GT Flex: A Coordinated Multi-Building Pilot Study

Ryan Meyer,[1] Brett Bridgeland,[2] Korbaga Woldekidan,[1] Brett Webster,[2] Tanushree Charan,[1] Jung-Ho Lewe,[3] Victor Olgyay,[2] and Sarah Zaleski[4]

1 National Renewable Energy Laboratory
2 Rocky Mountain Institute
3 Georgia Institute of Technology
4 U.S. Department of Energy

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Technical Report
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List of Acronyms

BEM	building energy model
CVRMSE	covariance of root mean square error
DER	distributed energy resources
DERMS	Distributed Energy Resource Management System
DOE	U.S. Department of Energy
GHG	greenhouse gas
GIT	Georgia Institute of Technology
HVAC	heating, ventilating, and air conditioning
NDA	non-disclosure agreement
NREL	National Renewable Energy Laboratory
PV	photovoltaic
RSS	residual sum of squares
RTP	real-time price
RTU	rooftop unit

Executive Summary

Buildings are a significant and untapped resource for providing utility electric grid services. Recent studies have estimated that buildings could reduce peak demand on the electric grid in the United States by almost 25% through effective combinations of energy efficiency measures and load flexibility strategies (Langevin et al. 2021). The U.S. Department of Energy (DOE) has established a goal to triple energy efficiency and demand flexibility in both residential and commercial sections by 2030 compared to 2020 levels (Satchwell et al. 2021). Such findings place buildings alongside electric vehicles, photovoltaics, electric batteries, and other distributed energy resources (DERs) as primary technologies needed for supporting high renewable energy generation grids.

Coordinating and optimizing multiple buildings and other DERs is more beneficial and valuable when compared with individual buildings and DERs operating as siloed resources, uncoordinated with others (Olgyay et al. 2020). Ultimately, impact to the electric grid is an aggregate of connected loads and resources. As we look toward a future grid of renewable electricity generation, balancing and offsetting the variability in generation of renewable sources requires coordination and control of connected assets.

This report presents findings from a pilot study at the Georgia Institute of Technology (GIT). The study evaluated value propositions of a multi-building-scale project seeking carbon reduction, energy efficiency, and grid-interactive capabilities by demonstrating how stakeholders can model the technical and financial merits of grid-interactivity and energy efficiency technologies coordinated across multiple assets.

The study focused on analyzing technical and economic feasibility of deploying thermal load flexibility strategies at the multi-building scale, coordinated to not exceed existing infrastructure constraints at the pilot site. In other words, this study evaluated the potential resource that exists today. Modeled results show that GIT can provide 3–3.5 MW of potential campus-wide load shed over a 4-hour event window through coordinated dispatch of thermal cooling load flexibility between multiple building and central plants without exceeding existing infrastructure capacities or exceeding occupant thermal comfort bounds. Under future high-renewable scenarios, this thermal flexibility resource is also valuable when coordinated to reduce curtailment of intermittent renewables.

The research team collected data for building load profiles when thermal load flexibility strategies were deployed, increasing available data for continued research. Data show that the building electric load can be reduced by 30%–50% across a defined 3- to 4-hour window for select pilot site buildings under various thermal load shifting scenarios.

The team performed economic analyses to effectively communicate various value propositions of grid-interactive efficient building thermal flexibility strategies. Load flexibility presents a financial value proposition to campuses today. By conducting rationalized, coordinated dispatch in response to real-time-price (RTP) fluctuations, the campus can benefit materially from daily price arbitrage. The RTP signal acts as an aggregating mechanism between the utility and customer to call on-demand flexibility resources, with a large portion of the benefit deriving from a relatively small number of days. Realizing and maximizing this benefit with thermal load flexibility requires careful attention to the timing of pricing signals and parameterization of dispatch to overcome efficiency penalties. Grid value and signals are expected to evolve over time, and thermal load flexibility shows potential to adapt dispatch logic to support intermittent renewable generation.

Ultimately, a primary objective of this pilot study is to present a conceptual and foundational framework to assist future multi-building-scale projects to assess the technical and financial merits, challenging our conventional approach to building infrastructure and working toward unlocking a greater potential of greenhouse gas and carbon reduction, energy savings, and enabling renewables on the future grid.

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1 What We Are Looking to Understand

Collections of buildings and distributed energy resources (DERs) that incorporate integrated energy management strategies at the multi-building scale can reduce energy costs, provide flexibility for various grid operations and scenarios, and offer alternative options for meeting greenhouse gas (GHG) emissions goals (Olgyay et al. 2020). Previous work explored many factors influencing multi-building-scale projects and qualitatively analyzed the potential value these projects have over traditional building-by-building approaches. Through this effort, a number of technical and market challenges were identified as potential barriers for more widespread adoption of coordinated multi-building and multi-asset projects.

This study set out to quantitatively evaluate specific value propositions of coordinating the dispatch of thermal load flexibility across multiple buildings on the Georgia Institute of Technology (GIT) campus. The team evaluated the technical and financial merits of grid-interactivity and energy efficiency technologies coordinated across multiple buildings in an effort to address some of these identified challenges hindering market transformation. Key research questions are discussed in this section, and associated pilot study activities and findings are described in Sections 2 and 3.

1.1 How Do Coordinated Multi-Building Projects Provide Greater Value Compared to Typical Building-by-Building Approaches?

A fundamental hypothesis behind coordinated multi-building projects is that multi-asset optimization of grid resources provides greater value than the sum of individually optimized assets. In other words, there are synergies gained through coordination of assets instead of simply allowing individual buildings or resources to act independently from one another. The coordination of buildings and DERs, like a demand response program, becomes a dependable and large enough resource that it can be deployed and/or procured with appropriate utility value.

Similar deductions can be made associated with shared, or community-scale, assets. For example, physically connected and shared resources—including on-site generation, energy storage, and thermal systems—can take advantage of the load diversity of connected buildings, resulting in higher utilization per unit of installed asset capacity.

This pilot study at GIT focused on a set of specific campus resources and infrastructure to analyze the impact of coordinated multi-building grid-interactive strategies including:

- Thermal system load flexibility strategies
- Individualized versus aggregate optimization
- Thermal system load flexibility strategies in high-photovoltaic (PV)-generation scenarios.

In particular, the pilot study assessed thermal system load flexibility at the individual building level and at the multi-building scale to understand the potential for providing grid services utilizing existing resources on campus. Strategies were assessed through experimental implementation at the individual building level, and through physics-based energy modeling and simulation methodologies ranging in scale from the building to the campus level.

Coordinating the dispatch of thermal system load flexibility across multiple buildings was also analyzed specific to the customer utility rate structure. This included considerations around existing infrastructure, in particular the district cooling systems where multiple buildings provided thermal system load flexibility in aggregate without exceeding capacity limitations of the shared system infrastructure.

Lastly, this study assessed how the load flexibility value proposition might change in a hypothetical, highly renewable electricity supply scenario, testing dispatch optimization in a system with a large amount of intermittent and otherwise-curtailed solar generation. This scenario represents the future opportunity to aggregate load flexibility behavior in response to aggregate supply-side conditions, in this case effectively using price arbitrage from low-cost solar as the organizing mechanism.

1.2 What Value Propositions and Financial Drivers Create Successful Multi-Building-Scale Projects?

Previous work summarized various value propositions and financial drivers that create successful implementations of coordinated multi-building-scale projects (Olgyay et al. 2020). This was assessed primarily through stakeholder interviews and inventory of ongoing multi-building-scale projects in the United States. Table 1 provides a summary of customer and utility benefits identified.

Table 1. Potential Value of Coordinated Multi-Building Approach

Source: Olgyay et al. (2020)

Customer Benefits	Utility/System Operator Benefits
• Capital expenditure (CAPEX) savings • Energy bill savings: energy efficiency • Energy bill savings: rate switching/arbitrage • Energy bill savings: demand charge reduction • Grid services: demand response/ancillary services • Resilience • GHG reduction goals	• Reduced capacity requirements for generation and transmission and distribution infrastructure • Streamline energy efficiency program delivery • Increased reliability • GHG reduction goals

The previous effort focused on qualitatively identifying a comprehensive set of value propositions, with any one project not necessarily realizing the entire list. Instead, this pilot study set out to quantitatively evaluate value propositions specific to the customer, utility, and project site.

The study took into consideration the specific utility rate structure and customer goals. Value propositions were quantified for customer energy savings, opportunities, and current value for providing grid services with assets in place now (thermal load flexibility). This pilot study also evaluated the hypothesis that thermal flexibility resources deployed across multiple buildings at the pilot site could reduce curtailment of intermittent renewables in high-renewable-generation scenarios in a market currently absent of commercial net energy metering.

1.3 What Are Techniques for Evaluating Trade-Offs Across Multiple Buildings?

Techniques for evaluating cost, carbon, and energy impacts for an individual building considering energy efficiency, generation, and electrochemical (battery) storage are well practiced today. Building energy models (BEMs) provide physics-based calculation tools to parametrically evaluate design and engineering decisions.

URBANopt™ was used in this study to evaluate multiple buildings and district thermal plans on GIT's campus. URBANopt is an advanced analytics platform for high-performance buildings and energy systems within one geographically cohesive area (Polly et al. 2016). URBANopt leverages the OpenStudio® and EnergyPlus™ modeling ecosystems, which are U.S. Department of Energy (DOE) open-source BEM tools (El Kontar et al. 2020).

Coupling the technical analysis of BEMs with financial metrics for capital investment options provides a standardized approach to industry that is widely accessible. Although physics-based BEMs provide the environment for evaluating thermal load flexibility strategies, there is limited existing information for practitioners to reference, and methodologies or metrics for evaluating such strategies are beginning to be created and standardized.

For projects considering behind-the-meter energy generation and storage, optimization and integration platforms such as REopt™ provide planners with optimal sizing and dispatch of DERs to achieve carbon, energy, and cost reduction goals integrated with a building load profile (Cutler et al. 2017).

In addition, there are many developments in urban planning, including electrical distribution and infrastructure design, that provide platforms for planners and designers to consider how communities and urban districts with DERs can be effectively designed, operated, and regulated as more and more energy generation is shifting toward renewable sources. Significant work has shown the potential for zero-energy districts (ZEDs), or those with zero carbon focus, to enable greater renewable generation opportunity and provide district-scale analysis processes to leverage for evaluating multi-building projects with coordinated assets (Doubleday et al. 2017, 2019).

A guide to master planning communities and urban districts was published in 2020, providing a framework for successful implementation of multi-building-scale high-performance strategies including methodologies for evaluating the technical and financial drivers (Pless et al. 2020). This pilot study leveraged this work for evaluating the technical and economic impact to develop a methodology for evaluating thermal system load flexibility coordinated at the multi-building scale and to evaluate specific value propositions from both the customer and utility perspective.

1.4 What Are Successful Methods to Implement and Scale Coordinated Multi-Building Projects?

There are a number of market challenges that potentially limit the ability for multi-building-scale projects to leverage the full extent of associated value propositions. These range from utility rate structures and incentives, associated local and regional regulations, a lack of standardized approaches for identifying and valuing energy resilience investments or other utility cost benefit scenarios, in addition to the added complexities of multiple stakeholder engagement compared with traditional building-by-building design approaches (Olgyay et al. 2020).

This study developed and evaluated several methods to streamline multi-building coordination:

- Characterizing and quantifying load flexibility resources for a coordinated set of buildings
- Using investigative modeling to isolate and parameterize the particular load flexibility value proposition
- Leveraging a price signal as an intrinsic aggregator mechanism, to the mutual benefit of customers and utilities.

2 What We Did

Section 2.1 outlines the pilot site chosen for the feasibility study, including physical characteristics and existing campus infrastructure as well as qualitative characteristics such as customer rate structures, carbon goals, and other campus planning considerations. The methodology developed to analyze the specific value propositions is summarized in Section 2.2.

2.1 Our Pilot Site

The GIT campus in Atlanta, Georgia, was selected for this feasibility study. The campus has more than 250 buildings and two central plants that provide campus chilled water and steam for a large portion of campus buildings. The pilot study focused on a specific subset of campus buildings for detailed thermal evaluation and thermal resource dispatch under various rate scenarios. Impacts of thermal resource dispatch were also scaled to evaluate campus-wide potential and the associated value to customers and utility stakeholders.

In coordination with a parallel research effort between Southern Company (SC) and GIT, 18 campus buildings were selected for detailed thermal evaluation. The subset of campus buildings was selected to include the following key characteristics:

- Diversity of building types and associated load profiles representative of campus as a whole
- Diversity in building vintages
- Diversity of HVAC systems, including on-site heating/cooling systems and central plant coupled systems
- Buildings with suitable controls infrastructure for future implementation of supervisory coordinated control over HVAC load flexibility.

Installation of a supervisory coordinated control system was outside the scope of this pilot study. However, results and key findings from this effort may be used to support future infrastructure upgrades on campus, including supervisory controls to coordinate dispatch of thermal load resources across multiple buildings. A summary of the buildings chosen for detailed thermal modeling as part of this study are shown in Table 2.

Table 2. Summary of Selected Campus Buildings for Detailed Analysis

Building Type	Vintage	Conditioned Floor Area [sqft]	Cooling Source	Heating Source	HVAC System*
Mixed Use	1959	108,288	Central	Central	FCU
Office	1924	127,477	On-site	On-site	VAV
Mixed Use	1920	62,262	Central	Central	VAV
Office	1955	10,019	On-site	On-site	VRF
Office	1967	43,182	Central	Central	CAV
Mixed Use	1969	98,291	Central	Central	VAV
Mixed Use	1998	28,954	On-site	On-site	RTU
Education	2002	230,798	Central	On-site	VAV
Mixed Use	2006	184,613	Central	Central	VAV
Education	2011	188,000	Central	Central	VAV
Education	2006	232,129	Central	On-site	VAV
Multi-Family	2004	27,350	Local plant	Local plant	FCU
Multi-Family	2004	26,182	Local plant	Local plant	FCU
Multi-Family	2004	29,759	Local plant	Local plant	FCU
Mixed Use	2015	178,798	Central	On-site	VAV
Mixed Use	2012	36,310	On-site	On-site	VAV
Office	2019	46,006	Central	Central	VAV
Education	2019	31,514	Central	Central	VAV

*FCU = fan coil unit, VAV = variable air volume, VRF = variable refrigerant flow, CAV = constant air volume, RTU = rooftop unit

Figure 1 shows a campus map with the 18 campus buildings and 2 central plants selected for detailed thermal modeling and analysis.

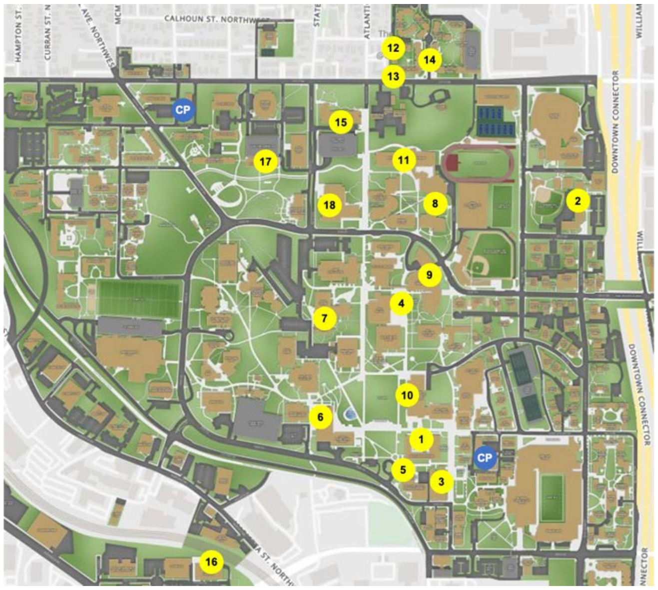


Figure 1. Campus map showing buildings and central plants for detailed modeling and analysis

The majority of GIT's main campus operates under a single substation, with three major Southern Company electric meters that are combined for billing. All load shaping activities are therefore inherently aggregated to the campus level for utility billing, allowing the campus to optimize synergistic dispatch among campus buildings and central plants. As a large consumer, GIT subscribes to a specialized rate structure. A significant portion of the campus electricity consumption falls under a customer base load, which defines an 8,760-hour annual campus load profile that will be met at an agreed-upon price for the entire year. That component of load and cost is effectively fixed prior to the start of the year, providing GIT a degree of energy cost predictability. Permanent improvements such energy efficiency or behind-the-meter solar would likely impact the customer base load in subsequent years.

Within a given year, all electricity consumption above the customer base load profile is then billed at an hourly-varying real-time price (RTP). The RTP is the electricity price on the margin at all times, so this becomes the focus of any load flexibility dispatch decisions. Southern Company communicates hourly RTP estimates one day ahead of time, then locks the precise price one hour ahead. Southern Company serves GIT as a vertically integrated utility in Georgia, so for purposes of time-specific GHG emissions analysis, this study uses utility-specific historic electricity grid emissions rates compiled by WattTime (WattTime 2021).

2.2 Our Methodology

This section provides an overview of the methodologies used to create physics-based BEMs to explore the impact of load flexibility strategies and associated financial implications and business models to drive successful implementation for the pilot site. Section 2.2.2 summarizes the calibration methodologies developed as part of this pilot study.

2.2.1 Buildings and Central Plant Models

URBANopt was used to simulate the energy consumption of the pilot buildings. URBANopt has been applied in a number of studies evaluating community-scale scenarios for energy efficiency, DERs, and other urban planning activities (Doubleday et al. 2017, Houssainy et al. 2020).

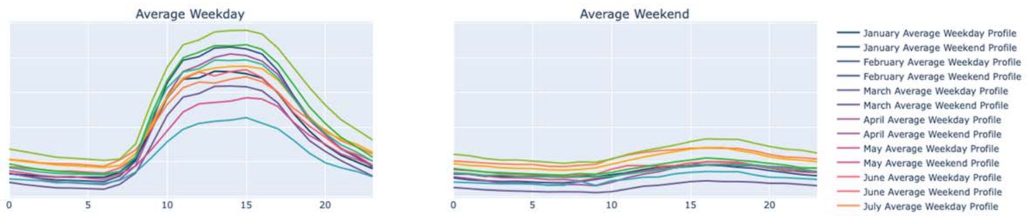
The primary input file for the URBANopt workflow is a GeoJSON input file containing information about each feature (building, central plant, etc.). An available GIT campus GeoJSON file was used as the starting point, along with additional information provided by GIT Facilities. A preprocessing script was developed to insert all additional characteristics into the campus-provided GeoJSON file in order to create the URBANopt features for the 18 buildings and two district plants. This study also leveraged model articulation methods and OpenStudio standards assumptions to generate BEMs as a starting point, after which a number of calibration steps were performed. Individual custom calibrated BEMs were not available for every campus building and were outside the scope of this feasibility study.

Campus central plant energy models were created in the same URBANopt workflow, and GIT facilities provided information regarding number of chillers, cooling towers, tonnage, and typical operating ranges. Plant-level metered electricity data was also made available including electricity and tonnage.

2.2.2 Model Calibration

Model calibration was a critical step before using BEMs to represent existing campus infrastructure and to evaluate technical merits of various strategies. Calibration against a long time period (e.g. multiple years of building-level and plant-level data as used for this study) helps tune the assumptions and minimize the differences between simulation predictions and measured data, thus generating a credible model. The calibration process for this pilot study had two main steps. The first calibration step adjusted high-level building parameters including hours of operation, seasonal occupancy patterns, HVAC operational schedules, night-time setbacks, weekend usage schedules, and thermal capacitance by creating scripts added to the URBANopt workflow.

Figure 2 shows the hours of operation preprocessing results for one of the 18 buildings as an example. Hours of operation for each building were extracted from the building-level utility metered electricity data through a residual sum of squares (RSS) linear regression analysis based on the assumption that average daily building load profiles contain distinct hours of high electric demand and distinct hours of low electric demand.



Month	Occupancy Start	Occupancy End
January	9	18
February	9	18
March	9	18
April	9	18
May	9	18
June	9	18
July	9	18
August	9	18
September	9	18
October	9	18

Month	Occupancy Start	Occupancy End
January	12	20
February	12	20
March	12	20
April	12	20
May	12	20
June	12	20
July	12	20
August	12	20
September	12	20
October	12	20

Figure 2. Hours of operation RSS analysis for one pilot study building

Other high-level building parameters, including seasonal occupancy patterns, HVAC operational schedules, night-time setbacks, weekend usage schedules, and thermal capacitance, were extracted through data analysis and GIT facilities operational information and used as inputs to the URBANopt workflow.

After the first calibration steps were complete, the URBANopt model was simulated to create annual load profiles for each building. Then a second, more detailed calibration process was used to more finely tune additional model parameters. Sub metered building-end-use electricity data were only available for a select few of the pilot study buildings. Therefore, the calibration process focused on whole-building electric metered data that was widely available for all pilot buildings. Calibration maintained proportions of interior lights and electric equipment power reductions during the second more detailed calibration step because sub metered data were not widely available.

Building simulation results from the first calibration step were compared against the measured utility metered kWh values. An optimization approach with the objective of minimizing the coefficient of variation of the root-mean squared error (CVRMSE) between simulation and metered data adjusted the model input values for the interior lights and electric equipment, while taking into consideration the effects these changes have on fan energy for both buildings connected to a central plant and those with stand-alone heating and cooling sources.

A similar process was applied to compute nighttime adjustments on interior lights and electric equipment model inputs so that the minimum kWh consumption for each day would closely align with measured utility data. Figure 3 compares the aggregated 18 building modeled electric profiles before and after calibration against available metered data for three consecutive weekdays in June.

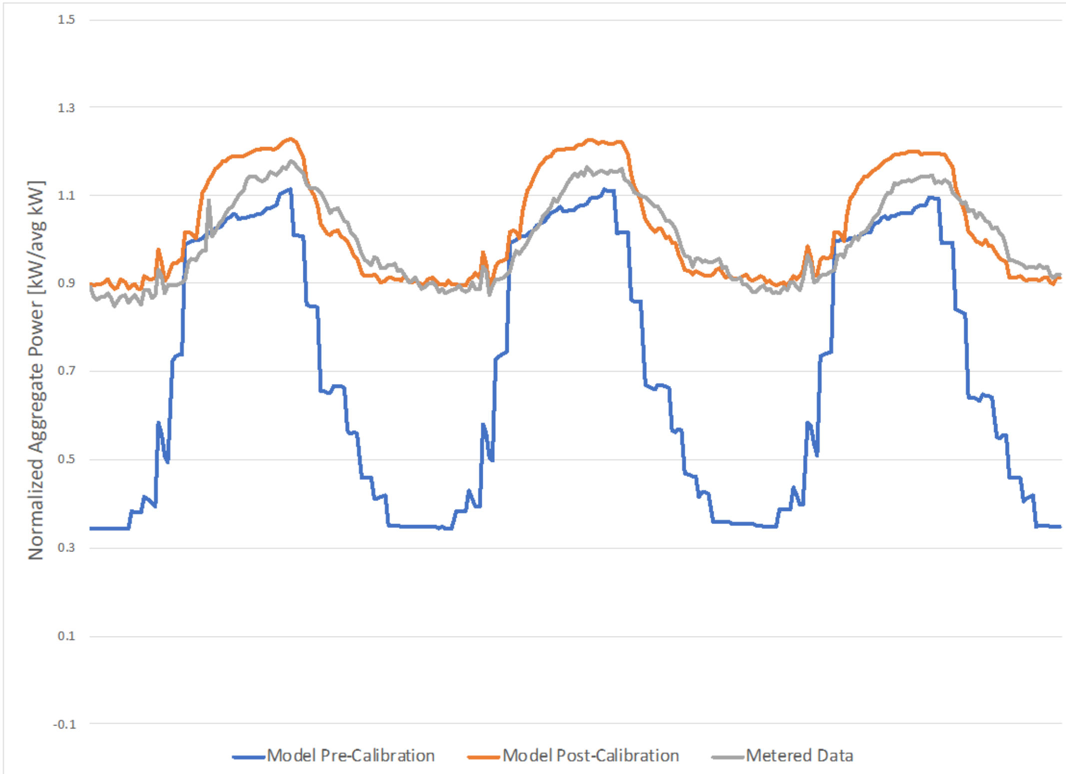


Figure 3. Two-step calibration results for aggregated building profiles

For the three consecutive example days shown in Figure 3, the post-calibration model aggregated results overestimate the load compared with the metered data. However, this is not a consistent pattern as there are days throughout the simulation year where the post-calibrated model underestimates the load compared to the metered data. All modeled buildings in which at least a full year of metered building-level utility data were available yielded a CVRMSE below 25%, indicating good model fit per ASHRAE Guideline 14, with values as low as 4%. A full year of metered building-level data were not available for the two campus buildings whose construction was completed in 2019.

It is important to point out that this study leveraged existing model articulation methods and OpenStudio standard assumptions to create the initial BEMs before calibration. These methods have explicit definitions that can be leveraged to create a number of prototypical commercial buildings (offices, hotels, warehouse, etc.) but do not have an explicit definition for a university building. University buildings often have customized programs to meet needs of campus (classrooms, labs, office space), and a building's programmed usage is a key driver for energy consumption. As such, the primary contributor for the discrepancies observed in the uncalibrated model results shown in Figure 3 as the Model Pre-Calibration aggregated profile were the assumed building usage definitions used as a placeholder to generate many of the 18 campus BEMs. A weighted average of office and classroom space types was assumed for the initial BEM creation, and then further refined through calibration steps. Therefore, the initial uncalibrated profile should not be considered a reflection in accuracy of the URBANopt model or associated model articulation methods within OpenStudio standards. The calibrated URBANopt model for the 18 buildings is used as the baseline for scenario comparison.

2.2.3 Thermal System Load Flexibility Modeled Strategies

A primary objective of this pilot study was to present a framework for assessing the technical and financial merits of multi-building-scale projects to assist future developers and stakeholders. As such, a set of strategies was selected to evaluate various value propositions at the chosen pilot site. The strategies evaluated focused on thermal system load flexibility dispatched across multiple buildings. All strategies were constrained to not exceed occupant thermal comfort bounds during various load flexibility scenarios.

Based on evaluation of the utility rate structure, it was determined that the thermal system load flexibility strategies should focus on shifting thermal cooling load. Although there is a high demand period on the electric grid during the January peak heating season, most heating load on campus is served by fuel sources (primarily natural gas) and thus is not considered for electrical load shifting potential in this study.[1] Thermal system cooling load flexibility strategies modeled included:

- Floating Strategies: Building-level thermostat cooling setpoints are forced into an unoccupied, or setback state, for a specific event period
- Precooling Strategies: Buildings are precooled to a lower cooling setpoint ahead of a specific event period, and then return to normal operation
- Precooling + Floating Strategies: Buildings are first precooled to a lower cooling setpoint ahead of a specific event period, and then thermostats setpoints are forced into unoccupied, or setback state during the event period.

These strategies were parametrically modeled in multiple URBANopt scenarios with parameters including cooling setback temperature and precooling temperature evaluated at multiple thresholds. Scenarios included 2°–4°F thermostat setbacks and for load shift events 2°–4°F precooling. Precooling occurred 1–2 hours ahead of primarily load shed events. The purpose behind this parametric analysis was to provide bounds for how much cooling load could shift for the various buildings.

Actual campus building thermostatic setpoints vary by building and zone, and a detailed audit was outside the scope of this study. Also, detailed audits of zone-level airflow under various cooling conditions were outside the scope of this study. Assumptions were made for average occupant metabolic rate (1.3 met) and clothing levels (0.65 clo) so that the upper bound of thermostat setpoint shifting of 4°F above or below setpoints in the modeled buildings was within acceptable operative temperature ranges assuming the average air speed was 20 fpm and there was not local control for airflow (ASHRAE 2017). Future research could focus on control schemes capable of dispatching thermal flexibility not only at the building level, but even down to the zone level in coordination with known campus classroom schedules. For the purposes of this feasibility study, the upper bound of 4°F of thermostat setpoint shifting was assumed reasonable to understand the technical and economic merits.

[1] Although heating electrification was beyond the scope of this study, it could be an important topic for future study, characterizing winter peak demand impact and load flexibility potential.

Figure 4 shows the effect of various modeled strategies on the building load profile for one of the 18 buildings. Figure 4 compares the modeled load profiles of a single day under the various scenarios to quantify and bound the potential for cooling load thermal flexibility.

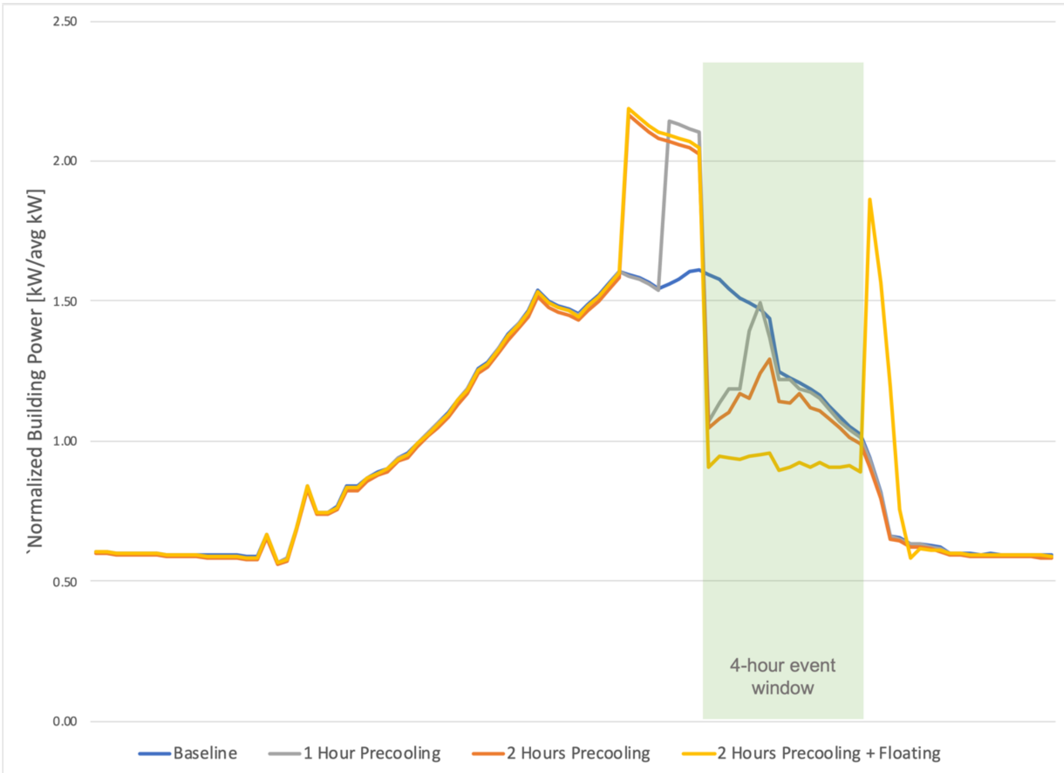


Figure 4. Normalized building load profile comparison for various thermal flexibility strategies for one pilot study building

The baseline scenario shows the predicted load profile when no precooling or floating is assumed. The precooling scenario profiles show a spike in energy consumption compared to the baseline for 1 or 2 hours ahead of the primary event window. Then the precooling scenario profiles are below the baseline at the start of the event window, and slowly rise at differing rates due to various zones requiring cooling.

The combined precooling and floating scenario generally follows the precooling scenarios during the precooling period, then shows reduced load during the primary event window (floating period) compared to the precooling scenarios. This is primarily due to the fact that the combined strategy allows the zone temperature setpoints to float to a greater extent following the precooling window, as opposed to the precooling strategies where zone temperature float only back up to normal thermostat setpoints. The combing precooling and floating strategy is able to maximize load reduction across the 4-hour window, but it exhibits a rebound spike in energy consumption after the floating period as buildings return to normal operation.

Two hours of precooling buildings up to 4°F enabled a full 4-hour load shed event duration. This strategy was carried forward to look at campus-wide impacts as an upper bound for the value of dispatching load flexibility for various grid services at the campus scale. This strategy was used for a variety of additional scenarios and results discussed in Section 3.

2.2.4 Campus-Wide Models

Developing detailed thermal models for all 250+ campus buildings was outside the scope of this pilot study. Results from the detailed 18 buildings and associated impact on central plant cooling profiles were used to assess the potential impact of campus-wide deployment of thermal load flexibility measures. Various cooling load profiles were generated for the scenarios of thermal load flexibility as input to the two campus district physics-based models. Calculated campus plant electric load profiles under various thermal load flexibility scenarios were then aggregated with building electric profiles to construct campus-wide profiles.

2.2.5 DER Optimization Models

XENDEE was used to assess the economic and GHG value of the load flexibility measures described above. XENDEE is a microgrid decision support software that optimizes investments in DERs according to financial and environmental objectives. It was selected for this study because of its capability to optimize dispatch of load flexibility resources across multiple buildings, by end use, alongside investments in other DERs such as solar PV and energy storage. It is also capable of power flow analysis, although this was beyond the scope of this pilot study. XENDEE is a commercially available software (Microgrid Decision Support Platform) that is built on the Distributed Energy Resource Customer Adoption Model (DER-CAM) model first developed at Lawrence Berkeley National Laboratory (Distributed Energy Resources Customer Adoption Model).

We built an 18-building model in XENDEE, with each building represented as a separate "node" with a unique load profile and flexibility parameters. XENDEE uses a "day-type" input data configuration, where load, utility rate, emissions intensity, and flexibility parameters are defined for a representative week, peak, and weekend day for each month. Load flexibility parameters were generated with URBANopt by running the precool and load shed measures on each building for representative week, peak, and weekend days in each month. These flexibility inputs were then input into XENDEE, along with the GIT rate schedule, location-specific hourly marginal electricity emissions rates, solar PV resource and cost data, and battery energy storage resource and cost data. The team was not able to acquire definitive cost data for the DERMS controls needed to coordinate flexibility dispatch across the 18 buildings, and therefore for the purpose of the XENDEE dispatch study were assumed to be zero, with the intention that the value generated from coordinated controls could theoretically be used to identify the cost-effective price point of the controls.

XENDEE was then used to generate the optimal dispatch strategy for load flexibility across the 18 buildings with and without the presence of PV and battery storage. Maximizing net present value across an analysis period of 30 years was the primary objective function, although co-optimization of net present value and GHG savings was also explored. Importantly, the building physics and thermal response are not explicitly modeled in XENDEE, so the resulting "optimized" load profiles were subsequently validated for their thermal behavior using URBANopt.

For the campus-wide models, a single load profile was input into XENDEE to represent the entire campus. Optimal solar PV sizing and load flexibility dispatch were assessed for a variety of campus-wide scenarios using this approach.

3 What We Learned

This section summarizes key findings from this study.

3.1 Key Finding 1: Individual Campus Buildings Can Provide Significant Load Shed Through Thermal Load Flexibility

Measured data from experiments conducted at select GIT campus buildings as part of this study show 30%–50% electric load reductions during targeted event windows, typically 1–3 hours, using thermal flexibility strategies. Limited studies exist focusing on technical evaluation or measurement of thermal flexibility strategies and their impact on building electric load profiles for commercial buildings. Keskar et al. (2020) performed experiments on three commercial buildings where building thermostats were perturbed to provide thermal load flexibility, and researchers measured the impact on whole building electric load to evaluate the potential for grid services. Their findings suggest that the available thermal inertia is an untapped but viable resource for providing grid services with little impact to occupants, but further research is needed. Opportunities to improve access and use of demand flexibility data sets for commercial buildings is a top recommendation in DOE's recent grid-interactive efficient building roadmap publication (Satchwell et al. 2021).

A key activity of this study involved collecting experimental data on campus buildings when load flexibility strategies were deployed. Due to unoccupancy of campus buildings during the COVID-19 pandemic, researchers at GIT performed thermal load flexibility experiments on select campus buildings without a potential concern of impacting thermal comfort of students and staff. Electrical response at the building level, and sometimes major equipment or terminal unit, was measured along with interior thermal response.

Multiple strategies were evaluated at a series of campus buildings and were implemented through schedule overrides of building automation system setpoints. Strategies evaluated included resetting building setpoints to unoccupied states in order to shed cooling load. Unoccupied states induced through the building automation system widened the temperature bias around the setpoint from +/-2°F during occupied states to +/-9°F for unoccupied. This strategy was implemented for 3 hours both in morning and afternoon. Figure 5 shows results comparing two consecutive days, one where an afternoon load shed experiment was carried out.

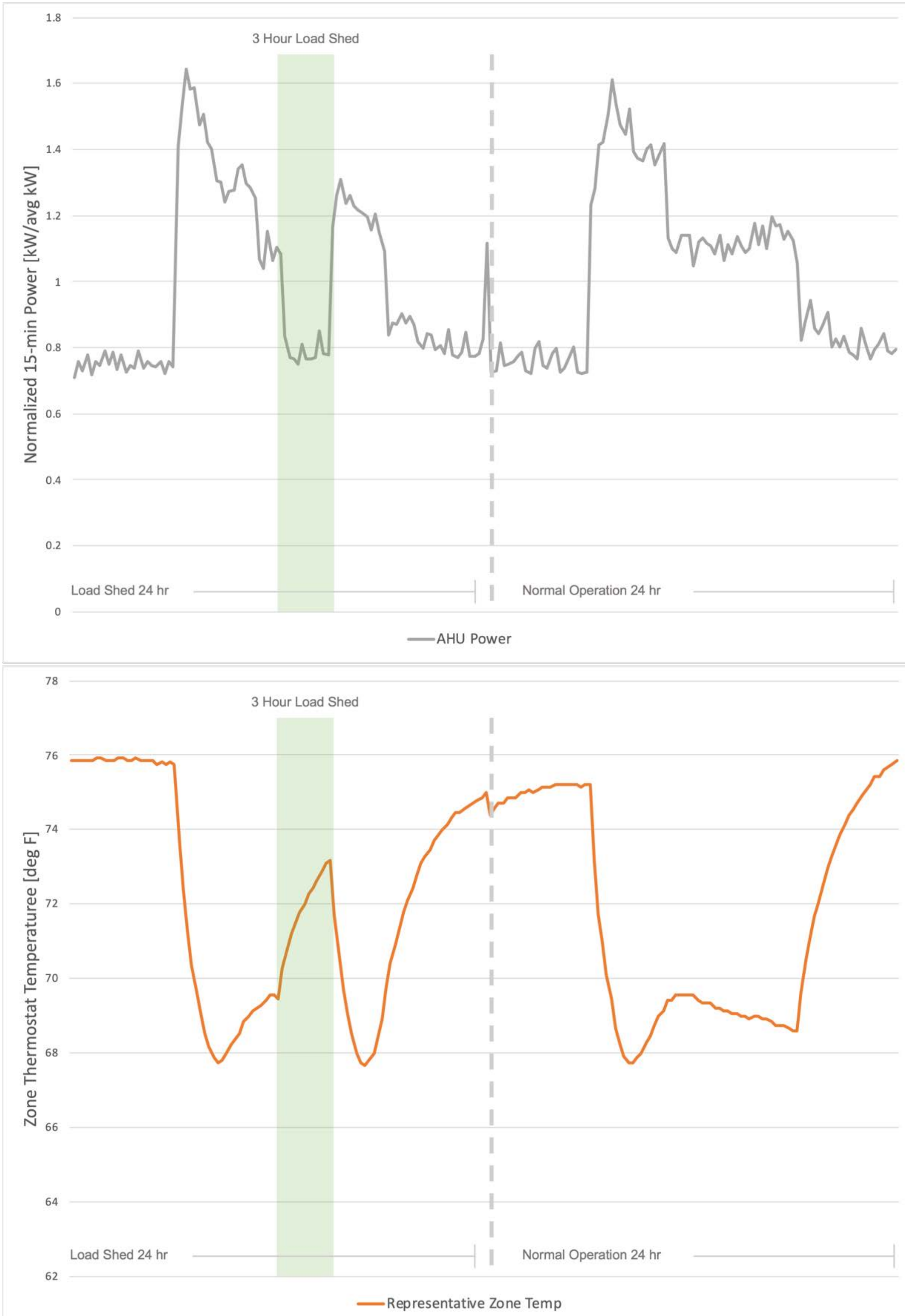


Figure 5. Direct HVAC control experiment results including (top) total HVAC air handling unit load and (bottom) representative zone thermostat temperature log

Results show that HVAC load is reduced by 30% for the 3-hour load shed experiment window. Temperature throughout the building increased during the 3-hour window, shown in Figure 5 by a representative zone. Although actual temperatures measured throughout the test building vary due to many factors, the change in temperature during the 3-hour window shown in Figure 5 is representative of thermostat readings throughout the facility. Normalizing the HVAC electricity profile by the measured hourly outdoor air dry-bulb estimates that daily HVAC consumption increased marginally by 1%–2% above normal operation primarily during the rebound period following the 3-hour load shed experiment window. Other normalization methods could be used to further evaluate and compare the profiles but was outside the scope of this study. These experiments also supported the modeling effort and methodologies utilized in this study, whose details are further discussed in Section 3.2.

Preheating strategy experiments were also conducted through schedule building automation system overrides at a select campus building with electric heat. Preheating conditioned the building earlier in the morning (3–5 a.m.) ahead of typically scheduled morning warm-up hours (6–8 a.m.) in an attempt to shift electric consumption earlier in the morning to avoid known grid wintertime constraints. Figure 6 shows the whole-building electric data collected from one of the preheating experiments compared with data collected from a normal operation day.

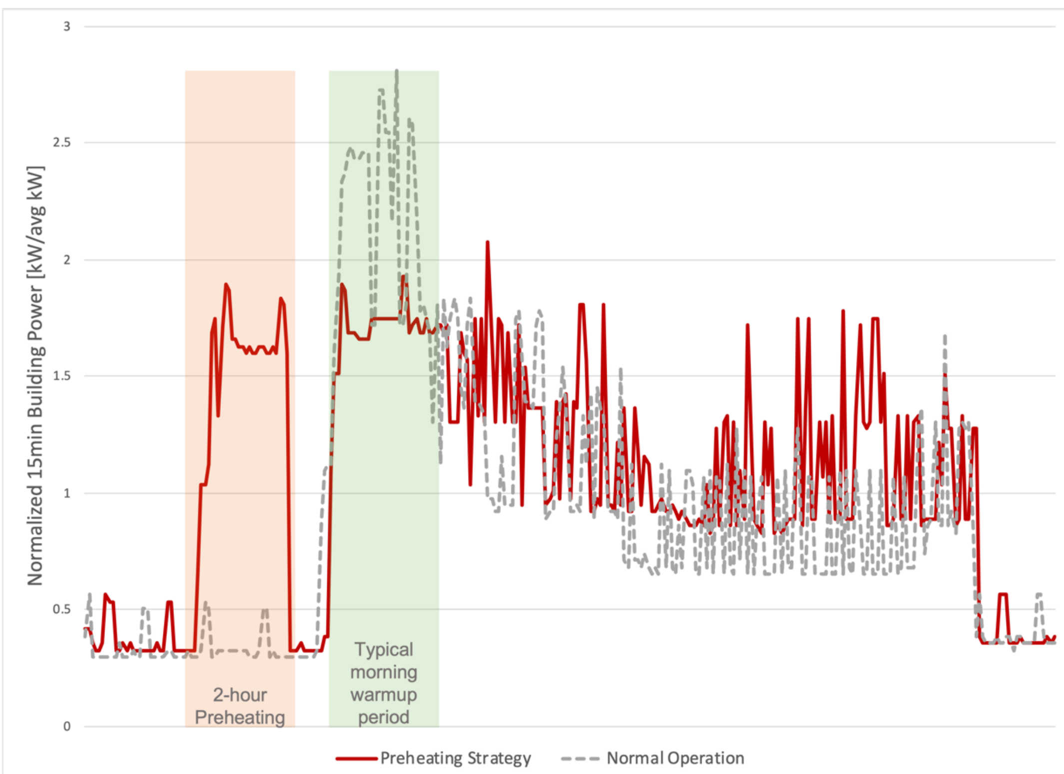


Figure 6. Building load profile comparison between normal operation and induced preheating strategy

Results shown in Figure 6 demonstrate that nearly 50% of the building electric load is reduced during targeted morning warmup hours (6–8 a.m.) compared to typical operation by preheating the building earlier (3–5 a.m.). Results shown in Figure 6 are normalized electricity consumption values, and the outdoor weather conditions were very similar between the consecutive experiment days. Normalizing the electricity profile by the measured hourly outdoor air dry-bulb estimates that preheating increased daily consumption by only 2%–4%, and the benefits could significantly outweigh this slight increase depending on utility grid needs or RTP pricing. It is important to note that this calculation is performed using a weather-normalized profile, but there may be some small roundtrip inefficiencies associated with preheating. Overall a substantial portion of the building load is shifted out of the morning warmup period (6–8 a.m.) by invoking the preheating strategy, and this load shift potential performed across multiple buildings could help off-set known wintertime grid constraints in the region.

It is also important to point out that the majority of campus building heating loads are met by equipment served by natural gas, and electrification was beyond the scope of this study and would require substantial capital investment. However, these experimental results show that characterizing the potential for winter peak demand reduction through thermal load flexibility is an important finding and should foster future studies specifically focused on winter demand and impacts of electrification in the region.

3.2 Key Finding 2: Modeled Thermal Flexibility Coordinated Across Campus Provides 3-3.5 MW of Load Shed for Targeted 4 Hours

Coordinated dispatch of thermal flexibility strategies at the multi-building scale can provide energy and capacity grid services to a utility at meaningful scales.

Similar to a demand response program, the value of grid services for a utility is realized at scale. Buildings exist at the interface between the supply and demand side of today's electric grid. As we continue to address technical challenges associated with GHG reductions on our electric utility infrastructure, buildings can play an increasingly important role providing various forms of grid services. Figure 7 provides a summary of various types of utility grid services and the associated applicable timescales for the necessary response from a potential resource.

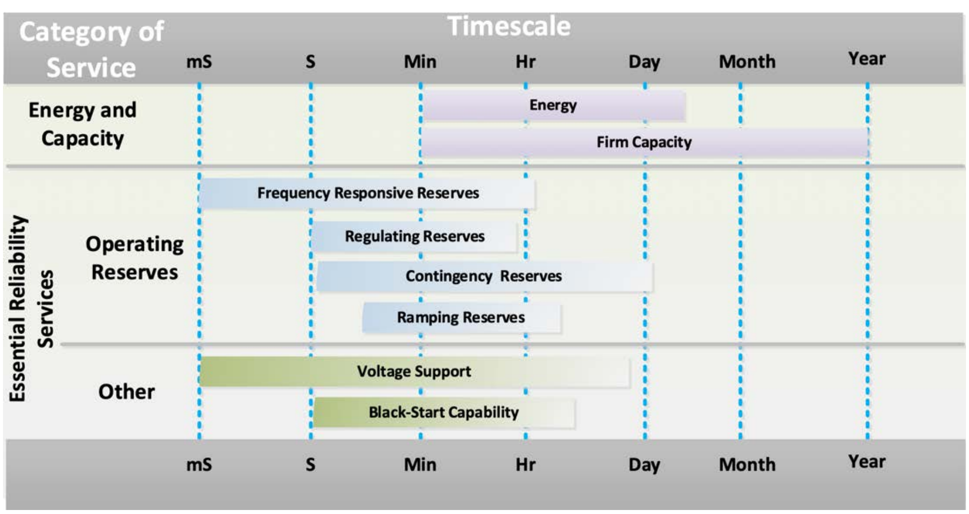


Figure 7. Utility bulk power services

Source: Denholm et al. (2019)

As discussed in Section 2, this study focused analysis on thermal flexibility strategies. Thermal loads in buildings respond at timescales of minutes to hours, or potentially longer with longer-duration storage. This resource aligns with energy and capacity grid services as shown in Figure 7.

GIT's campus has two central cooling plants serving the majority of campus buildings that account for 10%–35% of campus electricity demand depending on the time of year, averaging around 20%. Modeling analysis shows that 3–3.5 MW of campus-wide load can be shed for up to 4 hours during peak summer grid constraints through coordinated dispatch of cooling load flexibility at multiple buildings connected to campus central plants. This coordinated campus-wide shed event is on the order of 10% of campus electric demand during the targeted 4 hours. This analysis sought to quantify the maximum energy and capacity resource available through load flexibility without exceeding current chiller plant capacities.

The number of buildings providing coordinated dispatch depends on the available, or reserve, chiller plant capacity to accommodate the necessary pre-cooling each day. It should also be noted that modeled campus buildings were constrained to not exceed occupant thermal comfort bounds during various load flexibility scenarios. A central supervisory coordination controller with knowledge of reserve chiller capacity each day could be programmed to determine the number of campus buildings that should dispatch cooling load flexibility in order to maximize campus-wide electric load shed. Also, as is discussed in more detail in Section 3.3, the supervisory coordination controller could be programmed to determine the most appropriate days to execute multiple building cooling load flexibility based on the reserve chiller capacity and hourly RTP price.

When evaluating the potential resource within the bounds of existing infrastructure, chiller plant capacity was the main constraint. As discussed in Section 2, the thermal cooling flexibility strategy yielding the highest potential savings required precooling buildings ahead of the load shed event. When compared with normal building operation, coincident precooling across multiple buildings increases cooling demand on the chiller plants and therefore is the primary constraint when determining how much connected cooling load on campus chiller plants can be flexed. Cooling demand from connected buildings is variable, and therefore available reserve chiller capacity for potential precooling also varies. The 3–3.5 MW range is determined considering the minimum resource consistently available during peak summer cooling season.

This study also evaluated dispatching the coordinated thermal flexibility on days with elevated hourly energy pricing corresponding to the variable portion of campus's RTP rate structure, which is further discussed in Key Findings 4 and 5. The thermal flexibility resource on campus is directly related to available reserve capacity at campus central plants in order to provide the precooling. Future research could evaluate the technical and financial implications of adding thermal storage to campus infrastructure and assessing the impacts of using thermal storage to increase the load shifting capacity.

3.3 Key Finding 3: Customer Rate Arbitrage Valuation Different from Potential Utility Valuation Based on National Study

As mentioned in Section 2, the campus electricity consumption is master metered with a rate structure made up of a fixed base load and a variable RTP consumption charge provided one hour ahead and with day ahead estimates. Multiple years of customer hourly RTP data were provided to this effort through a non-disclosure agreement (NDA). Actual prices are not reported here. Through discussions with Southern Company, days with elevated RTP prices were assumed to occur most often during peak summer or winter days with increased constraints on the grid and were therefore characteristically the most important days to evaluate coordinated load flexibility. It should also be noted that there can be other instances experiencing elevated RTP prices when for example generation is challenged due to scheduled maintenance or other situations. Full RTP data and actual weather data for 2018 were available and selected for evaluation.

Two key value propositions for dispatching thermal cooling load flexibility across multiple buildings on campus are evaluated in this section. The first is a benefit to GIT for energy cost savings due to rate arbitrage, and secondly, the potential utility value of the resource based on a national study not specific to Southern Company or Georgia Power (Hledik et al. 2019). Table 3 summarizes these specific value propositions based on the modeled campus-wide load flexibility scenarios using the 2018 weather data and historical RTP price data.

Table 3. Potential Value Propositions to Customer and Utility for 2018

System Benefit Type	Customer Rate Arbitrage Benefits	Potential Utility/System Operator Benefits** (Hledik et al. 2019)
Marginal Energy Cost	$700 - $2,500 savings per event $18,000 - $38,000 per year*	$11,000 to $18,000 per year
Marginal Generation Capacity Cost	No agreement yet in place, as flex capacity only exploratory to-date.	$135,000 – $222,000 per year

*Range is based on dispatching load flexibility for various thresholds of RTP rates and is based on the 2018 RTP historical data. Customer value will vary year-to-year.
**Utility valuation is based on a national study and not official valuation from Southern Company or Georgia Power. Differences in marginal energy cost value are likely attributed to this GIT study's limitation to high price spike days with dependable savings margins, whereas other types of load flex might additionally operate across tighter price margins with lower per-kWh arbitrage savings – thus lowering the average marginal energy cost below levels in this study. Marginal generation value estimate here does not include possible de-rating of theoretical flex value based on actual performance during DR event or due to timelines of regulated capacity planning within Georgia Power.

For the results summarized in Table 3, 53 distinct high RTP price event days were extracted from the 2018 RTP historical price data set. The degree to which the RTP price spike each day varied and the impact to customer rate arbitrage benefits also varied. More details of these specific value propositions are discussed in the remainder of this section.

It is also important to note that this campus-wide modeled resource is not considered an official capacity resource recognized by Southern Company or Georgia Power as it cannot be called on in any hour of the year. Additionally, the value of capacity to the utility is based on a national study (Hledik et al. 2019). Future scenarios or utility programs with the ability to recognize the modeled campus-wide load flexibility as an official capacity resource would likely produce different valuations than shown in Table 3.

Figure 8 shows an example June weekday that saw elevated RTP pricing in 2018. **The RTP rate shown has been normalized.** Campus metered consumption is shown compared with modeled impacts of coordinated dispatch of cooling load flexibility.

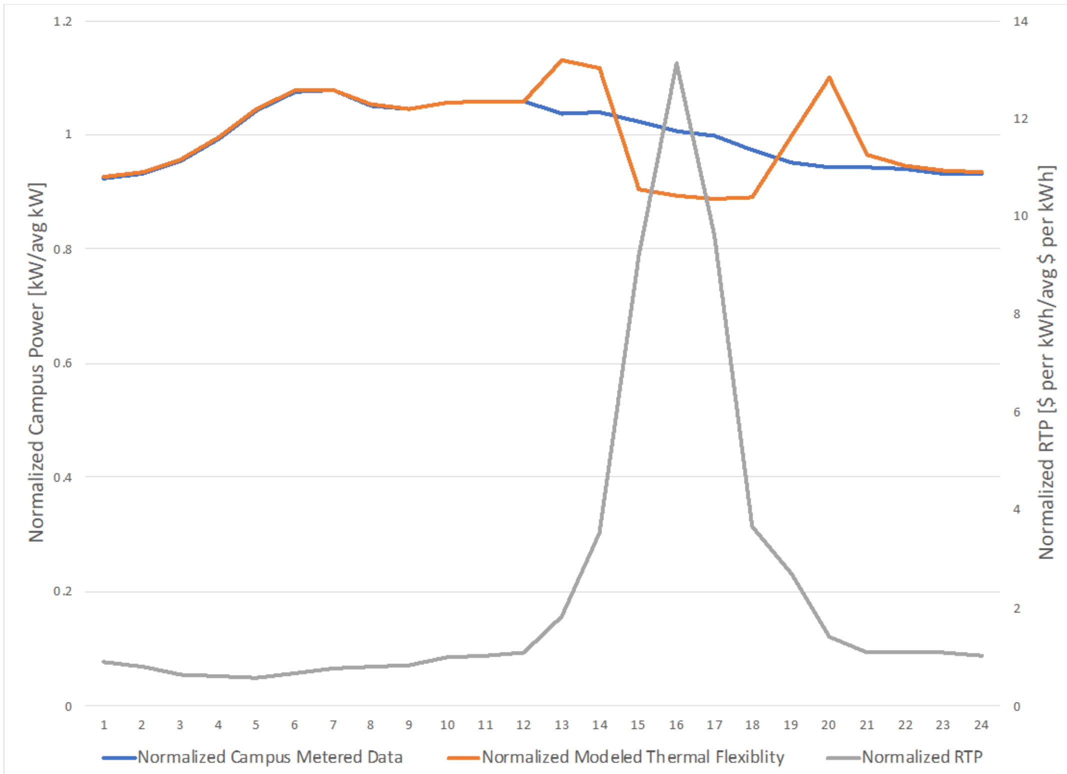


Figure 8. Campus-wide load profile comparison with coordinated thermal cooling load flexibility modeled for an elevated price signal from RTP for an example weekday in June 2018

The normalized RTP rate shown in Figure 8 follows a typical pattern observed where elevated prices are seen for 7–8 hours in the afternoon, with 4–6 hours of relatively high price spikes. The timing of the price spike is variable, but for summer peak cooling months the spike was typically observed in the afternoon and shifted by no more than 1 or 2 hours compared with the day shown in Figure 8. The dispatch of thermal load flexibility is timed to coincide with the peak pricing window to maximize the potential economic value.

Initial resource dispatch simulations were executed using XENDEE's optimization algorithm on a subset of campus buildings, taking inputs of baseline load, hourly load flexibility potential and hourly RTP, then optimizing for lowest annual cost. The software executed a logical approach of shifting as much load as possible out of the peak RTP time windows, confirming that price arbitrage be the primary benefit to campus.

XENDEE is an electricity grid modeling software and does not incorporate non-linear inputs of chiller efficiencies or capacity limitations, or thermal capacitance of buildings associated with load shifting. As described in prior sections, dispatch potential at GIT is ultimately limited by the spare central chiller capacity during precooling periods, not by thermal properties of the buildings. Because of this, dispatch control algorithms written for a supervisory control system or distributed energy resource management system (DERMS) need to be coordinated centrally by the campus but do not necessarily require complex, complementary control logic to dispatch between buildings. So, to better address these key thermal parameters, subsequent scenarios were evaluated using a methodology of manually programmed load shifting using temperature setpoint scheduling within energy modeling software, then applying the hourly RTP to the resulting hourly load profile. A strategy was developed to precool ahead of the RTP spike windows, then cool again at the end. This strategy, which is based on the thermal capacitance of the buildings, allowed a four-hour temperature float period that coincided relatively well with the duration of RTP spikes. Dispatch was limited by the central chiller spare capacity at both the front and back end of the shift and was also programmed to ease out of the float period and avoid a load spike still within the tail end of the high RTP period.

This form of thermal load shifting is not free, but rather sees a net efficiency loss analogous to roundtrip efficiencies with energy storage devices, such that the shifted scenario consumes more kWh annually than the baseline scenario. This is related to a few potential nonlinear factors: changing outdoor air temperatures impacting central plant operating efficiencies, full-load versus part-load chiller efficiencies, and increased heat transfer related to higher indoor/outdoor temperature delta in precooled buildings (see Section 3.4 for quantification of these penalties). Disaggregating these effects was beyond the scope of this study, but the result was a key constraint on load flexibility dispatch. Scenarios evaluated with uniform daily dispatch sometimes arbitraged against a very small RTP spike and/or missed the full RTP spike windows, and when coupled with roundtrip efficiencies saw unpredictable, small, and even negative price arbitrage benefit.

This series of exploratory modeling scenarios demonstrated that to realize and maximize the economic value of load flexibility, it is crucial that dispatch do two things:

1. Vary the time of shifting to tightly coincide load shifting with the peak pricing window

2. Deploy only when daily RTP price spikes are large enough overcome thermal efficiency penalties associated with the load shifting.

Dispatch times were tailored daily to match the RTP spike window. Then, dispatch days were characterized based on the relative daily price spike, defined as the proportion of afternoon prices divided by the morning prices. Due to an NDA with GIT and Southern Company, specific prices and cost savings results below have been normalized. Price arbitrage on days with RTP spikes below approximately three times the mean (3x) produced inconsistent and sometimes negative financial impact. As shown in Figure 9, days with a spike of approximately 3x or greater saw positive daily benefit of price arbitrage with good correlation, meaning that dispatching on all days with spikes above the 3x threshold would maximize annual financial benefit. In the case of the 2018 RTP, this included approximately 40 total days and resulted in campus-wide annual energy cost savings of approximately one-third of 1%. This annual savings potential provides the cost component of the cost/benefit test for investing in the DERMs system and operations. Approximately half of that total annual financial benefit resulted from only the eight days with price spikes above 5x, highlighting the importance of responding on the most crucial days.

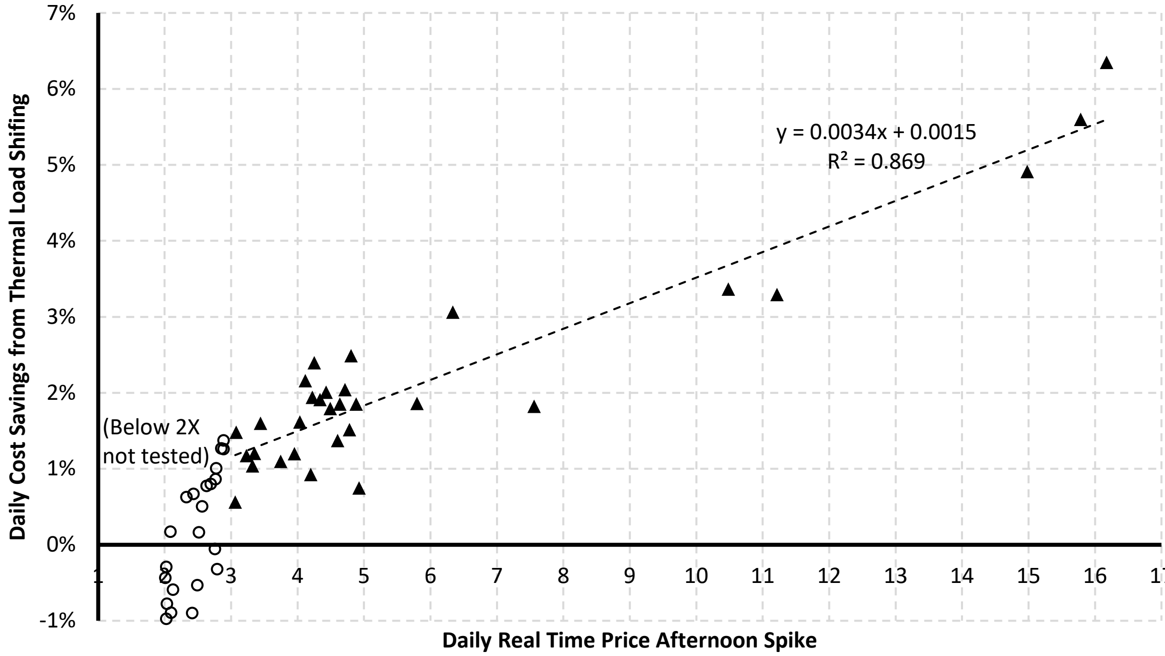


Figure 9. Correlation between daily utility electric cost savings from thermal load flexibility and daily RTP afternoon price spike

It should also be noted that based on review of multiple years' RTP histories, the number of moderate- and high-spike days can vary and even be substantially higher than those observed in 2018, perhaps due to weather-related strains on the regional grid. This may warrant further investigation in context of both a warming climate and increasing penetration of intermittent renewables, both of which likely present new balancing challenges in many electrical grids and opportunities for load flexibility value.

Subject to an NDA with GIT and Southern Company, this report does not quantify and compare the customer price benefit to the Southern Company-specific utility valuation of this load flexibility. However, a recent study from Brattle Group provides insights into the conceptual utility value stack and a national average quantification for load flexibility available for dispatch at the required times through a year. Depending on the timeframe, Brattle cites value potential of $25 to $41 per MWh for marginal energy costs and $45 to $74 per kW-yr for marginal generation capacity (Hledik et al. 2019). This is based on national data and not Southern Company or Georgia Power specific data. Using 428 flexed MWh from the 2018 3X price spike scenario would yield a utility marginal energy price value of $11,000 to $18,000. This is the same order of magnitude but actually less than the customer value found using current GIT RTP rates. Differences in value are likely attributed to this study's limitation to high price spike days with dependable savings margins, whereas other types of load flex might additionally operate across tighter price margins with lower per-kWh arbitrage savings – therefore making the average per MWh in the Brattle Group study lower than the average savings seen in the GIT model data. To estimate potential utility marginal capacity value, assuming 3 MW of load flexibility dispatch by the campus, that would suggest an estimated campus value proposition of $135,000 to $222,000. There is currently no capacity value compensation agreement between GT and GP, as flex capacity has only been exploratory to-date. Actual value of the compensation would be contingent upon the flex performance during a demand response event call, as well as larger regulatory issues such as capacity planning timelines within Georgia Power. Additional utility value noted by Brattle group, such as avoided transmission and distribution or ancillary services would also require further nuanced study and agreement.

This study highlights that the RTP rate structure can act as an aggregator signal to drive load shifting behavior, coordinating thermal flexibility and potentially other grid-interactive efficient building strategies at the multi-building scale to the mutual benefit of the customer and the grid operator. It also highlights the crucial role the campus coordinator plays in rationalizing the dispatch in reaction to the RTP. It requires characterizing roundtrip efficiencies based on nonlinear thermodynamic factors, then parameterizing dispatch procedures and sequences mapped to relative RTP spike magnitude. Unlike what might be expected with a monthly demand charge, the RTP intrinsically provides time-specific instructions, and when received by smart dispatch sequences by the customer can aggregate their activities without the need for an active demand response aggregator. Furthermore, scaling the price spike signal can intrinsically prioritize a cost-based hierarchy of dispatch.

3.4 Key Finding 4: Current Marginal Grid Emissions Limit Impacts of Coordinated Thermal Flexibility for Carbon Reductions

The scenarios described in Section 3.3 optimized dispatch of thermal load flexibility for customer cost savings, not GHG or carbon emissions reductions. This section considers GHG or carbon impacts from dispatch of thermal load flexibility strategies.

Results indicate that historical marginal emissions generally see elevated carbon levels on the grid for durations longer than 4 hours. Historical marginal emissions also show gradual changes and prolonged increases in carbon levels as opposed to abrupt changes seen perhaps with a high renewable generation mix. Therefore, the coordinated thermal load flexibility across multiple building on campus whose modeled analysis shows can provide significant load shed for 4 hours has limited impact on reducing carbon. Carbon reductions instead may require a different dispatch approach than what was evaluated in this study, such as longer-duration shifting and storage strategies. Details of the carbon reduction evaluation under both current and future supply-side scenarios is discussed below.

Historic hourly marginal grid emissions rates were obtained from WattTime and are shown in Figure 10.

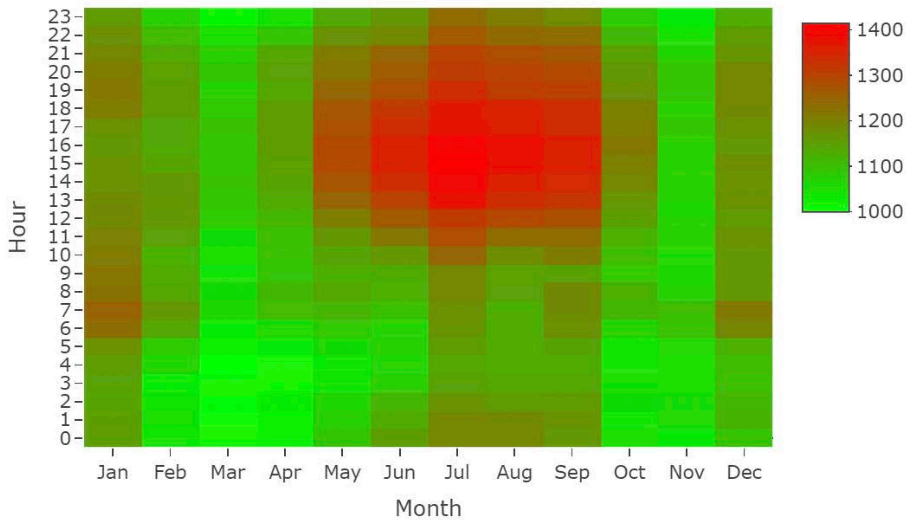


Figure 10. 2018 emissions profile showing modest, gradual, and more prolonged time windows of increased emissions than analogous RTP signals

Source: WattTime 2021

Applying these historic hourly marginal grid emissions rates resulted in none of the previously discussed scenarios representing a net GHG emissions reduction benefit. This was primarily because roundtrip efficiency penalties increased total electricity consumption by an average of 0.2% on load shifting days based on modeled scenarios. The modeled daily variation in electricity consumption ranged from 1.0% kWh increase to 0.5% kWh decrease. The RTP differential was at times large enough to overcome the cost of this increased electricity consumption and ultimately reduce total cost, but there was typically not significant enough daily carbon emissions variable to produce a net carbon reduction.

Figure 11 shows that the daily carbon emissions increased or decreased in close correlation to the change in daily electricity consumption. This suggests carbon impacts in these scenarios were driven primarily by roundtrip efficiency penalties related to the dispatch of thermal flexibility, rather than any potential time-of-use marginal carbon reduction.

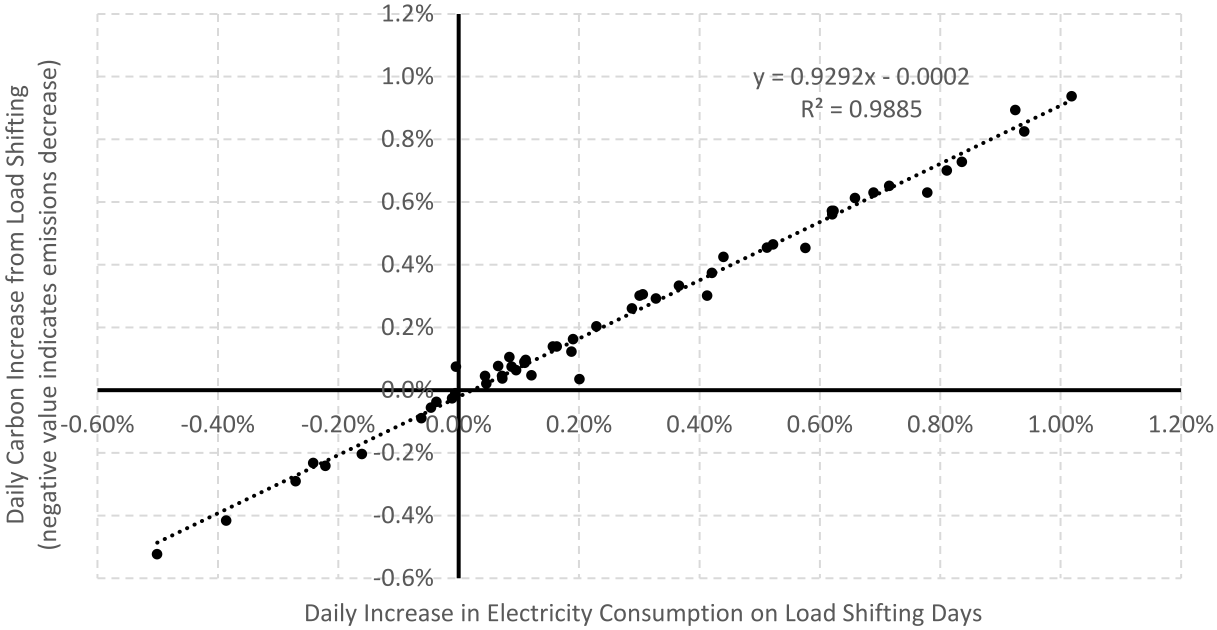


Figure 11. Carbon impact as a function of electricity consumption changes

Figure 12 shows that marginal carbon afternoon spikes were only 1.18x to 1.31x on days thermal load shifting was modeled. That spike is smaller than the analogous 3x RTP spike required to reliably deliver price arbitrage benefit. Somewhat higher carbon spike days did occur but were not correlated with RTP spike days; in general, the current RTP shows little correlation to carbon on low RTP spike days. Furthermore, the tested thermal shifting scenarios were developed with only a four-hour shifting window, tailored to conduct price arbitrage across a relatively compressed RTP spike window.

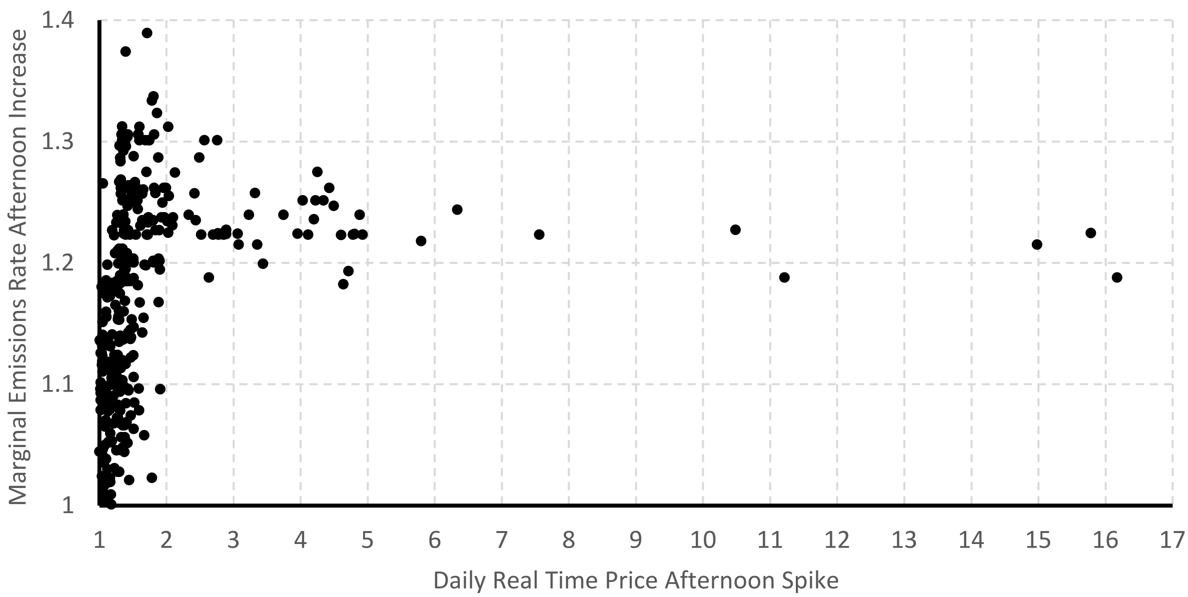


Figure 12. RTP daily price spike compared with marginal afternoon emissions rate shows no strong correlation between RTP and marginal carbon

Studies indicate that opportunities for coordinated carbon arbitrage should be expected to increase with increasing grid penetration of low- and no-carbon energy sources (Carmichael et al. 2021). In addition to shifting load out of high-emission windows, coordinated thermal load flexibility could also be used to reduce renewables curtailment in periods where generation exceeds demand.

Modeling described in Section 3.3 illustrated an ability to strategically shift *out of RTP spike periods*. Modeling also shows that thermal load flexibility can switch modes and dispatch to instead shift load *into solar curtailment periods*. Figure 13 below illustrates daily load profiles in a scenario with relatively high solar penetration that meets much, but not all, of peak summer demand, and then over-generates and is curtailed in peak solar hours of the shoulder seasons. The scenario is illustratively modeled with the solar behind the campus meter, but conceptually this could be analogous to a larger grid.

In the July scenario shown in Figure 13, absent any curtailment, we observe typical behavior of shifting load out of the elevated RTP spike, which typically occurs between hours of 2 p.m. and 5 p.m. But in shoulder months of March and October, thermal flexibility is able to shift demand from the hours adjacent to solar curtailment into the hours of curtailment, driven by a signal of very low-price electricity from the otherwise-curtailed solar. There is potential synergy in shoulder seasons—solar electricity production is relatively high while cooling loads are present but smaller, leaving additional spare chiller capacity to conduct load flexibility precooling. But load shifting through thermal flexibility is ultimately constrained in both magnitude and duration by factors such as chiller system capacities and the thermal inertia enabling building zone temperatures to float within comfort bounds. The October scenario shown in Figure 13 demonstrates that if the shifting window is longer than the targeted four hours based on the thermal load flexibility strategies evaluated in this study, then load shifting may be constrained to the leading and trailing edges of this window.

Figure 13. Electricity profiles in an illustrative, high-solar scenario for representative months (a) March, (b) July, and (c) October

The amount of curtailment reduction depends heavily on the assumed quantity of solar, but another scenario was evaluated to roughly quantify the maximum potential for GIT to use cooling load flexibility to reduce curtailment in an extremely high-renewable grid. The campus-wide model demonstrated that chiller dispatch optimization and cooling setpoint float alone can absorb enough electricity from otherwise-curtailed solar to comprise approximately 1% of annual campus electricity consumption for all of campus.

In the more immediate term, this strategy to reduce curtailment could be leveraged by the campus to increase behind-the-meter solar self-consumption and potentially support the investment of additional campus solar. In scenarios with a modest campus solar investment optimized by solar price economics, cooling load flexibility was able to increase campus solar self-consumption by up to 2%. Allowing that financial benefit to feed back into increasing solar investment enabled up to 4% additional solar compared to a solar scenario without load flexibility. These figures are provided for illustrative purposes and are highly dependent on the ratio of electric utility rates to solar PV prices, a broad range of which were evaluated.

4 Opportunities for Further Research

This study highlighted several key areas for further research:

1. A framework to better craft price signals, particularly carbon-based price signals, would be helpful to coordinate specific actions to the mutual benefit of specific customers and the utility. The magnitude, duration, and timing of the signals will determine which technologies can be deployed to successfully and comprehensively attain the utility's objective of the signal—capacity, transmission and distribution, carbon, etc.

2. Further study is required to parameterize critical, nonlinear, and roundtrip efficiencies that limit the cost-effectiveness and carbon reduction potential of cooling load flexibility. A better understanding of these factors would unlock additional savings.

3. This study demonstrated that cooling dispatch optimization can perform arbitrage across abrupt price signal changes such as an RTP or solar curtailment signal, as long as sufficient time is allowed for precooling or temperature floating in response. In the case of gradual price transitions, full-day timescales, or price signals with little forewarning, further study would be required to understand the degree to which chiller dispatch and building thermal inertia alone can deliver meaningful cost or carbon savings.

4. Additional building thermal capacitance and active thermal storage would enable additional load flexibility functionality and increased ability to solve grid challenges, particularly with longer time-scale signals. Considerations around insulation and building envelope upgrades should also be suitable for this evaluation. Although building envelope efficiencies may decrease the total amount of shiftable load, it may extend the time over which load can be shifted. Further study is also required to understand the degree of storage needed to conduct more meaningful carbon arbitrage, and the associated economics. Thermal storage could potentially benefit from diurnal temperature swings and part-load optimization, further helping roundtrip efficiencies and project economics.

5. This study focused on cooling flexibility only. Further study is warranted around thermal load flexibility of electric heating to solve an emerging set of heating season grid and demand challenges, particularly amid the beneficial electrification of fossil fuel heating.

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