Optimizing Building Load Management for Operational Emissions Reductions

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ABSTRACT

Low- and Net-Zero emissions policies continue to be a lever for driving decarbonization in the built environment, with frameworks being developed by model code and standards organizations as well as some leading states and jurisdictions. Methods for calculating building operational emissions largely rely on annualized electricity generation-based emissions data, drawing on regional information from the EPA's eGrid or the Cambium Standard Scenarios. However, opportunities to use more locally- and time-specific data to optimize building energy use for emissions reductions are emerging. Code and policy development aimed at increasing demand response technology penetration must evolve to capture the effectiveness of these emerging technologies at reducing emissions. This paper presents results from a study testing demand shifting in response to different control signals in three grid regions. The study examines how different emissions factor data sources and controls signals impact projected operational energy costs and emissions. The authors will make recommendations for how codes, policies, and programs aimed at reducing building operational energy emissions should consider emissions factors, and discuss limitations of existing emissions and demand signals in achieving emissions reductions. There is a need for utility-provided emissions signals so that building demand-shifting efforts can reliably align with grid emissions generation trends. Public utility commissions should be required to make regional and local generation emissions profile data available, align their cost structures with emissions production to incentivize emissions reductions, and provide clear signals that can be used to shift demand so that both cost and emissions are reduced.

Introduction

The landscape of building energy policy is undergoing a fundamental transition. For decades, the guiding star of building codes has been the reduction of operational energy cost or consumption, measured in kilowatt-hours (kWh) or British Thermal Units (BTU). However, as states and jurisdictions continue to develop climate mandates, the primary metric of success is shifting toward emissions performance (CO2e), exemplified by New York City's Local Law 97 (LL97), and Boston's Building Emissions Reduction and Disclosure Ordinance (BERDO).

While basic efficiency remains a foundational principal of emissions reduction, providing inherent passive operational decarbonization, national model energy codes like those developed by the American Society of Heating, Refrigeration, and Air Conditioning Engineers (ASHRAE) and the International Code Council (ICC) are developing frameworks that allow for direct emissions-based compliance, or through trade-offs between efficiency, on- and off-site renewable energy, and demand flexibility. The success of these compliance frameworks and code structures relies on assumptions regarding a building's local grid electricity generation emissions. Historically, codes have used national annual averages for energy cost, which simultaneously represents everywhere and nowhere, a methodology that has largely been transferred to emissions accounting. While methodologies have been developed and implemented for time-of-use (TOU) based energy cost calculations, similar methods have not been applied to emissions calculations (Pacific Northwest National Laboratory (PNNL) 2022). In both cases, these national averages fail to capture the realities of local cost structures, nor do they reflect generation emissions profiles of solar-saturated California or a coal-heavy Indiana.

An effective emissions-based building code or policy depends on the underlying grid characteristics because building emissions are highly sensitive to the generation dispatched at the time of energy use. Put another way, the emissions intensity of an additional kilowatt-hour is determined by the energy sources available when it is needed. For example, in a solar-heavy grid, a building's emissions footprint is lowest during sunny afternoons, whereas in a wind-dominated or coal-heavy region, the cleanest hours may follow entirely different seasonal or diurnal patterns.

The significant time dependent nature of the renewable energy generation technologies dominating new energy resource deployment – namely, solar and wind – are such that accounting for and crediting TOU based energy profiles may help more accurately account for building energy emissions, and appropriately credit building performance through code, policy, and program structures (Li 2026; Scoz 2024). Without regional or localized data, a national average signal may inadvertently encourage load-shifting that increases emissions in some jurisdictions. To maximize the "80/20 rule" – achieve 80% of the benefit for 20% of the cost – to the benefit of decarbonization, policymakers and program developers must understand this energy source sensitivity and whether it is applicable in their jurisdiction. If the goal is to align building demand with grid dispatch, we must determine if, where, and under what conditions a TOU rate is a sufficient proxy for emission intensity, or if the generation profile of a specific region necessitates more complex, real-time signals to achieve meaningful reductions.

Building Codes and Policies and Emissions Reductions

As of 2026, over 24 states plus the District of Columbia and Puerto Rico have 100% clean energy targets (Clean Energy States Alliance 2026). Building energy codes and existing building policies are increasingly viewed as critical policy tools to achieve building emissions reductions to support state and local jurisdictions in meeting these ambitious clean energy and climate targets. This can be seen in ASHRAEs position document on building decarbonization, in which they outline targets for new buildings to be net zero GHG emissions in operation (ASHRAE 2024). Additionally, 46 mayors, governors, and energy commissioners have signed onto the National Building Performance Standard (BPS) coalition to align building energy and emissions reductions with existing building policies (National BPS Coalition 2025). These actions point to a growing consensus among policy makers and industry leaders that building policies for new construction and existing buildings are essential tools for meeting local and regional climate and energy objectives.

Emissions Factors

The Cambium dataset, developed by the National Laboratory of the Rockies (NLR), provides hourly projections of U.S. electricity generation, system operations, and associated emissions informed by NLR's Standard Scenarios – a set of possible future scenarios of the U.S. power sector by 2050. These scenarios are generated using the Regional Energy Deployment System and Distributed Generation Market Demand Model for capacity expansion models. The datasets are updated periodically to reflect evolving technology and market trends (Cambium 2026; Sergi 2026).

By integrating projected emissions data across multiple future scenarios, Cambium helps to determine how the U.S. electricity grid may evolve under varying technological, economic, and policy conditions. This forward-looking analysis is essential for informed decision-making related to building and grid decarbonization strategies and energy infrastructure planning. The research and study presented in this paper utilizes emissions data and associated metrics derived from the Cambium dataset to evaluate operational emissions impacts of buildings.

The primary emissions metric is the Cambium Average Emissions Rate (AER), which represents the grid's emissions intensity. AER is calculated as the total greenhouse gas emissions from all operating generators during a given time period divided by the total electricity generated ($kgCO_2e/MWh$). This metric enables evaluation of building operational emissions under projected future grid conditions (National Laboratory of the Rockies 2022).

For evaluating grid emissions projections, it is important to incorporate time-varying factors to avoid discrepancies where annual averages alone may overlook substantial seasonal and diurnal variations or electricity generation from Distributed Energy Resources (DERs), potentially misrepresenting actual emissions and impacts (Bontekoe 2024). Additionally, annualized emissions factors cannot capture the impact of building load management technologies on building operational emissions. To improve accuracy of emission results, emissions calculations can leverage higher-resolution metrics with temporal granularity derived from Cambium models, or if available, from ISO or local utilities reporting data (Gagnon, 2025). Higher-resolution metrics include:

- Average Day AER: The mean hourly emissions profile for a typical day, calculated by averaging each hour across all days of the year (24 values).
- Average Monthly Day AER: A representative 24-hour profile for each month, determines average hourly values within each month (12 × 24 = 288 values).
- Hourly AER: hourly emissions factors for each hour of the year (8,760 values), capturing seasonal and diurnal variability.

In addition to the average emissions factors, Cambium also publishes Marginal Short- and Long-Run emissions data. A marginal emission rate is one that captures the rate of emissions that would be induced by a marginal increase in a region's load. For example, if a fleet of electric vehicles are charged, the additional generation used to meet that increased demand would be the marginal emission rate.

- Short-Run Marginal Emissions Rate (SRMER): Captures the immediate response of the grid to demand. Would describe the immediate operational impact of the charging example.

- Long-Run Marginal Emissions Rate (LRMER): Captures how a persistent demand change may influence the structure of the grid. LRMER would describe how the additional load from the fleet may prompt additional electric generators to be built.

SRMER treats the grid generation assets as fixed and attributes changes in demand only to what's available at the time, where LRMER is designed to describe the emission changes that would occur from grid generation planning from changing loads.

Building Energy Codes

As building energy codes are increasingly viewed as tools for achieving broader energy policy objectives beyond maximizing efficiency and minimizing cost, requirements for renewable energy, load management, and demand responsive controls have made their way into national model energy codes and state and local energy codes. These show up in both prescriptive paths, with requirements in the additional/optional energy credit sections of the IECC 2024 and ASHRAE 90.1-2022, and performance pathways, either requiring the load management credits to be achieved or allowing for load management systems to reduce costs through simulation procedures.

Both national model energy codes and state and local energy codes have developed approaches to assess performance based on operational emissions. These approaches vary in how they calculate operational energy emissions, such as which emissions factors they use, and none currently allow for load management technology to demonstrate emissions reduction potential in buildings. Given the intermittent nature of most renewable energy generation sources, significant opportunities exist for building load management to reduce operational emissions by aligning building energy use profiles with low emissions electricity generation hours. Although not a comprehensive survey, Table 1 provides a summary of how different codes and standards treat load management for compliance, and how they require or allow for the use of different emissions factors for operational emissions calculations.

Table 1. Energy and Emissions Code Approaches to Load Management and Emissions Factors

Code	Approach to Load Management for Energy Compliance	Emissions Factors for Operational Emissions Compliance
ASHRAE 90.1 – 2025[1]	Prescriptive Path: Optional energy credits available for load management technologies Performance Path: Load management technologies can be credited for cost savings through Energy Cost Budget method	N/a not assessed according to emissions

[1] ASHRAE 90.1-2025 is not yet published, this information is from the publicly available and published addenda to ASHRAE 90.1-2022 which form the basis of the 2025 standard.

ASHRAE 90.1 – 2025[2] Appendices M and N	N/a load management technologies cannot be used to demonstrate reduced operational emissions	Annualized CAMBIUM LRMER Factors used for calculation of operational CO2e emissions and renewable procurement requirements
ASHRAE 189.1 - 2023	Prescriptive Path: Optional energy credits available for load management technologies Performance Path: Does not require or allow for load management technologies	Prescriptive Path: N/a not assessed according to emissions Performance Path: Annualized 20-year eGrid emissions factors used for calculation of operational CO2e emissions for baseline and proposed buildings. Provides a Jurisdictional Option for the use of Month-Hour CAMBIUM LRMER in Appendix D
ASHRAE 90.2 – 2024	N/a no load management requirements are included	References 301-2022 CRI, which uses Month-Hour LRMER to calculate operational CO2e emissions performance
ANSI/RESNET/ICC/ 301 -2022	N/a no load management requirements are included	Uses Month-Hour LRMER to calculate operational CO2e emissions performance
Title 24 – 2025	Load management requirements are included in both the prescriptive and performance paths. Performance path metrics (Long-Term System Cost) and hourly source energy, are time based.	N/a not assessed according to emissions
Fort Collins 2026 Building Energy Code		Performance Path: Uses CAMBIUM Month-Hour LRMER to calculate operational CO2e emissions performance Prescriptive Path: N/a, performance-based code

Existing Building Policies

Building Performance Standards (BPS) are policies aimed at addressing the energy and emissions of existing buildings. A growing number of cities (14) and states (4) have adopted BPS and many more[3] are anticipated to join that list (Building Energy Codes Program n.d.). BPS

[1],[2] ASHRAE 90.1-2025 is not yet published, this information is from the publicly available and published addenda to ASHRAE 90.1-2022 which form the basis of the 2025 standard.

[3] 28 Cities and 4 States are part of the National BPS Coalition, considering BPS according to (Building Energy Codes Program n.d.)

programs set reduction targets for future building performance, many of which are in 5-year compliance cycles increasing in stringency towards final targets. Six of these policies use greenhouse gas emissions as their performance metric, and the authors have categorized the treatment of emissions factors, which are described below and summarized in Table 2.

Pre-Published Emissions Factors: Under this approach, jurisdictions publish emissions factors for all compliance cycles in advance to provide regulatory certainty and investment stability. By locking in emissions factors at the outset, they prevent compliance volatility driven by annual grid emissions changes, avoid shifting targets tied to Renewable Portfolio Standard (RPS) progress, and decouple building owner obligations from utility procurement delays or transmission constraints. This structure provides clear, investment-grade signals that support long-term capital planning. The tradeoff is reduced adaptability: if grid decarbonization lags projections, jurisdiction-wide emissions outcomes may underperform policy goals; if the grid decarbonizes faster than expected, building owners may perceive overcompliance relative to real-world emissions intensity. This model favors predictability over dynamic alignment with actual grid conditions. Currently Colorado is the only jurisdiction that has fixed pre-published emissions factors, and does not allow for Time-of-Use (TOU) emissions factor calculations

Periodic Update Model No-TOU: Under this approach, jurisdictions publish emissions factors for current compliance cycles while establishing defined update points prior to future periods. This acknowledges uncertainty in utility-led grid decarbonization and avoids locking in speculative long-term projections, while still providing advance notice to preserve investment visibility. By retaining the ability to recalibrate factors before subsequent compliance cycles, jurisdictions can better align compliance requirements with actual RPS implementation progress and evolving grid conditions. For example, Seattle has released preliminary forward-looking values to signal trajectory while maintaining authority to revise them before formal compliance deadlines. The tradeoff is moderate regulatory risk, as future multipliers are not fully fixed and may change before the next cycle.

Periodic Update Model with TOU: This model combines periodic emissions factor updates with TOU emissions accounting, where emissions rates vary by hour or season to reflect marginal grid intensity. Buildings can reduce reported emissions by shifting load to lower-emissions periods or deploying batteries, thermal storage, and on-site solar to optimize timing. This approach sends granular emissions signals, aligns building performance more closely with real-time grid conditions, and incentivizes load flexibility and demand management. The tradeoff is increased administrative and modeling complexity, along with potential compliance volatility if emissions intensity fluctuates significantly year-to-year.

Table 2. Summary of GHG based Building Performance Standards

Government	Performance Metrics (IMT 2025)	Emissions Factors
Level 1: Grid Emissions Factors are Pre-Published		
Colorado	GHG Emissions Intensity OR Site Energy Use Intensity	Annual emissions factors published by the city in advance for all compliance cycles
Level 2: Grid Emission Factors will be Periodically update with compliance cycles		

Cambridge, MA	GHG Emissions Intensity	Annual emissions factors published by the city, recalculated as policy reaches compliance windows
Maryland	Net direct emissions standards (kg CO2e per square foot).	Factors from EnergyStar Portfolio Manager, will stay up to date with current data
Seattle, WA	Greenhouse gas emissions intensity targets (GHGIT)	Annual emissions factors published by the city, recalculated as policy reaches compliance windows
Level 3: Grid Emissions Factors will be updated and allow for TOU Adjustments		
Boston, MA	GHG Emissions Intensity (kgCO2e/sq. ft.)	Annual emissions factors published by the city. Allows for TOU reporting which can include behind the meter battery storage and solar generation.
New York City, NY	GHG Emissions Intensity (kgCO2e/sq. ft.)	Annual emissions factors published by the city. Allows for TOU reporting which can include behind the meter battery storage and solar generation.
Yet to Publish Rules		
Evanston, IL	EUI, No Onsite Emissions, and, All Electricity sourced through renewable energy	Still in Rulemaking

Source Information (City of Boston 2025) (DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT 2025) (Maryland Department of the Enviornment 2024) (Municipal Code of the City of Cambridge 2025) (NYC Buildings 2019) (National Laboratory of the Rockies 2022) (Office of Sustainability & Environment 2026)

Study Methodology

The scope of this study focuses on three power markets: the California Independent System Operator (CAISO), which operates the majority of California's grid and a small portion of Nevada (CAISO 2026), the Midcontinent Independent System Operator (MISO), which serves multiple states across the Midwest and Southern United States (Participation in Midcontinent Independent System Operator (MISO) Processes 2024), and the Northwest Power Pool (NWPP) which serves multiple states in the pacific north west and portions of California and Nevada. These markets are largely represented in the Cambium dataset by the CAISO, MISO North, and Northern Grid West (NGW) grid regions. Portions of these Regional Transmission Organizations (RTO)/Independent System Operators (ISO) publish high-resolution operational and emissions data, including sub-hourly emissions intensity metrics, which are incorporated into this study to enhance temporal and regional accuracy in emissions analysis (CAISO 2026; MISO 2026).

The study analyzed a multifamily building energy model, testing the use of an electric battery storage system for load shifting to evaluate annual electricity cost and annual electricity generation emissions. This was completed in the three grid regions, under tariff structures with Time-of-Use (TOU) pricing from Pacific Gas & Electric (PG&E), XCEL Energy – MN, and

Portland General Electric (PGE). The study evaluated three conditions to establish emissions control baselines: the eGRID annual regional emissions factor, Cambium average annual emissions factor, and Cambium hourly emissions factors from the 2025 mid-case scenario. The emissions results of demand shifting were compared to the annual building emissions calculated according to the Cambium hourly emissions factors. The cost control baseline evaluated the base demand profile without shifting using the same utility price structure, and the cost results of the demand shifts were compared to this annual energy cost. The NGW grid region also presented two additional emissions profiles for comparison, which were calculated according to the PGE Average (the annual average PGE reported emissions), and the PGE Hourly (calculated using PGE hourly reported emissions).

Modeling Analysis Inputs and Assumptions

The analysis modeled a ~108,000 square foot mid-rise multifamily building designed to exceed the performance requirements of ASHRAE 90.1-2022. The analysis looked at two control signals: utility pricing structures (optimized for cost) and hourly emissions factors (optimized for emissions reduction). Cost optimization was done using an online tool called Energy ToolBase (ETB) that analyzes hourly demand and utility pricing structures and operates the battery energy storage accordingly. The emissions control signal was executed using two shifting approaches. One utilized ETB, but with an emissions control signal, to aggressively optimize for emissions reduction. The other was a simplified algorithm, developed by the authors, which identified 3-hour high and low-emissions periods each day based on the emissions control signal and discharged the battery during high periods and charged during low periods. The simplified algorithm also had controls that prevented shifts from increasing monthly maximum demand. Figure 1 presents an example of the simplified algorithm demand shift in response to the long-range marginal emissions (LRMER) signal. The modeled battery charges during the middle of the day when marginal emissions are low and discharges at night when they rise.

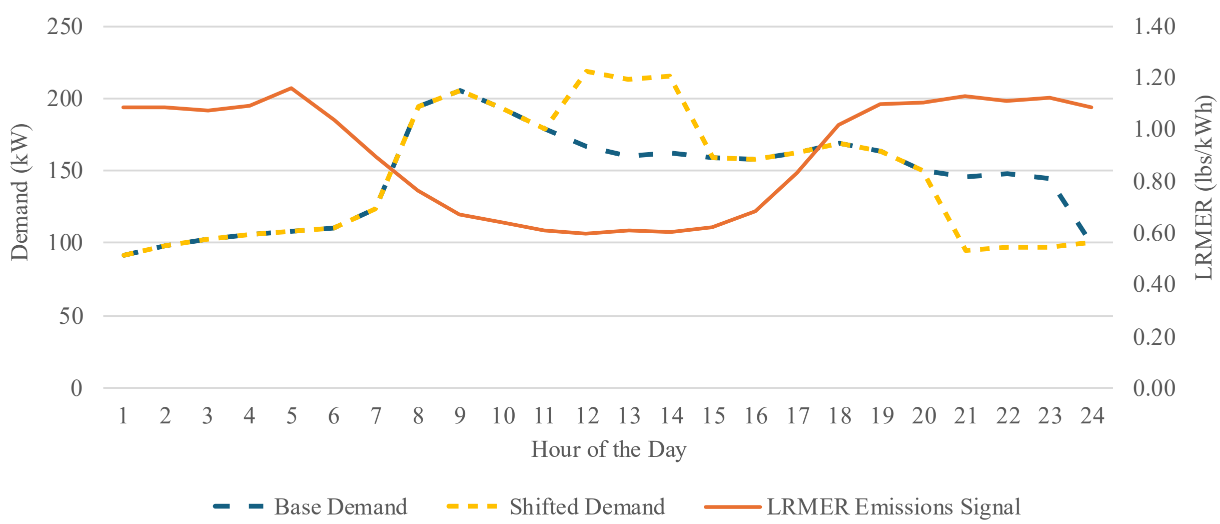

Figure 1. Emissions-Driven Demand Shift – MISO Simplified Algorithm

Three variations of emissions control signals were tested using both algorithms. The first used hourly emissions factors to optimize battery operations on a constantly updating basis. The second used the monthly average hourly emissions factors resulting in control profiles that updated each month. The final option used the annual average hourly emissions factors to create a fixed hourly control profile for the entire year. Table 3 describes how baselines for comparison, with no demand shifting, were derived using three different approaches to time-varying emissions factors. Table 4 describes the different cost and emissions control signals.

Table 3. Baseline Emissions Estimates without Shifting

Emissions Factor Profile	Description
No Shift - eGRID Annual	A single emissions factor that represents average emissions throughout the year
No Shift - Cambium Annual Avg	A single emissions factor that is calculated by averaging the Cambium Hourly AER factors
No Shift - Cambium Hourly AER	8760 emissions factors corresponding with each hour of the year from the Cambium AER dataset

Table 4. Control Signal Description

Control Signal	Description
PG&E B19, XCEL GSTOD, PGE Schedule 85	Uses utility tariff pricing as a DR signal
ETB – Hourly, Monthly, Annual	Uses Cambium hourly (8760 profile), monthly average hourly (a separate 24-hour profile for each month of the year), or annual average hourly (one 24-hour profile representing the average day) marginal emissions profile as a DR signal using the ETB algorithm.

CAMBIUM short-run and long-run marginal emissions rates (SRMER/LRMER) were used as emissions control signals. The emissions impact was estimated by multiplying the shifted hourly demand and the corresponding hourly marginal emissions factors. The resulting shifted demand profiles were tested using the cost module to estimate electricity cost impacts.

Modeling Results

The results of the analysis are presented below for the studied multifamily building in the CAISO, MISO, and NGW grid regions. The three grid regions were selected because they reflect some of the variability across the U.S. in a clean grid (CAISO), a dirty grid (MISO), and a grid with inconsistency across emissions factor data sources (NGW).

CAISO Analysis Results

The analysis results for the CAISO grid region are included below. Table 5 presents the energy cost and emissions control scenarios, with emissions calculated according to the three emissions factor profiles. Table 6 presents the results of seven control schemes that were executed according to energy cost, Long-Run emissions, or Short-Run emissions.

Table 5. CAISO Emissions and Cost Analysis Control Signal Results

Emissions Factor Profile	Electricity Cost (USD)	Estimated Electricity Generation Emissions (lbs CO2e)
No Shift - eGRID Annual Factor	$238,106	385,077
No Shift - Cambium Annual Factor	$238,106	395,727
No Shift - Cambium Hourly AER	$238,106	362,928

Table 6. CAISO Load Shift Signal Emissions and Cost Analysis

Control Scheme	Long-Run Cost Savings	Long-Run Emissions Savings	Short-Run Cost Savings	Short-Run Emissions Savings
PG&E B19	8.6%	-4.6%	8.6%	-3.0%
ETB - Hourly	-14.6%	21.9%	-13.5%	18.7%
ETB - Monthly	-12.2%	14.6%	-11.5%	3.9%
ETB - Annual	-7.8%	13.6%	-7.1%	0.1%
Simple - Hourly	0.0%	9.1%	-0.1%	8.0%
Simple - Monthly	0.0%	6.4%	0.0%	1.6%
Simple - Annual	0.1%	5.6%	0.3%	-0.3%

MISO Analysis Results

The analysis results for the MISO grid region are included below. Table 7 presents the energy cost and emissions control scenarios, with emissions calculated according to the three emissions factor profiles. Table 8 presents the results of seven control schemes that were executed according to energy cost, Long-Run emissions, or Short-Run emissions.

Table 7. MISO Emissions and Cost Analysis Control Signal Results

Emissions Factor Profile	Electricity Cost (USD)	Estimated Electricity Generation Emissions (lbs CO2e)
No Shift - eGRID Annual Factor	$120,355	913,429
No Shift - Cambium Annual Factor	$120,355	841,775
No Shift - Cambium Hourly AER	$120,355	880,561

Table 8. MISO Load Shift Signal Emissions and Cost Analysis

Control Scheme	Long-Run Cost Savings	Long-Run Emissions Savings	Short-Run Cost Savings	Short-Run Emissions Savings
XCEL GSTOD	7.3%	-1.2%	7.3%	-1.2%
ETB - Hourly	-8.2%	10.1%	-7.1%	15.1%
ETB - Monthly	-6.3%	4.0%	-4.0%	1.5%

ETB - Annual	-5.6%	3.3%	0.3%	0.2%
Simple - Hourly	-1.4%	4.6%	-0.1%	5.2%
Simple - Monthly	-1.7%	2.5%	0.2%	0.7%
Simple - Annual	-1.4%	2.4%	0.2%	0.1%

Northwest Analysis Results

The analysis results for the NGW grid region are included below. Table 9 presents the energy cost and emissions control scenarios, with emissions calculated according to the three emissions factor profiles. Table 10 presents the results of seven control schemes that were executed according to energy cost, Long-Run emissions, or Short-Run emissions.

Table 9. NGW Emissions and Cost Analysis Control Signal Results

Emissions Factor Profile	Electricity Cost (USD)	Estimated Electricity Generation Emissions (lbs CO2e)
No Shift - eGRID Annual Factor	$110,032	552.980
No Shift - Cambium Annual Factor	$110,032	56,672
No Shift - Cambium Hourly AER	$110,032	56,672
No Shift – PGE Average	$110,032	284,723
No Shift – PGE Hourly (Baseline)	$110,032	279,149

Table 10. Load Shift Signal Emissions and Cost Analysis

Control Scheme	Long-Run Cost Savings	Long-Run Emissions Savings	Short-Run Cost Savings	Short-Run Emissions Savings
PGE Schedule 85	5.4%	-1.9%	5.4%	1.0%
ETB - Hourly	-10.1%	5.7%	-11.0%	49.3%
ETB - Monthly	-8.2%	0.7%	-8.1%	11.1%
ETB - Annual	-4.4%	0.1%	-7.6%	4.0%
Simple - Hourly	-0.1%	1.9%	-0.1%	16.2%
Simple - Monthly	-0.2%	0.1%	0.1%	5.0%
Simple - Annual	-0.3%	-0.1%	0.1%	2.2%

The Pacific Northwest presents unique challenges for establishing electricity emissions factors. There is poor alignment between commonly used datasets eGRID, Cambium, and emissions estimates based on reported utility generation and import/export mix. As a result, additional data points were used to establish comparison baselines for this analysis. Given the significant difference between the EGRID and CAMBIUM annual emissions factors, the savings were calculated using emissions estimates based on historic reported demand and generation data from a local utility (PGE).

Unlike many regions of the United States, the Pacific Northwest does not operate under a single centralized RTO or ISO. Instead, electricity dispatch is managed through a network of balancing authorities, coordinated in part by the Northwest Power and Conservation Council.

The regional generation mix is also structurally different from most U.S. grids due to its heavy reliance on hydroelectric generation. While this resource base results in relatively low average emissions electricity generation, the transmission system in the region can be constrained. During periods when hydropower cannot be delivered where it is needed, utilities rely on a fleet of higher-emitting peaking resources to meet demand (Harrison 2022).

These structural characteristics contribute to the divergence observed across emissions datasets. The eGRID dataset, which is based on historical plant-level emissions reporting, captures the actual dispatch of these higher-emitting units and therefore reflects a grid mix that is more emissions intensive than the region's hydro capacity alone might suggest. In contrast, the Cambium dataset is forward-looking and models least-cost generation dispatch when estimating future emissions intensity. Because Cambium does not fully represent the region's transmission constraints, it often assumes hydroelectric resources can serve load wherever needed, resulting in projections that are significantly cleaner than those reflected in utility-reported data.

The differences between these datasets are reflected in Table 9. While the resulting emissions may appear unexpectedly high given the region's hydropower resources, they reflect real operational conditions rather than an accounting error. Given these dynamics, practitioners should exercise caution when developing or testing custom demand or emissions signals for the Pacific Northwest. At present, there is no third-party dataset that reliably provides forward-looking emissions factors while also capturing the region's operational transmission constraints.

Discussion

It is important to acknowledge the limitations of this study, which is only simulating and evaluating one building of a single typology (multifamily), according to one load management technology (storage), sized roughly according to the range of Californias Title 24 energy storage system requirements (2Wh/SF and 0.5W/SF), across 3 grid regions (NGW, CAISO, MISO). Additionally, this analysis is based on predictive emissions modeling provided from the Cambium datasets due to the lack of reported marginal emissions data from utilities. Despite this limitation, it begins to offer a lens into the variability of operational emissions performance when calculated according to and assessed against different emissions factors, and when these emissions factors are used as control triggers.

Just the selection of different emissions factors has an impact on the annual emissions projections of a building. Calculating annual emissions according to hourly emissions factors demonstrated a reduction in emissions for both the MISO (3.7%) and CAISO (6.0%) regions when compared to the eGrid flat emissions factor. The use of the annual average of the hourly factors demonstrated different results, with a reduction in the MISO region, and an increase in the CAISO region, reflecting the differences in seasonal generation across the two regions and the failure of the average to capture this effectively. The studied building uses most of the energy in the middle of the day. For the CAISO grid, which is cleaner with low-emissions generation during the day when the building is using the most energy, the averaged annual emissions factor increases the calculated emissions. For the MISO grid, which according to Cambium is dirtier during midday, the averaged annual emissions factor decreases the calculated emissions.

While most code and standards emissions compliance frameworks reference LRMER (when they reference time-based emissions factors at all), we see deviations between control schemes optimized around Long-Run emissions factors and the Long-Run and Short-Run emissions calculations, reflecting the differences between averages across longer terms and present-day generation emissions profiles. There may be opportunities for deeper emissions reductions or challenges with using the same load management strategies in the near term, even when compliance and building load management emissions reduction potential is assessed against long-term emissions factors.

Three major takeaways from this analysis for the “normal” or more predictable grid regions (MISO and CAISO) are: current control signals associated based on utility pricing structures were shown to decrease cost but increase emissions, control signals optimized for emissions reductions have the potential to significantly reduce operational emissions but also increase costs, and it is possible to reduce emissions while minimizing cost increases, but true optimization will require both price and emissions signals. Additionally, it appears that greater emissions reductions can be achieved using more granular control signals that better reflect actual grid behavior rather than general trends. Regarding implementation, aggressively optimized shifting for either cost or emissions resulted in rapid battery cycling, which may introduce real-world operational challenges and impact battery storage system performance.

While the financial structures are not currently established to incentivize load management for emissions shifting, we may see a regulatory landscape where the cost of emissions is more fully priced into utility generation and building energy use dynamics in the coming decades. Table 11 outlines how operational energy costs would change if the social cost of greenhouse gas emissions(SC-GHG) was priced in, using a $270 value, which is aligned with the 30-year average assuming a 2% discount rate from 2030-2060 in EPAs 2023 report on this topic (U.S. Environmental Protection Agency 2023). 14 states are using the SC-GHG in various policy structures (Institute for Policy Integrity n.d.) , and in grid constrained environments a jurisdiction may see value in addressing the co-benefits of building level deployment. This demonstrates how a well-structured program that includes SC-GHG can achieve significant emissions reductions while also providing cost savings to customers.

Table 11. Energy and Emissions Savings with SC-GHG Priced In

	Long Run Emissions Savings	Energy Cost Savings
CAISO ETB Hourly	21.9%	$(24,034)
CAISO Simple Hourly	9.1%	$4,459
MISO ETB Hourly	10.1%	$2,137
MISO Simple Hourly	4.6%	$3,783
NGW ETB Hourly	5.7%	$(8,965)
NGW Simple Hourly	1.9%	$606

Conclusions and Recommendations

Better understanding the dynamics of how emissions factors impact projected emissions results will help better inform building policy structures, performance analysis, compliance, and real-world emissions performance. Calculations using time-based emissions factors can demonstrate emissions reductions when compared to annualized emissions factors, and more accurately reflect the emissions performance of buildings. Currently the potential impact of demand response measures is largely unaccounted for in emissions-based building code and policy compliance frameworks. This should be further studied in more building types and regional or local grid regions, to ensure policy requirements are not overestimating the emission reductions required of buildings.

Emissions factor sources differ and are sometimes communicating conflicting information about when emissions are highest or lowest. Additional study is needed to identify the extent and cause of these discrepancies and understand which values are most accurate and should be referenced when using time-based emissions calculations for code or policy development and for compliance calculations. Utilities need to provide insight into their actual hourly emissions profiles to help inform these studies.

The ability to shift building energy use profiles shows promise for decarbonizing buildings and electric grids, and is a useful tool for energy cost control, but these outcomes are not necessarily aligned. Initial research, completed in this paper, suggests there are some programming and operational schedules that achieve emission and cost reductions (see CAISO LRMER Simple algorithm), although not as significant as optimizing around only one. For this study, the authors used available modeled emissions data to simulate a control signal, but this is not a realistic expectation for building owners and operators and presents a risk for building level decisions to be misaligned with actual utility generation emissions. There is a need for utility-provided emissions signals so that building demand-shifting efforts can reliably align with grid emissions generation trends. Public utility commissions should be required to make regional and local generation emissions profile data available, align their cost structures with emissions production to incentivize emissions reductions, and provide clear signals that can be used to shift demand so that both cost and emissions are reduced.

Developing emissions-based building codes and performance standards should outline pathways for using more granular emissions factors to more accurately match real-world emissions performance and account for emissions savings from load flexibility technologies. Policy frameworks should establish which emissions factors are permitted to prevent compliance "gaming" by evaluating multiple emissions factor scenarios and selecting the most favorable.

While the market appears to not fully be ready to design and implement demand-shifting technologies around emissions reductions, there is a clear indication that the same technologies that achieve energy cost savings can achieve emissions reductions. As utilities are required to meet targets associated with renewable portfolio standards, it is reasonable to think that they will see building load management and demand flexibility as cost-effective pathways to meet grid decarbonization goals, and will develop and implement rate structures and signals that factor in the cost of energy and emissions. Establishing minimum requirements around demand flexibility and load management in buildings will provide better forecasting to utilities on the presence and availability of these resources.

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