NREL
Transforming ENERGY

Value of EV Managed Charging to Bulk Power Systems

Luke Lavin and Elaine Hale

March 28, 2023

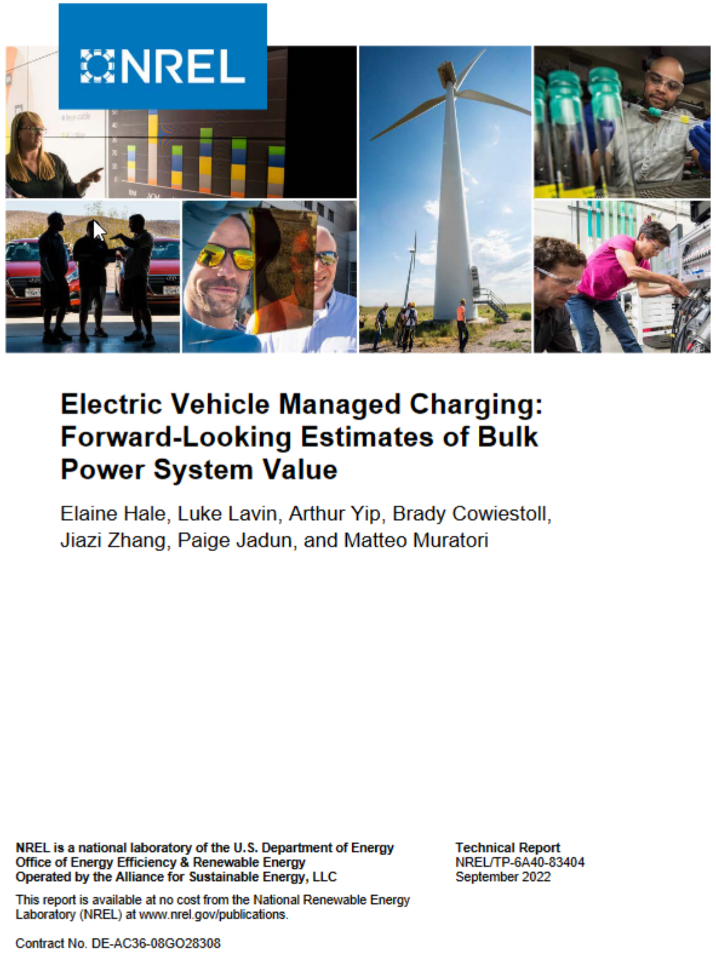
Joint work with: Arthur Yip, Brady Cowiestoll, Jiazi Zhang, Paige Jadun, and Matteo Muratori

Research Question

What is the value of light-duty electric vehicle (EV) managed charging (EVMC) to the bulk power system and how does it vary with:

- Single-day vs. Multi-day flexibility
- Dispatch mechanism:
  - Direct load control (DLC)
  - Real-time pricing (RTP)
  - Time-of-use tariff (TOU)
- EVMC participation levels

What is the value in terms of bulk power system energy, capacity, and avoided emissions?



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Electric Vehicle Managed Charging: Forward-Looking Estimates of Bulk Power System Value

Elaine Hale, Luke Lavin, Arthur Yip, Brady Cowiestoll, Jiazi Zhang, Paige Jadun, and Matteo Muratori

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Office of Energy Efficiency & Renewable Energy
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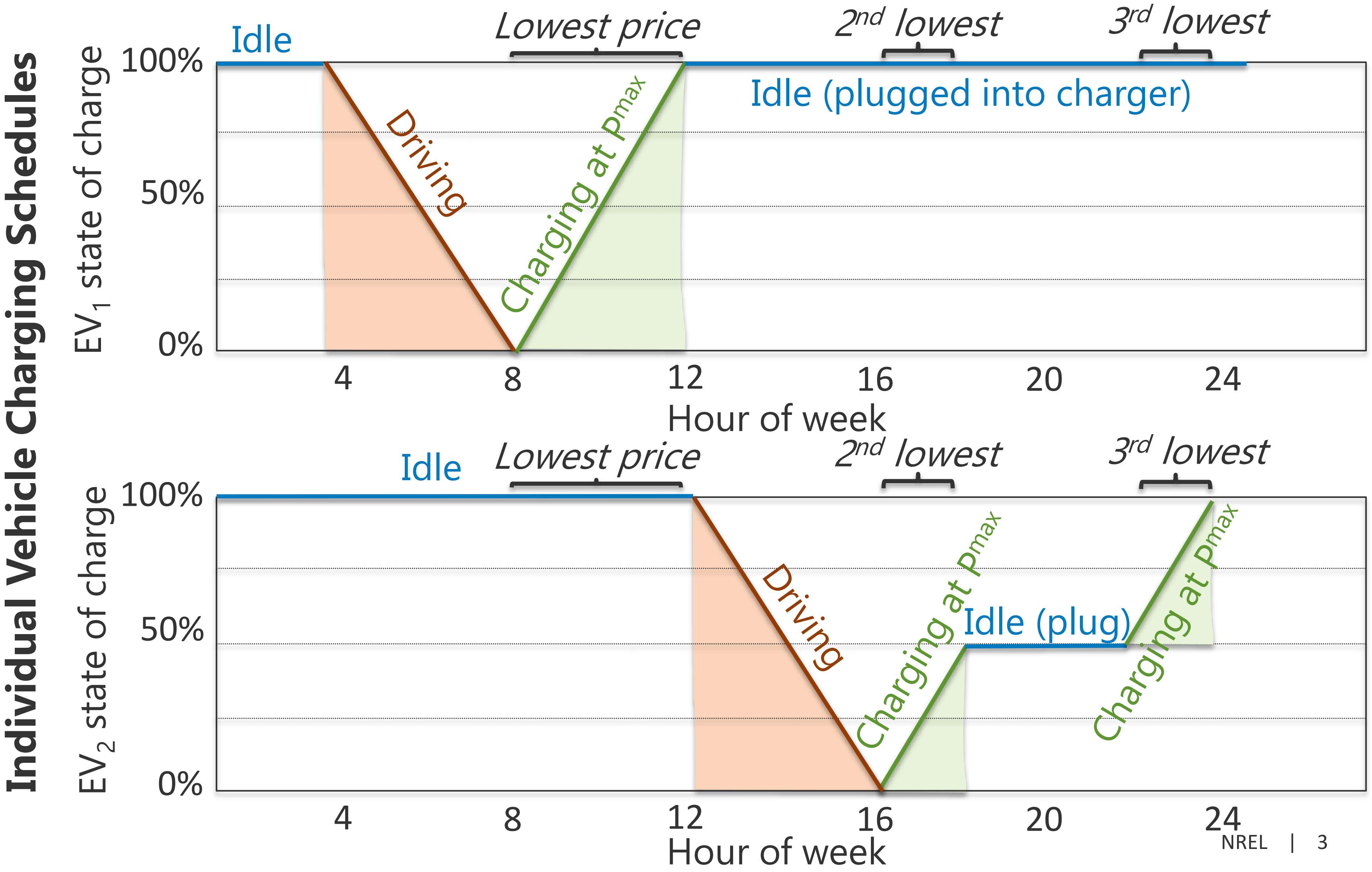
Methodological Finding: Energy and capacity bounds of EV aggregations *cannot* be naïvely added

- Aggregation is needed for EVs to participate in wholesale electricity markets (>0.1 MW), but simple addition of individual vehicle flexibility overestimates resource
- **Why:** A fully-charged vehicle's ability to increase load can be paired with another vehicle's ability to accept more charge



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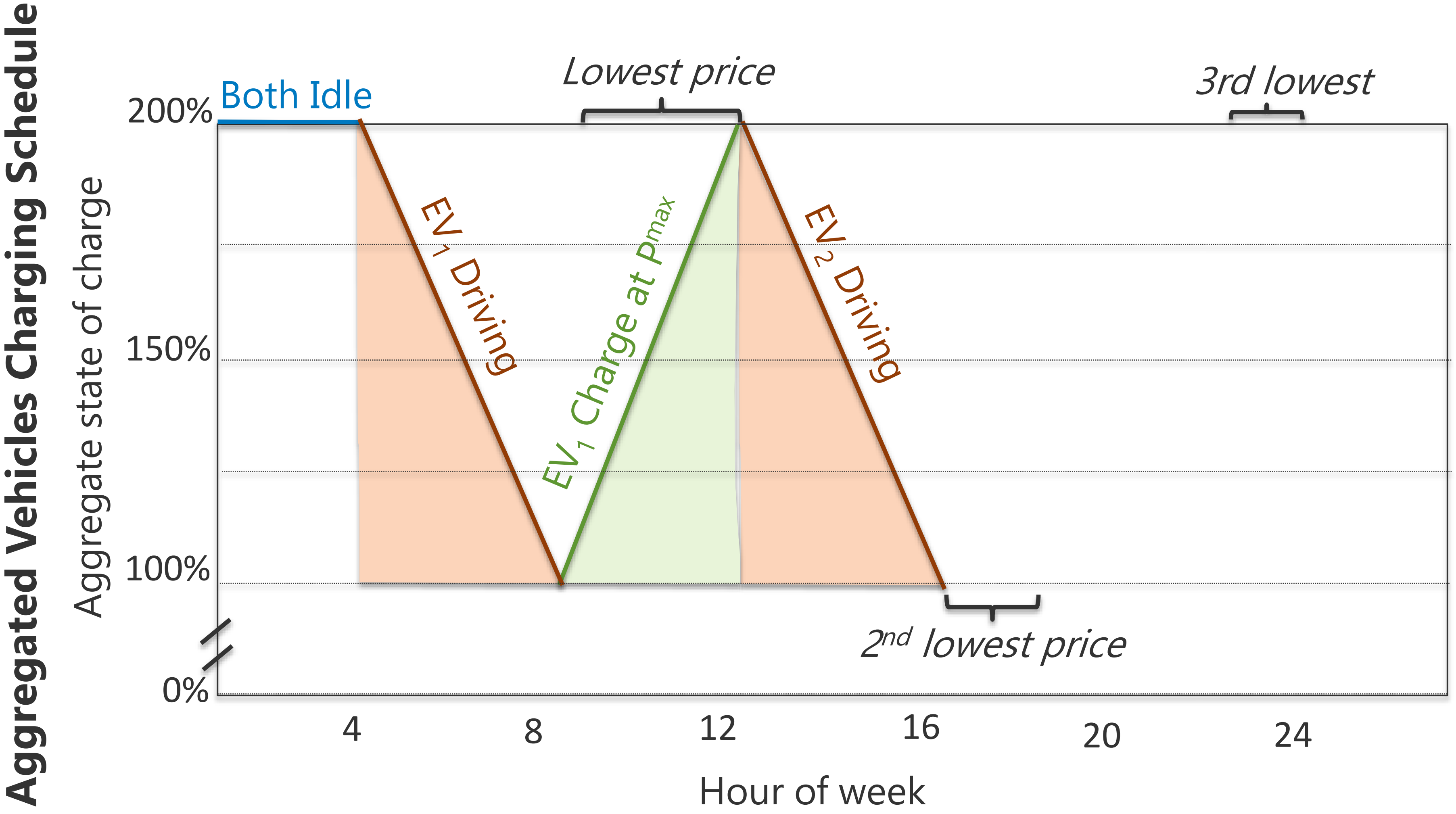

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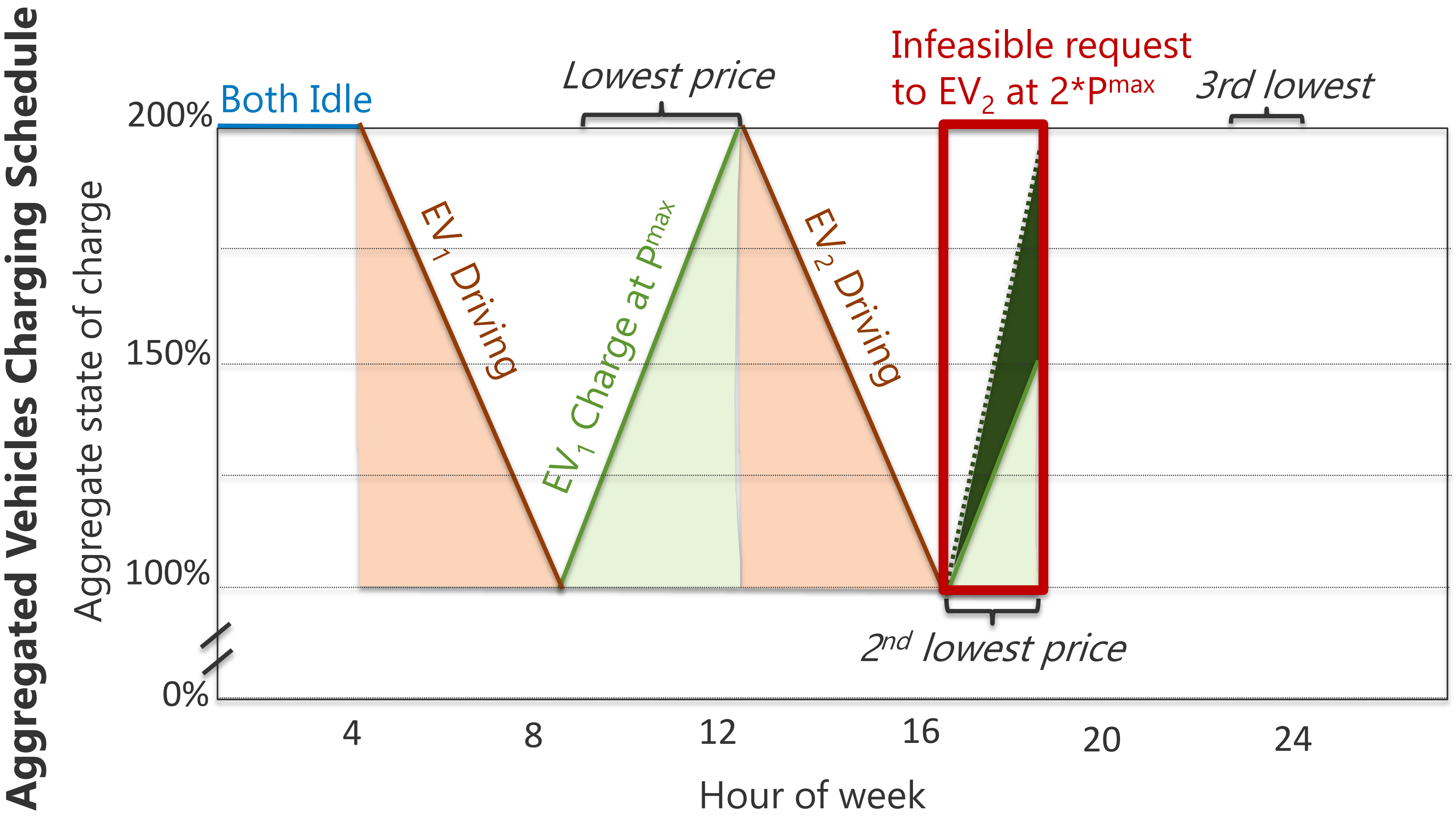

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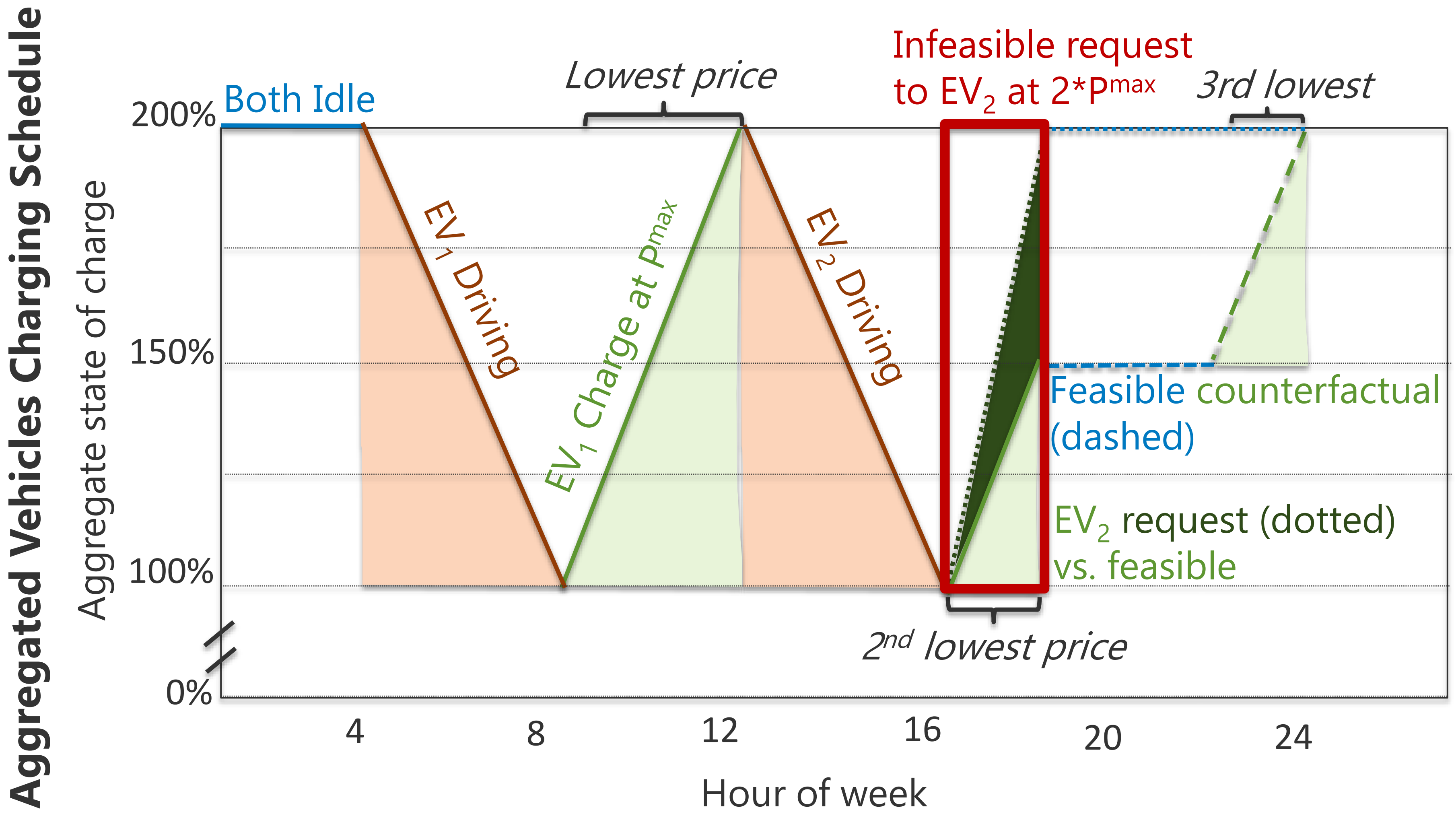


- **Question:** How feasible is Direct Load Control?

Tests show naïve aggregation produces highly infeasible charging flexibility requests

Legend

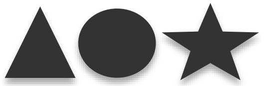
P^{max}: upward charging flexibility in each time period

P^{min}: downward charging flexibility in each time period

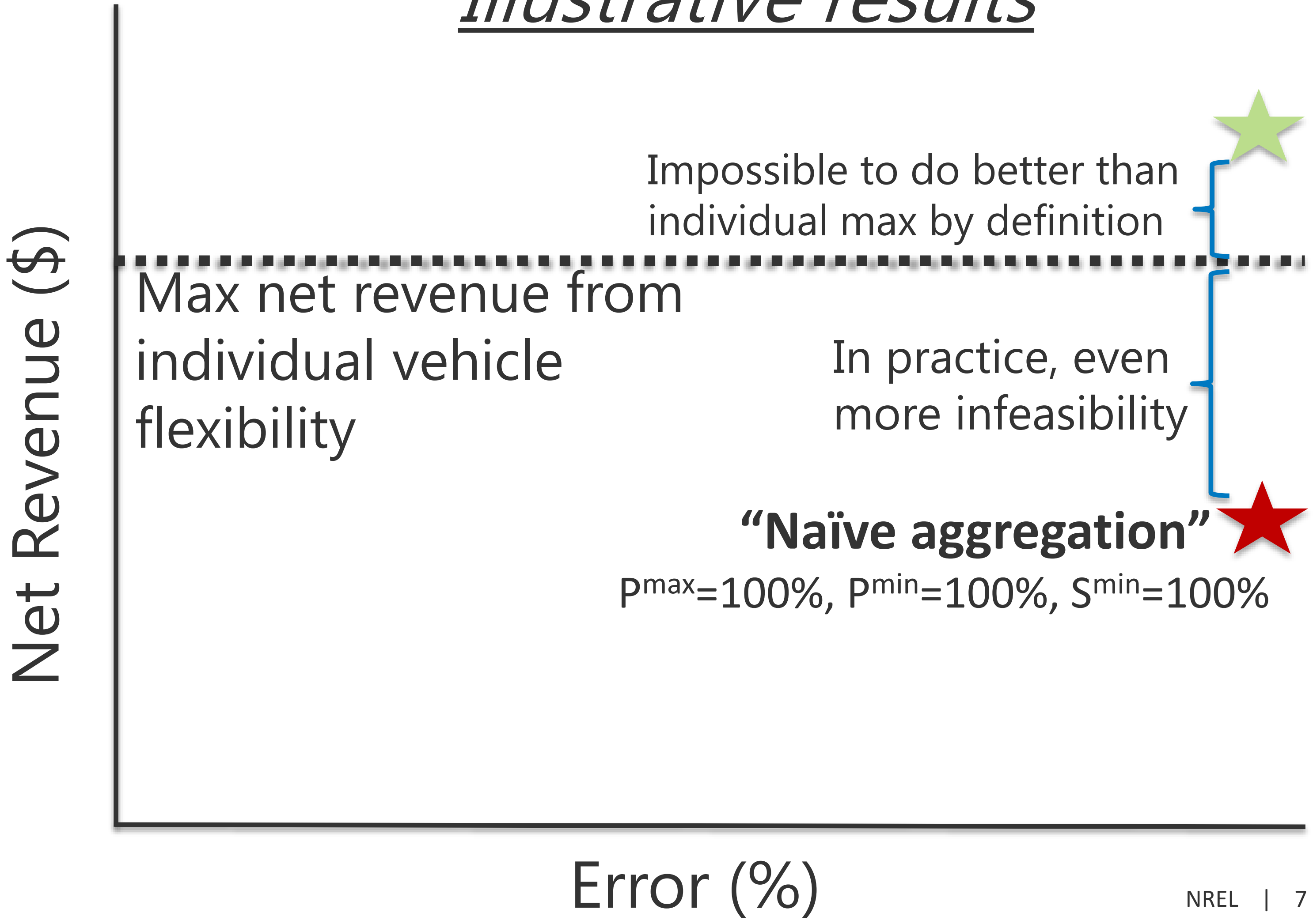
S^{min}: max quantity of deferred load in each time period

Red: Revenue under feasible re-dispatch to individual EVs

Green: Revenue if aggregate request was fulfilled


: Three different objectives

Illustrative results



Feasible redispatch of aggregate managed EV resource requires scaling power and energy bounds

Legend

P^{max}: upward charging flexibility in each time period
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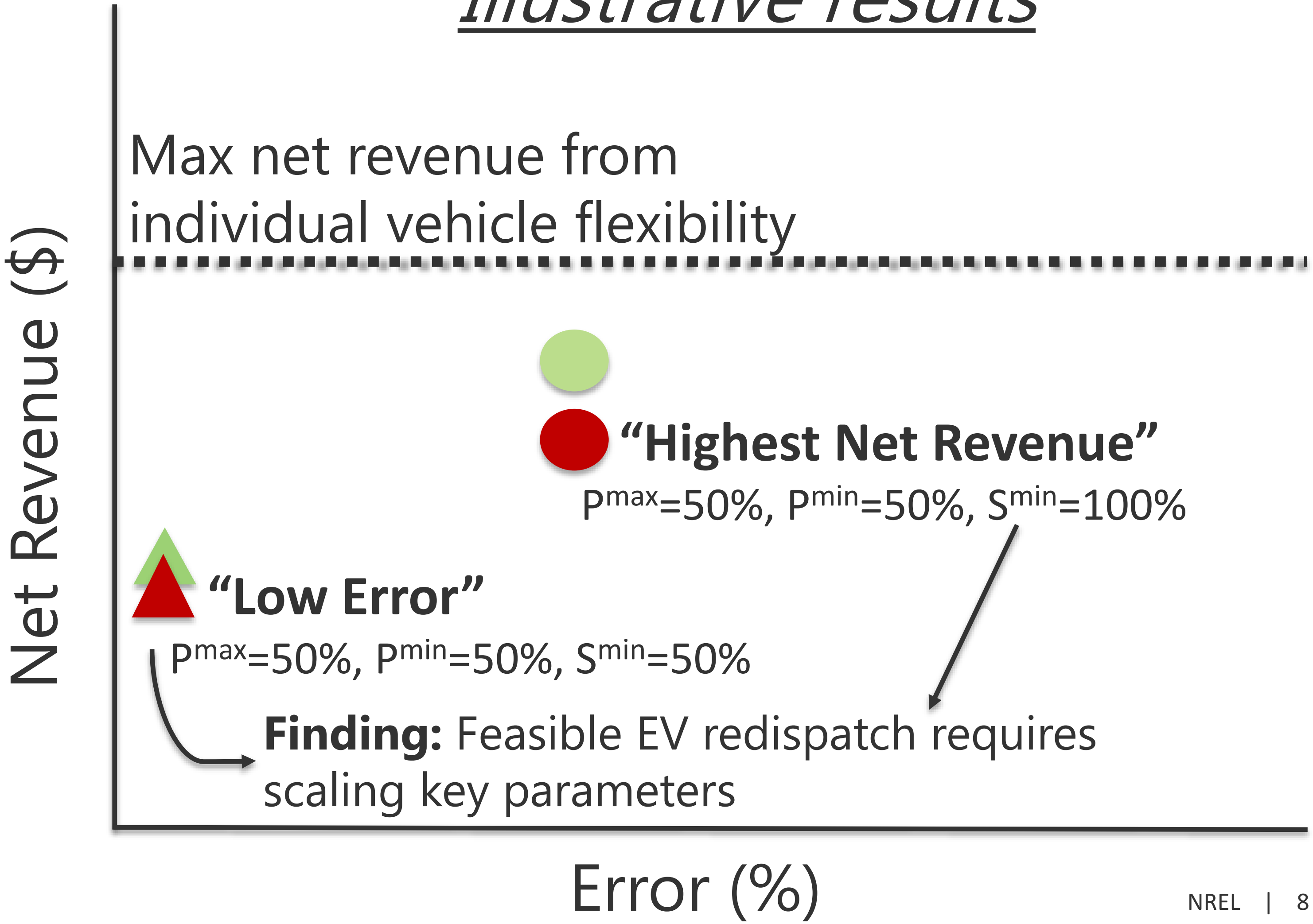


Study Setting

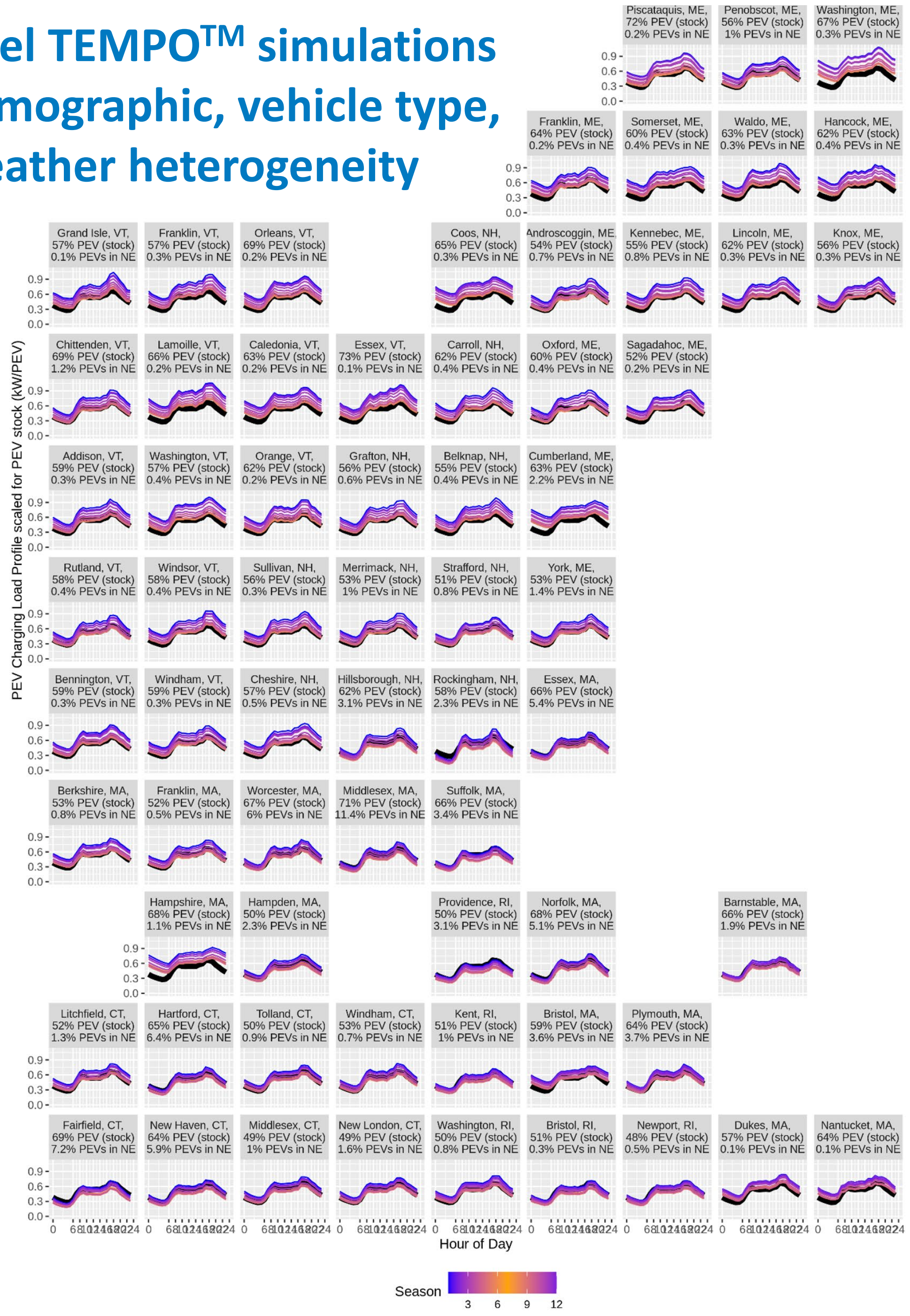
County-level TEMPO^{TM} simulations capture demographic, vehicle type, and weather heterogeneity

Hourly operational model of an envisioned 2038 New England Power System

- Peak load is 28.9 GW
  (0.5 GW from EVs; compare to 25.8 GW in 2021)
- Within-ISO generation is 84% clean
  (wind, solar, hydropower, biomass, nuclear)
- EVs are 45% of light-duty passenger vehicle fleet (100% of sales); 80% of EVs are battery electric vehicles

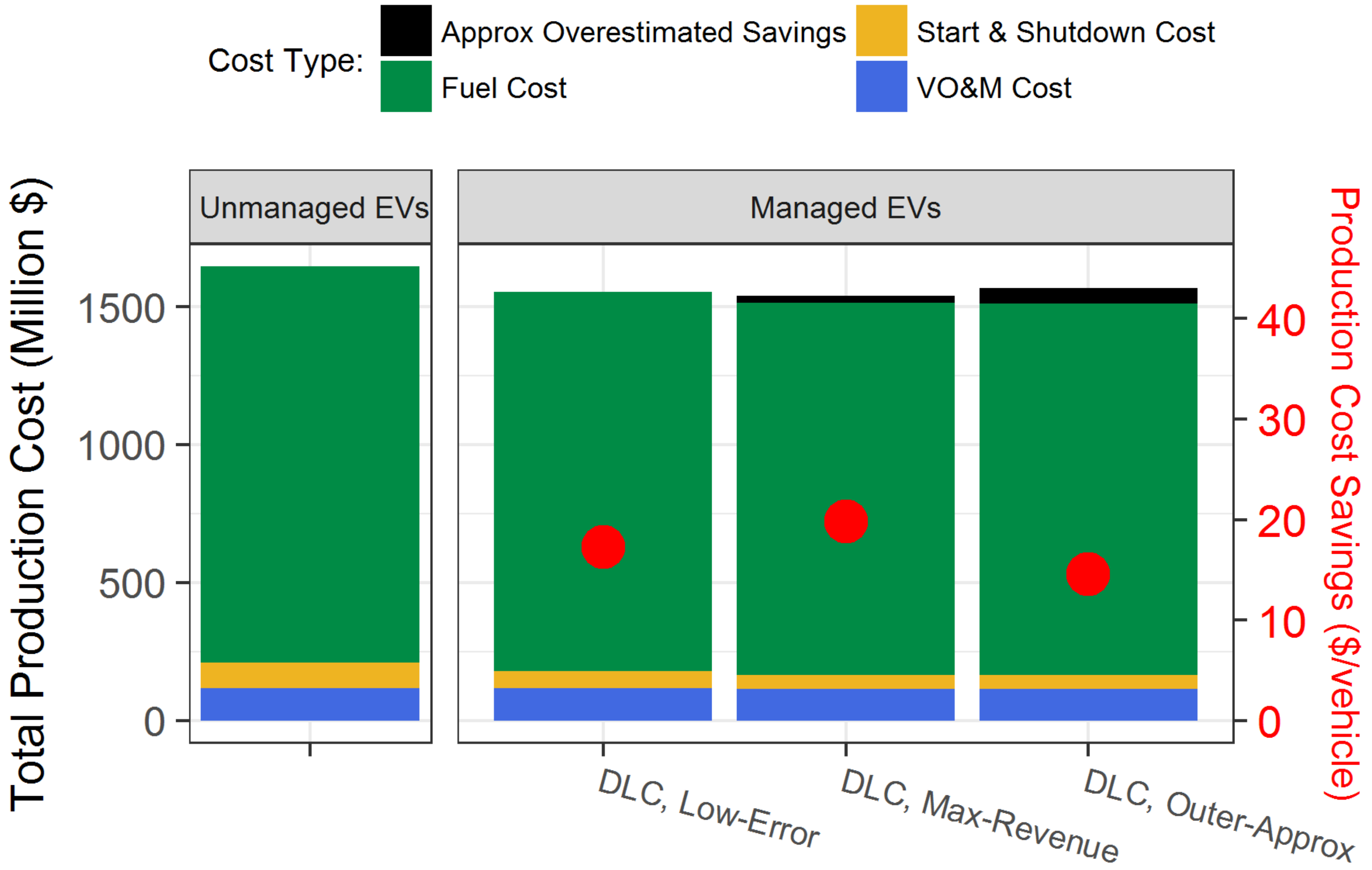
Charging flexibility (V1G) estimated from 101,000 sample vehicles’ charging profiles

- Mobility service is preserved in all scenarios
- Ubiquitous charging assumption



Key Finding: Aggregating vehicles for direct load control (DLC) comes at a feasibility cost

Estimated production cost savings for within-session aggregate flexibility models with different scaling factors

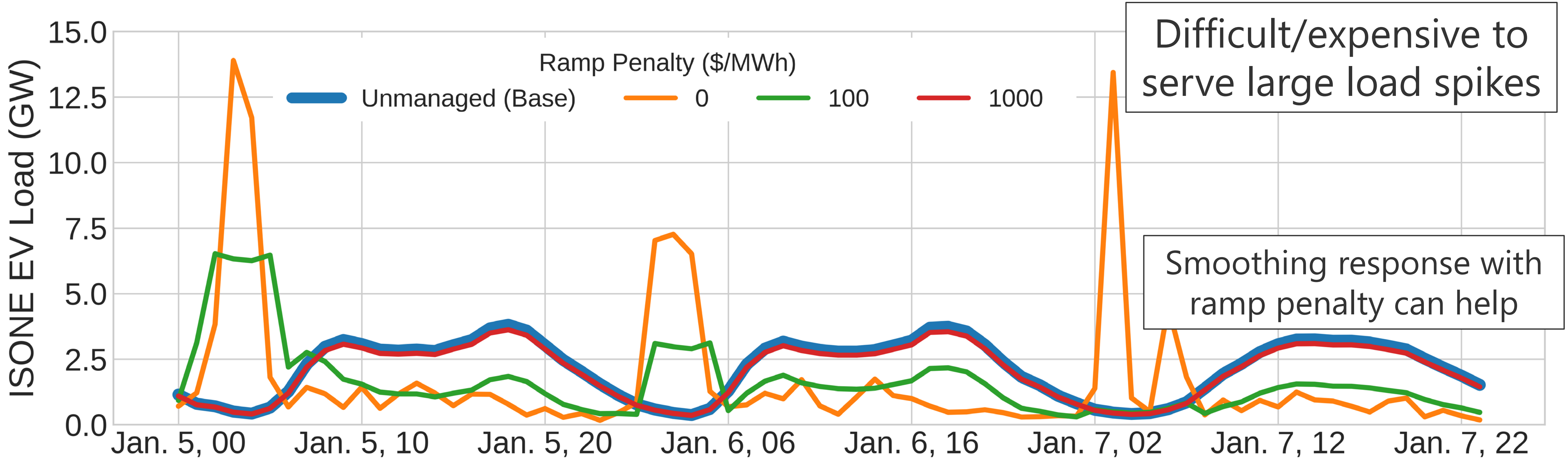


Recall: Naïve (“outer-approx”) aggregations effectively assume that one already-fully-charged vehicle’s ability to increase load can be paired with another already-charging vehicle’s ability to accept more charge.

Key Finding: Individual vehicles responding to price works for small numbers of vehicles, but is difficult to scale up

Charging profiles for the unmanaged case vs. vehicles responding to day-ahead energy prices

Energy prices were computed using the unmanaged profile as the EV load forecast (zero foresight of price-responsiveness)



This is an extreme example, but we also find that the bulk system value of 2% of vehicles responding to an RTP is improved with a small ramp penalty ($1/MW for within-session and $10/MW for within-week).

Key Finding: Highest per-vehicle value from low participation, RTP

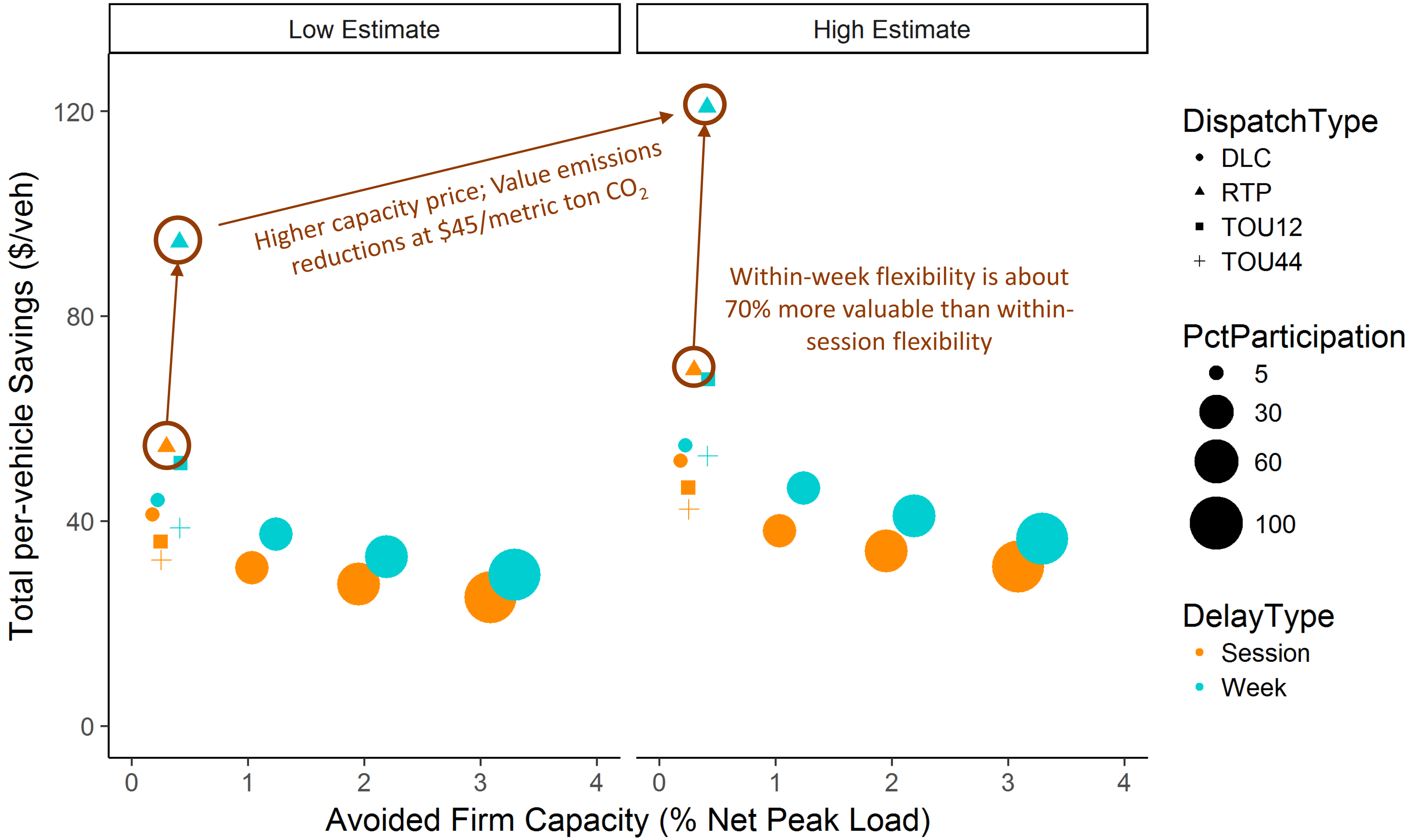
The highest per-vehicle-year value is produced at low participation rates by individual vehicles responding to real-time prices computed in the day-ahead market

- Per-vehicle value tops out at about $10/month, and that does not yet account for enablement and incentive costs

- Up to 1% of production costs and nearly 2% of within-ISO emissions can be avoided by about 2% of the 2038 LDV fleet actively participating in EVMC

- Price-responsive EVMC is not anticipated in the day-ahead unit commitment problem in this study (no foresight assumption)

All-in value of production cost savings, capacity savings, and emissions reductions

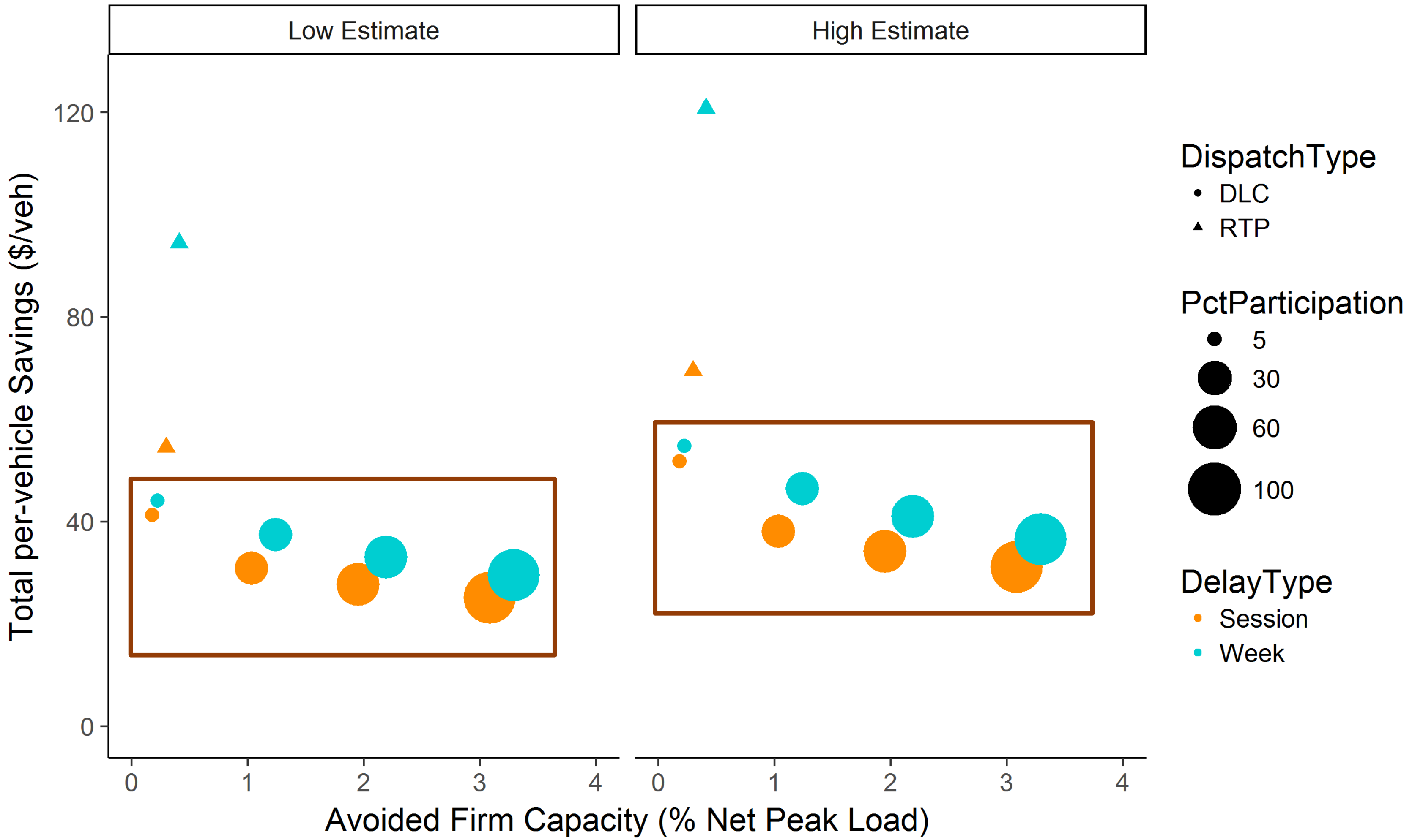


Key Finding: Higher participation levels require DLC and mute the advantages of multiday flexibility

Only direct load control provided significant production cost savings for all participation levels. With low-error DLC:

- All EVs (45% of the LDV fleet) providing within-session flexibility reduces production costs 4.4% and within-ISO emissions 5.2%
- All EVs (45% of the LDV fleet) providing within-week flexibility reduces production costs 5.6% and within-ISO emissions 6.9%
- Within-week is 70% more valuable than within-session flexibility at 5% participation with RTP; For DLC, the within-week advantage is 20% at 30% participation and drops to 17% for 100% participation

All-in value of production cost savings, capacity savings, and emissions reductions



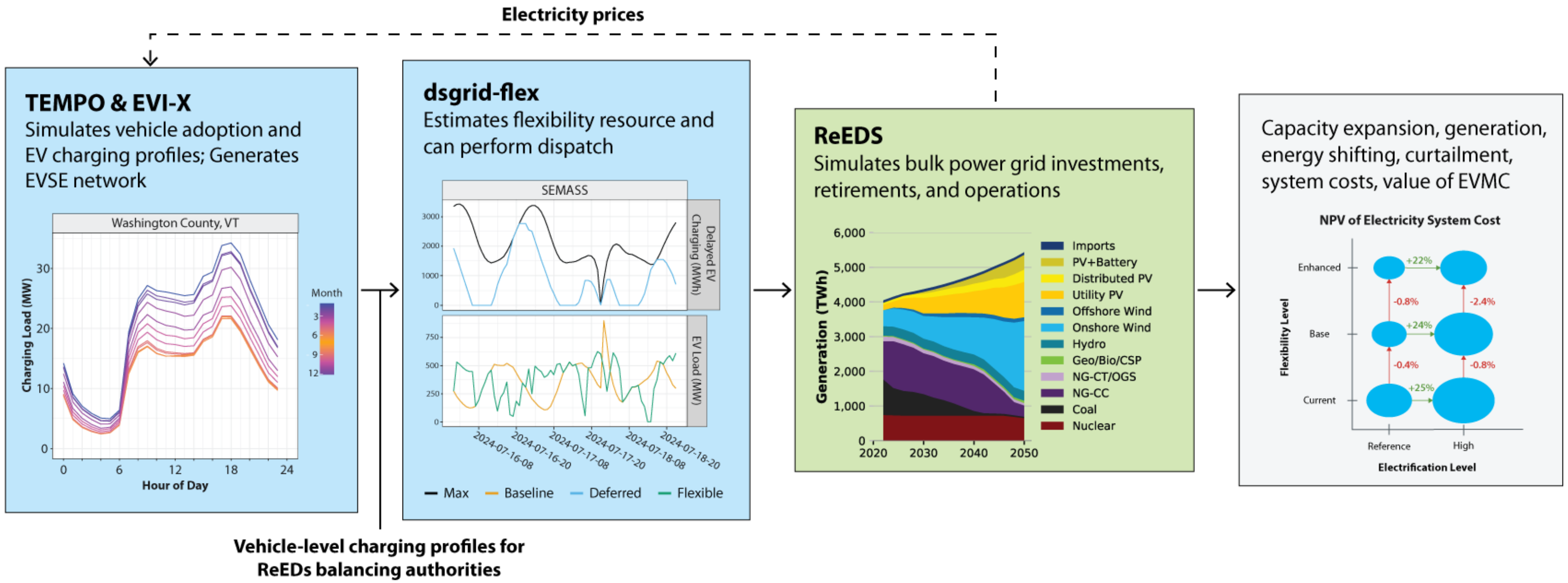
Summary of key findings

- Coordination of EVMC response is required starting at modest participation levels and comes at a cost
- Highest per-vehicle value is achieved at low participation levels responding to time-varying price
- Within-week flexibility is more valuable than within-session flexibility, but in our study the effect is muted at higher participation levels
- If all EVs fully participate through a low-error DLC mechanism, we estimate total system savings of:

Flexibility type	Production Cost Savings (%)	Power Sector Emissions Savings (%)	Firm Capacity from EVMC (MW)
Within-session (single day)	4.4	5.2	780
Within-week (multi-day)	5.6	6.9	830

yielding per-vehicle value estimates of **$25/vehicle-yr to $37/vehicle-yr.**

New Project: Managing Increased Electric Vehicle Shares on Decarbonized Bulk Power Systems



Building on the completed project's innovations around:

- Single and multi-day charging flexibility
- Exploration of aggregation and comparing direct control to price responsive dispatch

The new multi-year project, sponsored by the DOE EERE Vehicle Technologies Office (VTO), is extending the methodology to include:

- Capacity expansion modeling with EVMC as an investible resource
- Medium and heavy-duty vehicles
- Spatially resolved electric vehicle supply equipment (EVSE) and EV charging
- Fixed assets (e.g., EVSE scenarios) as management strategies
- Nationwide, path-dependent impacts on bulk power system costs and related metrics

Stay in touch!

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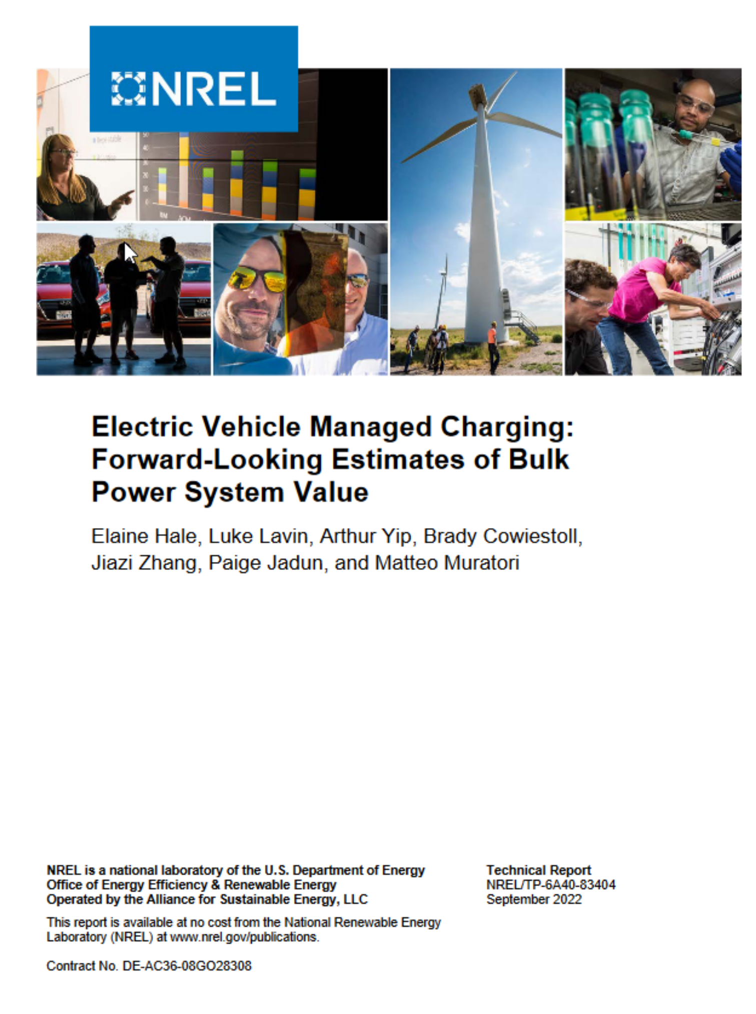

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Backmatter

General Problem Statement

Demand response is a long-standing source of power system flexibility

Increased solar and wind generation increases net-load variability and uncertainty

Additional balancing needs and a desire for less carbon emissions at affordable costs **increases interest in more forms of demand-side flexibility**

Demand response, ideally available year-round, can potentially **shift demand from high- to low-price times and reduce renewable energy curtailment**

Resource

Individual resources with equipment capacities in **kW**

What can aggregated electric vehicles contribute to power systems?

Target

Bulk power systems – generator plant capacities in **MW,** system capacities in **GW**

Research Question

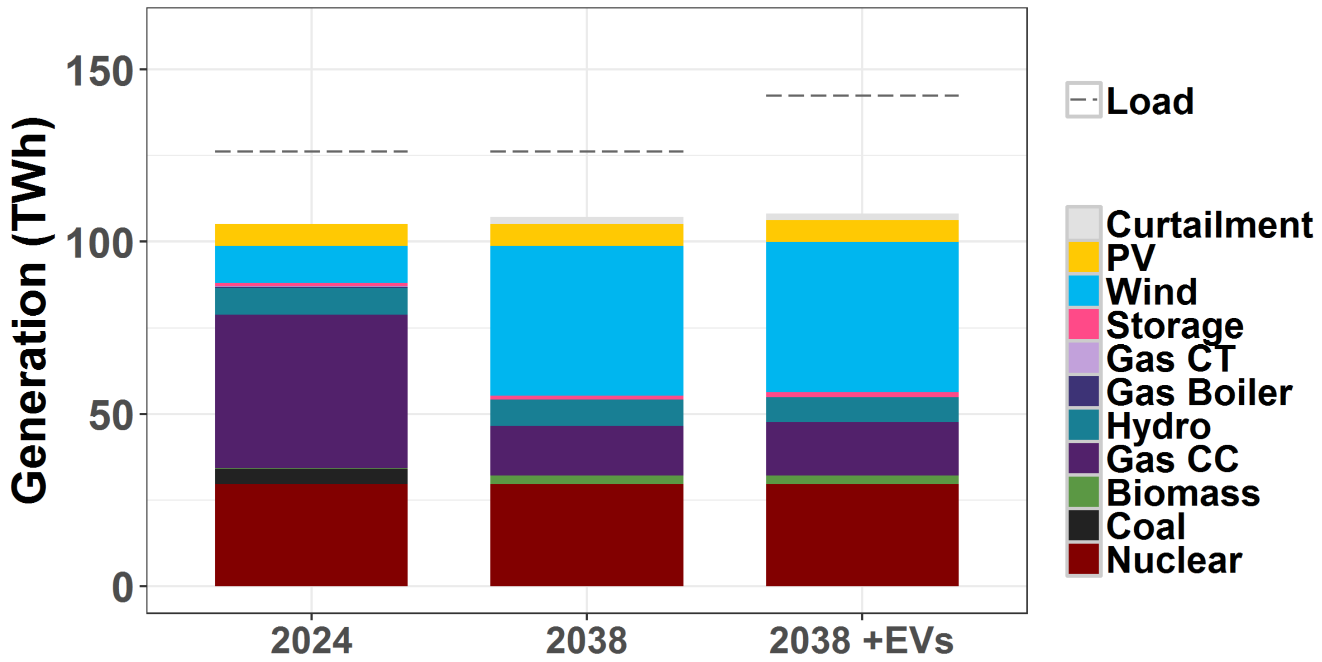
What is the potential value of EV managed charging (EVMC) and how does it vary depending on:

- Flexibility type (within-session or within-week)
- Participation level (5% to 100%)
- Dispatch mechanism (direct load control [DLC], real-time price [RTP], time-of-use [TOU] rate)

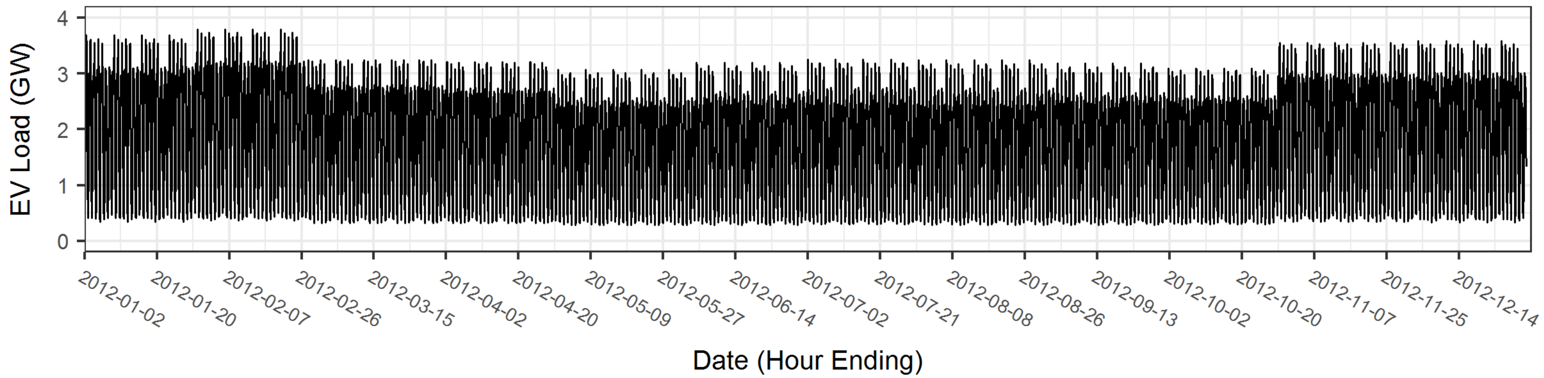
This study:

- Grid-to-vehicle (V1G)
- Constant mobility service
- Ubiquitous charging
- Technical potential (no costs for EVMC)
- Case study in an envisioned ISO-NE in 2038

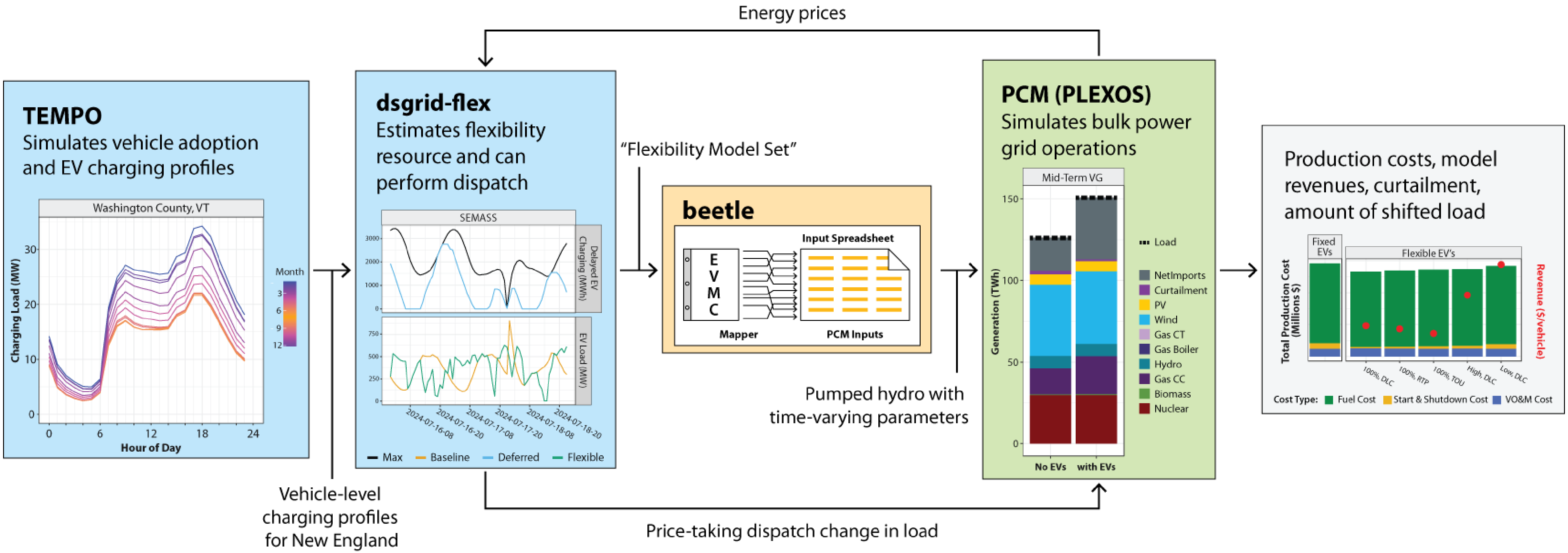
ISO New England (ISO-NE) PLEXOS Models Based on SEAMS



Personal Passenger Light-Duty Vehicle (LDV) EV Charging from TEMPO

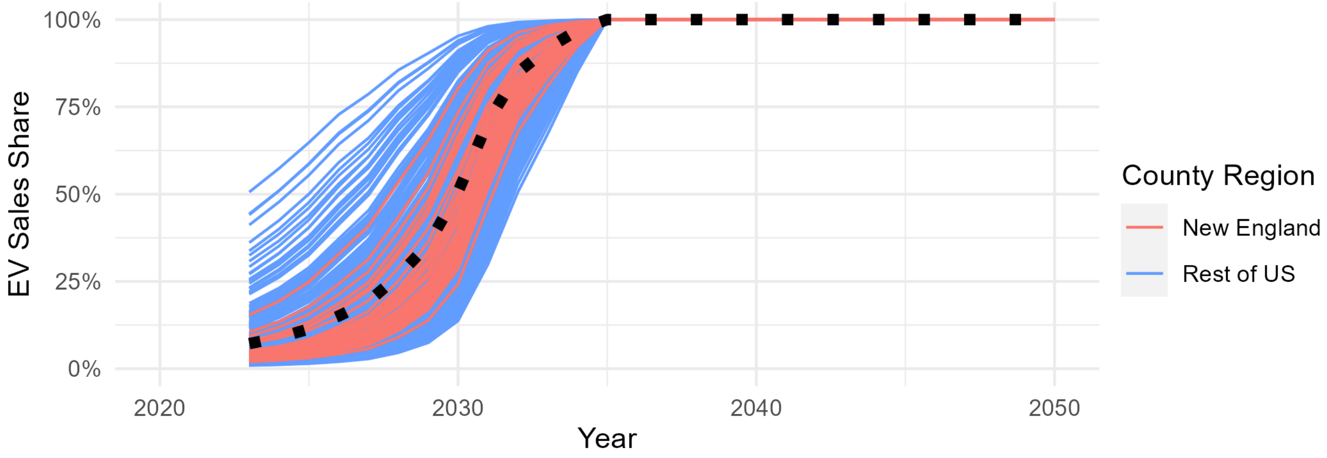


Analysis Approach
New high-resolution modeling capability

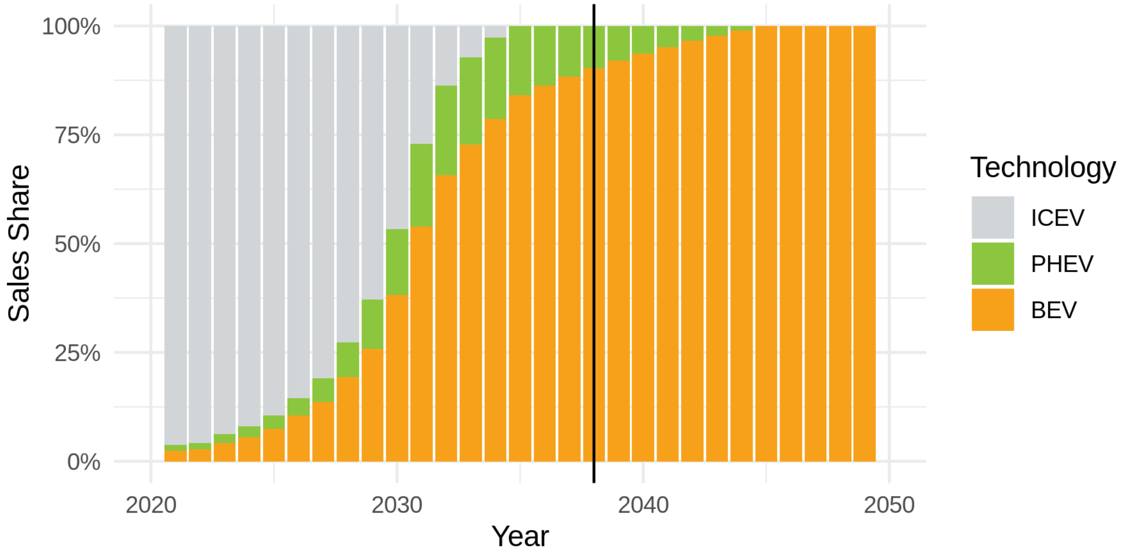


Analysis Approach
All EV Sales by 2035 Adoption Scenario from TEMPO

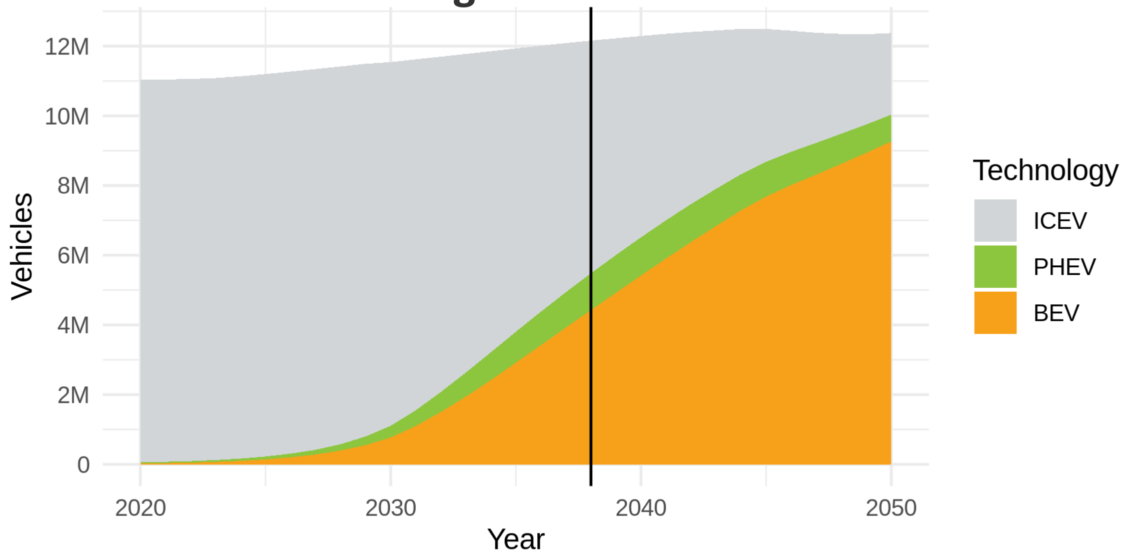
EV Sales Share of Passenger Light-duty Vehicles (LDVs) for All Counties in the Contiguous U.S.



Sales Share by Vehicle Type in New England



New England LDV Stock

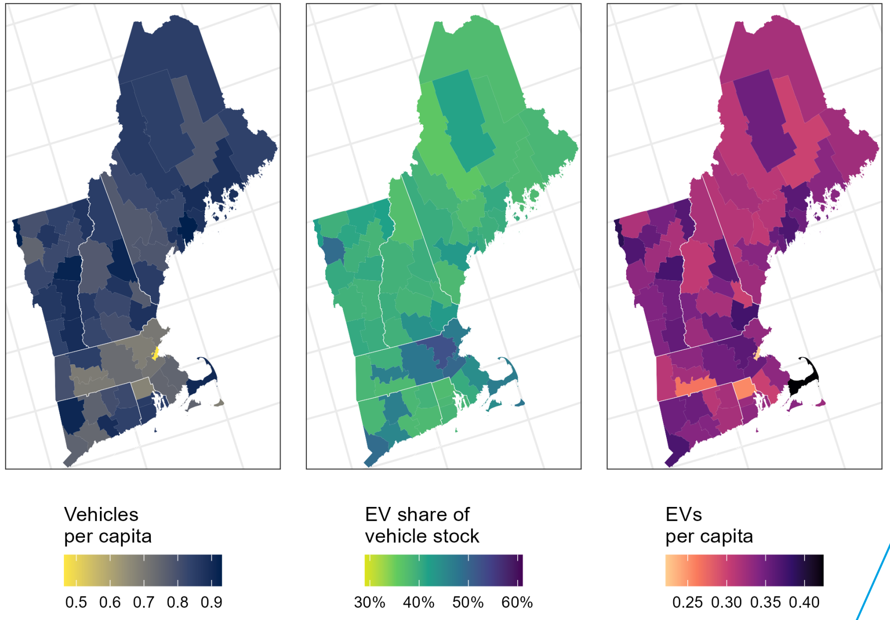


2038 Scenario

- 5.3 million EVs
- EVs are 45% of the LDV stock
- 80% of EVs are battery-electric vehicles (BEVs)
- 16.3 TWh/yr
- 3.79 GW unmanaged peak load

Analysis Approach
Heterogeneous, vehicle-level modeling with TEMPO

County-level demographic and weather patterns



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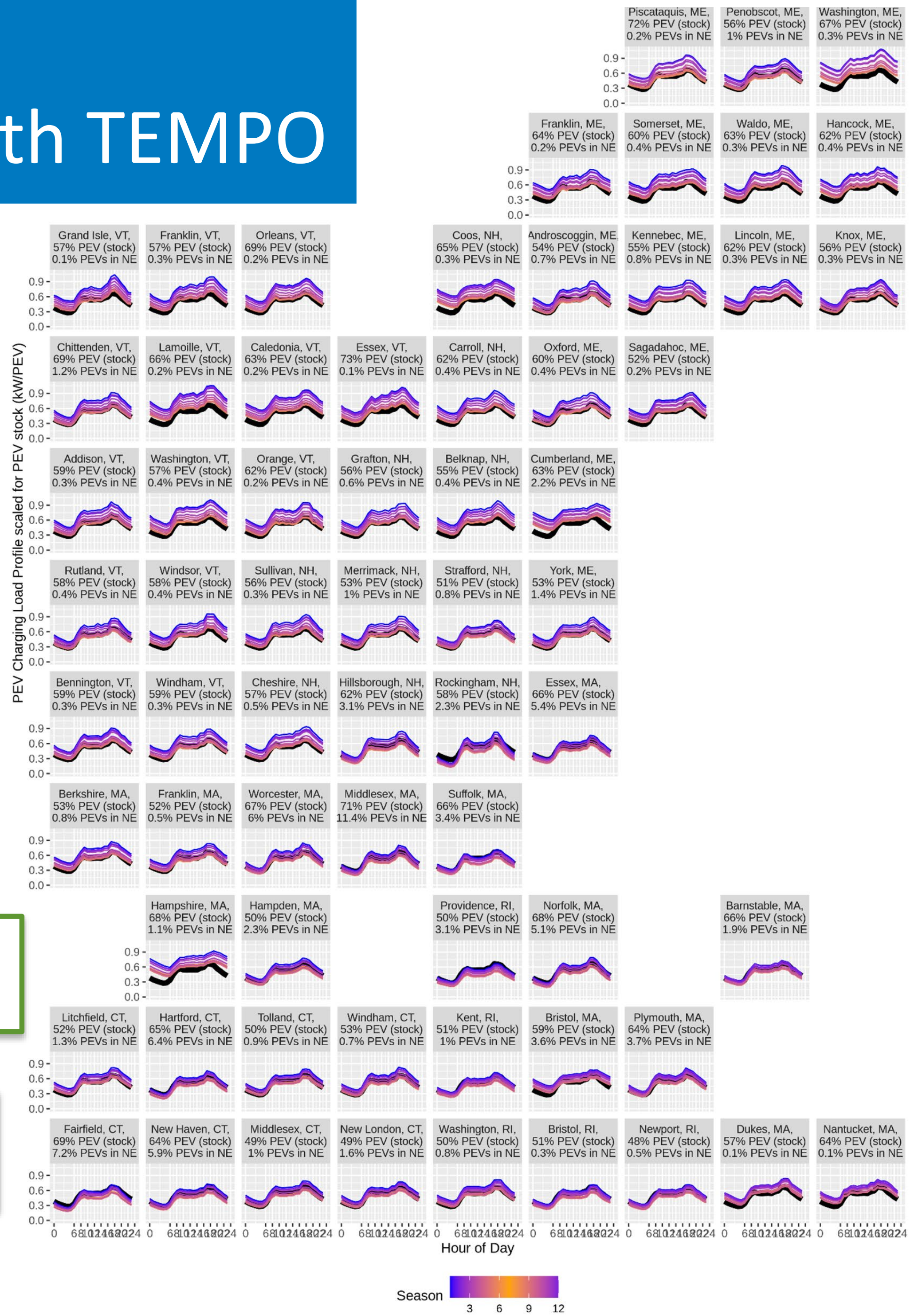
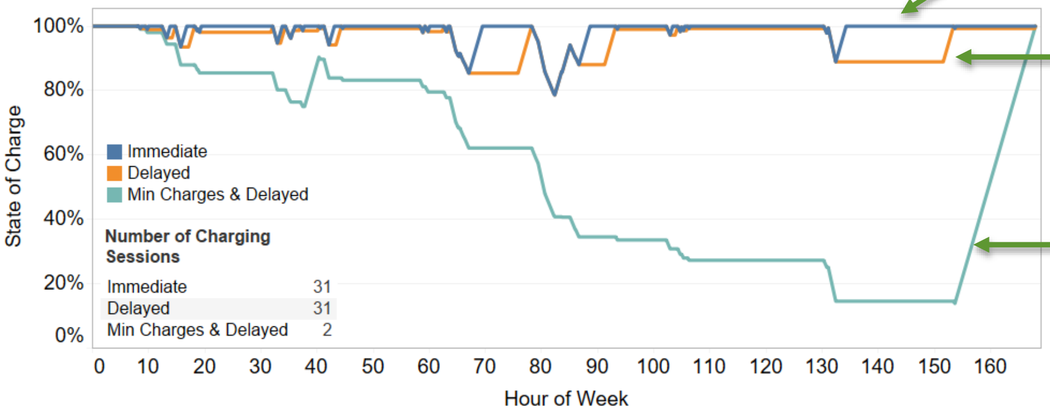


Sample-vehicle charging simulations



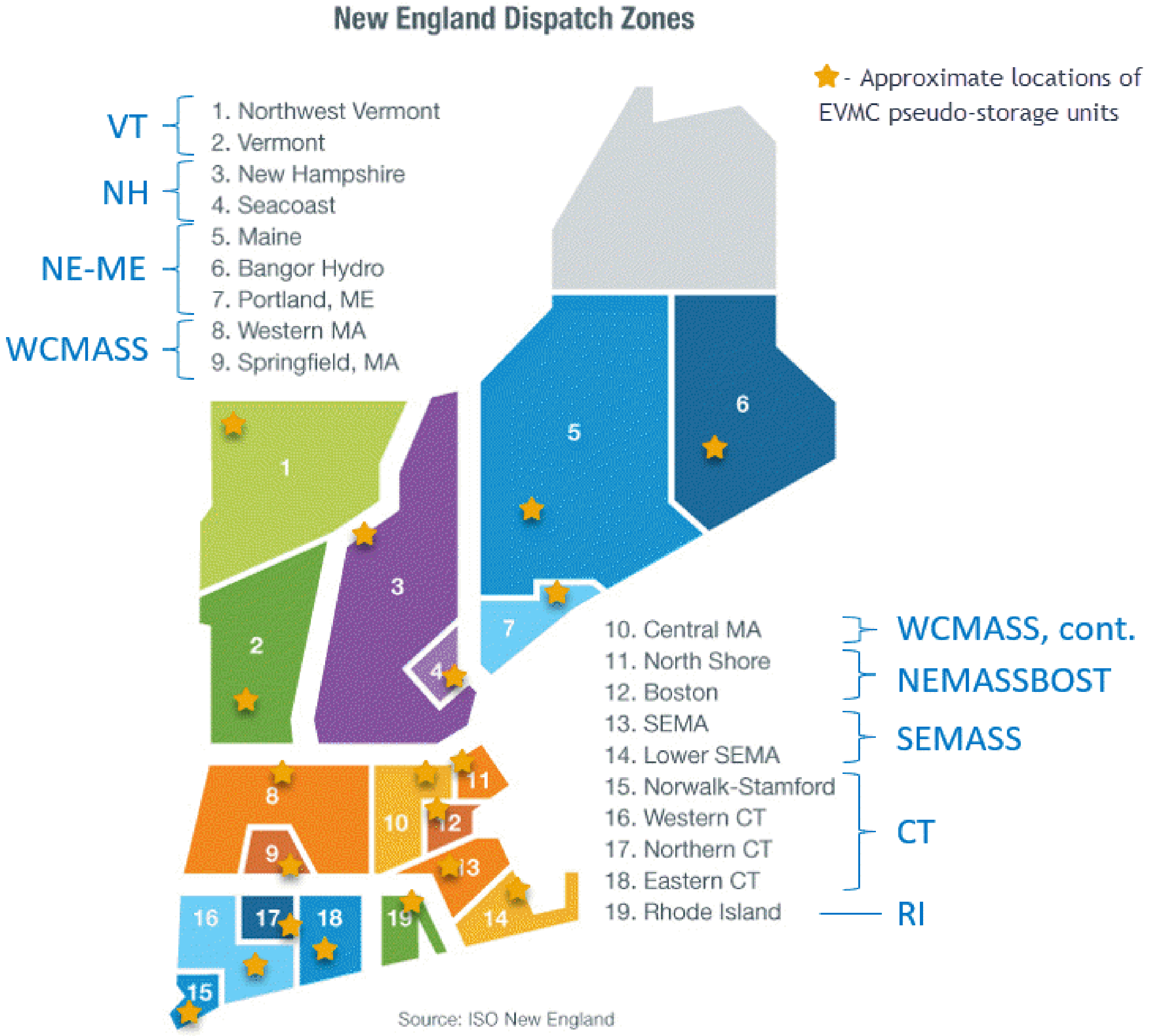
As-early-as possible, un-managed charging

As-late-as possible for within-session flexibility

As-late-as possible for within-week flexibility

Analysis Approach
Nodal Production Cost Model with DC Powerflow

- Isolated ISO-NE from the Interconnection Seam Study (SEAMS) 2038 model
- Analyzed resource adequacy and determined that more generation capacity was not needed to support additional EV load
- Determined that additional transmission capacity was required and checked our revised assumptions with ISO-NE
- Cost assumptions from SEAMS include regionalized 2038 fuel prices from the 2017 AEO and $45/metric ton CO_2 (emissions costs are included in the dispatch objective), **all in 2016$**
- Un-managed EV load and realizations of EVMC in the real-time (RT) model are represented regionally and distributed to nodes with load participation factors
- EVMC DLC is modeled in the day-ahead (DA) unit commitment (UC) model as pseudo-storages, one per dispatch zone
- The DA model with un-managed EV charging is used to create an 8,760-hour RTP signal; Two TOU rates are constructed to mimic the RTP: TOU-1-2 and TOU-4-4



Aggregation: Inner and Outer Approximations

Sufficient Aggregate Flexibility Model, max Energy (ΔS)

⋮

Sufficient Aggregate Flexibility Model, max Power (ΔP)

$\subseteq$

Sum of Individual Device Shiftability ($\sum_k \Delta S_k , \sum_k \Delta P_k$)

$\subseteq$

Necessary Aggregate Flexibility Model ($\Delta S, \Delta P$)

Outer Approximation *of aggregate shiftability sums individual power and energy bounds*

Inner Approximations *are provably decomposable, conservative estimates that can be tuned to favor higher power or higher energy capacity (or something in between)*

Concept described in, e.g., Hao et al. (2013)

Aggregation: Inner, Outer, and Scaled Outer Approximations

***Outer Approximation** is typically an infeasible overestimate of flexibility*

Sufficient Aggregate Flexibility Model, max Energy (ΔS)

⋮

Sufficient Aggregate Flexibility Model, max Power (ΔP)

$\ll$

Sum of Individual Device Shiftability ($\sum_k \Delta S_k$, $\sum_k \Delta P_k$)

$\subset$

Necessary Aggregate Flexibility Model ($\Delta S, \Delta P$)

Sum of Individual Device Shiftability ($\sum_k \Delta S_k$, $\sum_k \Delta P_k$)

$\approx \begin{matrix} a^* \\ b^* \end{matrix}$

Necessary Aggregate Flexibility Model ($\Delta S, \Delta P$)

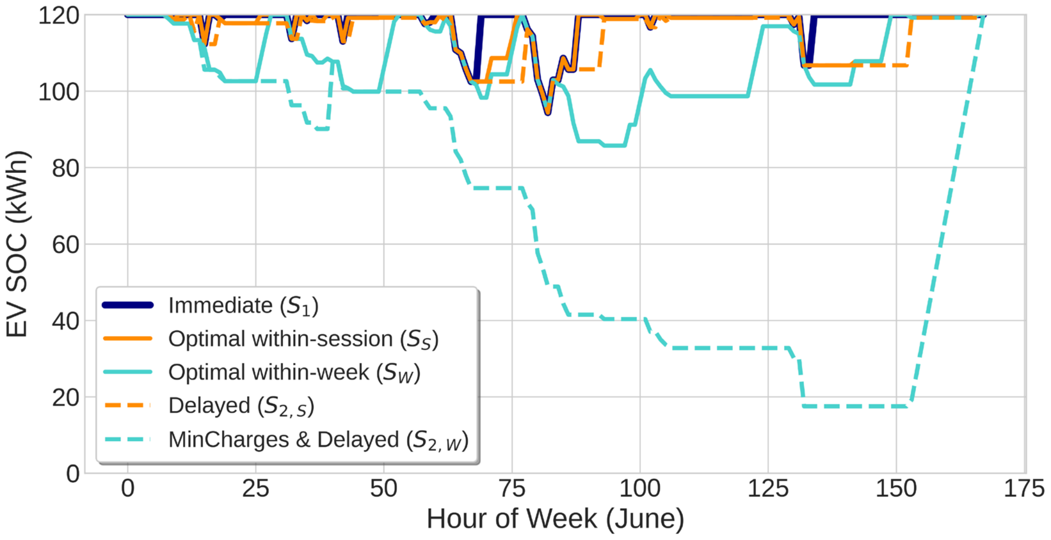
***Inner Approximations** might significantly underestimate resource*

***Scaled Outer Approximation** can yield more accurate representation of resource, but still does not provide a feasibility guarantee*

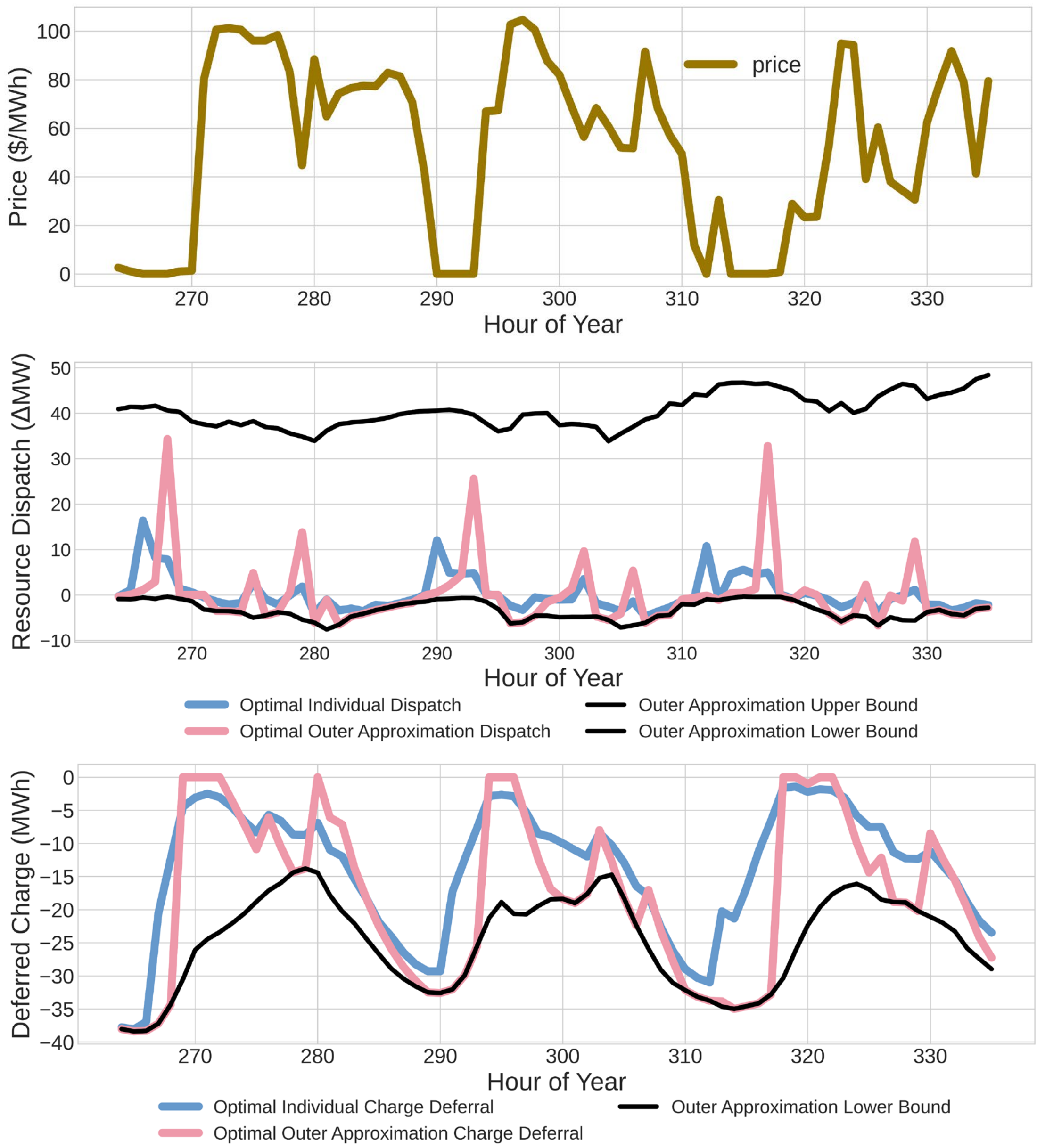
$$0 \leq a, b \leq 1$$

Analysis Approach
Deep dive into aggregation

Dispatch Individual Vehicles within Power and Energy Envelopes

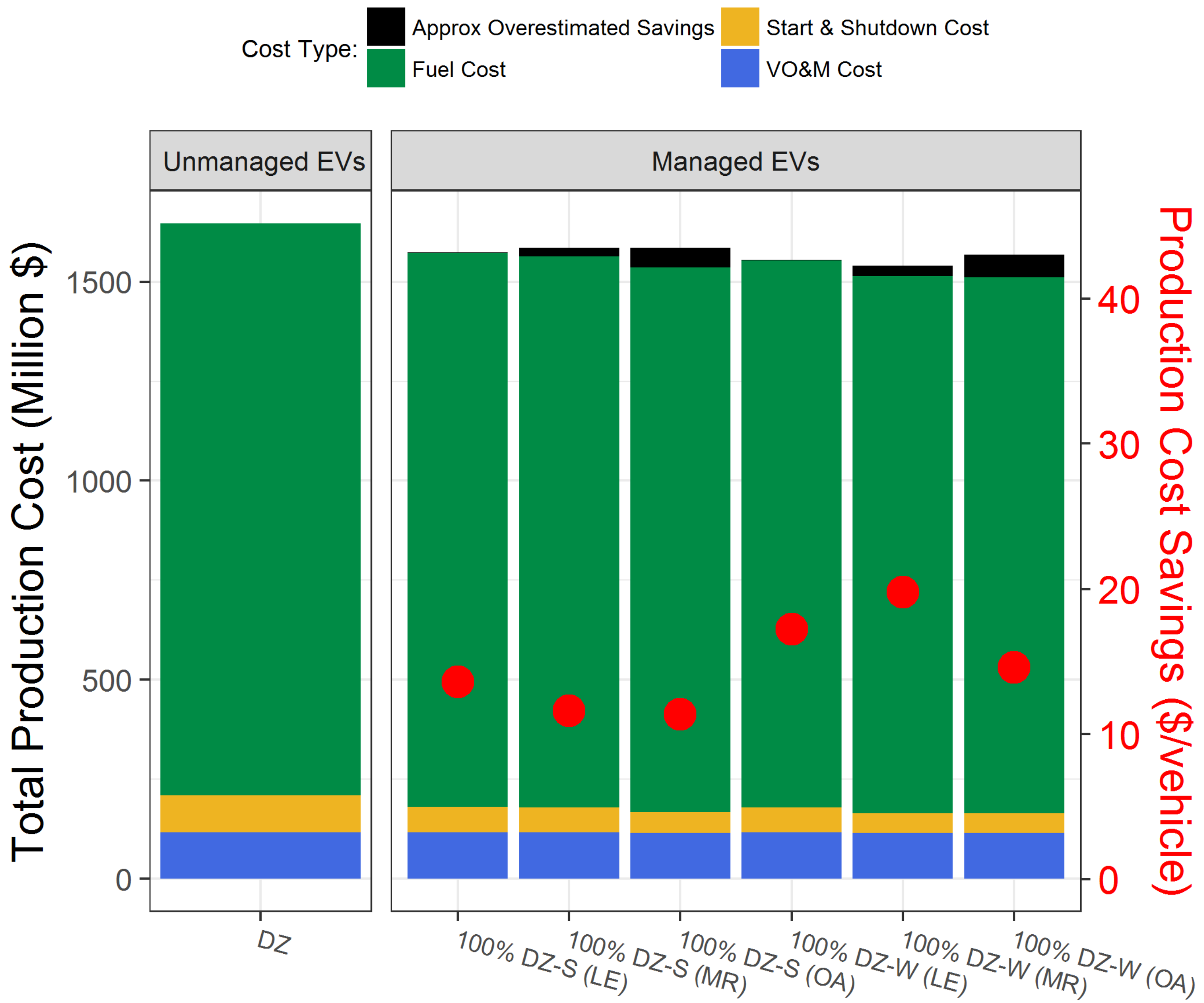


Simply Summing Power and Energy Bounds Overestimates Flexibility



Analysis Approach
Deep dive into aggregation

- Performed disaggregation experiments to
  - Estimate scaling parameters that produce “low error (LE)” or “maximum revenue (MR)”
  - Estimate to what extent each “scaled outer approximation” overpredicts value
- Result of applying overestimated savings results from price-taking experiments to production cost simulations shown here
- The report mostly focuses on DLC-LE results, because the reported performance should be feasible and accurate without scaling
- DLC-LE scales all parameters by 50%; real-world aggregation should be able to achieve more cost savings/revenue (e.g., compare –W (LE) to –W (MR) in this plot)

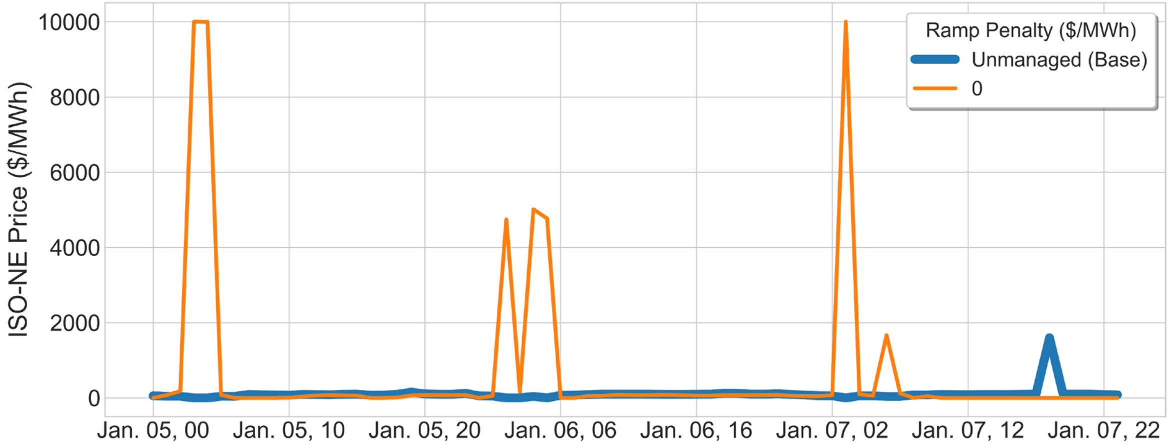


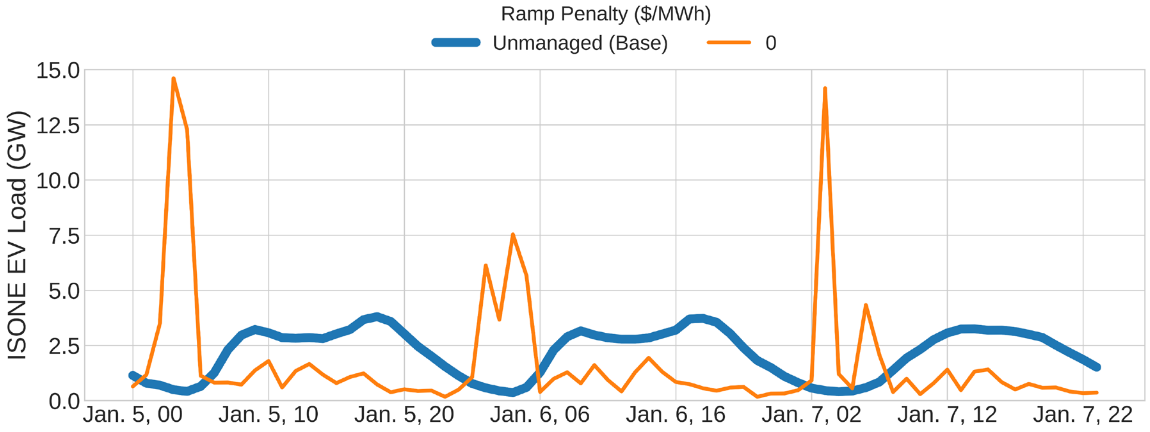
Analysis Approach
Testing the Limits of Price-taking

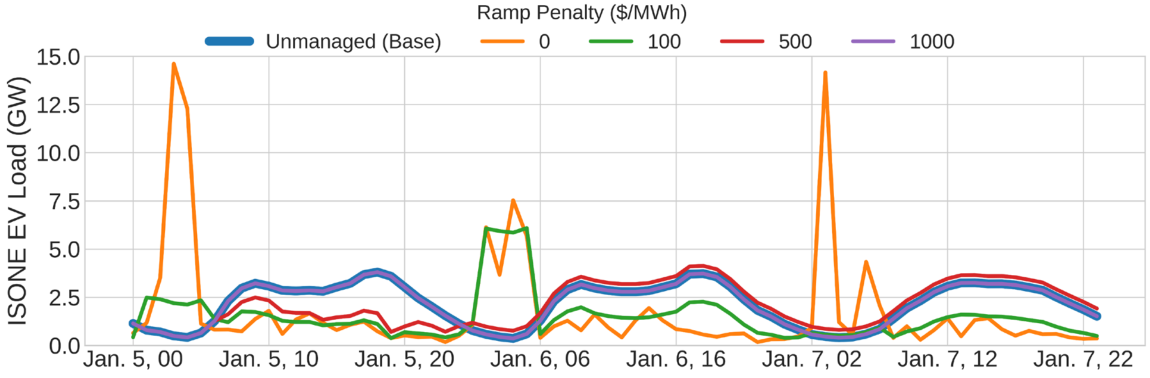
- Price-taking approaches are simpler than DLC, and let vehicles respond directly with their full flexibility
- However, too much flexible EV load chasing the same prices eliminates old, but creates new, price spikes
- Applying a penalty to aggregate ramps mutes response
- Simply muting response is not a sufficient strategy at moderate to high participation rates

Table 7. Optimal Ramp Penalties for the Price-taking Dispatch Mechanisms that Reduce Production Costs by at Least $1/vehicle-yr. Combinations that do not yield sufficient production cost savings for any value of ramp penalty are indicated with dashes.

Participation (%)	Within-session RTP	Within-session TOU-4-4	Within-session TOU-1-2	Within-week RTP	Within-week TOU-4-4	Within-week TOU-1-2
5	1	10	1	10	10	1
30	100	100	-	-	-	-
60	-	-	-	-	-	-
100	-	-	-	-	-	-

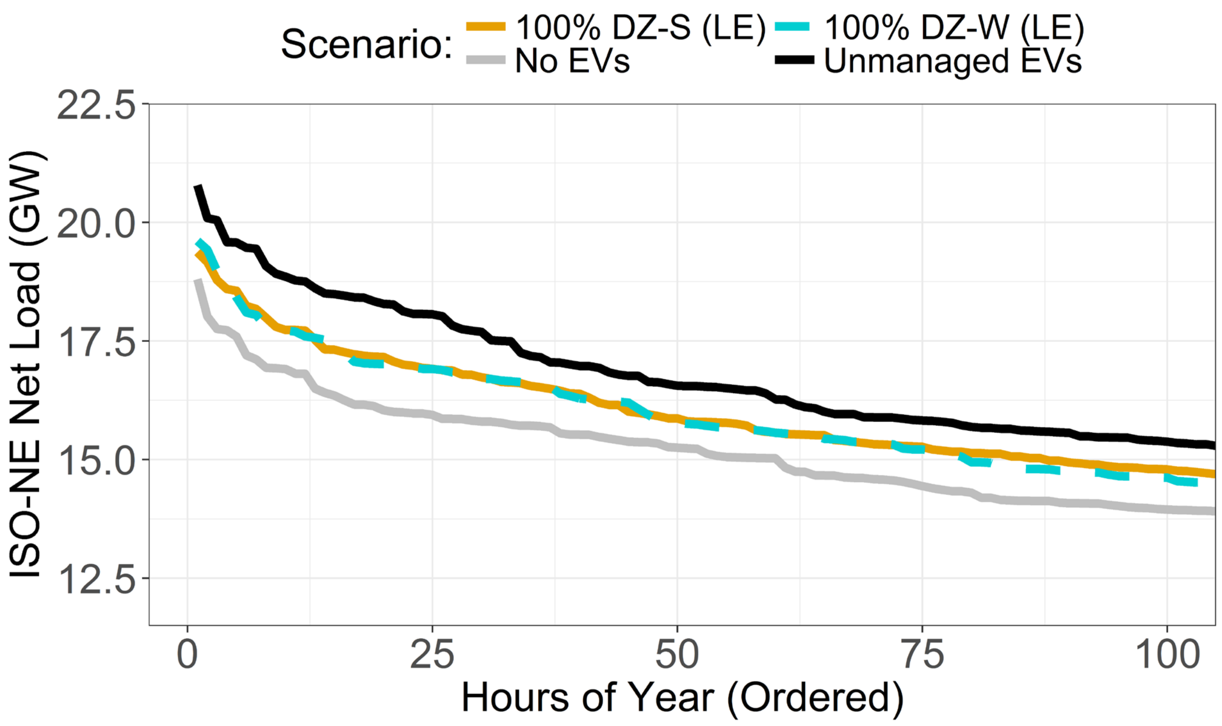






Analysis Approach
Capacity value

- Previous work (Stephen, Hale, and Cowiestoll 2020; Jorgenson et al. 2021) identified average MW reduction of the top 100 net-load hours as a reasonable heuristic for firm capacity
- Capacity value is monetized using the 2021 Cambium data set, specifically 2038 ISO-NE capacity prices under the Mid-case 95% decarbonization by 2035 and by 2050 scenarios
- On average, unmanaged EV load adds 1,620 MW to the top 100 hours of net-load in this system
- DLC-LE EVMC with 100% participation reduces that amount by about half



Time-of-Use (TOU) Rates

Objective:

- Minimize difference in hourly revenue from day-ahead "real-time price (RTP)" and TOU rate *assuming load is fixed*

Parameters:

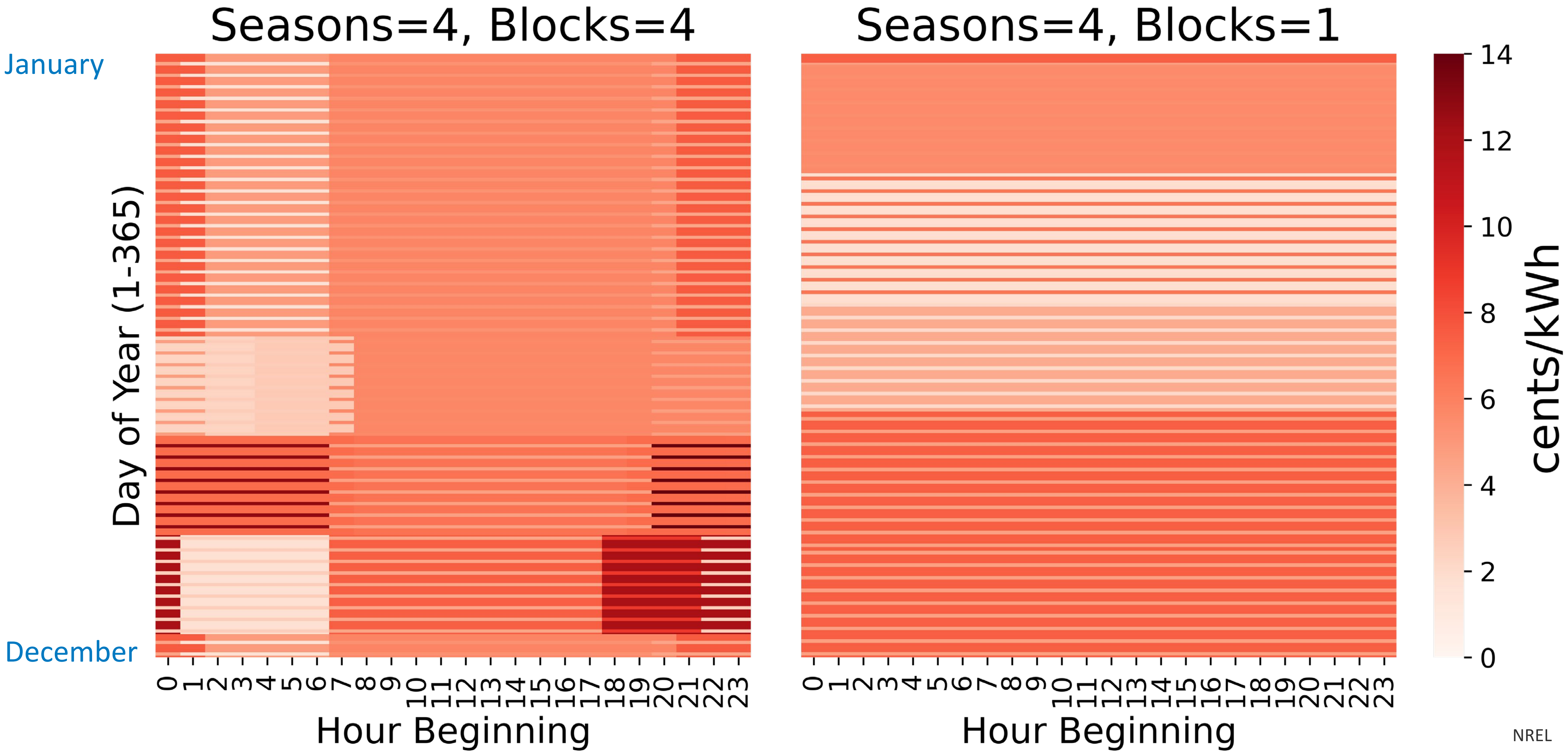
- Number of seasons
- Minimum length of season (days)
- Number of blocks
- Minimum length of blocks (hours)

Methods:

- Optimization problem is a mixed-integer linear program derived by linearizing a non-convex quadratic program—can solve for 1-2 months of data
- **Initial value computed using agglomerative clustering**—can be computed for the whole year and in test problems (1-2 months) results in a better objective value than the "optimal" solution

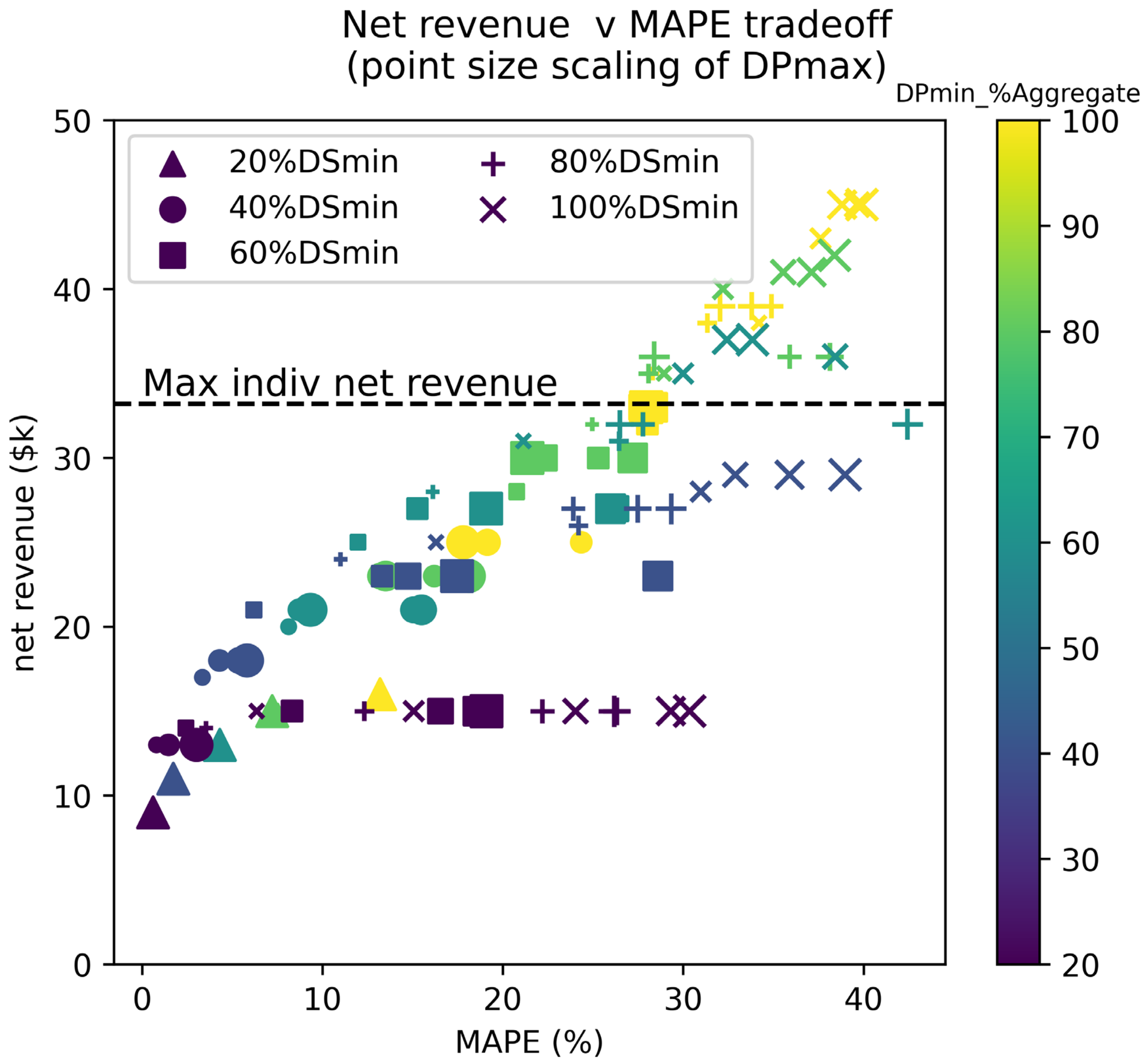
How many season-hour blocks are appropriate for TOU rates?

Feedback?



What is the trade-off between feasibility net-revenue for **within-session** charging delays

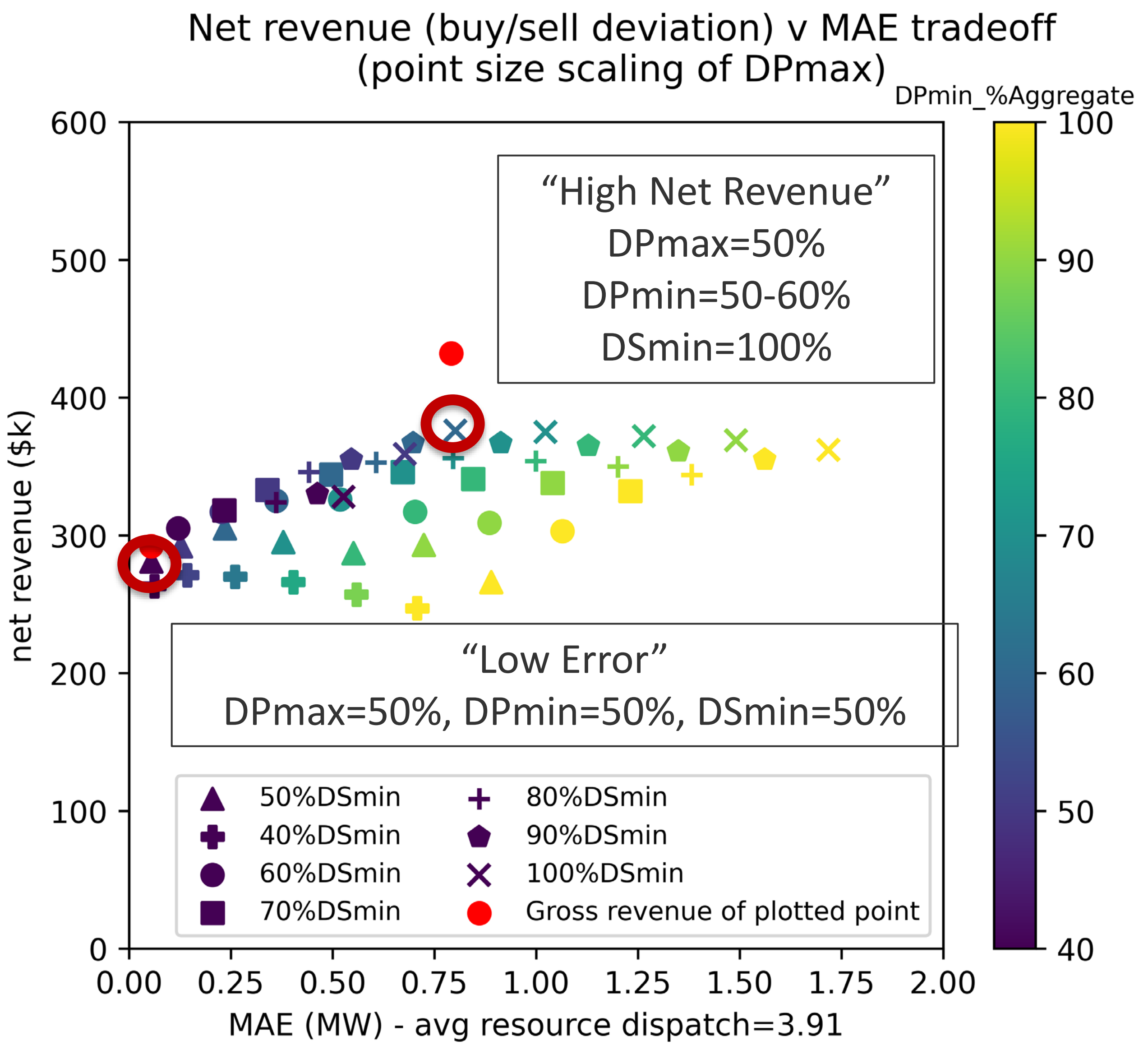
The net revenue shown is for the day-ahead aggregate plan, which is not actually feasible



Testing within-session delay scaled outer approximations

- Larger scaling test on 559 vehicle charging profiles
- DPmax scaling has little effect on revenue
- Run a "low error" and "high net revenue" point in PLEXOS DA based on DPmin and DSmin scaling

Feedback?



Phase 2 – ongoing work

Potential Learnings: Price-responsive can work at higher participation levels?

Legend

1	"Best" dispatch mechanism (highest savings/lowest costs)
4	"Worst" dispatch mechanism (lowest savings/highest costs)

- Depends on management/forecasting approach for price-responsive load
- Results and participation rate ranges are largely illustrative; need to do research!
- **Hypothesis:** Randomization and incorporation of price-responsive EV load in load forecast can make price-responsive dispatch (particularly TOU) preferable to DLC at higher participation levels than in Phase 1 work

Hypotheses:

In Phase 1, price-responsive only preferable at low participation. Fixing TOU44 makes it second-best? (Participation = 0-5%)

In Phase 2, adding randomization, then perfect foresight allow price-responsive TOU to remain preferable at higher participation levels? (Participation = 5-30%? and 30-60%?)

Eventually, resource is large enough that DLC is best, even though aggregation is imperfect? (Participation = 60-100%?)

Dispatch Mechanism	Participation = 0-5%	Participation = 5-30%?	Participation = 30-60%?	Participation = 60-100%?
DLC	4	3	3	1
TOU12	3	1	2	2
TOU44	2	2	1	3
RTP	1	4	4	4