Research article

Building flexibility revenue in modeled future bulk power systems with varying levels of renewable energy

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ABSTRACT

The buildings sector can provide important demand-side flexibility for the integration of renewable energy. With the changing power system and rapid advancement in building energy control technology, technology providers and demand response aggregators need to know what potential revenues could be obtained by providing grid services. We dispatch a normalized and parameterized model of building load shifting against marginal service prices from grid investment and operational models to produce a database of the capacity, energy, and ancillary service revenues (gross value of providing bulk power system services) for a marginal kilowatt-hour (kWh) of shiftable load. The database is geographically disaggregated, hourly, and parameterized so that flexibility value can be estimated for a wide range of building technologies. The database covers the contiguous United States under three 2030 grid scenarios. Given the high degree of uncertainty in such grid projections, the results are perhaps best interpreted in terms of regional climate and grid mixes and are thus potentially applicable in non-U.S. contexts. Upon analyzing the results, we find the monthly mean gross value of building load shifting is 0–38 cents/kWh-day and the daily gross value of shifting the highest-value hour each day can be up to 620 cents/kWh-day. The different revenues obtained by aggregating results in different ways, as well as observed regional and seasonal differences, suggest different building technologies and grid environments might call for demand response program designs and business models.

1. Introduction

Globally, electricity systems need to rapidly integrate massive amounts of renewable generation, including wind and solar, to meet the climate change challenge. As shown in numerous studies, high shares of variable generation require power systems to operate more flexibly than they do today. That flexibility can be sourced from generators, transmission, storage, and the demand-side. Buildings represent much of the current and potential demand-side flexibility, as they account for 74% of current total U.S. electricity use [1] and are expected to be further electrified with heat pumps and other technologies [2]. "Building flexibility" refers to a building's capability to shed, shift, and modulate load [3, 4]. With these capabilities, buildings can provide a range of grid services including, but not limited to, capacity, energy, and ancillary services.

Building technology providers or aggregators need to know what potential revenues could be obtained by providing what kind of grid services, when and where. This paper uses an integrated grid-building modeling framework to estimate the gross grid service revenue for a marginal kilowatt-hour (kWh) of generic building flexibility in a range of simulated future power systems at the national scale.

Building flexibility is examined in three types of research: flexibility potential studies, grid integration literature, and building control literature. Flexibility potential studies often focus on the potential to shed load [5] rather than to shift load. Some technical potential studies with shiftable loads focus on the building sector only [6], such as [7] for residential buildings and [8, 9, 3] for commercial buildings, using thermostatically controlled loads such as HVAC, heat pumps, water heaters, and refrigerators as the source for flexibility [4, 10]. Other technical [11] or economic potential studies [12, 13, 14] for flexibility include building, industrial, and transportation sectors as broadly-defined demand response and thus have less detailed representation of building technologies than the sector-specific studies. The grid integration literature typically takes the results from these demand response potential studies as an exogenous input to estimate the aggregated demand response value. This is done using either a capacity expansion model [15, 16, 17] or a production cost model [18, 19] to produce either the total capacity value [15, 16, 17], energy [18, 19], or

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ancillary service values [18, 19, 20, 21, 22]. Because of the computational complexity of the grid models, one study typically cannot provide all these grid service values. The building literature has been heavily focused on control strategies and optimization algorithms, using rule-based approaches [23, 24, 25, 26, 27] or predictive control-based approaches [28, 29, 30] to enhance the operational flexibility of buildings. Most of these studies (e.g., [31, 32, 33]) focus on buildings' electricity bill savings, rather than their value to the broader power system. Those that attempt to investigate building flexibility's grid value often have one or more of the following characteristics: (1) the analytical scope is limited to a single building [34] or small building clusters [35]; (2) it is based on specific building technologies (e.g., heat pump and latent heat storage [36]) in one building type (e.g., residential [37,38]); (3) it does not consider the spectrum of grid services (e.g., only regulation and spinning reserve value is estimated in [39, 40, 41, 42]); and (4) it only includes sheddable load, not shiftable load [43]. However, given the wide range of potentially flexible building loads—both now and in the future as the result of technological developments in equipment, controls, and communications, as well as emerging business models—it could be helpful to analyze the value of building flexibility in future power systems without being tied to a particular technology or building type.

This study bridges the grid and building disciplines by integrating grid capacity expansion and production cost models with a generic building flexibility model. It estimates the 8760 time series of gross bulk power grid service values (including capacity, energy, contingency reserve, flexibility reserve, and regulation reserve) that 1 kW h of marginal generic building flexibility could provide under various simulated 2030 grid scenarios at the national scale. Because the model year is near term, we assume the 1 kW h of building flexibility is a price-taker, without the volume of impact needed to set prices in the power system. Because our building flexibility is generic and could come from any type of building technologies, including those that do not require additional capital investment or operational cost, we limit the scope to only calculating the potential gross value in monetary terms rather than providing a full cost-and-benefit analysis.

Our contributions are threefold. First, we use a novel cross-sector framework integrating detailed power sector capacity expansion and production cost modeling with generic building modeling that provides values spanning across capacity, energy, and ancillary services. Second, we propose a generic building flexibility representation that is technology-agnostic. Instead of prescribing a specific technology (e.g., HVAC, heat pump) in a particular building sector (e.g., residential, commercial), we parameterize generic flexibility based on key flexibility metrics. Our results can therefore provide rough value estimates for all existing contexts and new technologies. Third, we provide an open database [44] containing geographically disaggregated 8760 time series data. Users (e.g., demand-side technology developers and aggregators) can create their own estimates depending on the location, timing, shifting behavior, and the type of service the building flexibility can provide (see details in Section 2.2 and example in Section 2.4).

Our generic building flexibility model could be used in any country or region with real-world or simulated time series price or emission data as inputs. Technology providers and demand-side aggregators may use our results database to inform decisions such as which geographical market is more profitable to enter, or what type of business models (e.g., providing services at limited number of hours per year or providing sustained service throughout a month) would be more suitable for their portfolio. Policymakers may use our range of building flexibility values to set cost targets for building technologies. Ultimately, the grid service values we quantify in monetary terms require market mechanisms through which they can be realized as actual revenues. In addition, because the United States comprises several climatic regions with different grid mixes, the general patterns of building flexibility value could inform building flexibility and power market discussions in corresponding climate and grid regions in other countries.

2. Methodology

We deploy a cross-sector integrated modeling framework (Figure 1) to perform (1) capacity expansion, (2) production cost modeling, (3) data processing and organization, and (4) building flexibility modeling to estimate the gross value of shiftable building electricity demand to provide multiple grid services (Figure 1). The capacity expansion model produces generation and transmission resource plans out to 2050. The production cost model is run over the 2030 capacity expansion results to produce hourly meter-level wholesale prices by location. And the price-taking building flexibility model optimizes the dispatch of the generic building technology against the hourly prices to maximize value.

2.1. Future grid system modeling

The first three steps of the multistage modeling process are used to produce sound simulated hourly prices for future grid scenarios that are then used as inputs to the building flexibility dispatch model. These three steps have been used for other studies; the novelty of our approach is in integrating them with the building flexibility dispatch model we develop (Section 2.2).

In the first step, we use three grid scenarios selected from the National Renewable Energy Laboratory (NREL)'s 2019 Standard Scenarios [45], focusing on year 2030. The Standard Scenarios are an annually updated suite of forward-looking U.S. electricity sector capacity expansion projections based on a consistent set of technology cost and performance data [46] and are developed using the ReEDS model [47]. To explore a range of future generation mixes, we select three grid scenarios that vary significantly in terms of wind, solar, and gas generation: Low RE, Mid RE, and High RE.[1] Annual, national-level (conterminous United States) generation results for these scenarios are shown in Figure 2.

In the second step, we use PLEXOS [48], a production cost model, to simulate the ReEDS system operations at hourly resolution. We use it to perform economic dispatch of the 2030 ReEDS-replica system using linear programming [47]. The ancillary service requirements are consistent with ReEDS but are modeled chronologically at hourly resolution. PLEXOS produces hourly energy and ancillary service (i.e., regulation, flexibility, and contingency reserve) prices for each simulated balancing area. Additional information about the ReEDS and PLEXOS models and inputs for the Standard Scenarios is provided in Appendix A.

In the third step, we use Cambium [49] to process the pricing data needed for our building flexibility dispatch model. Cambium distributes ReEDS' per megawatt (MW)-year capacity prices to 8,760 h based on the shadow price of ReEDS' planning reserve margin constraint and the hourly net load in each planning region.[2] All the modeled price outputs from PLEXOS are at the wholesale bus level. Cambium assumes distribution losses (around 5%) that vary slightly by region based on the approach described in [50] to produce meter-level wholesale prices of the following:

- Capacity price, representing the cost of capital investment needed to meet the next increment of load

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[1] Low RE = High RE Cost plus Low Natural Gas Price; Mid RE = Mid Case; High RE = RE Cost plus High Natural Gas Price in 2019 Standard Scenarios; details of these scenarios are in [45].

[2] ReEDS produces seasonal and annual capacity costs for each of the 134 simulated balancing areas (in $/MW of firm capacity). ReEDS also has 18 regional transmission organization (RTO)-like reserve-sharing subregions. For each RTO-like subregion, the hourly net load is aggregated. Then we find a cutoff at either the load of the 40th hour or 95% of the maximum load, whichever is lower. We then calculate, for each hour in each subregion, which fraction of load is above the cutoff divided by the sum of load above the cutoff. Each of the 135 balancing area's marginal capacity cost is allocated according to the derived hourly weights, so that the marginal capacity cost is balancing area-specific but the weights are RTO-specific.
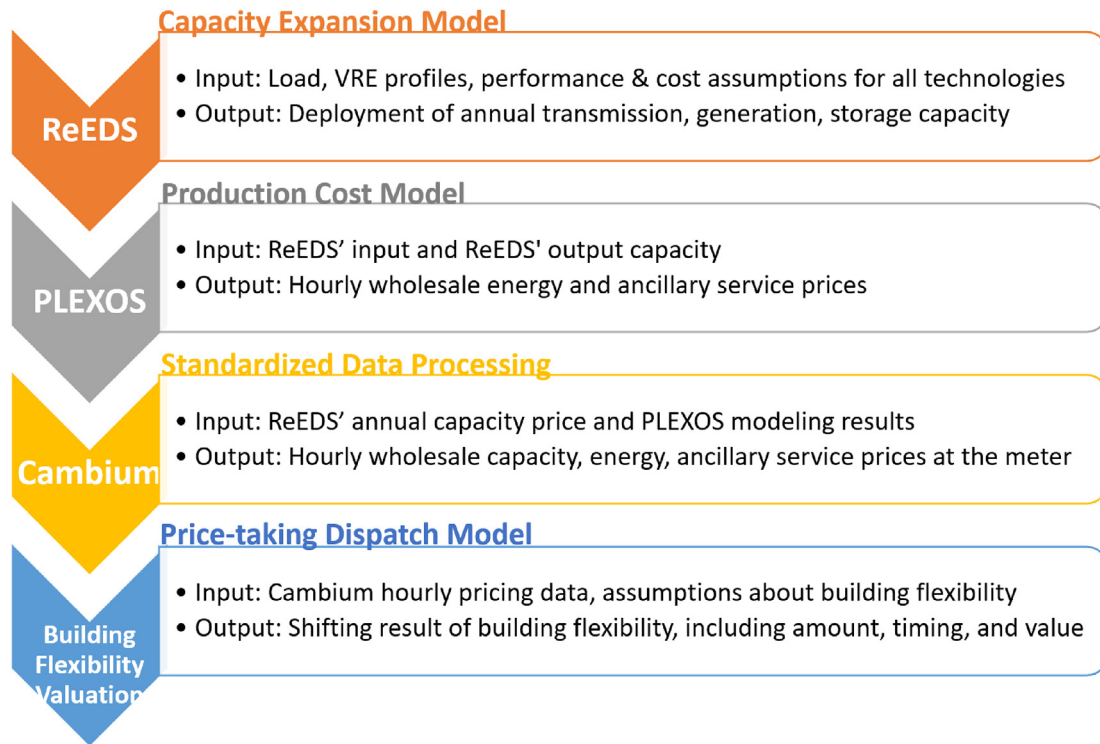
Capacity Expansion Model

ReEDS

- Input: Load, VRE profiles, performance & cost assumptions for all technologies
- Output: Deployment of annual transmission, generation, storage capacity

Production Cost Model

PLEXOS

- Input: ReEDS' input and ReEDS' output capacity
- Output: Hourly wholesale energy and ancillary service prices

Standardized Data Processing

Cambium

- Input: ReEDS' annual capacity price and PLEXOS modeling results
- Output: Hourly wholesale capacity, energy, ancillary service prices at the meter

Price-taking Dispatch Model

Building Flexibility Valuation

- Input: Cambium hourly pricing data, assumptions about building flexibility
- Output: Shifting result of building flexibility, including amount, timing, and value

Figure 1. Flow-chart of the modeling process. VRE is variable renewable energy.
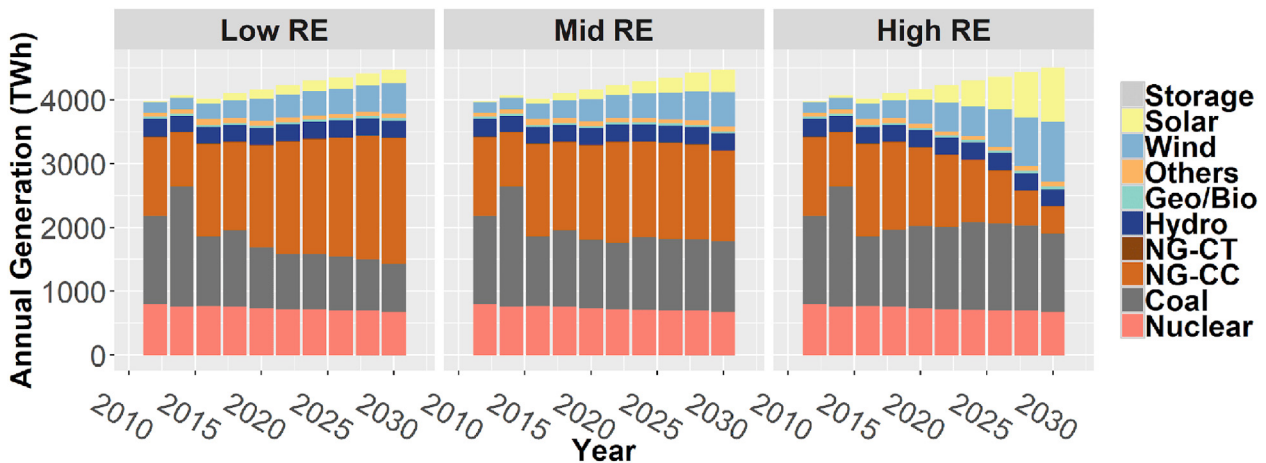

Figure 2. Conterminous U.S. annual generation from 2010 to 2030 in the Low RE, Mid RE, and High RE grid scenarios by technology type, 2010–2030. Geo/Bio = geothermal and biomass; NG-CT = natural gas combustion turbine; NG-CC = natural gas combined cycle, RE = renewable energy.

- Energy price, representing the operating cost of serving the next increment of load
- Ancillary service price: representing the cost of maintaining the supply-demand balance on faster timescales (e.g., regulation reserve), on slower timescales (e.g., flexibility or ramping reserves), or when an unexpected generator or transmission outage occurs (i.e., contingency reserves) [18, 19, 20, 21, 22]. Details of ancillary services are summarized in Appendix B.

These three steps produce the pricing data for 134 ReEDS-modeled balancing areas (Appendix C, Figure C.1). To reduce complexity, we map the ReEDS-modeled areas to U.S. Energy Information Administration's National Energy Modeling System (NEMS) Electricity Market Module regions. We then compute load-weighted price profiles for each of the 21 NEMS[3] regions (Appendix C, Figure C.2) and each future grid scenario (Low RE, Mid RE, and High RE). The pricing data are summarized in Appendix D.

2.2. Building flexibility dispatch model

We write the building flexibility dispatch model in the General Algebraic Modeling System (Version 24.9). It is a price-taking, mixed integer linear model, solved with CPLEX.

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[3] NEMS has 22 regions, but ReEDS' balancing areas in New York state do not clearly distinguish NYCW and NYUP, so we collapse those two regions (referring to them both as NYUP), which results in 21 regions. Specifically, the mapping difficulty is that ReEDS balancing area p127 contains all of NYCW and part of NYUP.

To examine the value of building flexibility in a generic way, we consider a marginal, shiftable unit of 1 kW h of energy consumption that occurs at hour h^*, where $h^* \in [1, 24]$ of a day, under baseline conditions. We assume this energy use could be shifted to a different hour to minimize grid costs, subject to a shifting window constraint. We also investigate the impacts of efficiency and dissipation, which are important for passive thermal storage end uses such as space cooling and water heating [51].

We assume a demand-side energy service (e.g., space cooling or clothes drying) originally provided at hour h^* would consume 1 kW h of electricity. This corresponds to a baseline power consumption $\tilde{P}_{h^*}$ of 1 kW. If the service is provisioned at a different hour h, we describe the impacts of efficiency (η_h) and dissipation (α) using Eq. (1):

$$S_{h+1} = (1 - \alpha \cdot \Delta t)S_h + \eta_h P_h \cdot \Delta t, \ \alpha \geq 0, \tag{1}$$

where S_h is the amount of energy service accumulated by hour h in kWh, $\Delta t = 1$ hour; η_h is efficiency, representing the relative ease with which electricity is converted to energy service; $\eta_{h^*} = 1$. η_h is analogous to the coefficient of performance of an air conditioner or a heat pump (which is known to vary significantly with outdoor conditions [52]), but in this case is measured relative to the conversion efficiency of the baseline hour. In other words, η_h is conversation efficiency of the equipment at hour h divided by the conversation efficiency at h^*. Dissipation (α in units of h^{-1}) represents the rate at which an energy service degrades over time. For example, space cooling provided in one hour results in a lower indoor air temperature that, absent additional cooling, will eventually re-equilibrate with outdoor conditions at a rate proportional to $1/RC$, where R is thermal resistance (K/kW), and C is thermal capacitance (kWh/K). Perfectly schedulable energy services (e.g., clothes drying, electric vehicle charging), for which the energy required to provide the desired level of service at a given time, do not depend on when the service is completed (e.g., starting at 18:00 or starting at 01:00 would consume the same amount of energy). They are not subject to dissipative effects and suffer no efficiency loss from changing the time of use, therefore could be described as $\alpha = 0$ and $\eta_h = 1$.

Transforming this model to measure changes relative to baseline, we define ΔP_h as the difference between optimized and baseline power draw (i.e., $\Delta P_h = P_h - \tilde{P}_h$ where $\tilde{P}_{h^*} = 1$ kW and $\tilde{P}_h = 0$ otherwise; ΔS_h as the difference between optimized and baseline energy service accumulation by hour h, i.e., $\Delta S_h = S_h - \tilde{S}_h$), and we define the following constraints using formulae 2, 3, and 4 over the shifting window $\left[\underline{h}, \overline{h}\right]$:

Change in energy service accumulation

$$\Delta S_h = (1 - \alpha \cdot \Delta t)\Delta S_{h-1} + \eta_h \Delta P_h \cdot \Delta t, \ h \in \left[\underline{h}, \overline{h}\right] \tag{2}$$

Power Shifting Constraints

$$\left.\begin{matrix} -1 & h = h^* \\ 0 & otherwise \end{matrix}\right\} \leq \Delta P_h \leq \begin{cases} 0 & h = h^* \\ \dfrac{(1 - \alpha \cdot \Delta t)^{h-h^*}}{\eta_h} & otherwise \end{cases} \tag{3}$$

Service Shifting Constraints

$$\begin{matrix} 0 & h \in \left\{\underline{h}-1, \overline{h}\right\} \\ -(1-\alpha \cdot \Delta t)^{h-h^*} & otherwise \end{matrix} \leq \Delta S_h \leq \begin{cases} 0 & h \in \left\{\underline{h}-1, \overline{h}\right\} \\ (1-\alpha \cdot \Delta t)^{h-h^*} & otherwise \end{cases}, \tag{4}$$

where the power and service shifting constraints are defined so that (1) the baseline amount of accumulated service provision as measured at the end of the shifting window must be provided by that time and (2) the baseline energy service must be fully delivered in any one of the hours within the shifting window.

Note that in Eq. (2), with increasing levels of dissipation, the fact that some of the bounds vary exponentially with $h - h^*$ opens the model to some nonsensical results. To ensure the same level of energy service is provided in this case, we do not allow the model to shift energy to later in

the day when $\alpha > 0$, that is, when $\alpha > 0$, $\overline{h} = h^*$. In addition, we add a power capacity limit in formula 5:

$$\Delta P_h \leq C \tag{5}$$

that is only potentially binding when $(1 - \alpha \cdot \Delta t)^{h-h^*} > \eta_h C$. C represents an equipment rating that would limit the amount of power consumption of the equipment/technologies. To limit model and scenario framework complexity relative to efficiency, we always set $\eta_{h^*} = 1$ and in all other hours ($h \neq h^*$), we set η_h to a single other value that can be less than one (less efficient than baseline), equal to one (exactly as efficient as baseline), or greater than one (more efficient than baseline). A simple example of how these parameters can be used to characterize different building technology is provided at the end of Section 2.4.

The objective function of the model is to maximize the gross value that can be obtained by the marginal unit of building flexibility, represented in formula 6

$$\sum_{h=1}^{8760} -\Delta P_h \cdot (CP_h + LMP_h) \tag{6}$$

where CP_h is the meter-level wholesale capacity price at 8760 h h, and LMP_h is the meter-level wholesale energy price at hour h.

2.3. Ancillary service provision

The generic building flexibility resources can potentially provide three types of ancillary services[4]: flexibility, contingency, and regulation reserves. Though we model building flexibility providing ancillary services, we do not include ancillary service value in the objective function, because (1) not all forms of building flexibility can provide all ancillary services and (2) ancillary service markets tend to be significantly smaller (on a kW-h basis) and less valuable (on a $/kW-h basis) than capacity and energy markets [53, 54]. However, at times, if the flexibility resource are able, providing an ancillary service during the baseline hour h^* would be more valuable than shifting that energy use to at another time. For the purposes of this paper, our reported estimations of gross revenues include ancillary services, assuming the generic resource can provide any of the services. But we also publish a database of our estimated hourly revenue from each individual service so others can evaluate specific technologies for which it may be possible to state which services can be provided, when, and in what quantities.[5] Technology providers and demand-side aggregators may use our results database to obtain the potential revenues for the services that they are capable and willing to provide. They may rule out any ancillary services their technology is unable to provide or that would be too costly to provide (e.g., if following a regulation signal would induce too much wear and tear [41]).

For this paper, we use a post-processing step to calculate the full gross value in monetary terms, including potential value from ancillary services and we disallow double counting of flexibility resource. We assign each kilowatt-hour (baseline energy use at the times h^*) of building flexibility to just one of four services, whichever brings the highest value:

- Energy shifting, where it can obtain the capacity and energy value
- Flexibility reserve
- Contingency reserve
- Regulation reserve.

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[4] Marginal reserve prices represent the opportunity costs and wear-and-tear costs borne by grid resources selected to provide those services in PLEXOS. The modeled reserve requirements are based on load and the amount of VRE in the system and are consistent with the ReEDS representation (Appendix B).

[5] The database is available at https://data.nrel.gov/submissions/155 ("Grid Service Values of Generic Marginal Building Flexibility in Modeled 2030 U.S. Power Systems").

If providing one of the ancillary services in the original usage hour (h^*) is more valuable than providing energy shifting to the most profitable available hour, that unit of flexible demand is assigned to the most valuable ancillary service at time h^* and its potential shifting value is discarded.

2.4. Scenarios

The combinations of parameters used for our analysis are shown in Table 1. The shifting windows $\left[\underline{h}, \overline{h}\right]$ are denoted relative to a baseline hour $h^* = 0$. All potential h^* hours based on a single day (1 through 24) are simulated. All combinations of those h^* hours plus each selection from each parameter column are simulated except that combinations including both nonzero dissipation ($\alpha > 0$) and shifting windows with $\overline{h} > 0$ are disallowed. A 24-hour sliding service period is evaluated for all 8,760 h of the year for each of the 21 regions and each of the 135 allowable combinations in the Scenario Matrix (Table 1). Overall, the scenario framework results in 24,834,600 modeled shifting opportunities.

The listed flexibility parameters are theoretical, but they can represent the performance of most potentially shiftable building energy technologies currently in either deployment or late-stage development. They were chosen by a technical review group and cross-referenced with building literature [51, 55, 56, 57]. As mentioned in Section 2.2, efficiency (η) represents a general non-time-dependent change in the ability to convert electricity to energy services, recognizing that in reality, efficiency loss/gain might physically depend on dynamic time-varying factors such as outdoor air temperature. Similarly, dissipation may in practice be a time-varying quantity related to several properties (e.g., the thermal inertia of the system) [58].

We can use a residential water heater to provide an example of how these parameters can be used to represent real-world conditions. In the no-shifting, baseline usage, the original power consumption P_h at baseline hour h^* would heat the water, and the resulting energy service would be stored as thermal energy in the tank (i.e., hot water available for use at the desired temperature at the end of h^*). The equipment efficiency and the amount of energy needed to heat the water to set point do not change significantly based on when the water is heated, so the service provision efficiency $\eta_h = 1$. However, there will be a gradual loss of the heat stored in the tank, and we use a dissipation rate α of 0.005 accordingly. Under these parameters the water heater that would consume 1 kW h of electricity at h^* would need to consume about 1.015 kW h of electricity if the consumption were shifted to three hours earlier, imparting more energy into the water (i.e., overheating it) in order to provide the same energy service, S_h, in terms of quantity of water available at the desired temperature, at the end of h^*. Allowing the power consumption to be postponed in this case would mean the energy service S_h would not unavailable at the end of h^* as originally desired, so we limit the water heater and all other dissipative loads to shifting earlier only.

Other load types and even other water heaters will have other parameter values. Loads that have efficiencies that vary with outdoor conditions, such as those HVAC loads with efficiencies that change with ambient temperature, are better represented by $\eta_h \neq 1$ for many shifting situations.

Even though these parameters are by no means comprehensive, and they do not capture some of the time-varying characteristics of certain technologies, they can be deployed to approximate the flexibility features of any existing or future building flexibility technology as it interfaces with the grid.

2.5. Caveats

Our study is limited in terms of scope and modeling approach in three ways. First, we analyze the gross revenue of a unit of building flexibility that is on the margin using a price-taking dispatch approach. A price-*making* approach would require specifying the building flexibility supply curve. Because building flexibility has unique regional and temporal profiles that are constrained by a complex set of technical and performance criteria including comfort levels and availability depending on frequency of usage [59], the costs of building flexibility are highly uncertain.[6] Therefore, we assume that in 2030, building flexibility would be an entrant to the U.S. power market and not yet take up sufficient market share to change the prices.

Second, to save computational time, we use linear programming in our production cost model, which results in flatter price profiles. In addition, the geographical aggregation, transmission, and generation simplifications in our models all contribute to the modeled future prices being less variable than currently observed real-world prices. Less price variation means we likely underestimate the gross value of building flexibility.

Third, we do not directly analyze sheddable load because a unit of sheddable load on the margin has the exact value of the energy not consumed, which is available in our database [60]. We do include building flexibility that provides ancillary service, which would necessitate a modulated reduction of energy consumption. But because ancillary service only makes up a small portion of the total value and typically lasts no longer than an hour [61], we assume the energy reduction for ancillary service can be made up within the service hour.

Despite these scope and modeling limitations, the study produces robust grid service revenue results for a marginal unit of shiftable building flexibility at the national scale.

3. Results and discussion

Our analysis shows that a daily marginal kilowatt-hour of building flexibility at a single baseline usage hour (h^*) has a monthly mean value

Table 1. Scenario Matrix, 135 potential combinations are created here by choosing one option from each column in all combinations, with the exception of nonzero dissipation cases, which are only allowed to shift earlier (i.e., 3 grid scenarios * 6 shifting windows * 3 efficiency rates * 1 dissipation rate ($\alpha = 0$) * 1 capacity limit +3 grid scenarios * 3 shifting windows * 3 efficiency rates * 3 dissipation rates * 1 capacity limit = 135).

Grid Scenario	Shifting Window $\left[\underline{h}, \overline{h}\right]$	Efficiency η	Dissipation α (h^{-1})	Maximum Power Capacity C (kW)
Low RE	[−1, 0]	0.75	0*	64*
Mid RE*	[−1, 1]	1*	0.005	
High RE	[−4, 0]	1.25	0.05	
	[−4, 4]		0.5	
	[−12, 0]			
	[−12, 11]*			

We define reference conditions as Mid RE grid conditions.* Shifting window [−12,11], efficiency 1, and dissipation 0, are marked with asterisks.

range of 0–38 cents/kW h-day,[7] depending on the original usage hour, month, region, building flexibility parameters, and grid scenario. The value of the highest-value hour each day across all the scenarios has a range of 0–620 cents/kW h-day. For context, [62] estimates the total operation cost of commercial cooling to enable demand response is \$50–100/kW-year.

Section 3.1 introduces the reference case and summarizes the regional and temporal variability in building flexibility value under those conditions. Section 3.2 examines the impact of the building flexibility parameters—shifting window size, dissipation, and efficiency—on the value of building flexibility under the reference grid scenario. Section 3.3 evaluates the impact of different grid scenarios under reference building flexibility conditions. Section 3.4 explores the value of building flexibility when only one hour each day can be utilized (i.e., the highest-value hour in a day). Section 3.5 compares the value results across all the independent variables in our analysis.

3.1. Reference case results

The reference case uses the Mid RE grid scenario and reference building flexibility conditions: a shifting window of [−12,+11], efficiency 1, and dissipation 0. This means each unit of energy use can be shifted to any time within the range of 12 h earlier and 11 h later than baseline time of use, with no efficiency gain or loss and no dissipation associated with shifting. The original kilowatt-hour is then assigned to provide either energy shifting or one of the ancillary services, whichever would result in the highest grid services.

The annual average gross value of such flexibility varies significantly with region and the original usage hour (Figure 3). Late afternoon and early evening baseline hours tend to be more valuable. In many regions, this period is associated with increasing net load and correspondingly higher wholesale electricity prices, whereas midday hours and midnight hours tend to have lower electricity prices because of high solar production at noon that drops off toward evening, high wind production at night, and low electricity consumption at night. Consistent with this temporal trend, the highest annual average values tend to occur in regions with higher levels of solar PV generation as a percentage of regional load,[8] such as AZNM and CAMX, which have 27% and 19% solar under Mid RE.

Although greater solar generation as a percentage of regional load can be associated with high building flexibility value, that finding does not generalize to VRE generation more broadly. For example, NYLI and NYUP have lower value throughout the day even though their VRE shares (40% and 39% respectively) are higher than many regions, including the aforementioned AZNM and CAMX (see Appendix E). The difference is that their VRE generation is wind-dominant. Wind generation produces electricity price variability, but it does not create a persistent diurnal pattern of energy value as solar does. Instead, in a well-connected, geographically large grid, wind tends to decrease the electricity price throughout the day and especially at night. In some circumstances, building flexibility provides value by correcting imbalances caused by wind forecast errors [63]; however, flexibility reserve prices for NYLI and NYUP are not very high in our model, perhaps because NYLI and NYUP are well-connected to neighboring balancing authorities and have large quantities of battery and pumped hydropower storage. Both grid connection and storage contribute to system flexibility and can lower and flatten price profiles, thereby reducing the value that building flexibility could provide.

Building flexibility also shows strong seasonal patterns. Figure 4 shows the hourly value of building flexibility by the original usage hour and day of the year for each region. For most regions, the summer months show more hours of significant value. For example, in regions such as MROE, SRGW, and SRSE, building flexibility is valuable during two original usage hours in the winter (i.e., around 8:00 and 19:00); but in the summer, building flexibility is valuable anytime in the afternoon or early evening. Building flexibility in ERCT has moderate value for most hours of the day regardless of the seasons because ERCT is nearly isolated, and therefore lacks a key source of flexibility—transmission imports and exports—that other balancing authorities use. In addition, ERCT has wind share of 24% and very little solar PV or storage in the Mid RE scenario, which results in high demand for flexibility throughout the year, except for hours when the load is very low (midnight to 04:00).

3.2. Impact of building flexibility parameters

Larger shifting windows, lower dissipation rates, and higher service efficiencies lead to higher building flexibility value, though to different degrees. Figure 5 shows the distribution of building flexibility average monthly value for all original usage hours, months, and regions by shifting window, dissipation, and efficiency under Mid RE. At this level of granularity, the range and variance of observed outcomes is huge. Even though most of these values are very low (as indicated by the median values denoted with red triangles), under certain circumstances, the building flexibility value exceeds 40 cents/kWh-day on average over a month, especially when the shifting window is wide (bottom left panel of Figure 5).

Of the three parameters, the shifting window has the greatest impact on building flexibility value. Observing the zero dissipation scenarios and comparing the distribution when the shifting window is [−1, +1] to the distribution for [−1, 0], [−4, +4] to [−4, 0], [−12, +11] and [−12, 0], we note that in each case halving the window size does not significantly impact the 95th percentile value, but doing so does halve the median value. This means the most valuable hours could be still captured by pre-shifting only; for example, the 95th percentile value is 5.32 cents/kW h-day for window [−12, 0] and 5.59 cents/kW h-day for window [−12, +11]. But a one-sided window would significantly impact the median value, especially for shorter windows. For example, the median value is 0.06 cent/kW h-day for window [−1, 0] and 0.18 cent/kWh-day for window [−1, 1]; both are much lower than the median value for window [−12, +11] of 0.75 cent/kW h-day.

Higher dissipation rates discourage shifting and limit the distance of shifting by exponentially increasing the energy consumption needed to provide the same level of service. Under Mid RE, window [−12, 0], and efficiency 1, the median of monthly average value is 0.52 cent/kW h-day when dissipation is 0 and 0.00 cent/kW h-day when dissipation is 0.5. Energy shifting happens much less frequently for large windows and low efficiency rates when dissipation equals 0.5 (right column of Figure 5) because the required energy consumption is constrained by the capacity limit we set in Section 2.4.[9]

The efficiency rates we set also impact the value of building flexibility. Under Mid RE, window [−12, +11], and dissipation 0, the median of monthly average value is 1.3 cent/kW h-day when efficiency is 1.25 and 0.23 cent/kW h-day when efficiency is 0.75.

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[7] This value represents, for example, the average value of a shiftable 1-kW h load that would be consumed at 19:00 under baseline conditions if it is instead optimally dispatched to provide grid services each day for an entire month.

[8] All renewable percentages in this paper refer to the corresponding renewable energy generation as a percentage of regional load.

[9] For example, when the window is [−12, 0], efficiency is 0.75, and dissipation is 0.5, if it is optimal to shift energy consumption to 12 h earlier, the building flexibility can only shift away 0.0117 kW h of energy instead of the full 1 kW h because the energy consumption will reach 64 kW h at the "shift-to hour" 12 h earlier. Under such circumstances, the value gained by shifting the 0.0117 kW h of consumption is the total energy shifting value of the 1 kW h for that original usage hour, and it will be compared with various reserve values for 1 kW h at the original usage hour.
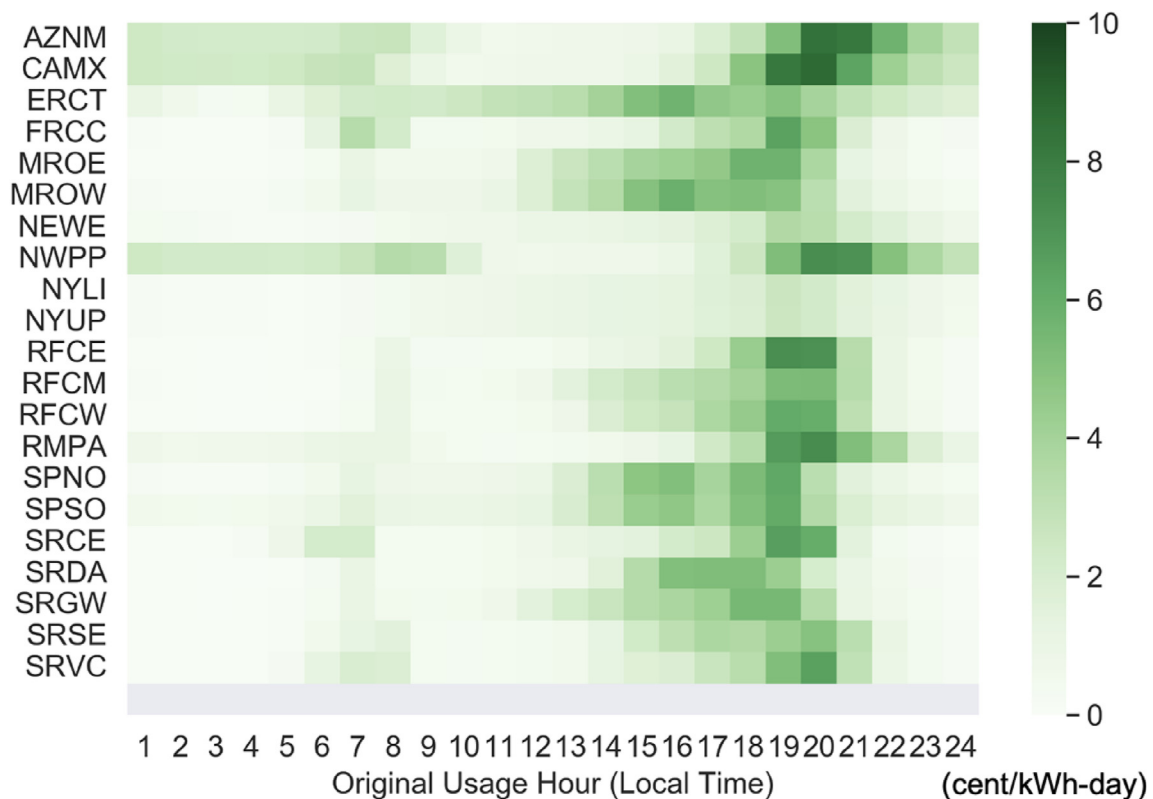
Figure 3. Annual average gross value (cents/kWh-day) of 1 kW h of daily shiftable building flexibility by original usage hour (x-axis) and region (y-axis) in the reference case (Mid RE, shifting window [−12,+11], efficiency 1, and dissipation 0). Darker shades correspond to higher average values, ranging from 0 to 10 cents/kWh-day. All acronyms are defined in the list of acronyms. A map of the regions is available in Appendix C, Figure C-2.

Fully characterizing the potentially time-varying dissipation rates and service provision efficiencies of flexible building loads remains an active area of research. Nonetheless, to put our assumed dissipation rate and efficiency ranges into some context [64], describes dissipation rates for residential thermostatically controlled loads as ranging from 0.012 h^{-1} (highly efficient refrigerators, water heaters) to 0.17 h^{-1} (less efficient air conditioner or heat pump systems), and [52] implies diurnal outdoor temperature swings of for example, 10 K, can move air conditioner and heat pump efficiencies through our assumed range of ±25%. These numbers are incomplete in terms of the range of potentially flexible loads (e.g., the studies reporting them look at only residential thermostatically controlled loads—not commercial or other types of loads), but they do provide a sense of scale. In general, we know these parameters depend highly on not only the application and particular equipment involved but also on buildings' physical characteristics, weather, human behavior, and control strategies. Thus, we choose to investigate fairly inclusive ranges for these parameters so our work can inform many applications.

3.3. Impact of grid scenarios

The impacts of grid scenarios on building flexibility value are complex. Higher VRE generation as a percentage of load is associated with higher volatility in energy prices, which provides energy arbitrage opportunities; however, capacity prices are much higher under Mid RE and Low RE because the low-cost wind and solar resources deployed for energy in High RE leads to an oversupply of capacity that suppresses firm capacity prices in our model. Note that high VRE scenarios do not always lead to lower capacity prices (e.g., when different reserve margin and generation retirement are assumed) [65]. In our model, spikes in capacity prices under the two lower RE grid scenarios increase the capacity value building flexibility can provide during certain hours of the year.

The value of building flexibility under different grid scenarios follows two strong temporal patterns, both seasonal and diurnal. Under reference

flexibility conditions (window [−12, +11], efficiency 1, and dissipation 0), building flexibility tends to have a higher monthly value under High RE for all months except July (Figure 6). This is mainly because of the increased energy price volatility and lower capacity prices in this scenario. In July especially, but also in August,[10] high summer[11] capacity prices under Low and Mid RE can drive the monthly average value for 1 kW h of daily shiftable building flexibility to over 15 cents/kW h-day for certain original usage hours and regions.

The second temporal pattern is diurnal. Greater shares of VRE contribute to higher monthly values for all hours of the day except for the daytime hours between 10:00 and 17:00 because solar generation under High RE suppresses energy prices then.

This diurnal pattern for the value of building flexibility is strongly associated with solar generation, but it is also attributable to other factors, including the generation mix, storage capacity, and interregional transmission capacity. To demonstrate this, we choose four regions—CAMX, ERCT, MROW, and NEWE—that are far apart geographically (representing the western, southern, northern, and eastern parts of the conterminous United States) and are diverse with respect to their non-VRE generation mixes and interconnectedness. Figure 7 shows how these regions' average monthly values vary with both original usage hour and grid scenario.

Across the grid scenarios and regions, we see the impacts of solar and wind generation, where (1) the former suppresses electricity prices

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[10] High values in the Low RE and Mid RE grid scenarios in months other than July do exist in several regions, but they are not visible in the Figure 6 summary because the whiskers do not cover the full range of values—only the 10th to 90th percentiles.
[11] For the Florida Reliability Coordinating Council (FRCC), high capacity prices usually occur in the winter. Other regions are summer-peaking, so high capacity prices typically occur in the summer.
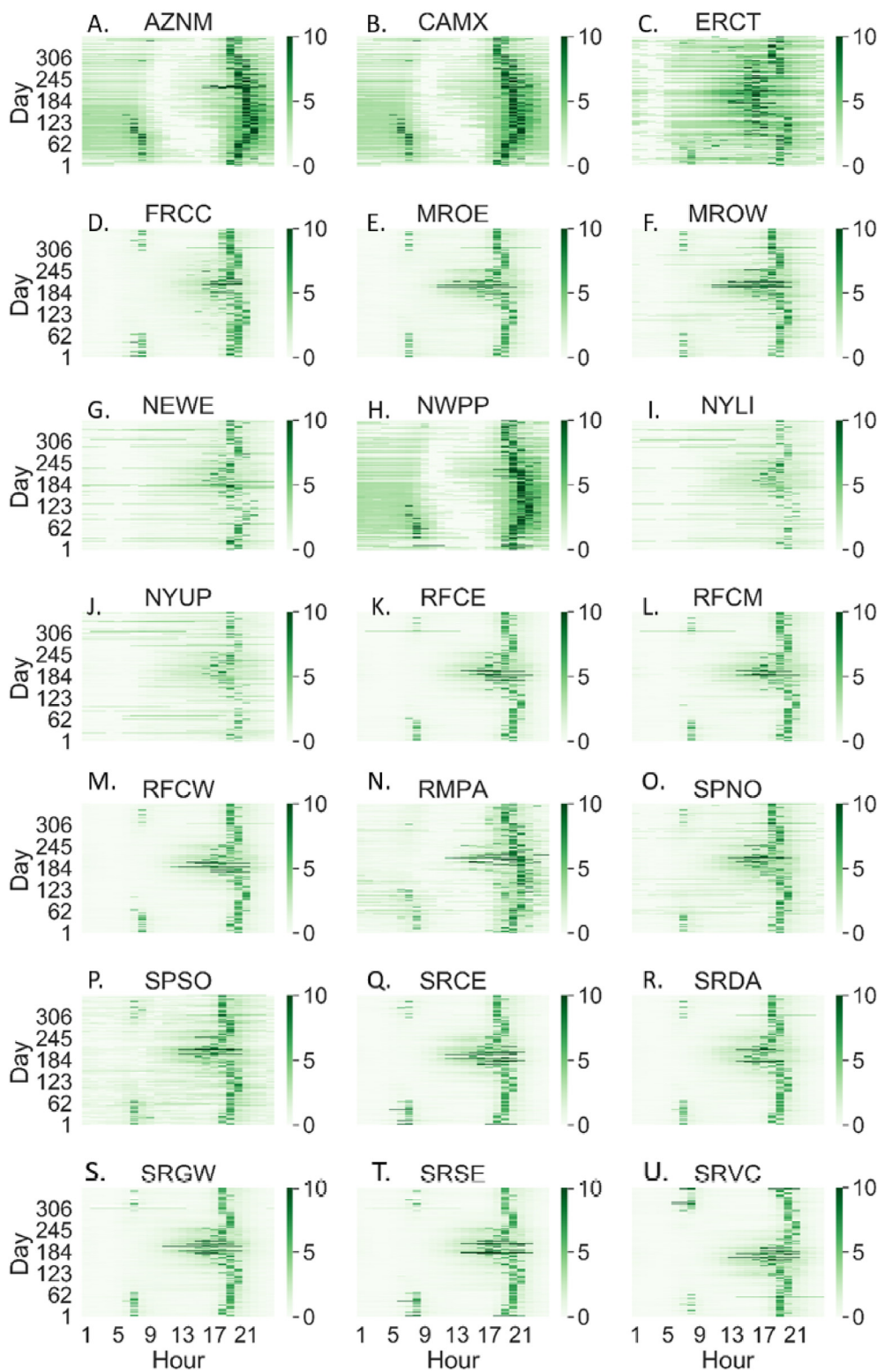
Figure 4. Hourly value (cents/kWh-day) for 1 kW h of daily shiftable building flexibility by original usage hour (x-axis of each subplot), day of the year (y-axis of each subplot) in the reference case (Mid RE, shifting window [−12,+11], efficiency 1, and dissipation 0). Each subplot (A through U) depicts the 8760 hourly value of a region (e.g., AZNM, CAMX). All acronyms are defined in the list of acronyms. A map of the regions is available in Appendix C, Figure C-2. Darker shades correspond to higher average values, ranging from 0 to 10 cents/kWh-day. Hourly values above 10 cents/kWh-day have the same dark shade as 10 cents/kW h-day.

midday to afternoon and increases prices during evening ramp events and (2) the latter tends to reduce electricity prices overall and especially at night to differing degrees. For example, CAMX's value shows a clear "duck curve" shape driven by solar generation in all cases, because even under Low RE, the solar PV percentage of load is 15% in CAMX. ERCT only has 2% solar PV under Low RE and thus shows high value for all afternoon hours, corresponding to the typical times of high summer load. However, ERCT reaches 20% solar PV and 38% wind under High RE,

which increases the value of building flexibility in general except for hours when solar suppresses electricity prices. This results in a higher value peak that occurs during evening hours (19:00–20:00), rather than in the afternoon. MROW is similar to ERCT but has greater share of wind and less solar PV. MROW's mean value is driven by a few high capacity value hours in the Low and Mid RE scenarios that cause the mean value to be much higher than the interquartile range. NEWE's solar PV and wind shares are 6% and 19% of regional load under Low RE and reach 13% and
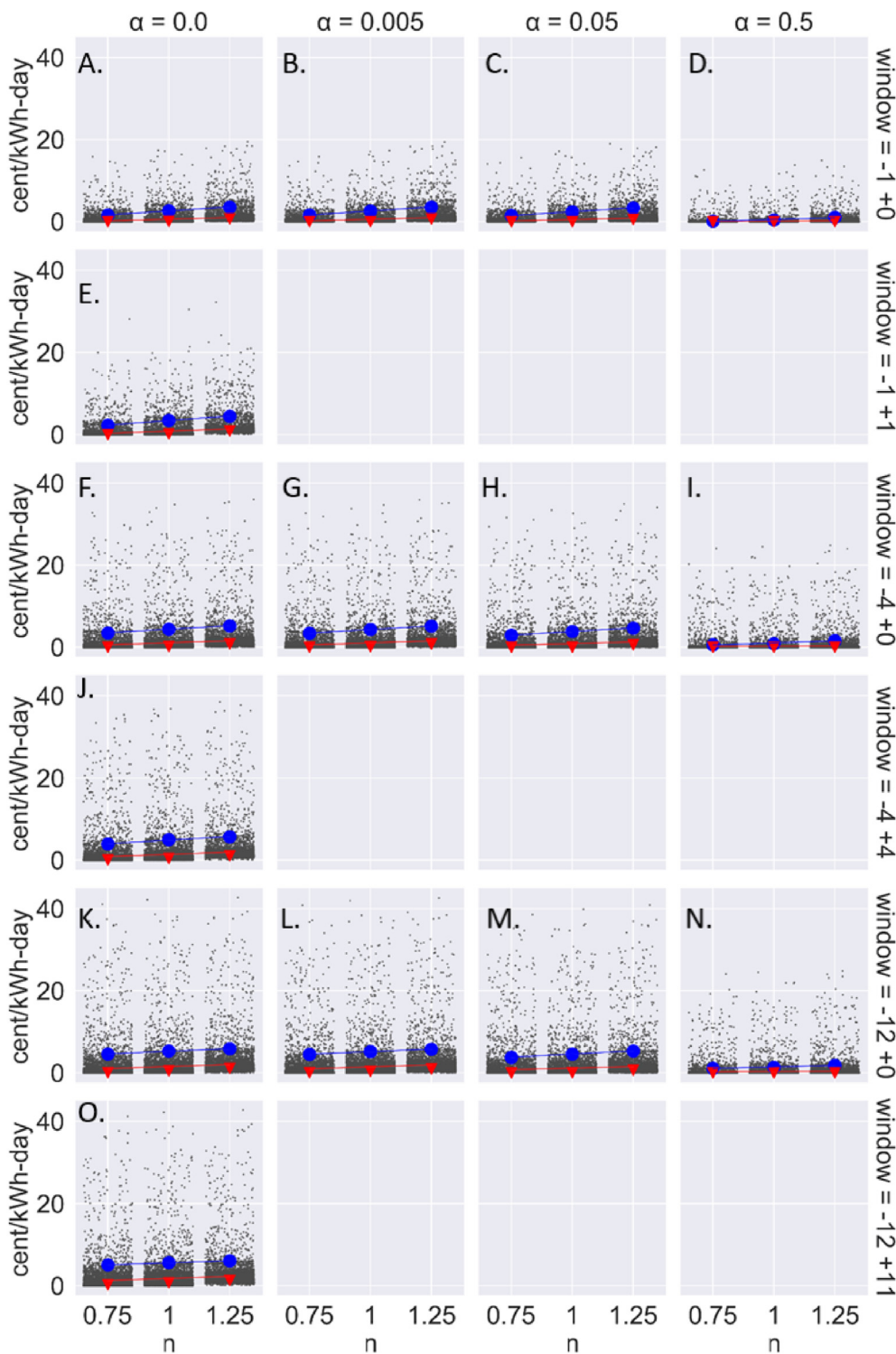
Figure 5. Average monthly value by shifting window (row), dissipation α (column), and efficiency η (x-axis of each subplot) under the Mid RE grid scenario. A. window $[-1, 0]$, $\alpha = 0$; B. window $[-1, 0]$, $\alpha = 0.005$; C. window $[-1, 0]$, $\alpha = 0.05$; D. window $[-1, 0]$, $\alpha = 0.5$; E. window $[-1, +1]$, $\alpha = 0$; F. window $[-4, 0]$, $\alpha = 0$; G. window $[-4, 0]$, $\alpha = 0.005$; H. window $[-4, 0]$, $\alpha = 0.05$; I. window $[-4, 0]$, $\alpha = 0.5$; J. window $[-4, +4]$, $\alpha = 0$; K. window $[-12, 0]$, $\alpha = 0$; L. window $[-12, 0]$, $\alpha = 0.005$; M. window $[-12, 0]$, $\alpha = 0.05$; N. window $[-12, 0]$, $\alpha = 0.5$; O. window $[-12, +12]$, $\alpha = 0$. Each black dot is the average monthly value of one original usage hour's value in one region under one set of building flexibility parameters (i.e., shifting window, efficiency, and dissipation) under Mid RE. Red triangles indicate the median and blue circles indicate the 95th percentile of the monthly results for each combination of building flexibility parameters.

30% under High RE conditions. Because NEWE is better grid-connected than ERCT and it has considerable storage and hydropower resources relative to its total system size (1.8 GW storage and 1.8 GW of hydropower in a system with 44 GW of installed capacity), the value of building flexibility in NEWE is lower than in the other three regions, although more PV does drive more evening value as we step through the Low, Mid, and High RE scenarios.

VRE generation strongly impacts the hour to which the building flexibility would shift, if it shifts (Figure 8). For most regions under reference building flexibility conditions (window $[-12, +11]$, efficiency 1, and dissipation 0) and under Low or Mid RE, consumption shifts to early morning (00:00 and 07:00, such as in ERCT, MROW, and NEWE in Figure 8). The exceptions are (1) two solar-heavy regions (AZNM and CAMX) where consumption shifts to the three hours before and after noon and (2) two wind-heavy regions (NWPP and RMPA) where consumption shifts to the afternoon and is spread out throughout the day rather than being concentrated in the morning. But under High RE, the consumption pattern shifts for all regions to be more spread out, and
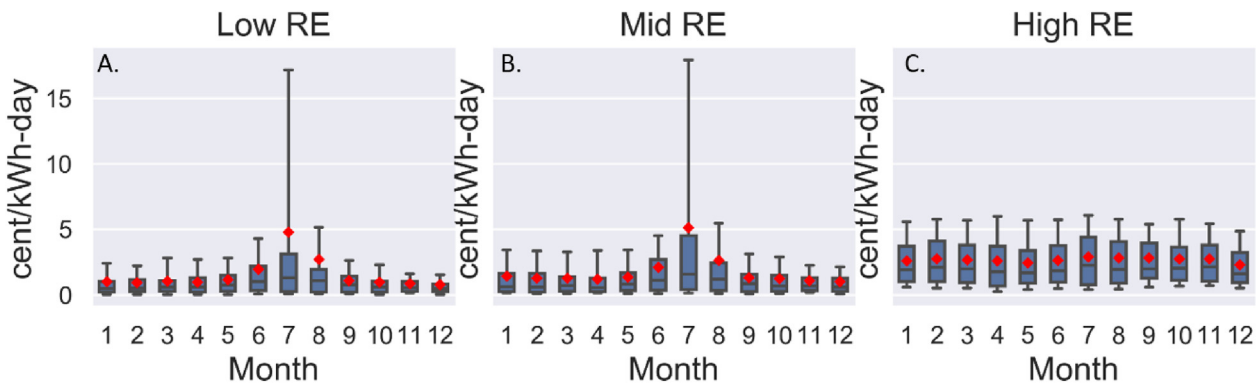
Figure 6. Box plot of mean monthly value for 1 kW h of daily shiftable building flexibility for each original usage hour and region under reference building conditions (window [−12, +11], efficiency 1, and dissipation 0) by month by grid scenario (panel). A. Low RE. B. Mid RE. C. High RE. Red dots indicate the mean values. Whiskers extend to the 10th and 90th percentiles of the distributions. Lower and upper bounds of the boxes show the first and third quartiles, and middle lines show the median value.
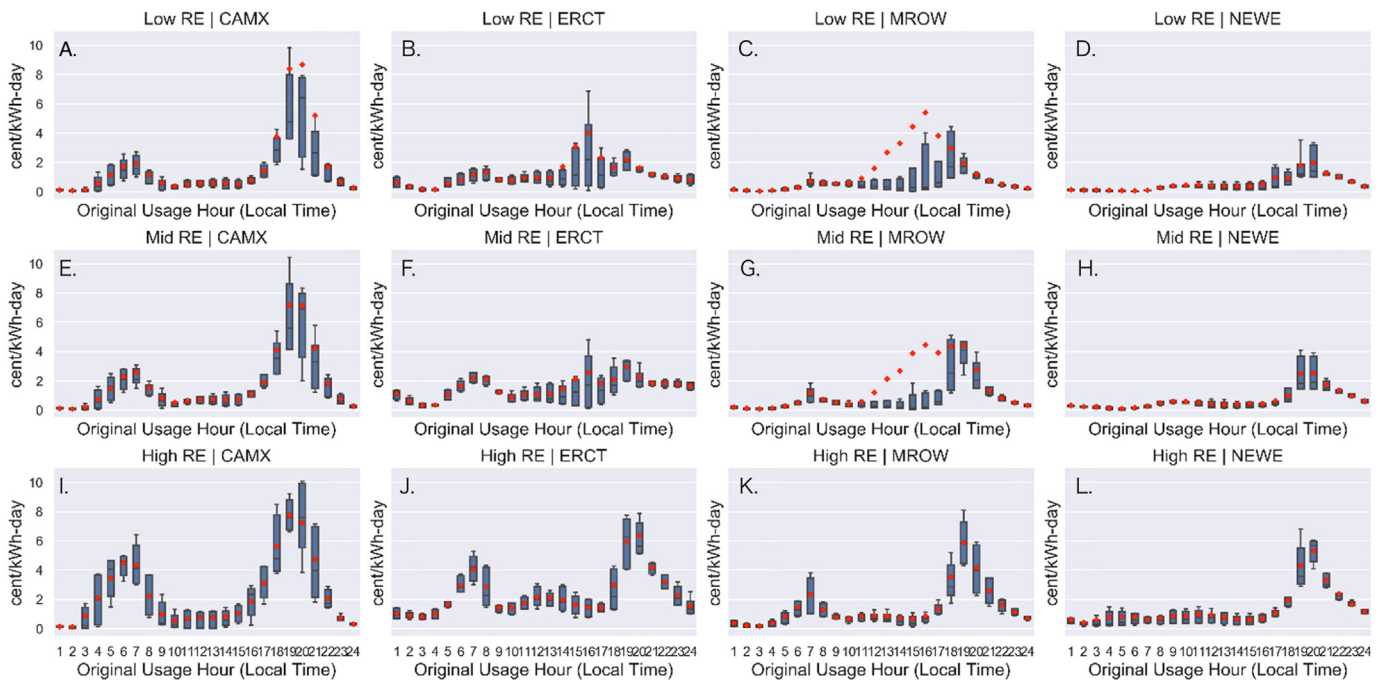

Figure 7. Box plot of average monthly value of 1 kW h of daily shiftable building flexibility under reference building conditions (window [−12,+11], efficiency 1, and dissipation 0) by original usage hour (x-axis of each subplot) and by grid scenario (A. B. C. D: Low RE, E. F. G. H: Mid RE, I. J. K. L: High RE) in four regions (A. E. I: CAMX, B. F. J: ERCT, C. G. K: MROW, D. H. L: NEWE). Red dots indicate the mean values across different months. Whiskers extend to the 10th and 90th percentiles of the distributions. Lower and upper bounds of the boxes show the first and third quartiles, and middle lines show the median value.

energy shifting occurs less often in a few regions, including ERCT, because there are instances of entire days with zero energy and capacity prices in the simulated prices.

3.4. Highest-value hour per day

In Sections 3.1.–.3, we describe flexibility value while always keeping separate the shifting from different original consumption hours of the day (1 through 24). That choice allows us to respect that monthly or annual values for multiple original usage hours are not necessarily additive because of the way we decompose our analysis. For example, adding the value for shifting from two different original usage hours might imply many cases of those two hours assigning their load to the same shift-to hour, and that may in reality violate an equipment capacity constraint. In this section, we compute the value of shifting 1 kW h of load per day with the original usage hour not fixed—but selected to be the highest-value hour for each day (analyzed by region, grid scenario, window size, efficiency, and dissipation).

Because we select the highest-value hour per day, the impact of capacity price is especially visible using this metric and is clearly seen by comparing distributions of daily value per region and grid scenario. For example, under reference building flexibility conditions, MROW has a few very high value days (over 300 cents/kWh-day) under Low RE and Mid RE (Figure 9). Under these two grid scenarios, almost half of MROW's flexibility value comes from capacity (Figure 10). These observations are driven by high capacity prices in a few hours and days of the year. In contrast, the NEWE daily values are spread more evenly throughout the year (Figure 9), and almost none is derived from providing firm capacity (Figure 10). More generally, the high-value days
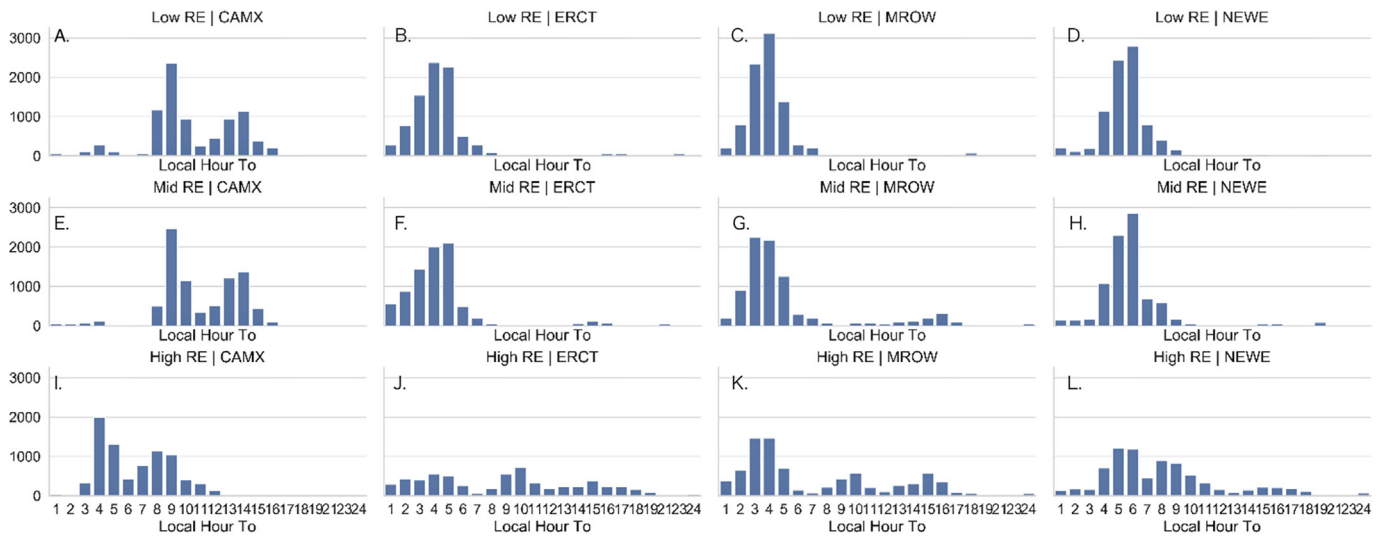
Figure 8. Histogram of the hour where building flexibility is shifted to under reference building conditions (window [−12,+11], efficiency 1, and dissipation 0) by grid scenario (A. B. C. D: Low RE, E. F. G. H: Mid RE, I. J. K. L: High RE) for four regions (A. E. I: CAMX, B. F. J: ERCT, C. G. K: MROW, D. H. L: NEWE), y-axis indicates the frequency (maximum is 8395, which means all the other 23 h shift to a particular hour every day). The X-axis shows the local time of energy consumption after shifting; the Y-axis is the number of occurrences over the year. Because each original hour of consumption is modeled separately, they can shift to the same hour.

shown in Figure 9 typically correspond to high capacity prices allocated to top net-load hours.

While three of the four selected regions provide values through a mix of capacity and energy services under Low and Mid RE, all regions obtain over 95% of their values by providing energy service under High RE (Figure 10). In all regions and under all grid scenarios, our analysis shows very little ancillary service value, even though greater shares of VRE can lead to higher reserve prices. This finding is mostly due to our selection of the highest-value hour per day; for almost all days, the highest-value hour will be driven by capacity, energy, or both. When we analyze all combinations of parameters and grid scenarios, we find that the ancillary service values only account for a small percentage of the sum annual value across grid services when we choose only the highest-value hour per day, except for very rare circumstances.

When only one hour each day can provide flexibility, the annual sum of gross value shows great regional variance. However, the total value for each region is similar under Low RE and High RE (Figure 11) though the source of value shifts from a large portion coming from capacity to almost all value coming from energy. Though it is similar, the High RE scenario does tend to show modestly higher value under reference flexibility conditions (bottom right of Figure 11), except in CAMX, NWPP, RMPA, and SPNO. Reducing the shifting window from [−12, +11] to [−12, 0] shows little effect on annual gross value. Even narrowing the window to

only [−1, +1] captures more than half the total annual value found for [−12, +11] (Figure 11). These results indicate building flexibility can provide value under Low and High RE even with shifting distance of just one hour if the highest-value hour per day can be identified.

3.5. Impact of all examined parameters

Under the modeled conditions, the original usage hour has the greatest impact on the value of building flexibility (Figure 12): the interquartile range of monthly values is highest at 19:00 at 0.64–4.26 cents/kW h-day and lowest at 3:00 at 0.00–0.53 cent/kW h-day. Building flexibility value can also vary greatly by month: the interquartile range of monthly values is highest in July at 0.01–1.60 cent/kW h-day and lowest in December at 0.00–0.78 cent/kW h-day.

Of the building flexibility characteristics, shifting window size has the biggest impact on value, even though one-sided windows (e.g., [−12, +0]) can capture most of the value obtained by full symmetrical windows (e.g., [−12, +11]) when only the highest-value hour in each day is selected. High dissipation effectively truncates what could otherwise be long duration shifting, because the energy consumption needed to provide the same service hours ahead of time grows exponentially with the distance of the shift. This is reflected in the low values shown in the dissipation 0.5 box plot. Efficiency has a smaller impact on building
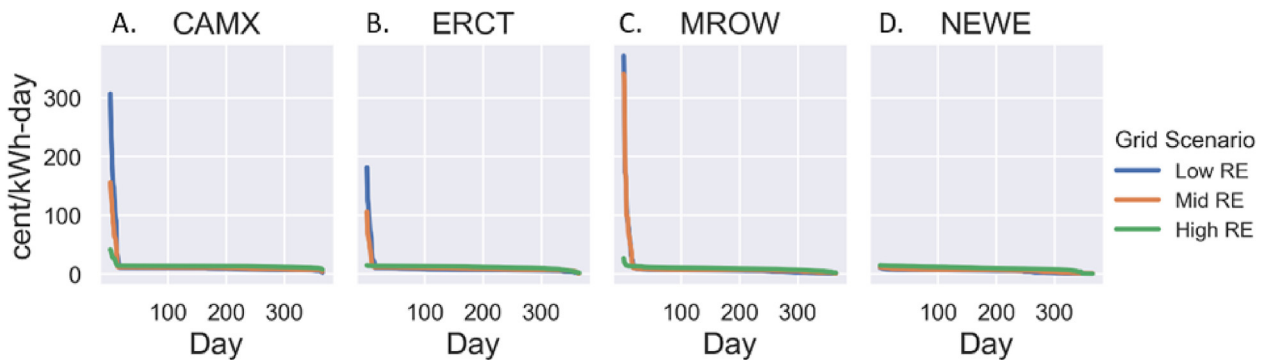

Figure 9. Daily value duration curve in four selected regions by grid scenario under reference flexibility conditions (window [−12,+11], efficiency 1, and dissipation 0) when shifting only the highest-value hour each day. A. CAMX. B. ERCT. C. MROW. D. NEWE. The highest-value hour for each day in each region is shown sorted in descending order.
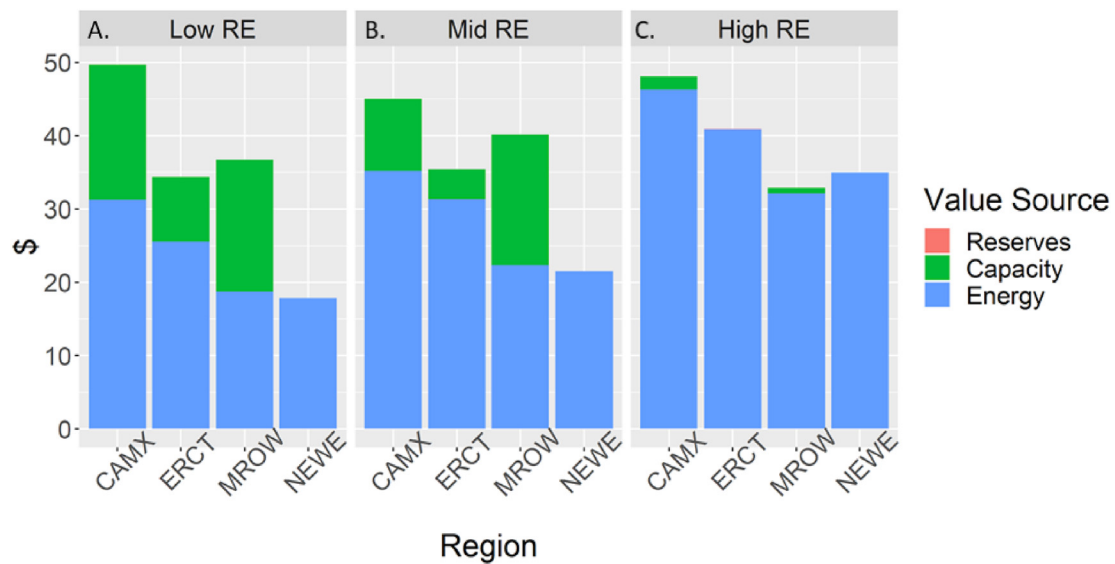
Figure 10. Annual value ($) of shifting 1 kW h from the highest-value hour of each day in four regions (bars: CAMX, ERCT, MROW, NEWE) by grid scenario (panel) and by value source (colors: reserve, capacity, energy) under reference flexibility conditions (window [−12,+11], efficiency 1, and dissipation 0). A. Low RE. B. Mid RE C. High RE. Each result is the sum of 365 potential shifting events. The reserve value includes flexibility, contingency, and regulation reserve.
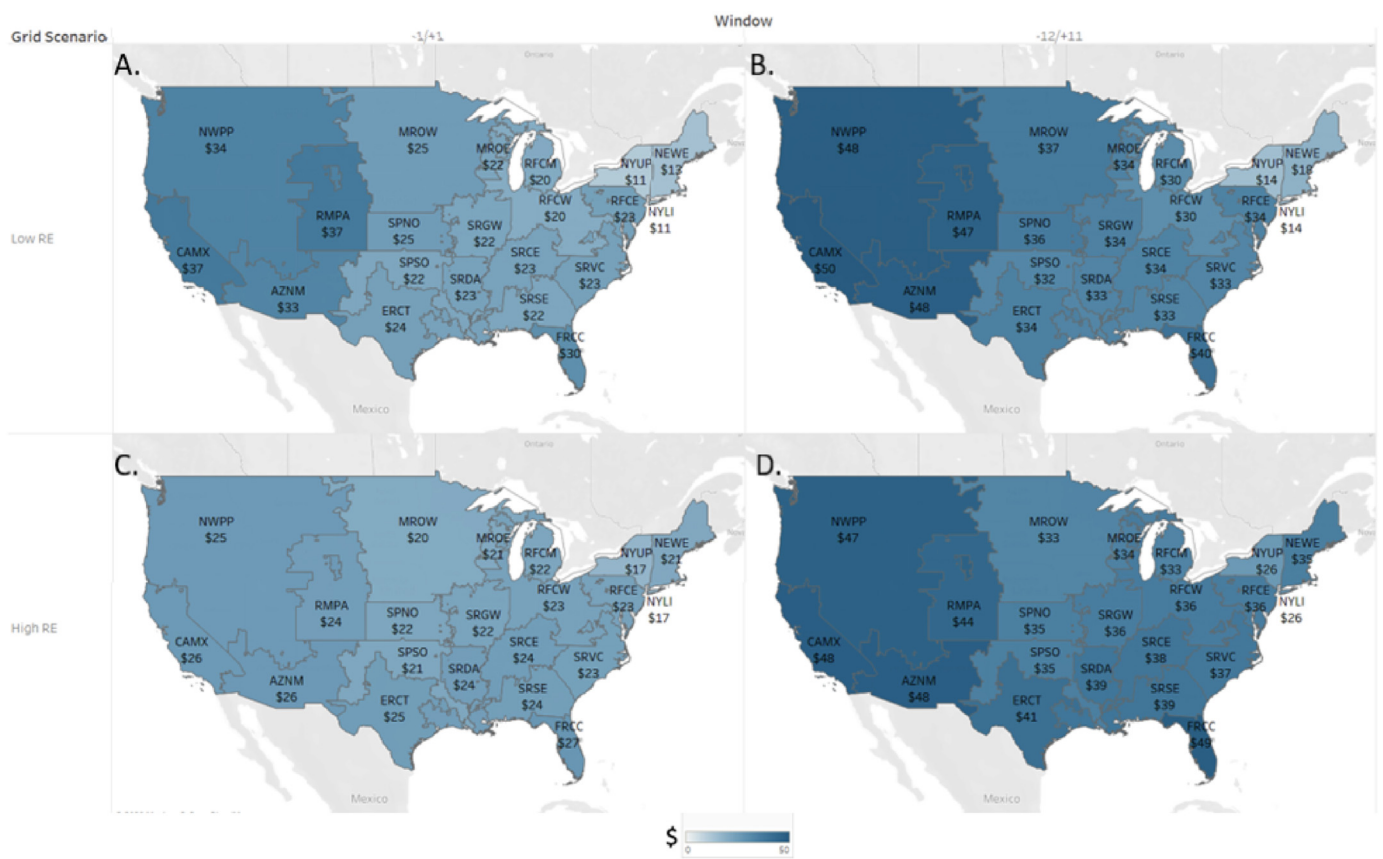

Figure 11. Annual value ($) of the highest-value hour of each day in 21 regions of the conterminous United States. A. Low RE, window [−1, +1]. B. Low RE, window [−12, +11]. C. High RE, window [−1, +1]. D. High RE, window [−12, +11]. Each result is the sum of 365 potential shifting events.

flexibility value than dissipation. The VRE deployment in the 2030 grid scenario has very little impact on the mean monthly value of building flexibility, but it can change both the diurnal pattern of energy shifting and the source of grid service value (Figure 10). The regional variance in

building flexibility value is also high, with many factors (e.g., generation mix, grid connection, and regional load patterns) potentially contributing.
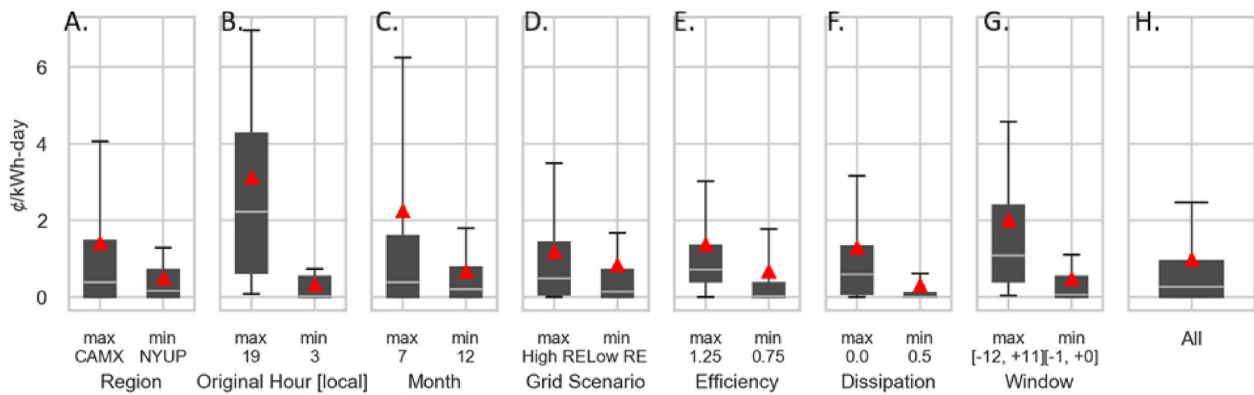
Figure 12. Box plot of average monthly value (cents/kWh-day) distributions by parameter for the highest and lowest mean value of each parameter (A through G) and the distribution across all examined parameters (H). Whiskers extend to the 10th and 90th percentiles of the distributions. Lower and upper bounds of the boxes show the first and third quartiles, and middle lines show the median value. Red triangles show the mean values. The figure shows the distribution of monthly mean values across all examined parameters (i.e., region, original usage hour, etc.) by parameter in the first seven panels, and the full distribution of the 816,480 monthly means in the last panel. In each of the first seven panels, the distributions for the parameter choice that yield the largest and smallest average value are plotted.

4. Conclusions

This is the first technology-agnostic analysis of the gross revenue of shiftable building flexibility for the entire conterminous United States under various projected future grid conditions.

We analyze generic building flexibility (1) as parameterized by shifting windows, efficiency, and dissipation, and (2) per region, grid scenario, and original usage hour. Our analysis is conducted using a novel cross-sector framework that bridges grid capacity expansion and production cost models with a building flexibility model. We estimate the gross value of a marginal kilowatt-hour of flexible building load based on various simulated 2030 grid conditions from five grid service value streams: capacity, energy, contingency reserve, flexibility reserve, and regulation reserve. Thus, the building flexibility we model may be interpreted as a presumed market entrant in the 2030 power system. Should building flexibility deployed by 2030 be of sufficient scale to impact market prices, gross values are likely to be lower than the current estimates, although this consideration is counterbalanced by the simplifications in our future power system models that result in the modeled future prices being less variable than currently observed real-world prices.

We draw several important conclusions from our analysis. First, the original usage hour has the greatest impact on the value of building flexibility, with the highest-value original usage hours often falling between 18:00 and 20:00. A larger shifting window can help access more energy arbitrage opportunities, but most of the highest-value opportunities each day can be captured with just one half of a symmetric shifting window. Second, increasing VRE generation as a percentage of load can change the hours from which or to which it is most valuable to shift energy. Solar generation creates a regular diurnal pattern in electricity prices from which building flexibility can capture value. Higher wind generation means building flexibility can shift to more hours throughout the day than Low RE, where it can shift to only a few hours in the early morning. Third, the main value streams for building flexibility in most cases lies in capacity and energy services, not in ancillary services. Furthermore, increasing VRE deployment can change the proportion of value derived from providing capacity versus energy. Capacity value is prominent in a limited number of hours, typically in the summer, for many regions under Low RE and Mid RE.[12] When this occurs, building flexibility might need to be activated only one hour each day for about 30 days each year to gain a substantial portion of the

total possible annual gross value. We do not see this pattern under High RE; instead, almost all value is derived from energy arbitrage and therefore requires more active days to capture most of the available gross value.

In this work, we provide (1) a novel cross-sector framework for estimating the gross value of generic building flexibility as a market entrant and (2) a database that building technology providers can search for a value based on region, the characteristics of the technology, temporal availability, or applicable grid services. Future work could address one limitation of this study by assessing the value of generic building flexibility when a significant quantity of demand-side flexibility is already present in the simulated power systems.

Declarations

Author contribution statement

Ella Zhou: Conceived and designed the experiments; Performed the experiments; Analyzed and interpreted the data; Contributed reagents, materials, analysis tools or data; Wrote the paper.

Elaine Hale, Elaina Present: Conceived and designed the experiments; Analyzed and interpreted the data; Contributed reagents, materials, analysis tools or data; Wrote the paper.

Funding statement

Data availability statement

Data associated with this study has been deposited at NREL Data Catalog (https://data.nrel.gov/submissions/155).

Declaration of interests statement

The authors declare no conflict of interest.

Additional information

No additional information is available for this paper.

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[12] For example, the FRCC region is an exception, as high capacity prices occur in the winter.

Appendix A

Additional information on the Simulated Future Grid Scenarios

The grid scenarios we use are selected from the 2019 Standard Scenarios Report [45]. They are generated using ReEDS and PLEXOS. ReEDS is a utility-scale investment model for long time horizons, and PLEXOS performs detailed (hourly in our study) simulations of an entire year's grid operations. Detailed documentation of ReEDS as well as its input data sources can be found at [47] and information on PLEXOS, a commercial software, can be found at [48].

ReEDS and the power systems exported to PLEXOS are zonal models with 134 balancing authority nodes connected with about 300 transmission corridors subject to linearized DC power flow constraints [66]. ReEDS and PLEXOS constraints and input data are described in detail in the model documentations cited above. We summarize some of the key input data sources here for readers' convenience.

- Electricity load: Historical load shapes are from ISOs and RTOs where applicable, and are from FERC Form 714 for other regions [47]; annual load growth rates are from the U.S. Energy Information Administration's Annual Energy Outlook (AEO) 2019 [67].
- Fuel prices: AEO 2019 [67].
- Existing fleet, announced retirements, and prescribed builds: based on the National Energy Modeling System database of AEO 2019 [67].
- Generator technology cost, performance, and financing: based on NREL's Annual Technology Baseline [46].
- Transmission capacity limits between balancing authorities in 2010: based on power-flow analysis using ABB's GridView model and National Electric Reliability Organization (NERC)-reported line limits [68].
- Transmission voltage assumptions: based on data from the Homeland Security Infrastructure Project 2012 [69].
- Transmission upgrade cost and financing: based on data from the Phase II Eastern Interconnection Planning Collaborative (EIPC) report [70].
- Policy information (e.g., renewable portfolio standards and carveouts, and state storage mandates): based on existing policy as of July 31, 2019.

ReEDS capacity builds have been validated and compared to historical data in [71]. Comparing ReEDS results and 2010–2016 historical builds, the study finds that ReEDS can produce results with reasonably high accuracy. In our work, because there is no way to compare future data now, we choose a High RE scenario and a Low RE scenario to capture a wide range of potential future trajectories and examine where building flexibility revenue could be within this range, rather than attempt to predict one future value.

Appendix B

Summary of Ancillary Services

We model three types of ancillary services in this work: flexibility, contingency, and regulation reserves. Flexibility reserves are typically held to manage net-load ramps and VRE forecast errors; contingency reserve is called on to increase generation immediately following unforeseen generation and transmission outages; and regulation reserve balances demand and supply on the timescale of seconds and mitigates frequency deviations both during normal operation and in case of contingencies [61]. Therefore, the required response times for flexibility reserve, contingency reserve, and regulation reserve are different: around 20–30 min for flexibility, 10 min for contingency, and 3 min for regulation. Note that in practice, resources providing flexibility or regulation reserves are expected to continually follow a signal once they have started responding. For example, a regulation reserve resource may have advanced notice that it will be expected to start providing regulation reserve service soon (e.g., within 3 min), and when that time is up, it will be evaluated on how well it followed a signal that may be changing as frequently as every four seconds.

The modeled requirements for these three types of ancillary service in our ReEDS and PLEXOS model are summarized in Table B.1.

Table B.1. Summary of ancillary service requirements.

Reserve	Load Requirement (% of load)[a]	Wind Requirement (% of generation)[b]	Solar PV[e] Requirement (% of capacity)[b]	Time to Ramp (minutes)
Flexibility	–	10%	4%[c]	20
Contingency	3%	–	–	10
Regulation	1%	0.5%[c]	0.3%[d]	3

[a] See [72], Section 5.3.4.
[b] Reserve requirements for wind and PV are derived from the outcomes from [72]. The flexibility requirement for wind is estimated as the ratio of the change in the reserve requirement to the change in wind generation from the High Wind scenario in [72]; the requirement is estimated similarly for PV using the High Solar scenario in [72].
[c] Additional flexibility reserve is held for PV equal to 4% of PV capacity during hours when PV is generating.
[d] The estimated regulation requirements (0.5% wind generation and 0.3% PV capacity) are based on incremental increases in regulation reserve across all scenarios in [72].
[e] The solar PV requirement only applies to daylight hours.

Only upward reserve is modeled in PLEXOS for two reasons. First, downward reserve is typically easier to procure because a system can easily decrease generation when needed, but upward reserve requires resources to ramp up. Second, previous building flexibility research [73] found that building flexibility has larger potential for upward flexibility service than for downward service. Because of computational resource limitations, we simplify the PLEXOS model representation by modeling only upward reserve.

Appendix C

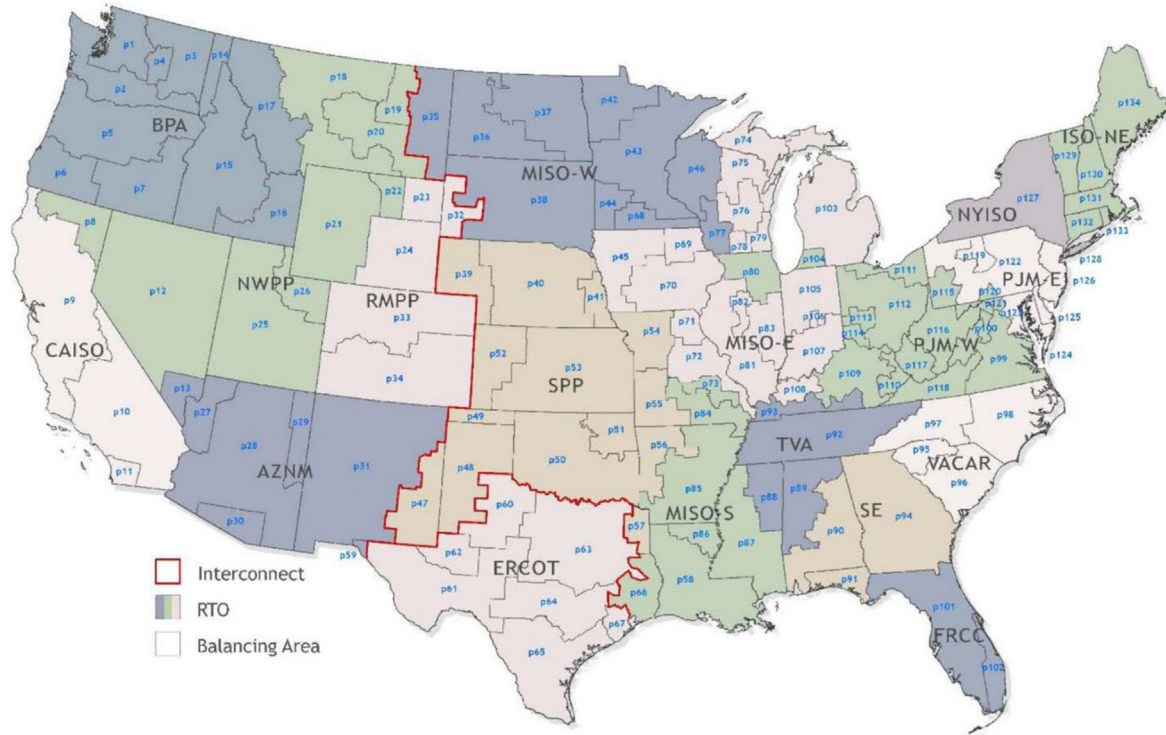*Mapping of ReEDS Regions and NEMS Regions*

Figure C.1. Map of ReEDS 134 modeled balancing areas and 18 RTO-level subregions. Source: [47].

Appendix D

Summary of Pricing Data Used as Inputs to Building Flexibility Dispatch Model

The modeled future grid service prices presented here are based on the grid composition in our selected scenarios (Section 2.1) and the model assumptions in [45]. They should not be interpreted as predictions of future grid prices or summaries of current real-world prices. In fact, we acknowledge that the modeled prices tend to have lower volatility than real-world prices (Section 2.5). The modeled ancillary service prices are lower than real-world prices partly because we allow variable renewable energy to provide ancillary service in the model based on both the technical capability of renewables and the increasing need for ancillary services in the future [75]. If current real-world prices at high geographical resolution are used, the resulting gross value for building flexibility will likely be higher than our estimates.

1.	ERCT	ERCOT All	12.	SRDA	SERC Delta
2.	FRCC	FRCC All	13.	SRGW	SERC Gateway
3.	MROE	MRO East	14.	SRSE	SERC Southeastern
4.	MROW	MRO West	15.	SRCE	SERC Central
5.	NEWE	NPCC New England	16.	SRVC	SERC VACAR
6.	NYCW	NPCC NYC/Westchester	17.	SPNO	SPP North
7.	NYLI	NPCC Long Island	18.	SPSO	SPP South
8.	NYUP	NPCC Upstate NY	19.	AZNM	WECC Southwest
9.	RFCE	RFC East	20.	CAMX	WECC California
10.	RFCM	RFC Michigan	21.	NWPP	WECC Northwest
11.	RFCW	RFC West	22.	RMPA	WECC Rockies

Figure C.2. Map of NEMS' 22 modeled regions. Source: U.S. Energy Information Administration [74].
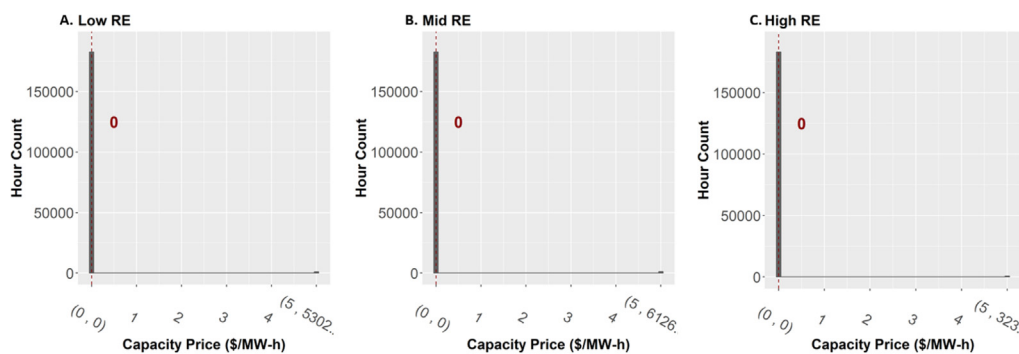
D.1. Capacity value

Figure D.1. Histogram of capacity prices under A. Low RE, B. Mid RE, and C. High RE. Values higher than $5/MW-h are grouped together in the final bin, which also marks the highest observed value in the corresponding scenario. The dashed dark red lines and the dark red numbers in each subplot show the median values.
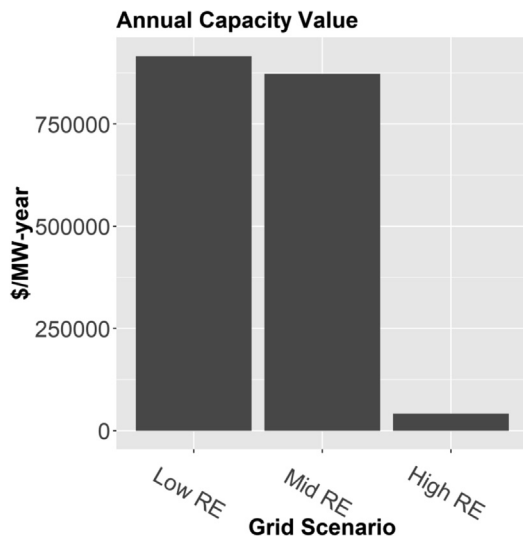
Figure D.2. Sum of annual capacity value across the regions under Low RE, Mid RE, and High RE.
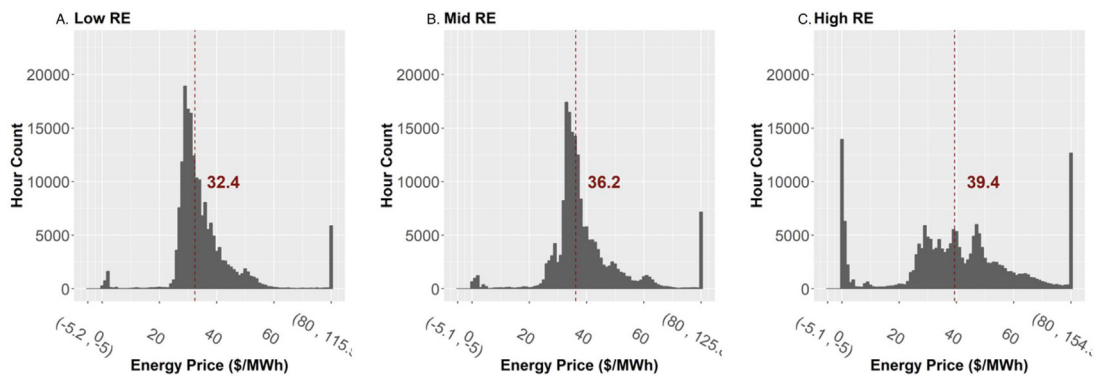
D.2. Energy prices

Figure D.3. Histogram of energy prices under A. Low RE, B. Mid RE, C. High RE. Values lower than $-5/MW h are grouped together into one bin; values higher than $80/MW h are grouped together into another bin. The range of the two end bins for each scenario show the lowest and higher observed value in the corresponding scenario. The dashed dark red line and the dark red number in each subplot show the median value.
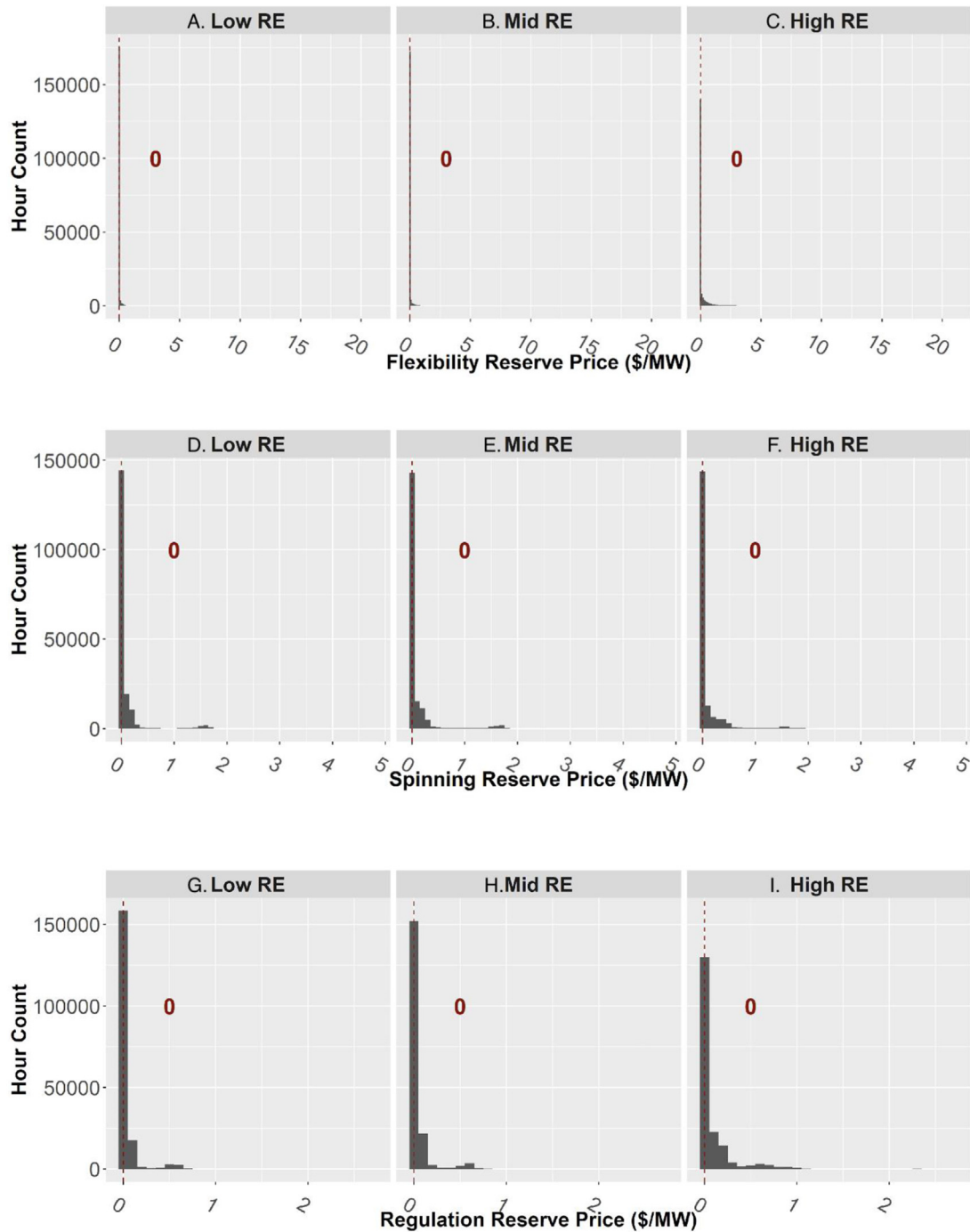
Figure D.4. Histogram of flexibility (A. B. C), spinning (D. E. F), and regulation (G. H. I) reserve prices under Low RE (A. D. G), Mid RE (B. E. H) and High RE (C. F. I). The dashed dark red line and the dark red number in each subplot show the median value.

Appendix E

Simulated 2030 VRE Annual Energy Shares in Each Modeled Region

VRE annual energy shares are calculated as the sum of post-curtailment wind and solar PV generation divided by the region's total load.

Table E.1. Simulated VRE annual energy shares (%) in each modeled region in 2030.

Region	Low RE	Mid Case	High RE
AZNM	36.05	39.50	55.81
CAMX	19.43	25.84	21.63

Table E.1 (*continued*)

Region	Low RE	Mid Case	High RE
ERCT	18.33	28.77	57.88
FRCC	3.23	9.68	34.22
MROE	6.02	23.57	71.10
MROW	36.85	39.61	45.55
NEWE	25.09	25.40	43.38
NWPP	20.93	22.65	37.35
NYLI	39.64	40.43	39.59
NYUP	27.42	39.42	47.78
RFCE	20.79	21.58	34.23
RFCM	5.66	9.08	59.76
RFCW	6.14	9.19	39.23
RMPA	33.20	33.11	42.31
SPNO	22.63	38.47	43.36
SPSO	61.68	62.37	68.47
SRCE	0.88	8.41	25.60
SRDA	0.49	2.15	31.90
SRGW	11.84	13.04	32.57
SRSE	1.71	2.40	14.83
SRVC	4.23	11.57	46.22

All acronyms are defined in the list of acronyms.

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