Commercial and Multifamily CO_2 Heat Pump Water Heater Market Study and Field Demonstration

Final Report

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Executive Summary

Domestic water heating accounts for approximately 32 percent of site energy consumption in multifamily buildings across the United States. This end-use has become a focus of many energy efficiency and decarbonization efforts due to its large energy footprint, impact on disadvantaged communities, and emerging technologies. Hot water in multifamily buildings is often supplied with a central system design, consolidating the heat source to a single point with distribution and recirculation throughout the building plumbing. There are approximately 58,000 buildings in California with these systems, comprising 1.9 million housing units. Further, the energy footprint of central domestic hot water systems in California non-residential buildings is approximately 50 percent that of the multifamily sector.

While these systems are historically almost exclusively natural gas-fired, central heat pump water heater systems are now becoming more available. Central hot water systems in new multifamily buildings are not required to be electrified by California building code, but new regulatory pathways do make it easier to obtain energy code credits for them. These central heat pump water heater systems have the potential to reduce greenhouse gas emissions, incur total system benefits, and enable electrical load shifting by using the heat storage capacity inherent in the storage tank volume.

Central heat pump water heater systems were installed in two low-income, high-rise multifamily buildings in San Francisco with 120 and 135 single-room occupancy residences, respectively. These installations replaced the existing natural gas-fired central systems costs of $4,082 and $6,311 per residence. The individual heat pumps have rated coefficients of performance (i.e., efficiency) of 4.11 at standardized laboratory conditions and use carbon dioxide as a low-global warming potential refrigerant. The systems included electric resistance swing tanks to meet recirculation, temperature maintenance loads and the storage volumes were large enough to facilitate load shifting controls.

The two systems were measured and monitored between January and October of 2023 to evaluate their performance. Both systems were observed to reduce energy consumption and greenhouse gas emissions substantially over the monitoring period in comparison to an efficiency code-compliant gas alternative. Input energy was reduced by 68 – 69 percent due to observed whole system daily coefficients of performance between 2.3 and 3.1 during the monitoring period.

Load shifting capabilities of the two installations were also tested. The systems were programmed to load up during the off-peak and partial-peak period of 12 – 4 p.m. with load shed during the peak period of 4 – 9 p.m. The load shift tests were successful and showed an average load shed of 32 – 63 percent during the peak period. Refinement and optimization of load shifting control strategies will be needed to realize maximum energy cost and greenhouse gas benefits.

Central heat pump water heaters have immense potential societal and energy benefits, albeit with some addressable challenges to equitable, reliable, rapid market transformation. Annualization of the results to typical weather years across California climate zones suggested an overall greenhouse gas reduction of 85 percent when compared to a high-efficiency natural gas baseline. Across the state, the total potential yearly impact in existing multifamily buildings is 1.7 million tons of avoidable greenhouse gas emissions and $350 million in total system benefits, conservatively. Utility programs will need to support the market's investment to reap these nascent total system benefit returns. Several recommendations for future study, product development, and program support are provided.

Abbreviations and Acronyms

Acronym	Meaning
A	Amps
ACC	Avoided cost calculator
AWHI	Advanced Water Heating Initiative
CA	California
CASE	Codes and Standards Enhancement
CEC	California Energy Commission
CHPWH	Central heat pump water heater
CO_2	Carbon dioxide
CO_2e	Carbone dioxide equivalent
COP	Coefficient of performance
CT	Current transducer
CTA	Consumer Technology Association
CZ	[California] climate zone
DAC	Disadvantaged community
DHW	Domestic hot water
EPIC	Electric Program Investment Charge Program
ER	Electric resistance
GHG	Greenhouse gas
gpm	Gallons per minute
GWP	Global warming potential
HPWH	Heat pump water heater

Acronym	Meaning
HX	Heat exchanger
IOU	Investor-owned utility
IPMVP	International Performance Measurement and Verification Protocol
kWh	Kilowatt-hour
M&V	Measurement and verification
MXV	Mixing valve
NEEA	Northwest Energy Efficiency Alliance
NOAA	National Oceanic and Atmospheric Administration
OAT	Outside air temperature
P	Power
PG&E	Pacific Gas and Electric
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SGIP	Self-Generation Incentive Program
SOO	Sequence of operations
SRO	Single room occupancy
T	Temperature
TH	Thermistor
TOU	Time-of-use
TSB	Total system benefit
WH	Water heater

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Introduction

This work studies California (CA) multifamily building applications of central heat pump water heating (CHPWH) systems with carbon dioxide (CO_2) refrigerant. Two low-income elder living buildings in San Francisco were retrofitted with CHPWH systems, presenting an opportunity to study the emerging technology in situ. The project team collaborated with the building owners, system designers, and heat pump equipment manufacturers to study the performance and load shifting capacity of the system. The project team used these results to quantify system energy efficiency benefits, market potential, and electrical load management. The report includes recommendations for product design, program support, and additional future study directions.

Background

Domestic hot water (DHW) has one of the largest energy footprints of all residential end-uses in the United States. According to the Energy Information Administration, domestic water heating accounts for about 32 percent of site energy consumption in multifamily buildings with five or more units across the country (U.S. EIA 2018a). Across the individual California multifamily building responses in the 2020 Residential Energy Consumption Survey, this figure was about 45 percent of total site energy usage (U.S. EIA 2023a). Thus, it is natural for this high-impact end-use and building sector to be the focus of substantial effort by the energy efficiency industry towards energy savings, decarbonization, and greenhouse gas (GHG) emission reduction goals.

Hot water demand in multifamily buildings is often satisfied by one or more centralized systems (as opposed to distributed water heaters in every unit). Central hot water system designs vary, but at minimum comprise a primary heat source, hot water storage, and temperature maintenance system. Common features include:

- A heat source, historically almost always direct-fired natural gas in California but also can be electric resistance (ER), steam, or other alternative fuels.
- Hot water storage in one or more pressure-rated vessels (i.e., tanks).
- Continuous pumped recirculation through a distribution piping network that includes one or more loops to maintain hot water supply in proximity to end-uses (showers, sinks, etc.) and branch take-offs to the dwellings.
- Recirculation pump speed or flowrate controls based on load parameters such as occupancy schedules, pressure setpoints, or return temperature.
- Mixing valves that can temper hot water supply with cold water for delivery of DHW at the desired temperature setpoint.

The design and specifications of a central DHW system for any given building will depend on factors such as code requirements at the time of construction, building layout (e.g., high-rise vs. one- or two-story complex), peak hot water loads, location, and other factors that an engineering firm will consider. Thus, there is a wide variety of hot water system types in the California multifamily and commercial building stock.

Supporting energy efficiency in multifamily buildings can have substantial energy impacts while also benefiting lower-income, hard-to-reach, renter populations which disproportionately comprise multifamily building occupants. According to the 2021 US Census American Community Survey, about 90 percent of apartments in buildings with three or more dwellings are occupied by renters in California. This compares to less than 45 percent for the total residential population. Thus, a focus on end-uses and energy systems in multifamily buildings can benefit these underserved communities, especially when measures can impact whole buildings and bridge the split renter-owner incentive. Upgrades to central DHW systems are one such measure.

Multifamily Central Domestic Hot Water System Market Size

Available information in hot water research literature and building surveys can be used to partially characterize the existing building stock with central DHW systems. Information on multifamily buildings that have central DHW systems is much more readily available than non-residential commercial buildings. As of 2015, there were nearly 12 million residences in multifamily buildings with more than five units across the United States served by central DHW systems (U.S. EIA 2018a). About 3.1 million of these dwellings were in the Pacific region (U.S. EIA 2018b). Assuming that these dwellings are distributed across the five Pacific states proportionally to state population suggests that there were about 2.3 million multifamily dwellings in California served by central DHW systems in 2015.

This is similar to the total multifamily market size suggested by recent Title 24, Part 6 efforts completed by the Statewide Codes and Standards Enhancement (CASE) Team (Pande, et al. 2022) (Goyal, et al. 2022). These CASE reports assessed the new construction and existing multifamily building market size based on four building prototypes: low-rise garden, low-rise loaded corridor, mid-rise, and high-rise. Table 1 lists the market share of each building type across the multifamily sector and their respective share of the total number of residences as concluded in the CASE reports. These studies reasonably assume that all central DHW systems are natural gas-fired in California.

Table 1: California multifamily market share across building types (Pande, et al. 2022) (Goyal, et al. 2022).

Building Type	Stories	Percentage of existing multifamily buildings	Percentage of existing multifamily residences
Low-rise garden	1 –2	50%	24%
Low-rise corridor	3	42%	39%
Mid-rise	4 – 6	6%	21%
High-rise	7+	2%	16%

Three studies have identified market penetration of central DHW systems in the multifamily sector, as listed in Table 2. The values in the rightmost column from the California Multifamily Energy Use Survey were used to estimate the total market size since they were based solely on the California market and actual field data collection.

Table 2: Multifamily central DHW market penetration.

Building Type	(Pande, et al. 2022) (Goyal, et al. 2022)	(NEEA 2019)	(Evergreen Economics 2021)
Low-rise garden	37%	30%	**24%**
Low-rise corridor	49%	30%	**24%**
Mid-rise	97%	59%	**63%**
High-rise	100%	98%	**100%**

The CASE Reports identified the number of existing multifamily residences in each California climate zone (CZ). They also report a new construction growth rate of 1.2 percent per year; this can be used to project future central DHW systems in new buildings. Combining the building stock estimate with the market share rates in Table 1 and Table 2 suggests there are about 1.9 million multifamily dwellings served by central DHW systems in California with the following distribution across CZs:

Table 3: Estimated market size of existing CA multifamily buildings and residences served by central DHW.

	Number of buildings				Number of residences			
CZ	Low-rise 1-2 story	Low-rise 3 story	Mid-rise 4-6 story	High-rise 7+ story	Low-rise 1-2 story	Low-rise 3 story	Mid-rise 4-6 story	High-rise 7+ story
1	99	83	30	17	969	1,618	2,315	2,673
2	590	493	179	102	5,755	9,610	13,749	15,876
3	3,075	2,567	934	529	29,990	50,080	71,651	82,731
4	1,616	1,349	491	278	15,758	26,315	37,649	43,471
5	260	217	79	45	2,535	4,234	6,058	6,994
6	1,832	1,529	556	315	17,865	29,834	42,684	49,285
7	1,693	1,413	514	291	16,509	27,568	39,443	45,542
8	2,839	2,370	862	489	27,684	46,230	66,143	76,371
9	6,304	5,262	1,915	1,085	61,480	102,666	146,888	169,602
10	1,835	1,532	557	316	17,899	29,890	42,765	49,378
11	475	396	144	82	4,629	7,730	11,059	12,770
12	2,641	2,205	802	455	25,757	43,011	61,538	71,053
13	894	746	271	154	8,715	14,554	20,822	24,042
14	459	383	139	79	4,477	7,477	10,698	12,352
15	232	194	71	40	2,265	3,782	5,411	6,248
16	160	133	48	27	1,556	2,599	3,718	4,293
All	25,004	20,871	7,594	4,305	243,844	407,199	582,591	672,681

The 2019 California Residential Appliance Saturation Study estimated that the typical energy consumption for multifamily residences with natural gas water heating is 252 therms per year (DNV GL Energy Insights USA 2020). Combining this annual usage with the market size estimates in Table 3, Estimated market size of existing CA multifamily buildings and residences served by central DHW, it suggests about 480 million therms of natural gas is consumed on site each year for multifamily building central DHW in California.

Non-residential Central Domestic Hot Water System Market Size

Characterizing the non-residential market use of central DHW was difficult due to information gaps in publicly available literature and data. The market share of central DHW systems in commercial buildings was only available in the Northwest Energy Efficiency Alliance's (NEEA) Commercial Building Stock Assessment which examined buildings in the Pacific Northwest (Cadmus Group 2020) That study characterizes hot water systems as DHW tank, tankless, or boiler. Boilers were found to have significant market share in office, education, healthcare, and lodging building types. Assuming that boilers correspond to central DHW and that the northwest market is similar to California's, this data can be combined with California data to estimate the total non-residential central DHW floor space and energy consumption as shown in Table 4.

Table 4: Estimated market size of existing CA non-residential buildings served by central DHW.

	Offices	Education	Healthcare	Lodging	Source
Fraction of total comm gas consumption, A	14%	11%	14%	9%	(Itron 2006)
Percent comm gas for HW boilers, B	4%	23%	23%	37%	(Cadmus Group 2020)
Total CA comm gas usage, C (ktherm/yr)	2,534,025 (in 2022)				(U.S. EIA 2023b)
Central DHW usage (ktherm/yr)	14,499	64,546	79,967	83,962	A x B x C
Total central DWH energy usage (ktherm/yr)	242,974				A x B x C
Floor area, D (1,000 ft^2)	1,022,013	651,048	232,606	270,044	(Itron 2006)
Floor area served by central DHW (1,000 ft^2)	40,881	149,741	53,417	99,916	B X D

Note that this estimate necessarily excluded the market share of central DHW that uses ER or other fuels as a heat source. While ER systems should be the absolute highest priority for retrofit or efficiency measures in this subject matter, they are rare and existing datasets did not have enough information to estimate their market size.

Emerging Technology: Central Heat Pump Water Heater Systems

Transforming the DHW market in multifamily buildings towards heat pumps could have substantial energy efficiency, GHG emission, and decarbonization impacts. Central heat pump water heater systems are equivalent to the central DHW systems described above but utilize heat pumps as a primary heat source. Recent and ongoing research and product development has made this a realistic option for both retrofit and new construction applications.

In this burgeoning product space, air-source heat pumps have become the focus due to their broad applicability, equipment availability, and potential impact. Although there are many refrigerant options for heat pumps, available air-source heat pumps for CHPWH systems in the United States mainly rely on R513a, R32, R134a, R410a, and R744 (i.e., CO_2). Of these, R513a, R32, and CO_2 are each considered to be low-global warming potential (GWP) options (GWP of 573, 675, and 1, respectively). Internationally, R290 (i.e., propane) is also used; in the United States its use is currently restricted by UL 60335-2-40. R290 is a natural refrigerant with excellent thermodynamic properties and an ultra-low GWP of three.

In general, heat pump water heaters (HPWH) operate most efficiently under single-pass operation, where the temperature of incoming water is raised to the hot storage temperature in one large lift. CHPWH systems using CO_2 refrigerant also typically requires separation of primary (incoming make-up water) and temperature maintenance (recirculation water). This is because CO_2 refrigerant operates most efficiently when incoming heat pump water is below 90 °F. Recirculation return water is typically above 105 °F so the direct heating of recirculation return water cannot be done efficiently with most CO_2 HPWHs.

This contrasts with multi-pass systems where water is circulated multiple times through the heat pump heat exchanger to incrementally raise its temperature. With increasing incoming water temperature to the heat pump, efficiency will often decrease. Thus, it is often advantageous to design a system that maximizes the primary HPWH lift. This factor becomes impactful when building loads are low and the return temperature from the recirculation loop is relatively high (i.e., close to the DHW setpoint). In this case, it makes sense to have separate heat sources for the primary and temperature maintenance loads to maximize total system efficiency, minimize heat pump short cycling, and minimize energy costs.

For a DHW system with recirculation and a variable load profile, especially with periods of low demand, recirculation loop temperature maintenance becomes a key design factor. The temperature maintenance heat source is typically recommended to be either a multi-pass HPWH or an ER integrated storage tank water heater (although a natural gas-fired heat source could apply as well). The temperature maintenance section can be plumbed in parallel to the primary heating system or in series. A temperature maintenance storage tank is often called a “swing tank,” typically referring to a series-plumbed design with an ER temperature maintenance tank. It is typical for a swing tank to be the primary heat source when loads are low (e.g., late night in a multifamily building), maintaining recirculation temperature while draws from the hotter primary storage volume are small.

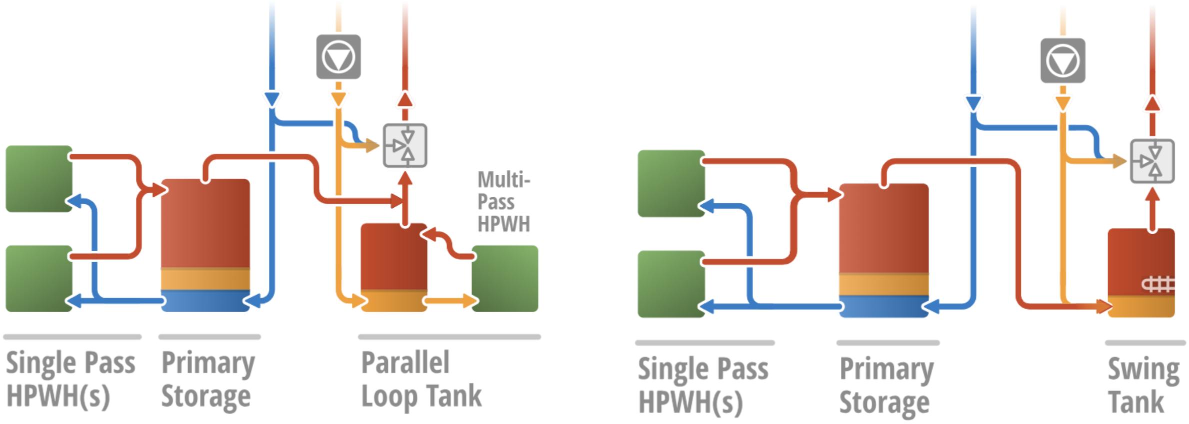

Figure 1: Parallel multi-pass HPWH and series ER swing tank temperature maintenance. (Ecotope 2020).

Another common design option is to isolate the primary HPWH water loop from the storage and potable water plumbing. This is done by using a heat exchanger between a HPWH loop and a DHW loop. For certain HPWH models, this is necessary to ensure that water quality can be maintained to avoid equipment damage without having to purify or treat the potable DHW used by residents. This arrangement can also enable freeze protection since a water-glycol mixture can be used in the isolated primary HPWH loop that circulates outdoors.

Although a CHPWH system could be custom designed from a variety of off-the-shelf components from any number of equipment sources, there are a handful of manufacturers that are leading product line development. These manufacturers offer both CHPWH system components for site-built custom designs and, more recently, packaged skid options as part of a transition towards more standardized, simplified offerings.

These CHPWH systems have become a viable, commercially available solution for multifamily and non-residential buildings in the United States. Naturally, they are most feasible and economical in new construction but retrofitting existing buildings is also possible and presents a huge opportunity. For the retrofit of existing buildings, consideration must be given to details such as available electrical power capacity and infrastructure, integration into existing plumbing, condition of existing DHW distribution systems, airflow requirements, and physical space for the placing of heat pumps and storage tanks.

As shown in Table 5, several recent multifamily CHPWH design studies and field demonstrations in the United States have confirmed the viability and performance of these systems, as well as some cost estimates. Efficiency is quantified as the system coefficient of performance (COP), the ratio of energy delivered to the hot water distribution system to the energy input. This includes energy for both hot water consumption as well as for temperature maintenance in the distribution loop.

Table 5: Literature survey summary of field and case studies.

System Description	Location	Number of Dwellings	COP	DHW Usage (gal/day-person)	Cost	Source
New construction R134a single pass HPWHs in parking garages	Seattle, WA	92 and 118 (apartments)	2.4 - 2.8 (annualized)	13 and 19	n/a	(Heller and Oram 2015)
New construction outdoor HPWHs coupled with indoor ER storage	Davis, CA	12 (dorms)	2.12 (annualized)	12.3	n/a	(Hoeschele and Weitzel 2017)
Retrofit CO_2 with storage tanks and ER swing tank, replacing ER	Seattle, WA	60 (apartments)	3.3 (monitoring period)	20	$1,964 per residence	(Banks, Grist and Heller 2020)
Retrofit CO_2 with storage tanks and ER swing tank, replacing ER	Seattle, WA	100 (low-income senior housing)	2.3 (monitoring period)	18	n/a	(Banks, Spielman and Heller 2022)
New construction CO_2 HPWHs with storage tanks and ER swing tank	Sunnyvale, CA	66 (apartments)	3 - 5 (monitoring period)	20.7	n/a	(Dryden, et al. 2023)
New construction CHPWH planning	New York, NY and Bay Area, CA	n/a	n/a	n/a	$1,110 – 3,540 per residence	(Gartman and Armstrong 2020)
Retrofit CHPWH cost planning	n/a	n/a	n/a	n/a	$1.5-3 per ft^2 living space	(Steven Winter Associates 2019)

Although CHPWHs have predominantly been applied in multifamily buildings thus far, there are many other building types that are excellent candidates for this technology. Building types such as hospitality, lodging, schools, offices, and healthcare are all promising applications of CHPWH systems, assuming the designers and implementers have a solid understanding of the technology and design considerations. Sizing and design tools are less available for non-residential buildings, for now.

Emerging Technology: Central Heat Pump Water Heater Load Shifting

Across these markets, the adoption of CHPWHs will add load to the California electrical grid since nearly all central water heating is powered with natural gas burners. Thus, it is crucial to include electrical demand management at individual installations or in aggregate by using CHPWH load shifting controls and storage capacity. This is a necessary facet for ensuring beneficial electrification in the public interest (Farnsworth, Lazar and Shipley 2019). By leveraging the stored hot water as a thermal battery, the load can conceivably be shifted away from periods of peak grid demand, when energy costs and carbon emissions are high. Such controls will not only mitigate the grid impacts of this market transformation but will also minimize energy costs incurred by building owners and residents for their hot water.

For instance, Ecotope has worked on prototype load shift programming in field demonstrations (Spielman 2022). In general, the load shifting of a CHPWH system is performed through “load up” and “shed” programming. During load up mode, additional heat is stored in the tanks in preparation for shed mode where that stored heat is then used to coast through the high-emission, high-cost period. The paper proposed and modeled load up and shed modes based on adjustment of three operating parameters:

1. Thermistor locations in the storage volume that are used to trigger calls for primary heat: by widening the gap between the on and off temperature sensor locations, total thermal storage capacity can be increased or discharged more fully.
2. Hot water temperature setpoint: can be increased to increase thermal storage across the stratified volume during the load up mode.
3. Heat pump capacity: in the case of the system under study, the heat pumps can be ramped up to generate more heat during the finite load up period in a shorter amount of time.

The CHPWH industry has prepared for external signaling that can trigger such programmed load shifting modes or settings. The Advanced Water Heating Initiative (AWHI) grid connectivity working group has coordinated with stakeholders to establish the Consumer Technology Associate (CTA) 2045 technical specification (brand name EcoPort) for products certified by the OpenADR Alliance. This device-to-device communication port allows for such external triggering of load shifting. A service provider, utility, or program administrator can use this for load management of these distributed resources via standard communication protocols (e.g., via Wi-Fi, Zigbee, Bluetooth, FM, etc.).

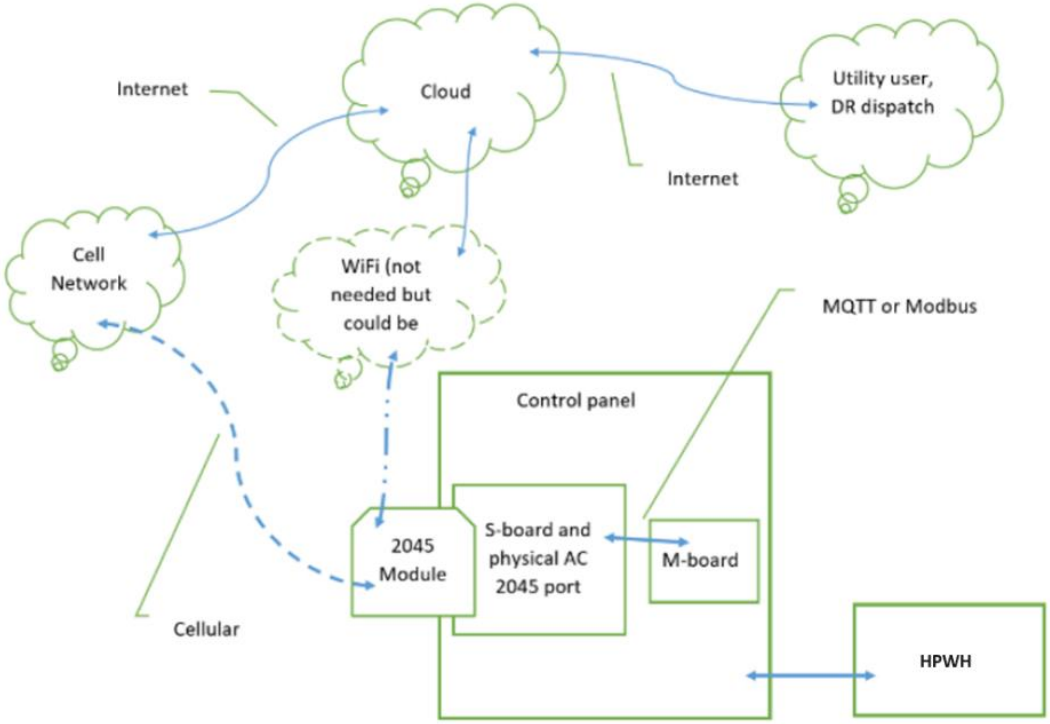

Figure 2: Sample CHPWH communication diagram using a CTA 2045 module (Spielman 2022).

This new CTA 2045 interface technology is being included in many integrated HPWH and CHPWH products now. A pilot program called WatterSaver in PG&E's territory is testing these capabilities in practice for aggregated impact across participant sites but has yet to enroll a CHPWH, due to the lack of CHPWH installations with load shifting capabilities; all enrollees have been with integrated HPWHs thus far.

Load shifting and sizing implications have been studied through modeling and some limited field testing has been conducted with integrated HPWHs in previous works (Brooks, et al. 2020) (Delforge and Vuknovich 2018) (Zhang, Higa and Kim 2020). However, very few actual field demonstrations of CHPWH load shifting have been published. One instance at the Bayview Tower project in Seattle has been tested in trials, demonstrating feasibility and some load shed abilities (Banks, Spielman and Heller 2022) (Spielman and Johnson 2023). A recent CEC EPIC study also tested load shifting capabilities of a CHPWH system by simply turning off some of the CHPWHs during load shed events without any anticipatory load-up period or controls (Dryden, et al. 2023).

Market Barriers and Study Justification

As with any emerging energy technology, there are identifiable market barriers to CHPWH and load shifting adoption (Opinion Dynamics 2022) (New Buildings Institute 2023). These barriers impact new construction and existing buildings differently, but include:

- Higher first cost and complexity than similarly sized gas-fired equipment.
- Limited subject matter expertise among design and construction firms.
- Uncertainty on energy cost parity or savings relative to natural gas systems.

- Long lead times and low availability of CHPWH equipment, especially low-GWP.
- Distribution systems and recirculation losses in existing buildings may require remediation for enabling cost-effective CHPWH implementation.
- Site-level electrical infrastructure constraints (e.g., utility service, circuit, or panel limitations).
- Inaccessible installation locations (e.g., pathways for storage tanks in existing buildings).
- Limited physical space for storage tank arrays or heat pump units requiring sufficient ambient air (e.g., external placement).
- Few field demonstrations and case studies.
- Unknown long-term performance, useful life, and lifetime maintenance burden.
- Lack of load up and shed control best practices, testing, and benefits of load shifting.

CHPWH industry stakeholders have been working together to address these concerns through several valuable efforts:

- Sizing tools such as Ecosizer provide guidance in heat pump and storage capacity for given design configurations, loads, and whether load shifting is desired (Ecotope 2020).
- AWHI has developed roadmaps to address many of these barriers, allowing coordination between manufacturers, regulators, subject matter experts, and utility partners.
- The CEC has funded ongoing multifamily field demonstrations with load shifting in five Southern and Northern California locations through their EPIC program (CEC 2019).
- The Statewide CASE Team continues to investigate and propose CHPWH energy code changes for adoption by the CEC. Recent CASE reports paved an easier pathway to Title 24, Part 6 compliance for CHPWH systems and set requirements for central DHW system distribution (Pande, et al. 2022) (Goyal, et al. 2022).
- Technology transfer efforts, including design guides (EPRI 2022).
- Manufacturers continue to collaboratively expand production and product lines.
- The California Public Utilities Commission Energy Division has provided guidance and proposed rules for anticipated CHPWH incentives through the long-standing statewide Self-Generation Incentive Program (SGIP) (California Public Utilities Commission 2021). Energy Division staff recommended that 5 percent ($2.12 million) of the HPWH program budget be reserved for multifamily CHPWHs with amounts based on thermal energy storage capacity, up to $1,200 per kWh storage capacity, including adders for systems based on low-GWP refrigerants. Commercial CHPWHs were recommended to not be eligible due to uncertainties in applications in that market sector. This new SGIP offering could pave the way for future expansion of support based on early findings.

Field demonstration, testing, and validation of these systems is crucial to addressing market barriers. Field demonstrations can expand confidence in CHPWH reliability, load shifting controls, energy use, and energy costs. They provide a test bed for new developments, enable verification of system performance, illuminate needs for further research and development, and validate extensive modeling that has been part of many CHPWH industry developments in recent years. They are key for assessing the knowledge transfer of CHPWH system design and installation from subject matter experts and researchers to a broad set of implementers. This field demonstration project hopes to add to the CHPWH body of knowledge to those ends.

Objectives

The study objectives are:

1. Characterize the energy performance of CO_2 CHPWH retrofit installations through measurement and verification (M&V) principles.
2. Assess energy, cost, and GHG savings relative to a natural gas baseline system.
3. Implement load shifting controls and assess their performance.
4. Quantify the potential California market size.
5. Assess the impacts of low-GWP refrigerants over conventional alternatives.
6. Assess the success of technology transfer from subject matter experts to implementers.
7. Develop conclusions and recommendations for manufacturers, designers, utilities, and program administrators towards increased market adoption.

Host Sites

The host sites are two multifamily buildings for low-income, senior citizens located in a disadvantaged community (DAC) designated area in downtown San Francisco. The buildings are operated by a nonprofit organization whose mission is to provide affordable, equitable housing and services for low-income communities in San Francisco. The building profiles are shown in Table 6. Both buildings comprise primarily single-room occupancy residences (SROs) and common space on the ground and basement levels. The buildings have minimal common area hot water loads.

Table 6. Host sites.

	Site 1	Site 2
Year built	1914	1926
Number of residences	119 (118 SROs and one 1BR)	133 (131 SROs and two 1BRs)
End-uses per residence	Three (kitchenette sink, bathroom sink, shower/tub)	
Number of residents	120	135
Floor area (square feet)	51,250	50,538
Stories	7	10
California climate zone	3	3

Both buildings have recirculating central DHW systems. In 2022, the recirculation and distribution piping systems were rebalanced, correcting excessive recirculation rates and losses in preparation for the CHPWH retrofits. Both gas-fired systems were replaced with custom-engineered, site-built CHPWH systems in 2022 and 2023. These efforts were supported by the Low-Income Weatherization Program administered by the Association for Energy Affordability.

Figure 3: Swing tank and storage tank array, mixing valve, and rooftop HPWHs.

The CHPWH systems have similar design at each site comprising of two CO_2 heat pumps, storage tank arrays, recirculation pumps, electronic mixing valves, central control systems with telemetry, and an ER swing tank. Each HPWH has a dedicated plate and frame heat exchanger (HX), isolating the HPWH water loop from the potable DHW plumbing. Table 7 outlines some of the CHPWH system characteristics. The documented cost includes all design, installation, and commissioning costs (although program incentives reduced the customer cost).

Table 7. Host site CHPWH systems.

	Site 1	Site 2
Number of HPWH units	2	2
Per unit HPWH rated capacity (Btu/h)	136,000	136,000
Per unit HPWH rated power (kW)	9.73	9.73
HPWH rated COP (DOE CFR 431 standard conditions)	4.11	4.11
Storage tank quantity, excluding swing tank	8	11
Storage capacity, excluding swing tank (gal)	1,550	2,150
Swing tank capacity (gal) / power (kW)	200 / 18	200 / 18
Full Installed Cost ($/residence)	$4,082	$6,311

Figure 4 and Figure 5 show plumbing line diagrams of each site along with selected M&V datapoint locations. Each HPWH unit was paired with its own secondary heat exchanger (HX) to separate potable DHW loop from the HPWH loops. The storage tank banks were plumbed in a combination of series and parallel arrangements. As seen in the figures, sets of two or three tanks were arranged in parallel with several of these sets plumbed in series. In these plumbing diagrams, WH stands for water heater, T and TH for temperature measurement, P for power measurement, ST for storage tank, HX for heat exchanger, and CT for current transducer.

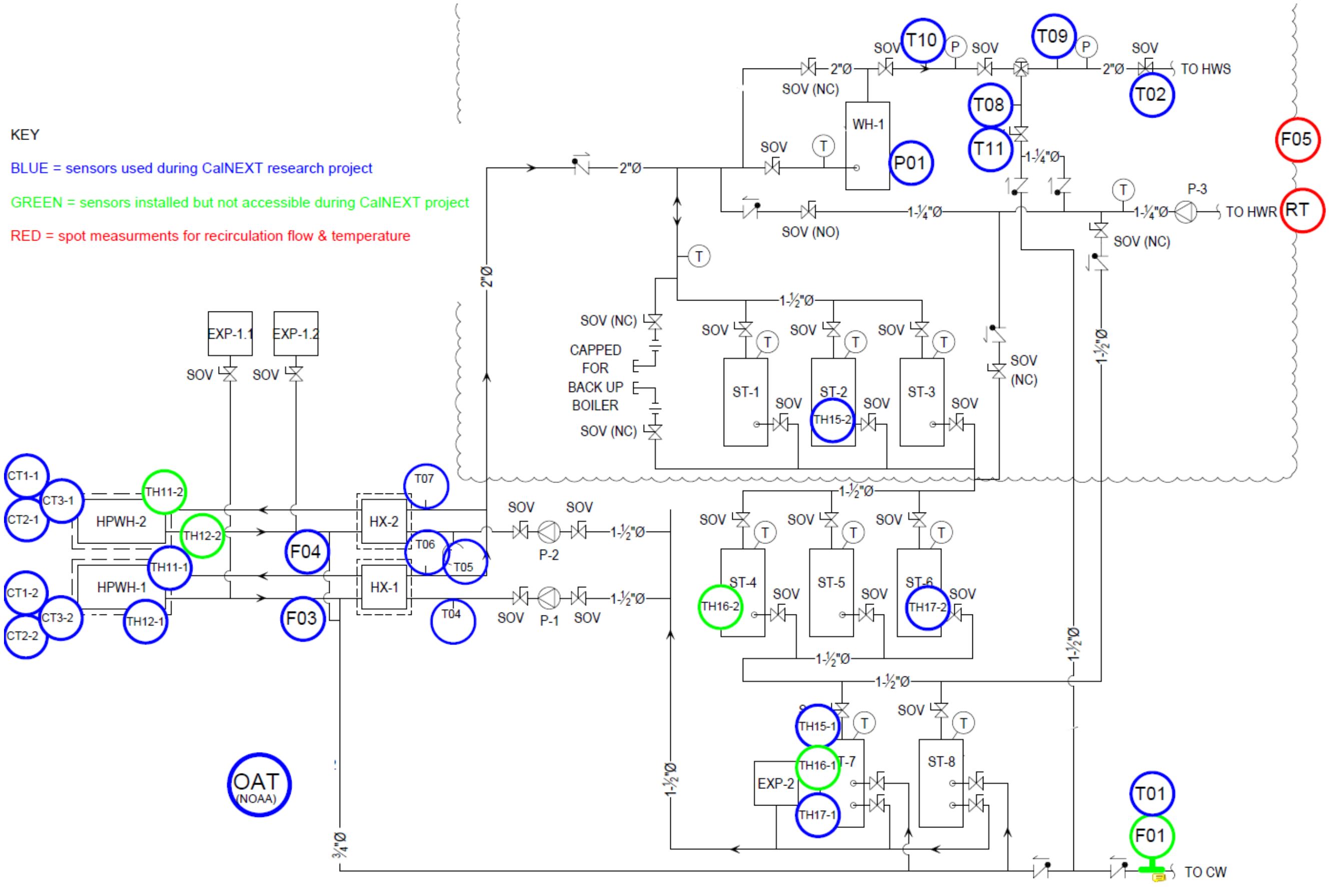

Figure 4: Site 1 plumbing line diagram and M&V datapoints.

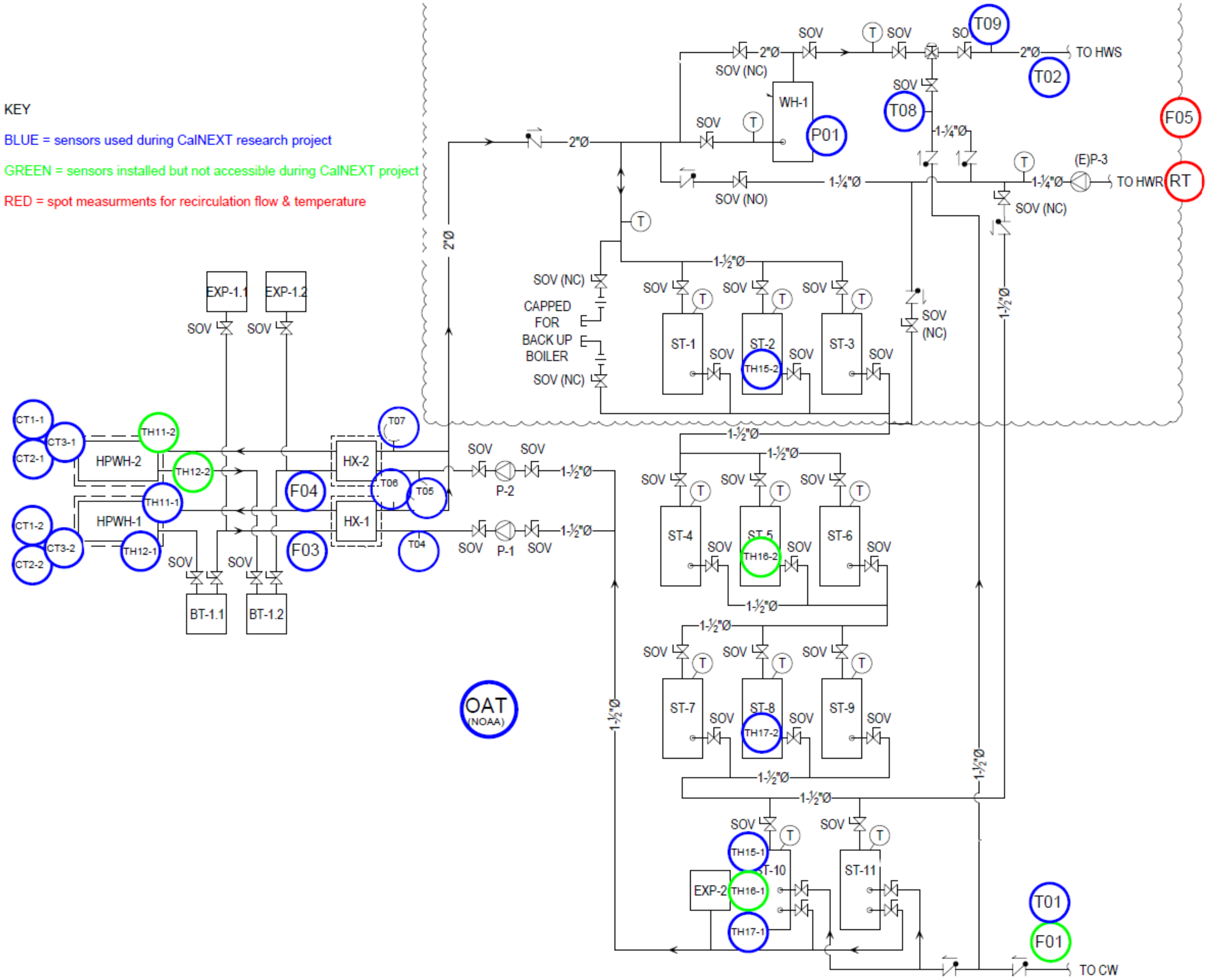

Figure 5: Site 2 plumbing line diagram and M&V datapoints.

The CalNEXT project team conducted a design review of these sites during commissioning and M&V preparations. In general, the system was well designed in coordination with the HPWH manufacturer with a quality installation. However, the team identified two design choices that could be problematic:

- Site 1 storage sizing was significantly oversized. Ecosizer modeling suggested that the storage volume was about 190 percent what the project team would have recommended. Oversized storage can cause high systems costs, higher thermal losses, and lower efficiency.
- The combination of parallel and series plumbing between the storage tanks could lead to difficulty with system balancing and may reduce the effective storage volume. Series arrangements do not require balancing since there is one inlet and one outlet in the volume and stratification is maintained naturally. Parallel arrangements require physical flow balancing to maintain temperature stratification and maximize effective storage volume. With proper balancing, parallel arrangements can provide increased stratification due to low inlet/outlet velocities and lower pressure drop. Additionally, parallel arrangement enables isolation of individual tanks for maintenance without shutting down the whole system. Combining series and parallel into a single system could result in simultaneous benefits from each design option but it is much more difficult to maintain system balance and proper control.

Methodology

The field demonstration phase of the project occurred in five steps:

1. Host site review and inspection
2. M&V planning and datapoints
3. Sequence of operations adjustment
4. Load shift commands, monitoring period, and troubleshooting
5. Calculations

Host Site Review and Inspection

The CalNEXT project planning process began with interviewing the installation contractor as they completed the renovation project. This interview included video-recorded tours of each central plant with recommended locations for installing temperature and flow meters. The installation contractor expressed some concern regarding the study's need to measure cold water supply to the heat pump plant. Both sites experienced issues with high water pressure from incoming city water. The contractor attempted to mitigate the issues by adding pressure reducing valves to the system which were not originally planned. Additionally, the installer noted that water coming into the heat pump plant at Site 2 was shared with a boiler used for the space heating system throughout the building. The research team proceeded with selecting a flow meter location at the cold water after the space heating boiler takeoff despite limited uninterrupted pipe length before the metering location; there was no other suitable location that would not have compromised measurements. During the M&V phase of the study, both high water pressure and the flowmeter location contributed to some unquantifiable uncertainty and data loss.

Next, the inspection process included determining the as-built control sequences. The installations were custom programmed by the manufacturer and the building owner requested the most efficient program possible. Therefore, the system was initially set to have a single mode of operation with parameters most closely related to “shed” mode. For future projects, it is recommended that the engineer of record includes an intended sequence of operations (SOO) with the design as these controls are directly tied to the sizing needs of a system, especially in the case of a load shift capable system.

M&V Planning and Datapoints

The project team developed a measurement plan that would gather data sufficient for assessment of the installed CHPWH systems based on Option B (retrofit isolation – all parameter measurement) of the International Performance Measurement and Verification Protocol (IPMVP). The selected datapoints consisted of various power, temperature, and flow measurements as identified in Figure 4 and Figure 5. The measurement points are listed in Table 8. Local outside air temperature (OAT) was collected from NOAA data for the Oakland International Airport weather station, KOAK.

Table 8: Measurement points (reference Figures 4 and 5).

Point Description	Site 1 Tags	Site 2 Tags
Incoming city water temp (°F)	T01	T01
Mixing valve water temperatures (°F)	T08, T09, T10, T11 Spot measurements: F05 (circulation), RT	T08, T09 Spot measurements: F05 (circulation), RT
Supply water temp (°F)	T02	T02
Tank temps (°F)	TH15-2 (ST 2), TH17-2 (ST 6), TH15-1 (ST 7), TH17-1 (ST 7)	TH15-2 (ST 2) , TH17-2 (ST 8), TH15-1 (ST 10), TH17-1 (ST 10)
Secondary loop temps into and out of HX-1 and HX-2 (°F)	T04, T05, T06, T07	T04, T05, T06, T07
Inlet and outlet water temps at HPWHs (°F)	TH11-1 and TH12-1 (HPWH 1) TH11-2 and TH12-2 (HPWH 2)	TH11-1 and TH12-1 (HPWH 1) TH11-2 and TH12-2 (HPWH 2)
Incoming city water flow (gpm)	F01	F01
Primary loop flow (gpm)	F03 (HPWH 1), F04 (HPWH 2)	F03 (HPWH 1), F04 (HPWH 2)
HPWH current (A)	CT1-1, CT2-1, CT3-1 (HPWH 1) CT1-2, CT2-2, CT3-2 (HPWH 2)	CT1-1, CT2-1, CT3-1 (HPWH 1) CT1-2, CT2-2, CT3-2 (HPWH 2)
Swing tank power (A)	P01	P01
Outdoor air temperature (°F)	NOAA Hourly Data for KOAK weather station	

M&V instrumentation was added to each host site the week of January 16, 2023. The images in Figure 6 illustrate some of the temporary sensors installed by the research team.

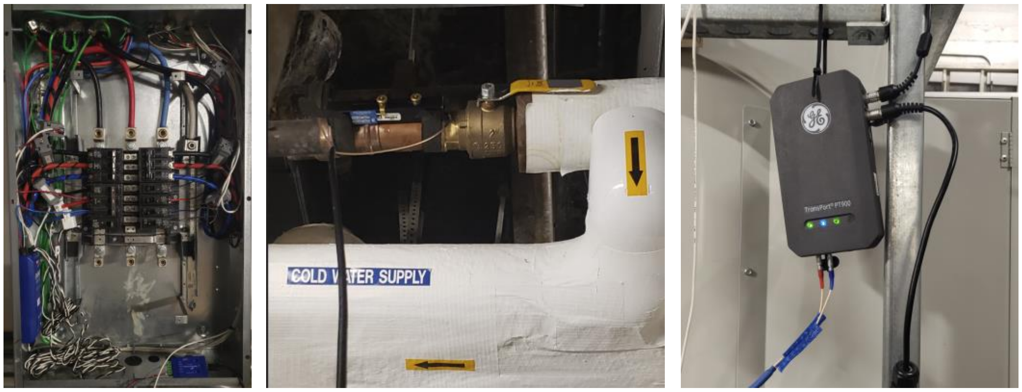

Figure 6: Swing tank power metering and city water ultrasonic pipe surface flow metering

Sequence of Operations Adjustment

The systems' initial programming did not include load shifting controls, so Ecotope created an SOO with three modes: normal, load up, and shed. The manufacturer was able to reprogram each system with the SOO parameters during the same week as the initial instrumentation installation. The load shift schedule was selected based on PG&E's time of use (TOU) pricing and intended to find the maximum duration a shed period could be sustained. Therefore, the first sequence (SOO1) did not aim for maximum peak demand avoidance; rather, the goal was to clearly demonstrate the system's ability to react to a load shift signal and measure how long the system could maintain a shed period. When paired with the current manufacturer control options (simultaneous heat pumps operation), the SOOs selected for the demonstration are almost certainly not the optimal schedule in terms of energy cost minimization, demand cost minimization, or CO_2 reductions. Those require further study.

Table 9 lists the control parameters for each programmed mode: standard operation (Mode 1), load up (Mode 2), and load shed (Mode 3). For each mode, on/off thermistor locations are selected for calls for heat to maintain a temperature setpoint and differential across the thermocline between the two thermistor locations. The thermistor locations are fixed in the storage tanks which ideally naturally maintains a passive stratified thermocline with the coldest temperature at the bottom and hottest temperature at the top. For instance, when the system is in Mode 1 under SOO1 for Site 1, the system will call for heat from the HPWH whenever the temperature at 57 percent height is less than 115°F and stop calling for heat when the temperature at 11 percent height reaches 125°F.

Based on experience in past work with the CHPWHs by the same manufacturer, the load up and shed mode parameters were programmed into the control system over two phases: SOO1 tested initial settings while SOO2 tested refined settings based on observations. Note that Site 2 programming for SOO1 was not implemented effectively and only SOO2 enabled load up and shed modes.

While SOO2 resulted in more effective load shifting at both sites, it did introduce mild short cycling of the heat pumps. For the longevity of the heat pump, it is best to reduce the number of times the system turns on and off by maintaining cycle times that are several hours in length. A third SOO was developed in an attempt to alleviate this issue; however, the project timeline did not permit the implementation of this sequence. While the second set of controls was effective in demonstrating load shift capability, it is important to note that more work is needed to optimize the efficiency and load shift strategy of the systems while also integrating GHG and energy cost minimization.

Table 9: Load shift control modes[1].

Control Parameter	Site 1 (S001)	Site 1 (S002)	Site 2 (S002)
Mode 1 ON thermistor	57% height (TH16-2)	30% height (TH17-2)	22% height (TH-17-2)
Mode 1 OFF thermistor	11% height (TH16-1)	30% height (TH17-2)	22% height (TH17-2)
Mode 1 differential	10°F	15°F	10°F
Mode 1 Setpoint	125°F	130°F	125°F
Mode 2 ON thermistor	30% height (TH17-2)	11% height (TH16-1)	14% height (TH15-1)
Mode 2 OFF thermistor	11% height (TH16-1)	11% height (TH16-1)	14% height (TH15-1)
Mode 2 differential	10°F	10°F	10°F
Mode 2 Setpoint	125°F	125°F	125°F
Mode 3 ON thermistor	69% height (TH15-2)	69% height (TH15-2)	78% height (TH15-2)
Mode 3 OFF thermistor	57% height (TH16-2)	69% height (TH15-2)	78% height (TH15-2)
Mode 3 differential	10°F	15°F	10°F
Mode 3 Setpoint	125°F	130°F	125°F

Load Shift Commands, Monitoring Period, and Troubleshooting

Load shift controls were added to the CHPWH systems as part of this project. As previously discussed, the control sequences were programmed into the system locally. Then, the project team

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[1] S001 tested initial settings. S002 tested refined settings based on observations. Note that Site 2 programming for S001 was not implemented effectively and only S002 enabled load up and shed modes.

worked with a third party to send load shift control signals to the CHPWH systems through EcoPort communication modules. The selected schedule shown in Table 10 was designed for a resultant dataset that would allow comparison between standard operation and load shifting days across similar weather conditions (roughly a day-on, day-off test strategy). Secondly, the load shift time period was selected to coincide with PG&E's TOU pricing, which also aligns with a typical peak demand period for a multifamily residential building.

Table 10: Load shift schedule.

Schedule Parameter	Timing
Normal operating days	Tues, Thurs, Sun
Load shift days	Mon, Wed, Fri, Sat
Load shift day schedule	Mode 2 (load up): 12:00 - 15:59 Mode 3 (load shed): 16:00 - 20:59 Mode 1 (normal): all other hours

The monitoring period began immediately after installation and commissioning with the timeline shown in Table 11. However, due to several incidents, the usable period was truncated (starting March 1 and May 3 for Site 1 and 2, respectively). Initially, there was a data connectively issue with flowmeter data mapping to the control and monitoring system; this required extensive troubleshooting. There was also a water pressure incident that wetted some of the equipment and necessitated a site visit to reset and reprogram. Other issues included failure of a set of three CTs on a heat pump, the manufacturer's controller going off-line, and the failure of a cell modem.

Table 11: Monitoring period and logging interval, all in 2023.

Point Description	Site 1	Site 2
Total monitoring period	Jan 24 – Sept 30	Jan 20 – Oct 2
Truncated period	March 1 – Sept 30	May 3 – Oct 2
No load shift period	March 1 – April 20	May 3 – July 28
Load shift S001 period	April 20 – July 28	n/a
Load shift S002 period	July 28 – Sept 30	July 28 – Oct 2
Data logging interval	1-minute	1-minute

In addition to these issues, the original M&V plan consisted of two flow meters per site, one for cold make-up water and another to measure hot water entering the temperature maintenance tank from the primary storage. However, only the make-up water flowmeter could be placed due to plumbing constraints. To get a better understanding of the recirculation water flow, an ultrasonic pipe surface flowmeter was used for spot measurements of the recirculation flow rate and return temperature. The flow data at each site was collected over one evening to observe the low-load recirculation rate.

Calculations

The measured data was used to evaluate the systems' performance. Two methods for calculating the COP of CHPWH systems were available. The first method follows the guidelines specified in the Advanced Water Heating Specification (NEEA 2022). The second method, derived by Ecotope, has been used on several other monitored sites (including Bayview) and provides a similar level of accuracy with proper data.

Method 1:

$$COP_{Sys} = \frac{Primary\ Load\ +\ Recirc\ Load}{Total\ Electric\ Use}$$

$$= \frac{500 * Flow_{CW} * (Temp_{OutMXV} - Temp_{CW}) + 500 * Flow_{RecircReturn} * (Temp_{OutMXV} - Temp_{RecircReturn})}{Power_{HPWH1} + Power_{HPWH2} + Power_{SwingTank}}$$

Method 2:

$$COP_{Sys} = COP_{HPWH} * \frac{Electric\ Use_{HPWH}}{Total\ Electric\ Use} + COP_{resistance} * \frac{Electric\ Use_{Resistance}}{Total\ Electric\ Use}$$

where COP_{HPWH} is calculated using power into the HPWH, flow through the HPWH, and inlet and outlet temperatures of the HPWH flow. The ER swing tank COP is assumed to be 1.

Findings

Analysis of the data included examining hot water load, total system energy use, an assumed gas baseline, electrical demand, GHG emissions, customer utility costs, annualization, and extrapolation to the statewide market.

Hot Water Usage Profiles

Including hot water usage in the common areas by building staff, the average daily hot water usage was 24.8 and 27.4 gallons per day per resident at Site 1 and Site 2, respectively. This is higher than most other reporting but within expected bounds (see Table 5). Similar per person usage was reported for some months in a recent California multifamily CHPWH study (Dryden, et al. 2023). The observations were also within the measured single-occupancy water usage range used for validating a commonly accepted DHW usage regression model (Parker, Fairey and Lutz 2015). Average weekly and daily hot water usage profiles are shown in Figure 7, consolidated from the minute interval data[2]. Both buildings were observed to follow a bi-modal shape typical to multifamily buildings.

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[2] All margins of error throughout the report reflect confidence intervals of 95 percent.

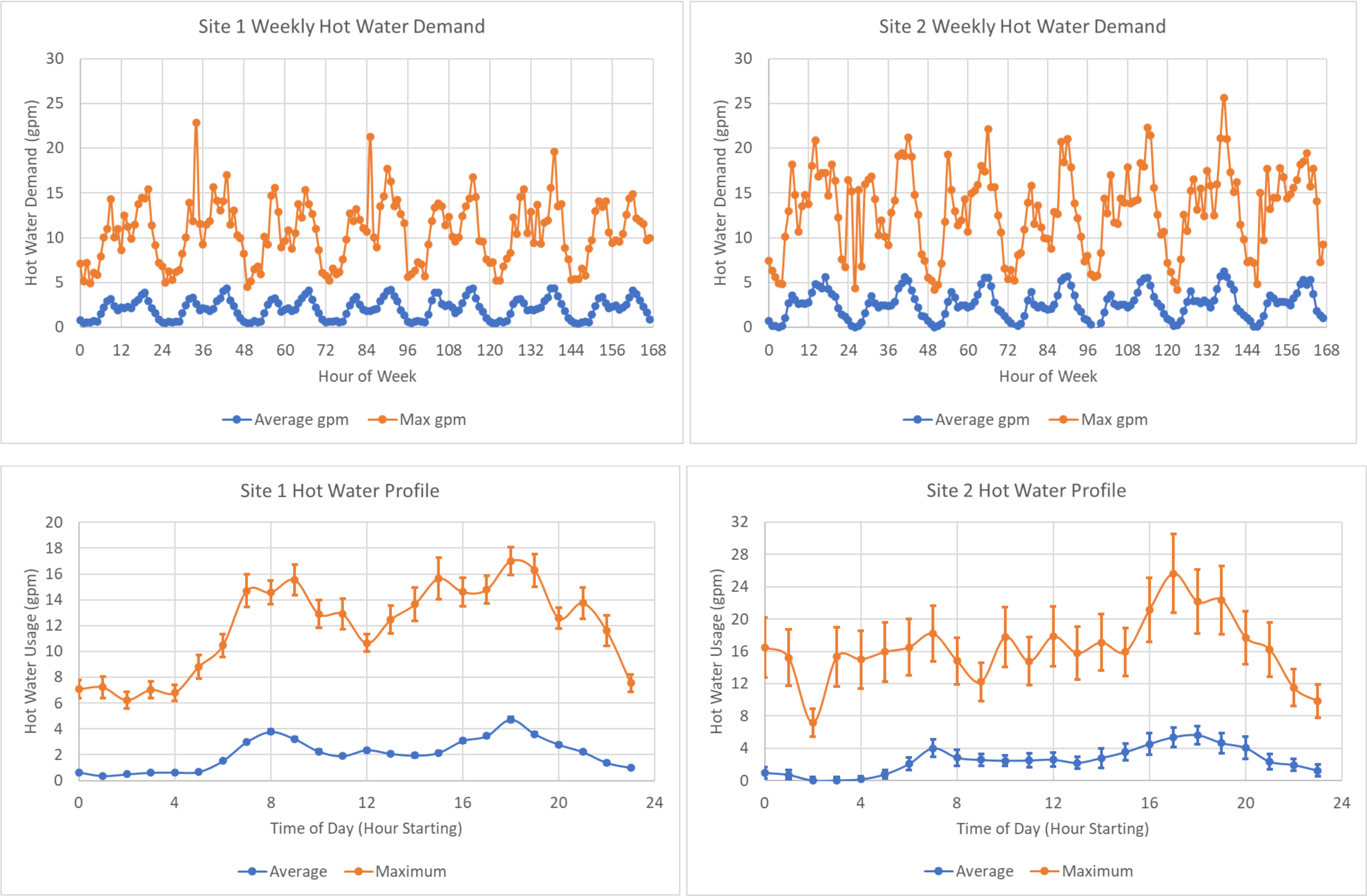


Figure 7: Weekly and daily hot water usage profiles.

Energy Usage, Efficiency, GHG Emissions, and Energy Costs

The overall average system COP across the measurement period was 2.6 and 2.7 for Site 1 and 2, respectively. The CHPWH systems were found to be operating within an expected efficiency range; these two systems achieved Tier 3 efficiency of NEEA's Advanced Water Heating Specification over the monitoring period.

Figure 8 shows the daily system COP over the monitoring periods alongside average daily outside air temperature. Calculating COP on a daily interval is logical because the system is generally able to fully recover from hot water loads and reset over a daily cycle, the smallest possible fully representative draw and recovery interval. Both sites had daily COPs that varied between 2.3 and 3.1.

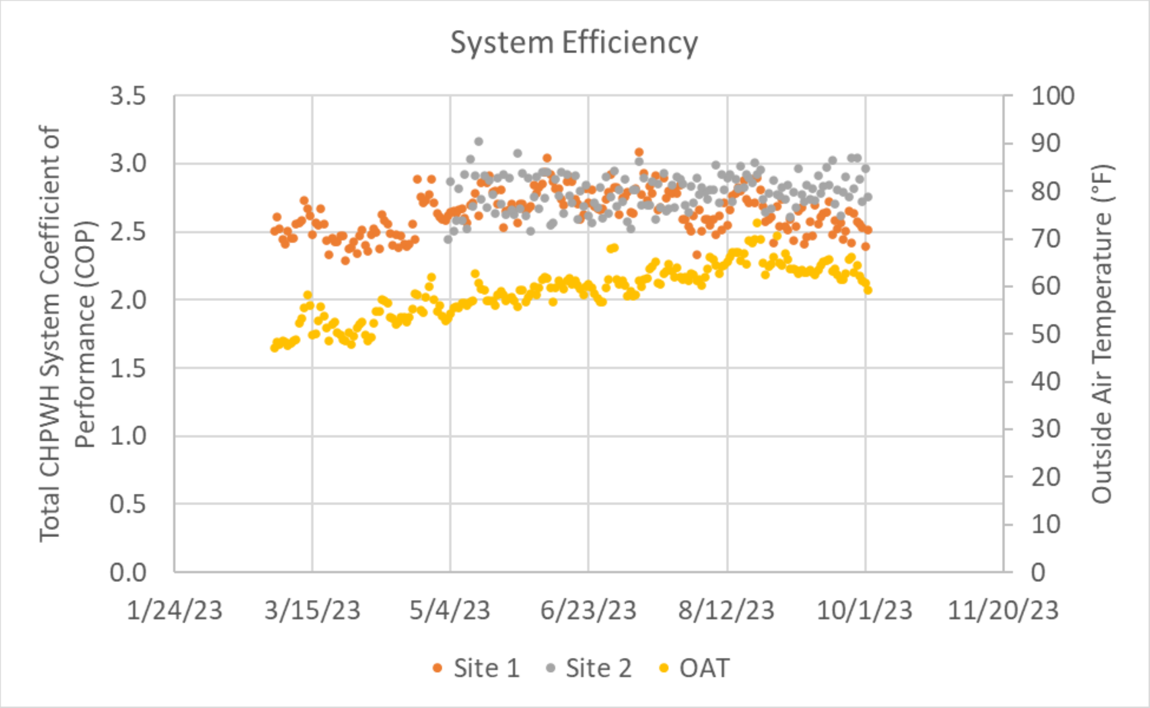


Figure 8: System COP across monitoring period (Site 2 truncated).

The temperature maintenance ER swing tanks account for about 25 percent and 14 percent of the total CHPWH system energy consumption at Site 1 and 2, respectively.

A gas water heater with Title 24 code efficiency (86 percent) was selected as the baseline for comparison. For this baseline, the daily natural gas consumption was calculated using the daily measured loads and assumed gas heater efficiency:

$$Baseline\ Energy\ Consumption\ \left(\frac{therm}{day}\right) = \frac{Primary\ Load\ (Btu) + Recirc\ Load\ (Btu)}{0.86 * 99{,}976.1\ \left(\frac{Btu}{therm}\right)}$$

GHG emissions were calculated for the baseline gas and CHPWH electrical energy consumption based on the 2025 energy code hourly emissions factors (California Energy Commission 2023).

These factors define the expected GHG emissions per kWh and per therm site energy usage for each hour of the year in each California climate zone.

Figure 9 shows the daily energy consumption (in Btu for common unit comparison) and resultant GHG emissions for the assumed baseline and measured CHPWH at Site 1 over the monitoring period.

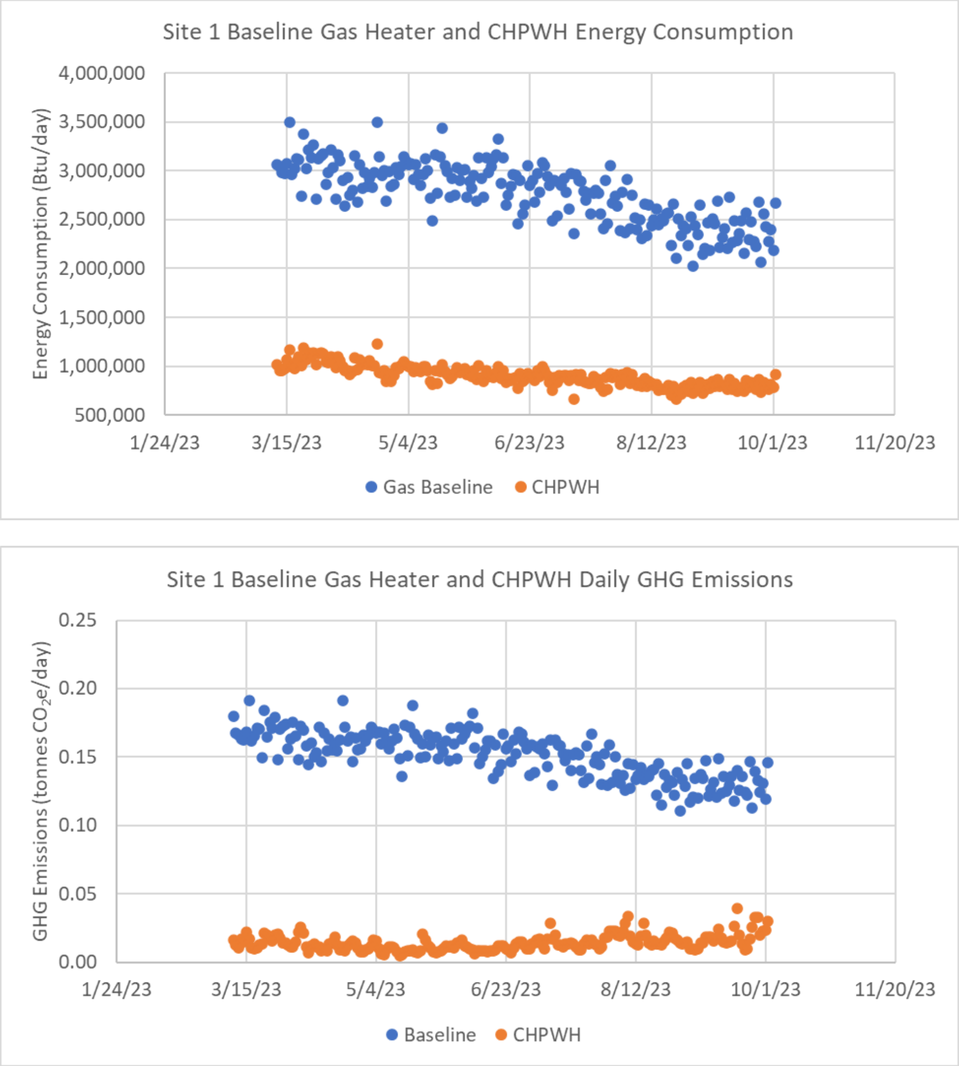
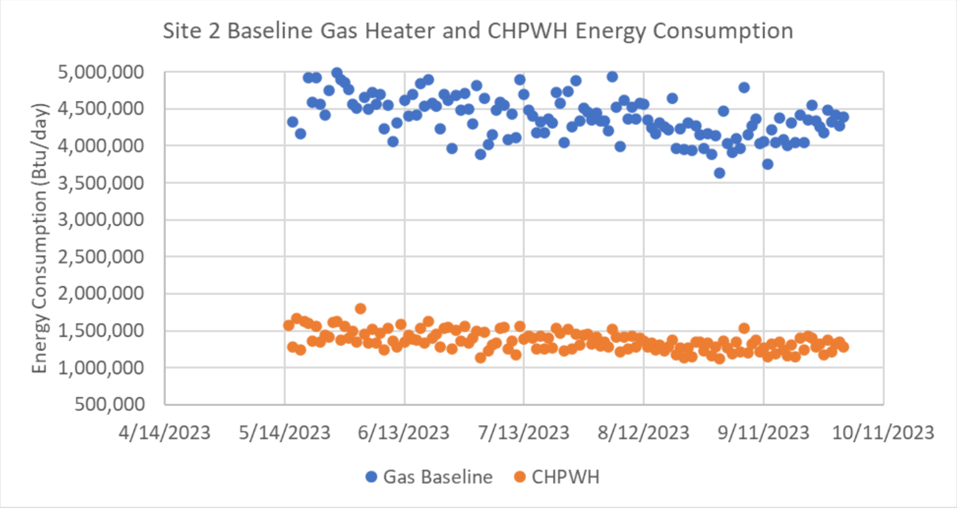


Figure 9: Daily baseline and CHPWH energy consumption and emissions over the monitoring period (Site 1).

Figure 10 shows the same for Site 2.



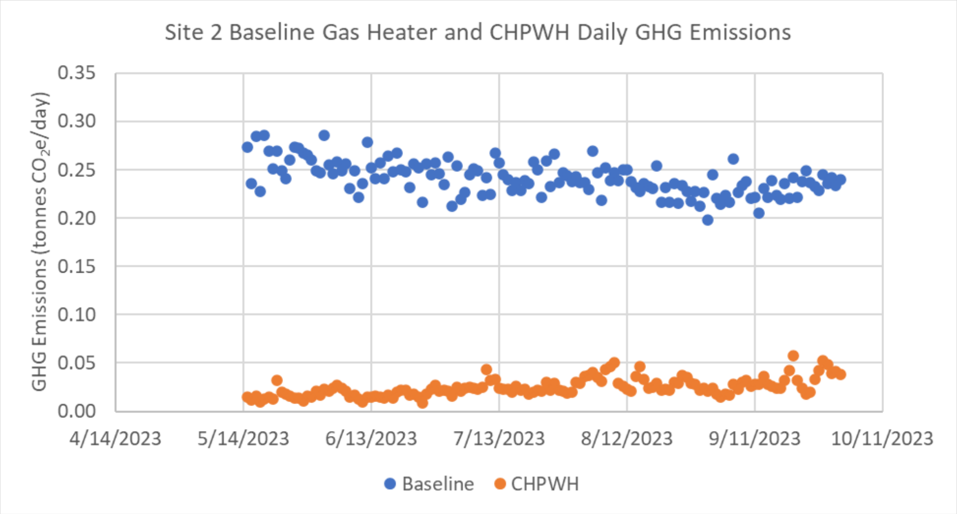


Figure 10: Daily baseline and CHPWH energy consumption and emissions over the monitoring period (Site 2).

Energy and peak demand costs were calculated based on the host site's TOU rate schedule (B-19 S TOU) for electrical energy and G-NR1 for natural gas. Since the peak CHPWH electrical demand was observed to be relatively constant across the day, it was assumed that the full peak demand for each TOU period would be additive to the total building peak demand in each TOU period. While there were substantial energy and GHG emissions savings due to the measure, energy costs increased, largely due to the difference between natural gas and electrical energy per unit costs. Demand charges accounted for 60 – 70 percent of the total CHPWH utility costs. Energy costs over the monitoring period are presented with and without the host site's CARE discount, a program in which some low-income multifamily buildings may be enrolled.

Two things should be noted about these energy cost values. First, the monitoring period was skewed towards months with high summer demand charges. This would increase the billed cost disparity between the gas baseline and CHPWH and not reflect overall annual cost differences. Second, piped natural gas customer rates have fallen over the past year. The customer gas rate is currently lower than it has been in recent years; therefore, the calculated baseline utility costs over the monitoring period is lessened and the difference between baseline and CHPWH utility cost is larger than it would be otherwise. In other words, the energy cost difference between the CHPWH and baseline is somewhat driven by the increasing spread between the utility rates for gas and electrical energy.

Table 12: Energy usage, savings, emissions, and energy costs over the monitoring period.

	Site 1	Site 2
Monitoring length (days)	214	153
Baseline energy (therms)	6,175	6,833
CHPWH energy (kWh)	57,212	61,773
Baseline energy (kBtu)	617,360	683,127
CHPWH energy (kBtu)	195,214	210,778
Energy savings (kBtu)	422,145 (68%)	472,348 (69%)
Baseline GHG emissions (tons CO_2e)	33.7	37.3
CHPWH GHG emissions (tons CO_2e)	3.2	3.7
GHG emissions savings (tons CO_2e)	30.5 (90%)	33.6 (90%)
Baseline customer utility costs[3] ($)	$8,009 $6,407 (w/ CARE discount)	$8,702 $6,962 (w/ CARE discount)
CHPWH customer utility costs ($)	$25,879 $18,116 (w/ CARE discount)	$23,114 $16,180 (w/ CARE discount)
Customer utility cost increase ($)	$17,870 (223%) $11,708 (183% w/ CARE discount)	$14,412 (176%) $9,218 (142% w/ CARE discount)

Load Shifting

As described in the Methodology section, load shift controls were programmed and triggered externally on Monday, Wednesday, Friday, and Saturday with load up from 12:00 - 15:59 and load shed from 16:00 – 21:00. Other days and hours operated under standard settings. Note that these times were selected only to demonstrate the capability of this equipment to shift load off the 16:00 - 21:00 peak TOU period. There is ample room to further optimize controls based on load patterns, CHPWH capabilities, TOU pricing, and GHG avoidance. Once implemented, there were no reports of

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[3] Energy costs include demand charges, assuming peak CHPWH demand coincides with peak of remaining building loads.

low hot water availability from building staff or occupants; by all accounts, hot water demand is still being met during the load shift days without interruption.

Figure 11 shows the consolidated daily profile of logged tank temperatures and system power on standard operation and load shift days for Site 1. The tank temperatures were taken at different heights in the total storage to observe the thermocline. The plots clearly show that the recirculation supply temperature stays unaffected by load shifting, and that tank temperatures throughout the thermocline are increased during the load up period, resulting in a higher level of total thermal storage at the beginning of the load shed period.

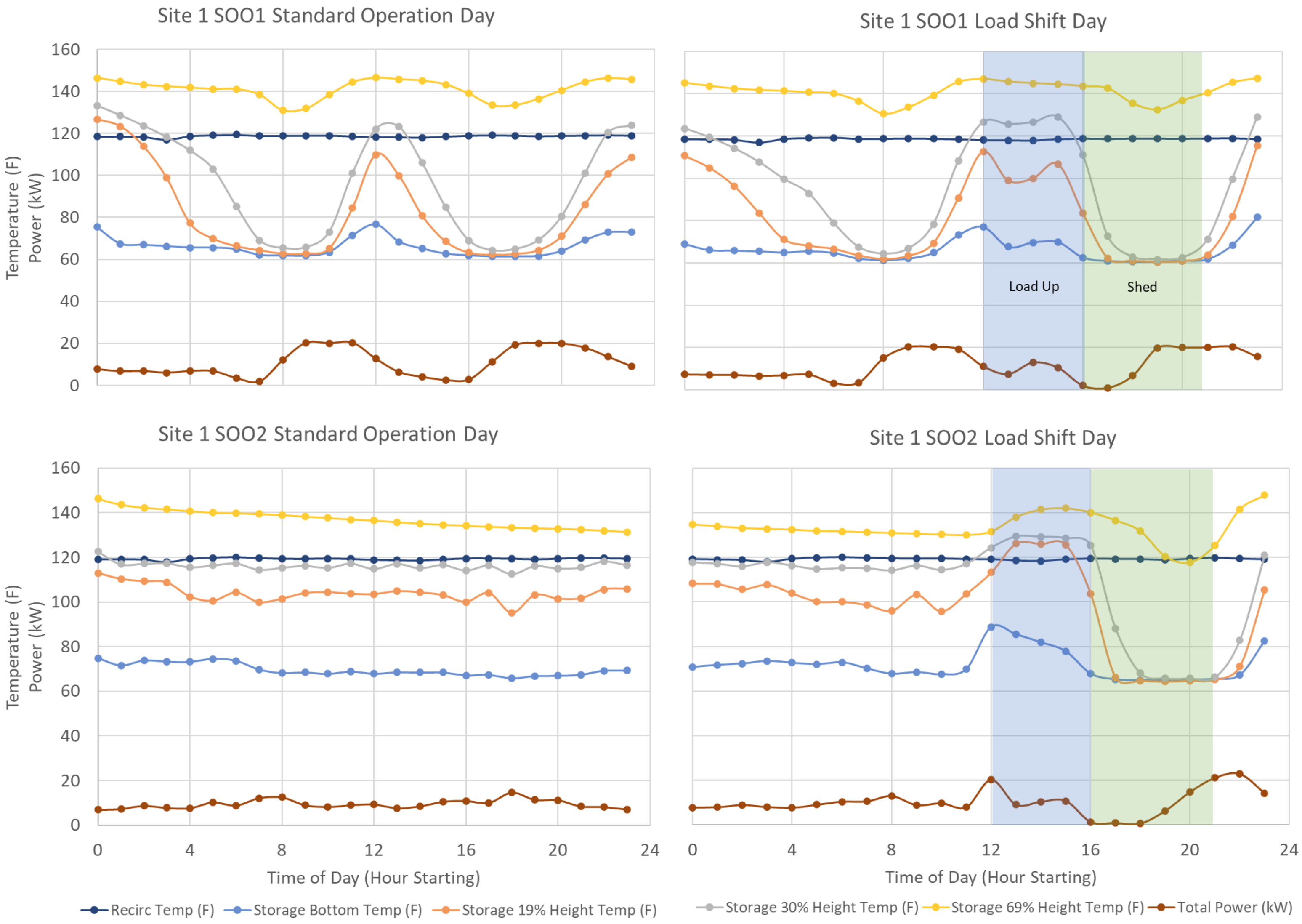

Figure 11: Standard operation and load shift day thermocline temperatures (Site 1)

Figure 12 displays the hot water usage, peak electrical power, and average system power across the typical standard and load shift day for Site 1 for SOO1.

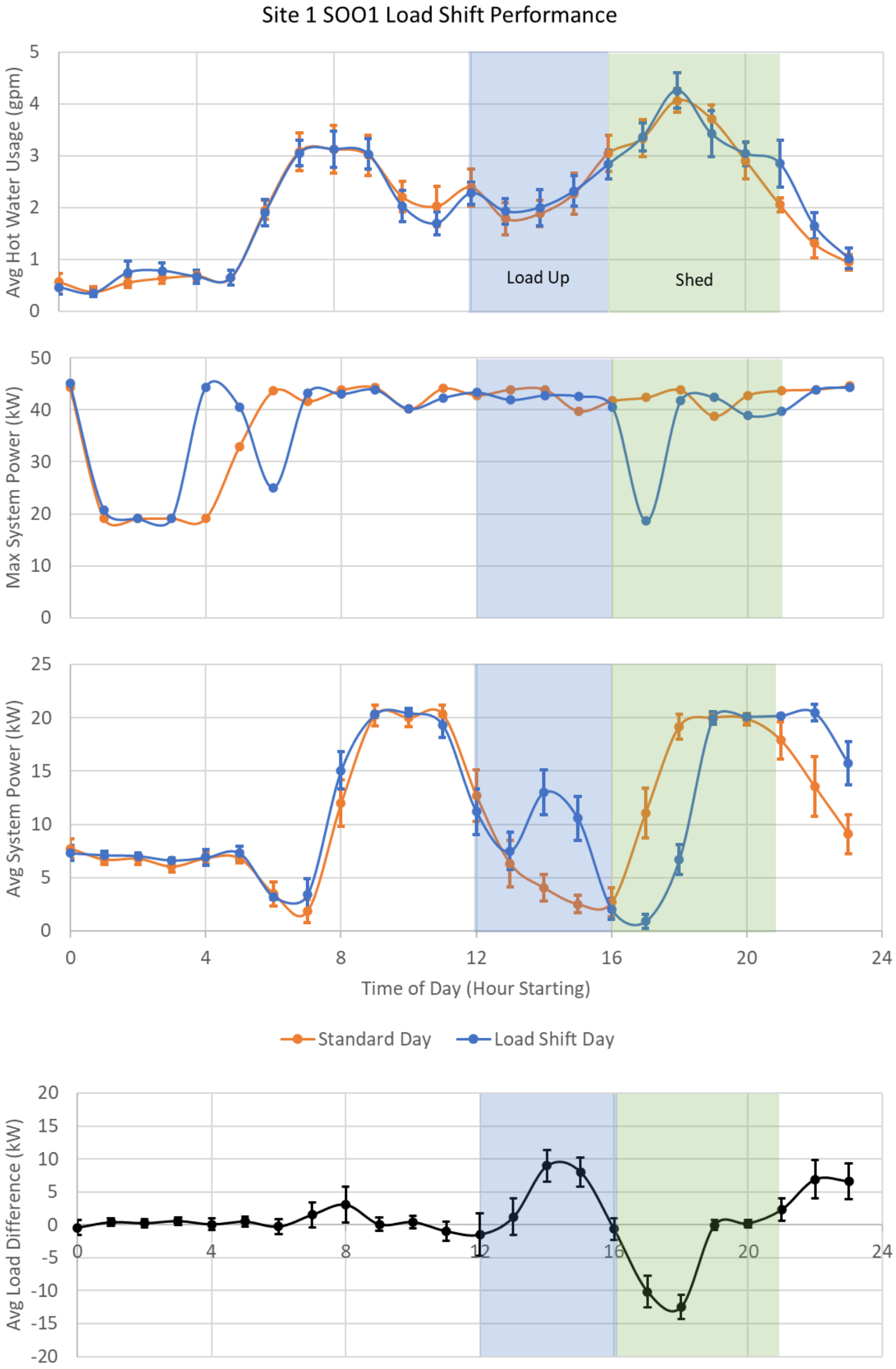

Figure 12: Site 1 SOO1 load shift performance.

The consistent water use profile suggests that user behavior and hot water delivery is unimpacted. Peak system power is shown to be unchanged with respect to TOU periods (therefore the tested load shift strategies did not impact customer billing demand charges). However, they were not optimized to that end, only to test maximum load shift capacity of the system during the peak TOU period. Finally, the difference between the average hourly power (can also be thought of as kWh) clearly shows an increase in usage during the load up period and a decrease during the shed period, thereby successfully shifting electrical load. The system was able to coast through about two hours of the shed period, on average. There does appear to be a bounce back period after the shed is complete, but the system is fully recovered by the next day.

Figure 13 shows similar results for SOO2 at Site 1. Differences from SOO1 include a larger shed impact and larger bounce back effect, as expected for the more aggressive settings.

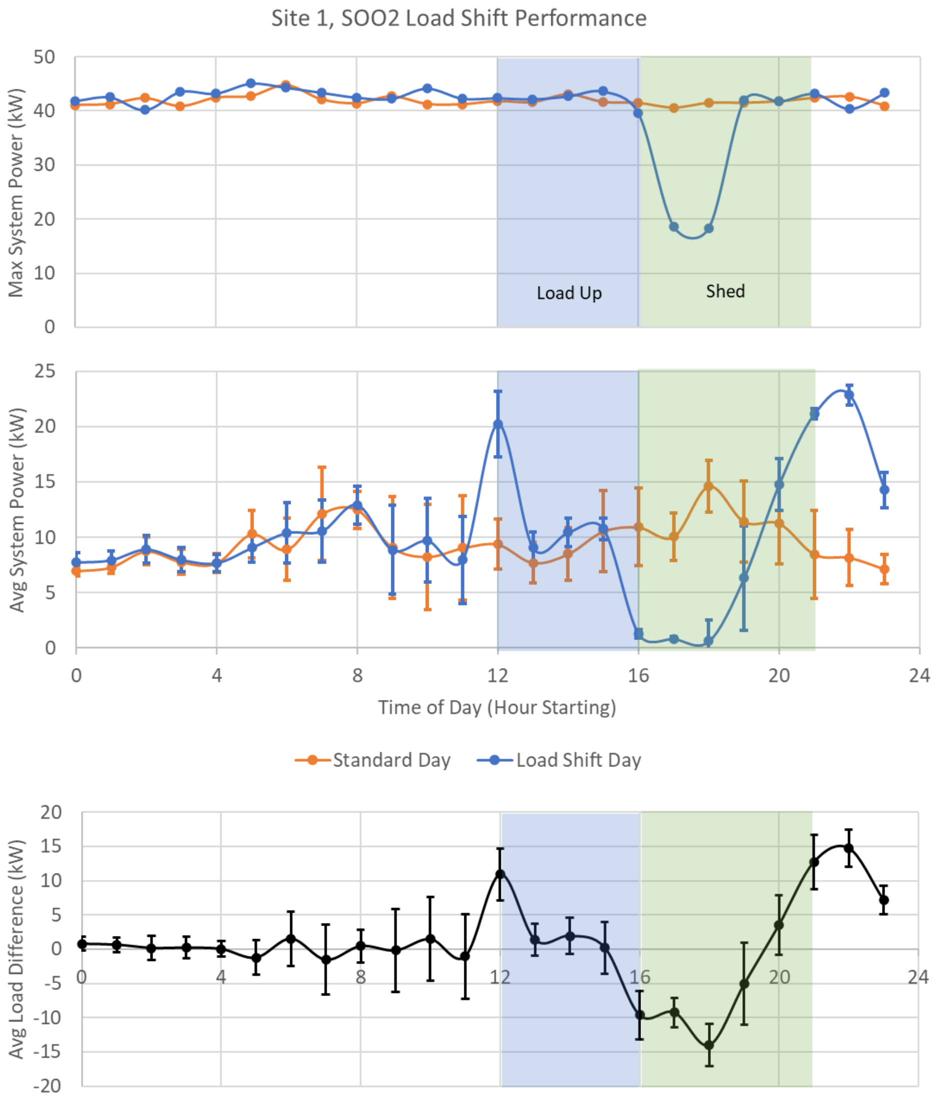

Figure 13: Site 1 SOO2 load shift performance.

The day-on, day-off load shift M&V test strategy did not work as cleanly at Site 2. As seen in the first two plots, the system was not able to recover by the end of the day. In other words, the recovery period after load shift carried through until the next day. This would skew results when comparing load shift to non-load shift days. However, the system was fully able to recover from the load shift period by about 7 a.m., well before the next hot water draw peaks and any load up and shed periods. So, fair comparison could still be made to establish load up and shed magnitudes compared to the preceding baseline, standard operation day.

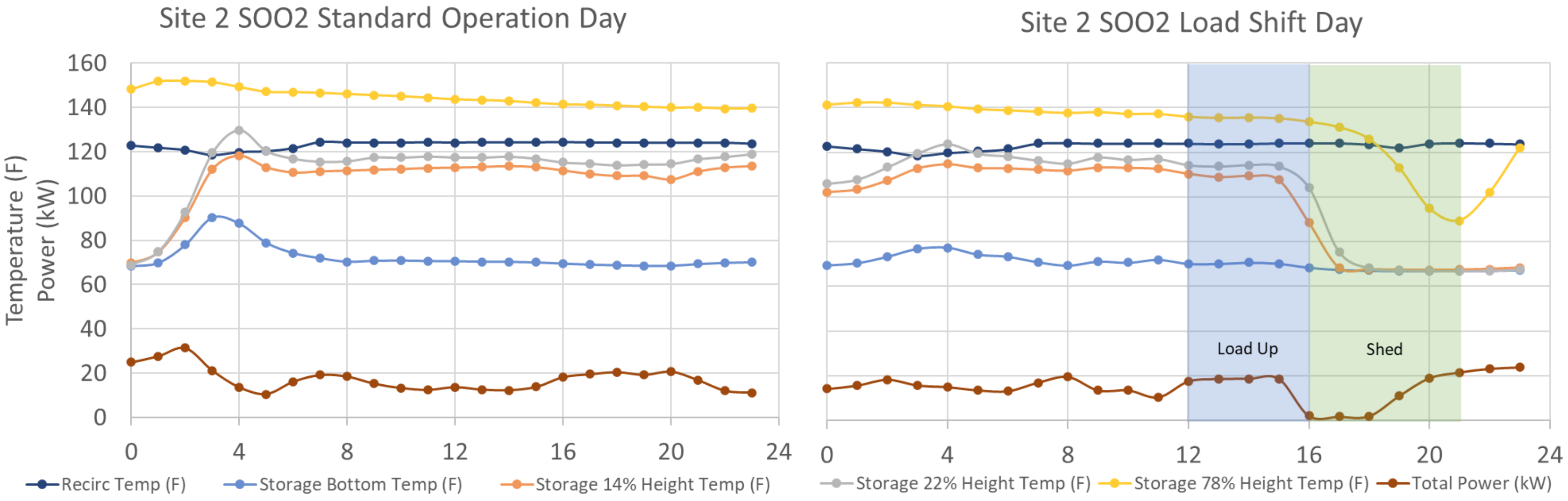

Figure 14: Standard operation and load shift day thermocline temperatures (Site 2).

Site 2 was able to shed for four hours, on average, but also saw an extended bounce back period that lasted until the following day.

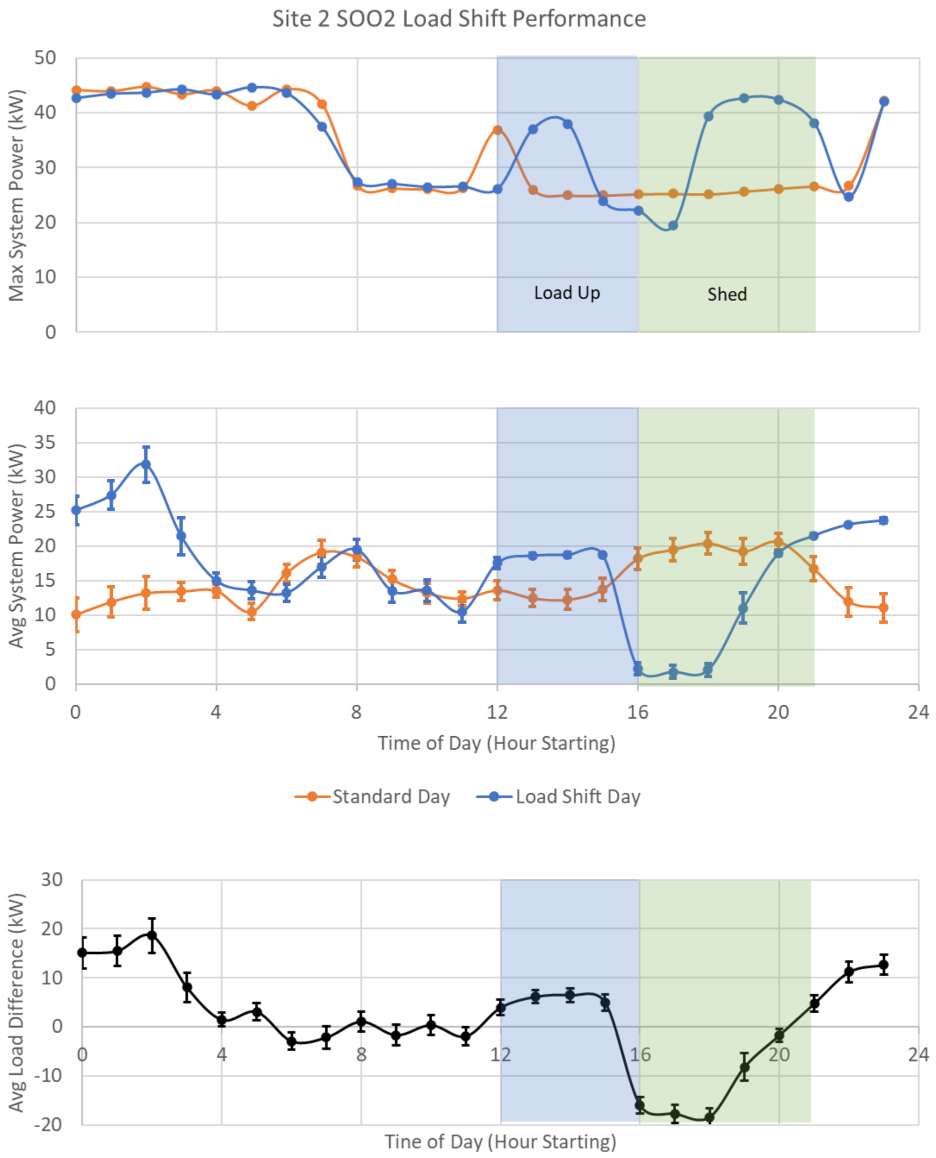

Figure 15: Site 2 SOO2 load shift performance.

Table 13 compares the energy consumption during load up and shed periods. Usage during the load up period is increased by 40 – 65 percent and decreased during the shed period by 32 – 63 percent, demonstrating successful load shift abilities.

Table 13: Magnitude of load up and shed effects.

Time of Day (Hour)	Standard Operation Day Energy (kWh)	Load Shift Day Energy (kWh)	Difference (kWh)
Site 1 S001			
Load up (12-16)	25.6	42.3	-16.7 (-65%)
Shed (16-21)	72.9	49.7	23.1 (32%)
Site 1 S002			
Load up (12-16)	36.1	50.5	-14.4 (-40%)
Shed (16-21)	58.3	23.8	34.5 (59%)
Site 2 S002			
Load up (12-16)	52.0	73.6	-21.5 (-41%)
Shed (16-21)	97.9	35.9	62.0 (63%)

The load shift magnitudes were also investigated with respect to time over the monitoring period. It is conceivable that load shed magnitudes could be affected by weather, day of week, or other factors glossed over when consolidating to a representative, average day. To investigate this, the team calculated the in-10 rolling baseline for each load shift day for the load up and shed timeframes. The in-10 baseline analysis compared each load up and shed during load shift days to the same periods during non-load shift days over the preceding 10 days. These are plotted in Figure 16 and the data suggests a consistent level of dispatchable, reliable load shed capacity across seasonality and weather conditions (no load shed reliability or magnitude dependence on weather was observed).

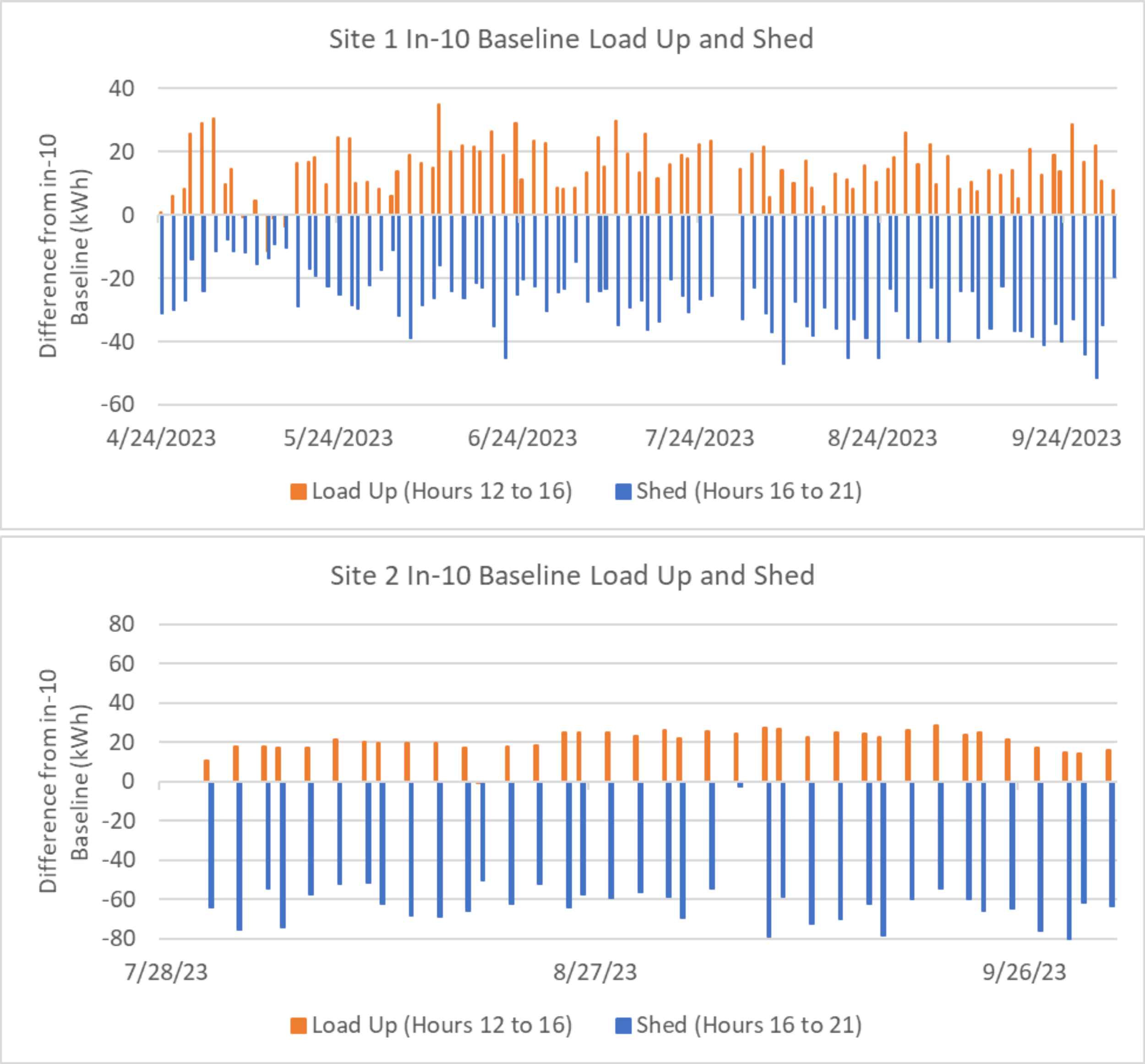

Figure 16: Load up and shed magnitudes relative to a rolling in-10 baseline.

Annualization

It is valuable to extrapolate monitored data and results to typical weather years, if possible. This can allow for estimation of impacts in other climate zones. Site 1 results produced dependable linear regression relationships for energy usage and efficiency on a daily basis (see Appendix B). The team explored regressions of hourly energy use and efficiency with respect to various independent variables, but none were found that could be used for extrapolation to annual weather years because statistical fits were poor. Only daily regressions were possible – this remains consistent with the daily draw and recovery cycles typical to a multifamily building.

After this annual extrapolation, the team could determine yearly GHG impacts and total system benefits (TSB). The TSB metric is used by California energy programs to quantify a measure's total value to customers, the electric grid, and towards climate goals by accounting for the costs of energy, ancillary services, generation, transmission, and distribution. The TSB of an intervention can be calculated as the net avoided costs of electricity, natural gas, and refrigerant emissions. Avoided costs for each of these sources are determined by using factors from the avoided cost calculators (ACC) developed for the CPUC (CPUC 2023).

No statistically significant, reliable regression could be found for Site 2. However, the average efficiency over the monitoring period for Site 2 was very similar to Site 1 and the resultant annualized average efficiency. So, Site 2 impacts and efficiency would be nearly equivalent to those of Site 1 across climate zone extrapolations.

Some key assumptions were made for the calculation of annual energy, GHG, and TSB impacts across the year:

- Daily GHG and ACC factors were calculated based on hourly GHG and ACC factors by weighting to the average, daily CHPWH load shape.
- Energy consumption will be dependent on the temperature of incoming utility water, whose patterns will differ across CZs. It was assumed that the regressions to OAT inherently captured this effect.
- A regression for daily hot water use in gallons per day could not be established; the average weekly profile was used in annualization.
- Annual host site energy cost could not be calculated since energy usage could not be calculated on an hourly basis from available regressions. This means that energy costs and demand charges for TOU periods could not be calculated.

As an example, Figure 17 shows the annualized results for CZ3, the location of the host sites. Results for each CZ were calculated and produced similar 8,760 profiles.

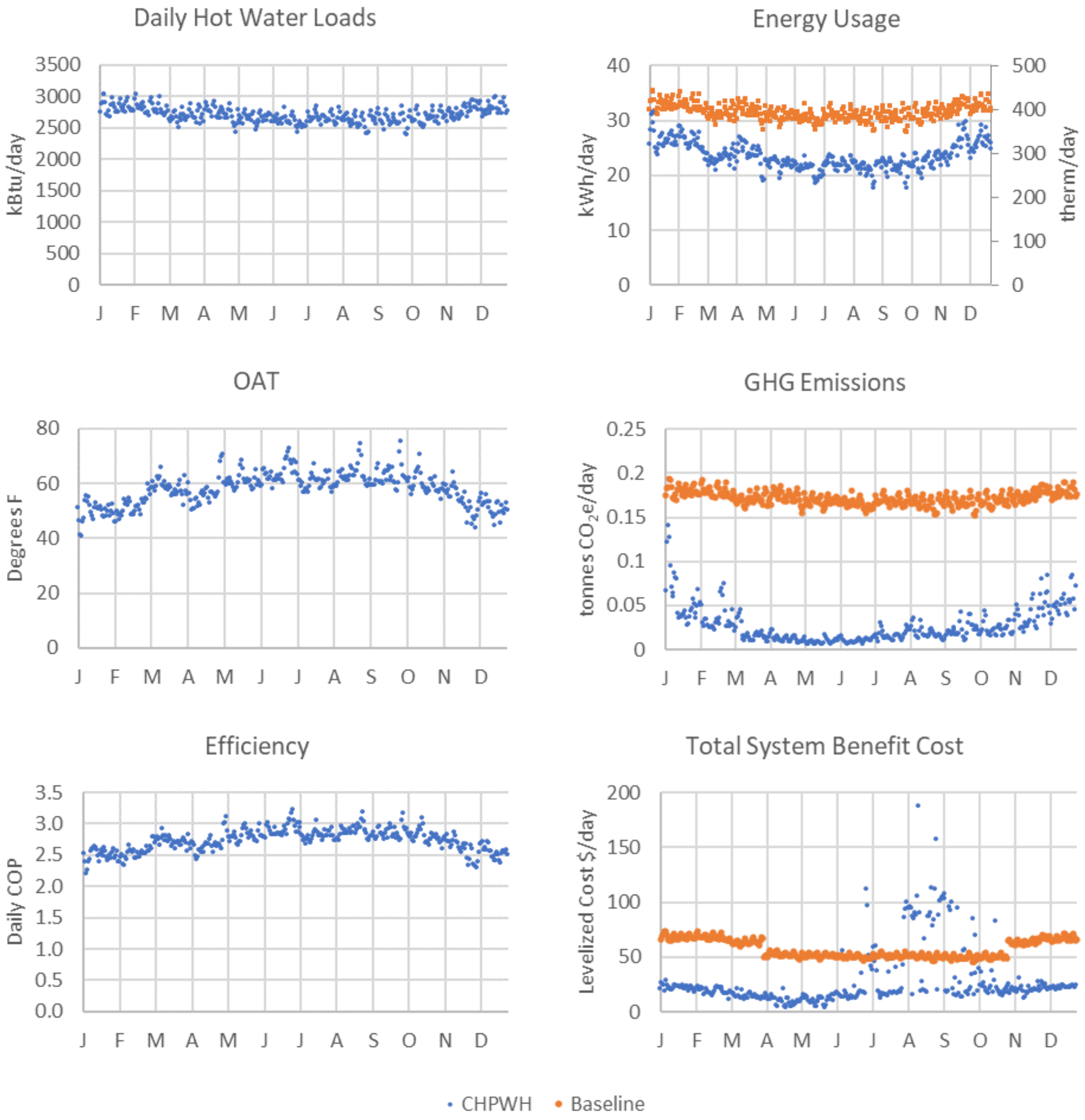

Figure 17: Annualized results for Host Site 1 in CZ3 (typical for all CZs).

Table 14 lists the energy, GHG, and TSB impacts for a Site 1 building operating in each California CZ. On average, the building would reduce GHG emissions by 85 percent and levelized cost of energy consumption by about 52 percent. The host site was located in CZ3 and has resulted in about 53.2 reduced tons of GHG emissions per year and a net benefit to society of about $10,820 per year (i.e., TSB).

Table 14: Annualized Site 1 Impacts across California CZs

CZ	Baseline Energy (therms/yr)	CHPWH Energy (kWh/yr)	Baseline GHG Emissions (tons CO_2e/yr)	CHPWH GHG Emissions (tons CO_2e/yr)	GHG Emissions Savings (tons CO_2e/yr)	Baseline ACC Levelized Cost ($/yr)	CHPWH ACC Levelized Cost ($/yr)	TSB ($/yr)
1	11,936	118,014	65.2	10.4	54.8	21,744	11,173	10,571
2	11,494	107,894	62.8	9.8	53.0	20,990	9,895	11,095
3	11,485	106,827	62.8	9.6	53.2	20,947	10,127	10,820
4	11,220	101,716	61.3	9.2	52.1	20,495	9,225	11,270
5	11,485	106,941	62.8	9.5	53.2	20,939	10,257	10,682
6	11,061	96,982	60.4	8.7	51.7	19,424	9,918	9,506
7	11,047	96,572	60.4	8.6	51.8	20,151	10,222	9,929
8	10,922	94,568	59.7	8.5	51.1	19,188	9,368	9,820
9	10,961	96,408	59.9	8.8	51.1	19,263	9,301	9,961
10	10,944	96,269	59.8	8.8	51.0	19,244	9,085	10,159
11	11,044	100,269	60.3	9.5	50.9	20,242	8,630	11,612
12	11,220	102,472	61.3	9.5	51.8	20,524	9,159	11,365
13	10,916	97,087	59.6	9.1	50.5	20,010	8,423	11,587
14	11,072	102,738	60.5	9.7	50.8	19,503	9,443	10,061
15	10,200	83,404	55.7	7.9	47.8	17,970	7,545	10,425
16	11,844	123,542	64.7	11.5	53.3	20,834	11,328	9,506
Average	11,178	101,981	61.1	9.3	51.8 (85%)	20,092	9,569	10,523 (52%)

Table 15 lists the same energy, GHG, and TSB on a per resident basis.

Table 15: Annualized Site 1 Impacts across California climate zones on a per resident basis

CZ	Baseline Energy (therms/yr)	CHPWH Energy (kWh/yr)	Baseline GHG Emissions (tons CO_2e/yr)	CHPWH GHG Emissions (tons CO_2e/yr)	GHG Emissions Savings (tons CO_2e/yr)	Baseline ACC ($/yr)	CHPWH ACC ($/yr)	TSB ($/yr)
1	99.5	983.5	0.54	0.09	0.46	181	93	88
2	95.8	899.1	0.52	0.08	0.44	175	82	92
3	95.7	890.2	0.52	0.08	0.44	175	84	90
4	93.5	847.6	0.51	0.08	0.43	171	77	94
5	95.7	891.2	0.52	0.08	0.44	174	85	89
6	92.2	808.2	0.50	0.07	0.43	162	83	79
7	92.1	804.8	0.50	0.07	0.43	168	85	83
8	91.0	788.1	0.50	0.07	0.43	160	78	82
9	91.3	803.4	0.50	0.07	0.43	161	78	83
10	91.2	802.2	0.50	0.07	0.42	160	76	85
11	92.0	835.6	0.50	0.08	0.42	169	72	97
12	93.5	853.9	0.51	0.08	0.43	171	76	95
13	91.0	809.1	0.50	0.08	0.42	167	70	97
14	92.3	856.2	0.50	0.08	0.42	162	79	84
15	85.0	695.0	0.46	0.07	0.40	150	63	87
16	98.7	1029.5	0.54	0.10	0.44	174	94	79
Average	93.2	849.9	0.51	0.08	0.43	167	80	88

For extrapolating Table 15 impacts to a household with more than one resident, these values should be multiplied to scale to occupancy. Assuming that about 30 percent of the hot water load is for recirculation losses, multiplying each entry by about (0.3+0.7*occupants) would reflect the impacts on a per multifamily dwelling. For instance, since the average multifamily dwelling in California has about 2.6 occupants (DNV GL Energy Insights USA 2020) the values are multiplied by 2.1.

Statewide Potential

The annualized impacts in Table 15 were combined with the multifamily market size in Table 3 to estimate total statewide potential for CHPWH systems in the existing building stock, assuming an average multifamily dwelling size of 2.6. The total statewide potential across CZs is listed in Table 16. There is an opportunity to reduce about 1.7 million tons of GHG emissions per year with a TSB of $350 million per year across California.

Table 16: Estimated total statewide potential impacts.

CZ	Baseline Gas Usage (Mtherms/yr)	CHPWH Energy (MWh/yr)	Avoidable GHG Emissions (tons CO_2e/yr)	Potential TSB (Million$/yr)
1	1.6	15,792.5	7,334.7	1.4
2	9.1	85,757.2	42,127.5	8.8
3	47.6	442,479.0	220,270.0	44.8
4	24.4	221,375.3	113,326.6	24.5
5	4.0	37,448.8	18,635.5	3.7
6	27.3	239,299.0	127,646.1	23.5
7	25.2	220,193.5	118,006.3	22.6
8	41.8	361,586.0	195,511.9	37.6
9	93.1	818,625.5	434,202.2	84.6
10	27.1	237,992.8	126,047.2	25.1
11	7.1	64,104.4	32,536.7	7.4
12	39.9	364,526.4	184,371.2	40.4
13	13.1	116,863.3	60,809.7	14.0
14	6.9	63,533.0	31,399.2	6.2
15	3.2	26,089.6	14,965.6	3.3
16	2.6	26,551.3	11,444.3	2.0
Totals	373.8	3,342,217.6	1,738,634.5	350.0

These CZ and statewide potential impact estimates should be used to calibrate expectations and general understanding. Although calculated system performance is similar to previous studies, it should be noted that these market estimates are based on only a single experiment and an assumed high-efficiency baseline. Existing gas water heaters and recirculation systems likely have higher losses across the building stock which would indicate that these statewide savings figures could be underestimates. Future and ongoing field demonstrations should attempt to provide similar statewide extrapolations or regression analyses. Additional annualized estimated impacts based on other field demonstrations will lend additional confidence and accuracy as the knowledge base of this technology grows.

It was not possible to extrapolate the findings to non-residential building types. However, it can be inferred that the total potential energy efficiency benefits for the non-residential building market base identified in Table 4 is about 50 percent of the total multifamily market potential.

There is largely negligible low-GWP refrigerant TSB impact when comparing a gas central DHW market to the potential replacement with CO_2-based CHPWHs since CO_2 has a GWP value of only 1. However, it is worth considering what the TSB impacts of a low-GWP refrigerant choice are in comparison with some remaining mid- and high-GWP options. It is conceivable that some CHPWH systems could still be built with R134a, R410a, and R32 heat pumps. Those systems will have total system cost penalties in comparison to both CO_2 and gas systems. Using the ACC for refrigerants, the total system cost penalty for each common CHPWH refrigerant option is listed in Table 17 for assumed charges. The TSB impacts are small compared to the energy usage TSB impacts. For that reason, the refrigerant TSB was not included in the statewide potential total.

Table 17: Estimated refrigerant TSB impacts for Site 1 building type.

Alternative refrigerant	Refrigerant charge (lbs)	TSB penalty ($/yr)	TSB penalty per resident ($/resident-yr)
R744 (CO_2)	28.6	Negligible	Negligible
R134a	45.6	4,358	36
R410a	45.6	6,367	53
R32	45.6	2,059	17

Discussion and Recommendations

The field study and analysis confirmed the substantial energy efficiency and GHG benefits of CHPWH systems, on a per system and statewide basis. The technology is clearly optimal over existing and alternative high-efficiency natural gas-fired systems, based on those two metrics. The analysis suggested that there are approximately 1.7 million tons of avoidable greenhouse gas emissions and $350 million of TSB potential per year in the existing California multifamily building stock. The host sites' CHPWHs achieved Tier 3 efficiency of NEEA's Advanced Water Heating Specification. It is easy to imagine that the total statewide potential is even greater than estimated if product improvements and technology transfer yield adoption of systems that can achieve higher Tier 4 efficiencies (not to mention that many existing gas systems are likely less efficient than the assumed efficiency code-compliant baseline). The CHPWH systems also clearly demonstrated load shifting capabilities over multiple hours through peak TOU periods without impacting customer hot water supply.

This is still a new technology, so there are many nuances and challenges associated with the design of these systems which need to be addressed or anticipated so that this burgeoning market transformation proceeds smoothly. The following are some specific examples of design and installation challenges observed during this study:

- While generally user-friendly, the control panel locked out the host site operators multiple times. As with any new product, hand-off to the customer should include better training so that there are fewer assistance calls made to contractors and service providers.
- Lack of thermal storage design guidance led to oversizing of the storage volume and a complex combination of parallel and series tank plumbing. The research team suspects this piping design caused the storage system to underperform in load shifting. Design guidelines, recommendations, and training will be needed for engineering firms to properly specify well-functioning thermal storage systems.
- The installations had very high costs due to complicated retrofitting, plumbing design, building water pressure regulators, oversized storage volume, and limited accessibility to roof and basement areas. Crane operators had to navigate equipment placement across neighboring buildings to reach a small rooftop area midway up the building. Further training and experience with these systems will likely bring costs down over time.

Design and installation of these systems is more complicated than a natural gas system. There are many engineering and technical details in which only manufacturers, researchers, and a limited number of subject matter experts are currently well-versed. Successful market transformation can be accelerated if these systems become more plug-and-play, requiring less specialized knowledge on the part of the designers and installers. This will require more research, training, and education for all stakeholders in this market. It will also be necessary for the manufacturers and their supply chain partners to focus on the delivery of more complete water heating system packages rather than simply selling heat pumps to the market. This can take the form of efforts such as:

- Development and availability of packaged, pre-designed, or skid-based systems that reduce points of failure, design steps, and involved parties.
- Load shifting implementation needs to be more routine and depend on fewer manual settings and less subject matter expert input. This will require manufacturers to be more involved in establishing standardized load shift control recommendations for their products.
- More research needs to be done to understand and quantify measures leading to temperature maintenance energy losses. These measures could then be built into tools such as the Ecosizer to enable better system optimization for temperature maintenance loads. In retrofit scenarios, it is important to measure, optimize, and rebalance the recirculation and distribution system before CHPWH sizing and installation.
- Manufacturers should consider enabling user portals or interfaces that make standard monitoring data available to customers. The project host sites repeatedly asked whether they could have access to the data and expressed interest in access to real-time monitoring capabilities.

- System designs should be simplified as much as possible. This could involve testing designs that eliminate ER swing tanks and intermediate heat exchangers between the HPWH and DHW loops to seek efficiency gains.
- California program designers should study the total market potential and projected GHG and TSB over time under assumed adoption rates. This could help calibrate expectations and target installations per year necessary for defined statewide climate and program goals.
- Focus should be given to the development of sizing tools, design guidelines, regulatory pathways, and product offerings targeted to non-residential applications. The total non-residential market-wide energy footprint is approximately 50 percent of the multifamily market.

A primary barrier to equitable market transformation is the customer's cost of energy. In comparison to a high-efficiency gas water heater, the customer's cost of energy may more than double as observed at the host sites over the monitoring period. This is especially apparent during summer months when demand charges are high. The cost disparity is dominated by peak demand charges; these were approximately two-thirds of the incurred electrical energy billing at the host sites over the monitoring period. This challenge is particularly relevant for commercial and multifamily hot water systems since usage often coincides with peak whole building electrical demand throughout the entire year. Hot water electrification will incur peak demand charges all through the summer months when those demand charges are highest (in contrast to space heating which is most prevalent only in winter months when demand charges are low or non-existent). The cost disparity is also being driven by the increasing difference in unit cost between electricity and natural gas – customer costs for piped natural gas have reduced over the past year while electrical rates have gone up.

Although they have the potential to mitigate this issue, the tested load shifting strategies did not reduce costs during this study. The tested sequences and schedules were designed to confirm maximum load shift magnitude during the peak TOU period rather than optimize cost or GHG emissions. Future optimized CHPWH controls can likely address this and requires additional research and development.

Possible paths to customer energy cost mitigation include:

- Adjust system load shift controls and SOOs to reduce demand charges in the customers TOU peak pricing window. For example, two simple controls changes could be implemented to achieve lower demand charges at the two host sites right away. The first change could be to limit the system to only a single HPWH during the 4 – 9 p.m. peak period instead of allowing both to come on. The second is adding a lockout relay to prevent the swing tank from turning on during the 4 – 9 p.m. peak pricing timeframe. These two changes would likely reduce peak demand by approximately 30 kW during the peak pricing window. This could reduce monthly demand charges by about $1,100 during summer months.
- Tools that can prescribe optimized load management control settings based on equipment and site conditions could also be a significant step towards energy cost mitigation in the absence of the above automated strategy. For instance, a tool that accepts a hot water usage load shape, storage tank specifications, and TOU pricing could output an optimal control sequence to be used in any given installation.

- Operating parameters should include variable capacity control of the HPWHs. For instance, cost and GHG emissions may be optimized by running the HPWHs at part speed during high-cost, high-emissions TOU periods rather than simply trying to stay off as long as possible. This may also help with mitigating short-cycling, or systems with multiple HPWH but no variable speed control could stage or lock out units to keep total peak demand low during high-cost periods.
- While the current state of technology and near-term solutions should rely on static load shift SOOs and programming, there may be a future where "self-learning" load shift controls could prove optimal. Manufacturers and researchers should explore the benefits and roadmap of developing intelligent load shift controls that do not rely on static SOOs or setpoints. Load shifting could be optimized with a "self-learning, machine-learning" strategy that considers factors such as building hot water loads, TOU costs, peak system and whole building electrical demand, HPWH capacity control points, and CHPWH system capabilities to maximize the load shift benefits. A control system that has established the empirical relationships between the various control points and the parameters to be optimized could realize savings beyond the capabilities of static controls. However, this proposition is not currently available and could cause operational issues if not carefully studied and implemented. Although it would be a long-term goal, this may be the ultimate solution after enough intelligence is gained through lab testing, field testing, and modeling of this technology.
- Cost burden to host sites is large for fuel switching in both first and ongoing operating costs. Regulators and programs will need to evaluate the overall technology benefits and to what extent customers can be supported for equitable market transformation. Cost-effectiveness criteria in program design and measure evaluation should take into account the TSB of CHPWH to maximize customer support consistent with the true emerging technology value.
- In the face of market electrification, creative means of supporting customers to reduce cost burden in excess of natural gas system parity may be necessary. For instance, separate metering and rate schedules for CHPWH systems could provide dedicated, lower-cost billing for this very large electrified end-use. Multifamily residents are typically already lower-income than the general population and should not be required to unfairly absorb disproportionate costs of electrification and GHG emissions reduction.

More field testing is recommended. Several field studies are ongoing through other CalNEXT, EPIC, and Bonneville Power Administration efforts. The US Department of Energy is also sponsoring 10 – 12 field pilots over the next few years. For these and future field studies, there are several recommendations based on learnings during this project:

- To enable fair evaluation of load shifting GHG and cost impacts, a different on/off M&V strategy is recommended. The day-on/day-off strategy used here resulted in some challenges with the post-load shift recovery time and bounce-back carrying over into the next day. Longer on/off intervals are recommended so that full hot water draw and recovery cycles can reset. For instance, week-on/week-off or multiple days on/off could be more effective for evaluation. Be cognizant of carry-over effects between load shift and non-load shift days during analysis.
- Lab testing of load shift controls could be helpful, especially in the development of optimized, streamlined, or self-learning controls. In the field, there are uncontrolled variables and customer impacts that make comprehensive test plans more complicated to implement. A

PG&E laboratory test in San Ramon is embarking on some limited load shift testing during Q4 2023.

- Compare measured demand peaks to the rest of the whole building peak demand to evaluate impacts of demand charges. Develop control algorithms which can minimize peak load pricing impacts.
- Field test measurements should be standardized around the Advanced Water Heater Specification M&V guidelines to make comparison possible across field test datasets.
- Quantify GHG, customer energy cost, and TSB of load shifting at other ongoing projects in a similar way. Simply comparing energy consumption during various TOU periods of time is not a sufficient evaluation; shifted energy consumption does not guarantee cost, energy, or GHG savings. Future studies should compare the total energy consumption, GHG, cost, and peak demand between normal and load shift operating days that includes full draw and recovery cycles in include any bounce-back effects.
- Quantify GHG, customer energy cost, and TSB over gas baselines to refine the total statewide impacts presented in this study. More measured results of hot water usage, load profiles, COP results, and regression analyses can be used to refine and increase confidence in the CZ and statewide extrapolations.
- Test CHPWH systems in non-residential buildings, especially hospitality, foodservice, lodging, education, offices, and healthcare buildings.

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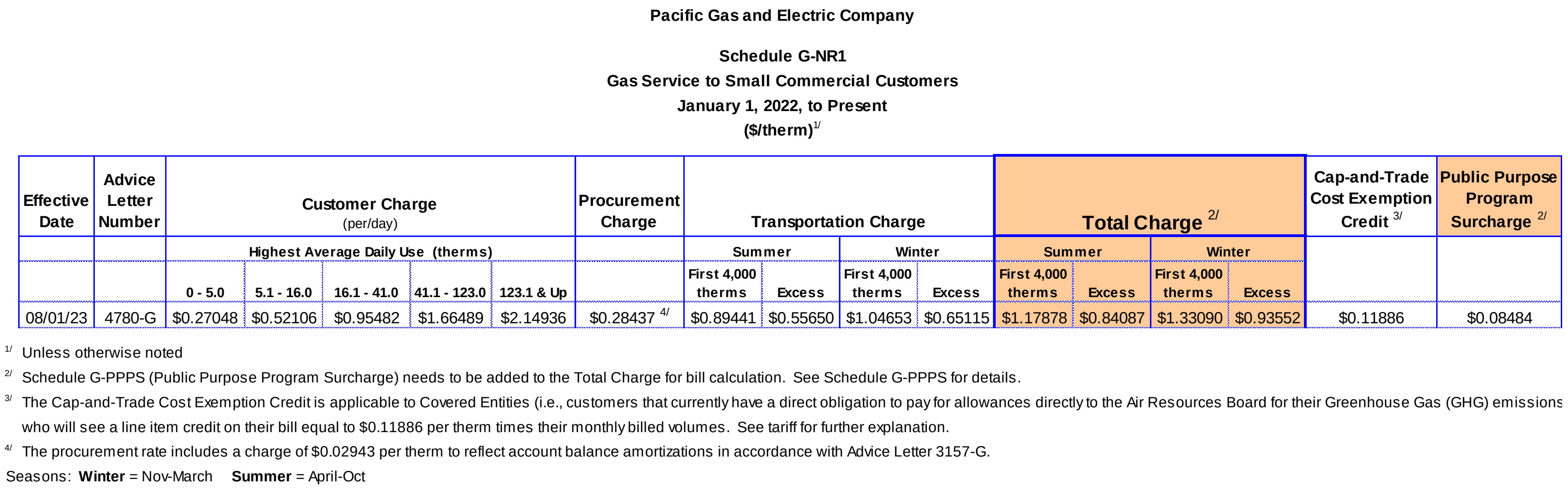
Appendix A: Utility Rate Schedules

The following figures show the rate schedules for the host sites used in energy cost calculations (PG&E 2023).

Table 18: Gas rate schedule.



Pacific Gas and Electric Company

Schedule G-NR1
Gas Service to Small Commercial Customers
January 1, 2022, to Present
($/therm)[1/]

Effective Date	Advice Letter Number	Customer Charge (per/day)					Procurement Charge	Transportation Charge				Total Charge [2/]				Cap-and-Trade Cost Exemption Credit [3/]	Public Purpose Program Surcharge [2/]
		Highest Average Daily Use (therms)						Summer		Winter		Summer		Winter			
		0 - 5.0	5.1 - 16.0	16.1 - 41.0	41.1 - 123.0	123.1 & Up		First 4,000 therms	Excess	First 4,000 therms	Excess	First 4,000 therms	Excess	First 4,000 therms	Excess		
08/01/23	4780-G	$0.27048	$0.52106	$0.95482	$1.66489	$2.14936	$0.28437 [4/]	$0.89441	$0.55650	$1.04653	$0.65115	$1.17878	$0.84087	$1.33090	$0.93552	$0.11886	$0.08484

[1/] Unless otherwise noted

[2/] Schedule G-PPPS (Public Purpose Program Surcharge) needs to be added to the Total Charge for bill calculation. See Schedule G-PPPS for details.

[3/] The Cap-and-Trade Cost Exemption Credit is applicable to Covered Entities (i.e., customers that currently have a direct obligation to pay for allowances directly to the Air Resources Board for their Greenhouse Gas (GHG) emissions who will see a line item credit on their bill equal to $0.11886 per therm times their monthly billed volumes. See tariff for further explanation.

[4/] The procurement rate includes a charge of $0.02943 per therm to reflect account balance amortizations in accordance with Advice Letter 3157-G.

Seasons: **Winter** = Nov-March **Summer** = April-Oct

Table 19: Electric rate schedule.

Rate Schedule	Customer Charge ($ per meter per day)	Season	Time-of-Use Period	Demand Charge ($ per kW)	Time-of-Use Period	Total Energy Charge ($ per kWh)	PDP[1/] Charges ($ per kWh)	PDP[2/] Credits DEMAND ($ per kW)	PDP[2/] Credits ENERGY ($ per kWh)	Power Factor Adjustment ($/kWh/%)	"Average" Bundled Total Rate[3/] ($ per kWh)
				Secondary		Secondary		Secondary	Secondary		
B-19 TOU		**Summer**	Max. Peak	$38.75	Peak	$0.21585	$0.90	($6.47)	$0.00000	$0.00005	**Secondary** $0.29400 **Primary** $0.25621 **Transmission** $0.22415
	Mandatory B-19 S: $38.23489		Max. Part-Peak	$8.11	Part-Peak	$0.17342		($0.94)	$0.00000		
	Mandatory B-19 P: $58.87921		Maximum	$30.20	Off-Peak	$0.14341		-	-		
	Mandatory B-19 T: $93.48361	**Winter**	Max. Peak	$2.53	Peak	$0.18890		-	-	$0.00005	
	Voluntary B-19: S, P, T: $7.65463		-	-	Off-Peak	$0.14329					
			Maximum	$30.20	Super Off-Peak	$0.08210					

[1/] Peak Day Pricing (PDP) Consecutive Day, Three-Hour Event. PDP Charges apply to all Usage During PDP Event Hours. See specific tariff for further details and program options.

[2/] Peak Day Pricing (PDP) Consecutive Day Three-Hour Event. PDP Credits apply to components shown in all summer billing months. See specific tariff for further details and program options.

[3/] Based on estimated forecast. Average bundled rates provided only for general reference, and individual customer's average rate will depend on its applicable kW, kWh, and TOU data.

This table provided for comparative purposes only. See current tariffs for full information regarding rates, applicability, eligibility and additional options.

Table 20: Electric TOU periods.

B-1, B-6, B-10 and B-19 Time Periods		
B-1, B-10 and B-19		
Summer (June-September)		
Peak:	4:00 pm to 9:00 pm	Every day, including weekends and holidays
Partial-Peak:	2:00 pm to 4:00 pm AND 9:00 pm to 11:00 pm	Every day, including weekends and holidays
Off-Peak:	All other hours	
Winter (October-May)		
Peak:	4:00 pm to 9:00 pm	Every day, including weekends and holidays
Super Off-Peak	9:00 am to 2:00 pm	Every day in March, April and May only, including weekends and holidays
Off-Peak:	All other hours	
For Customers on B1-ST Only		
Partial-Peak:	2:00 pm to 4:00 pm AND 9:00 pm to 11:00 pm	Every day, including weekends and holidays
B-6		
Summer (June-September)		
Peak:	4:00 pm to 9:00 pm	Every day, including weekends and holidays
Off-Peak:	All other hours	
Winter (October-May)		
Peak:	4:00 pm to 9:00 pm	Every day, including weekends and holidays
Super Off-Peak	9:00 am to 2:00 pm	Every day in March, April and May, including weekends and holidays
Off-Peak:	All other hours	

Appendix B: Regressions

Several regressions were used for the extrapolation of findings to typical weather years for each CZ.

For Site 1, daily COP was calculated as a function of gallons of hot water used per day (GPD), OAT, and outside air relative humidity (OARH).

$$Daily\ COP = \frac{COP1 + COP2}{2} = \frac{f_1(GPD, OAT) + f_2(GPD, OAT, OARH)}{2}$$

where f_1 and f_2 are regressions established as follows:

Table 21: Site 1 system COP1 regression

COP1 Regression, *f₁*					
R Square	0.716				
Standard Error	0.079				
Observations	90				
	Df	SS	MS	F	Significance F
Regression	2	1.369	0.684	109.463	1.76e-24
Residual	87	0.544	0.006		
Total	89	1.913			
Independent Variable	Coefficients	Standard Error	t Stat	P-value	95% Confidence Interval
Intercept	-0.181888	0.202	-0.899	0.371	(-0.5840, 0.2202)
GPD	0.000365	4.28e-5	8.529	4.13e-13	(0.0003, 0.0005)
OAT	0.031440	0.002	14.488	6.54e-25	(0.0271, 0.0358)

Table 22: Site 1 system COP2 regression

COP2 Regression, f_2					
R Square	0.783				
Standard Error	0.069				
Observations	90				
	Df	SS	MS	F	Significance F
Regression	3	1.497	0.499	103.367	1.99E-28
Residual	86	0.415	0.005		
Total	89	1.913			
Independent Variable	Coefficients	Standard Error	t Stat	P-value	95% Confidence Interval
Intercept	-0.365636	0.181	-2.016	0.047	(-0.7261, -0.0052)
GPD	0.000352	3.769e-05	9.350	9.518E-15	(0.0003, 0.0004)
OAT	0.028854	0.002	14.633	4.618E-25	(0.0249, 0.0328)
OARH	0.004895	0.001	5.162	1.555E-06	(0.0030, 0.0068)

Additionally, the data allowed a regression of daily hot water load in Btu as a function of GPD and OAT.

$$Daily\ Hot\ Water\ Load\ (Btu) = f_3(GPD, OAT)$$

where f_3 was established as follows:

Table 23: Site 1 system hot water load regression

COP2 Regression, f_2					
R Square	0.735				
Standard Error	117,060.7				
Observations	90				
	Df	SS	MS	F	Significance F
Regression	3.277e12	1.638e12	119.563	1.463e-25	3.277e12
Residual	1.178e12	1.370e10			1.178e12
Total	4.455e12				4.455e12
Independent Variable	Coefficients	Standard Error	t Stat	P-value	95% Confidence Interval
Intercept	1,352,257.06	300,723.522	4.497	2.144e-5	(754,438.48, 1,950,075.64)
GPD	769.555	65.268	11.791	1.1828e-19	(639.81, 899.30)
OAT	-16,457.329	3,230.212	-5.095	2.0416e-6	(-22,878.78, -10,035.88)

Appendix C: Billing Data Analysis

Monthly billing data from the host sites was used to validate the findings from the field demonstration. The weather-normalized differences in electrical and gas billing data for the whole building before and after the retrofit should show the changes in energy consumption attributable to the measure (i.e., IPMVP Option C). This assumes that no other uncontrolled changes in the building such as occupancy or other renovations occurred across the baseline and post periods.

Figure 18 plots the whole building electrical energy and natural gas consumption per billing period as a function of average outside air temperature before and after CHPWH retrofit.

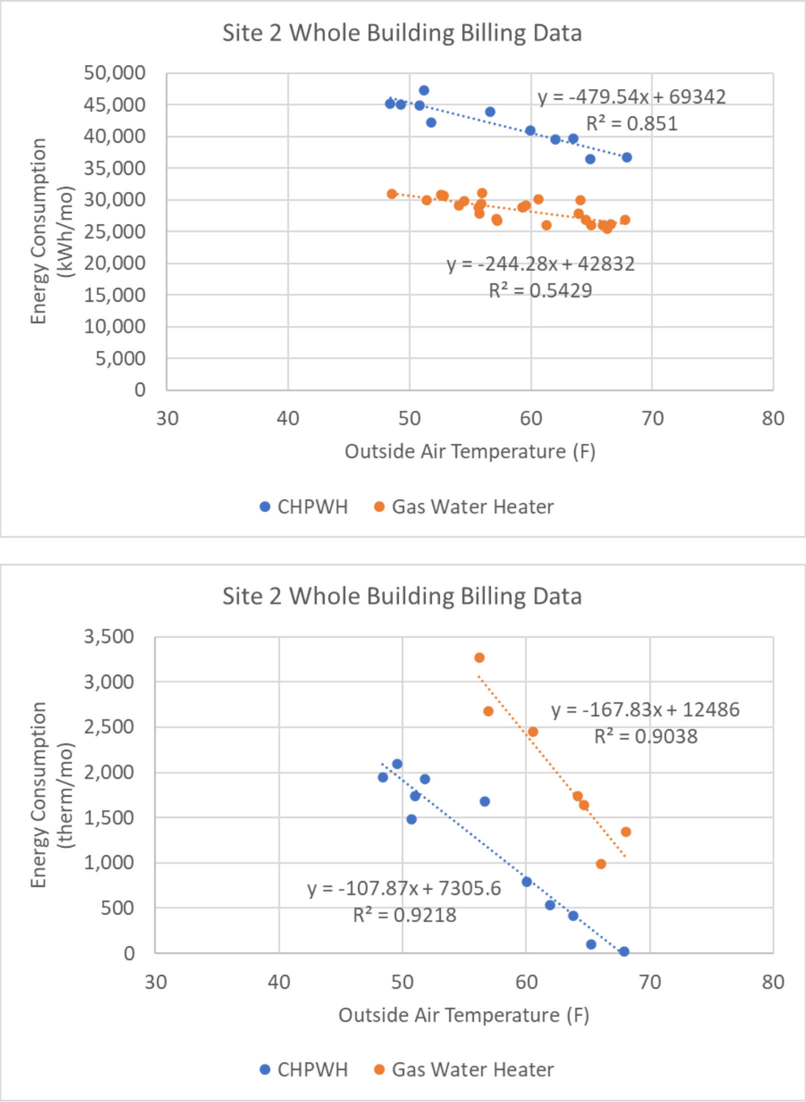


Figure 18: Site 2 whole building energy consumption before and after the CHPWH retrofit.

24 months of billing data was used for the electrical baseline prior to the CHPWH retrofit. Only seven months as used for the gas baseline because there were significant hot water distribution system upgrades that changed the load profile. For fair comparison to the post-CHPWH installation

monitoring period, only the months after distribution system upgrades can be used as the baseline. As expected, electrical energy consumption goes up and gas consumption goes down after the retrofit.

Extrapolating the baseline regression for the whole building consumption to the monitoring period can predict what the baseline energy would have been without the CHPWH retrofit. The difference between this prediction and the actual billed consumption should approximately reflect the CHPWH retrofit impacts. Figure 19 shows these energy impacts from billing data regression in comparison to the values determined from the monitoring data in the Findings section. This comparison validates the model, calculations, and findings from monitoring data.

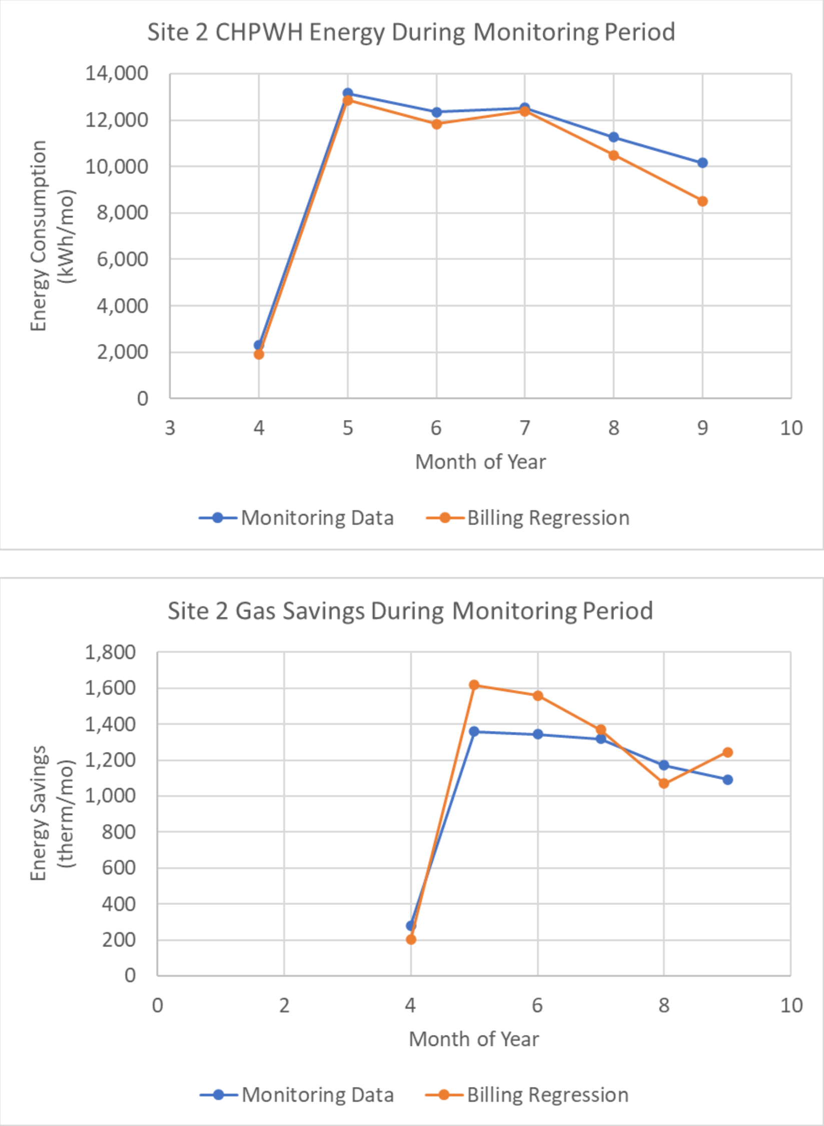


Figure 19: Site 2 comparison of energy impacts calculated from monitoring data (IPMVP Option B) and billing data (IPMVP Option C).

The difference in total CHPWH electrical and gas energy consumption estimates over the monitoring period between the two methods is 6.1 percent and 7.5 percent, respectively.

A similar analysis for done for Site 1. However, the electrical billing data did not allow for any regression to weather and so could not be normalized. Only the gas billing data could be compared to the analysis done with the measured data with the baseline data having little dependence on outside air temperature.

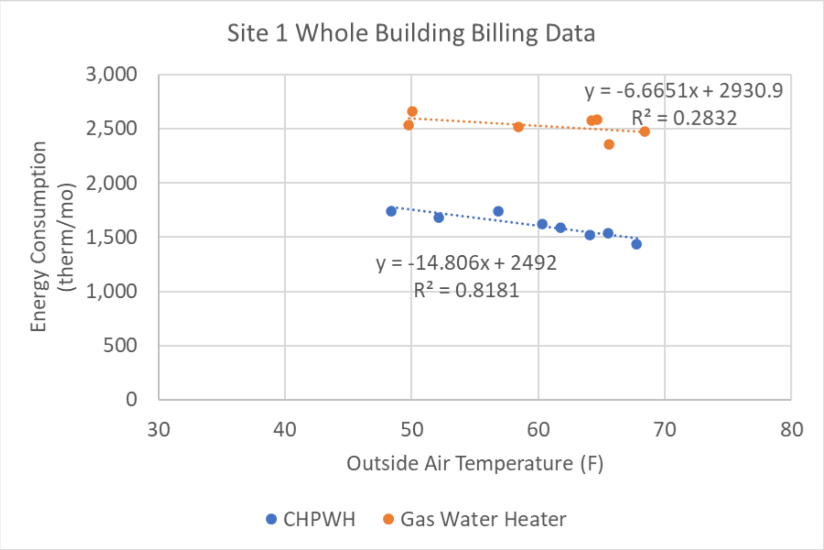


Figure 20: Site 1 whole building natural gas consumption before and after the CHPWH retrofit.

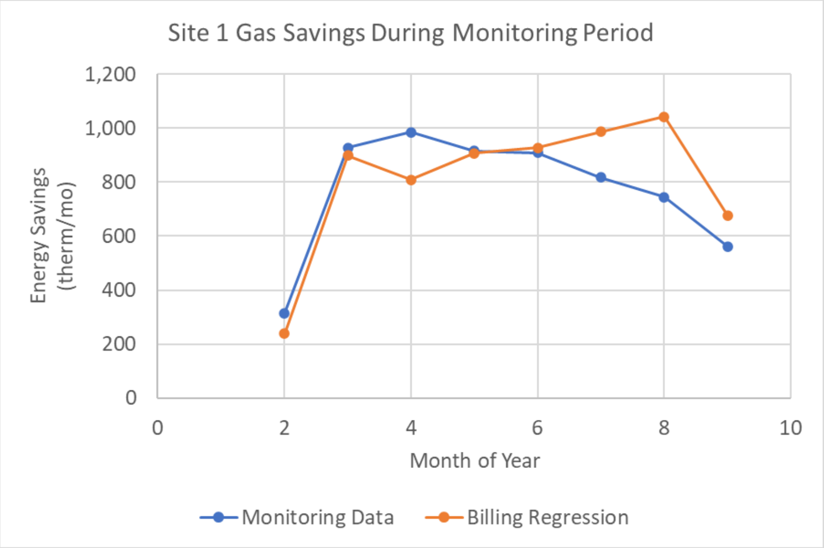


Figure 21: Site 1 comparison of energy impacts calculated from monitoring data (IPMVP Option B) and billing data (IPMVP Option C).

Again, the billing data analysis validated the results of the Findings section using the monitoring data. The difference between estimates of the total gas savings over the monitoring period is only 5.1 percent.

Table 24: Comparison of energy estimates calculated through monitoring and billing data.

	Monitored Data (IPMVP Option B)	Billing Analysis (IPMVP Option C)	Difference
Site 1			
Natural Gas Savings (therm)	6,175	6,488	313 (5.1%)
Site 2			
CHPWH Energy (kWh)	61,773	58,002	3,771 (6.1%)
Natural Gas Savings (therm)	6,568	7,064	496 (7.5%)