Pacific Northwest NATIONAL LABORATORY

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Realizing Demand Flexibility with Commercial Building Energy Codes

December 2021

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U.S. DEPARTMENT OF ENERGY

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Summary

Building codes dictate standard design practice in the construction industry and must evolve accordingly to support the integration of newer, advanced technologies and innovative practices. Energy codes have historically focused on energy efficiency within buildings and across their systems. However, many of tomorrow's technologies go beyond efficiency and target increased flexibility. Such demand flexibility (DF) measures can postpone or reduce their electric load based on a price or other grid signal. These include smart appliances, connected lighting, and connected mechanical systems and energy storage. Expanding codes to enable such grid-interactive efficient buildings (GEBs) has the potential to influence their implementation on a large scale, which will support on-site renewable-energy utilization, building-grid integration, and energy resilience. However, considering DF measures in code development creates a new set of challenges for codes and the practices contained therein.

This report considers the role of commercial building energy codes in enabling GEB. Specifically, it highlights the status of DF measures in ASHRAE Standard 90.1, the U.S. national model energy code for commercial buildings. It examines the model code-development process and identifies components preventing the consideration and inclusion of DF measures, including code scope, characterization and analysis of proposed new prescriptive measures, and the time-of-day and geographic differences in their benefits. The report presents findings from code development analyses that show the cost benefit of DF measures and the potential limitations of the current code development process. To encourage building flexibility and improved energy resilience moving forward, recommendations are made for removing code development barriers and sanctioning measures that go beyond efficiency in future model codes.

Specifically, the analysis described in this report was conducted to better understand the impact of electric rate on the cost effectiveness of DF and distributed energy resource (DER) measures in order to inform the code development process. It investigates the benefits of incorporating an optional time-of-use (TOU) electricity rate into the internal processes followed by the ASHRAE 90.1 Standing Standard Project Committee (SSPC) to assess cost effectiveness of new technologies. The findings demonstrate that there can be substantial differences in measure cost savings based on the ASHRAE blended and ASHRAE TOU rates. For example, while many low-cost DF measures are likely to be proven cost effective with the ASHRAE blended rate, a fixed $/kWh charge for each hour of the year, this is less likely to be the case for DF and DER measures with higher first costs. In addition, analysis demonstrates that using the ASHRAE TOU rate increases cost savings attributed to standard efficiency measures that provide demand as well as energy-use reductions. Thus, including the TOU option in the code development process improves demand savings valuation, which will expand the body of proven and advancing technologies that can be included in energy codes.

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The authors acknowledge the Building Technologies Office of the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy for supporting this research and development effort. The authors thank Jeremy Williams, Program Specialist, for his guidance and strong support of the Building Energy Codes Program and this work. Finally, the authors would like to acknowledge the PNNL contributors, including David Winiarski and Matt Tyler.

Acronyms and Abbreviations

ANSI	American National Standards Institute
ARI	American Refrigeration Institute
BECP	Building Energy Codes Program
COP	coefficient of performance
DER	distributed energy resource
DF	demand flexibility
DOE	U.S. Department of Energy
EER	energy efficiency ratio
E/P	energy to power ratio
EV	electric vehicle
GEB	grid-interactive efficient building
HVAC	heating, ventilation, and air conditioning
ICC	International Code Council
IECC	International Energy Conservation Code
kW	kilowatt
kWh	kilowatt hour
LCC	life cycle cost
OA	outside air
O&M	operation and maintenance
PNNL	Pacific Northwest National Laboratory
SHGC	solar heat gain coefficient
SSPC	Standing Standard Project Committee
TDV	time dependent value
TOU	time-of-use

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1.0 Introduction

Building codes dictate standard design practice in the construction industry, and they must continually evolve to account for advancing technologies and innovative practices. Energy codes have historically focused on energy efficiency within buildings and across their systems. However, many of tomorrow's technologies go beyond efficiency and target increased flexibility. Such demand flexibility (DF) measures can postpone or reduce their electric load based on a price or other grid signal, and include smart appliances, connected lighting, and connected mechanical systems and energy storage. Expanding codes to enable such grid-interactive efficient buildings (GEBs) has the potential to influence their implementation on a large scale, which will support renewable-energy grid-integration, building-sector decarbonization, and energy resilience. However, considering DF measures in code development creates a new set of challenges for codes and the practices contained therein.

This report considers the role of commercial building energy codes in enabling GEBs. Specifically, it highlights the status of DF measures in the American Society of Heating, Refrigeration and Air-Conditioning Engineers (ASHRAE) Standard 90.1, the U.S. national model energy code for commercial buildings. It examines the model code-development process and identifies components barring the consideration and inclusion of DF measures, including code scope, characterization and analysis of proposed new prescriptive measures, and the time-of-day and geographic differences in their benefits. The report presents findings from code development analyses that indicate the cost benefit of DF measures and the limitations of historic code development conventions. To encourage DF and improved energy resilience moving forward, recommendations are made for removing code development barriers and sanctioning DF measure consideration in future model codes.

1.1 GEB Concepts

As defined by the U.S. Department of Energy (DOE) based on stakeholder input (DOE 2019),

> A GEB is an energy efficient building that uses smart technologies and on-site distributed energy resources (DERs) to provide DF while co-optimizing for energy cost, grid services, and occupant needs and preferences, in a continuous integrated way.

Energy efficiency measures lower overall building energy use, which can reduce peak loads and flatten the daily load curve. Alternatively, DF measures can shift load to be non-coincident with the electricity system peak or to coincide with peak renewable energy generation. Such dynamic measures can be automatically deployed in reaction to a demand response event, energy use threshold, or price increase. DF measures can work in conjunction with on-site DERs, which include energy generation and storage systems (e.g., rooftop photovoltaics, battery storage, and electric vehicles). DF measures allow the building to function as a DER by changing the timing and magnitude of grid electric loads.

The vision for GEB includes the integration and optimization of DF measures and DERs. The strategy includes the use of advanced building technologies, such as a connected heating, ventilation, and air conditioning (HVAC) system; connected lighting; dynamic windows; occupancy sensing; thermal mass; distributed generation; and battery storage. Their operation is supported by sensors and controls coupled with smart analytics that optimize energy use while meeting occupant needs and preferences (DOE 2019).

Achieving the GEB vision will result in buildings that are responsive and able to provide new grid services. For example, energy efficiency provides generally continuous service by decreasing electricity generation capacity requirements. While efficiency can be used to shape the electricity supply curve seasonally and daily, DF can operate across a finer range of timescales, depending on the end use and technology. Load shifting and shedding can impact daily behavior to mitigate supply source ramping and capture surplus renewables. Hourly responses can help manage supply contingency events and provide some net load tracking. Fast response (referred to as shimmying or modulation), which occurs over minutes or seconds, can support grid balancing to smooth short-term net load changes and support frequency regulation (Alstone et al. 2017).

The value of grid services is time dependent and varies regionally and geographically. It is dependent on seasonal system peaks and coincidence factors[1], which influence the time of peak and off-peak periods and the avoided costs associated with demand savings (Mims et al. 2017). Distribution system constraints can also impact the locational value of efficiency and the value of DF services. From a building owner perspective, DF value is linked to utility rates, demand response program incentives, aggregator service contracts, and/or penalties for exceeding peak thresholds. Thus, an important consideration for building owner investments in DF technologies is their ability to provide added value, which model codes are not currently taking into account.

1.2 National Model Commercial Building Energy Codes

Historically, the intent of energy codes is to cost-effectively minimize the use of energy in buildings. To achieve this, building energy codes address the design and construction of new buildings and major renovations. They provide minimum requirements for energy performance-related features that are within the scope of design and construction teams. Addressing efficiency at the time of construction offers an opportunity to influence building performance at minimal incremental cost.

The United States does not have a national energy code. Instead, states or local jurisdictions can choose to adopt one of the national model energy codes or develop their own state-specific code. These national model energy codes are developed by two organizations. ASHRAE develops the model commercial energy code, known as ASHRAE Standard 90.1 (ASHRAE 2016). The International Code Council (ICC) develops the International Energy Conservation Code (IECC), which contains requirements for residential and commercial buildings (ICC 2018). The national model codes are periodically updated, with new codes published every 3 years.[2]

DOE plays a supportive role in the development of building energy codes as defined by federal statute, namely the Energy Conservation and Production Act as modified by the Energy Policy Act of 1992. The statute directs DOE to review the technical and economic basis for voluntary building energy codes and participate in the industry review process, including seeking adoption of all technologically feasible and economically justifiable energy efficiency measures.

As one of DOE's national laboratories, Pacific Northwest National Laboratory (PNNL) has played a major role in supporting DOE's Building Energy Codes Program (BECP) since the

[1] The coincidence factor is the ratio of the simultaneous maximum demand of two or more loads within a specified period to the sum of their individual maximum demand within the same period.
[2] For more information, see DOE's Energy Codes 101 webpage at https://www.energy.gov/eere/buildings/articles/energy-codes-101-what-are-they-and-what-doe-s-role

program's inception in 1993. PNNL is closely involved in upgrading the model codes and standards, providing assistance to the ASHRAE Standing Standard Project Committee (SSPC) for 90.1 (SSPC 90.1), and participating in the industry process to update the IECC for both commercial and residential buildings.

PNNL's role in model code development includes 1) quantifying energy performance reduction to indicate the progress of building standards after each 3-year code cycle and 2) evaluating the economics of substantive code change proposals supported by DOE and other stakeholders during the 3-year development cycle. To carry out the performance analysis, PNNL has developed and maintains a suite of prototype building simulation models characterized in a range of U.S. climate zones[1], which are available for download.[2] The progress indication is determined from the simulation results, which are scaled by floor area weighting factors based on building type and geographic area determined from new building construction data (Jarnagin and Bandyopadhyay 2010). The ongoing economic assessment of proposed code changes follows a defined methodology (Hart and Liu 2015). For example, the ASHRAE 90.1 SSPC discusses cost-effectiveness analysis related to the American National Standards Institute (ANSI) consensus process in its work plan developed for the 2022 code cycle.[3] The document states that ASHRAE or ANSI does not have an overt requirement for economic analysis but that the committee often uses economic analysis to support the consensus decision-making process. Included in the work plan are energy prices and life cycle cost (LCC) analysis parameters used to substantiate code change proposals for the 2022 code cycle.

The methodology applied by PNNL to determine commercial code proposal cost effectiveness includes three primary steps: 1) evaluating the energy and energy cost savings of code changes, 2) evaluating the incremental first costs related to the changes, and 3) determining the cost effectiveness of energy code changes based on those costs and savings over time. Cost effectiveness is defined primarily in terms of LCC evaluation. The methodology includes calculating several LCC-derived metrics intended to assist states considering adoption of new codes. In this study, the code development cost-effectiveness methodology is applied, and economic metrics determined in order to investigate the benefit of considering DF measures in codes.

[1] This approach is consistent with the climate zones specified by IECC or ASHRAE for residential or commercial buildings, respectively. These include 16 building types simulated across 17 of the 19 climate zones identified by ASHRAE Standard 169 that are used to set energy codes requirements. Recently developed climate zones 0A (extremely hot and humid) and 0B (extremely hot and dry) are not yet incorporated.

[2] https://www.energycodes.gov/development/commercial/prototype_models

[3] The 2022 Work Plan was presented and approved at ASHRAE SSPC 90.1 meeting on February 3, 2020 in Orlando, Florida.

2.0 Considering GEB in Model Codes

In the United States, advanced codes are starting to support the delivery of GEB and DERs that promote electric load flexibility and responsiveness. For example, DER and DF measures are recognized in California's 2019 Title-24 building energy code (CEC 2018), and are defined as follows:

> Measures that reduce TDV[1] energy consumption using communication and control technology to shift electricity use across hours of the day to decrease energy use on-peak or increase energy use off-peak, including but not limited to battery storage, or HVAC or water heating load shifting.

However, a review of the ASHRAE Standard 90.1-2016 commercial building prescriptive requirements was conducted to evaluate the status of such GEB considerations in national model codes (Franconi et al. 2019). The assessment determined that there are many instances where requirements are specified for active controls for HVAC, lighting, power, service hot water heating, and elevators. Yet, the direct or indirect automated control of such equipment or systems, instigated in response to a grid signal, is not yet addressed.

A limitation for considering GEB in model energy codes is the historical focus of codes on energy efficiency improvements that can be broadly cost justified on a flat, blended national average cost per unit energy basis, which accounts for energy use and demand charges. As a result, past commercial model code cost-effectiveness assessments have applied the flat utility rate specified in the ASHRAE Standard 90.1 Work Plan, which cannot account for the time-dependent benefits of demand response.

Accounting for grid services in future model code development will require continuing to address code-minimum energy efficiency requirements while also accounting for demand response and load flexibility measures. An obvious challenge is that the impact of energy efficiency measures is based on assessing annual energy use reductions, while the value of demand response is time-of-day and location specific. A demand response assessment falls outside of the methodologies historically followed for assessing the impact of code changes and their cost effectiveness.

Some headway is being made though. Included as part of the ASHRAE 90.1-2022 Work Plan is a TOU rate that can be used as an optional alternative to the traditional blended energy rate. The ASHRAE TOU rate represents a typical U.S. TOU rate that was developed from nearly 1,700 compiled commercial building rates that include demand charges offered by utilities located across the country (McLaren 2017). The ASHRAE TOU rate includes electricity kilowatt-hour (kWh) and kilowatt (kW) charges that vary by hour of day and season. It permits economic value to be assigned to DF measures that are capable of targeted electric load reduction and shifting. More details regarding the development of the ASHRAE TOU rate are provided in Appendix A. The inclusion of a TOU rate into the code development methodology allows DF

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[1] Time dependent value (TDV) is the basis for determining cost effectiveness of energy efficiency measures for new buildings in California. TDV is based on a series of annual hourly values of electricity costs in a typical weather year. Values are developed for residential and nonresidential buildings in each of the 16 California climate zones. Retail costs are not used since they are based on averages over time periods rather than hourly differences in the cost of generation. The approach supports energy efficiency measure savings to be valued on a time-dependent basis, which better reflect the actual costs to consumers and the utility system.

measures, which may not provide an overall energy use reduction (such as battery storage), to demonstrate an economic justification.

2.1 Demand Flexibility Measure Analysis

This GEB-in-codes study characterizes, evaluates the performance of, and determines the cost benefits of a handful of demand flexibility measures. The analysis objectives are to investigate the implications of TOU electric rates on the cost effectiveness of traditional energy efficiency measures, as well as a variety of DF measures that provide demand reduction but some or no energy savings.

Using building simulation analysis, the performance of the PNNL medium office prototype building model[1] (Thornton et al. 2011) was evaluated in three ASHRAE-specified climate zones, specifically: 2A (Tampa, FL), 4A (New York City, NY), and 6A (Rochester, MN). Three electric rates were used to evaluate annual energy costs. Each is summarized in the next section. They include a fixed blended rate (ASHRAE blended), a moderate TOU rate (ASHRAE TOU), and an aggressive TOU rate (ConEd TOU).[2]

2.1.1 Electric and Gas Energy Rates

Figure 1 provides a snapshot comparison of the electric rates used in the study. The two charts show values for a winter week and a summer week for the three rate schedules. Solid lines indicate energy costs (left y-axis scale). Dashed lines indicated demand cost (right y-axis scale).

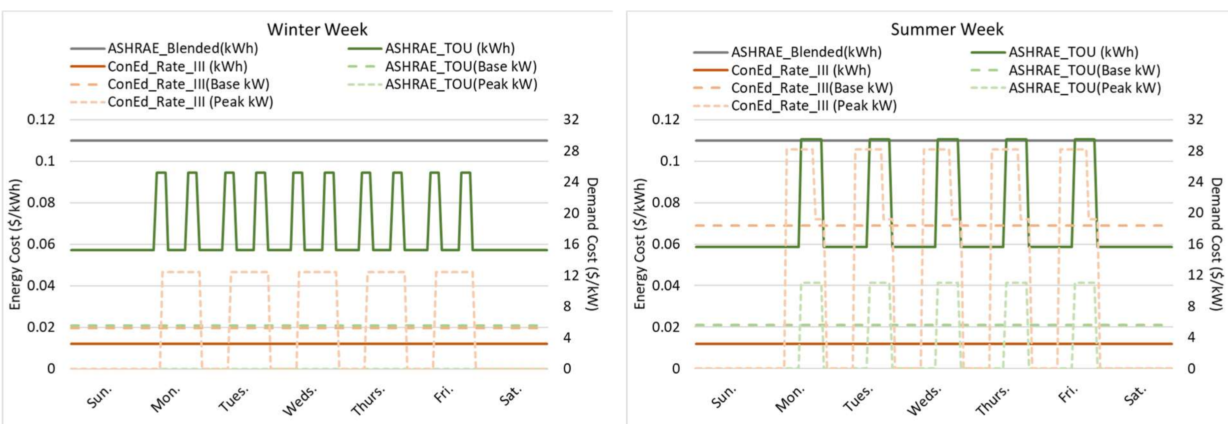


Figure 1. Comparison of Rates Uses in the DF Measure Analysis

2.1.1.1 Rate Descriptions

The standard natural gas price used in the analysis is $0.08021/therm, which is the value stated in the ASHRAE 90.1-2022 Work Plan.

[1] The medium office prototype is a 3-story, 53,600-square-foot building. It has a slab-on-grade foundation, packaged air-conditioning with gas furnace mechanical system, and ducted air distribution system with variable-air-volume boxes and electric reheat.

[2] In this study, the classification of TOU rates as moderate or aggressive is based on the price variation in the tariff and duration of peak periods that result in higher demand costs, which encourages customers to invest in controls and technologies allowing load shifting.

ASHRAE Blended Electric Rate

This is the standard electric energy price stated in the ASHRAE 90.1-2022 Work Plan, equaling $0.1099/kWh for electricity (which includes demand charges). This rate is updated every 3 years and is based on published Energy Information Administration utility energy data (EIA 2019).

ASHRAE TOU Electric Rate

This is the alternative TOU electric rate included in the ASHRAE 90.1-2022 Work Plan. The winter electric price schedule applies October through May. The summer electric price schedule applies June through September. This rate excludes a winter peak demand charge.

- Winter
  - $0.0946 per kWh, peak hours
  - $0.0571 per kWh, off-peak hours
  - $5.59 per kW, base
  - No peak kW charges
  - Peak: Monday–Friday, 6 AM to 10 AM and 5 PM to 9 PM
- Summer
  - $0.1104 per kWh, peak
  - $0.0586 per kWh, off-peak
  - $5.59 per kW, base
  - $10.99 per kW, peak
  - Peak: Monday–Friday, 1 PM to 9 PM.

ConEd TOU Electric Rate

Published as Consolidated Edison New York City, Rate III, General Large Voluntary Time-of-Day,[1] this electric rate is available for commercial services ranging from 10 kW to 1,500 kW. The winter electric price schedule applies October through May. The summer electric price schedule applies June through September. The summer rate includes two peak demand periods (which are shown as a single data series in Figure 1 for simplicity).

- Winter
  - $0.1197 per kWh, all hours
  - $5.26 per kW, base
  - $12.43 per kW, peak
  - Peak: Monday–Friday, 8 AM to 10 PM
- Summer
  - $0.1197 per kWh, all hours

[1] Retrieved on December 31, 2019, from https://openei.org/apps/USURDB/rate/view/5cd201dc5457a3c62754e9d4#1__Basic_Information

- $18.36 per kW, base
- $28.15 per kW, peak 1
- $19.20 per kW, peak 2
- Peak 1: Monday–Friday, 8 AM to 6 PM
- Peak 2: Monday–Friday, 6 PM to 10 PM.

Monthly energy (kWh) cost is equal to the product of the energy consumed and the cost per unit energy. The determination of the monthly electric demand cost is not intuitive. The base demand charge is applied to the maximum peak demand for the month regardless if it occurs during an off-peak or on-peak period. The peak period demand charge is applied to the maximum demand occurring during the period. Note that as indicated by the ASHRAE TOU winter peak period, a peak period may span non-contiguous hours.

The total monthly charge for demand can be determined from Equation (1).

$$Monthly\ kW\ Cost = kW_{max\ month} * kW\ Cost_{base} + \sum_{i=0}^{n} kW_{max\,peak\,period,i} * kW\ Cost_{peak\,period,i} \quad (1)$$

where n is the number of peak demand periods in the electric rate for the month.

2.1.2 Measures

A set of measures was analyzed to better understand the variation in attributed value that can occur when considering TOU electric rates in addition to a blended electric rate. Table 1 outlines the measures, which are individually modeled in the medium office building simulation model. The medium office baseline condition is a minimally compliant ASHRAE Standard 90.1-2016 building. The assessment includes two energy efficiency measures, five DF measures, and one DER measure. The DF and DER selected measures were informed by, and are consistent with, measures considered in related work (Alstone et al. 2017; Jungclaus et al. 2019; Langevin et al. 2019). More measure details, including building simulation model input values, are presented in Appendix B.

Table 1. Demand Flexibility Analysis Measures

Measure	Name	Description
Standard Efficiency	SHGC decreased by 10%	The window solar heat gain coefficient (SHGC) is decreased by 10% compared to baseline values.
	EER increased by 20%	The energy efficiency ratio (EER) of the packaged air-conditioning units is increased by 20% compared to the baseline value.
Demand Flexibility	Lighting 20% load reduction	Light levels are decreased in regularly occupied spaces during TOU peak periods by reducing power 20% relative to installed design capacity.
	Pre-cooling with zone temp setup	Preceding the summer afternoon TOU peak period, the building temperature setpoint is ramped down in order to decrease the cooling load in the afternoon.
	Early preheat	A ramped pre-heat is initiated 2 hours early during winter to reduce the morning heating demand.
	OA ventilation ramp down	Outside air (OA) is supplied earlier and stays at a lower rate during the winter morning peak period; in summer, it exceeds design flows prior to the peak afternoon period then ramps down over the afternoon.
Distributed Energy Resource	Battery storage – monthly and daily forecast	Semi-optimized battery storage (sized at 5 Wh/ft^2 of floor area or 268 kWh) charge/discharge strategy that aims to minimize monthly demand costs. The battery is charged at night. The battery is discharged during the day based on a worse-day load profile prediction for each month. The hourly discharge for the worse day was determined using an optimization function. The monthly forecast sets a reduced demand goal for each hour based on that achieved for the worse day. The battery is discharged to achieve the target. The daily forecast applies the worse-day discharge strategy for each day in the month, which results in more daily charge/discharge than the monthly forecast.

3.0 Results and Discussion

The annual energy use and costs determined for each simulation run are summarized in Table 2**Error! Reference source not found.**. As indicated in the table,**Error! Reference source not found.** the energy consumption, peak demand, and associated energy savings are fixed for a specific measure and climate zone, but their annual electric costs and savings differ for the three electric rates. For the three climate zones, annual natural gas costs for the building are negligible compared to the annual electric costs. To indicate measure impact on demand over the year, the sum of each month's maximum demand savings is included (column 3). A change in this value indicates changes in monthly peak demand over the year, although the savings may only occur in summer or winter months. This metric is more revealing than examining the maximum annual demand, which not all measures impact.

All measures decrease demand overall except for the pre-cooling measure, which shifts yet increases demand outside of the ASHRAE TOU summer peak period. The standard efficiency measures impact demand at levels equivalent to the DF measures. They have the largest impact in the warmer 2A climate since they address cooling load and cooling equipment efficiency. Overall, the battery storage results in the most substantial reduction in demand and annual cost savings. This is not unexpected since battery storage is a more capital intensive DER while the DF measures are generally low cost.

Figure 2**Error! Reference source not found.** highlights the energy and demand cost contributions to the total annual cost for the three electric rates. It is worth noting that the average annual electric cost for the baseline building across the climate zones is nearly equal for the ASHRAE blended rate and the ASHRAE TOU rate.[1] And while the ConEd TOU rate is much more aggressive than the ASHRAE TOU rate, its average annual baseline cost across the three climate zones is only about 20% higher.

The baseline annual energy cost breakdown for energy and demand is significantly different for the two TOU rates. For the ASHRAE TOU rate, energy and demand costs contribute about 66% and 34% to total annual costs, respectively. By contrast, the breakdown is 9% and 91% for the ConEd TOU rate, which should improve the economics of DF measures. Across all the measures except battery storage, the allocation of annual cost between energy and demand varies little compared to the baseline data. For the battery measure though, the ASHRAE TOU energy cost allocation increases by 8% to total 74% and the ConEd TOU by 2% to total 11%. The lower portion of cost allocated to energy use for ConEd can be explained by its high demand and low energy rates.

The annual energy costs vary significantly across the measure and electric rates. In general, the standard efficiency and DF measures show lower annual electric costs with the ASHRAE TOU rate compared to the ASHRAE blended rate. However, two exceptions, the early pre-heat and the 10% reduction in SHGC, occur in climate zone 2A due to the measures' impact being dominated by energy and not demand savings in this warm climate. In general, the measures result in lower annual energy costs than the baseline for the ConEd TOU rate - except for the pre-cooling measure. This measure's scheduling and the other DF and DER measures were developed based on the ASHRAE TOU peak periods. In actual application, the savings for the measures would be greater since their operational schedules would be optimized for the ConEd TOU peak periods.

[1] This is not coincidental. See Appendix A for more details regarding the development of the ASHRAE TOU rate.

Table 2. Annual Energy Consumption and Costs

Measure	Annual Energy Use				Annual Energy Costs									
	Electric			Gas	ASHRAE Blended			ASHRAE TOU			ConEd TOU			Gas ($)
	Energy (kWh)	Sum of Months Max kW	Peak Demand (kW)	Therms	kWh (%)	kW (%)	Total ($)	kWh (%)	kW (%)	Total ($)	kWh (%)	kW (%)	Total ($)	
2A-Tampa, FL														
Baseline	470,127	1,655	155.6	1,118	100	-	51,667	68	32	50,127	10	90	57,679	90
SHGC decreased by 10%	466,676	1,640	154.2	1,119	100	-	51,288	68	32	49,749	10	90	57,179	90
EER increased by 20%	465,262	1,606	148.9	1,118	100	-	51,132	69	31	49,220	10	90	55,975	90
Lighting 20% load reduction	466,358	1,630	149.6	1,118	100	-	51,253	69	31	49,374	10	90	56,501	90
Pre-cooling with zone temp setu	475,804	1,791	189.7	1,118	100	-	52,291	69	31	49,828	9	91	63,889	90
Early preheat	468,955	1,654	155.6	1,119	100	-	51,538	68	32	50,022	10	90	57,660	90
OA ventilation ramp down	465,880	1,642	152.2	1,112	100	-	51,200	68	32	49,487	10	90	57,040	89
Battery storage - monthly peak	475,638	1,311	125.4	1,118	100	-	52,273	75	25	45,284	12	88	48,404	90
Battery storage - daily peak	480,497	1,311	125.4	1,118	100	-	52,807	75	25	45,170	12	88	48,462	90
4A-JFK Airport, NY														
Baseline	409,321	1,665	233.7	2,171	100	-	44,984	66	34	45,676	9	91	55,120	174
SHGC decreased by 10%	408,160	1,660	234.1	2,224	100	-	44,857	66	34	45,479	9	91	54,781	178
EER increased by 20%	407,689	1,641	233.7	2,171	100	-	44,805	66	34	45,181	9	91	54,029	174
Lighting 20% load reduction	406,192	1,639	233.7	2,174	100	-	44,640	66	34	44,975	9	91	53,839	174
Pre-cooling with zone temp setu	414,943	1,824	233.7	2,171	100	-	45,602	66	34	45,763	8	92	62,448	174
Early preheat	407,629	1,587	194.9	2,186	100	-	44,798	67	33	45,023	9	91	54,283	175
OA ventilation ramp down	408,406	1,659	233.7	1,986	100	-	44,884	66	34	45,401	9	91	54,923	159
Battery storage - monthly peak	413,273	1,234	164.1	2,171	100	-	45,419	74	26	40,408	11	89	45,093	174
Battery storage - daily peak	419,691	1,234	164.1	2,171	100	-	46,124	74	26	39,920	11	89	45,089	174
6A-Rochester, MN														
Baseline	441,219	1,988	234	5,069	100	-	48,490	65	35	50,053	9	91	60,963	407
SHGC decreased by 10%	440,723	1,984	234	5,131	100	-	48,435	65	35	49,882	9	91	60,511	412
EER increased by 20%	440,179	1,963	234	5,069	100	-	48,376	65	35	49,573	9	91	59,771	407
Lighting 20% load reduction	438,382	1,971	234	5,073	100	-	48,178	65	35	49,417	9	91	59,734	407
Pre-cooling with zone temp setu	447,006	2,130	234	5,070	100	-	49,126	65	35	49,930	8	92	67,564	407
Early preheat	440,620	1,851	195	5,091	100	-	48,424	66	34	49,052	9	91	59,617	408
OA ventilation ramp down	440,813	1,974	234	4,472	100	-	48,445	65	35	49,715	9	91	60,167	359
Battery storage - monthly peak	443,880	1,441	160	5,069	100	-	48,782	73	27	44,050	11	89	49,074	407
Battery storage - daily peak	451,589	1,441	160	5,069	100	-	49,630	73	27	43,256	11	89	49,094	407

Measure annual cost savings are presented in Figure 3. Due to the large range of savings across the measures, the measure results are presented in two charts to improve resolution. In general, the annual savings are greater with increasing demand rate. As noted above, the DR and DER measure savings for the ConEd rate could be greater if their scheduling had been optimized for the ConEd TOU peak rate period instead of that for the ASHRAE TOU.

In Figure 4, the whole-building electric load profile is shown, by climate zone and month, for the baseline condition and each measure. The data are for the day with the highest baseline peak demand occurring in the month.

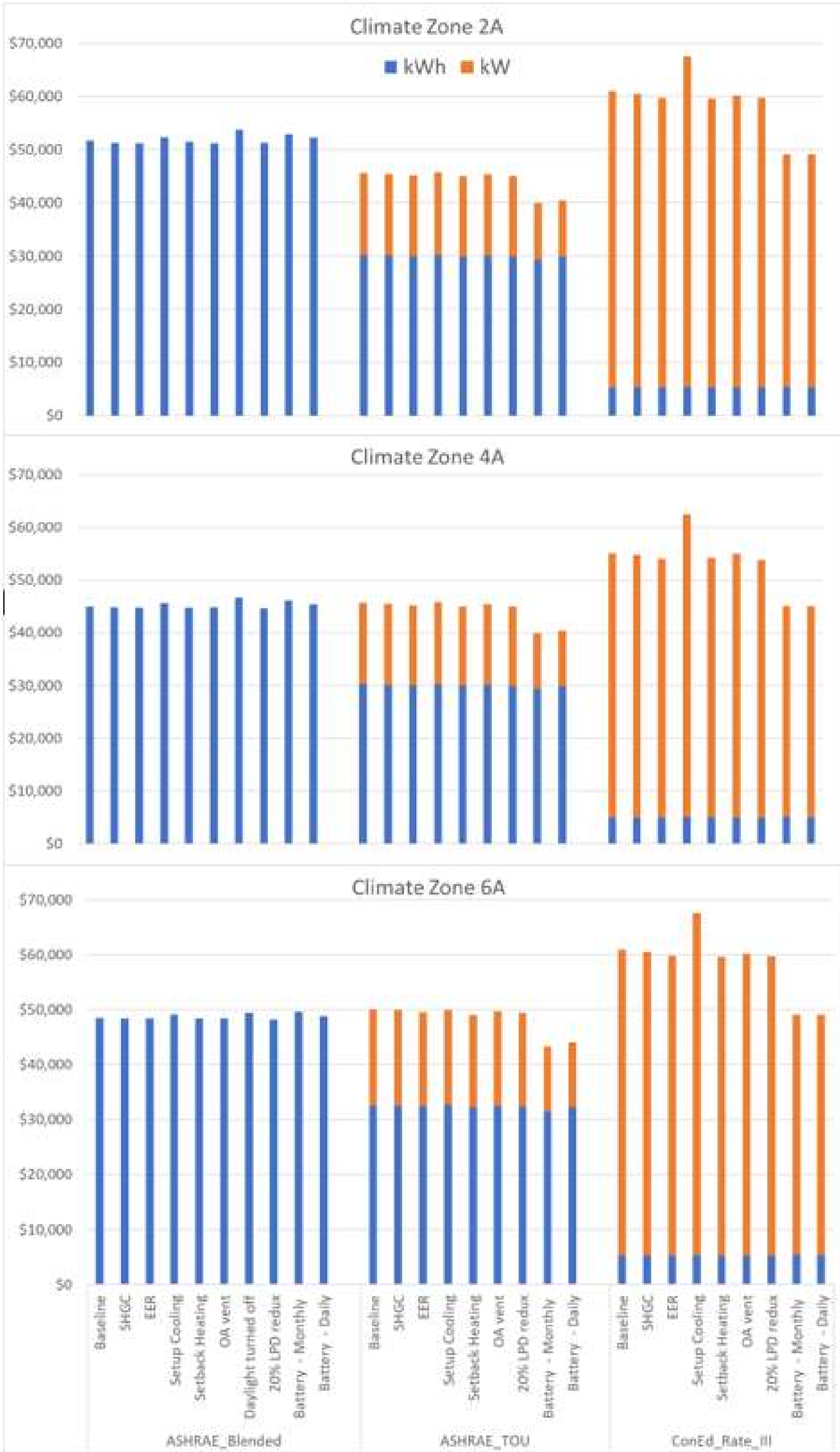


Figure 2. Annual Electric Energy and Peak Demand Cost Contributions

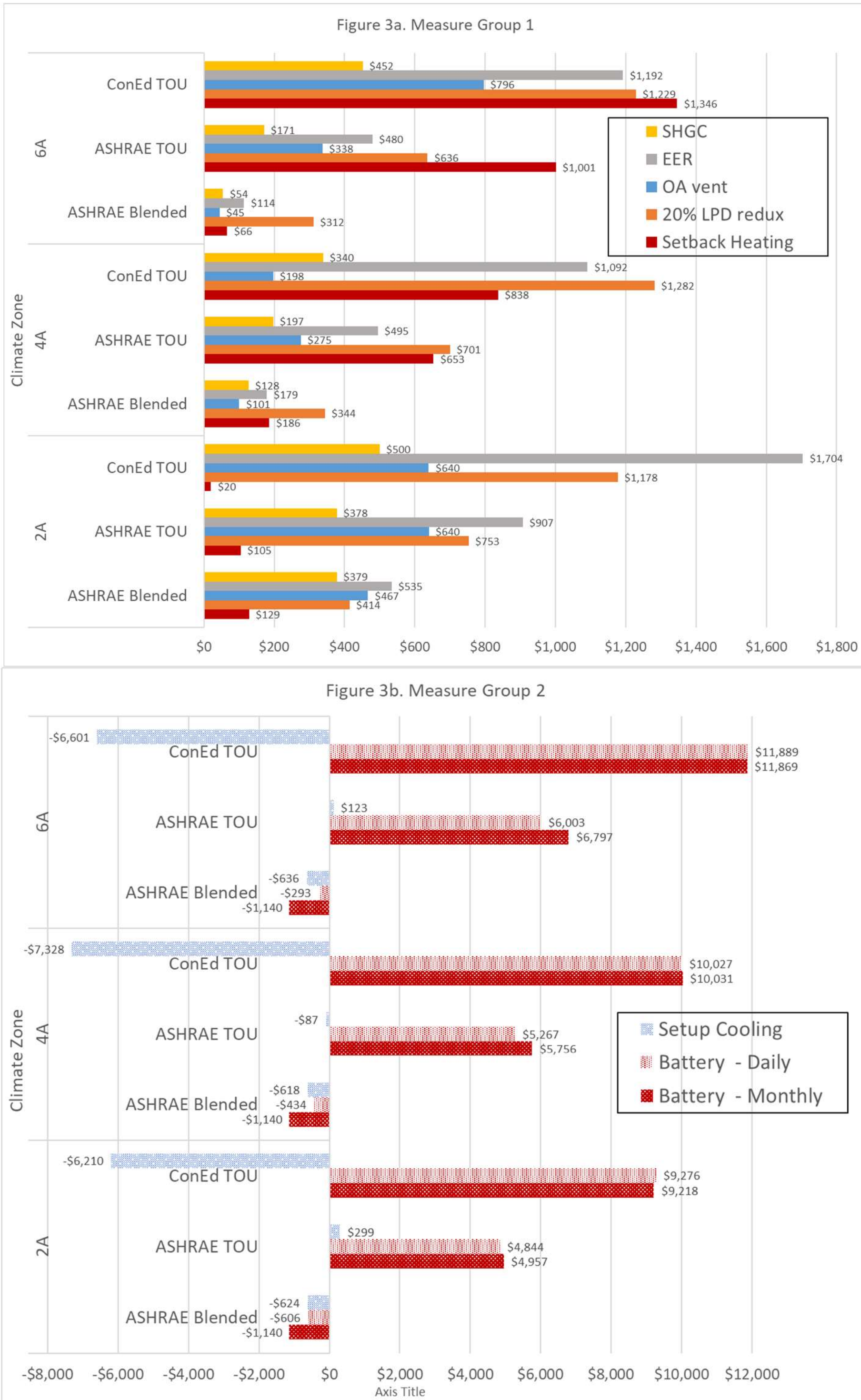


Figure 3. Annual Electric Cost Savings

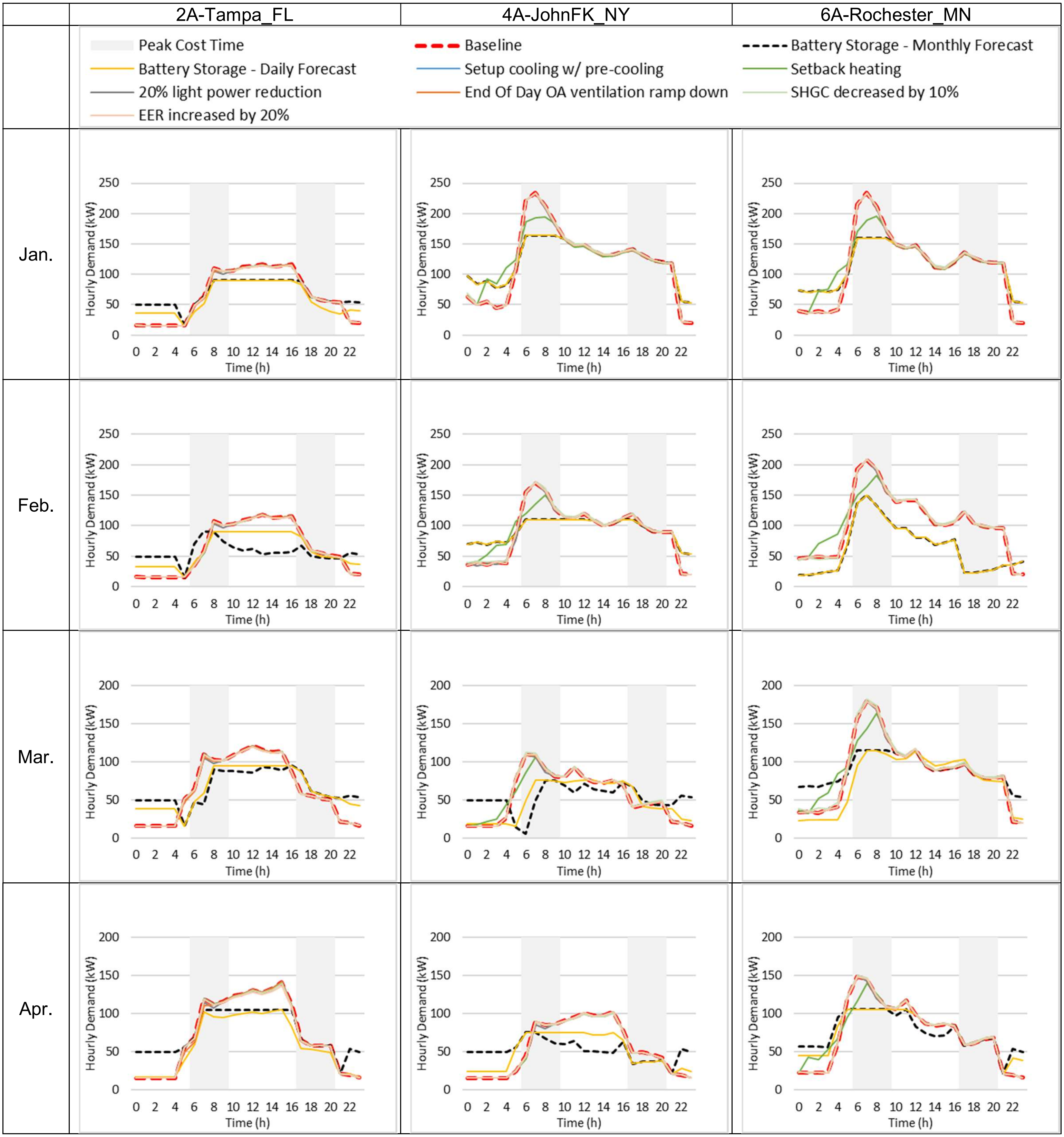


Figure 4. Baseline and Measure Load Profiles

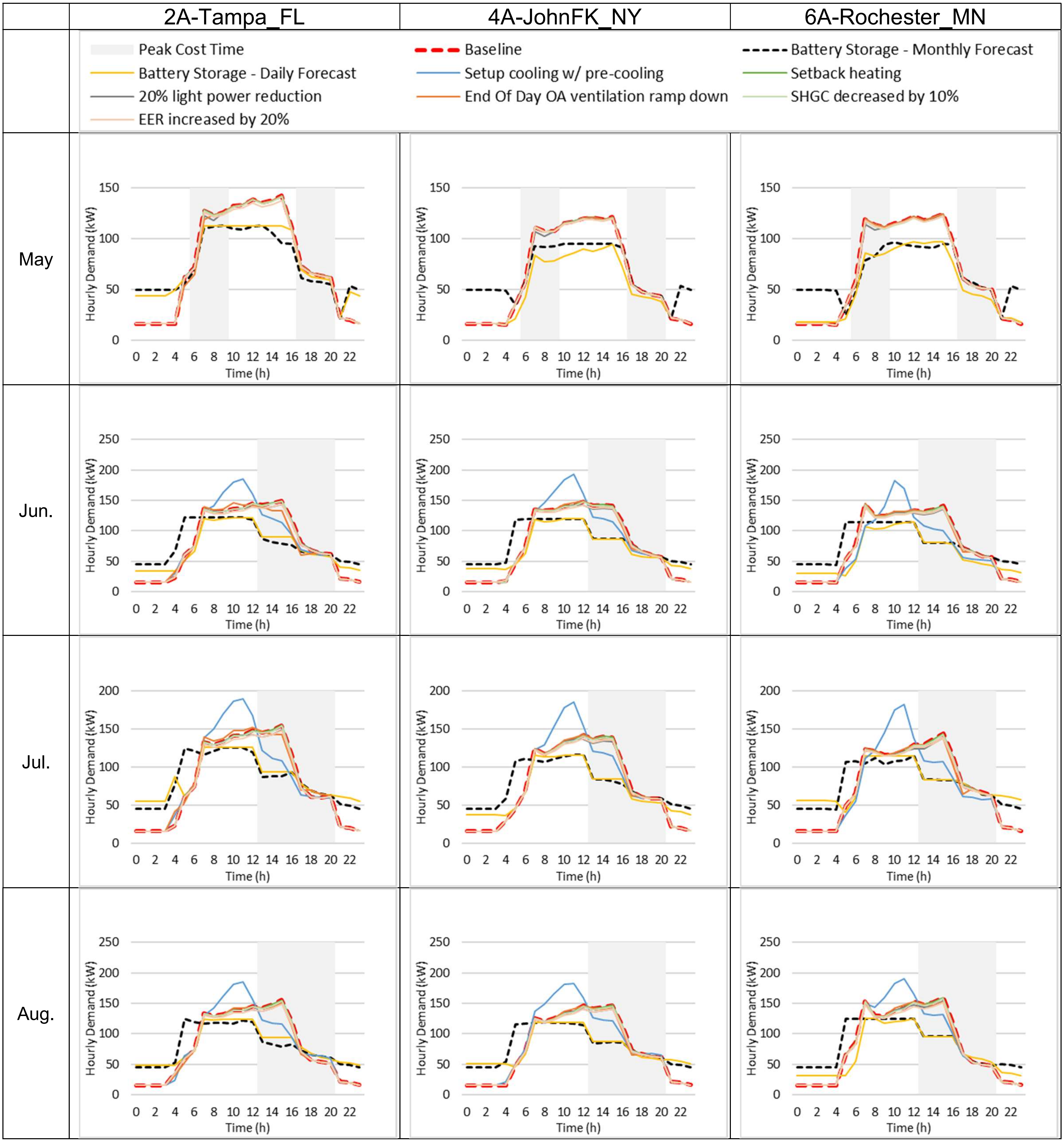
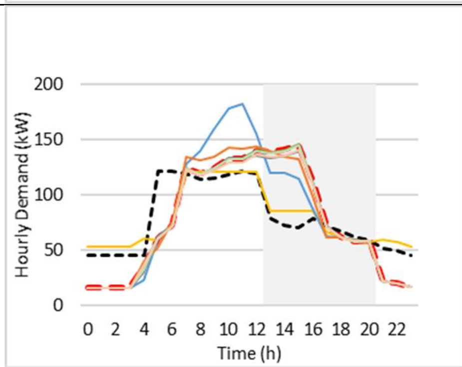
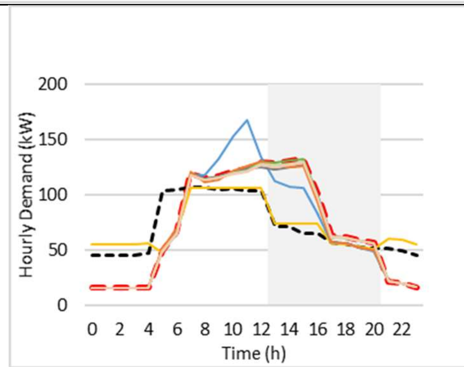
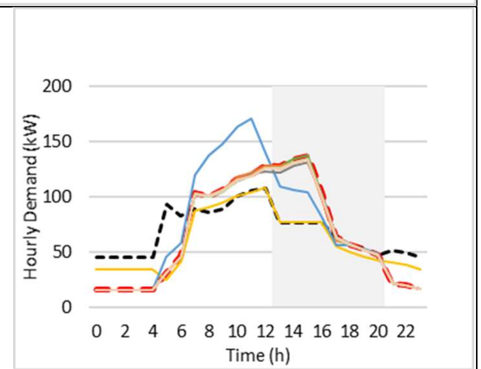

2A-Tampa_FL
4A-JohnFK_NY
6A-Rochester_MN
Peak Cost Time
Baseline
Battery Storage - Monthly Forecast
Battery Storage - Daily Forecast
Setup cooling w/ pre-cooling
Setback heating
20% light power reduction
End Of Day OA ventilation ramp down
SHGC decreased by 10%
EER increased by 20%
May
Jun.
Jul.
Aug.
Hourly Demand (kW)
Time (h)

Figure 4**Error! Reference source not found.**. Baseline and Measure Load Profiles (continued)

<table>
<tr><th></th><th>2A-Tampa_FL</th><th>4A-JohnFK_NY</th><th>6A-Rochester_MN</th></tr>
<tr><td></td><td colspan="3">Peak Cost Time
Baseline
Battery Storage - Monthly Forecast
Battery Storage - Daily Forecast
Setup cooling w/ pre-cooling
Setback heating
20% light power reduction
End Of Day OA ventilation ramp down
SHGC decreased by 10%
EER increased by 20%</td></tr>
<tr><td>Sep.</td><td>
</td><td>
</td><td>
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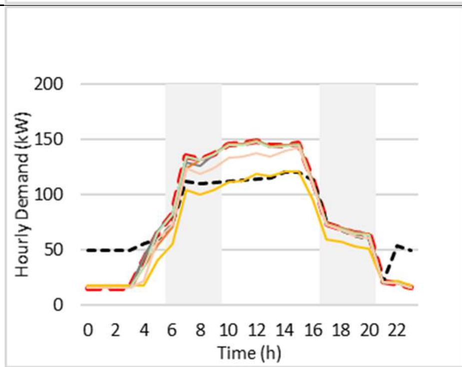
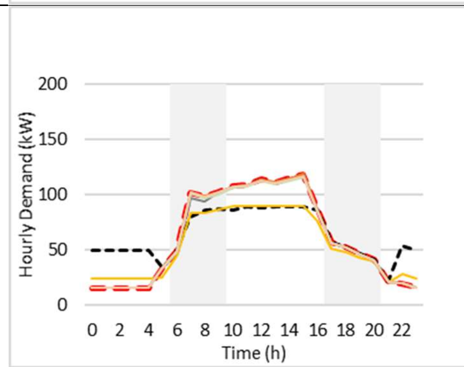
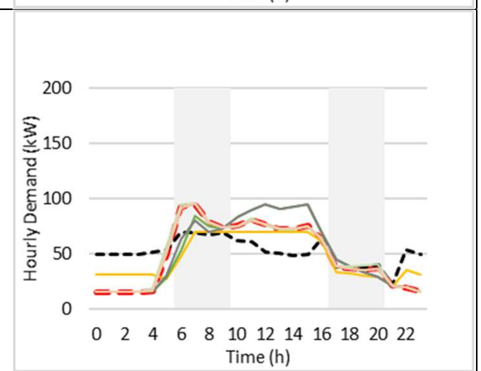
<tr><td>Oct.</td><td>
</td><td>
</td><td>
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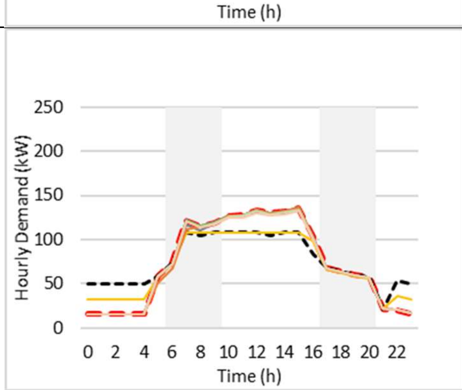
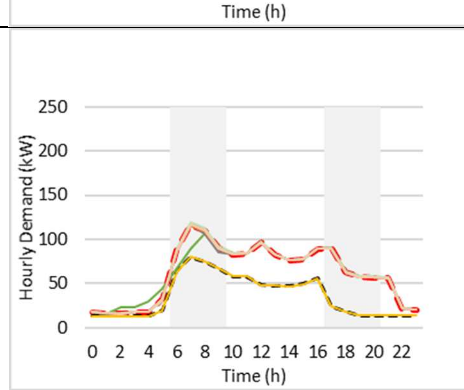
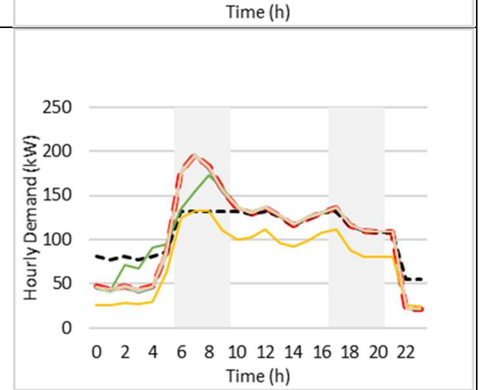
<tr><td>Nov.</td><td>
</td><td>
</td><td>
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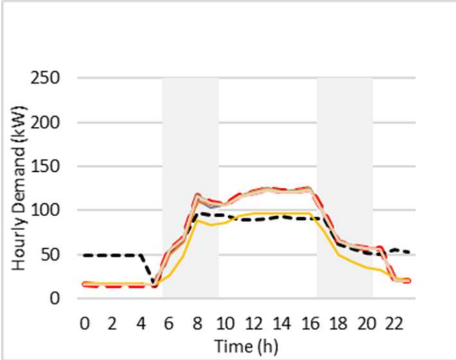
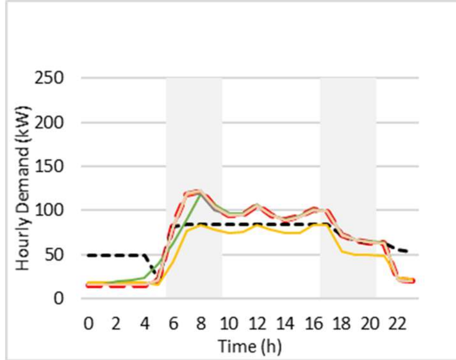
Dec.





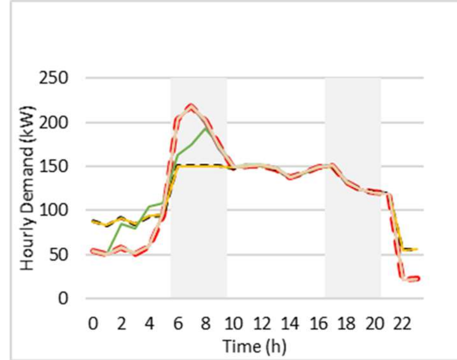


Figure 4**Error! Reference source not found.**. Baseline and Measure Load Profiles (continued)

The impact of efficiency measures is typically based on annual energy and cost data. However, understanding the impact of DF measures on demand requires a more granular treatment, which includes the examination of daily loads. In Figure 4, the shaded columns indicate the winter and summer peak demand periods for the ASHRAE TOU rate. The charts reveal that the building in climate zones 4A and 6A in winter has steep early morning demand ramp-up due to electric reheat. These winter peaks are significantly higher than the building's summer peak—even when compared to climate zone 2A. As indicated by the charts, the winter peak is 230 kW while the summer peak is 150–160 kW for the two cooler climates. By contrast, the climate zone 2A maximum peak over the year is 190 kW.

In general, the measure peak day load profile follows the baseline peak day load profile except for the pre-cooling and battery storage measures. The pre-cooling measure manifests a spike in demand prior to the start of the ASHRAE TOU summer peak demand period, which causes an increase in annual costs with the ConEd TOU rate since the spike occurs during its summer peak period, which starts at 8 AM. The charts reveal that the building loads for the two battery storage measures closely follow each other. The curves for the battery storage-day-peak-measure verify that this discharge strategy offsets greater demand over the month but results in the same adjusted peak demand, which dictates the monthly demand cost, which is the same as the battery-storage-month-peak-measure.

A cost-effectiveness assessment was completed for each measure. The values used in the analysis for measure costs and life are provided in Table 3. The measure cost is the price paid by the building developer. The operation and maintenance (O&M) cost covers maintenance and other ongoing costs. Cost data were obtained from RS Means (RS Means 2018) although the battery costs were based on a literature review of values cited for Li-Ion systems (Mongird et al. 2019). For the battery measures, two sets of costs are included (2018 and 2025) due to their anticipated cost reduction. The cost data indicate three tiers of first cost values (low, medium, and high) that correspond to the three measure categories, namely: DF, standard efficiency, and DER.

As part of the economic analysis, three metrics were evaluated, including simple payback, the ASHRAE Standard 90.1 scalar ratio, and the LCC, which are shown in Table 4. Table 4 cells highlighted in green indicate that the metric value meets code cost-effectiveness criteria. While the measure simple payback is included in the table, note that only the scalar ratio and LCC values are used to determine cost effectiveness in code development. The Scalar Method is an alternative life-cycle cost approach for individual or combined energy efficiency changes. The calculation considers first costs, annual energy cost savings, annual maintenance, taxes, inflation, energy escalation, and financing impacts. So, the scalar method addresses the major drawback of the simple payback method. It establishes a discounted payback threshold (scalar ratio limit) based on the measure life. A measure is considered cost-effective if the simple payback (scalar ratio) is less than the scalar limit. For determining cost effectiveness for a package of measures or across measures with different life spans, the LCC is typically determined assuming a 40-year analysis period, which considers equipment replacement cost and salvage value. Per the ASHRAE 90.1-2022 Work Plan, the scalar limits based on a 40-year analysis are 25.1 and 22.0 for measures impacting heating (fossil fuel) or cooling (electric), respectively. For more information, see the documented methodology for evaluating cost effectiveness for commercial energy code changes (Hart et al. 2015). The LCC analysis represents the private or business ownership point of view. It considers initial costs being financed, and considers tax impacts for savings, interest, and depreciation. The scalar method (McBride 1995) represents a pre-tax private investment and uses standard LCC techniques, although the parameters and methodology are established by the ASHRAE 90.1 committee.

Table 3. Measure Economic Parameters[a]

Measure		First Costs ($)	O&M Costs ($/Year)	Measure Life (Years)
SHGC decreased by 10%		5,300	0	30
EER increased by 20%		28,300	0	15
Lighting 20% load reduction		280	0	15
Pre-cooling with zone temp setup		280	0	15
Early preheat		280	0	15
OA ventilation ramp down		280	0	15
Battery storage	2018 value	98,600	680	10
	2025 value	71,200	530	10

[a] Measure cost was evaluated using engineering judgement.

Table 4. Measure Cost Effectiveness

Measure		Annual Energy Savings ($/year)			Simple Payback (years)			Code Cost-Effectiveness Indicators					
								ASHRAE Scalar (years)			Net LCC ($)		
		ASHRAE Blended	ASHRAE TOU	ConED TOU	Blended Rate	ASHRAE TOU	ConEd TOU	Blended Rate	ASHRAE TOU	ConEd TOU	Blended Rate	ASHRAE TOU	ConEd TOU
Climate Zone 2A - Tampa, FL	SHGC decreased by 10%	379	378	500	13.8	13.8	10.4	16.4	16.5	12.4	613	632	(1,340)
	EER increased by 20%	535	907	1,704	52.1	30.7	16.3	85.0	50.1	26.7	42,673	36,656	23,773
	Setup cooling w/ pre-cooling	(624)	299	(6,210)	NA	0.9	NA	NA	1.5	NA	10,590	(4,332)	100,886
	Setback heating w/ pre-heating	129	105	20	2.2	2.7	15.1	3.5	4.3	22.8	(1,576)	(1,187)	189
	OA ventilation ramp down	467	640	640	0.6	0.4	0.4	0.9	0.7	0.7	(7,145)	(9,947)	(9,938)
	20% light power reduction	414	753	1,178	0.7	0.4	0.2	1.1	0.6	0.4	(6,187)	(11,664)	(18,533)
	Battery Storage - Monthly 2018	(1,140)	4,957	9,218	NA	22.6	11.4	NA	50.2	25.2	241,419	142,871	74,003
	Battery Storage - Daily 2018	(606)	4,844	9,276	NA	23.3	11.3	NA	51.5	25.0	232,787	144,705	73,063
	Battery Storage - Monthly 2025	(1,140)	4,957	9,218	NA	15.8	8.1	NA	35.1	17.9	178,403	79,856	10,987
	Battery Storage - Daily 2025	(606)	4,844	9,276	NA	16.3	8.0	NA	36.0	17.8	169,771	81,689	10,047
Climate Zone 4A -JKF Airport, NY	SHGC decreased by 10%	128	197	340	69.5	36.1	18.1	82.9	43.1	21.6	5,588	4,470	2,159
	EER increased by 20%	179	495	1,092	155.2	56.2	25.5	253.3	91.8	41.6	48,415	43,315	33,670
	Setup cooling w/ pre-cooling	(618)	(87)	(7,328)	NA	NA	NA	NA	NA	NA	10,498	1,921	118,961
	Setback heating w/ pre-heating	186	653	838	1.6	0.4	0.3	2.6	0.7	0.5	(2,248)	(9,801)	(12,782)
	OA ventilation ramp down	101	275	198	1.0	0.6	0.7	1.6	1.0	1.2	(4,293)	(7,117)	(5,863)
	20% light power reduction	344	701	1,282	0.8	0.4	0.2	1.3	0.6	0.4	(4,999)	(10,769)	(20,156)
	Battery Storage - Monthly 2018	(1,140)	5,756	10,031	NA	19.1	10.4	NA	42.3	23.0	241,419	129,953	60,856
	Battery Storage - Daily 2018	(434)	5,267	10,027	NA	21.1	10.4	NA	46.8	23.0	230,018	137,853	60,913
	Battery Storage - Monthly 2025	(1,140)	5,756	10,031	NA	11.1	6.6	NA	29.7	16.3	178,403	66,937	(2,160)
	Battery Storage - Daily 2025	(434)	5,267	10,027	747.3	12.1	6.6	NA	32.8	16.3	167,002	74,837	(2,103)
Climate Zone 6A - Rochester, MN	SHGC decreased by 10%	54	171	452	0.0	0.0	0.0	NA	56.3	15.9	6,912	5,027	481
	EER increased by 20%	114	480	1,192	243.7	58.0	23.3	397.7	94.6	38.1	49,468	43,556	32,045
	Setup cooling w/ pre-cooling	(636)	123	(6,601)	NA	2.3	NA	NA	3.7	NA	10,800	(1,462)	107,214
	Setback heating w/ pre-heating	66	1,001	1,346	6.2	0.3	0.2	10.2	0.5	0.3	(179)	(15,299)	(20,878)
	OA ventilation ramp down	45	338	796	0.4	0.3	0.2	0.7	0.5	0.3	(10,456)	(15,197)	(22,601)
	20% light power reduction	312	636	1,229	0.9	0.4	0.2	1.5	0.7	0.4	(4,465)	(9,708)	(19,295)
	Battery Storage - Monthly 2018	(1,140)	6,797	11,869	NA	15.9	8.7	NA	35.1	19.2	241,419	113,130	31,139
	Battery Storage - Daily 2018	(293)	6,003	11,889	NA	18.2	8.7	NA	40.3	19.2	227,726	125,971	30,822
	Battery Storage - Monthly 2025	(1,140)	6,797	11,869	NA	9.6	5.6	NA	24.8	13.7	178,403	50,114	(31,877)
	Battery Storage - Daily 2025	(293)	6,003	11,889	297.3	10.7	5.6	NA	28.4	13.7	164,710	62,955	(32,194)

For the standard measures analyzed, the cost effectiveness increases as the demand rate increases. This should not be interpreted as a general trend though since the time of day that an efficiency measure saves energy may not coincide with the peak rate period and its higher demand costs. In general, the low-cost DF measures have a quick payback and are cost effective based on both metrics (excluding the locations that did not benefit from the pre-cooling or pre-heating measures). Since the DF and DER measures' operation were defined to maximize cost savings based on the ASHRAE TOU rates, the ConEd TOU cost-effectiveness metrics do not represent their actual full economic potential. The study authors believe that these measures could be fine-tuned to have equal or greater cost effectiveness than that shown for the ASHRAE TOU.

The DER battery measure is cost effective based on both metrics for the three climate zones based on the ConEd TOU rate assuming projected 2025 battery costs. For 2018 costs, the battery measure is also cost effective in climate zone 6A based on the ASHRAE 90.1-scalar limit. The results highlight the benefit of considering actual utility rates in evaluating high capital cost measures, such as battery storage, that displace, shed, or shift demand. It is also worth noting that the ConEd rate is available in New York City, the location representing climate zone 4A. Thus, the results provide an indication of the actual potential savings and cost effectiveness for this location (albeit without the fine tuning of the DF and DER measures' operating strategies).

4.0 Conclusions

The analysis was conducted to better understand the impact of electric rate structure on the cost effectiveness of DF and DER measures in the code development process. Specifically, it investigates the benefits of incorporating the optional ASHRAE TOU rate in order to better account for the value of advancing new technologies. It also considers cost effectiveness based on the more aggressive ConEd TOU rate to provide a regional perspective. The analysis findings, summarized below, provide insights into these considerations.

- The standard efficiency measures impact monthly demand at levels equivalent to the DF measures.
- Some of the DF measures impact energy use at levels equivalent to the standard efficiency measures.
- The impact and cost of the DER measure examined greatly exceeded the impact and cost of the standard efficiency and the DF measures.
- The breakdown in annual costs between energy and demand can vary widely across TOU rates.
- In general, the ASHRAE TOU rate reported higher savings for DF and DER measures compared to the ASHRAE blended rate. This was also the case for one of the two standard efficiency measures.
- In general, the savings trends were 1) consistent across the two TOU rates and 2) higher for the ConEd rate. However, this was not the case for two of the measures because their operation was not optimized for the peak demand periods defined in the ConEd rate.
- The battery storage measure is cost effective across the three climate zones based on the ConEd TOU rate and anticipated 2025 first costs. It is also cost effective for climate zone 6A based on 2018 pricing and on the ASHRAE 90.1-2022 scalar limits.

In addition, the findings demonstrate that there can be substantial differences in measure cost savings based on the ASHRAE blended and ASHRAE TOU rates. The large variation in savings impacts the cost-effectiveness and benefit of DF and DER measures. In addition, considering TOU rates can increase cost savings attributed to standard efficiency measures that provide demand as well as energy-use reductions. Thus, incorporating the ASHRAE TOU rate into the code development process improves demand savings valuation, which will expand the body of proven and advancing technologies that can be considered in energy codes.

Allowing new code changes to be assessed with the ASHRAE TOU rate provides a more realistic approach to address the time-varying impacts of buildings’ interaction with the grid. However, there are challenges for using this typical national TOU rate to address regional variations in grid capacity constraints. The illustrative example from the analysis is the battery storage measure, which proved cost effective based on the ConEd Rate but not the ASHRAE TOU rate. One solution is to follow a performance instead of a prescriptive path for demonstrating compliance, which permits the use of actual electric rate schedules. However, the performance path is less widely utilized than the prescriptive approach due to its complexity and time requirements.

Codes do have other mechanisms that can support the inclusion of DF and DER measures to better serve the needs of local jurisdictions. For example, the ASHRAE 90.1 Standard is referenced by the IECC commercial code, which is adopted by states across the country.

Optional appendices are included as part of the code that states can voluntarily adopt. New appendices can be proposed and adopted that include measures that address grid-related constraints. Also, the 2021 IECC- commercial code includes section C406 that defines additional efficiency package options. Recent refinements to the section include the assignment of efficiency credits to the package options to provide better resolution of anticipated impact (Hart et al. 2019). An expanded set of package options could be defined that addresses integrated solutions including DF and DER measures.[1] Potentially, the assignment of their value could be defined by region or grid constraints.

4.1 Next Steps

In order to incorporate GEB considerations in codes, DF and DER measures need to be effectively valued as part of the code development process. This will involve adding more complexity and detail to code development methods, including evaluating the impact of proposed new code changes on demand load profile and quantifying the benefit beyond efficiency. This includes the value of new grid services delivered by shedding and shifting load across a range of timescales. To do so, requires Standard 90.1 to expand its focus from annual energy savings and more effectively accounting for a building's interactions with its sources of energy.

In the near term, codes can feature DF and DER measures that can be demonstrated to be cost effective based on typical U.S. TOU rate structures, as represented by the ASHRAE TOU rate. This will capture new, lower cost measures or incremental improvements to technologies already being addressed in codes. To address more capital-intensive investments that can provide regional or local benefit, other approaches will need to be followed. Two potential mechanisms are including new voluntary appendices to the IECC commercial code and additional efficiency package options that feature DF or DER measures as part of section C406.

Moving forward, the limitations in the code development process will need to be overcome in order to address current limitations for considering DF and DER measures. This includes side stepping the need to demonstrate cost effectiveness of newly proposed prescriptive measures based on a blended rate and adding code options that include DF and DER measures of interest to capacity- or distribution-constrained jurisdictions. In addition, the benefit of "readiness" measures associated with DF and DERs, such as those that capacitate grid communication protocols or provide infrastructure to facilitate the installation of a photovoltaic system or charging electric vehicles (EV), may need to be recognized. Doing so can be challenging following current cost-effectiveness methods since they incur costs but do not guarantee savings. Lastly, the analysis of the impact of new code changes will require more sophisticated methods of assessment. Each will need to have its operation optimized to maximize cost savings according to assumed peak demand rates and their associated TOU schedules. For improved accuracy, the end-use load profiles depicted in the simulation analyses will need to be scrutinized and informed by related research and metered data.

In summary, in order to advance codes and incorporate tomorrow's technologies, the code development process should evolve to account for the more dynamic nature of DF and DER measures and their effective integration with building systems and the grid. This will be accomplished in part by improving valuation methods and including voluntary code options. It will also require a more granular analysis of measure impact on load profile in future code

[1] An approach similar to the IECC additional efficiency package options has been proposed for the ASHRAE 90.1-2022 Standard. It includes credits for demand flexibility measures.

change impact assessments. Due to the ongoing maintenance practice currently followed in code development, these changes are already underway as the DOE, ASHRAE 90.1 SSPC, the IECC, and other key players continue their work and commitment to code advancement. As part of this, electrification, and storage-ready requirements along with grid-enabled systems are being discussed. As a result, it is anticipated that new opportunities to provide grid services that include DF and DER measures will be reflected in the next code cycle.

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Appendix A – Development of ASHRAE Time-Of-Use Rate

The introduction of a time-of-use (TOU) rate into the code development process allows demand flexibility (DF) and distributed energy resource (DER) measures, which may not provide an overall reduction in energy use, to be justified based on cost effectiveness. The ASHRAE TOU rate was specifically developed because of this issue. The ASHRAE TOU rate represents a typical U.S. TOU rate. The rate values and TOU structure were developed from published utility rate data and information gathered from an investor-owned utility (IOU) survey. More details about the rate, its development approach, and data sources are provided below.

The ASHRAE TOU Rate was developed by the ASHRAE 90.1 SSPC Economics Working Group (EWG) in the Summer of 2019 as part of their regular duties to update economic parameters utilized in the code development process. The update occurs at the beginning of each new code cycle. Their recommendations are incorporated into the ASHRAE 90.1 Work Plan, which is drafted to direct the development of the new code. The Work Plan is voted on by the full ASHRAE 90.1 SSPC during the ASHRAE Winter Conference Meeting. For the ASHRAE 90.1-2022 code cycle, the committee voted on February 3, 2020 and approved including the ASHRAE TOU rate as an optional alternative for evaluating code change proposals. The rate, as stated in the ASHRAE 90.1-2022 Work Plan, is defined as follows.

- Winter (October through May)
  - $0.0946 per kWh, peak hours
  - $0.0571 per kWh, off-peak hours
  - $5.59 per kW, base
  - No peak kW charges
  - Peak: Monday–Friday, 6 AM to 10 AM and 5 PM to 9 PM
- Summer (June – September)
  - $0.1104 per kWh, peak
  - $0.0586 per kWh, off-peak
  - $ 5.59 per kW, base
  - $10.99 per kW, peak

As mentioned, the rate was developed from published and survey data. The utility rate data source is the OpenEI database[1], which includes over 15,000 published commercial and industrial rates offered by municipalities, cooperatives, and IOUs. A dataset was created from the OpenEI data that includes nearly 8,000 rates, after excluding industrial and unique commercial rates (such as agricultural pumping). The dataset encompasses 2,400 utilities representing 70% of the electric load across the lower 48 U.S. states (NREL 2017).[2] Based on an analysis of the dataset, the approximately 6,200 rates listed without demand charges have an average maximum allowable customer demand of 52 kW. This implies that rates without demand charges are available generally for smaller buildings. Nearly 1,700 of the listed rates

[1] For more information about database, refer to Utility Rate Database: https://openei.org/wiki/Utility_Rate_Database

[2] The NREL dataset was developed to support a market potential study for battery energy storage. It is available for download at https://data.nrel.gov/submissions/74.

include demand charges and have an average maximum allowable demand of 700 kW, with minimum demand to qualify ranging from 50 to 3000 kW. For those rates including a demand charge, the average cost is $10.18/kW (the standard deviation is $7.35/kW and the maximum listed is $90/kW). This average demand charge was used as the starting point for establishing the demand charge in the ASHRAE TOU rate.

The ASHRAE TOU rate includes electricity kWh and kW charges that vary by hour of day and season. The on-peak off-peak rate schedule and kWh values were established based on survey data. The survey was developed by the Edison Electric Institute (EEI) and provided to member IOUs.[1] The survey respondents represent ~ 13% of U.S. IOU commercial customers.[2] A summary of key survey results that informed the ASHRAE TOU rate are provided below.

- About 80% of TOU rate customers have kW demand charges.
- Many customers have two demand charges and two seasons – a peak and non-peak season with a peak demand charge and a monthly base demand charge. The difference between the peak and base demand charge ranged from ~ $4.00 to $5.50 per kW.
- The average energy rates for Summer on-peak and off-peak charges are $0.096/kWh and $0.066/kWh. The average difference between on-peak and off-peak charges is $0.030/kWh.
- The average energy rates for Winter on-peak and off-peak charges are $0.092/kWh and $0.064/kWh. The average difference between on-peak and off-peak charges is $0.028/kWh. The average difference between Winter on-peak and off-peak energy charges is $0.028 per kWh.
- The number of on-peak hours per week averaged 39 for Summer and 33 for Winter.
- The average Summer weekday schedule started/ended at 12:45 PM and 8:00 PM.
- The average Winter weekday schedule started/ended at 7:50 AM and 1:30 PM and 5:00 PM and 9:15 PM.

Based on the data outlined above, as well as professional judgement and some additional data not reported herein (including the most common responses for peak period start and end times), the values underlying the ASHRAE TOU rate are as follows.

- Winter (October through May)
  - $0.0876 per kWh, peak hours
  - $0.0528 per kWh, off-peak hours
  - $5.18 per kW, base
  - No peak kW charges
  - Peak: Monday–Friday, 6 AM to 10 AM and 5 PM to 9 PM
- Summer (June – September)
  - $0.1023 per kWh, peak
  - $0.0543 per kWh, off-peak

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[1] Organized in 1933, EEI provides public policy leadership, strategic business intelligence, and essential conferences and forums to all U.S. investor-owned electric companies.
[2] ASHRAE TOU rate presentation made by Stephen Rosenstock to the ASHRAE 90.1 EWG on September 19, 2019.

- $5.18 per kW, base
- $10.18 per kW, peak
- Peak: Monday-Friday, 1 PM to 9 PM

This initial rate was then adjusted based on simulation analysis results for the code medium office prototype building, which was modeled in climate zones 2A, 4A, and 6A. Specifically, each initial rate TOU price component (kWh and kW price during winter and summer) was scaled by a factor of 1.08 in order that the average of the annual energy costs determined for the three climate zones would to be equal to that determined for the ASHRAE Blended Rate.

Appendix B – Demand Flexibility Measures' Modeling Approach

The eight measures evaluated in the demand flexibility (DF) analysis are listed in Table B.1. Two standard measures are included in order to evaluate the potential cost benefits associated with building efficiency improvements with time-of-use (TOU) electric rates considered as part of the model code development process. The five dynamic DF measures, designed to reduce peak demand and its associated cost, incorporate operational strategies that were developed through engineering judgement or semi-optimized analysis based on the ASHRAE TOU rate and its associated peak demand periods. For consistency and simplicity, the DF measures and their associated operational strategies were not modified (e.g., customized) for the ConEd TOU rate. However, doing so would improve the ConEd cost savings reported in the study.

Table B.1. Demand Flexibility Analysis Measures

Measure Type	Name
Standard Efficiency	Solar heat gain coefficient (SHGC) decreased by 10%
	Energy efficiency ratio (EER) increased by 20%
Demand Flexibility	Lighting 20% load reduction
	Pre-cooling with zone temp setup
	Early-preheat
	Outdoor air (OA) ventilation ramp down
	Battery storage – (a) monthly forecast and (b) daily forecast

Each of the measures was added to the medium office baseline simulation model, representing a minimally compliant ASHRAE 90.1-2016 building.[1] The analysis was completed using the EnergyPlus 9.0 simulation program. Each measure, including its model input assumptions, is described below.

1. SHGC decreased by 10%

The maximum SHGC specified in ASHRAE Standard 90.1-2016 is reduced by 10%. However, SHGC requirements are not modeled as listed in the Standard as they vary by framing type. Thus, a weighted SHGC is used in each model. Each value is calculated using a set of weights for each type of framing and for each building type. Table B.2 shows the weighted code SHGC for each of climate zones modeled in this study for the baseline medium office building and the values used for the measure. The simulation model utilizes a simplified glazing modeling approach, which allows the user to directly specify a window performance metric, such as SHGC, without having to define the window assembly layer-by-layer.

[1] The ASHRAE 90.1-2016 code prototype building simulation models are available for download at https://www.energycodes.gov/development/commercial/prototype_models. However, it is worth noting that the simulation models used in this study include enhancements made after February 2018, which results in some variation from the published prototypes and their energy consumption published in final determination. For more details, see https://www.regulations.gov/document?D=EERE-2017-BT-DET-0046-0008.

Table B.2. Baseline and Measure Modeled SHGC

Climate Zone	Baseline Modeled SHGC	Measure Modeled SHGC
2A	0.25	0.225
4A	0.36	0.324
5A	0.38	0.342

2. EER increased by 20%

The code-required EER of the packaged air-conditioning units is increased by 20%. Typically, the EER rating takes into account the fan power, but most building energy modeling software, including EnergyPlus, requires that the efficiency values be based on the American Refrigeration Institute (ARI) performance test conditions for the direct expansion cooling unit and the fan be specified separately. Thus, to characterize this measure, fan power is subtracted from the EER expression to determine the cooling unit input coefficient of performance (COP) value. Equation (B.1) is used for the conversion. It assumes that the fan power ratio at testing condition is 0.12 and remains constant. Table B.3 shows the COP values modeled both in the baseline and measure models.

$$COP = \frac{(\frac{EER}{3.413} + 0.12)}{(1 - 0.12)} \tag{B.1}$$

Table B.3. Baseline and Measure Modeled COP

Climate Zone	Baseline Modeled COP	Measure Modeled COP
2A	3.40	4.05
4A	3.40	4.05
5A	3.40	4.05

3. Lighting peak reduced by 20%

This measure involves decreasing ambient lighting levels by 20% compared to their installed capacity during the ASHRAE TOU rate summer peak periods. To incorporate into the model, adjustments were made to the interior lighting operating schedule profiles. Figure B.1 shows the modeled baseline and measure lighting profiles. Simulated lighting power is determined for each timestep by multiplying the total installed lighting power input value by hourly fractions from these profiles. Since this measure aims to decrease cooling loads, the modified schedule was only applied during the TOU summer period during normal operating hours, which is from 1 PM to 5 PM for June through September.

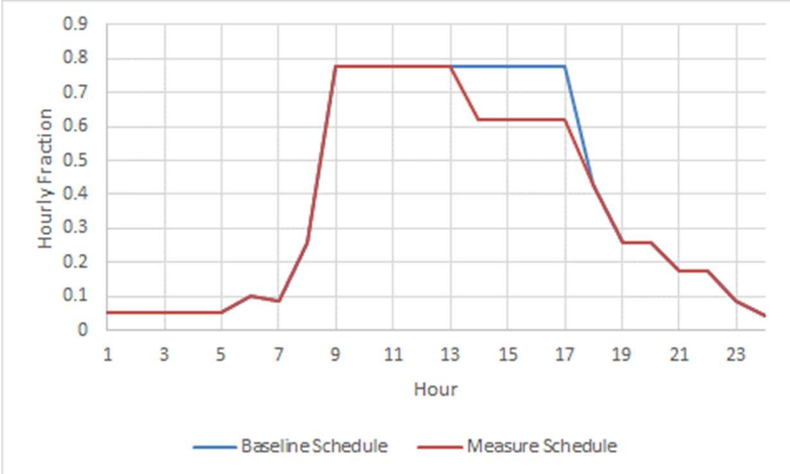

Figure B.1. Summer Weekdays Baseline and Measure Interior Lighting Profiles

4. Pre-cooling zone temperature setup

Preceding the start of the ASHRAE TOU summer peak demand period, the building temperature is ramped down starting at 9 AM to pre-cool the building then ramped up starting at 3 PM. To incorporate into the simulation model, the cooling thermostat schedule was lowered to force the HVAC system to over-cool the building ahead of the TOU peak period and then raised during and after the TOU peak. Figure B.2 shows the baseline and measure weekdays and Saturdays cooling thermostat setpoints. Since this measure aims to reduce building demand during the summer period, the measure was only applied during the months of June through September for all climate zones.

Figure B.2. Summer Weekdays and Saturday Baseline and Measure Cooling Thermostat Setpoint

5. Early pre-heat

A ramped pre-heat is initiated 2-hours early during winter to reduce the morning TOU peak demand. The same approach as for the previous measure was used. Here, the heating setpoints during the winter period (October to May) were modified for all climate zones, as shown in Figure B.3.

Figure B.3. Winter Weekdays and Saturday Baseline and Measure Heating Thermostat Setpoint

6. OA ventilation ramp down

In the winter, outside air is supplied earlier and stays at a lower rate during the morning peak period. In the summer, it exceeds design flows prior to the peak afternoon period then ramps down over the afternoon. In the model, this measure was achieved by applying an hourly schedule multiplier to modify the amount of outside air supplied to each packaged rooftop mechanical system during weekdays, as shown in Figure B.4. The baseline condition does not utilize a schedule multiplier. For the summer profile, the hourly fractions have been reduced but adhere to outside air requirements specified in ASHRAE 62.1 Section 6.2.6.2 “Short Terms Conditions.” The winter profile assumes that the building air has been flushed during the night from infiltration, which eliminates the need to purge the building with more outside air during winter weekday mornings.

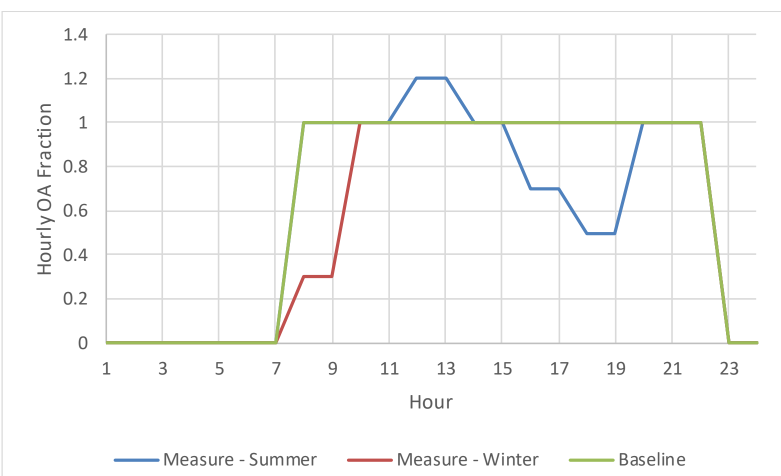

Figure B.4. Winter Ramp Up and Summer Ramp Down Weekdays Measure OA Fraction

7. Battery Storage

The battery storage measure utilizes a Li-ion battery to shift and levelize electric demand in order to reduce peak demand costs. In the analysis, the battery capacity is sized at 5 Wh/square foot of building floor area.[1] For the medium office building, this results in a 268 kWh battery storage capacity. Battery characteristics (and costs) are based on published values (Mongird et al. 2019). Specifically, the following assumptions are used in the measure analysis.

- An energy to power ratio (E/P) of 4 hours[2]
- A system round trip efficiency of 82.6%[3]
- A discharge capacity of 80% of rated capacity.

Two different charge/discharge strategies are applied to weekday operation and are referred to as the monthly forecast and the daily forecast. Both strategies assume that the battery becomes fully charged at night. For winter, nighttime charging occurs over a 7-hour period between 10 PM and 5 AM. For summer, charging occurs over an 8-hour period between 9 PM and 5 AM. The battery charge/discharge strategies are derived from a worse-day demand profile defined for each month for each location. Each worse-day profile is comprised of the maximum hourly demands that occur for a given hour over the month (based on the building simulation results). These profiles formed the basis for the 12 semi-optimized monthly charge/discharge strategies defined for the building for each climate zone. Based on the worse-day profile, the battery discharge amount for each hour was established using an optimization function that minimized the monthly demand charge. It is worth noting that the afternoon peak demand for each worse-day profile coincides with the ASHRAE TOU peak periods.

For some summer months, the demand for hours preceding the peak period was also reduced if discharge capacity was available after worse-day peak period demand was reduced. For winter months, the ASHRAE TOU rate includes a base demand charge but not a peak demand charge. Thus, the winter discharge strategy reduces demand costs by flattening or truncating all hourly demand peaks seen during the day as much as possible subject to the available battery discharge capacity. For the two colder climate zones, the building in winter has maximum demand during weekday mornings resulting from electric reheat. For these climates if the demand optimization reveals discharge availability after the morning warmup would reduce the overall daily peak demand, battery capacity is also used to offset demand during later hours of the day.

a. Monthly Forecast

   In this strategy, the battery discharge availability determined from the optimization analysis is applied to the worse-day demand profile. The resulting net-demand after discharge sets the building demand not-to-be exceeded for each hour. This demand 'goal' then establishes the battery discharge amount for each hour for each day. Thus with this strategy, the total battery discharge amount for each day will be less than that determined for the worse-day.

b. Daily Forecast

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[1] The battery size specification of 5 Wh/sq. ft. is based on language included in ASHRAE 189.1-2020 Addendum ac, which establishes an exception for automated DR control requirement.

[2] For example, discharging the fully charged battery occurs in no less than 4 hours.

[3] For example, power conversion and other system losses result in the battery providing 0.826 kWh of energy offset for each 1 kWh of energy used for charging.

In this strategy, an hourly net-demand target is not set for each weekday. Instead, the hourly discharge availability established for the worse-day demand profile is assumed and applied as the battery discharge for all weekdays in the month. This strategy results in using the full battery discharge capacity each day. While this will result in greater electrical demand reduction over the day compared to the month forecast, it may not meaningfully impact monthly demand costs yet will incur higher energy costs due to battery system inefficiencies.

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