Building Demand Flexibility: Grid Service Value of Future Market Entrants

Ella Zhou, Elaine Hale, and Elaina Present

BTO Sensors and Controls RDO Feedback Industry Workshop

December 8, 2020

Contents

Project Overview

Goal: Estimate the value of building flexibility to the grid to inform technology cost targets. Value streams of interest include capacity, energy, and ancillary services.

Motivation: Better understand the potential magnitude of the building sector's role in supporting the future U.S. electric grid, and the factors that are likely to influence that magnitude.

Approach: Conduct scenario analysis using a price-taking model to dispatch generic demand-side flexibility resources against modeled future grid scenario hourly prices.

Project Status

FY20 Phase 1

- Dispatch model design and implementation
- Analysis of flexible building value for select 2030 grid scenarios, maximizing grid service monetary value

FY21 Phase 2

- Analysis of flexible building value for select 2050 grid scenarios with varying levels of other sources of flexibility
- New: Include demand-side flexibility in capacity expansion and production cost modeling (price-forming); mixed integer programming; dispatch model upgrades

1

2 Methods: Modeled Future Grid Conditions

3

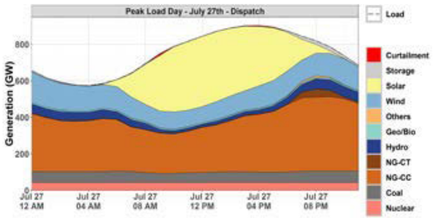
4

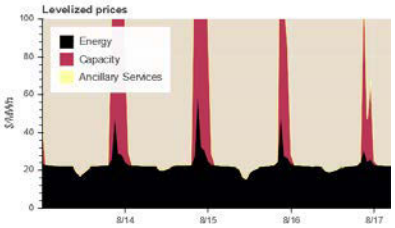
5

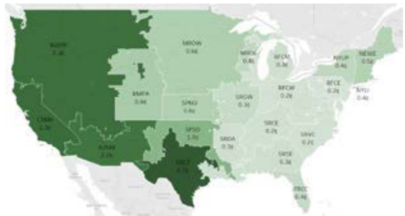
6

Method for Estimating Grid Service Value of Future Market Entrants

ReEDS	PLEXOS	Cambium	Price-Taker Model
• Produces installed generation and transmission capacity	• Produces hourly generation dispatch and electricity prices	• Compiles capacity, energy, ancillary service prices, and emission rates	• Dispatches the flexible building against price data





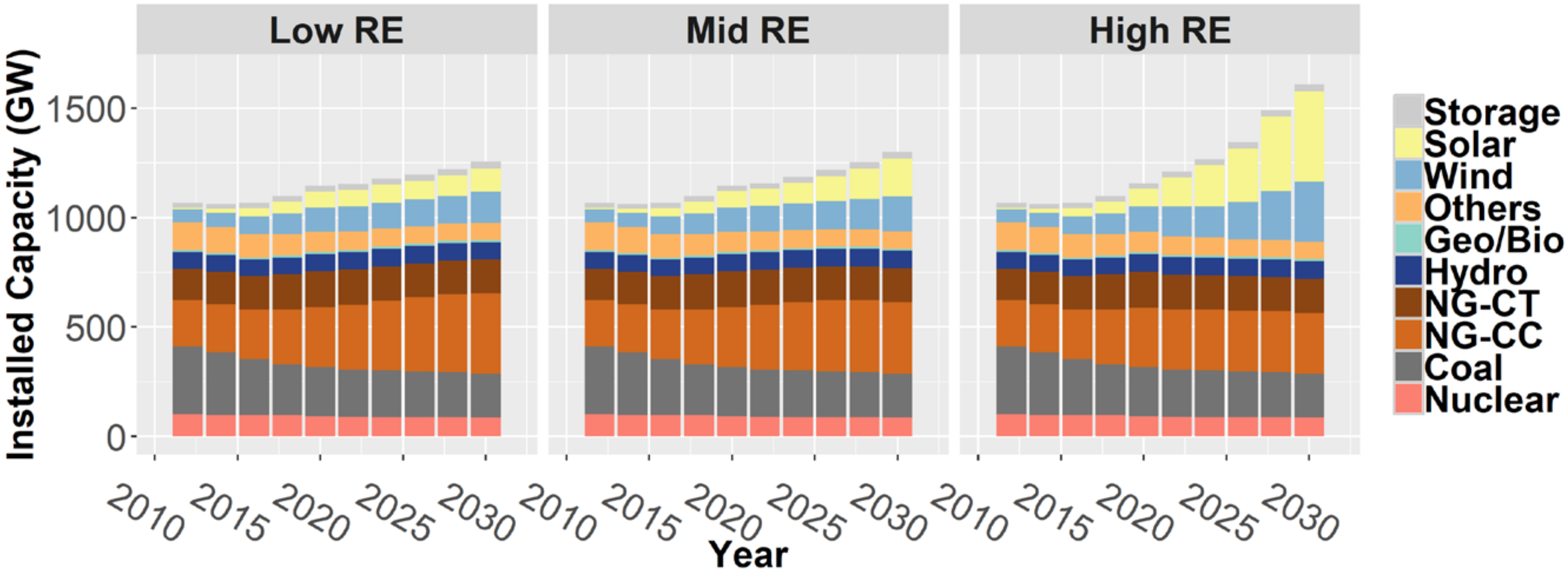


Future Grid Conditions from the 2019 NREL Standard Scenarios

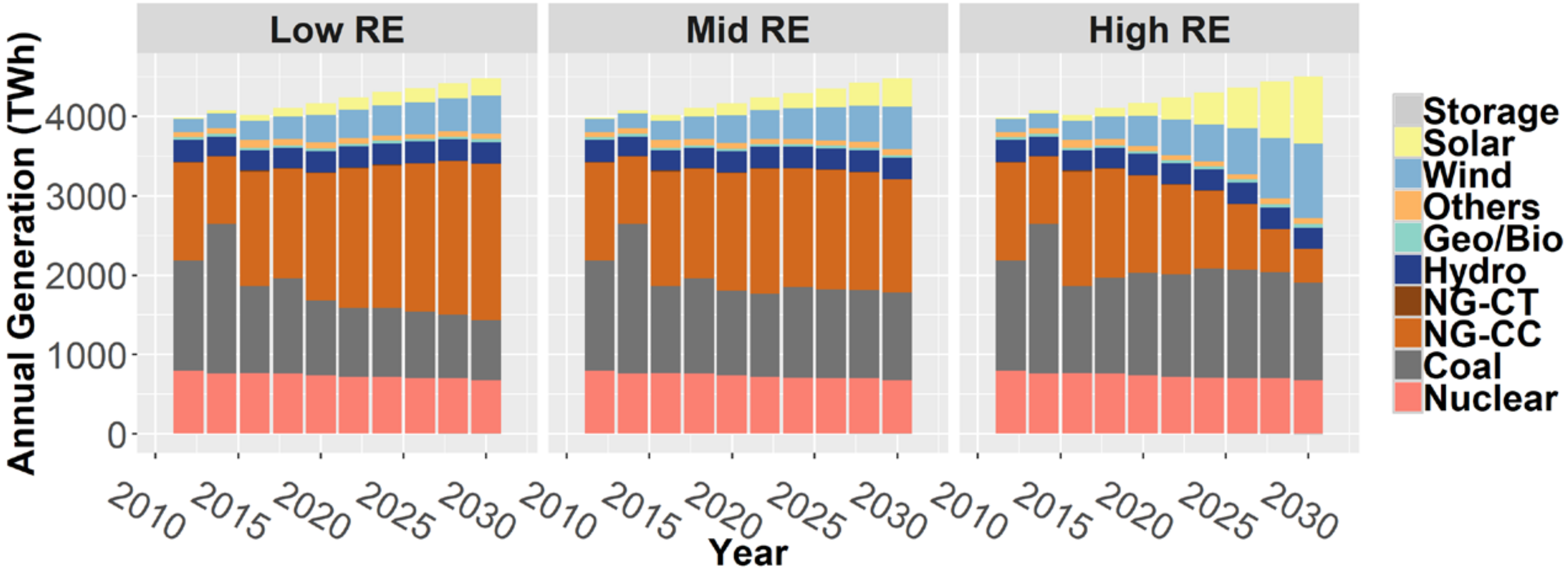
Estimated grid service value of a 2030 market entrant:

- **Mid RE** (Mid Case 2030)
- **High RE** (Low RE Cost High NG Price 2030)
- **Low RE** (High RE Cost Low NG Price 2030)

Installed Capacity



Generation



2030 RE* Penetration	16%	21%	41%

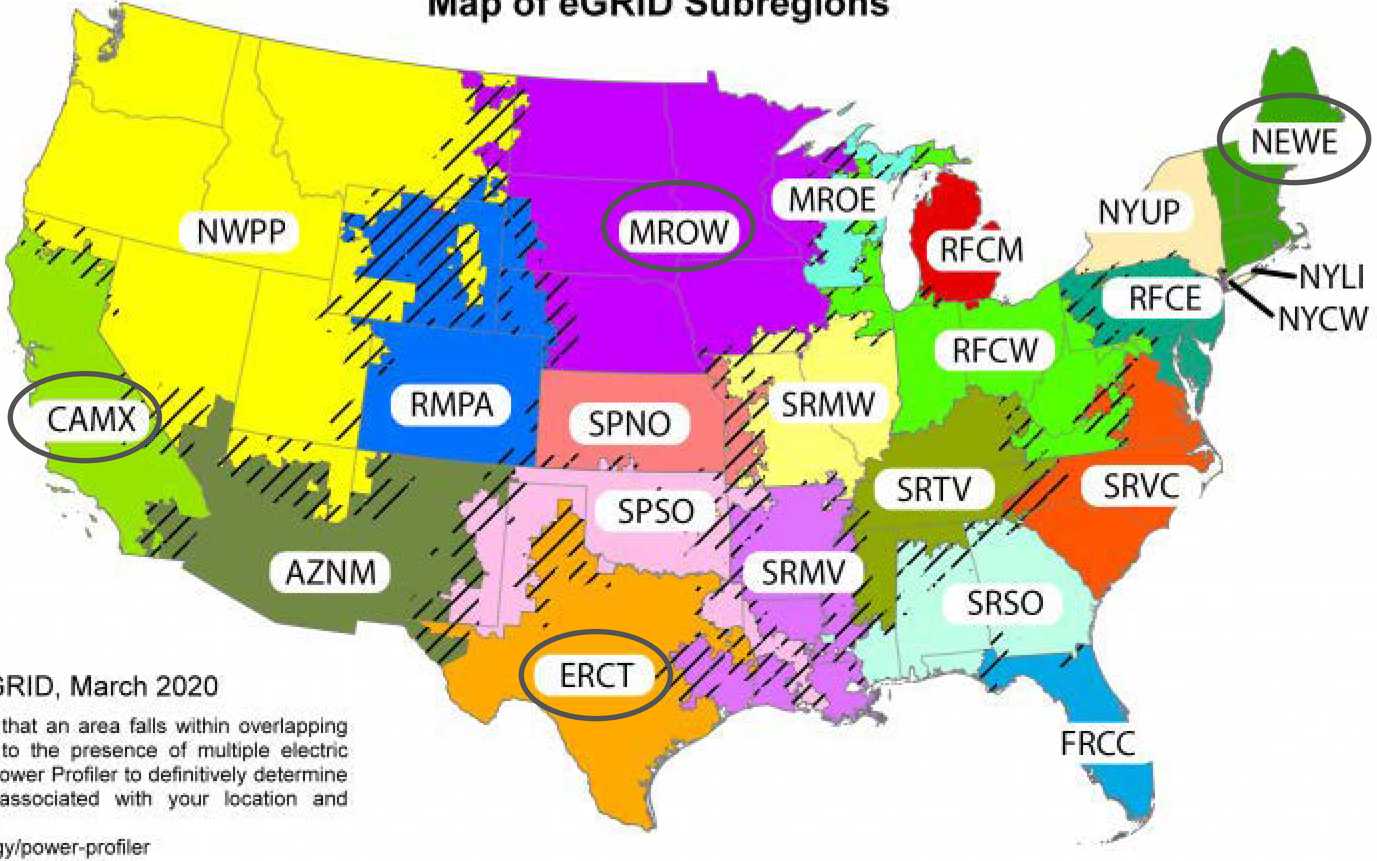
*RE includes solar, wind, geothermal, biomass, and other renewable generation, does not include hydro.

Geographic Resolution in Price Taker Model

Lesser known abbreviations

- MRO*: Midwest Reliability Organization
- SPNO & SPSO: Southwest Power Pool
- SR**: SERC
- RFC*: ReliabilityFirst Corporation

Map of eGRID Subregions



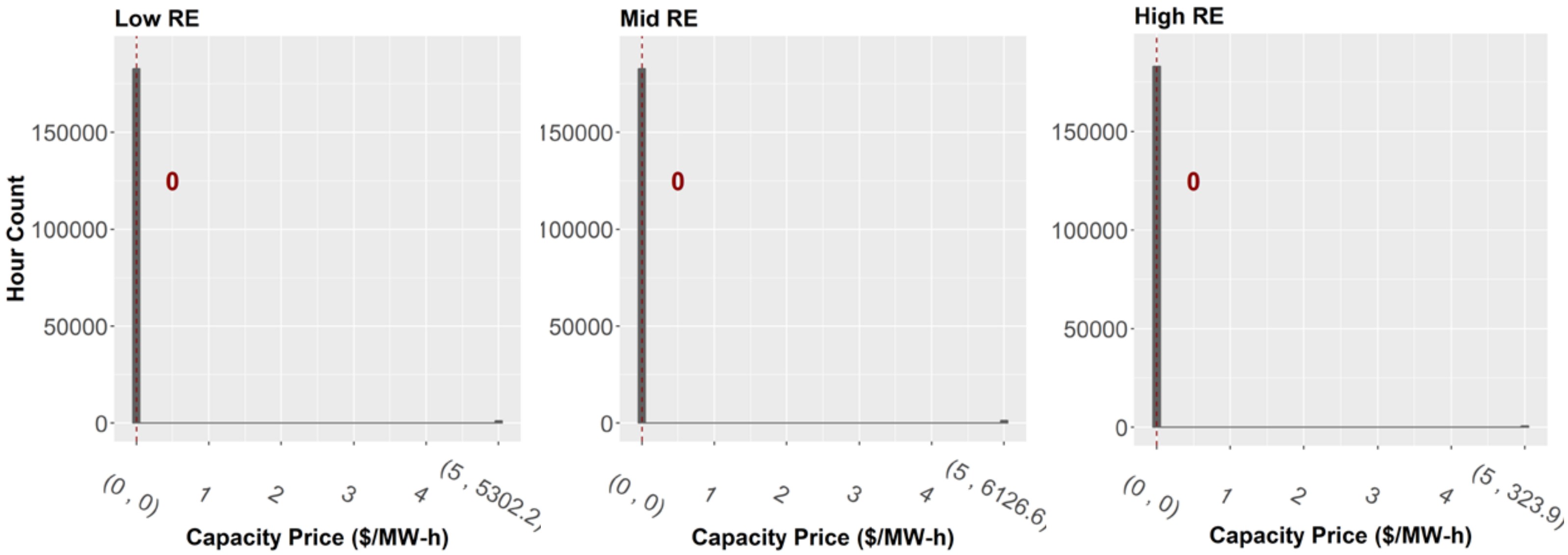
USEPA, eGRID, March 2020

Crosshatching indicates that an area falls within overlapping eGRID subregions due to the presence of multiple electric service providers. Visit Power Profiler to definitively determine the eGRID subregion associated with your location and electric service provider.
http://www.epa.gov/energy/power-profiler

Grid Services Valued

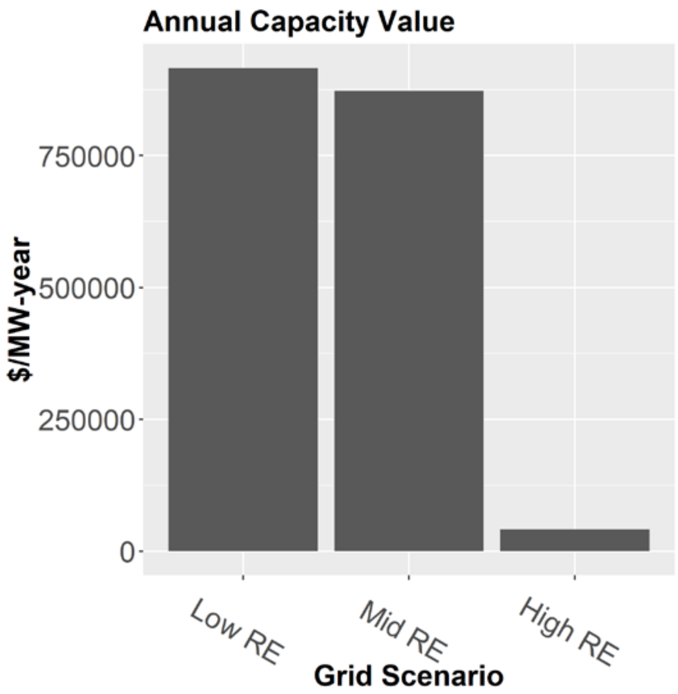
- Capacity price (ReEDS)
- Energy price (i.e., locational marginal price from PLEXOS)
- Ancillary service prices for flexibility reserves, regulation reserves, and spinning reserves (PLEXOS)

Capacity Prices

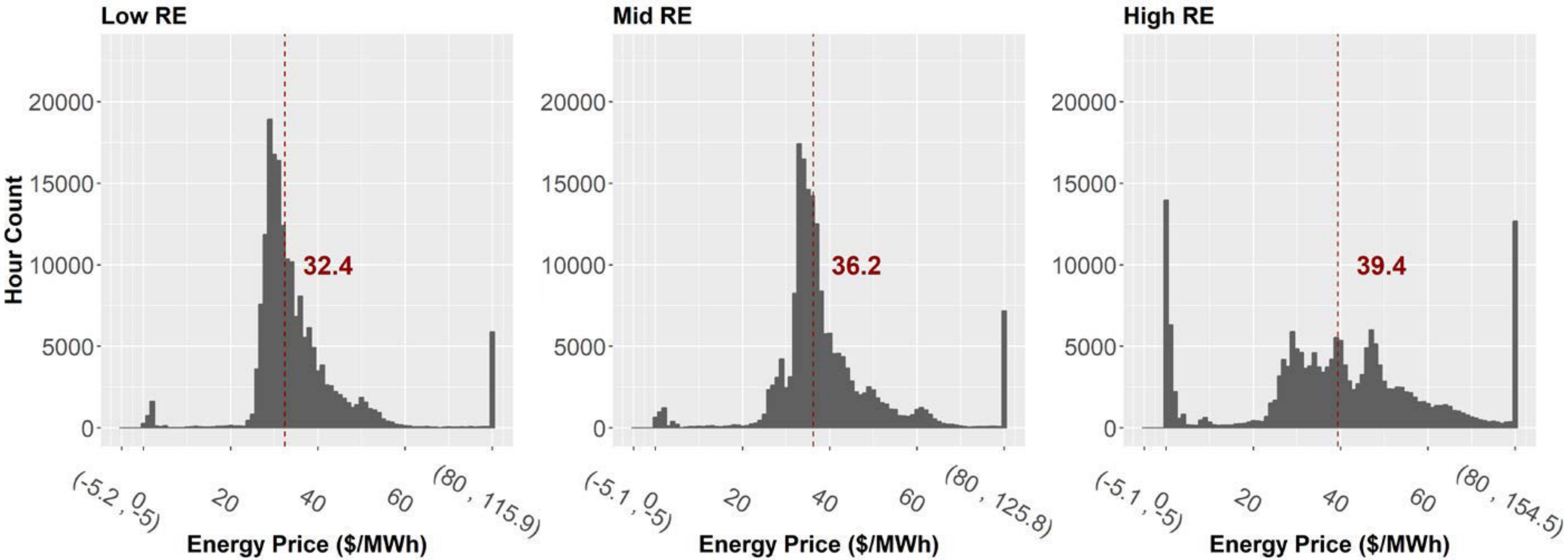


The dashed lines show the median value for each grid scenario.

Capacity Prices

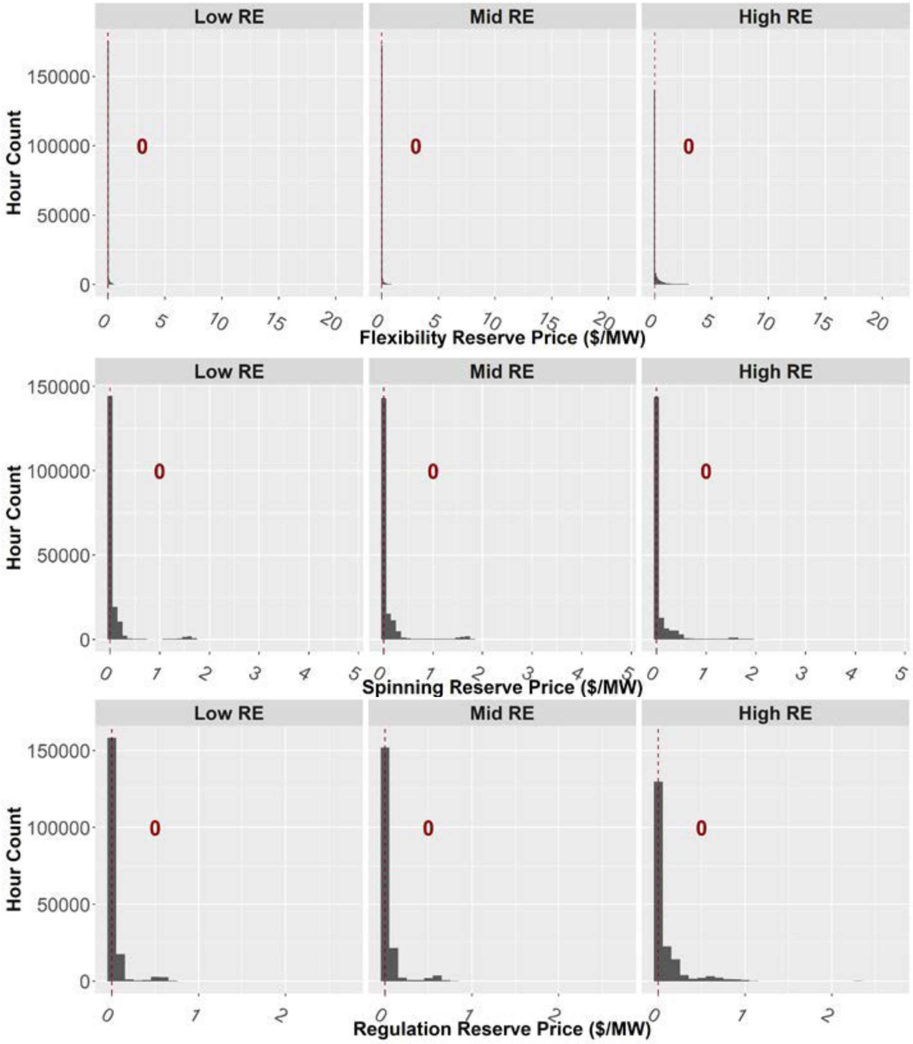


Energy Prices



The dashed lines show the median value for each grid scenario.

Ancillary Service Prices



1

2

3 Methods: Building Demand Flexibility

4

5

6

Price Taker Model Overview

Key Inputs

- Capacity, energy and ancillary service price time series
- (Emissions time series)
- Flexible building parameters

Maximize Grid Service Value, subject to:

- Shifting window≤ 24 hours
- Dissipation (optional)
- Efficiency (optional)
- Power capacity constraints

Key Outputs

- Shifting results
- Hourly profits
- (Hourly emissions)

For simplicity, dissipation and efficiency effects are modeled as constants

(not as time-varying functions of, e.g., outdoor temperature)

Building Flexibility Representation

Let P_h (kW) be the power consumed by the building in hour h.

Let S_h (kWh) be amount of energy service that has been provided by hour h.

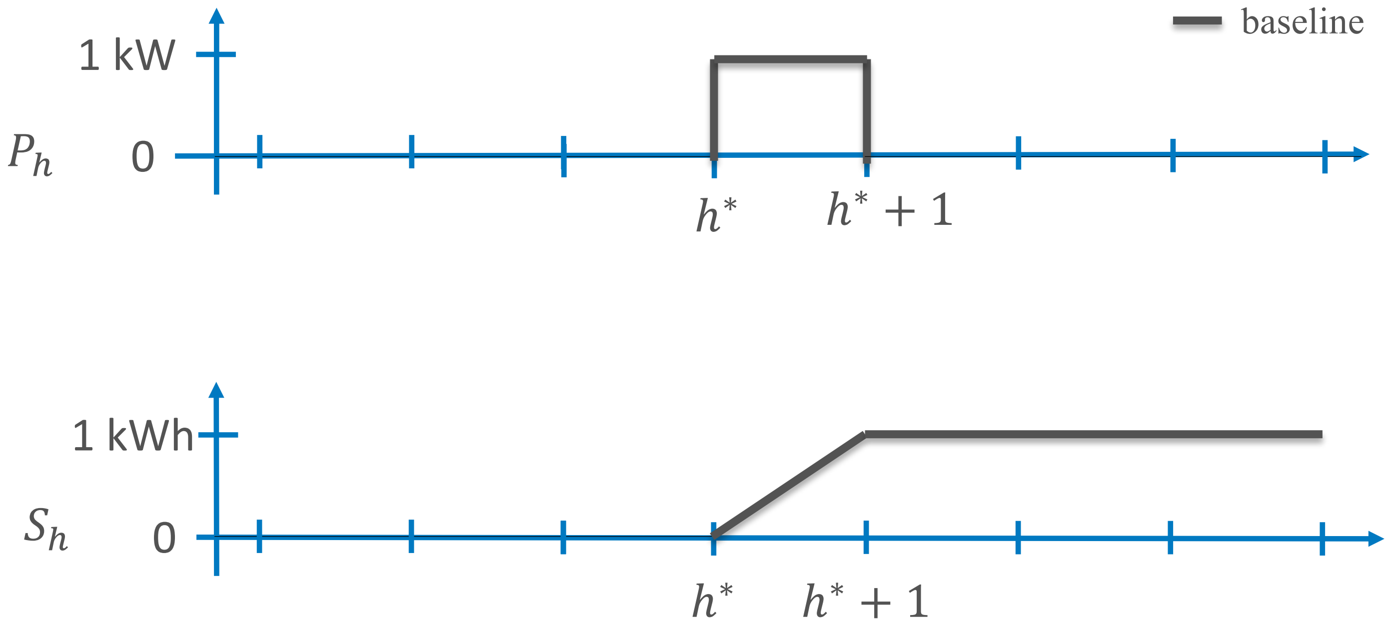
Then

$$S_{h+1} = S_h + P_h \cdot \Delta t, \qquad \Delta t = 1 \text{ hour}$$

is a basic model of how energy service accumulates.

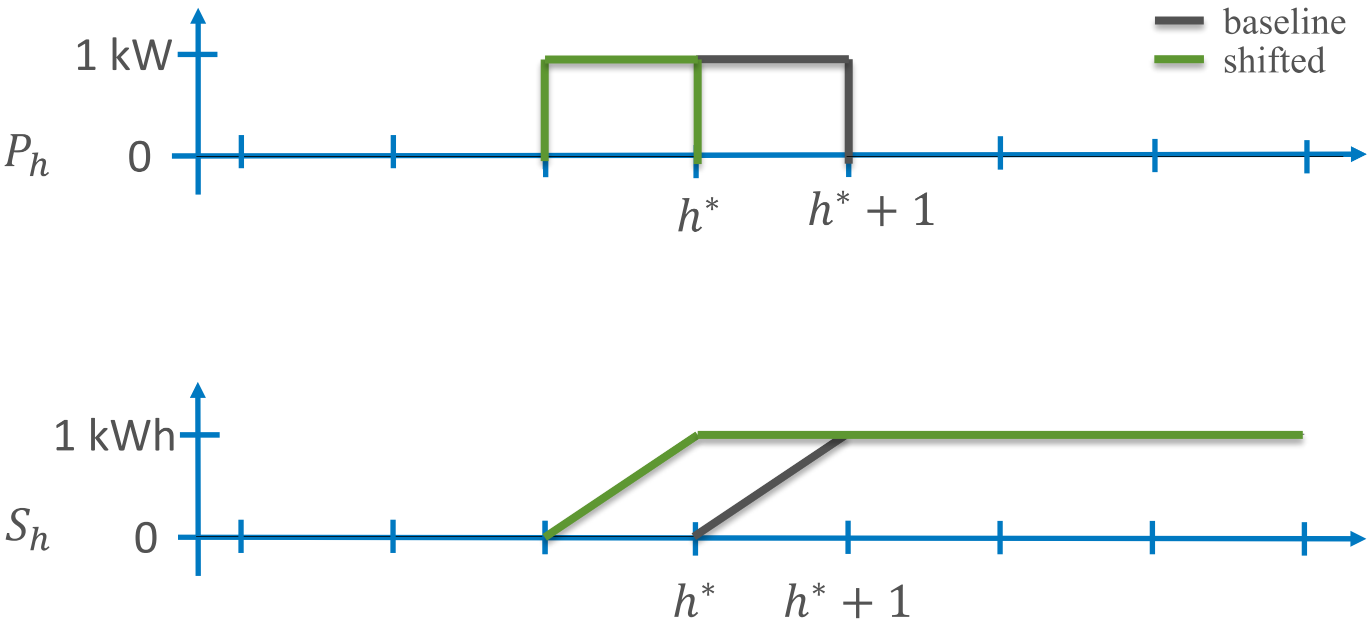
Building Flexibility Representation

To develop a flexibility model, we consider 1 kWh of load that in the baseline (no-shifting) case, occurs at hour h^*:



Building Flexibility Representation

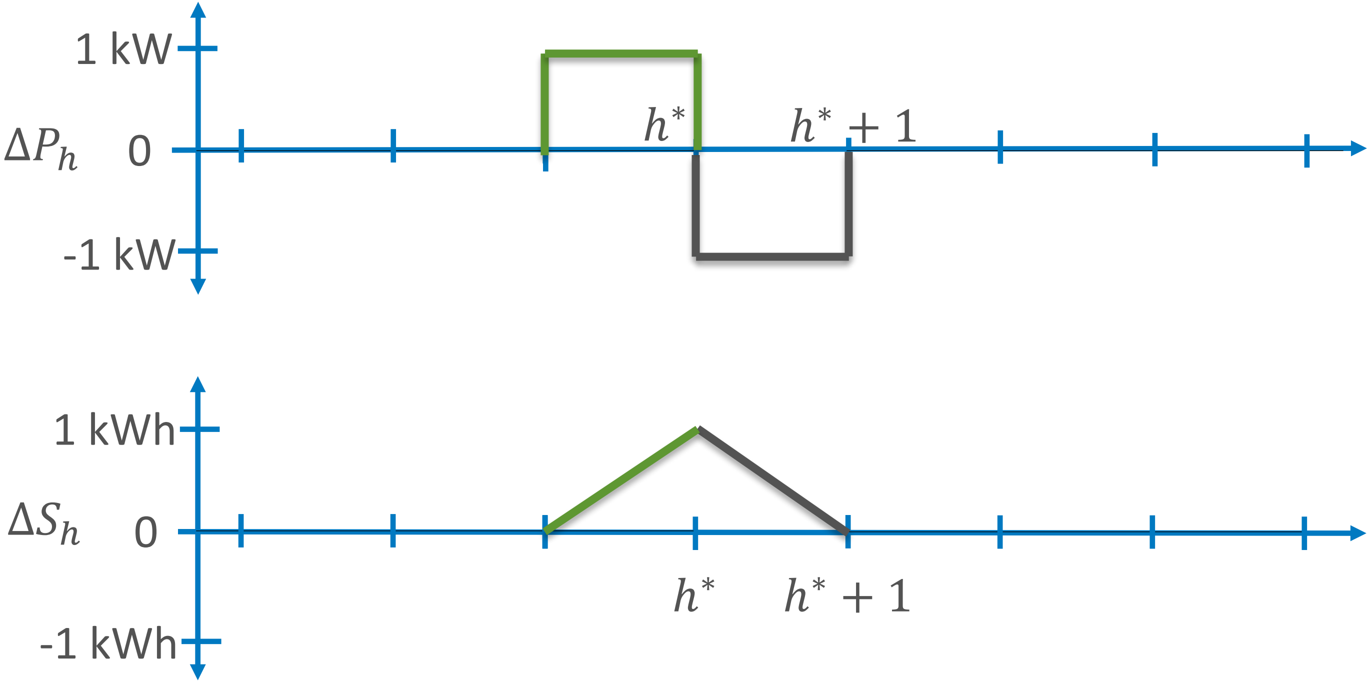
Then we can imagine shifting the energy use:



Building Flexibility Representation

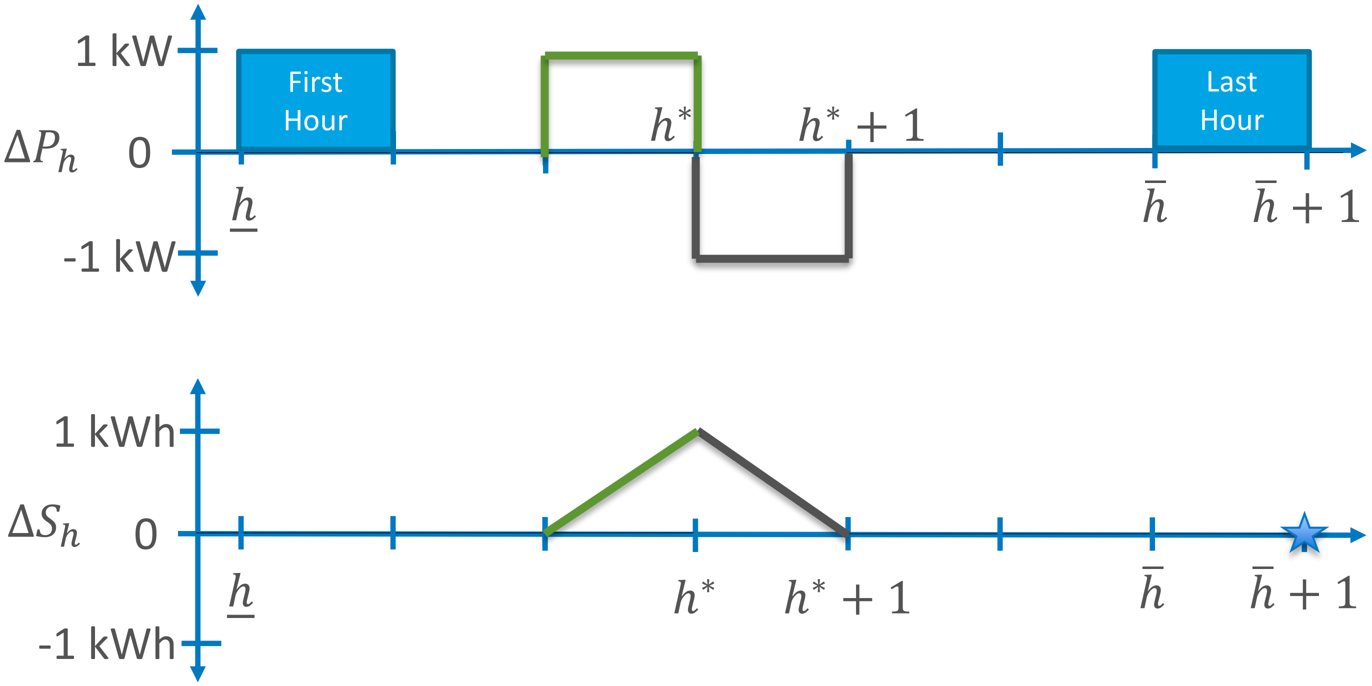
And computing the difference:

$$\Delta P_h = P_h - \tilde{P}_h$$



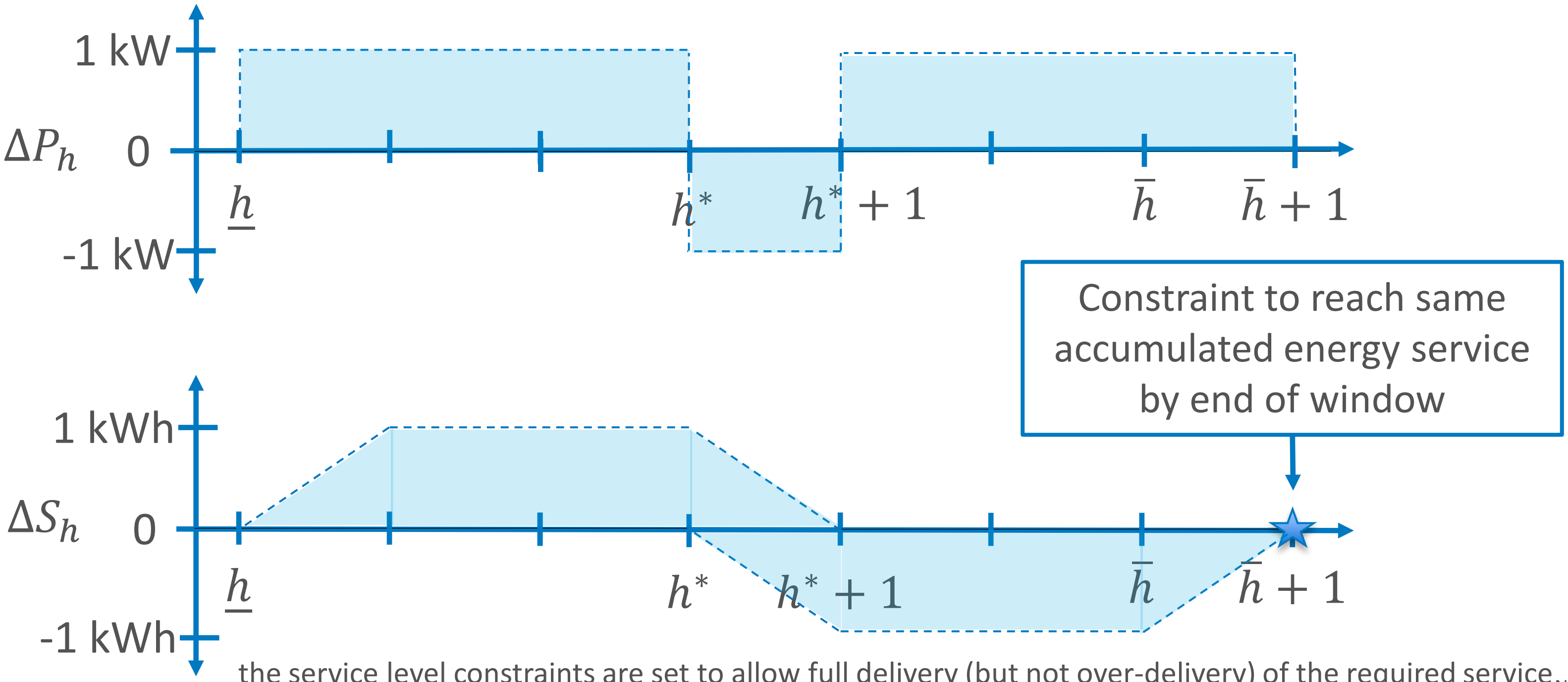
Building Flexibility Representation

We impose a shiftability window:



Building Flexibility Representation

We impose a shiftability window:

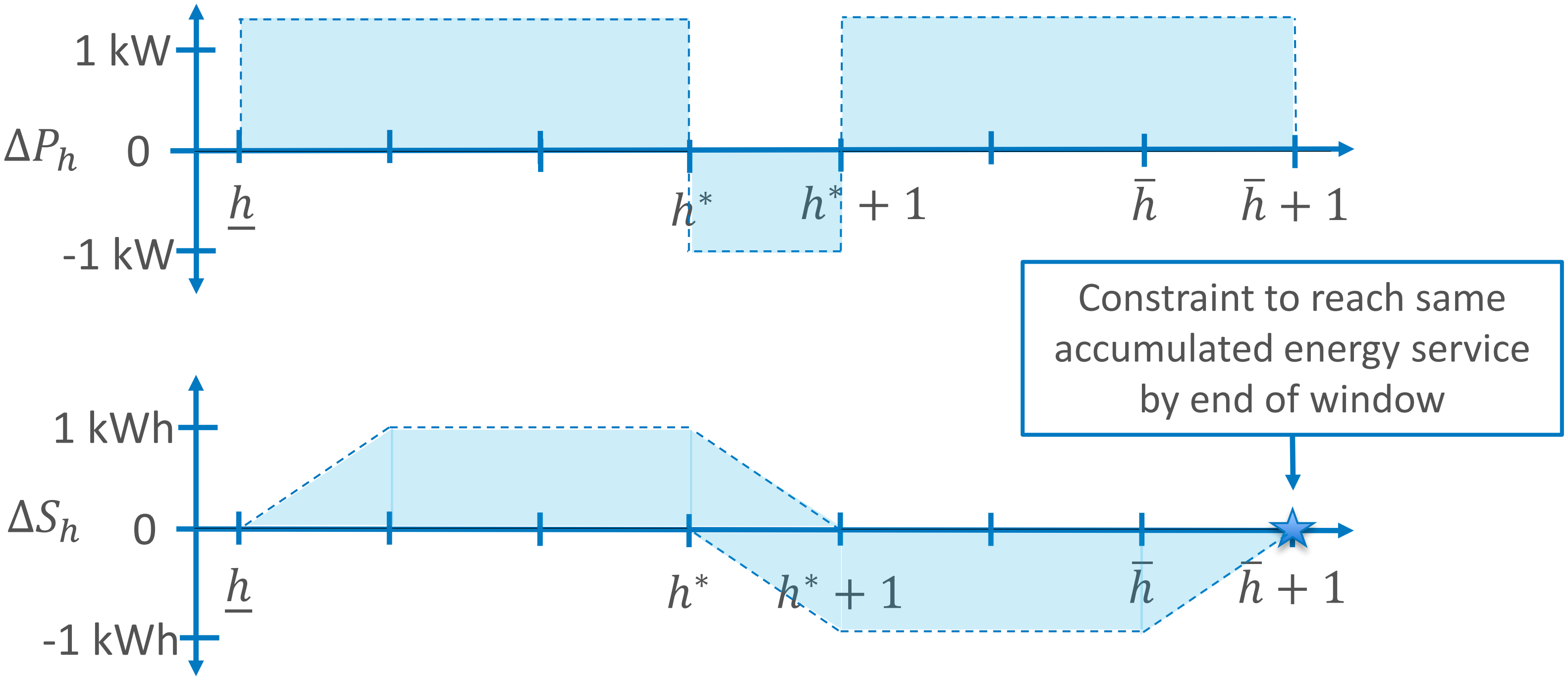


the service level constraints are set to allow full delivery (but not over-delivery) of the required service anytime in the shifting window

Building Flexibility Representation: Service Efficiency

If service is delivered less efficiently outside of the original hour:

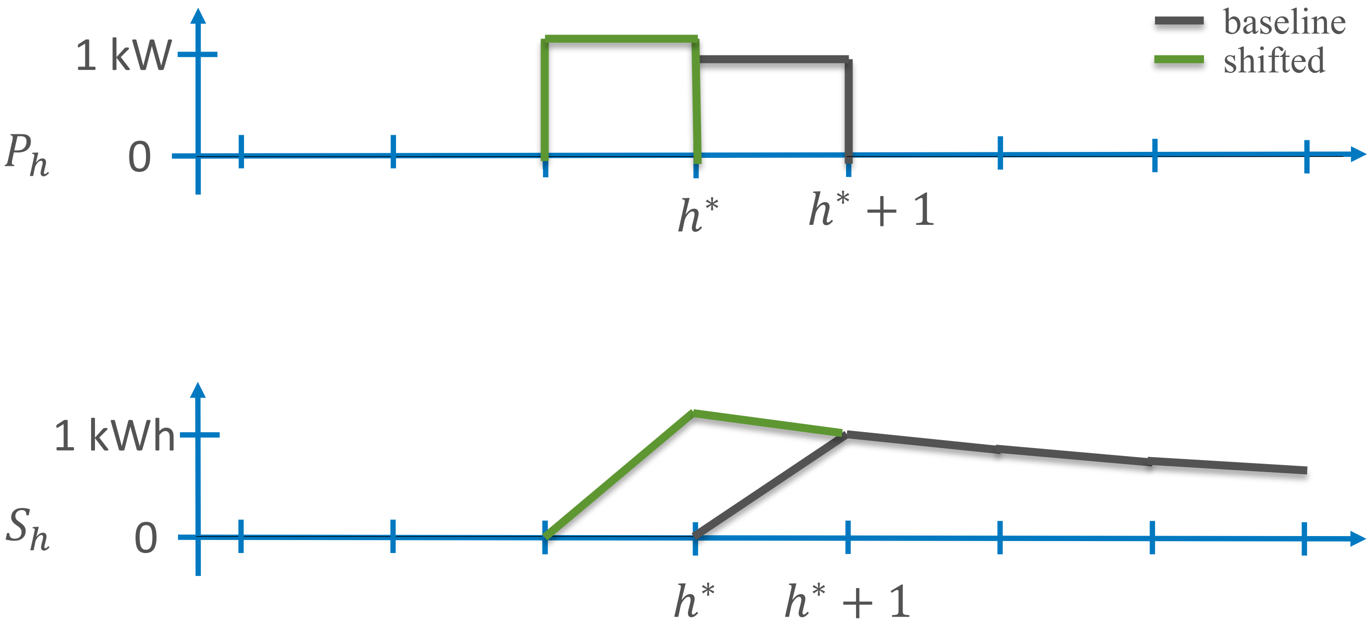
$$S_{h+1} = S_h + \eta_h P_h \cdot \Delta t,\ \ \eta_{h^*} = 1,\ \ \eta_h < 1\ \forall h \neq h^*$$



Building Flexibility Representation: Dissipation

If the energy service is subject to dissipation effects:

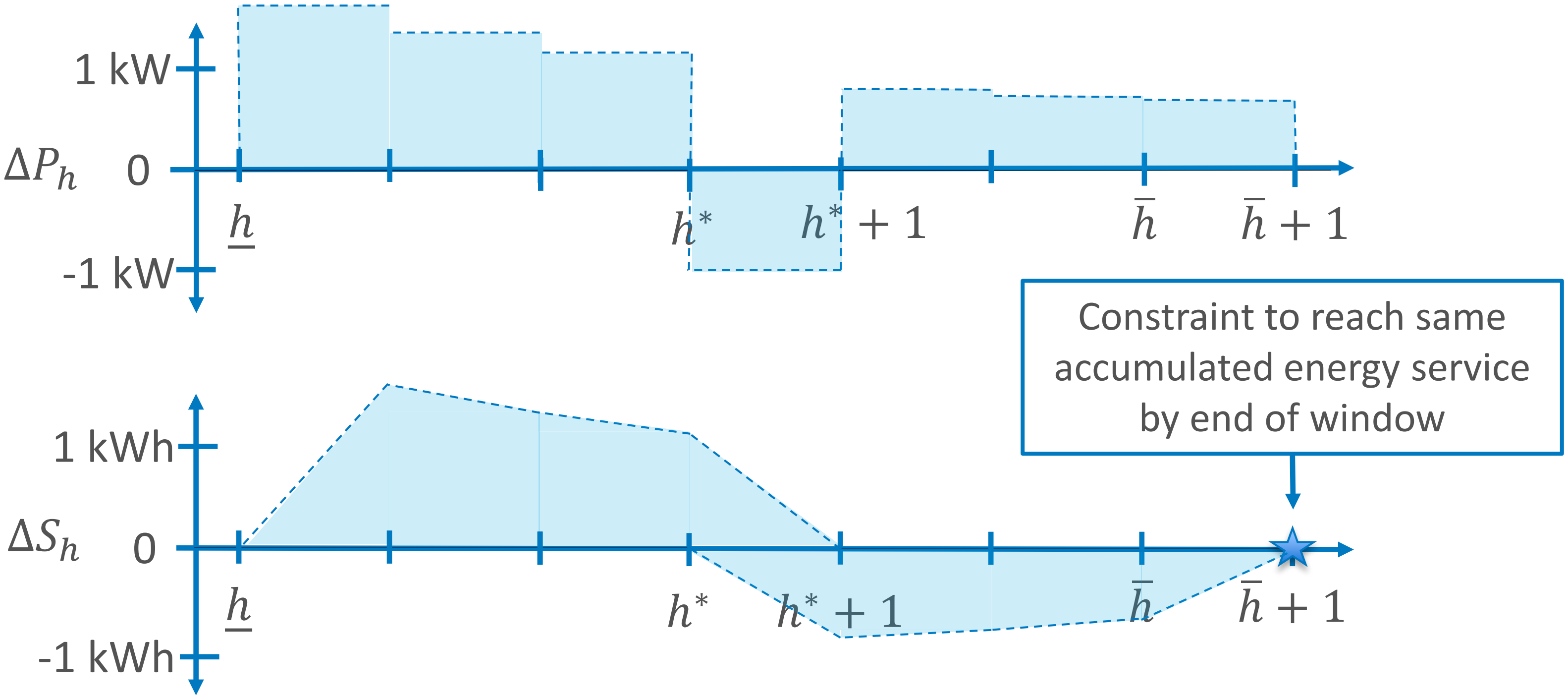
$$S_{h+1} = (1-\alpha)S_h + \eta_h P_h \cdot \Delta t, \alpha \geq 0$$



Building Flexibility Representation: Dissipation

If the energy service is subject to dissipation effects:

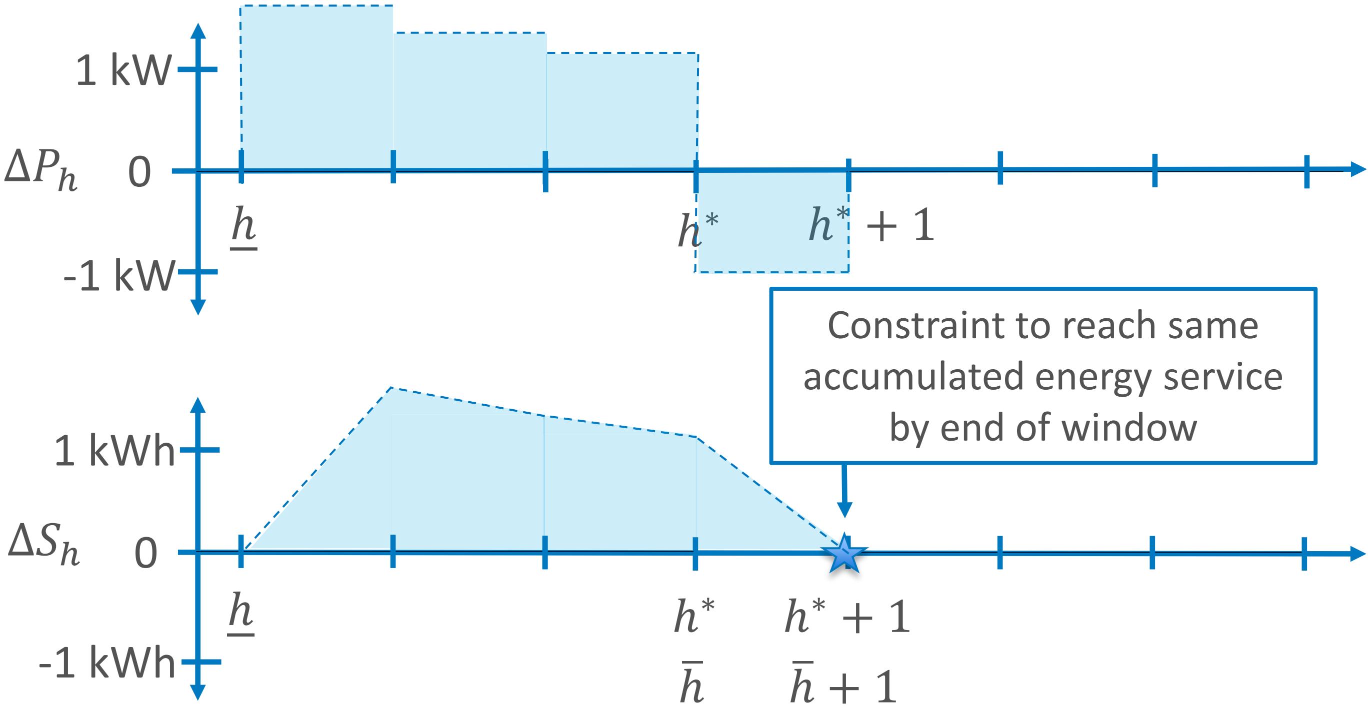
$$S_{h+1} = (1 - \alpha)S_h + \eta_h P_h \cdot \Delta t, \alpha \geq 0$$



We do not allow scenarios with non-zero dissipation to delay service

If the energy service is subject to dissipation effects:

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



Building Flexibility Representation: Capacity Limit

$$\max(\Delta P_h) \leq 64\ \mathrm{kW}$$

Limits the flexible building unit's maximum amount of power increase.

In general, we want to allow full shifting to any hour within the window, but this leads to extremely unrealistic bounds with high dissipation and large windows (e.g., 2,048 kW with dissipation 0.5 and -12/0 window).

We do not attempt to realistically model power capacity headroom. That is, it may not be possible to shift to certain hours because the equipment would already be operating and unable to increase load as much as desired.

Objective Function Components

Let $G_h = -\Delta P_h \cdot \Delta t$ be Generation from the grid perspective

- Capacity value of shifting = Capacity price * G_h

  (Annual capacity price [$/kW] is distributed to hours [$/kWh] by Cambium)

- Energy value of shifting = Energy price * G_h
- Emission impact of shifting = Emission factor * G_h
- Objective Function 1: Maximize $\sum(\text{capacity} + \text{energy value})$
- [Objective Function 2: Minimize $\sum(\text{emission})$]

Grid Service Provision

As a post-processing step, we determine whether the baseline load at hour h^* should be used for shifting or ancillary services:

1. For each shifting window (of length $\leq$ 24 hours), calculate

$$\text{capacity} + \text{energy value of shifting}$$

2. Compare this net profit to the ancillary service prices and choose exactly one of

- shifting (capacity + energy)
- spinning reserves
- regulation reserves
- flexibility reserves

whichever service is most valuable to provide.

Scenario Matrix

Total number of shifting opportunities simulated: 24,834,600 (21 regions x 24 hours x 3 grid scenarios x 45 flexibility parameter sets x 365 days)

Original Usage Hour	Grid Scenario	Shifting Window	Efficiency	Dissipation *	Capacity Limit
Hour 1 through 24	Low RE	Pre 1 post 0	0.75	**0**	**64**
	Mid RE	Pre 1 post 1	**1**	0.005	
	High RE	Pre 4 post 0	1.25	0.05	
		Pre 4 post 4		0.5	
		Pre 12 post 0			
		Pre 12 post 11			

* Dissipation cases are only allowed to shift earlier.

1

2

3

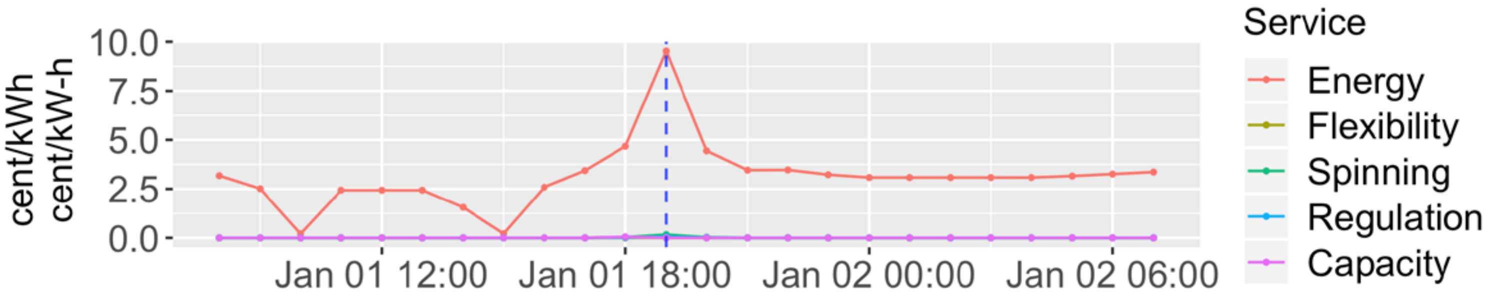
4 Example: One-Day Dispatch

5

6

Example Day Prices

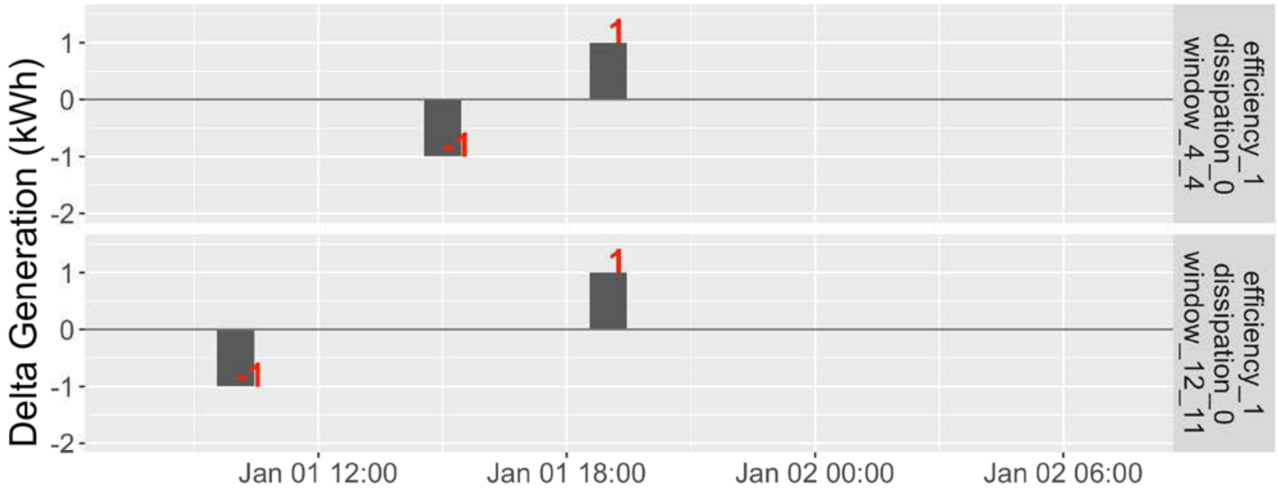
- 1 kWh of flexible load in NWPP, original usage hour at 1/1/2030 19:00 local time.
- Prices (cent/kWh) for various services during the 24-hour period around the original hour (1/1/2030 8:00 – 1/2/2030 7:00):



Local Time	8:00	15:00	19:00
Energy	0.21	0.22	9.53
Flexibility	0	0	0
Spinning	0	0	0.17
Regulation	0	0	0.06
Capacity	0	0	0

Dispatch with Different Windows

Local Time	8:00	15:00	19:00
Energy + Capacity (cent/kWh)	0.21	0.22	9.53



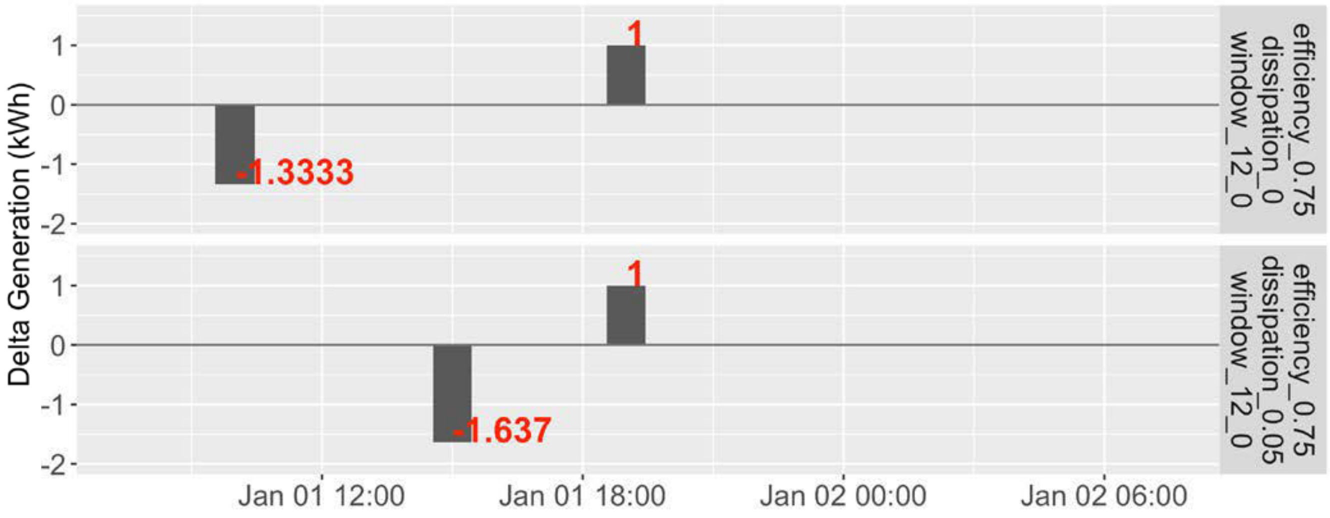
Demand-side cannot service energy and ancillary services at the same time. The model opts for the service that maximizes the profit.

Window -4/+4:
Profit = (-1)*0.22 + (1)*9.53 = **9.31**

Window -12/+11:
Profit = (-1)*0.21 + (1)*9.53 = **9.32**

Dispatch with Different Efficiency and Dissipation

Local Time	8:00	15:00	19:00
Energy + Capacity (cent/kWh)	0.21	0.22	9.53



Both scenarios have window -12/+11.

Efficiency 0.75, Dissipation 0:

Profit = (-1/0.75)*0.21 + (1)*9.53 = **9.25**

Efficiency 0.75, Dissipation 0.05:

Profit = $(-1/0.95^4/0.75)$ *0.22 + (1)*9.53 = **9.17**

1

2

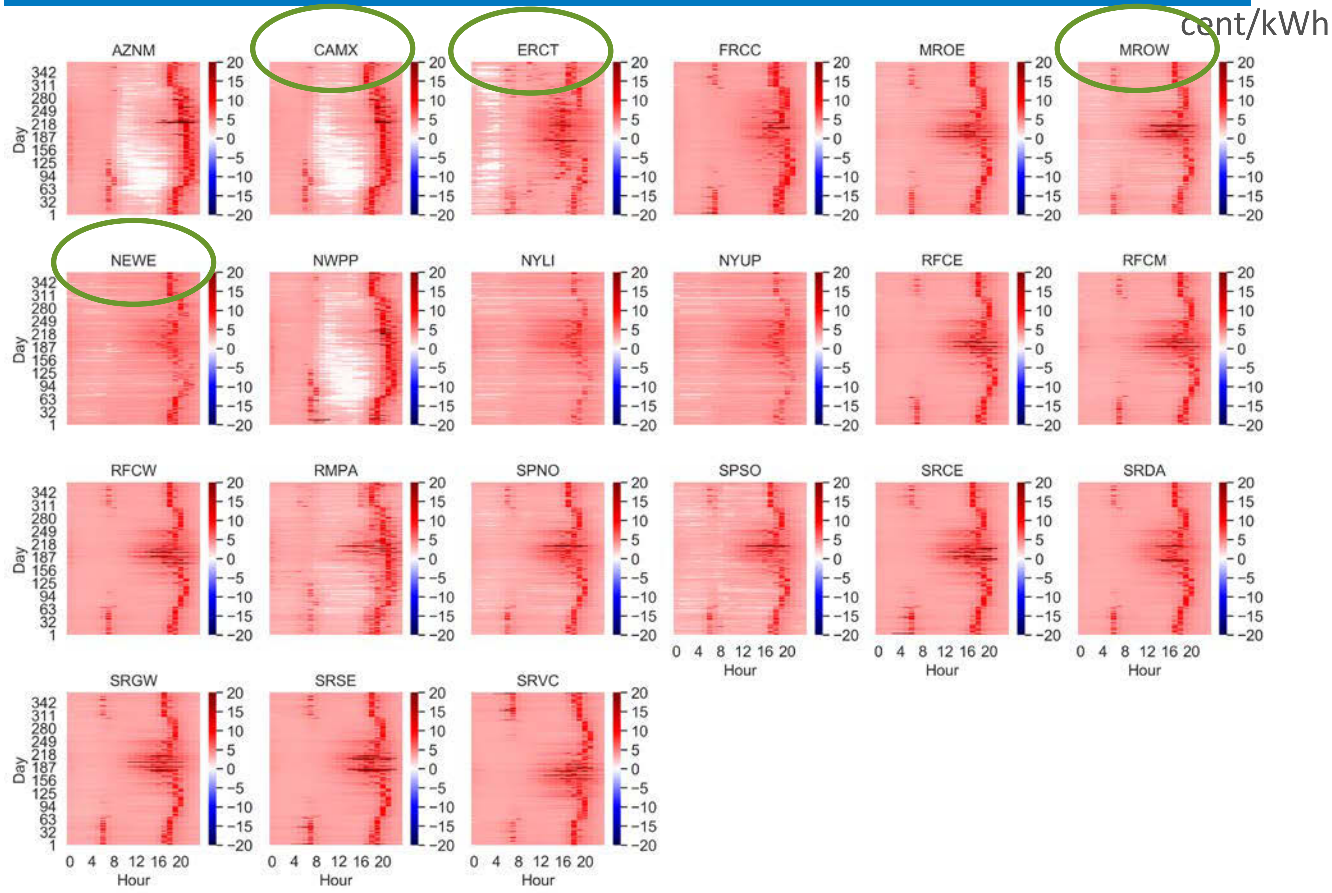
3

4

5 Results: Impact of Flexibility Parameters and Grid Scenario

6

Input Data: Mid RE Energy + Capacity Prices

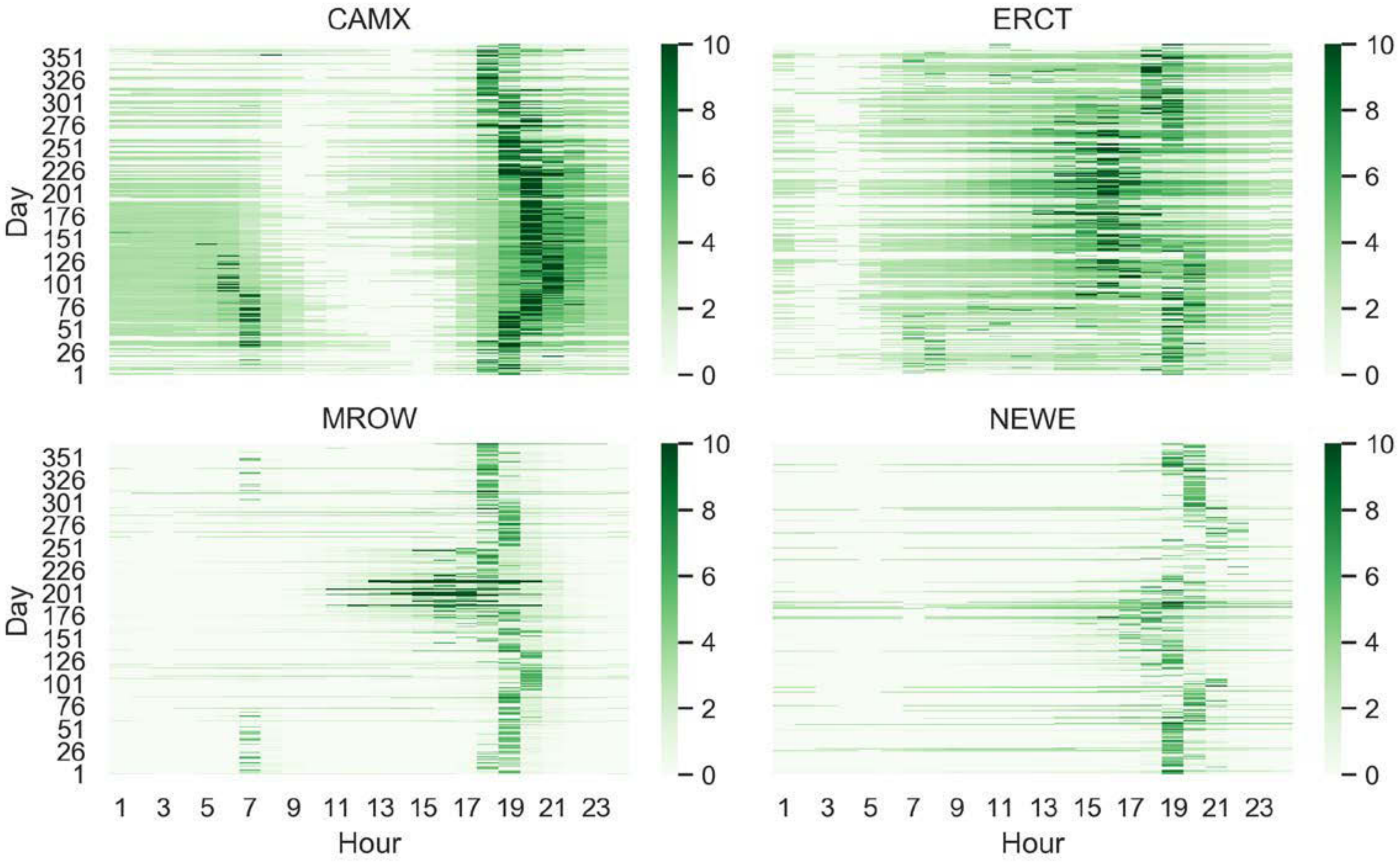


Building flexibility would receive profit by moving horizontally from deep red hours to white/lighter shaded hours.

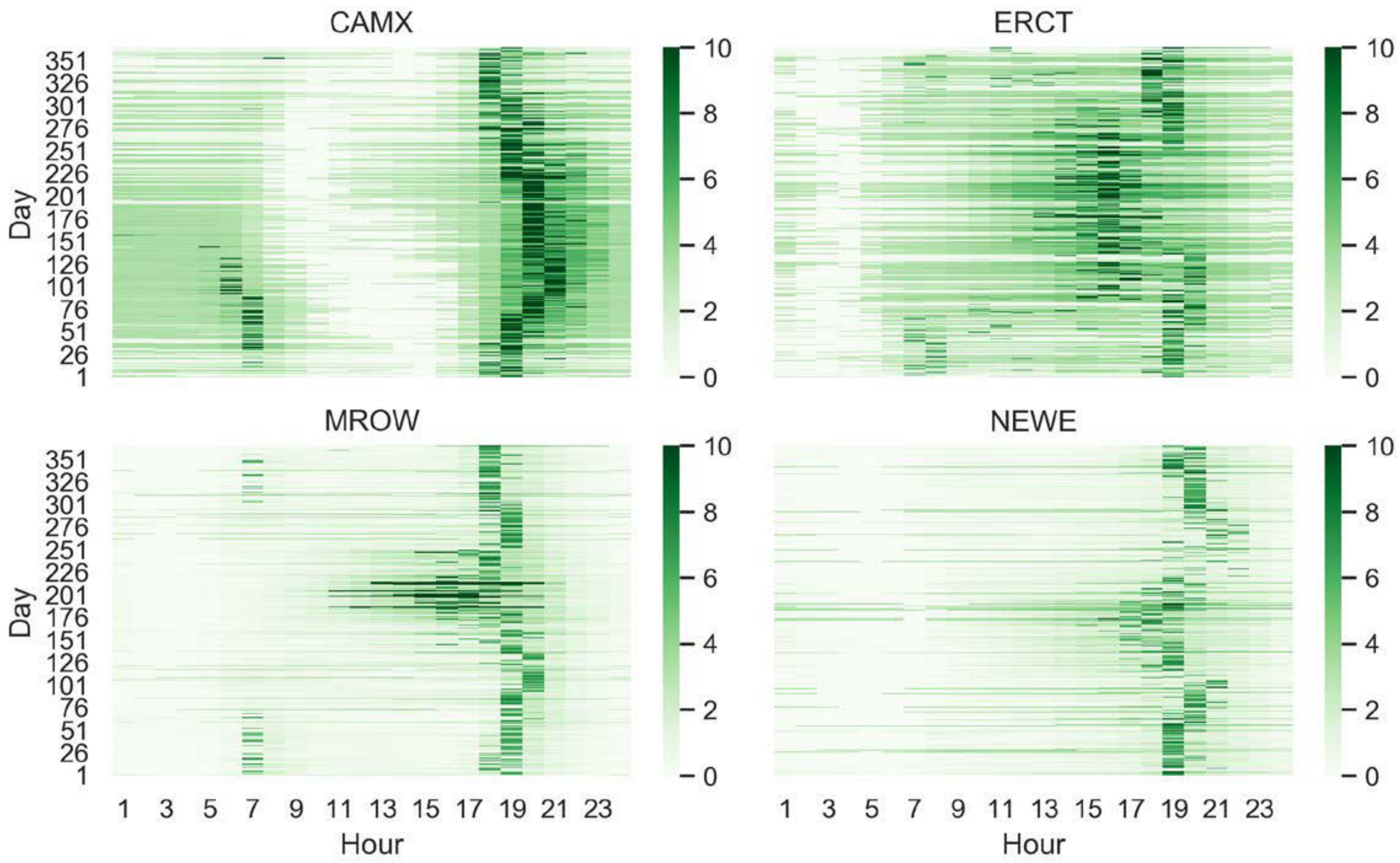
Impact of efficiency:
0.75 -> 1 -> 1.25

We start with just 4 selected regions,
Mid RE, Dissipation 0, Window -12/+11

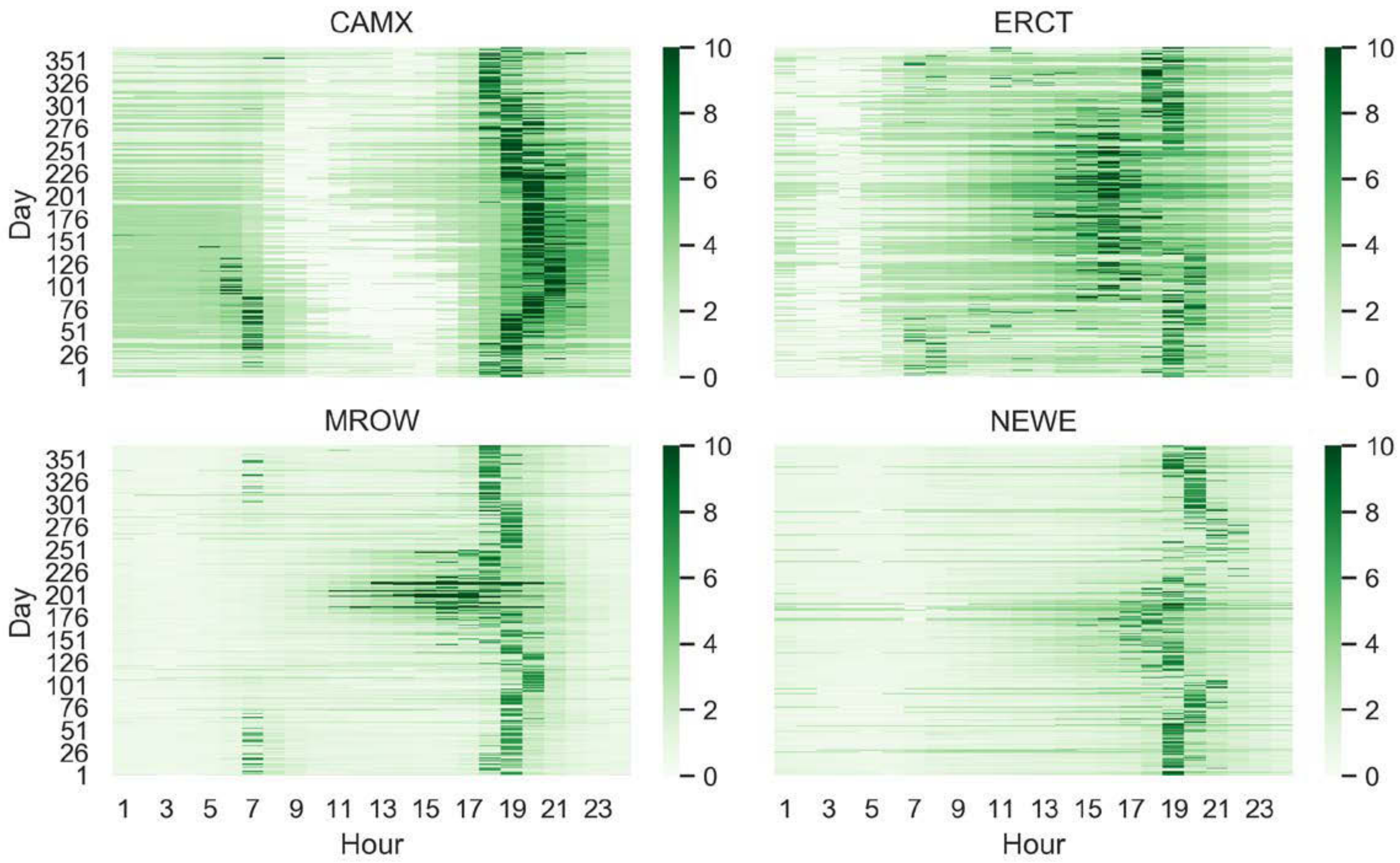
Mid RE Efficiency 0.75
Average Daily Profit (cent/kWh)



Mid RE Reference
Average Daily Profit (cent/kWh)



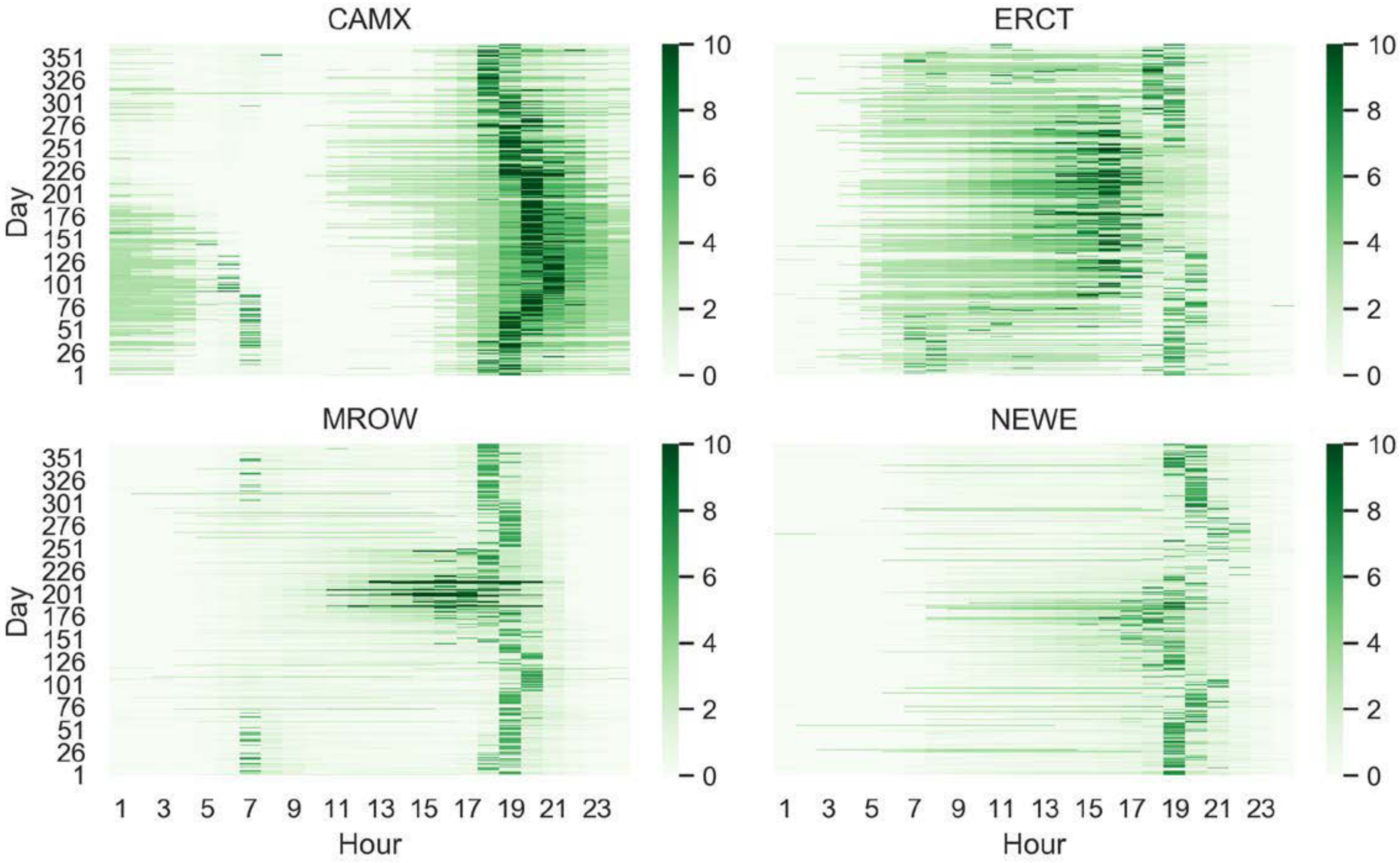
Mid RE Efficiency 1.25
Average Daily Profit (cent/kWh)



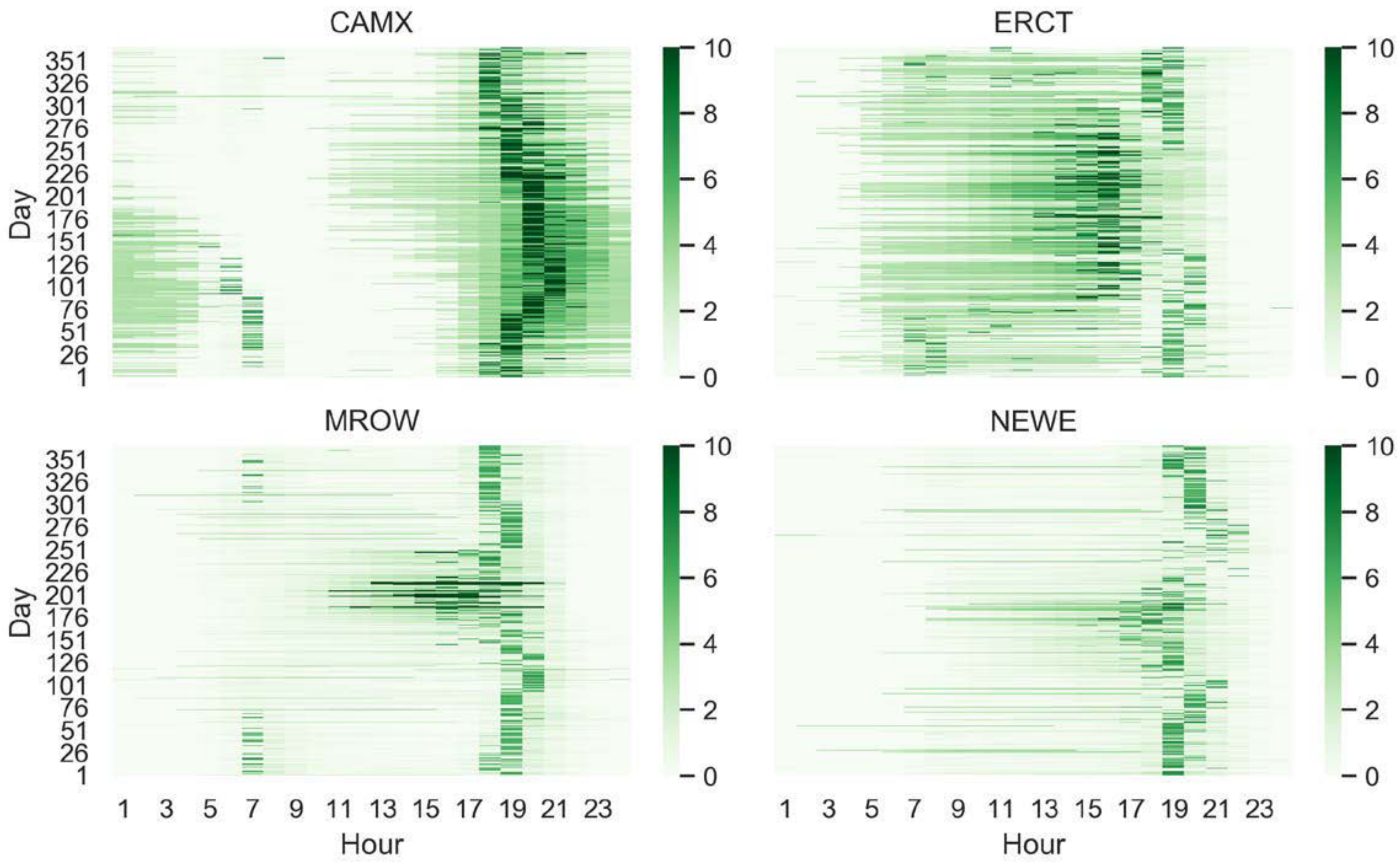
Impact of Dissipation:
0 -> 0.005 -> 0.05 -> 0.5

Mid RE, Efficiency 1, **Window -12/0**

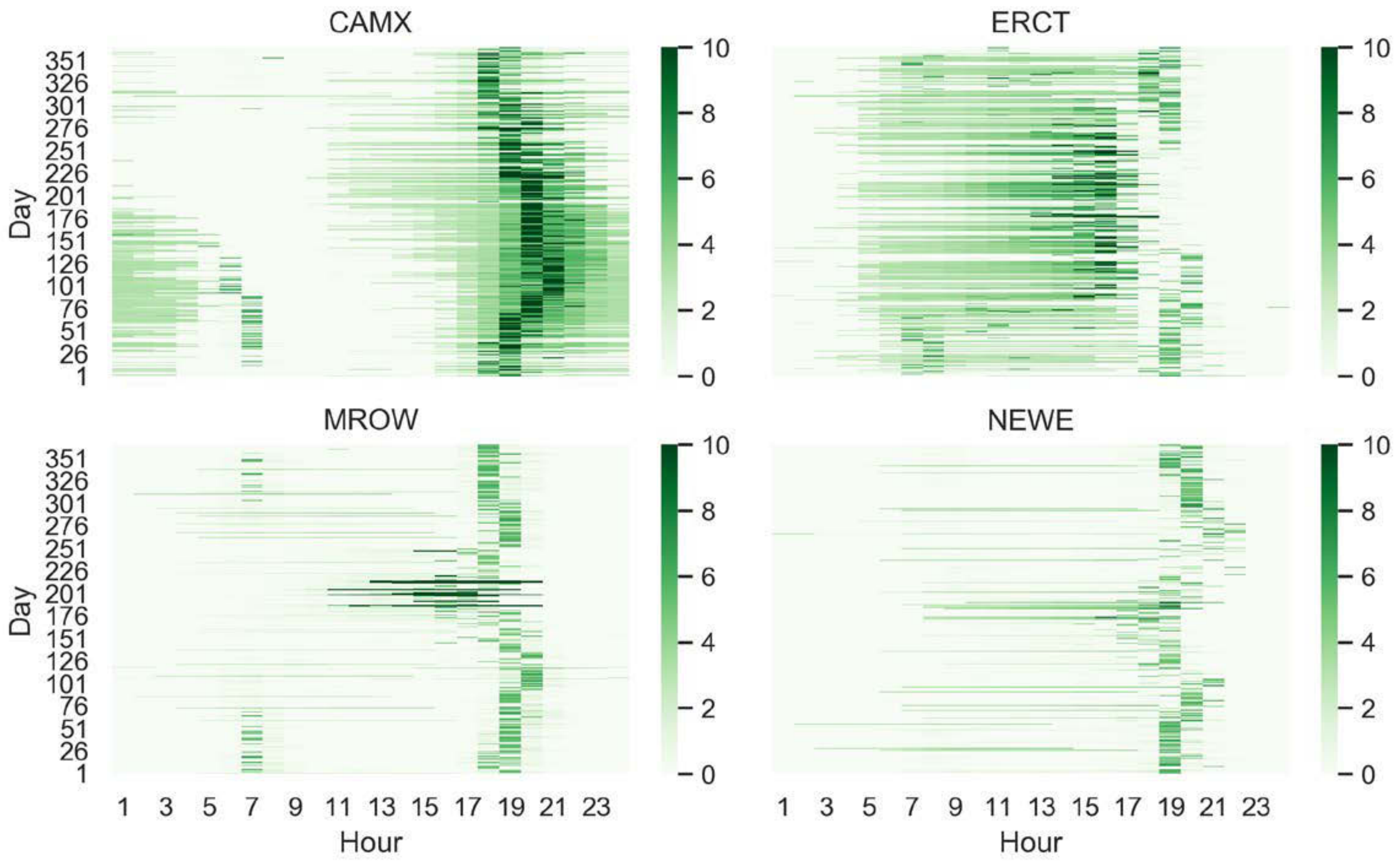
Mid RE Dissipation 0
Average Daily Profit (cent/kWh)



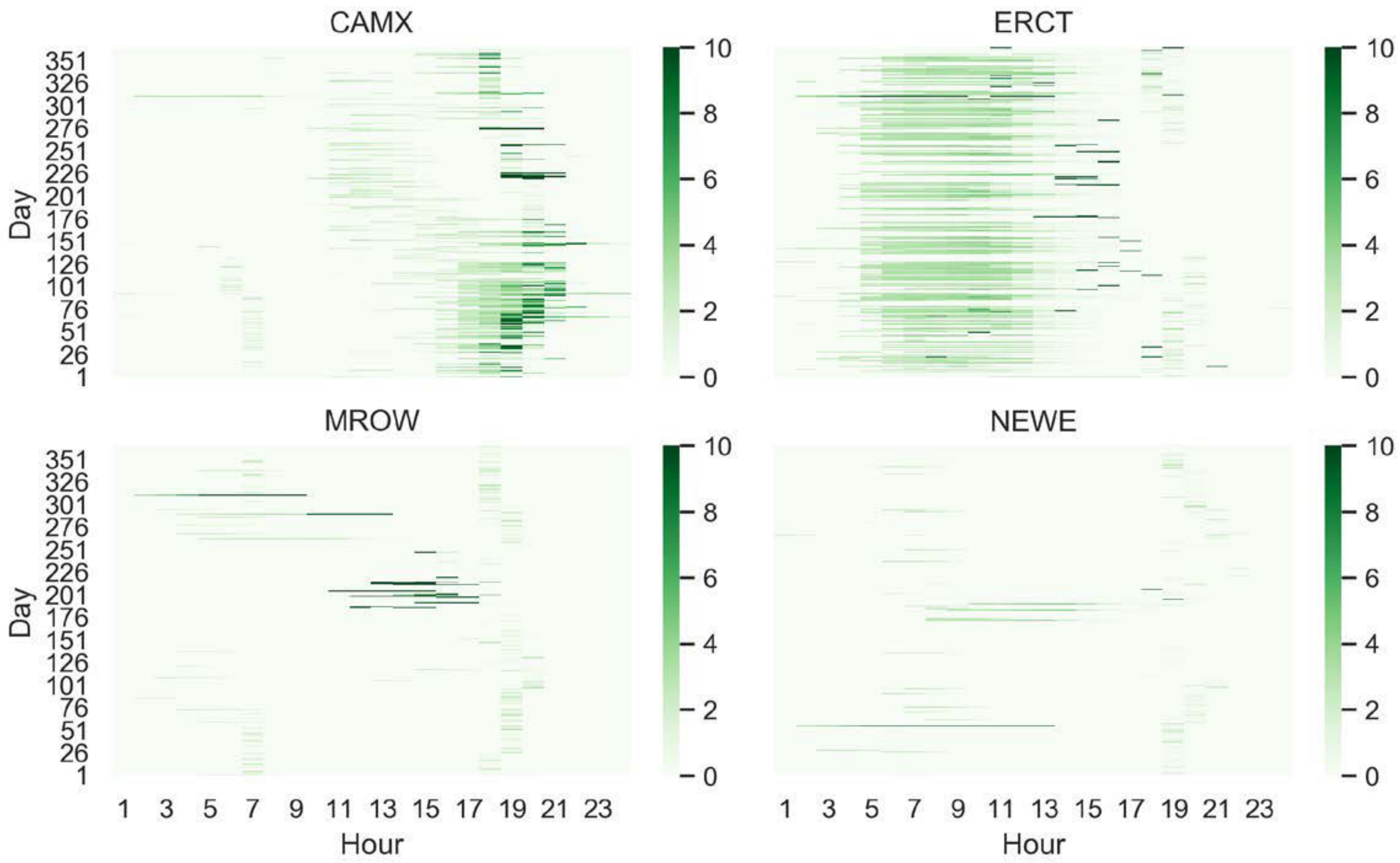
Mid RE Dissipation 0.005
Average Daily Profit (cent/kWh)



Mid RE Dissipation 0.05
Average Daily Profit (cent/kWh)



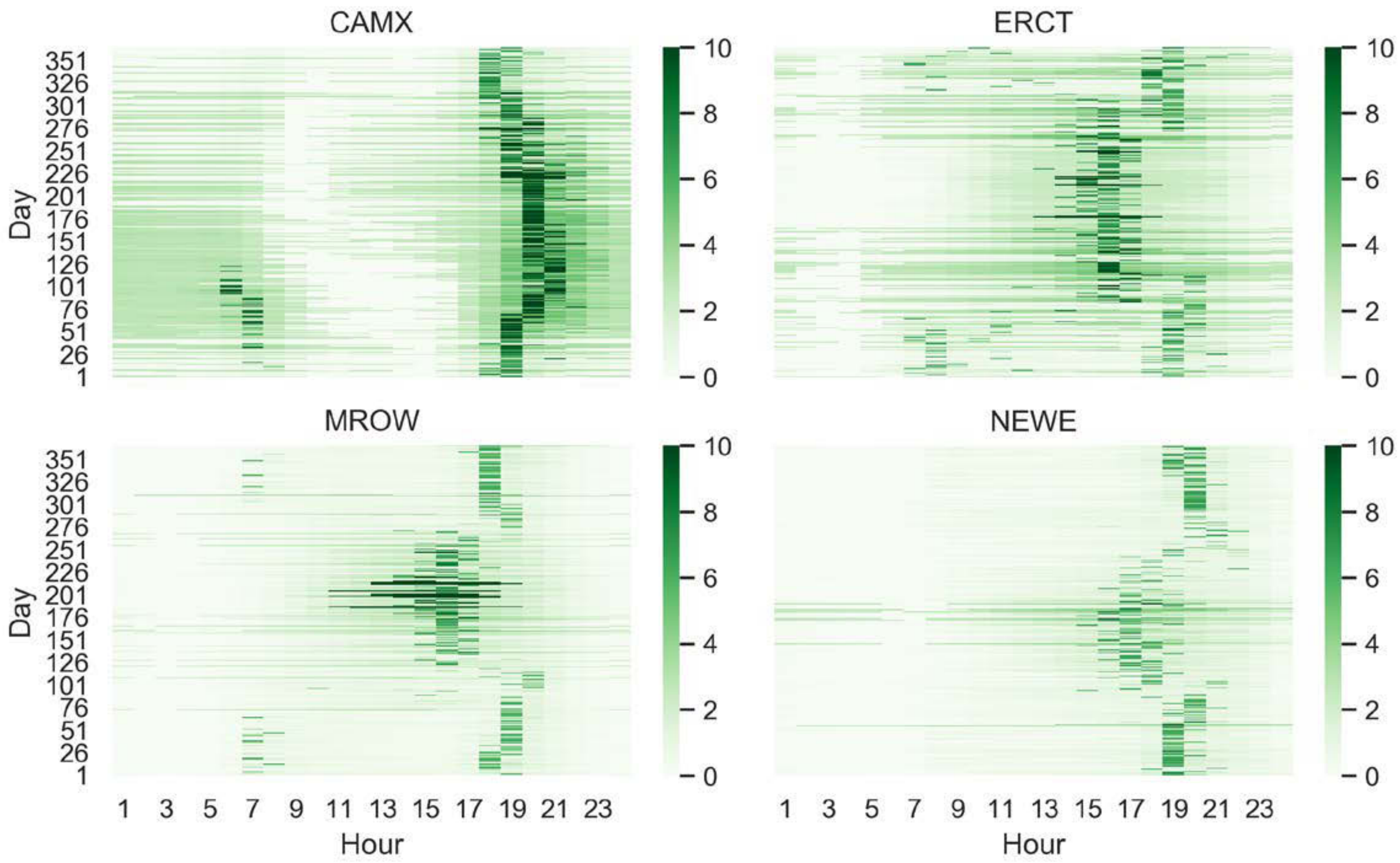
Mid RE Dissipation 0.5
Average Daily Profit (cent/kWh)



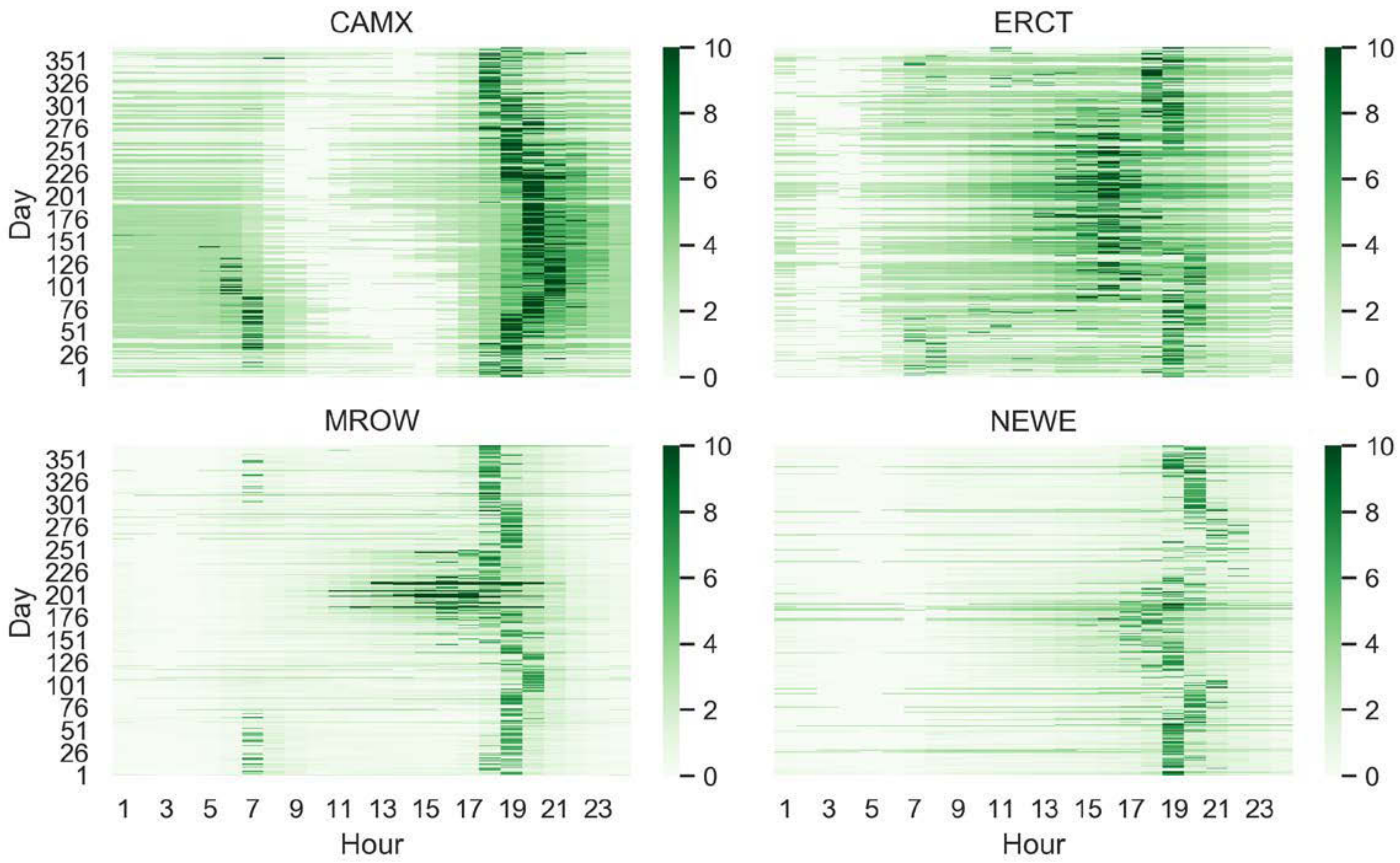
Impact of Grid Scenario: Low RE -> Mid RE -> High RE

Efficiency 1, Dissipation 0, Window - 12/11

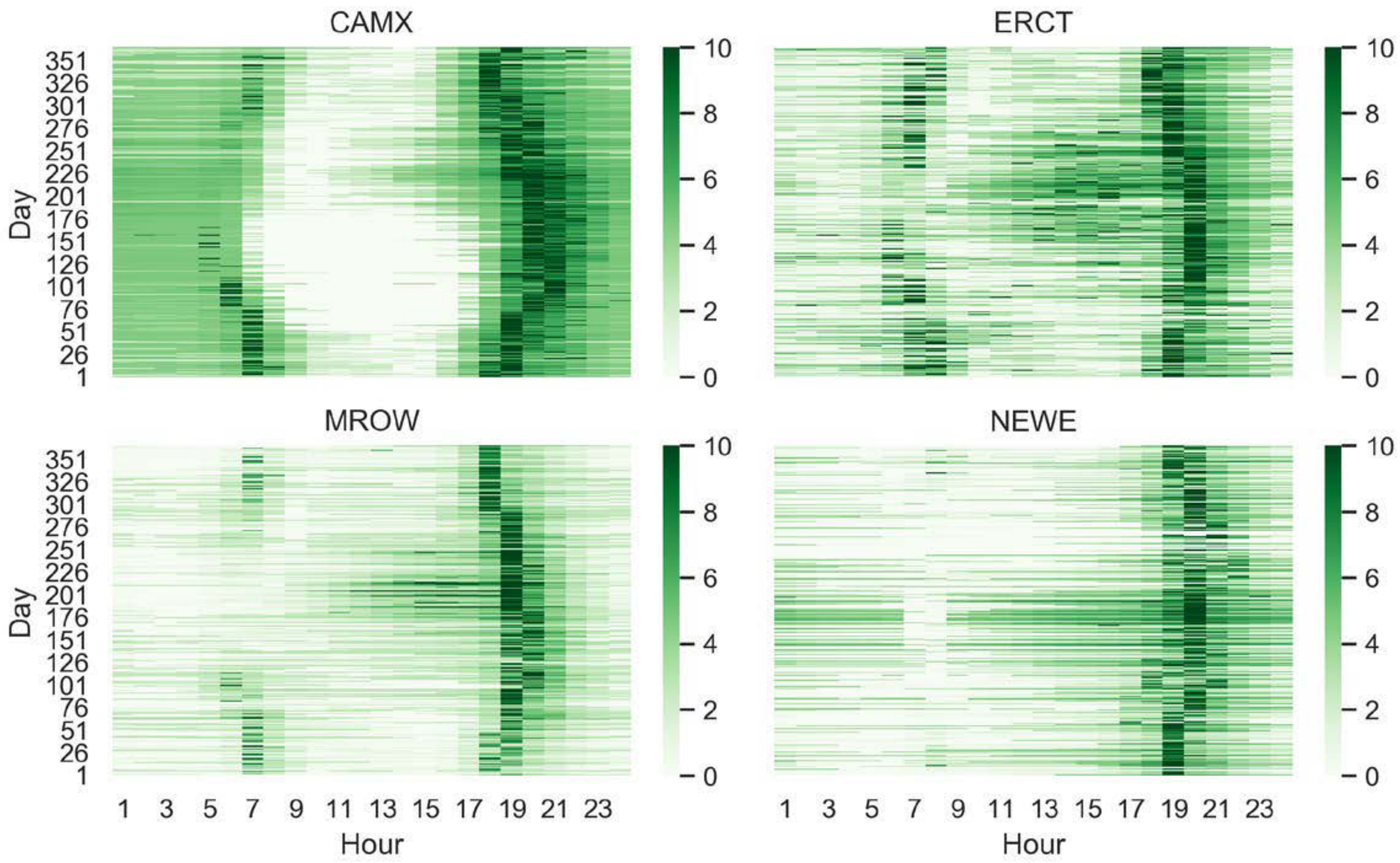
Low RE
Average Daily Profit (cent/kWh)



Mid RE Reference
Average Daily Profit (cent/kWh)



High RE
Average Daily Profit (cent/kWh)



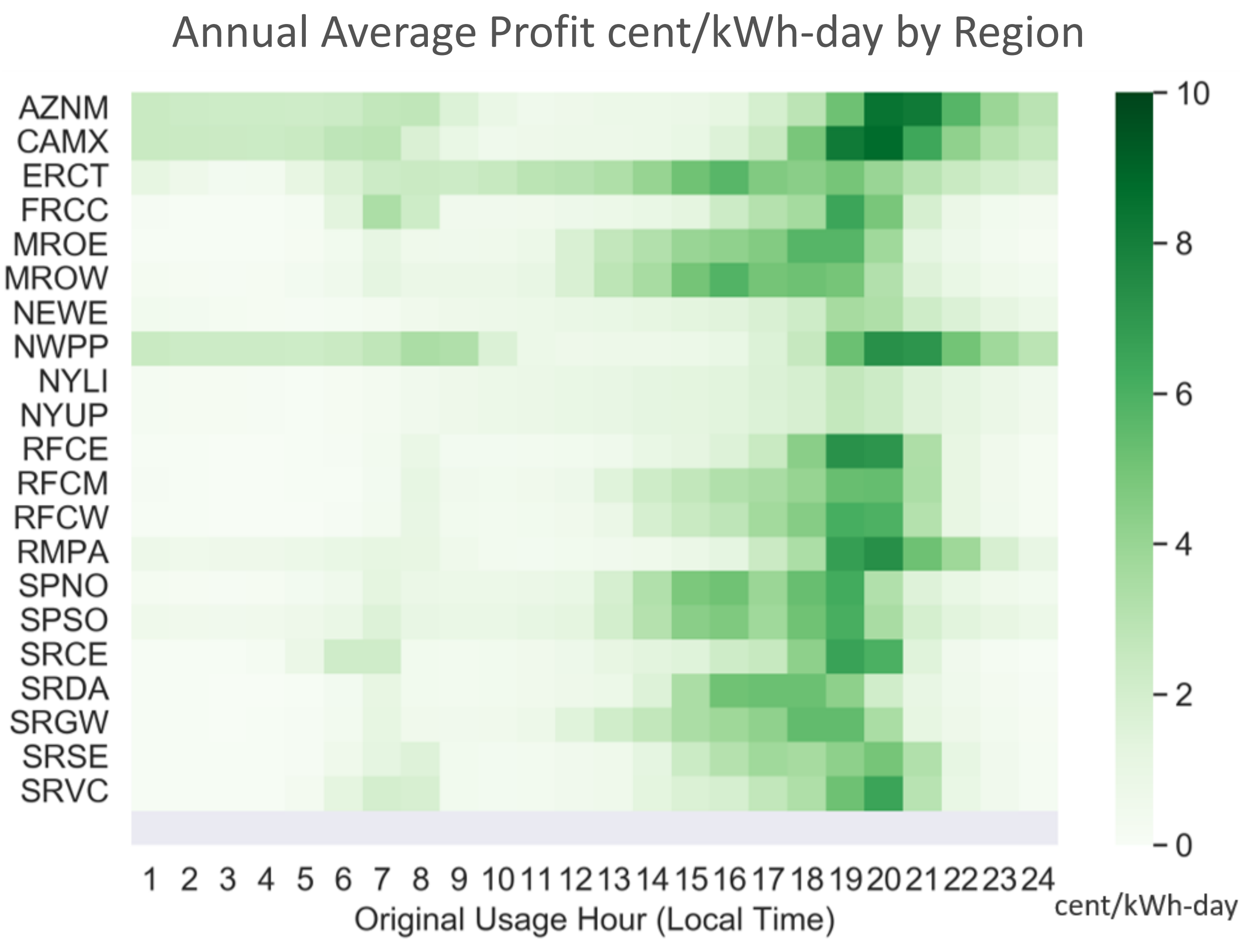
The trends we observed through the selected regions hold true on the national scale

Mid RE 2030

Efficiency: 1

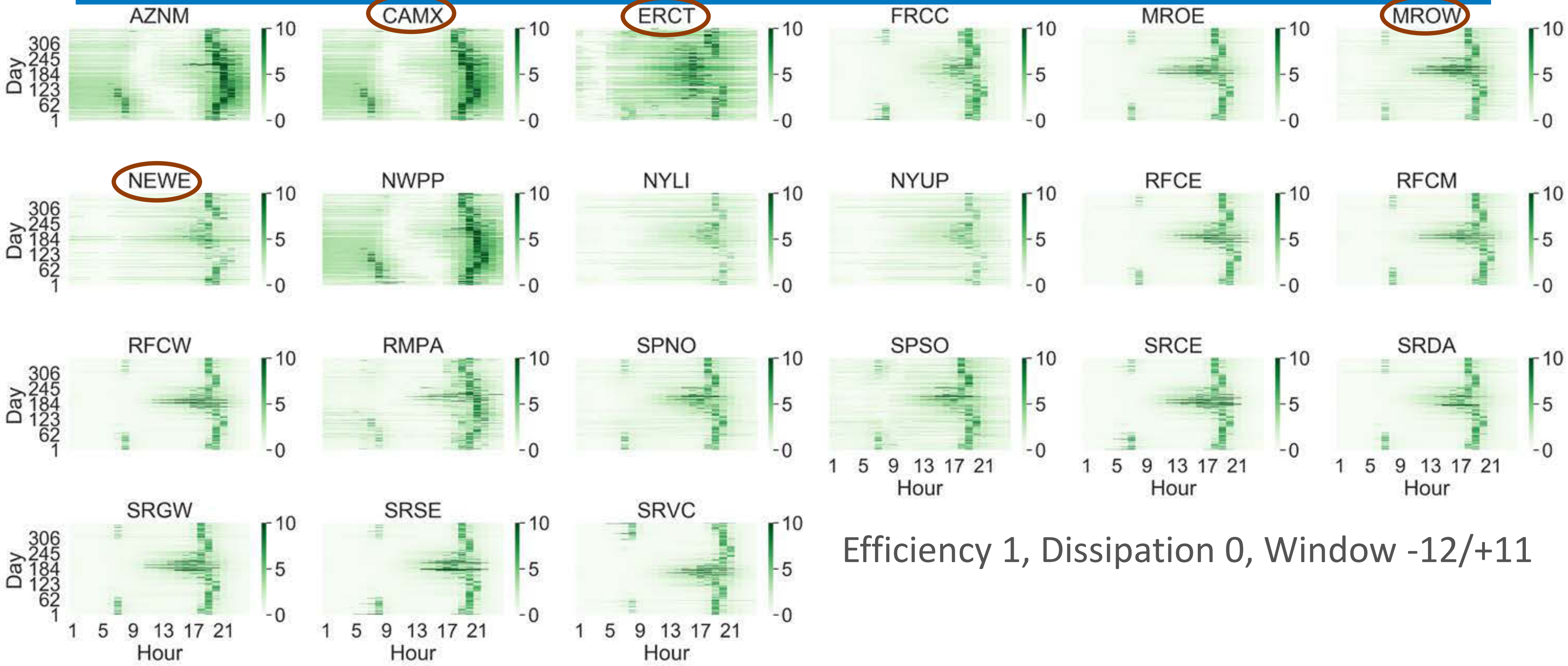
Dissipation: 0

Shift Window: -12/+11



Evening-hour flexibility has higher values than the other hours.

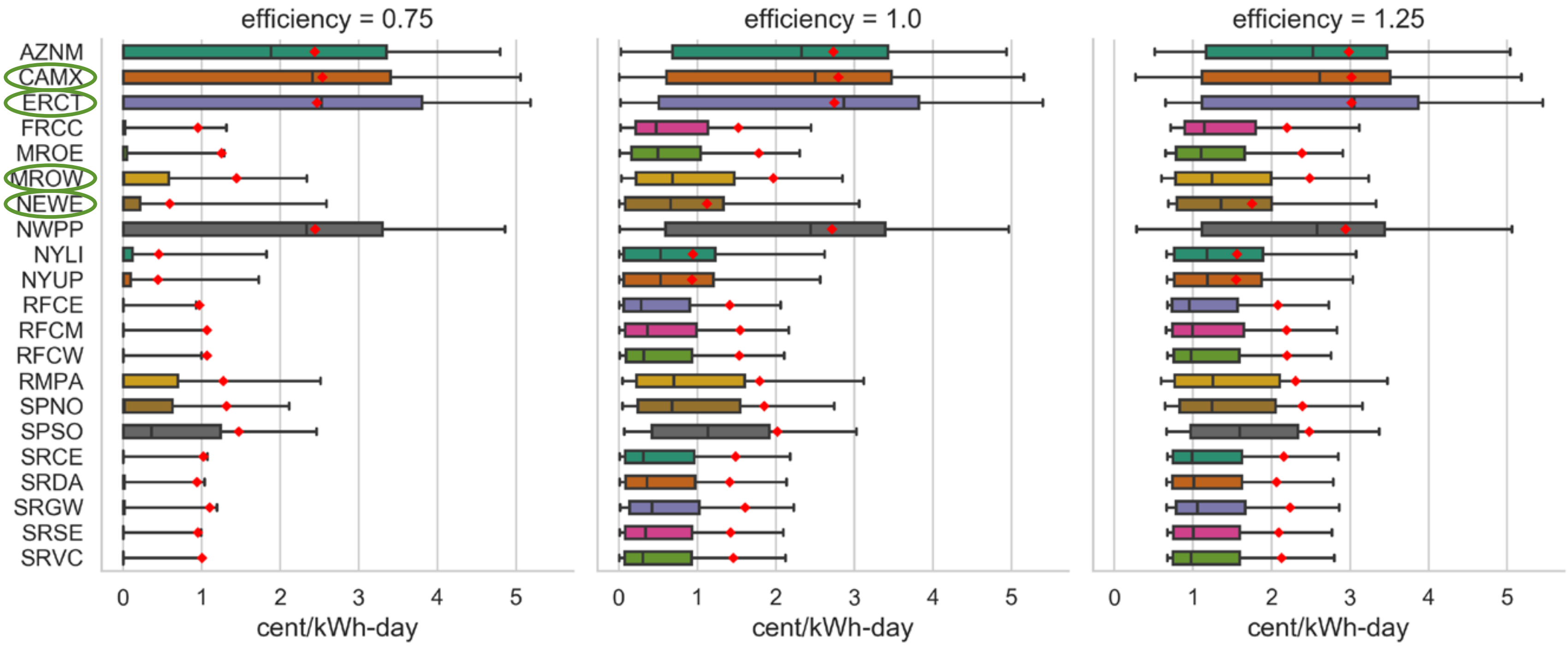
Temporal pattern (cent/kWh-day)



Efficiency 1, Dissipation 0, Window -12/+11

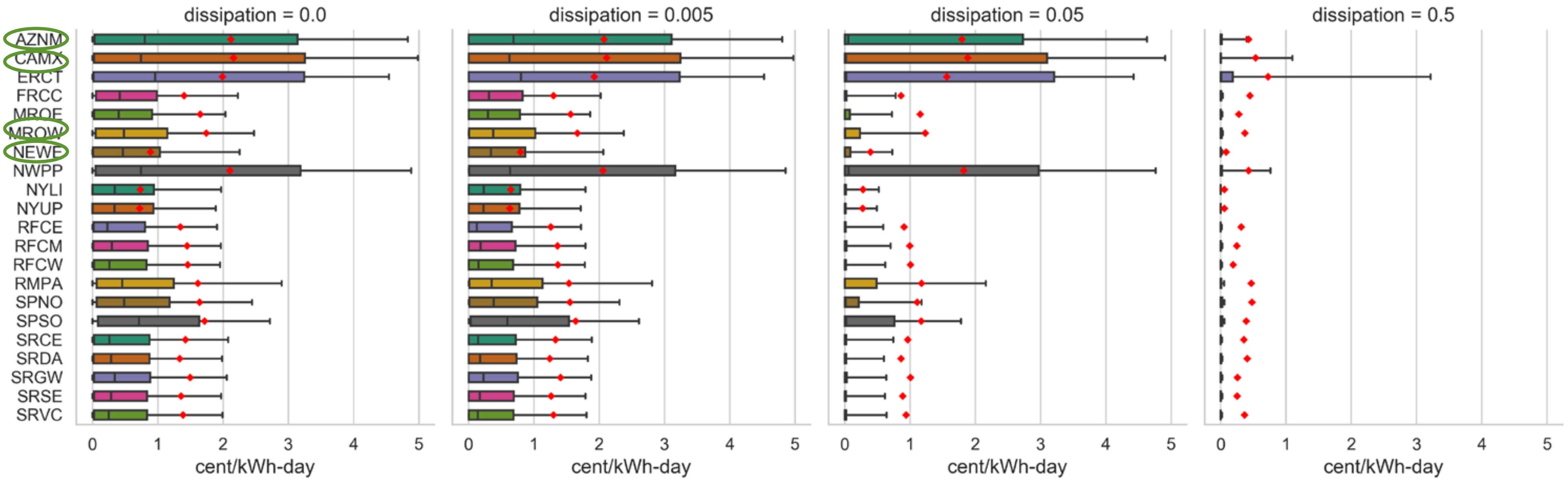
- More afternoon hours in the summer have high value.
- Western states have higher annual average for evening hours.

Higher efficiency leads to slightly higher value



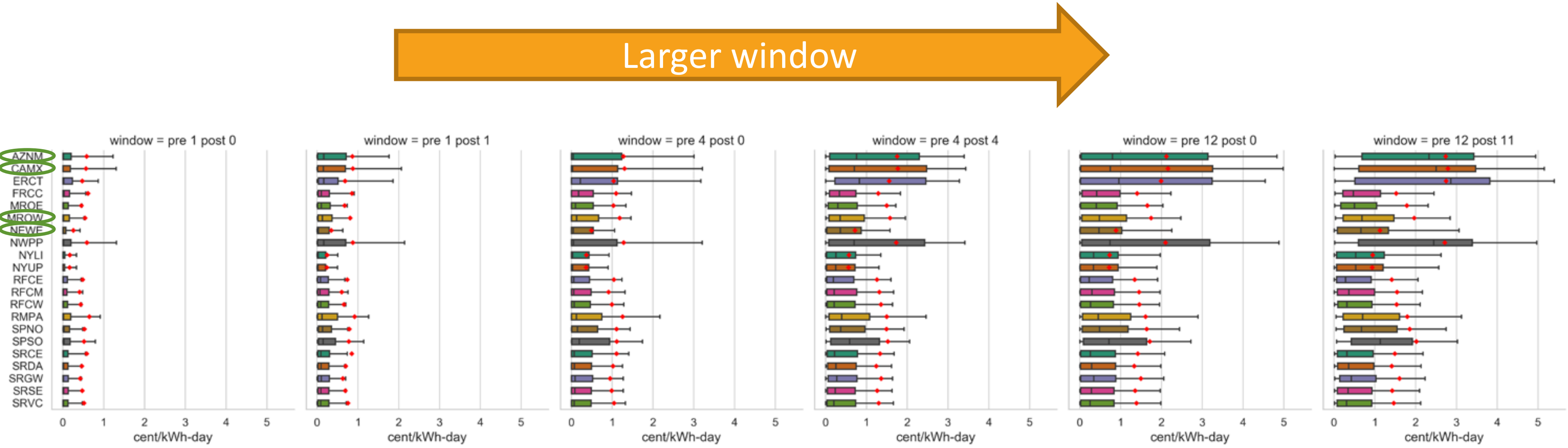
Distribution of hourly profits (cent/kWh-day) by region by efficiency for Mid RE, dissipation 0, window -12/+11 runs for all original usage hours. Red dots indicate the mean values. Whiskers extend to the 10th and 90th percentiles of the distributions.

Higher dissipation leads to diminishing value



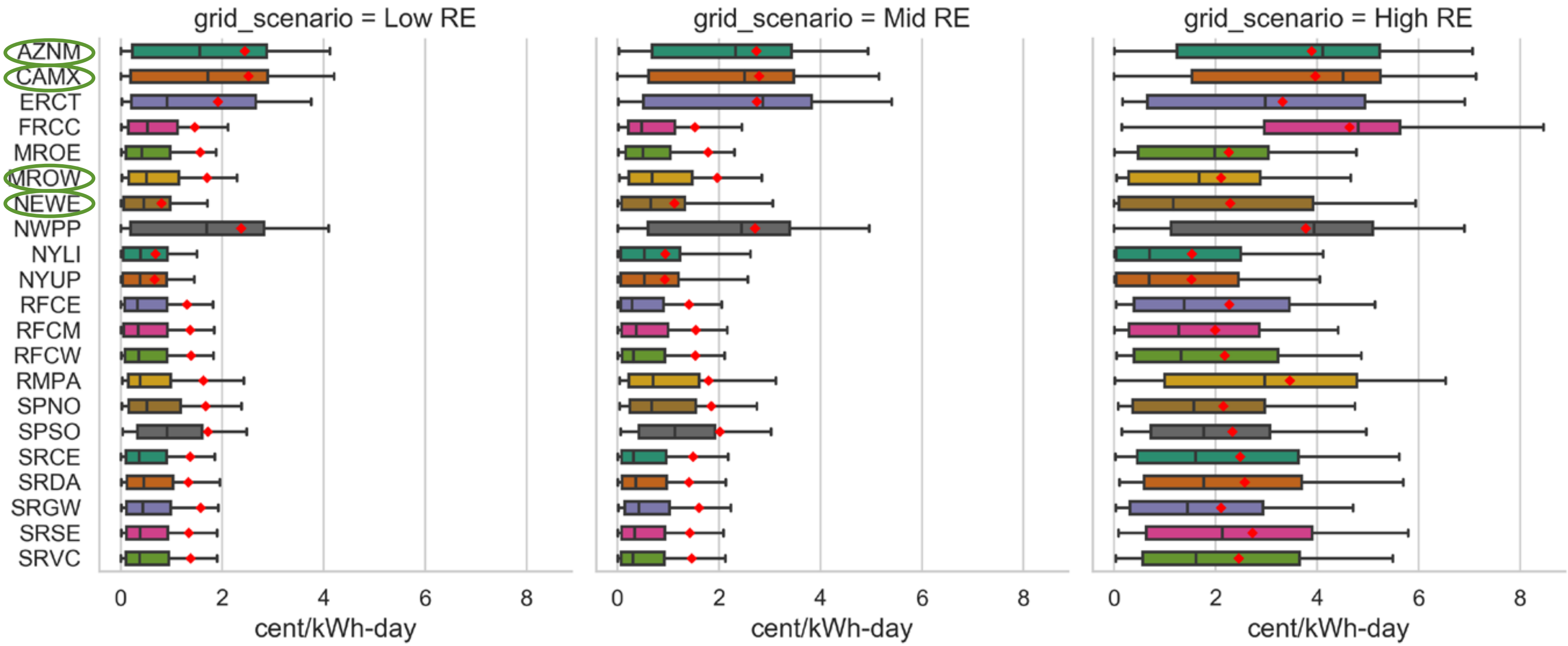
Distribution of hourly profits (cent/kWh-day) by region by dissipation for Mid RE, efficiency 1, window -12/0, for all original usage hours.

Larger shifting window leads to higher value



Distribution of hourly profits (cent/kWh-day) by region by window for Mid RE, efficiency 1, dissipation 0 runs for all original usage hours.

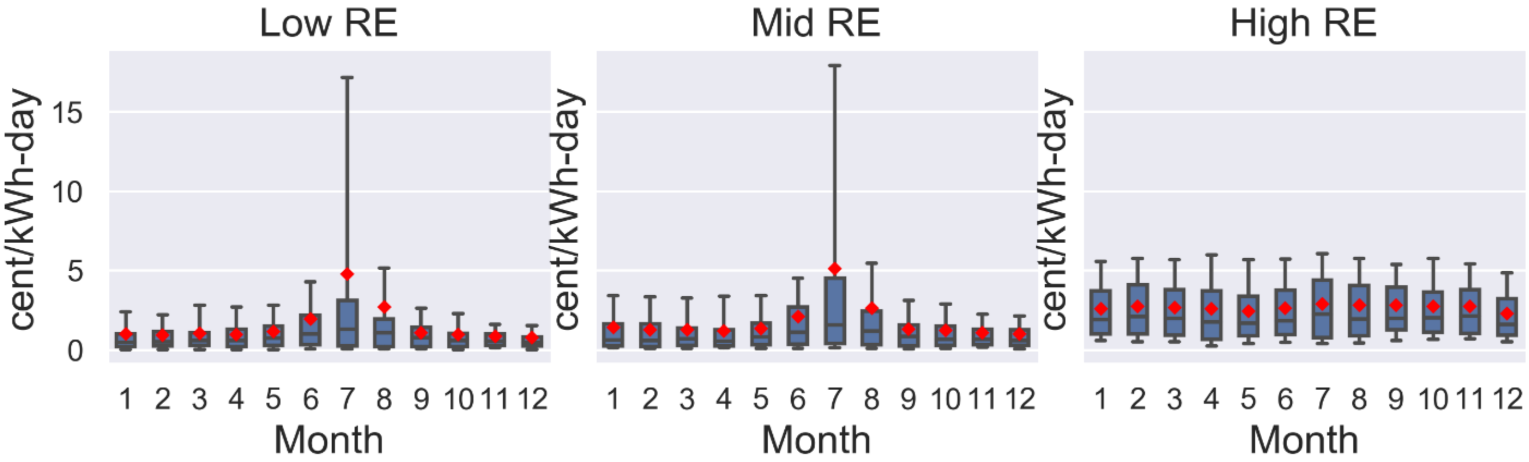
Higher RE penetration leads to higher average value, but it's complicated…



Distribution of hourly profits (cent/kWh-day) by region by scenario for efficiency 1, dissipation 0, window -12/11, for all original usage hours.

Capacity prices in lower RE can result in extreme high prices over short periods

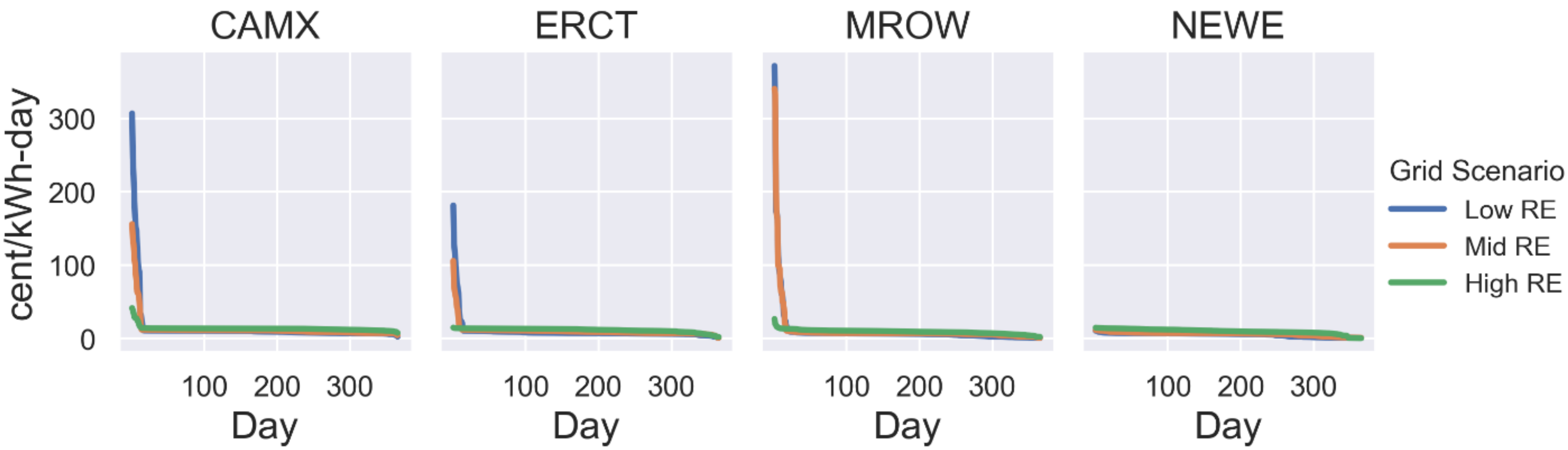
Hourly value averaged over a month (672 – 744)



Boxplot of mean monthly value for each original usage hour and region under window [-12, +11], efficiency 1, dissipation 0 by month and grid scenario. Whiskers extend to the 10th and 90th percentiles of the distributions.

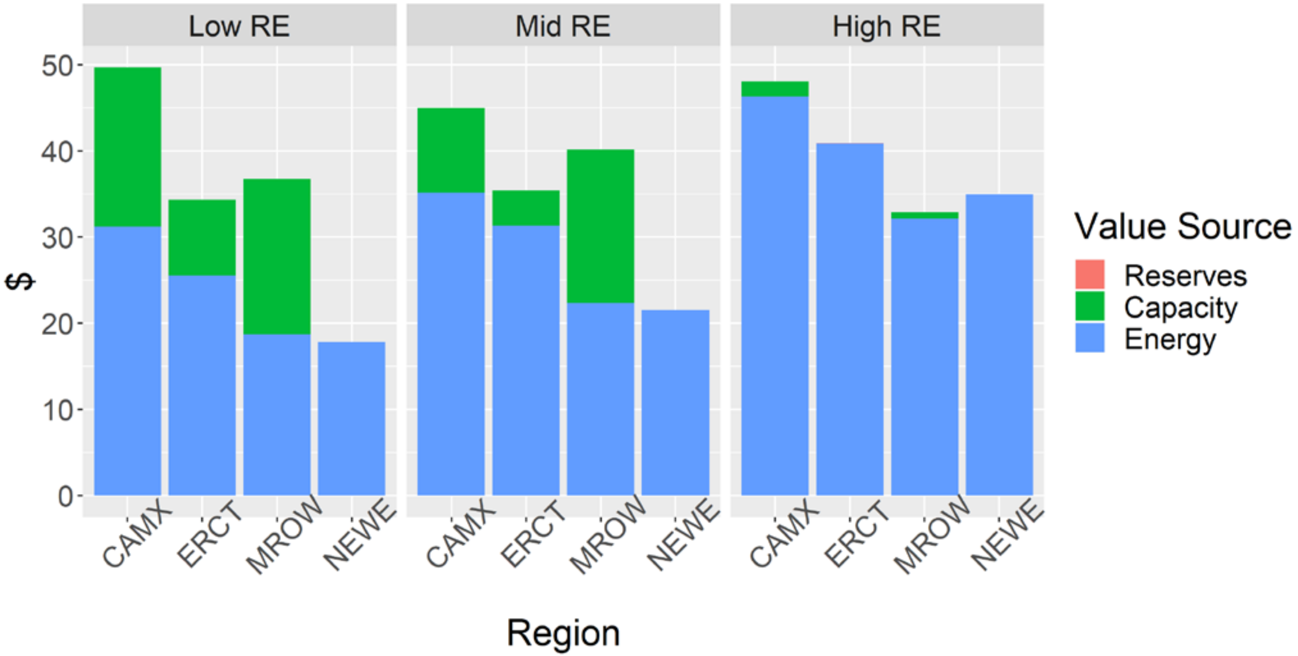
If only one hour each day is shiftable, the highest value hour will be utilized…

Daily Value Duration Curve

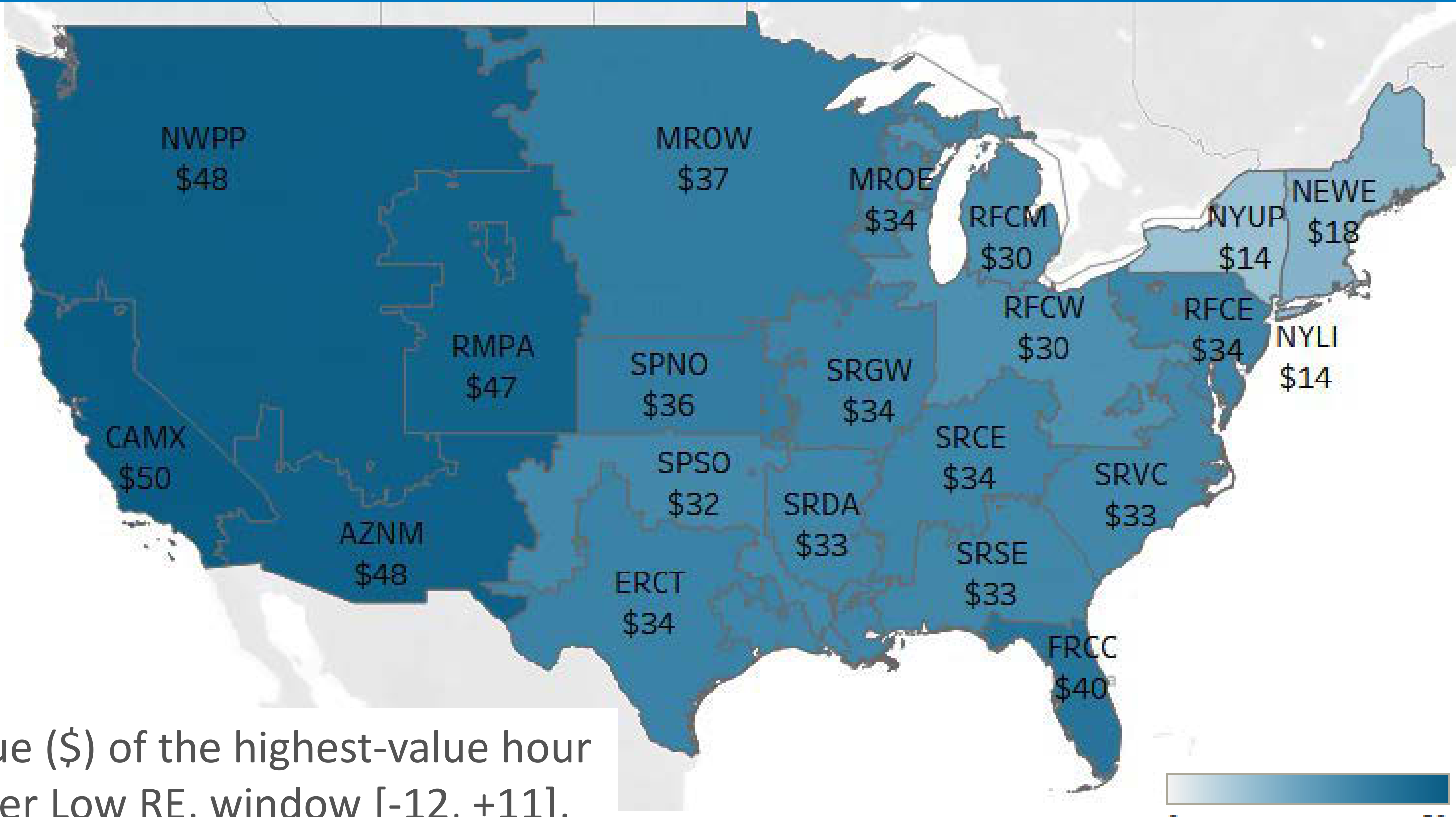


The highest-value hour for each day in each region is shown sorted in descending order.
Mid RE, Efficiency 1, Dissipation 0, Window -12/+11

Annual sum value of shifting 1kWh from the highest value hour of each day

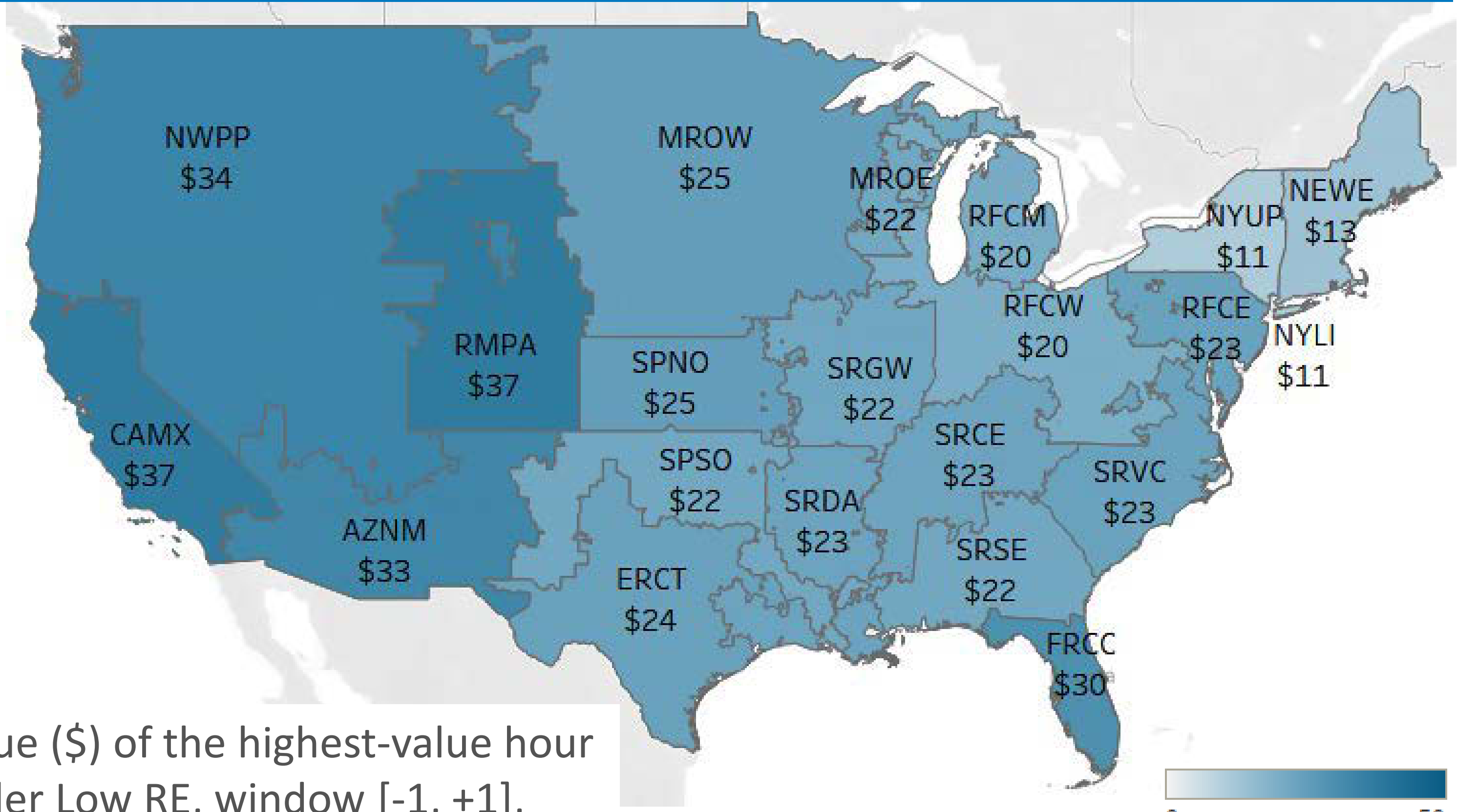


Low RE, window [-12,+11]



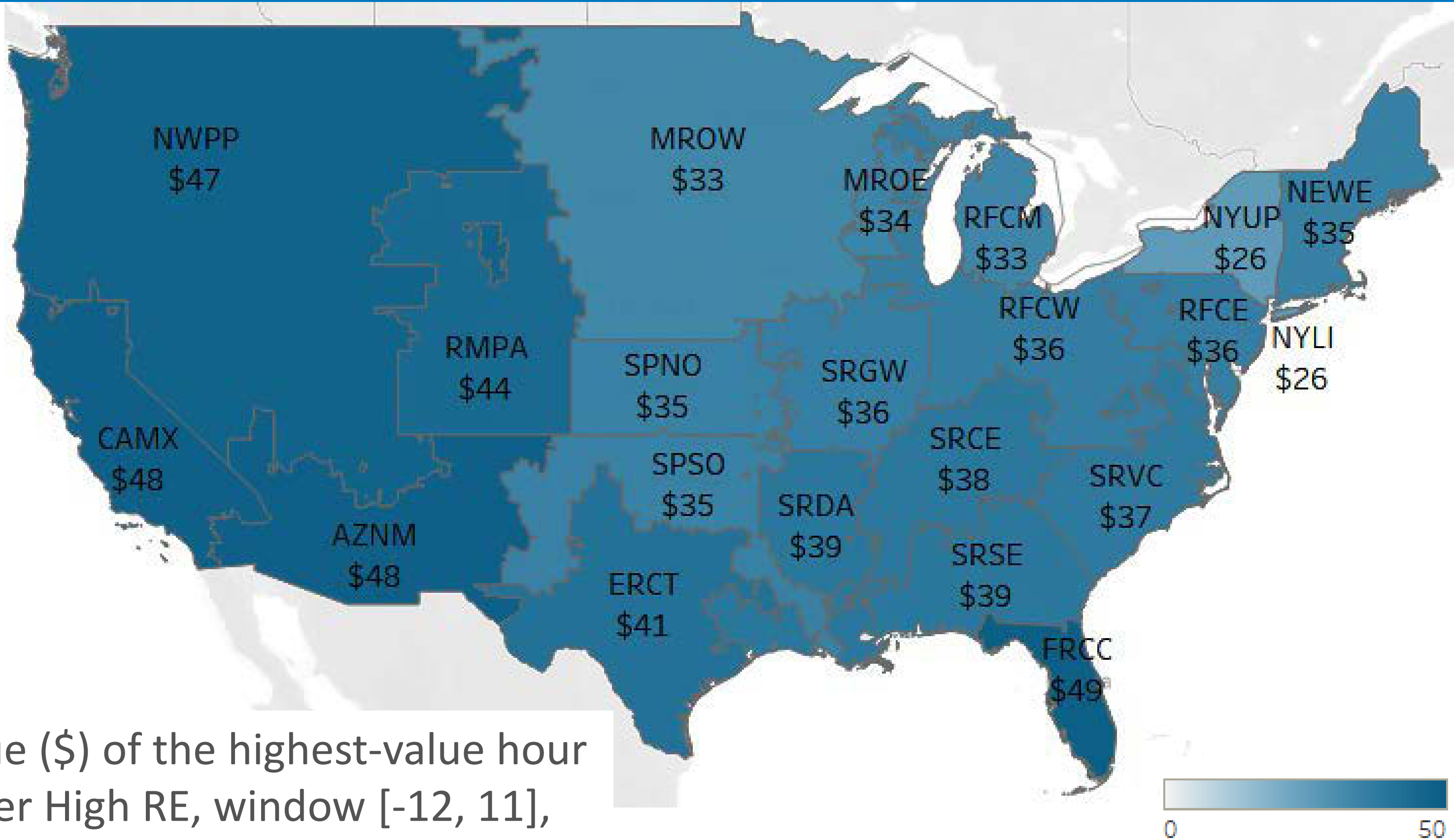
Annual sum value ($) of the highest-value hour of each day under Low RE, window [-12, +11], efficiency 1, dissipation 0.

Low RE, window [-1,+1]



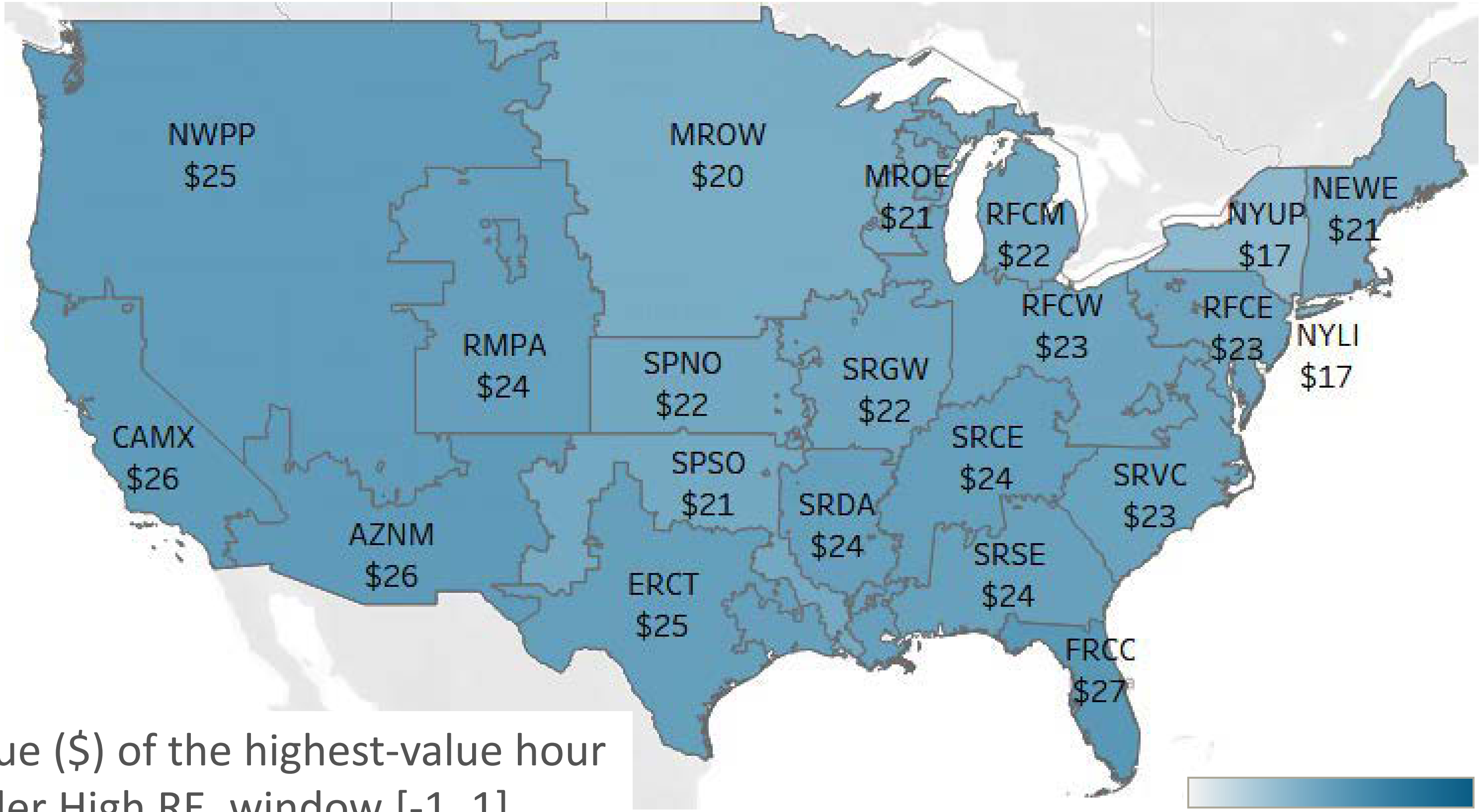
Annual sum value ($) of the highest-value hour of each day under Low RE, window [-1, +1], efficiency 1, dissipation 0.

High RE, window [-12,+11]



Annual sum value ($) of the highest-value hour of each day under High RE, window [-12, 11], efficiency 1, dissipation 0.

High RE, window [-1,+1]



Annual sum value ($) of the highest-value hour of each day under High RE, window [-1, 1], efficiency 1, dissipation 0.

1

2

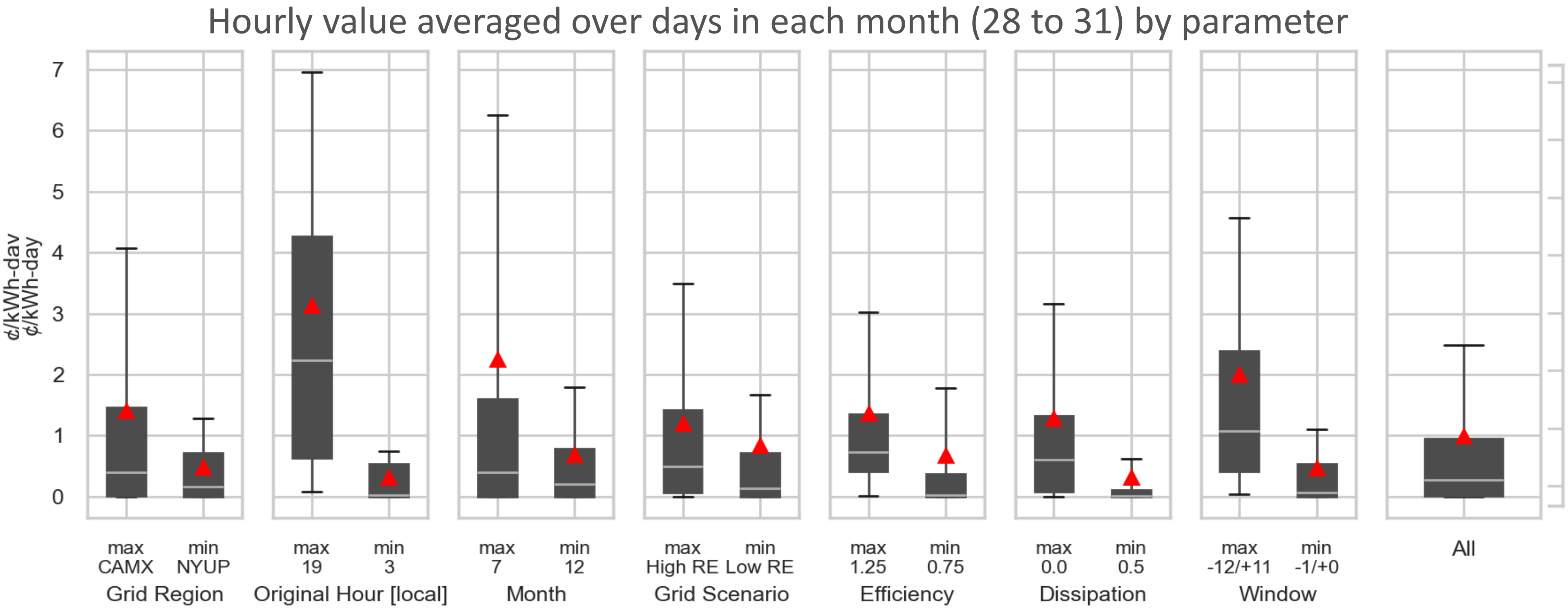
3

4

5

6 Summary and Conclusions

Summary



A box plot is shown for the configuration in each parameter that leads to the min/max average monthly value. Whiskers of the box show the 10-90% of the distribution; lower and upper bounds of the box show the first and third quartiles; red triangles show the mean values.

Conclusions

- Across all regions and scenarios, average monthly values range from 0 to 38 cent/kWh-day.
- Value of the highest-value hour each day across all the scenarios has a range of 0–620 cents/kWh-day.
- Original usage hour has the biggest impact on value, with evening hours being extremely valuable. Lower dissipation, larger window, and higher RE penetration lead to higher monthly averages. Efficiency has limited impact.
- High capacity values in certain scenarios contribute to extreme high values over short periods.
- Focusing on the mean values, top values, or the highest-value hour per day can lead to different observations; therefore, all results are provided in an open database.

Questions and Discussion

www.nrel.gov

ella.zhou@nrel.gov

NREL/PR-6A20-78452

This work was authored by the National Renewable Energy Laboratory, operated by Alliance for Sustainable Energy, LLC, for the U.S. Department of Energy (DOE) under Contract No. DE-AC36-08GO28308. Funding provided by the U.S. Department of Energy Office of Energy Efficiency and Renewable Energy Building Technologies Office. The views expressed in the article do not necessarily represent the views of the DOE or the U.S. Government. The U.S. Government retains and the publisher, by accepting the article for publication, acknowledges that the U.S. Government retains a nonexclusive, paid-up, irrevocable, worldwide license to publish or reproduce the published form of this work, or allow others to do so, for U.S. Government purposes.

NREL
Transforming ENERGY

Backup Slides

The NREL 2019 Standard Scenarios are 36 power system build-outs to 2050. Mid Case takes the first of each category

An NREL report identifies themes from the scenarios (https://www.nrel.gov/analysis/standard-scenarios.html)

Companion product of the Annual Technology Baseline (https://atb.nrel.gov)

Electricity Demand Growth

- Reference Demand Growth
- Low Demand Growth
- High Demand Growth
- Vehicle Electrification

Fuel Prices

- Reference Natural Gas Prices
- Low Natural Gas Prices
- High Natural Gas Prices

Financing Assumptions

- Mid Finance Projections
- Shortened Cost Recovery
- Extended Cost Recovery

Model Foresight

- No Foresight
- Perfect Foresight

Electricity Generation Technology Costs

- Mid Technology Cost
- Low RE Cost
- High RE Cost
- Low Wind Cost
- High Wind Cost
- Low PV Cost
- High PV Cost
- Low Geothermal Cost
- High Geothermal Cost
- Low CSP Cost
- High CSP Cost
- Low Hydro Cost
- High Hydro Cost
- Low Offshore Wind Cost
- High Offshore Wind Cost
- Low Battery Cost
- High Battery Cost
- Nuclear Technology Breakthrough
- 2018 ATB Mid Technology Cost

Combination Scenarios

- Low Natural Gas Prices & Low RE Cost
- High Natural Gas Prices & Low RE Cost
- Low Natural Gas Prices & High RE Cost
- High Natural Gas Prices & High RE Cost

Resource and System Constraints

- Default Resource Constraints
- Reduced RE Resource
- Barriers to Transmission System Expansion

Existing Fleet Retirements

- Reference Retirement
- Accelerated Retirements
- Extended Lifetimes
- Endogenous Retirements

The NREL 2019 Standard Scenarios are 36 power system build-outs to 2050. Mid Case takes the first of each category

An NREL report identifies themes from the scenarios (https://www.nrel.gov/analysis/standard-scenarios.html)

Companion product of the Annual Technology Baseline (https://atb.nrel.gov)

Electricity Demand Growth

- Reference Demand Growth
- Low Demand Growth
- High Demand Growth
- Vehicle Electrification

Fuel Prices

- Reference Natural Gas Price
- Low Natural Gas Prices
- High Natural Gas Prices

Financing Assumptions

- Mid Finance Projections
- Shortened Cost Recovery
- Extended Cost Recovery

Model Foresight

- No Foresight
- Perfect Foresight

Electricity Generation Technology Costs

- High CSP Cost
- Low Hydro Cost
- High Hydro Cost
- Low Offshore Wind Cost
- High Offshore Wind Cost
- Low Battery Cost
- High Battery Cost
- Nuclear Technology Breakthrough
- 2018 ATB Mid Technology Cost

Scenarios for 2030 analysis year

- High RE: low RE cost and high natural gas price assumptions
- Low RE: high RE cost and low natural gas price assumptions

Combination Scenarios

- Low Natural Gas Prices & Low RE Cost
- High Natural Gas Prices & Low RE Cost
- Low Natural Gas Prices & High RE Cost
- High Natural Gas Prices & High RE Cost

Resource and System Constraints

- Default Resource Constraints
- Reduced RE Resource
- Barriers to Transmission System Expansion

Existing Fleet Retirements

- Reference Retirement
- Accelerated Retirements
- Extended Lifetimes
- Endogenous Retirements

PLEXOS hourly economic dispatch of select Standard Scenario-model year combinations

PLEXOS is commercial power system production cost modeling software licensed from Energy Exemplar. Production cost models are (sub-)hourly operational models of bulk power systems (analogous to EnergyPlus for buildings).

Use cases include:

- Western Wind and Solar Integration Study
- Eastern Renewable Generation Integration Study

For this study, PLEXOS uses linear programming to perform hourly economic dispatch of the U.S. power system (represented by the 134 ReEDS balancing areas) for select Standard Scenarios and model years (ReEDS computes build-outs for 2010-2050 in 2-year increments). Key outputs for this analysis include hourly prices and marginal generators.

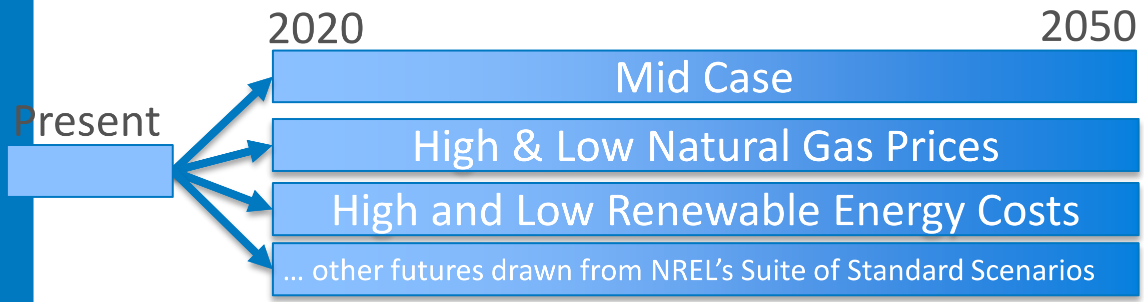
What is Cambium?

A database that contains projections of hourly cost and emission data for a suite of future grid scenarios

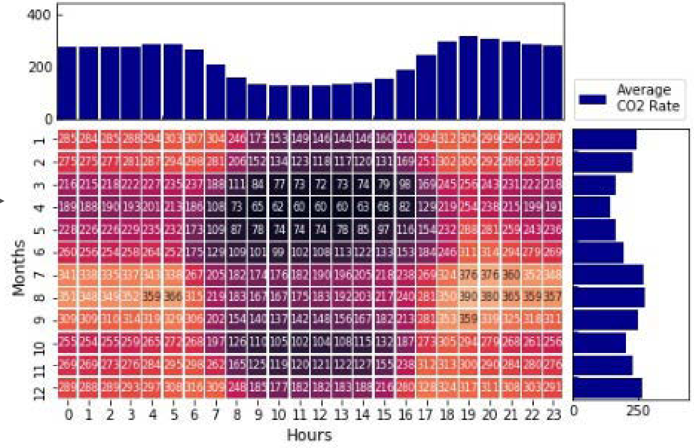
- Marginal costs
  - Energy
  - Capacity
  - Ancillary services
  - Policy
- Emission rates
  - Marginal
  - Average
- A wealth of operational data
  - Load and variable generation
  - Generation by technology
  - Amount of curtailed energy
  - Much more

134 regions covering the contiguous U.S.

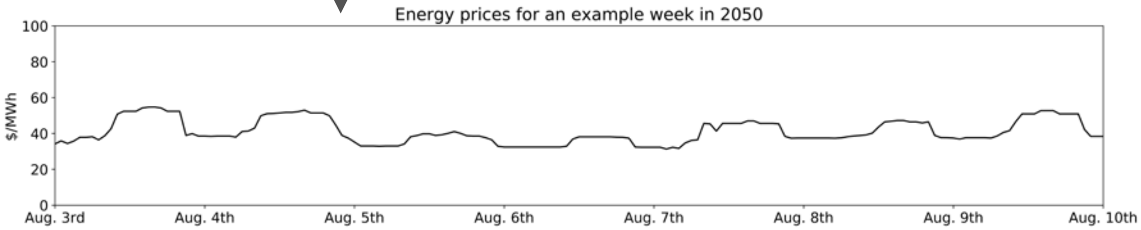
Biennial data through 2050



Example of projected CO_2 emission patterns in 2050 in our "low renewable energy cost" scenario.



Cost and emission data are hourly timeseries.



Ancillary Service Assumptions in the PLEXOS Model

Reserve Product	Timeframe (second)	Load Requirement (% of load)	Wind Requirement (% of generation)	PV Requirement (% of capacity)
Regulation	300	1%	0.5%	0.3%
Spinning	600	3%	—	—
Flexibility	1200	—	10%	4% when PV is generating