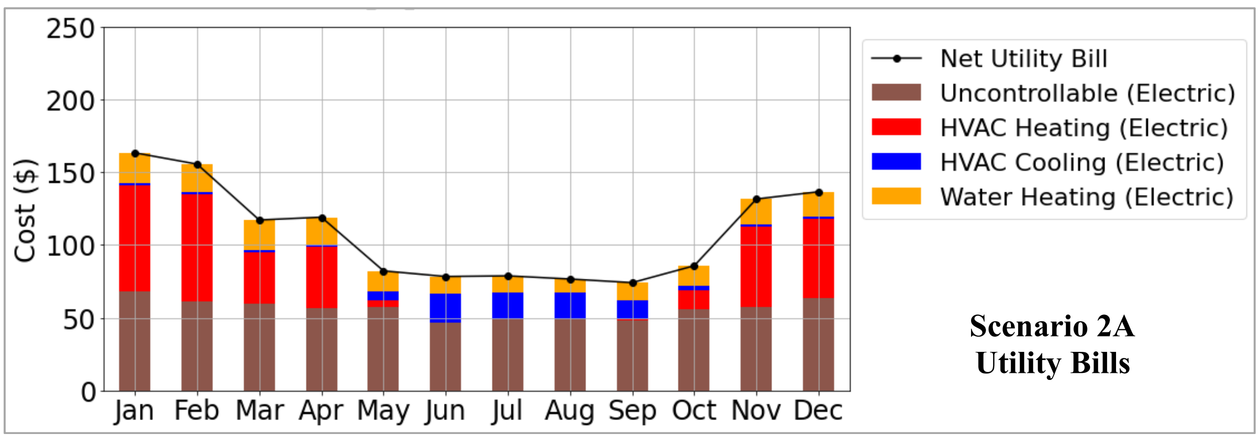

Figure 12. Scenario 2A monthly utility bills by end use (averaged across community for one house)

Scenario 2B incorporates additional DERs, and the results are shown in Figure 13 and Figure 14. The additional DERs include a HEMS, the largest PV allowable by the local utility, and a 6-kWh home battery. EVs are also added for one-third of the homes in the community, reflecting a high adoption scenario. Although the battery has a small net positive load on the homes due to the roundtrip efficiency losses, it nevertheless contributes to energy bill savings because of load shifting: Batteries can perform arbitrage, storing charge during sunny off-peak hours in the midday and discharging during peak periods. Note that there is some energy loss associated with the battery, but the magnitude is too small to be visible in the source energy chart. EVs represent a substantial load, with a higher annual energy use than space cooling, despite its implementation in only 10 out of 30 homes. The rooftop PV was sized according to the maximum allowable by Xcel Energy, which is up to 120% of the existing load in the home. In cases where the roof area was insufficient to accommodate a system of this size, the maximum PV array size possible for that roof area was applied. The 120% limit is relative to energy consumption of the baseline scenario, so the maximum PV size is calculated based on pre-retrofit utility bills. This means that PV sizing calculations do not account for the anticipated increase in energy needs due to the acquisition of an EV, or a result of electrification (this is most relevant for scenario 3). The overall result is that the community is a slight net consumer of electricity annually, although there are many hours of the year where the community is a net producer. In the utility bill analysis (Figure 14), the battery yields homeowners a small amount of savings per year through arbitrage, along with higher savings in the summer because of the ample solar resource and a large difference between on-peak and off-peak rates.

That the net utility bill change is positive (costing approximately $100 more per household per year) is somewhat misleading, as it is clear that the increased cost is entirely attributable to the inclusion of EV, which is offsetting gasoline that would otherwise be purchased by the homeowner. Further, recall that there are only 10 EVs (not 30) in this community, so that if the bill increase is all from EV charging, we can estimate that each EV-owning household spends approximately $300 per year on electricity to charge their car ($100 x 30 / 10 EVs = $300 per EV). In comparison, the annual cost estimate to fuel a gasoline-powered vehicle that is driven the same number of miles is $1,003. Our calculations assume that each EV replaces a gasoline-powered vehicle with an average fuel consumption of 24.1 miles per gallon (Bureau of Transportation Statistics N.D.), is driven 12,889 miles per year (The Zebra 2022), and that the average price of gasoline is $2.328 per gallon (U.S. Energy Information Administration 2021). The homes that do not own EVs would not see their utility bills increase in this scenario.

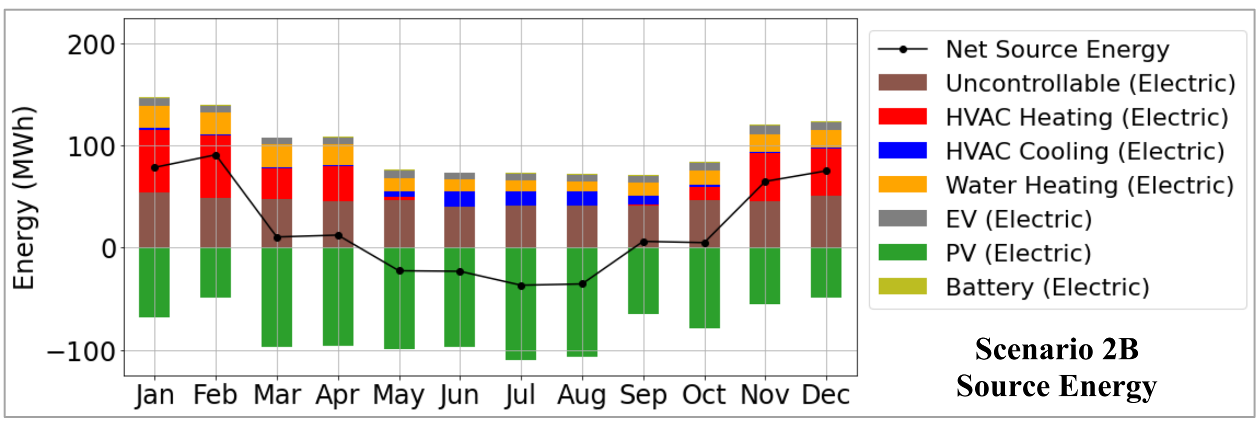

Figure 13. Scenario 2B monthly source energy consumption by end use (for entire community)

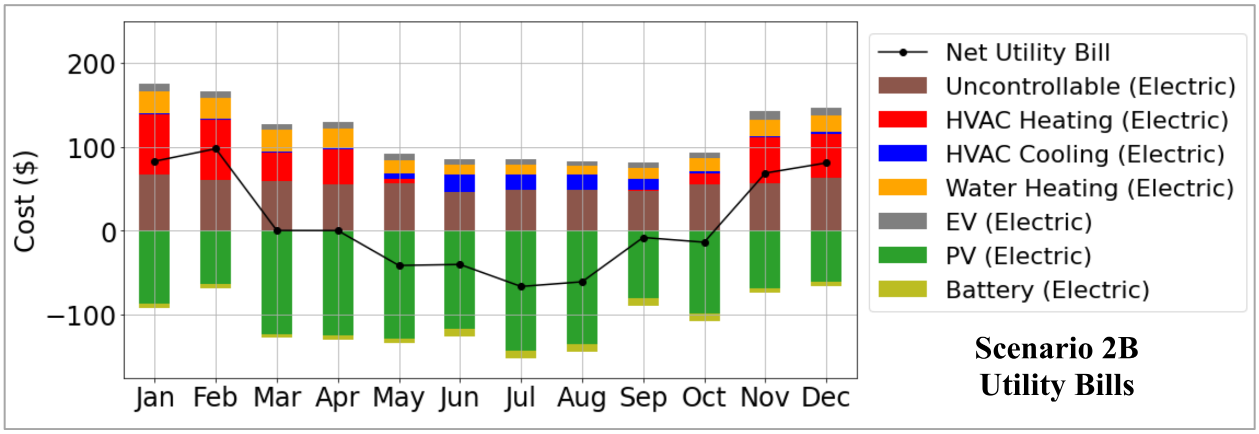

Figure 14. Scenario 2B monthly utility bills by end use (averaged across community for one house)

3.4 Scenario 3 Results

Scenario 3 represents electrification without any efficiency improvements. This case includes a federal minimum efficiency (SEER 13 HSPF 8.2) ASHP, an electric resistance water heater, and an electric range, with no efficiency upgrades from the baseline. In scenario 3A there are no additional DERs employed; this scenario has high source energy use in comparison to any of the previous scenarios (Figure 15). The largest cause of this source energy increase is the switch from natural gas to an electric resistance water heater, although space heating also accounts for some of the increase. As illustrated by the utility bills in Figure 16, this scenario is close to a worst-case scenario where a community undergoes electrification without consideration to efficiency and there are no additional tools to facilitate load shifting. This scenario would lead to over 40% higher utility bills for the homeowners.

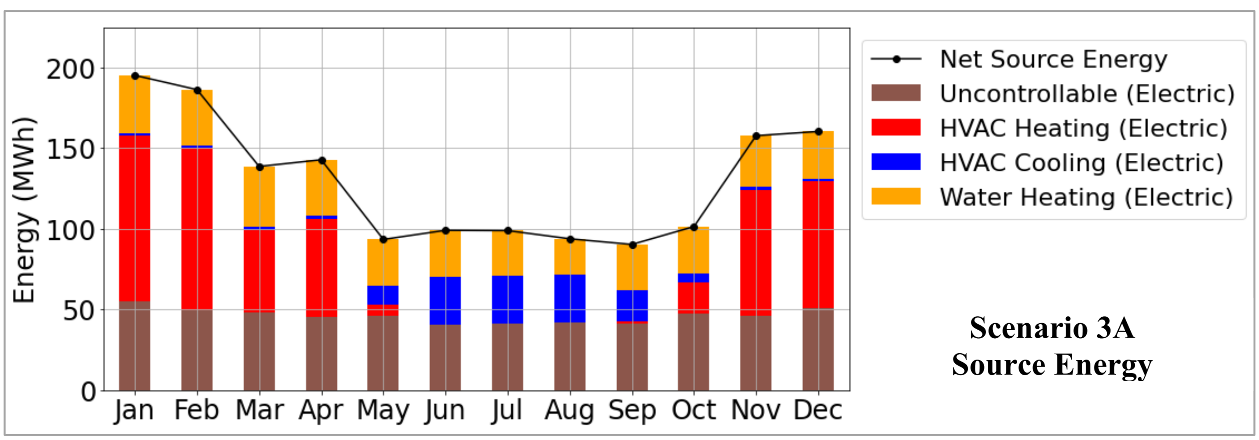

Figure 15. Scenario 3A monthly source energy consumption by end use (for entire community)

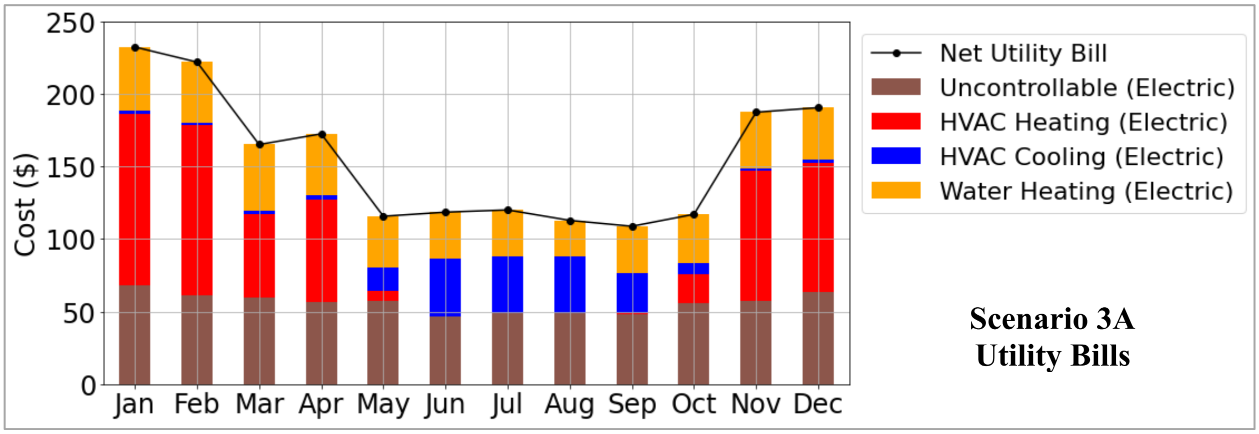

Figure 16. Scenario 3A monthly utility bills by end use (averaged across community for one house)

Scenario 3B includes the addition of a HEMS, EV, and battery, but no PV to help power the new electric loads. The source energy consumption of this scenario is shown in Figure 17, and the utility bills are shown in Figure 18. The addition of EV results in energy use increase over scenario 3A, making this the highest source energy scenario in our study. The HEMS is able to reduce some energy use for heating, cooling, and water heating by operating at the edge of the flexibility band for comfort, keeping the indoor air at a comfortable level slightly outside the setpoint and the water heater tank at a slightly lower temperature when idle. The battery performs energy arbitrage, using grid power during off-peak periods rather than solar energy produced on-site. This scenario has slightly lower bills than scenario 3A despite the overall energy use increase, because the battery and the HEMS are able to shift loads out of the peak period by preconditioning the space and preheating the water heater.

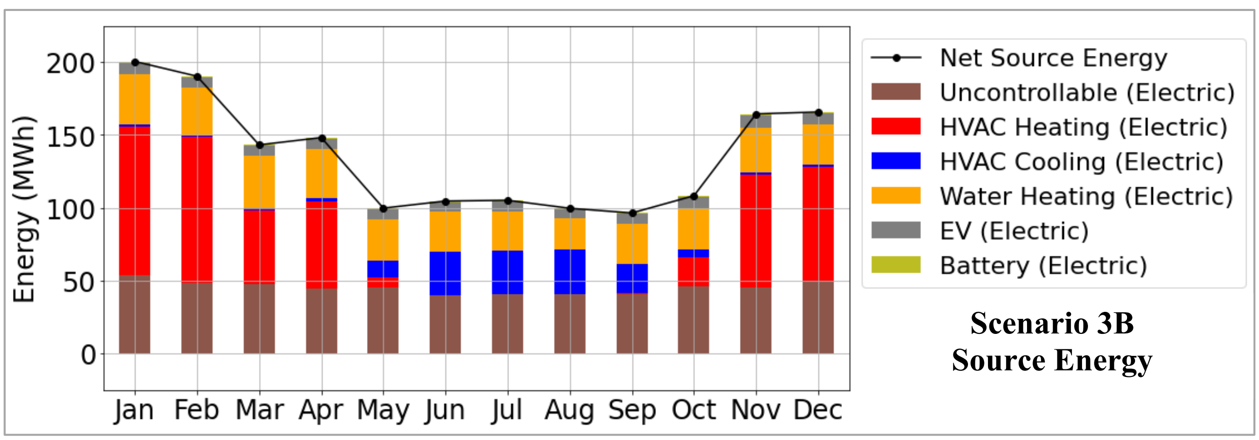

Figure 17. Scenario 3B monthly source energy consumption by end use (for entire community)

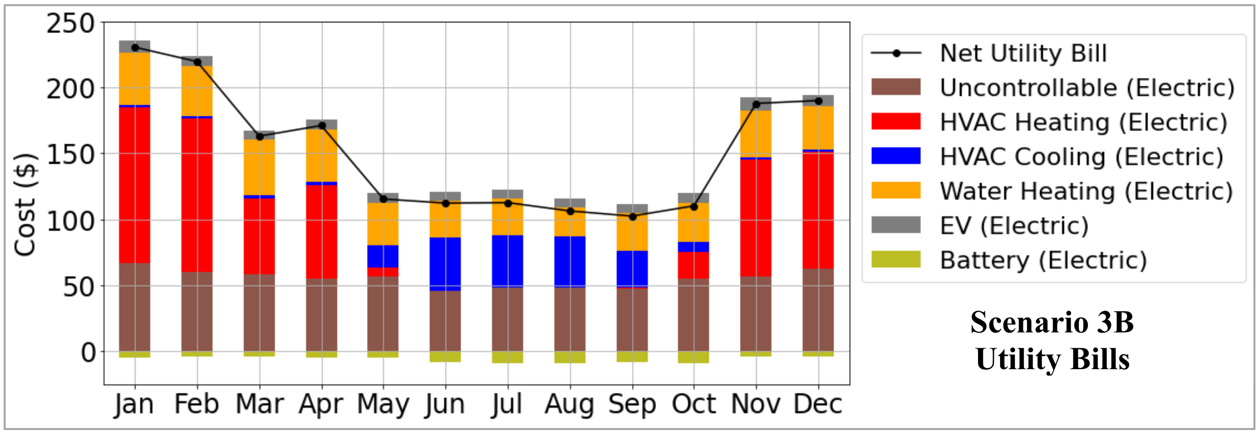

Figure 18. Scenario 3B monthly utility bills by end use (averaged across community for one house)

Scenario 3C adds PV to these homes, which has only minor impacts on the energy consumption in this case. Slight differences are likely due to the HEMS making different decisions about shifting loads when on-site solar energy is available. As in scenario 2B, because PV sizing is determined based on the baseline utility bills (before the inefficient electrification in this case), the community is still a net consumer, although the net consumption drops by 60% on an annual basis. There are times of year where this community can export power, especially during the summer months (Figure 19). Homeowners in this scenario still have utility bills to pay but they are approximately 60% lower than they would be without PV (Figure 20).

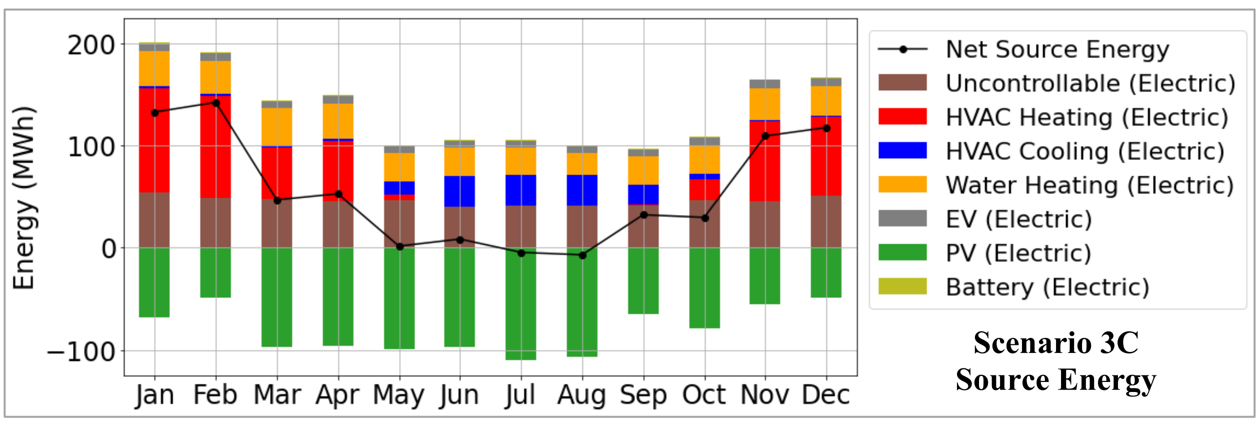

Figure 19. Scenario 3C monthly source energy consumption by end use (for entire community)

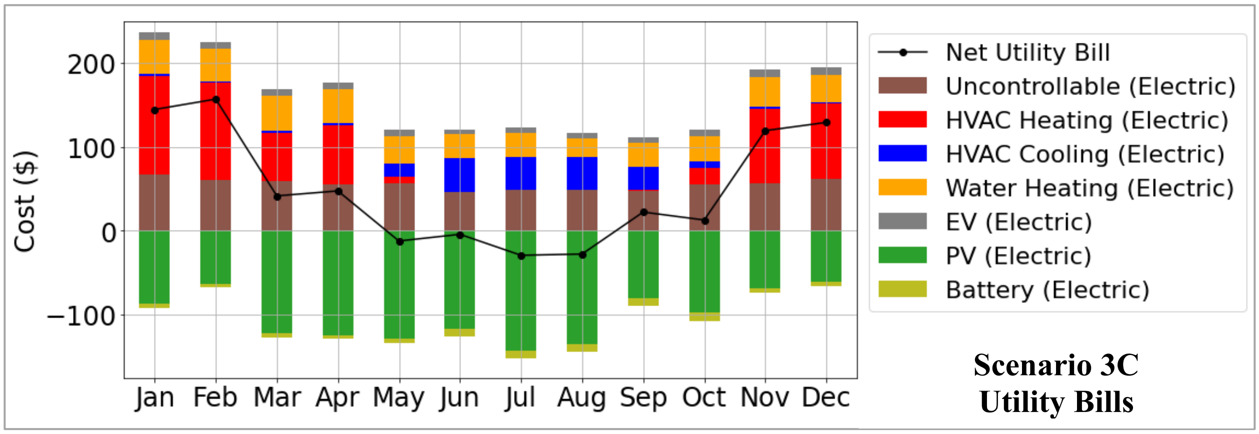

Figure 20. Scenario 3C monthly utility bills by end use (averaged across community for one house)

3.5 Comparing Across Scenarios

Figure 21 shows the monthly source energy consumption for all scenarios side-by-side. Efficient electrification with additional DERs, represented by scenario 2B and shown in red, is clearly the optimal approach from an annual source energy perspective. During the summer months this scenario is a net producer of electricity, and the net load during the shoulder seasons is minimal.

Figure 22 compares the average monthly utility bill across cases. Retrofitting the homes to cost-efficiently electrify (scenario 2A) is nearly cost neutral in terms of utility bills with the baseline. There are higher energy bills in the winter because the heating load is electrified and the ASHP has lower performance at colder temperatures. However, bills are lower during the summer months because the higher-rated ASHP replacement can more efficiently cool the homes than the central air-conditioning systems included in the baseline. When additional DERs, including PV, battery, and a HEMS, are installed, bills decrease significantly. This is largely due to the rooftop PV, but the HEMS and the battery also provide savings. The battery provides a small bill credit via energy arbitrage around the TOU rate. The HEMS also tries to precondition the space and heat water ahead of peak periods, effectively performing arbitrage as well, while still maintaining comfort for the occupants.

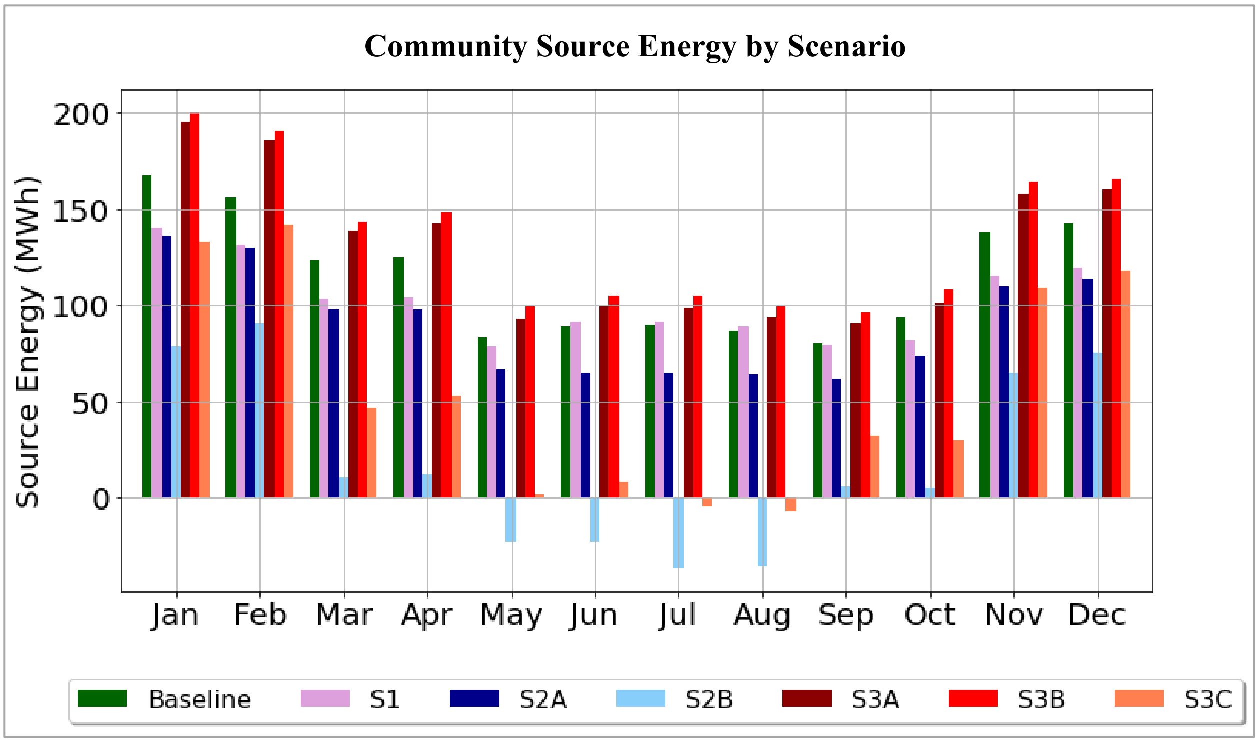

Figure 21. Monthly source energy consumption across all scenarios (for entire community)

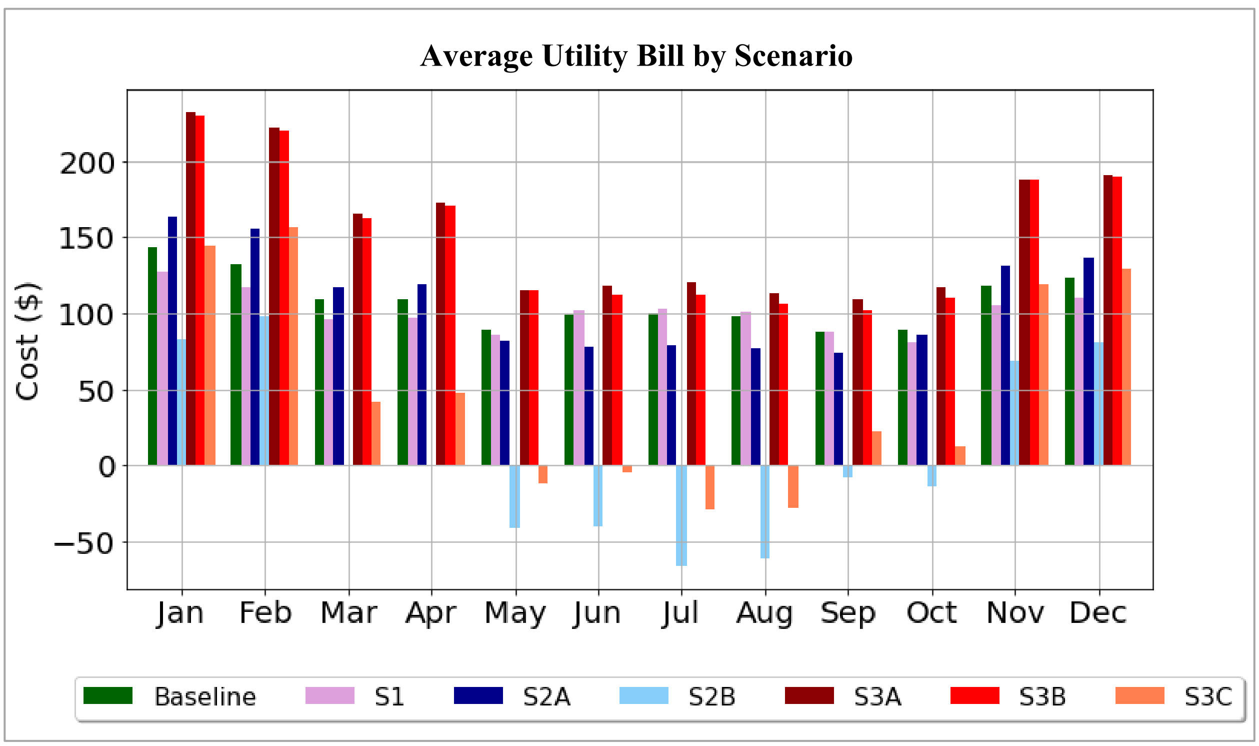

Figure 22. Monthly utility bills across all scenarios (averaged across community for one house)

Figure 23 and Figure 24 show the time series of the community load profile over several days in July and January, respectively. On an annual basis the efficiency retrofit saves energy, but during peak periods the two-speed air conditioner (which has a higher SEER rating) is more likely to operate at the higher speed, and hence can impose a greater load than the single-speed air conditioner. When additional DERS are incorporated the impact of the PV becomes immediately apparent. In scenarios with PV, this community is a net producer during the summer months and can output more than twice as much power as it would otherwise consume during peak periods. In scenarios where a HEMS is installed, there is a large spike ahead of the peak period when the HEMS preconditions the space (within the allowable comfort band) and preheats the water. This spike is most noticeable in scenario 3, where the electric resistance water heaters produce a much bigger load than the HPWH alternative.

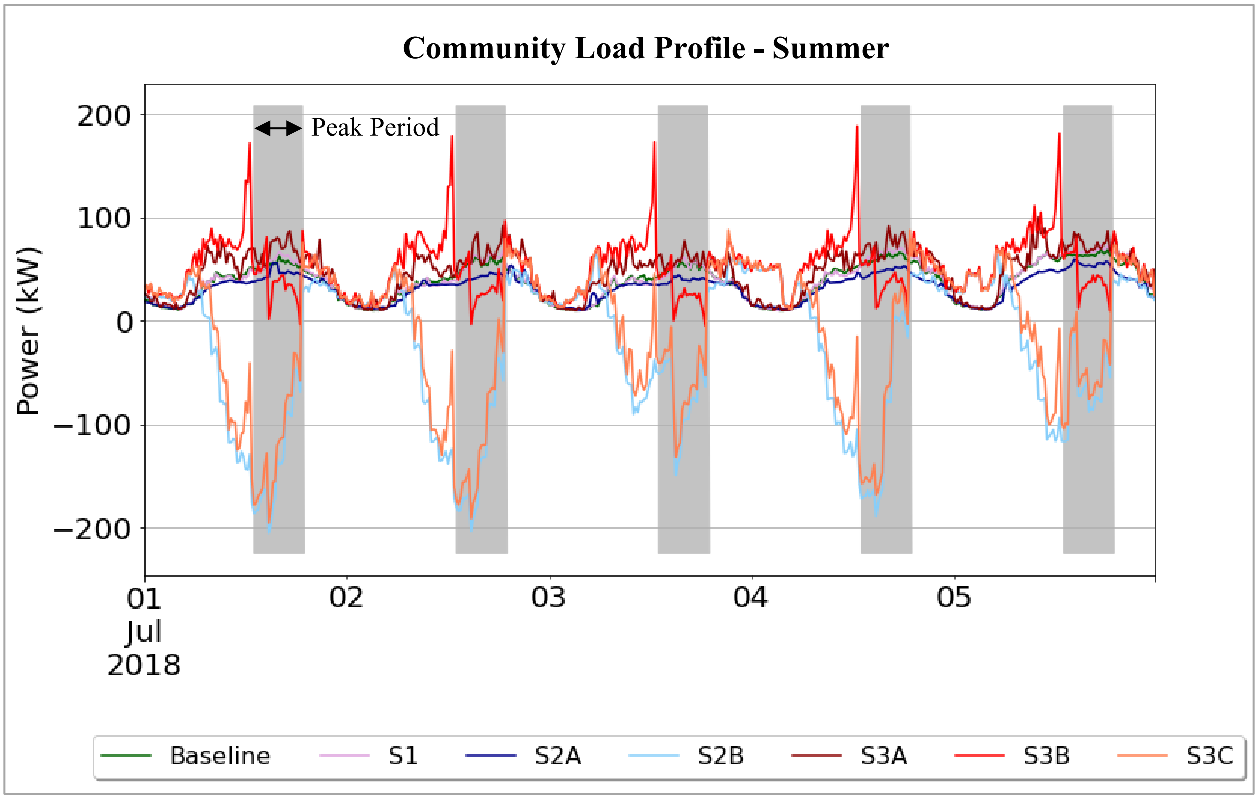

Figure 23. Summer community load profile by scenario

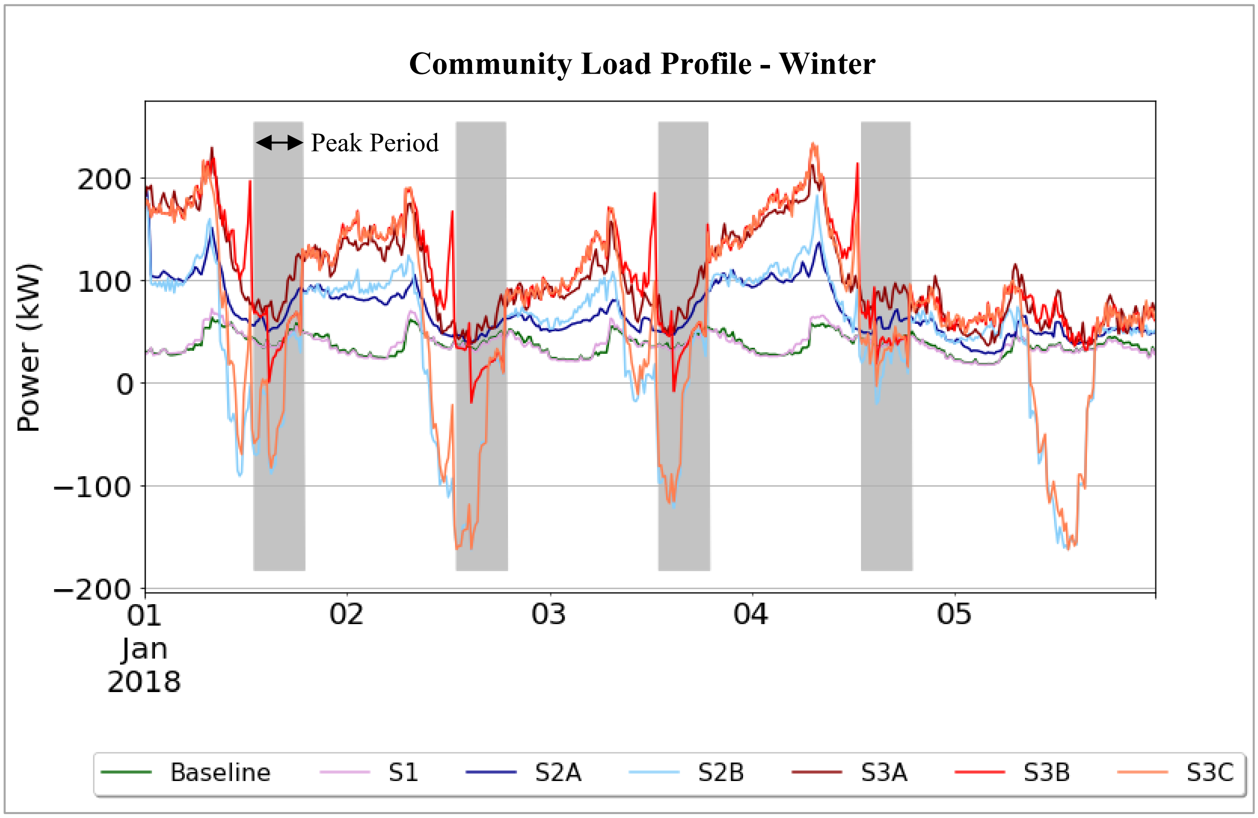

Figure 24. Winter community load profile by scenario

Figure 25 shows a violin plot of the community power consumption during the peak period for all scenarios. A violin plot is similar to a box plot, but with the addition of a rotated kernel density plot (essentially a histogram rotated 90 degrees and mirrored on the vertical axis). The name "violin" refers to the resulting shape's resemblance to the instrument. The small white dot in the center of each violin represents the median value (in this case median community power consumption) and the black vertical rectangle ("box") represents the interquartile (2nd and 3rd quartile) range. The broader sections of the violin represent a higher probability of occurrence (i.e., higher community power consumption), whereas the narrower sections represent a lower probability (i.e., lower community power consumption).

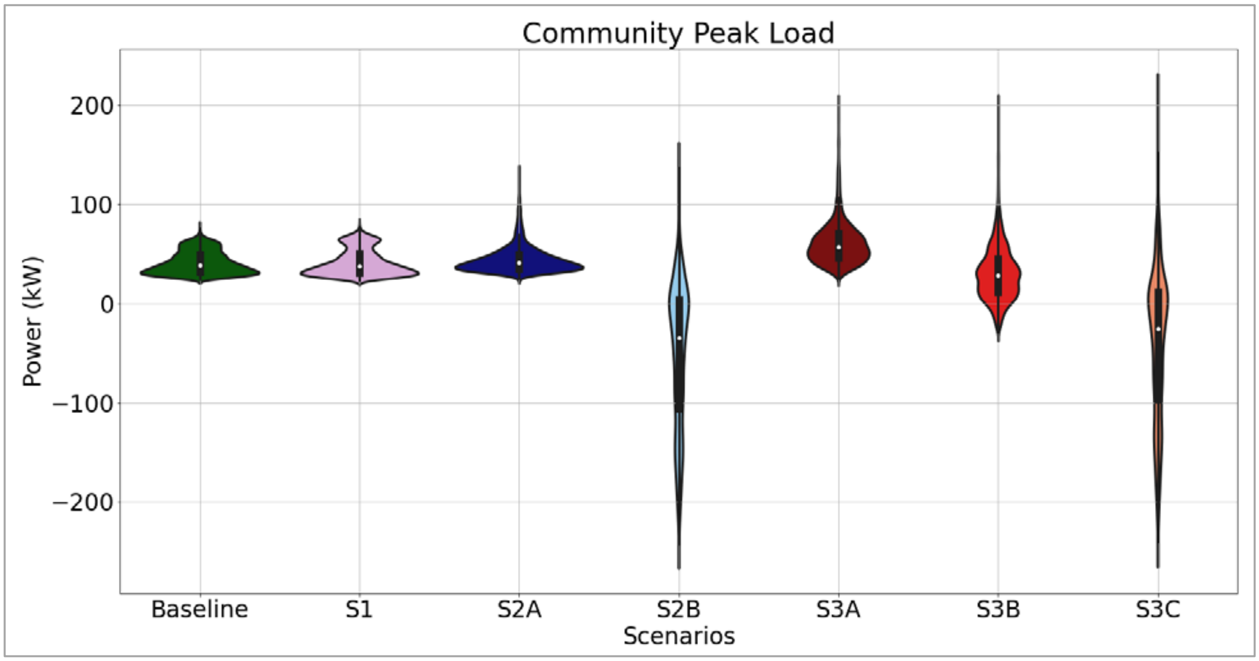

Figure 25. Community load distribution during peak price period by scenario

In the baseline scenario where space and water heating are mostly performed by natural gas appliances, the electric power consumption is largely distributed around a relatively low level of base load comprising cooling, appliances, lighting, and household miscellaneous electric loads. Both the baseline and scenario 1 have bimodal features; the second bump (the top part of the violin) is likely caused by the air conditioner running, and the narrow tip of the violin represents the hottest hours where all homes are in cooling mode simultaneously. The peak load in these scenarios is during the summer.

When efficiently electrifying in scenario 2A, both the average load and peak load rise because of the electrification. The rise in these peak loads is largely due to cold, cloudy afternoons. At low enough temperatures, the ASHP struggles to meet the load, and backup electric resistance heaters kick in. Adding PV, controls, and batteries (scenario 2B) cannot reduce the peak load when it occurs as a result of a cold and cloudy afternoon, but the DERs can lead to a much greater spread in load and a lot of time net producing.

In scenario 3, loads go up much more substantially as the inefficient electrification leads to higher energy use as well as even higher peak loads. In scenario 3B, the average load during the peak period is reduced because the HEMS can shift loads away from the peak period and the battery also discharges to perform arbitrage during this time. However, the actual peak load (which occurs on cold winter nights, and which is different from the average load during the utility's peak pricing period) is unaffected by the HEMS and the battery because there are no load-shifting opportunities available to mitigate these peaks: The battery has not yet had a chance to recharge after discharging earlier in the day during the peak pricing period.

Table 4 shows the community average site electric load and total site electricity consumed during the peak price period for each scenario. Comparing the baseline to the standard energy-efficiency retrofit in scenario 1, there is a slight increase in the average power and total energy use during the peak period. This can be largely attributed to the upgrade from a single-speed air conditioner to a two-speed unit with a higher seasonal efficiency rating. While the retrofit saves energy on an annual basis, during the hottest outdoor conditions (which tend to coincide with peak price periods) the energy consumed by the air conditioner can increase slightly. This highlights an important fact: Not all energy-efficiency measures provide peak savings. When we select equipment based on efficiency, we may simultaneously wish to consider the peak load from that equipment and weigh the relative costs and benefits of energy bill savings and peak reduction. The impact of adding PV is shown clearly by the negative load and energy consumption in scenario 2B and scenario 3C; these communities are net producers during peak hours due to the large amount of PV installed. This is particularly important for scenario 3, where the inefficient electrification increases the peak load by more than 45%.

Table 4. Average Site Electric Load and Total Site Electricity Use During Peak Price Period

Scenario	Average Site Electric Load During Peak [kW]	Total Site Electricity Use During Peak [MWh]
Baseline	41.2	64.0
1	41.4	64.4
2A	44.5	69.2
2B	-52.5	-81.7
3A	60.8	94.5
3B	30.4	47.3
3C	-42.8	-66.4

3.6 Carbon Emissions

To evaluate the impact of electrification, DERs, and building controls on carbon emissions, we used the WattTime grid marginal carbon emission data to quantify the carbon emissions associated with electric consumption in the community (WattTime 2022). Grid carbon emissions vary by time and location. WattTime provides granular real-time and historical marginal carbon emission data as the marginal operating emissions rate (MOER). The highest level of spatial granularity for carbon emissions data is the balancing authority of the grid. The Central Park neighborhood in Denver is within the Public Service Company of Colorado (PSCo)[8] balancing authority so we used the MOER data for PSCo balancing authority. The marginal carbon emissions data for one week in July 2018 is shown in Figure 26. The minimum, average, and maximum MOER in Denver for 2018 are 556, 1,275, and 1,698 lbs. CO_2 per MWh, respectively. To calculate the carbon emissions due to natural gas consumption, we assumed a constant emissions factor of 11.7 lbs. CO_2 per therm (U.S. Energy Information Administration 2021).

The community-wide carbon emissions calculated for each scenario are summarized in Figure 27. Scenario 2B is the lowest carbon emitter in any given month, in stark contrast to scenarios 3A and 3B, which are consistently the highest emitters. It is important to note that the variability in emissions levels across scenarios is largely attributable to differences in equipment

[8] PSCo is the operating subsidiary of Xcel Energy in Colorado.

efficiencies and presence (or lack) of PV rather than the timing of the load (e.g., hours where electricity is generated by more coal). As illustrated by Figure 26, the emissions rate is relatively flat over time in this region, so the total amount of energy used is the dominant driver of emissions. Scenario 2B combines efficient electrification with PV generation, so its carbon impact is much less than that of 3A and 3B, which employ inefficient electrification strategies and no PV.

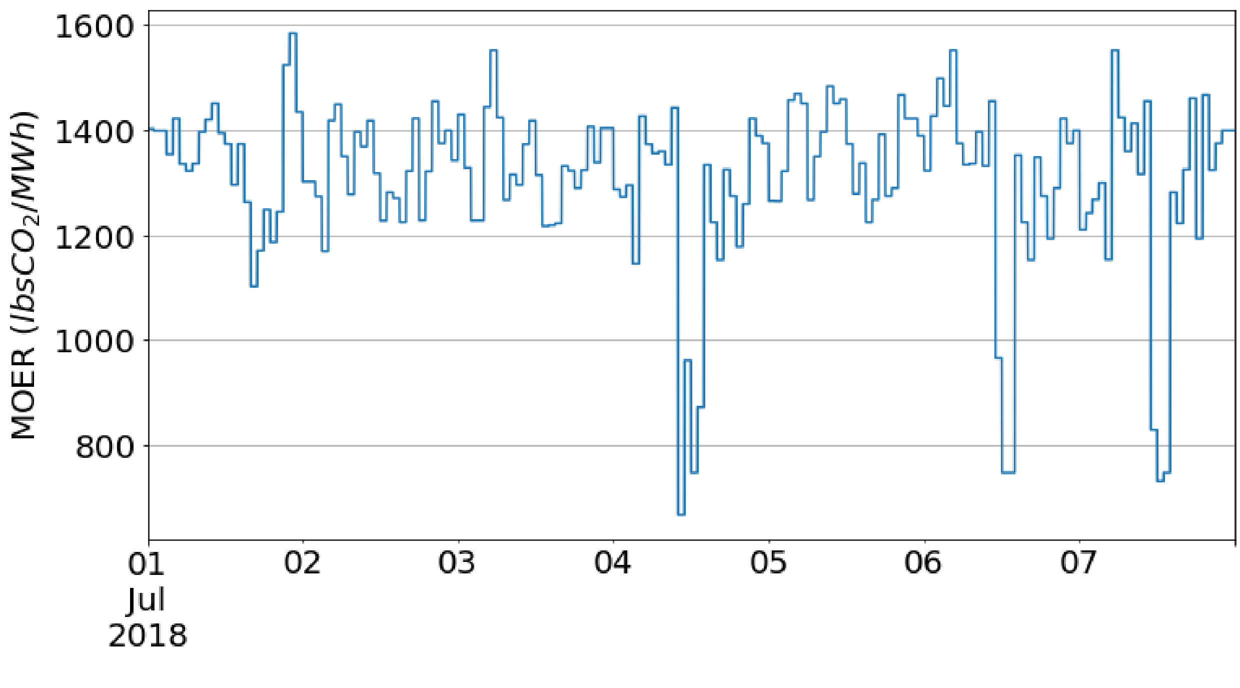

Figure 26. Grid MOER in Denver during one week in July 2018

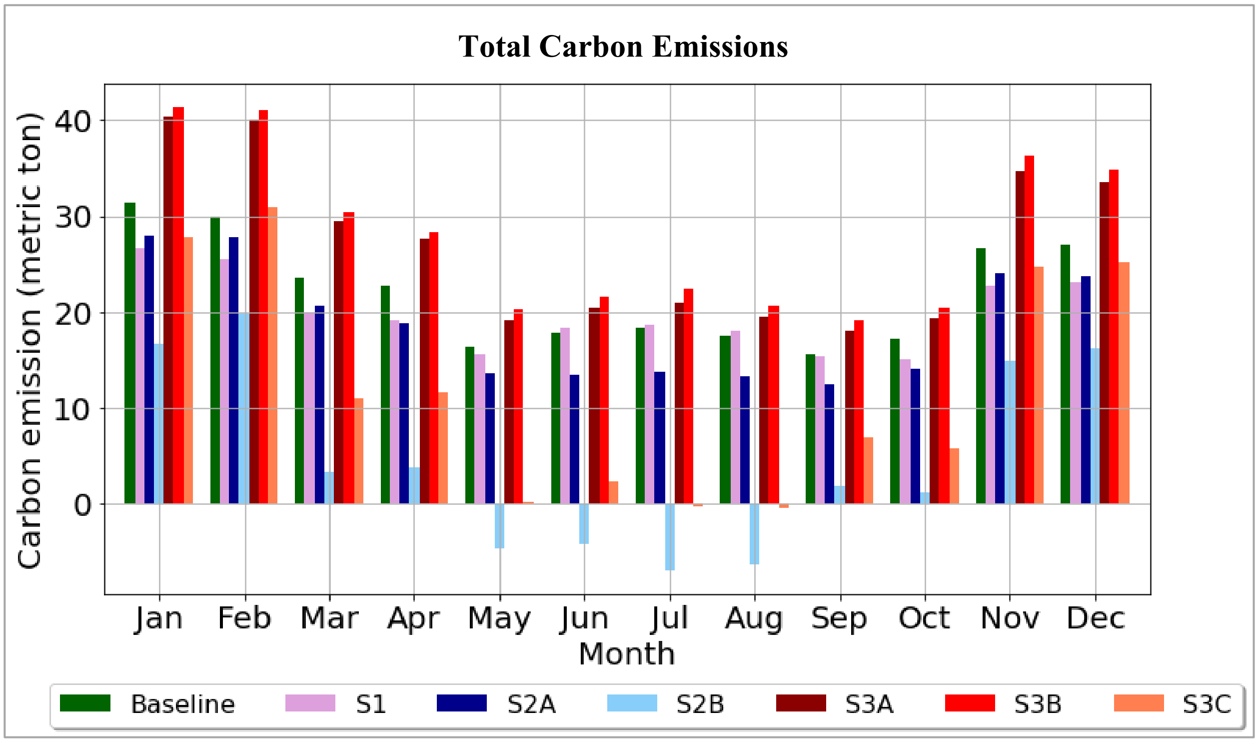

Figure 27. Total carbon emissions for the community by scenario

3.7 Distribution System Impacts

Figure 28 shows the distribution of the house-level voltage (at 1-minute intervals) for each scenario. A national standard for voltage regulation is set by the American National Standard Institute (ANSI). The ANSI standard range for distribution system voltage is between 0.95 and 1.05 per unit (p.u.); these limits are shown by the horizontal red lines. Frequent undervoltage or overvoltage can cause equipment to overheat or degrade in performance and reliability (Maintech Engineering and Supplies 2021). Across scenarios the house-level voltage is well within the standard voltage limits most of time, as indicated by the shape of the violins. However, the low-end tail in each plot suggests that there are instances of undervoltage in all scenarios. The undervoltage observed for baseline and scenario 1 is due to undervoltage conditions in a small subset of houses that have electric space and water heating (unlike the majority of baseline homes which use natural gas) during certain times of the year. The magnitude of undervoltage is highest (i.e., the tail is longest) in scenario 3 compared to other scenarios because of the increased electric load. While none of the scenarios exceed the upper limit, the addition of PV in scenarios 2B and 3C creates some higher voltage instances during times of PV production.

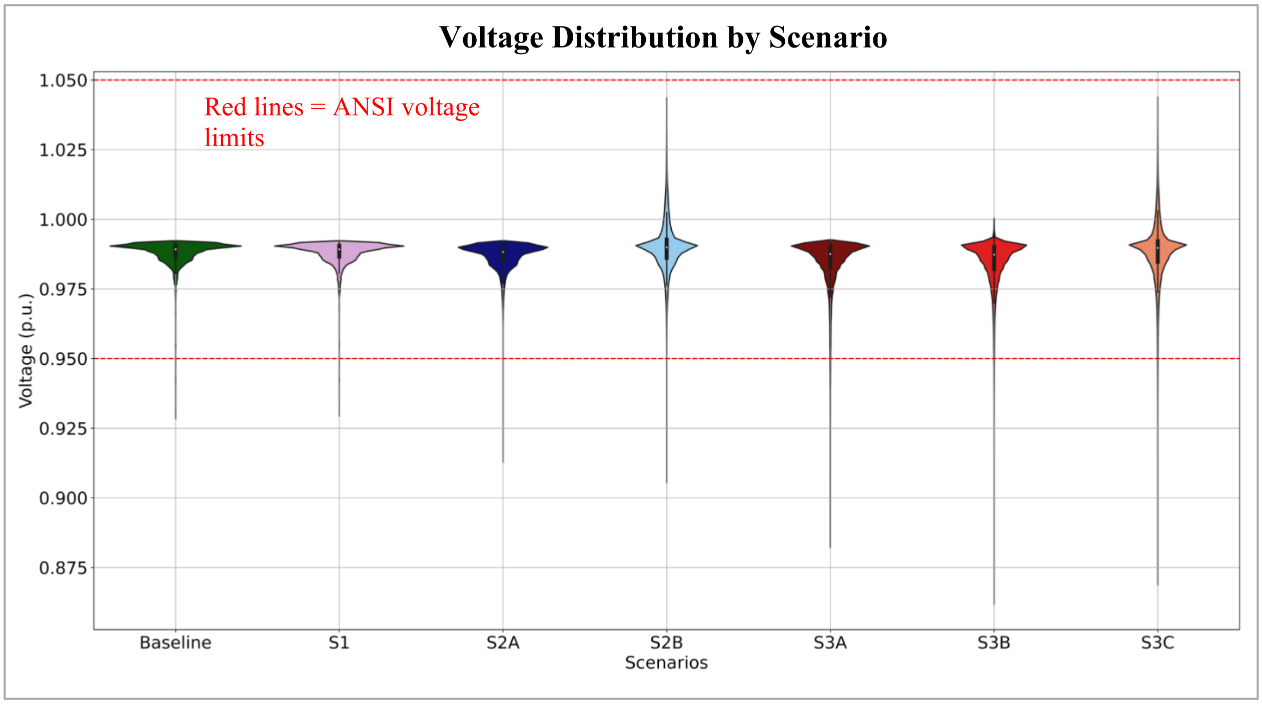

Figure 28. Distribution of house-level voltage by scenario

A more detailed voltage profile of each house (labeled n1 through n30) for the baseline scenario is shown in Figure 29. The box plot shows the distribution of the voltage profile, where the box represents the interquartile (2nd and 3rd quartile) range and the green line within the box represents the median voltage. The black circles represent the outliers in the voltage distribution. The voltage profile for most houses except for n3 and n4 are always within the acceptable limits. Out of the 30 homes, only n2, n3, and n13 have electric space and water heating, keeping the total load and undervoltage conditions on the grid fairly minimal. Both n3 and n4 are located at the end of the distribution feeder, contributing to higher voltage drop in the distribution lines. In addition, n3 has an ASHP and electric resistance water heater as well as higher plug load consumption. For these reasons, instances of undervoltage can be seen in n3 and n4, especially when the backup element in n3's ASHP turns on.

Figure 30 shows the voltage distribution for each house in scenario 3A. As we electrify the HVAC and water heater, the electricity consumption increases and thus lowers the voltage profile compared to the baseline scenario. There are many more instances of undervoltage in scenario 3A compared to the baseline scenario.

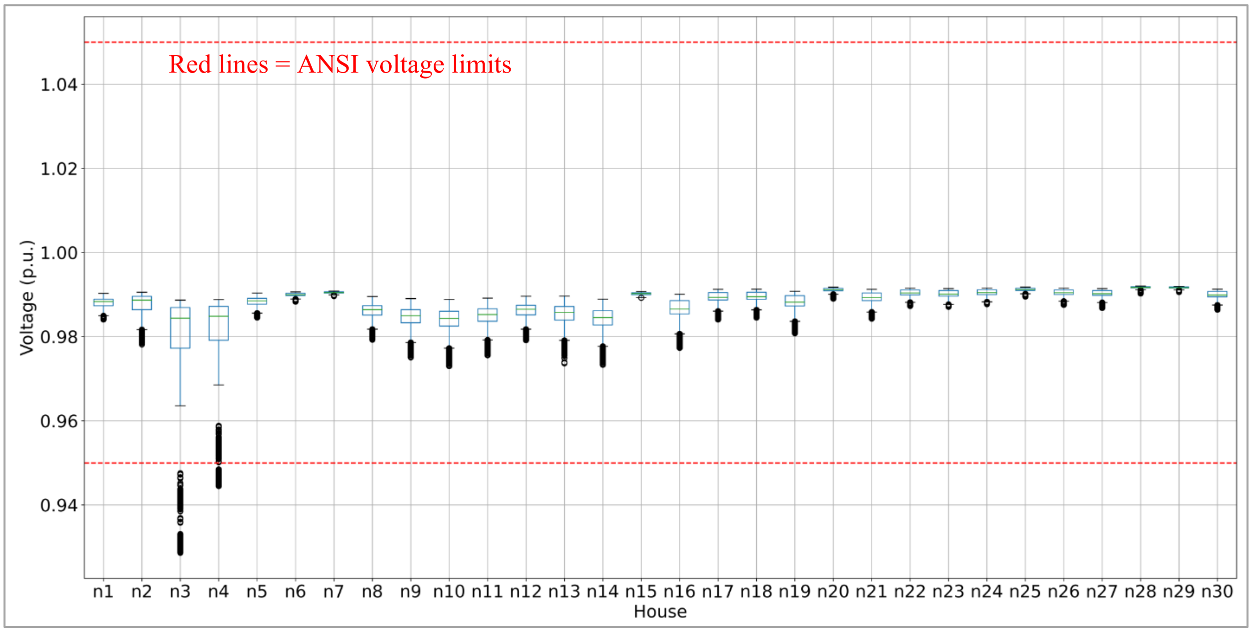

Figure 29. Voltage distribution of each house for the baseline scenario

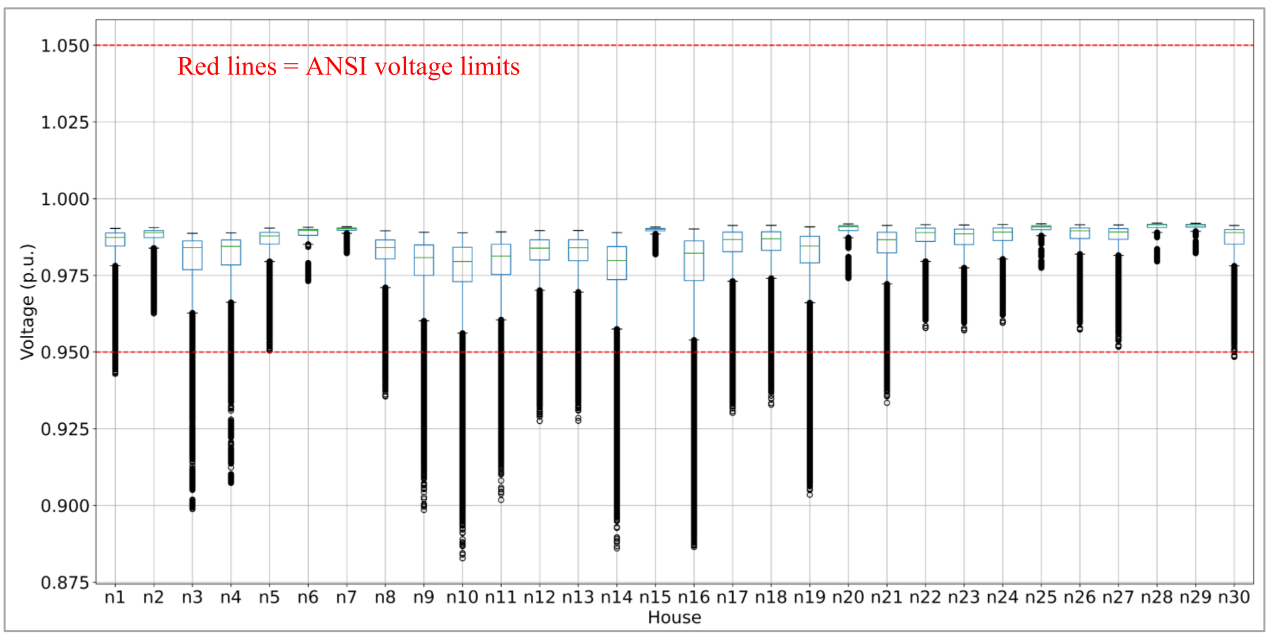

Figure 30. Voltage distribution of each house for scenario 3A

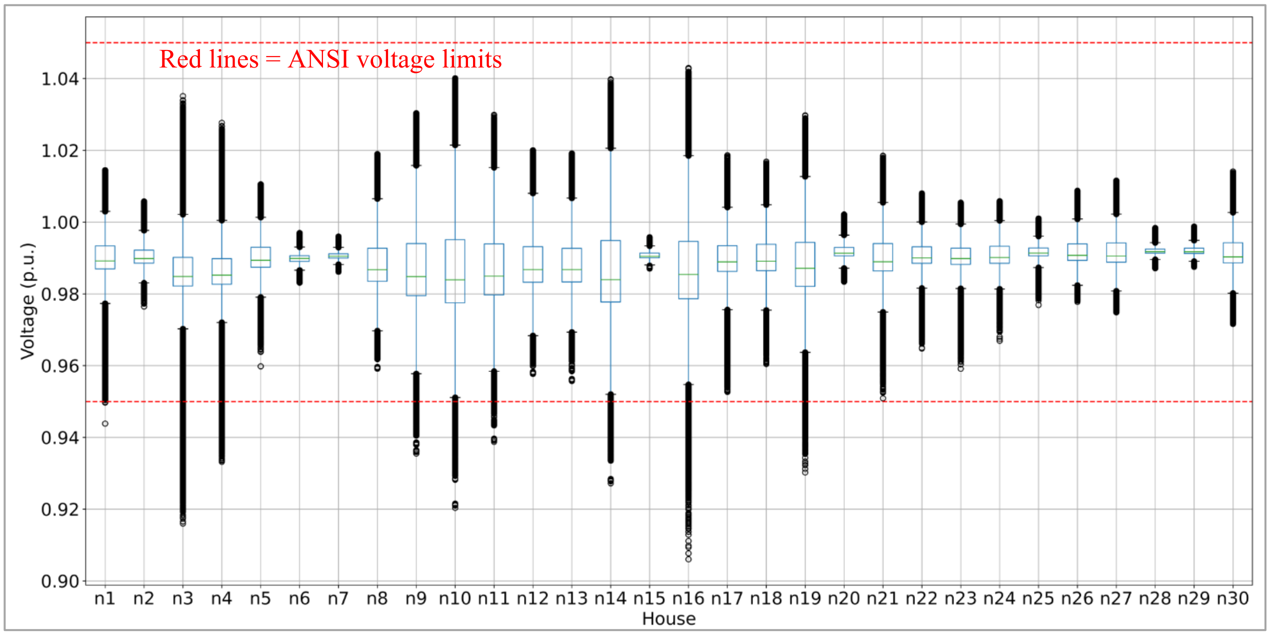

Figure 31. Voltage distribution of each house for scenario 2B

Figure 31 shows the voltage distribution for each house in scenario 2B. The addition of PV is responsible for the instances of higher house voltages, mainly during periods of PV production when there is substantial energy exported to the grid. However, the overvoltage is still within the permissible limit of 1.05 p.u. for all homes.

The distribution of transformer loading for one of the transformers is shown in Figure 32 for each scenario. The transformer loading is calculated using Equation (1):

$$Transformer\ Loading\ (\%) = \frac{Demand\ kVA}{Transformer\ rated\ kVA} \times\ 100\ \% \qquad (1)$$

It is notable that in our distribution system model, comparatively fewer residential customers are connected to each transformer with respect to its transformer capacity (i.e., rated kVA). This situation is typically found only in newer distribution systems. Despite the higher per-customer transformer capacity, the average transformer loading increased by 80% to 92% in scenario 3 cases compared to the baseline. There are numerous instances where the transformer is significantly overloaded in scenario 3. Such overloading can adversely affect the life of the transformer, so electrification of a residential community requires an in-depth study of its impacts on the distribution system. Transformer loading is lower in all scenario 2 cases compared to scenario 3 because of the use of more efficient appliances.

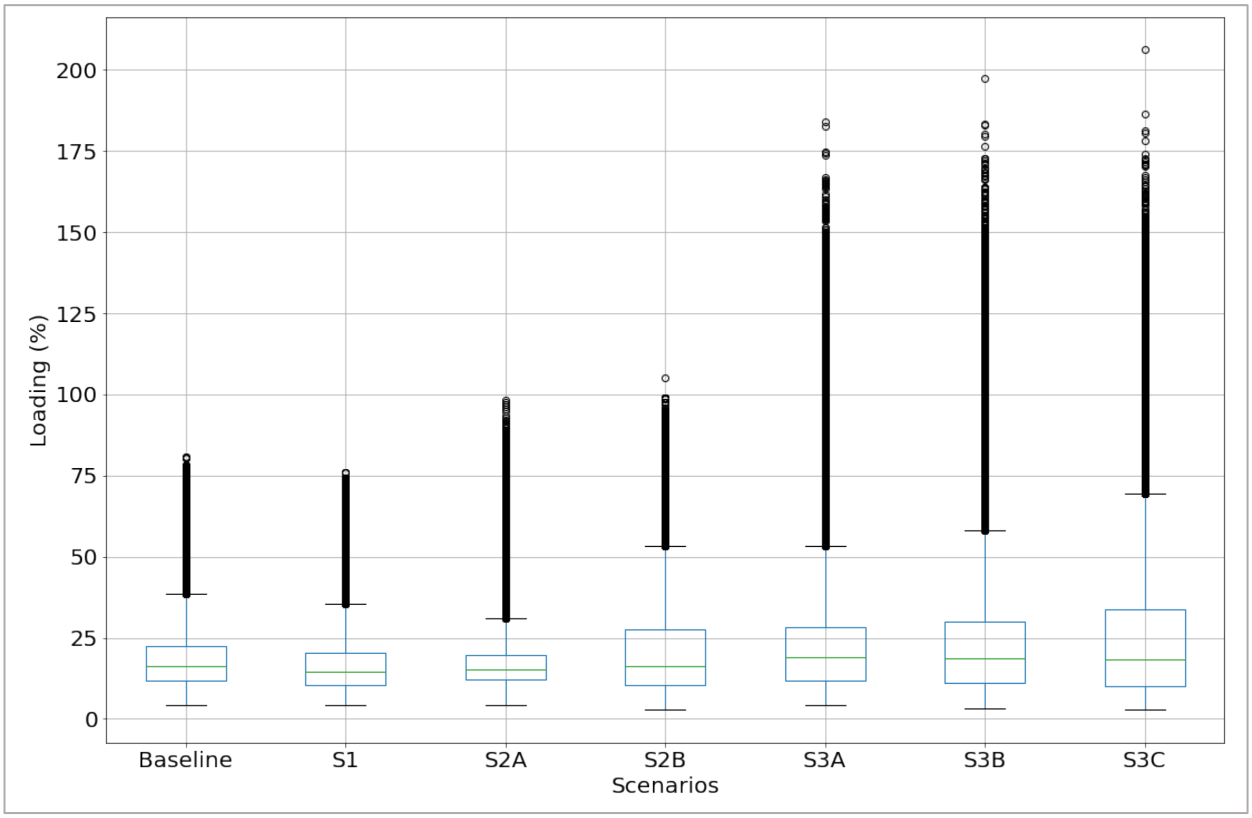

Figure 32. Transformer loading for transformer 91129481

4 Conclusions and Future Work

To facilitate comparison, key findings for each retrofit scenario are summarized in Table 5. One important conclusion is that electrification can be achieved without negatively impacting the monthly utility bill. Our simulation results clearly indicate that combining DER technologies with energy efficiency retrofit measures is indeed a promising strategy in our pursuit of beneficial electrification in existing homes. Scenario 2B shows overall lower source energy use, lower carbon emissions, and lower utility bills (with the caveat that homes with EVs will see higher electric bills in exchange for eliminating more expensive gasoline costs).

Our analysis simultaneously highlights a number of issues that will require further research combined with innovations in policy and programmatic strategies in order to ensure that the proposed solutions are practicable and broadly adoptable.

Efficient electrification alone can result in small energy bill savings, but these savings only tell part of the story because the upgrades require upfront costs, and modest utility bill savings result in long payback periods that are not appealing to most homeowners. Importantly, adding DERs (especially PV) as part of efficient electrification produces much bigger savings than efficient electrification without DERs.

As explained in the scenario 1 results, upgrading the air conditioner from a single-stage unit to a two-stage unit with a higher seasonal efficiency rating can result in a higher peak load despite the annual energy savings if the new unit tends to operate at stage 2 during peak periods in the summer. This phenomenon raises interesting questions about the relative tradeoffs that can exist between energy efficiency and peak load reduction. Not every piece of efficient equipment will provide peak load reduction, and creative strategies (e.g., precooling just enough to be able to operate in stage 1 during peak period) may be worth exploring to optimize for both energy efficiency and peak load reduction.

For peak load management, while electrifying a neighborhood increases the maximum load, batteries and PV can reduce summertime peak load to the point that the community can be a net producer during peak periods as long as the surrounding communities are not yet electrified. Looking forward, however, if the broader system transitions along with this neighborhood, the entire distribution system could be faced with winter peaks that occur primarily in the early mornings. This could be the case even with efficient electrification because the heat pumps' backup electric resistance heaters are most likely to kick on during the coldest hours. If peaks occur in the early mornings, PV would not be able to shift the load in a meaningful way. This type of scenario would have implications for the relative value of different DER technologies and their implementation. Further study is needed to explore how load management could be optimized to accommodate wide-scale winter peaks through a judicious combination of generation, storage, and efficient end-use equipment.

The practice of sizing PV systems based on a home's past energy bills (where the maximum allowable array size is determined to be equivalent to 120% of the home's energy use profile in the previous year) also emerged as an issue worth further consideration. When a home undergoes electrification and/or acquires an EV, a significant increase in electrical load should be expected. It would seem prudent to modify current policy so that homeowners can match the size of their

PV installations to future anticipated load in these types of scenarios, should they choose to electrify and install PV simultaneously.

In our simulations the HEMS algorithm based its control decisions on occupant comfort and the cost of energy to the homeowner (i.e., utility bills under TOU rates). It would be worthwhile to explore how prioritizing other benefits such as carbon emissions reduction might alter the overall load profile of a home, and the impact of such a change on the other benefits. This would be particularly interesting for regions of the country where the carbon emissions rate varies more dramatically over time, and so optimizing for emissions reduction would not necessarily produce the same results as minimizing energy use or energy cost.

Table 5. Summary of Key Findings by Retrofit Scenario

Scenario	Electrification	Energy Efficiency	HEMS	Battery	EV	PV	Key Results
1		X					• ~15% decrease in winter energy use from pre-retrofit, largely due to more efficient heating equipment.
2A	X	X					• Efficiency improvements result in source energy savings over baseline or scenario 1 (despite electrification). • Utility bill costs are similar to baseline (because electricity is relatively more expensive than natural gas, on a per-unit energy basis).
2B	X	X	X	X	X	X	• Lowest source energy use of any scenario. • Lowest carbon emissions of any scenario. • EVs represent a substantial community load (higher than space cooling) despite its adoption in only one-third of homes. • Although the battery has a small net positive load on the homes due to roundtrip efficiency losses, it contributes to energy bill savings because it enables arbitrage via load shifting. • Utility bill increase is entirely attributable to EV addition, so the average homeowner actually saves money over the baseline. (EV charging costs less than equivalent gasoline per mile driven.) • PV sizing is based on pre-retrofit energy bills, so maximum size allowable is insufficient to meet electrification demands. Community is a slight net consumer of electricity annually but there are periods of net production.
3A	X						• Utility bills increase by 40% for the average homeowner.
3B	X		X	X	X		• Highest source energy use of any scenario. • Highest carbon emissions of any scenario. • Slightly lower bills than 3A despite the overall energy use increase because of HEMS and battery.
3C	X		X	X	X	X	• Addition of PV saves homeowners 60% relative to 3B, but community is a net consumer of electricity annually. • PV sizing is based on pre-retrofit energy bills, so maximum size allowable is insufficient to meet electrification demands.

Moving forward, demand flexibility is likely to play a prominent role in electrification because its value goes beyond just reducing peak demand. Demand flexibility can be leveraged to shift a home's load based on grid peak capacity or the locational marginal price, and thus provide system-wide savings as the grid becomes more heavily driven by renewables with more dynamic generation profiles. In practice, to implement this type of load flexing that accommodates system-wide peaks and valleys, homeowners need to be incentivized through suitable utility rate structures.

We also learned about distribution system impacts. Electrification of a neighborhood increases the system load and thus creates stress in the distribution system. Planning of the distribution system should be done together with electrification. Electrification without energy efficiency upgrades could cause substantial damage to the distribution transformers if a neighborhood is not designed to handle the larger loads.

In this work we developed and demonstrated an analysis framework and a functional co-simulation platform that can be broadly applied to community-scale beneficial electrification studies in other regions, climates, utility infrastructures, and building typologies. Efforts are underway to further streamline our co-simulation workflow so that the end-to-end process, which involves numerous computational tools, can be more efficient, faster, and accessible to a broader userbase. Improvements in this regard would greatly benefit future projects.

Using techniques developed here we can make specific, targeted recommendations based on quantified projections of energy demand in any given community. Because the scope of this work is limited to a modeling study and not a field project, it was not practical to collect detailed audit data on actual homes in order to recreate an existing neighborhood. Our approach of creating a synthetic neighborhood inspired by Central Park is well suited to produce scenario studies that are perhaps more generally applicable to other neighborhoods of similar vintage, but to obtain more detailed and nuanced results that realistically predict electrification scenarios it is necessary to model the actual buildings and electrical infrastructure that serves those buildings. This is precisely how we would begin a future field demonstration. We are pursuing field opportunities using an experimental plan that we developed based on the work presented in this report.

References

Alternative Fuels Data Center. N.D. “Electric Vehicle Infrastructure Projection Tool (EVI-Pro) Lite Assumptions and Methodology.” U.S. Department of Energy Office of Energy Efficiency and Renewable Energy. https://afdc.energy.gov/evi-pro-lite/load-profile/assumptions.

Bureau of Transportation Statistics. N.D. “Average Fuel Efficiency of U.S. Light Duty Vehicles.” https://www.bts.gov/content/average-fuel-efficiency-us-light-duty-vehicles

Building America. 2013. “Building America 2014 House Simulation Protocols.” https://www.energy.gov/eere/buildings/downloads/building-america-2014-house-simulation-protocols.

Colorado Electric Vehicle Plan. 2020. State of Colorado. https://drive.google.com/file/d/1-z-lNQMU0pymcTQEH8OvnemgTbwQnFhq/view.

Jin, Xin, Jeff Maguire, and Dane Christensen. 2018. “Economic Sizing of Batteries for the Smart Home: Preprint.” Golden, CO: National Renewable Energy Laboratory. NREL/CP-5500-71619. https://www.nrel.gov/docs/fy18osti/71619.pdf.

Maintech Engineering and Supplies. 2021. “Overvoltage & Undervoltage: All You Need To Know.” https://www.mes.com.sg/2019/09/19/overvoltage-undervoltage-all-you-need-to-know/.

U.S. Energy Information Administration. 2021. “Frequently Asked Questions: How much carbon dioxide is produced when different fuels are burned?” https://www.eia.gov/tools/faqs/faq.php?id=73&t=11.

U.S. Energy Information Administration. 2021. “Weekly Retail Gasoline and Diesel Prices.” https://www.eia.gov/dnav/pet/PET_PRI_GND_DCUS_YDEN_A.htm

WattTime. 2022. “Automated Emissions Reduction.” https://www.watttime.org/solutions/automated-emissions-reduction-aer/.

Xcel Energy. 2020. “Public Service Company of Colorado; Natural Gas Rates Summary; Effectively October 1, 2020.” https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/Gas_Tariff_Summary_Sheet_10.01.2020.pdf.

Xcel Energy. N.D. “Colorado – Electric: Public Service Company of Colorado Electric Tariff Index.” https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/Regulatory%20Filings/CO%20Recent%20Filings/PSCo_Electric_Entire_Tariff.pdf.

The Zebra. 2022. “Average Miles Driven Per Year in the U.S.” https://www.thezebra.com/resources/driving/average-miles-driven-per-year/#states-where-people-drive-the-most-and-least