Thermal Storage as Electric Demand Response Technology: Case Study for an Institutional Building in British Columbia

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ABSTRACT

Electric utilities are increasingly challenged to balance supply and demand for electric grids. Most demand-side solutions emphasize measures for electric equipment, including electric battery storage. This project investigates the technical and economic feasibility of implementing thermal energy storage as a demand response strategy in an electrically heated institutional building. The University of British Columbia's Forestry Science Building was selected as a case study, leveraging its hourly metered thermal load. The baseline scenario assumes electric boilers supply all of the building's thermal demands. Electric boiler technology was chosen based on the high temperature requirements for this existing building. The objective of this project is to evaluate the potential of phase change material (PCM) technology to shift thermal load from peak to off-peak periods. Comparisons are included for hot water thermal storage as well as electric battery technology.

Analyses of hourly-based and daily-based thermal load revealed significant seasonal variation in heating demand, ranging from negligible demand to 1,100 kWh/day. Another finding is that the peak building thermal load (5am-2pm) is not coincident with the electric utility's winter peak hours (4pm-9pm).

The system was modelled using RETscreen. Storage sizing was conducted using two approaches: based on daily thermal loads and the thermal load during the utility's winter peak hours. Different heating time periods were used for sizing storage, resulting in capacities of 2000 kWh to 7000 kWh, depending on the design criterion. Two thermal load shifting strategies were examined: aligning with utility's peak hours and the building's inherent peak hours. The economic results were reported for a 2,000 kWh sized system in terms of net present value and simple payback period.

Introduction

Objectives

The basic objective of the project is to examine the technical and economic potential of using phase change material (PCM) thermal storage technology as a demand response measure, and to compare it to hot water storage and electric battery storage. The idea is to conduct a case study for an electrically heated commercial / institutional building and examine how adding thermal storage could be used to shift electric demand to off-peak time periods. The University of British Columbia (UBC) provided thermal load data for the Forest Sciences Centre to examine how to convert this building to electric space heating with thermal storage.

Hourly thermal loads of the Forestry Science Centre were obtained from the district energy system. The actual heating system is from district energy hot water (typically ~ 85 ˚C or

185 ˚F). There is also in-building heat recovery chiller, which is a vapor compression cycle (refrigeration cycle) technology that delivers chilled water for space cooling, with heat recovery used for space heating and/or Domestic Hot Water (DHW). Normally heat is rejected by a cooling tower.

In general, electrification of heating is a common decarbonization strategy in British Columbia (BC). Assessments have indicated that electrification that is implemented without careful consideration of electric grid requirements can cause reliability problems that can be expensive to fix (Bounocore 2022). Therefore energy storage in some form is expected to be an important element of heating electrification.

For this study, the actual thermal production is assumed to be produced by electric boilers, which are resistance heaters with assumed thermal efficiency of 99.5%.[1] Electric boiler technology was chosen because: a) the requirement for 85 ˚C (185 ˚F) hydronic water temperature is challenging and relatively expensive with heat pump technology, and b) electric boilers are common in BC. Electric boiler system without thermal storage is considered the baseline for this project. Then we examined effects on electric load shifting using electric boilers in combination with thermal storage from peak hours (4 pm-9 pm, Monday – Friday) to off-peak hours from November to February. The choice of peak hours aligns with the peak period defined by the electric utility, BC Hydro.

Because this study is for a building in British Columbia, all currency in this study is in Canadian dollars. To convert to U.S. dollars, a typical multiplier is 0.73 (e.g. $1,000 Canadian is approximately $730 US dollars).

Thermal Storage Technology

Thermal energy storage (TES) is a technique that involves storing thermal energy for heating or cooling purposes. It is mainly divided into two categories: sensible thermal storage and latent thermal storage.

Sensible thermal storage is one of the simplest methods for storing thermal energy, achieved by raising or lowering the temperature of a solid or liquid material, such as water, sand, molten salts, or rocks. Among these materials, water stands out as the most cost-effective option. Water tanks are widely used in both residential and industrial settings. This method offers two key benefits: it is highly economical and avoids the hazards linked to toxic substances (e.g. potentially toxic PCM materials include paraffin wax, salt hydrates, and fatty acids; see Chandel and Agarwal, 2017). The amount of heat stored is calculated based on the sensible heat of the medium, the temperature change, and the mass of the material (Sarbu and Sebarchievici 2018).

Different from sensible thermal storage, latent thermal storage is another main type of thermal storage. It uses PCM to release or absorb energy through changing its physical state (Faraj et al. 2021; Sadeghi 2022). In part, these materials behave similarly to sensible heat storage materials, where their temperature increases proportionally with the system's enthalpy. However, as the process continues, they transition to absorbing or releasing heat at approximately a constant temperature due to a phase change in their physical state. PCM materials can be engineered to a specific design melting point temperature to optimize specific applications. Some of the advantages of PCM vs. hot water storage include:

- Greater energy density (smaller space requirements)

[1] Actual thermal efficiency for electric boilers may be as low as 92% according to ASHRAE Handbook Systems and Equipment (2024), Chapter 32. Thermal losses occur from boiler exterior surfaces and makeup water.

- Constant temperature output (the melting temperature can be engineered)
- Longer heat retention
- Less thermal stratification

According to their physical transformation capabilities, PCMs are classified into organic, inorganic, and eutectic materials. Organic includes paraffin compounds and non-paraffin compounds. Inorganic includes salt hydrate and metallics, while eutectic includes organic-organic, inorganic-organic, and inorganic-inorganic combinations.

One of the requirements for using thermal storage as a demand response technology is the ability to adequately control the process. There is ample evidence that control technology is readily available for this application. For example, the use of phase change thermal storage is already in use in a more complex application in Vancouver, BC[2]. In general, there are many demonstrated applications of TES controls for applications which are more complex than the case study in this paper (e.g. see Zotica et al, 2020).

Peak Shaving and Load Shifting

With rising energy costs and the growing importance of electric grid reliability, utility customers are exploring efficient strategies to manage their energy usage. Peak shaving and load shifting are two widely adopted approaches for reducing costs and managing energy consumption (Shirazi and Jadid 2017; Guo and Zhaoyu 2021). While both methods help operations lower demand charges and optimize energy use, they function differently and are tailored to distinct situations.

Peak shaving is a technique aimed at minimizing a facility's highest energy demand during peak hours (Diversegy 2024). This method involves either decreasing energy usage from the utility or utilizing on-site alternative energy sources such as solar power or energy storage systems to avoid using power from the grid. After peak shaving, the overall consumption from the power grid is reduced, as illustrated in Figure 1 (Spendiff-Smith 2024).

Load shifting is a method that shifts energy usage from times of high demand to periods of lower demand, which can reduce electricity bills, especially demand charges or other time-variant costs. The main difference between peak shaving and load shifting is that the overall consumption from the power grid remains the same when applying load shifting. Figure 2 shows the load shifting principle (Spendiff-Smith 2024). Load shifting is especially beneficial for operations with time-variant pricing options such as time-of-use (TOU), critical peak rebates, critical peak pricing, or real time pricing. For example, the UBC Forest Sciences building falls under the university's transmission service account with BC Hydro. BC Hydro has optional time-variant rates for transmission service customers[3]:

- RS 2801: transmission TOU (winter on-peak $0.17713/kWh; off-peak $0.04096/kWh)
- RS 2802: Transmission service TOU with modified winter demand; same TOU as RS 2801, but with different peak demand prices for Non-Peak and Peak periods.
- RS 2821: transmission service critical peak pricing offers a lower demand charge in all months, but applies a critical peak charge for up to 15 peak events 4pm-8pm weekdays
- RS2822: TOU combined with critical peak pricing

[2] www.districtenergy.org/blogs/district-energy/2025/10/06/cadillac-fairview-tackles-downtown-vancouver-co2-e

[3] www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/tariff-filings/electric-tariff/bchydro-electric-tariff.pdf. These optional rate schedules were not opted in by the university, but are illustrative of time variant rate designs that incentivize load shifting.

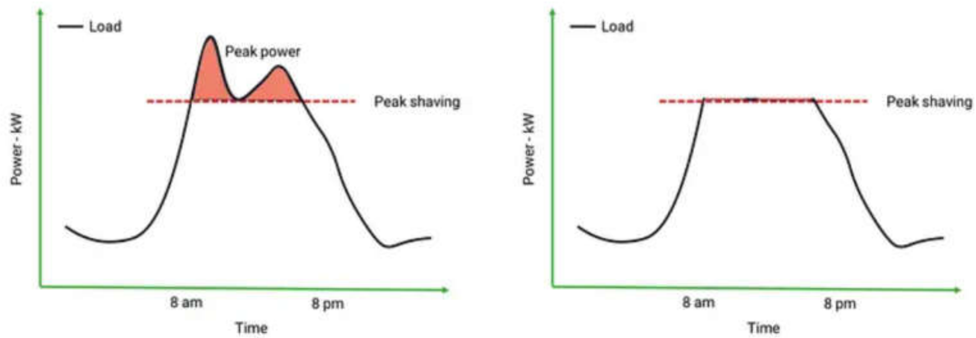

Figure 1. Illustration of peak shaving.

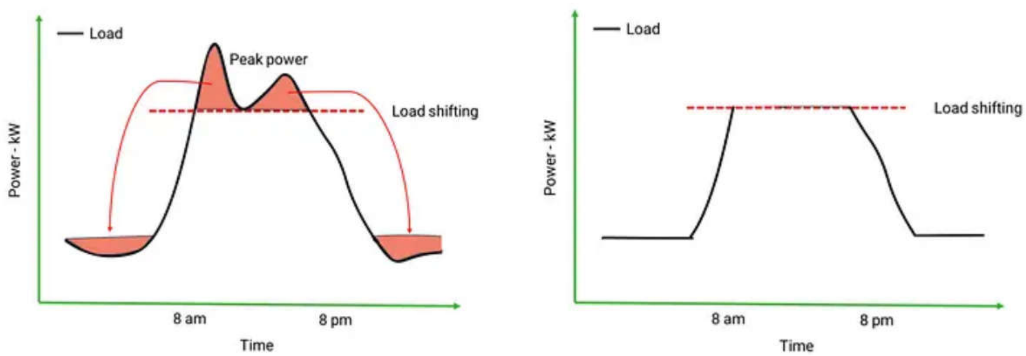

Figure 2. Illustration of load shifting.

Thermal Load Data

Thermal load data for the UBC Forest Sciences Centre for calendar year 2023 were used for this study. Analyses were conducted for both hourly data, and daily totals.

Hourly Thermal and Electric Loads

Twelve months of hourly thermal load and electricity load from are shown in Figures 3 and 4. From Figure 3, it can be seen that during summer time, the load is lower, while in winter the load is much higher. Compared to thermal load, electricity load is more stable, in the range of 500 kW throughout the year.

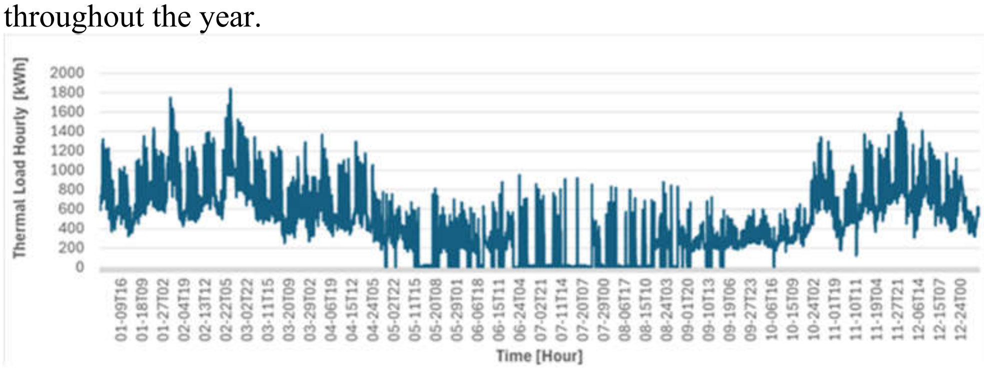

Figure 3. Hourly thermal load of Forestry Science

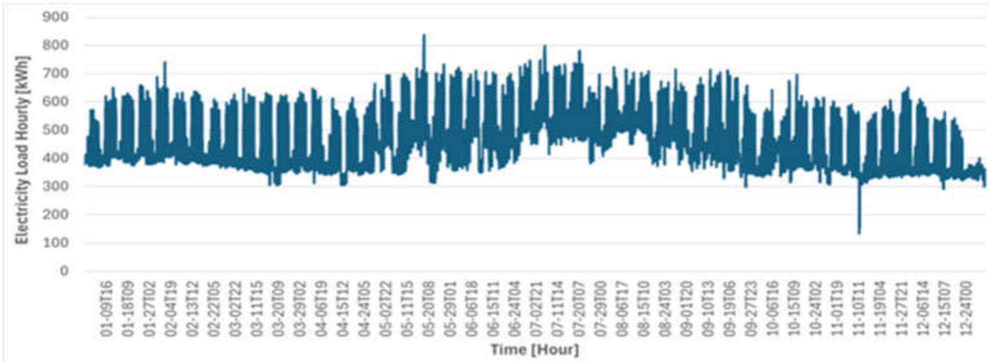

Figure 4. Hourly electricity load of Forestry Science

Daily Thermal Loads

The daily-based thermal load of Forestry Sciences is represented in Figure 5. We can see that the peak months are from November to February, which aligns with the electric utility's (BC Hydro) winter peak time period. From October 23, heating started, and the thermal load increased dramatically. In addition, it appears to vary step-wise from March to September. These daily load variations are likely driven by a combination of outdoor air temperatures and occupancy schedules.

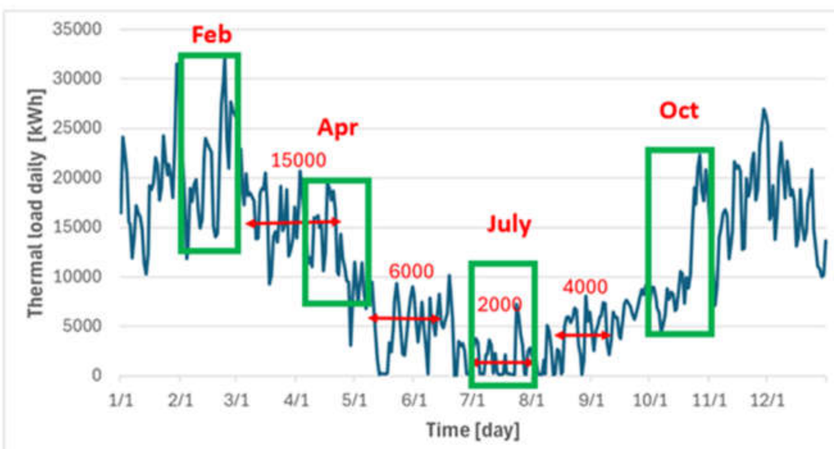

Figure 5. Daily-based thermal load of Forestry Science

To illustrate daily thermal load characteristics during winter months, data for February are illustrated in Figure 6, which show that variations exhibit a regular pattern. Then, we picked one day, February 14, to observe in hourly detail, which is shown in Figure 7. We can see that the peak hours of the thermal load are from around 5 am to 2 pm, which is not synchronous with the BC Hydro's peak hours (4 pm-9 pm). In February, from 4 pm to 9 pm, the thermal load is around 800 kWh hourly.

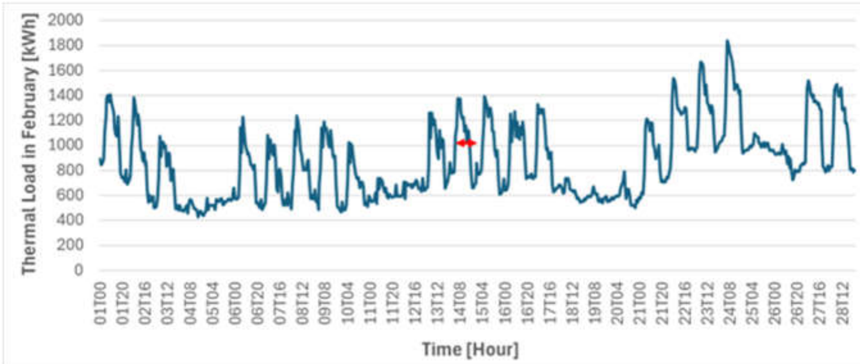

Figure 6. Daily-based thermal load in February

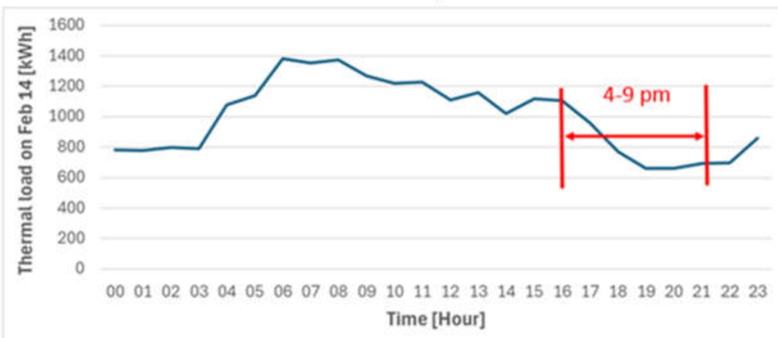

Figure 7. Daily-based thermal load on February 14

Similar analyses were carried out for monthly and daily patterns for April, July, and October. A summary comparison of seasonal variation in thermal loads is provided in Figure 8. This shows that the building peak thermal loads occur from 5am to 2pm, and that building loads are lower, but still significant, during the utility peak hours of 4pm to 9pm. With a load shifting strategy in mind, it would be valuable to the utility to shift electric load during 4 pm to 9pm. We can see that the highest thermal load from 4 pm to 9 pm is approximately 1,100 kWh hourly, and it happens on February 14. The lowest peak hour consumption is about 300 kWh hourly and occurs on October 10, and 0 kWh in July.

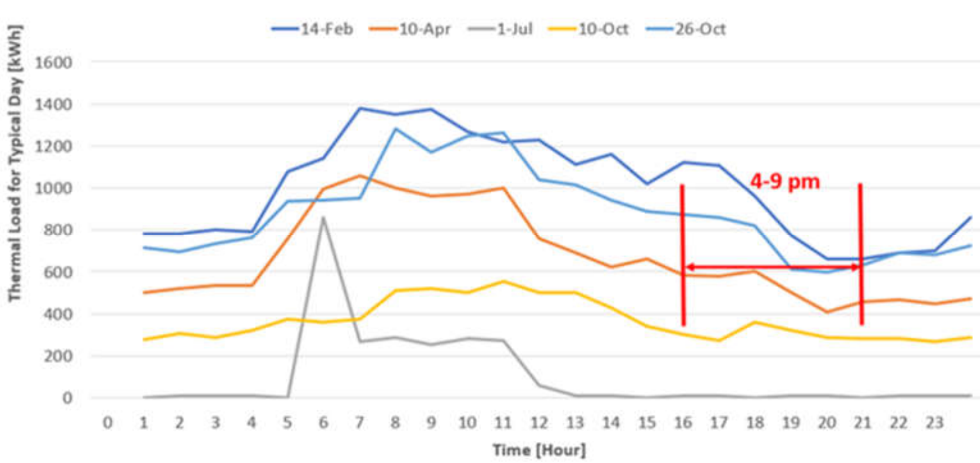

Figure 8. Thermal load comparison for typical day

Sizing of Hot Water Thermal Storage

Sizing Using Daily Average Thermal Loads

One strategy to size thermal storage is to use the average daily load during the coldest months of January to February. The total thermal load for the two months is 1,171,000 kWh, and the total days is 59 days, resulting in an average daily consumption is 19,850 kWh/day. If storage was to be sized for 10%, 20%, and 30% of the average daily consumption, the capacities of the thermal storage systems would be 1,984 kWh (2,000 kWh), 3,969 kWh (4,000 kWh), 5,954 kWh (6,000 kWh), respectively.

Another strategy would be to size the thermal storage based on the average winter conditions. Using the time period of October 23 to February 28, the total thermal load is 2,381,600 kWh, and the total days is 129 days. Then, the whole winter's average daily consumption is 18,460 kWh/day If storage was to be sized for 10%, 20%, and 30% of the average daily consumption, the size of the thermal storage system is 1,846 kWh (2,000 kWh), 3,692 kWh (4,000 kWh), 5,538 kWh (6,000 kWh), respectively. This strategy results in the same size or storage capacity as the coldest month averages above.

A similar assessment was carried out to size TES for average winter plus spring operation (October 23-May 31), resulting in average daily consumption of 15,905 kWh/day. A comparison of these three sizing assessments is provided in Figure 9, indicating a TES system sized in the range of 1,000 to 6,000 kWh would be suitable based on daily averages.

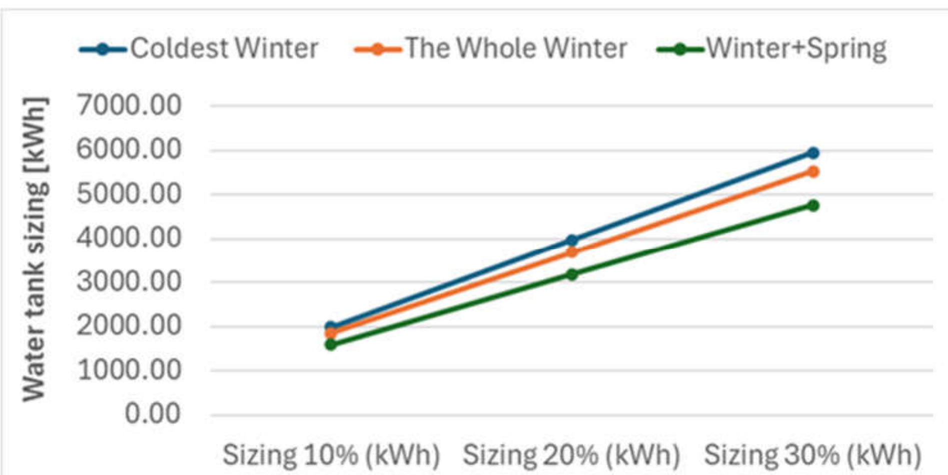

Figure 9 shows the water tank sizing for the above three cases.

Sizing Using Utility Peak Hour Thermal Load

Another strategy is to size the thermal storage based on loads during the peak time period as defined by the electric utility, which is weekdays, 4pm to 9pm from November to February[4].

Sizing based on the coldest 7 days was examined, using the coldest 7 days from February 22 to February 28, 4 pm - 9 pm. Figure 10 shows the thermal load from February 22-28 only for

[4] E.g. see https://www.bchydro.com/news/conservation/2026/thinking-about-time-of-day-pricing.html

peak hours. The total thermal load for the 7 coldest days is 42,416 kWh, then the average consumption is: 42,416 kWh/6 = 6,059 kWh, or roughly 6,000 kWh.

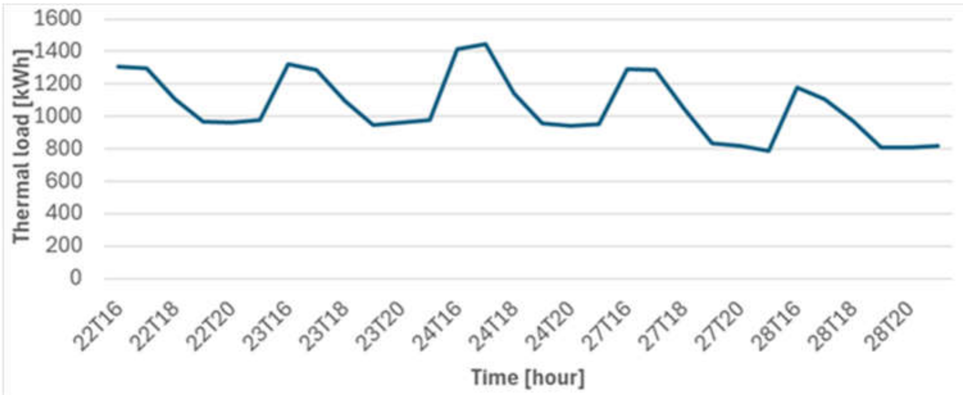

Figure 10. Thermal load from February 22-28, peak hours

Sizing based on the single coldest day is another strategy, which was February 24, 4 pm – 9 pm. The total thermal load for this period was 6,848 kWh, or about 7,000 kWh.

Yet another strategy would be to size the TES based on the entire month of February, Monday-Friday, 4 pm – 9 pm. Figure 11 shows the thermal load in February only for peak hours. The total thermal load for February is 96,628 kWh. Then the average daily consumption is 96,628 kWh /20 days = 4,831 kWh, around 5000 kWh.

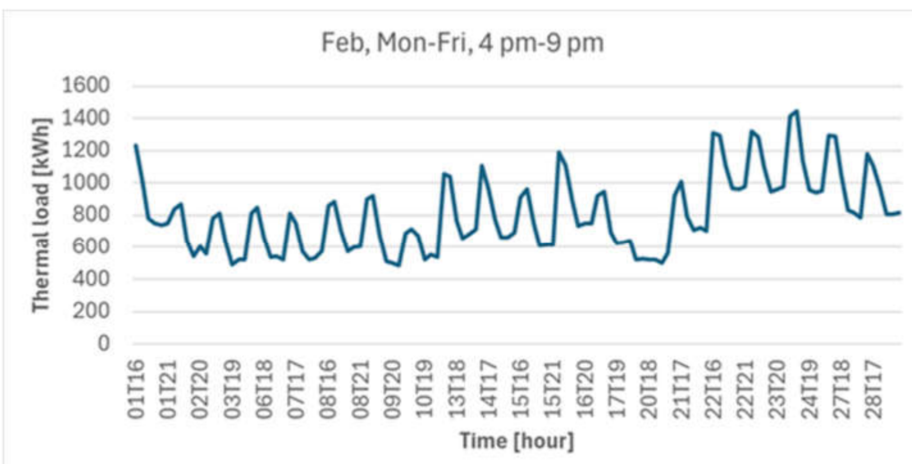

Figure 11. Thermal load for February, peak hours

Heating Water Temperatures and Flows

Supply and Return Temperature Analysis

An analysis of supply and return temperatures was conducted, which is useful to develop specifications for thermal storage. Figure 12 provides supply and return temperature for 2023, and the temperature differential is provided in Figure 13. We can see that the temperature difference in 2023 is approximately 5°C throughout the whole year. The maximum supply temperature is 88.4°C, and the maximum return temperature is 83.2°C. Figures 14 and 15 provide the percentage and number of hours of supply and return temperatures for different ranges in 2023. The same analyses were conducted for three additional years (2021-2024), with similar results.

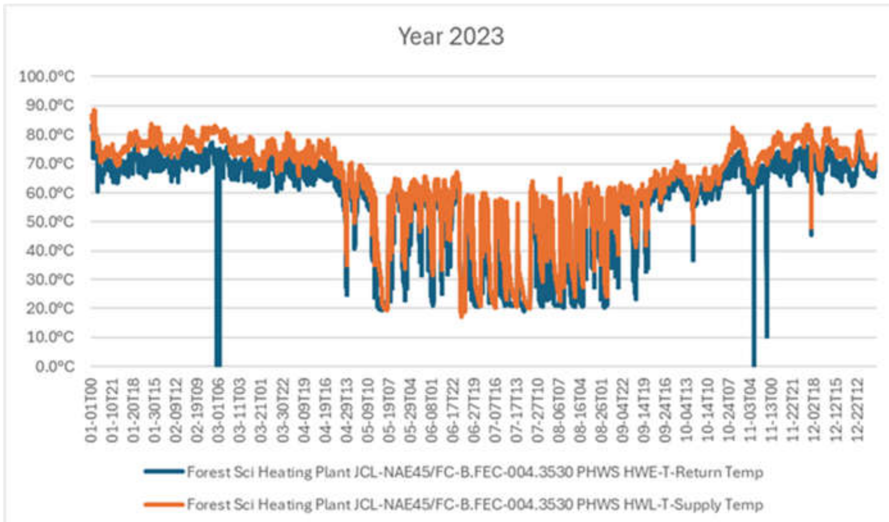

Figure 12. Supply and return temperature in 2023

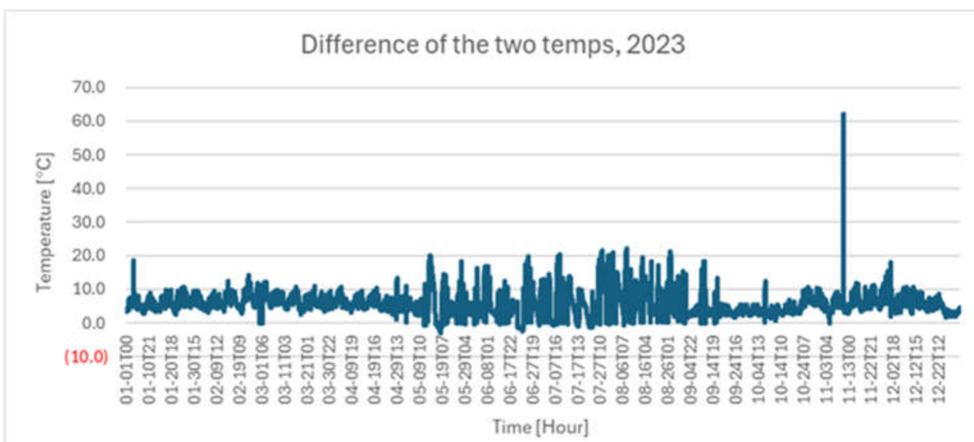

Figure 13. Difference of the supply and return temperature in 2023

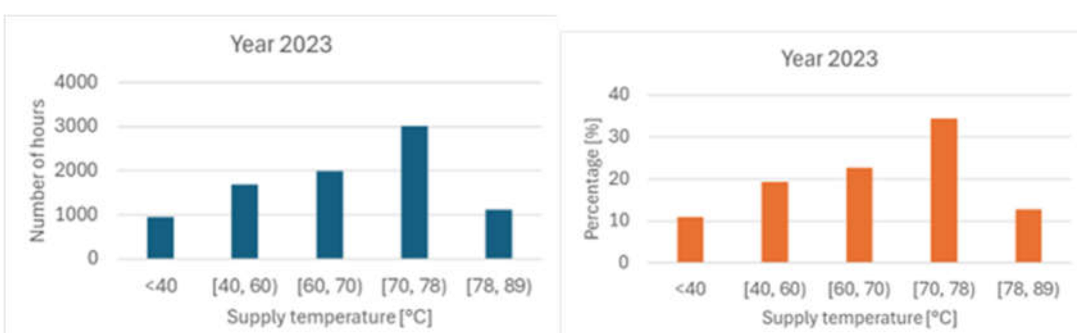

Figure 14. Percentage and number of hours of supply temperature in 2023

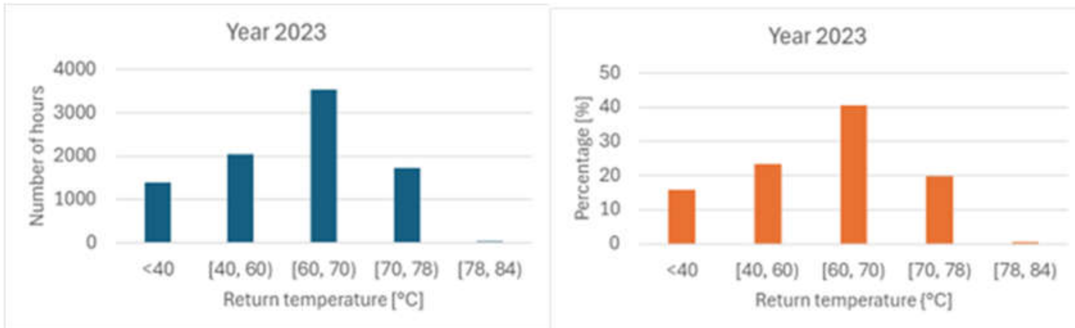

Figure 15. Percentage and number of hours of return temperature in 2023

An analysis of supply temperatures was also conducted for peak hours as defined by the electric utility (4-9pm, November to February, weekdays). Figure 16 shows the supply temperature for peak hours in 2023. It is between 65-85°C. After calculation, the 98th percentile of the supply temperature is 82.2°C.

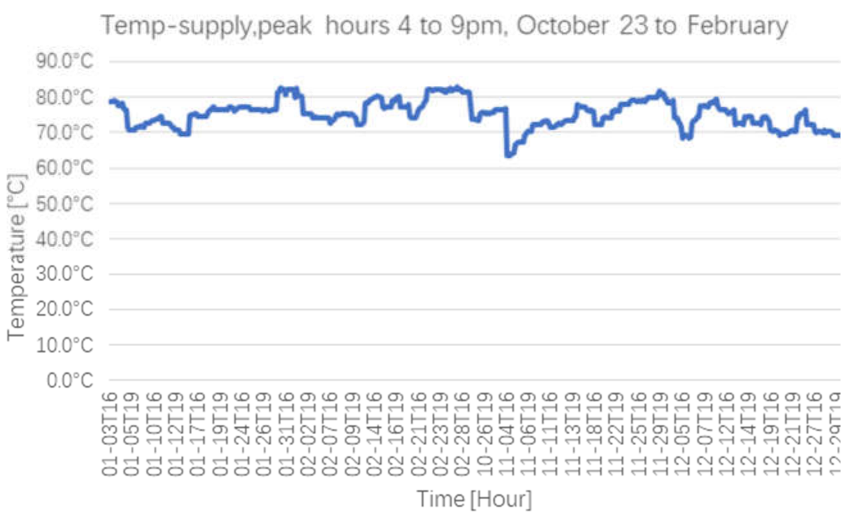

Figure 16. Supply temperature for peak hours in 2023

Hydronic Flow Rate Analysis

Besides supply and return temperature, flow rate was also assessed. In this section, the analysis is based on whole-day data. Figure 17 provides the average flow rate. The same analyses were conducted for other years from 2021 to 2024, with similar findings.

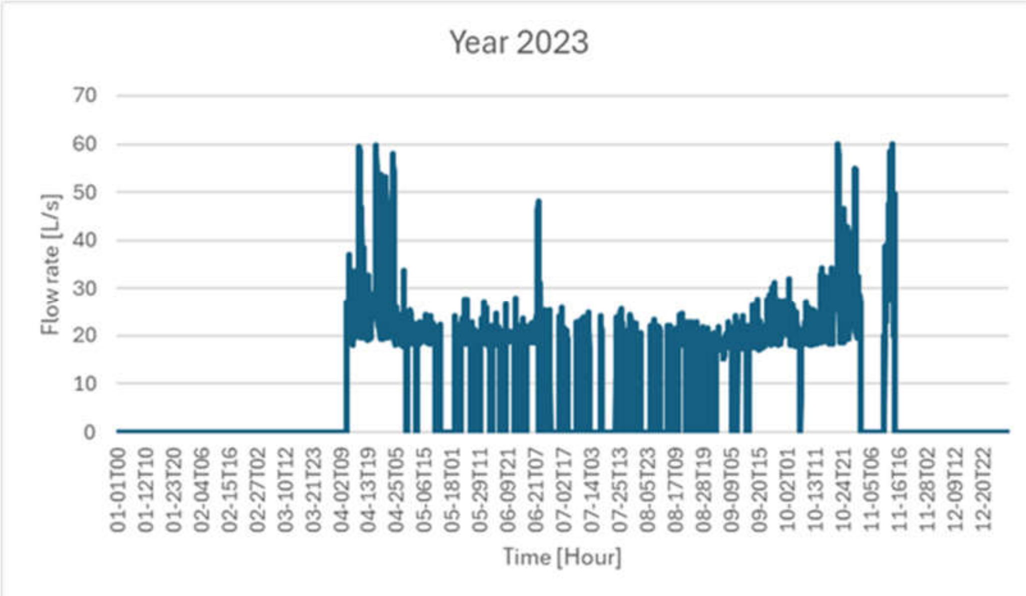

Figure 17. Flow rate data for 2023

Another approach was to analyze the flow rate only for peak hours. The calculated 98th percentile of flow rate is 29.5 L/s (approximately 30 L/s or 475 gallons per minute).

Thermal Load Shifting Analysis[5]

The primary strategy examined in the study is an analysis of load shifting (refer to Figure 2). By shifting thermal loads with an electrically-heated building, this effectively results in electric load shifting. The reason is that load shifting has the most value to the electric utility, and therefore customers such as the university are likely to be incentivized to shift electric loads based on the utility's peak period. Common incentives include rate incentives such as time-of-use rates (Badtke-Berkow et al. 2015) and subsidies such as critical peak rebates (Zinaman et al. 2017).

Two scenarios for using thermal storage were assessed: 1) shifting peak loads during the same time as the building peak electric loads to reduce peak electric demand charges, and 2) to reduce peak loads during the electric utility peak hours. In the scenarios, baseline is where the thermal load is supplied by an electric boiler with an efficiency of 99.5%. Baseline electricity consumption as follows:

Hourly baseline electricity consumed = Hourly building thermal load / Electric boiler efficiency (2)

Combining the electric boiler with thermal storage, round trip energy losses need to be accounted for. We assumed a round trip efficiency of 90% (Sadeghi, 2022). Then we can calculate the hourly electricity consumed by the system with thermal storage, illustrated by Equation (3).

[5] As stated in the introduction, all currency in this study is Canadian dollars as this case study is in British Columbia.

Hourly heating electricity consumed = (Hourly thermal load + hourly thermal energy charge – Hourly thermal energy discharge) / Electric boiler efficiency (3)

The electricity rate for this building is BC Hydro's large general service rate[6] $0.2882/day basic charge, $13.30/kW monthly demand, and $0.0653/kWh energy charge (rate as of 2025).

Shifting During Building Peak Pours (5am-2pm)

The peak hours of the Forestry Building are 5am to 2pm, which are quite different from the peak hours of the electric utility. Then, we apply a thermal storage system to shift the peak hours' load of the Forestry Building to 10pm to 3am as the demand response approach.

In this strategy, from 5am to 2pm, the thermal load of Forestry Building is supplied by the thermal storage system, which means that the thermal storage system is discharging. While from 10pm to 3am, when the load is off-peak, the thermal storage system is charged.

Simulations were run to compare the cost of baseline (electric boiler) and system with thermal storage (electric boiler + thermal storage) with the size of the thermal storage system. For this analysis, we chose a system capacity of 2,000 kWh thermal storage. The results are shown in Table 1 if the full capacity of 2,000 kWh is utilized, modelled as 100% thermal storage charge and discharge occurring each day. If full capacity could be utilized, the total cost saving in customer demand charges is estimated to be $8,088 annually. However, full capacity utilization throughout the year for multiple years is impractical. In the subsequent economic analysis, 75% utilization of thermal storage capacity for an average utility bill cost savings of $6,000 annually (value rounded to reflect appropriate accuracy).

Table 1. Shift during building peak hours: thermal storage vs. baseline with 2,000 kWh storage

Month	Baseline (electric boiler)				System with thermal storage (electric boiler + thermal storage)				Cost saving
	Energy cost	Monthly peak (kW)	Peak demand cost	Total cost	Energy cost	Monthly peak (kW)	Peak demand cost	Total cost	
November	$34,258	1,604	$21,333	$55,592	$34,696	1,403	$18,660	$53,356	$2,236
December	$33,967	1,443	$19,195	$53,161	$34,419	1,307	$17,377	$51,795	$1,366
January	$38,608	1,757	$23,365	$61,973	$39,060	1,556	$20,692	$59,752	$2,221
February	$38,244	1,849	$24,595	$62,839	$38,652	1,648	$21,922	$60,574	$2,265
Total seasonal cost saving									$8,088

Shift During Electric Utility Peak Hours (4pm-9pm)

The utility peak where this facility is located is 4pm-9pm weekdays. An alternative scenario was modelled where the customer is compensated for demand response during the utility peak period at a rate of $40 per kW reduced. This is within the range of published offerings for multiple utilities (e.g. National Grid in the U.S. and FortisBC and BC Hydro in Canada). With these programs, customers must participate in a minimum number of events per

[6] The Forest Science building is actually part of the campus-wide system which is a transmission service customer. The general rate schedule is assumed because a building of this type would commonly usually be in this rate class.

season. For this study, a 300 kW peak shift (300 kW is utilizing 75% of the full storage capacity, to be comparable to the utility peak demand savings scenario) was estimated to result in customer compensation of $16,000 per 4 months (November to February). This load shift could be achieved without affecting customer demand charges.

Life cycle economics estimates

As introduced in this study, the main technology examined in the design was PCM. Here we conduct an economic analysis of PCM technology based on peak demand charge savings for the customer, as well as a scenario where the customer is compensated as demand response. Table 2 provides technical and cost information for the PCM thermal storage technology used in this study.

Table 2. eSTOR ES100 Dual Loop Thermal Storage Module Specifications

Item	**Details**
Energy capacity	2,000 kWh
Power capacity each unit	100 kW (341,200 Btu/hr)
Dimensions (W x L x H)	61 cm x 183 cm x 152 cm (24" x 72" x 60")
PCM melting temperature	80°C (176°F)
Included features	- Dual loop - WiFi connection - Controller to break circuit when charged - Built-in freeze protection
Temperature Sensors	(4) Internal Media Temp Sensors
Flow Rate (DHW loop)	0 – 3.5 L/s (0 – 55 gallons per minute)
Flow Rate (heating loop)	0 – 4.7 L/s (0 – 75 gallons per minute)
Electrical	120/240 V, single phase, 50/60 Hz
PCM costs	$220,000
Ancilliary and installation costs	$550,000

For comparison to the PCM technology, we developed two additional technology comparisons:

- Hot water storage sized at 2,000 kWh (sensible heat storage at 5.0 ˚C ΔT design, 344 cubic meter volume, estimated capital cost $180,000)[7].
- Electric battery storage of 2,000 kWh, with capital cost estimate of $1,370,000 (cost based on lithium ion phosphate battery technology, per Cole and Karmakar, 2023).

As introduced above, two compensation scenarios were quantified for the 2,000 kWh systems: 1) annual savings of $6,000 (based on 75% of storage capacity utilized over the long term), and 2) annual compensation of $16,000 from a utility demand response program. The financial parameters applied were a 6.0% discount rate and 20 year project life (chosen because

[7] This cost estimate is based on a few Canadian case studies. E.g. see https://www.hydroquebec.com/business/energy-savings-business/projects-scenarios/commercial-project-4.html

the PCM is reported to have a 20 year equipment life). No capital cost incentive or subsidy was assumed to apply. The results of the analysis are provided in Table 3.

Table 3. Financial simulation results.

	PCM	Hot water	Electric battery
capital cost	$770,000	$180,000	$1,370,000
utility bill demand cost savings			
annual savings	$6,000	$6,000	$6,000
simple payback, years	128	30	228
net present value	-$701,000	-$81,000	-$1,301,000
utility demand response compensation			
annual savings	$16,000	$16,000	$16,000
simple payback, years	48	11	61
net present value	-$586,000	$4,000	-$1,186,000

Discussion

Based on this technical-economic analysis, the study demonstrates that cost savings on common utility demand charges do not justify investment in thermal storage as an electric demand response technology. Of course, this finding could have been anticipated with a much simpler back-of-envelope analysis.

One of the objectives of this study was to examine PCM as a thermal storage technology, based on some of the common advantages as highlighted in the introduction. The final results in Table 3 indicate that PCM technology, at least for this case study application, is much more expensive than conventional sensible hot water storage technology.

The somewhat unique contribution of this study is to provide a case study with realistic cost estimates for achieving the exact same electric load shifting with three different technologies: thermal storage with PCM, thermal storage with conventional hot water, and electricity storage with battery technology. The emphasis for electric utility load shifting is more often on electric battery technology, or directly modulating electric-driven equipment (Spendiff-Smith 2024). This analysis highlights that the use of thermal storage is technically viable for an electrically heated building, and that it is potentially cost effective, at least under the assumption that it would be compensated as a demand response technology (as indicated by a positive net present value for the hot water storage option). In reality, we are not aware of demand response programs or subsidies that identify thermal storage as an eligible technology. However, this analysis provides one case study indicating that demand response programs or subsidy policies could consider thermal storage where it can be directly used to shift electric demand.

Conclusions

This study examined one institutional building as a case study for using thermal storage as an electric demand response technology in British Columbia. PCM technology is considered to have advantages vs. conventional hot water storage such as smaller space requirements and the ability to engineer the melting temperature. However, this case study demonstrated that PCM is technically viable, but that it was much more expensive that conventional hot water storage. A comparison of thermal storage to electric battery storage revealed that thermal storage would be substantially lower cost, and could yield a positive net present value to the utility customer for this case study if it was compensated for the same demand response service. A strength of this study is that it is based on a real institutional facility (i.e. real thermal loads and realistic retrofit cost estimates). A limitation of this study is that it is one case study, and thus not necessarily generalizable. Nonetheless, the study does provide some evidence that thermal storage for electrically heated buildings may be much more cost effective as compared to electric batteries, and thus could be examined as an eligible technology for utility demand response programs or other demand response policies.

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