BUREAU OF ENERGY AND
TECHNOLOGY POLICY

November 3, 2022

Active Demand Response

Technical Session 5
CT 2022 Comprehensive Energy Strategy

Session is being recorded

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- Use the chat function to ask questions about presentations or procedures.

Today's Agenda – Morning

Click on an agenda section heading to jump to the relevant slides

Welcome & Introduction	9:00-9:20 am
Public Comment	9:20-9:35 am
Topic Introduction	9:35-10:10 am
Active Demand Response Potential	10:10-10:45 am
Q&A	10:45-11:00 am
Barriers to Active Demand Response	11:00-12:15 pm
Q&A	12:15-12:30 pm
---------------------------------LUNCH------------------------------------	12:30-1:00 pm

BUREAU OF ENERGY AND TECHNOLOGY POLICY

Today's Agenda – Afternoon

Click on an agenda section heading to jump to the relevant slides

Solution Strategies	1:00-2:15 pm
Q&A	2:15-2:30 pm
Public Comment	2:30-2:45 pm
Wrap Up	2:45-3:00 pm

UPCOMING TECHNICAL SESSIONS

Session 6: Alternative Fuels

Friday, November 4, 2022, from 9 a.m. to 5 p.m. ET

Other sessions on Natural Gas Planning & Policies and Carbon Pricing & Low-Carbon Incentives to be announced for November

CO_2

More information on the CES webpage: https://portal.ct.gov/DEEP/Energy/Comprehensive-Energy-Plan/Comprehensive-Energy-Strategy

BUREAU OF ENERGY AND TECHNOLOGY POLICY

Technical Session	Meeting Date(s)	Deadline for Written Comments
4	No meeting held	Nov. 21, 2022, at 5:00 p.m. ET
5	Nov. 3, 2022 9 a.m. - 3 p.m. ET (Today)	Nov. 21, 2022, at 5:00 p.m. ET
6	Nov. 4, 2022 9 a.m. - 5 p.m. ET	Nov. 21, 2022, at 5:00 p.m. ET

Written Comment Opportunities

- **After each technical session DEEP is accepting written comments**
- **Please see the October 19th notice and the October 28th notice for submission instructions and specific questions for which DEEP is seeking responses**
- **More information on the CES web page: https://portal.ct.gov/DEEP/Energy/Comprehensive-Energy-Plan/Comprehensive-Energy-Strategy**

WELCOME & INTRODUCTIONS

Thanks for joining our technical session today!

Comprehensive Energy Strategy Scope & Objectives

- **Scope**: electricity, thermal energy, and fuels for transportation

- **Objectives:**
  - Examine future energy needs in the state and identify opportunities to reduce costs, ensure reliable energy availability, and mitigate public health and environmental impacts of CT's energy use
  - Provide recommendations for legislative and administrative actions to aid in achievement of interrelated environmental, economic, security, and reliability goals

BETP Mission: to manage energy, telecommunication, and broadband policy issues and program deployment with the goal of establishing a clean, economical, equitable, resilient, and reliable energy future for all residents.

DEEP’s Approach to the 2022 CES

5 Key Lenses

- **Climate** – meeting greenhouse gas reduction obligations under Global Warming Solutions Act
- **Equity** – energy decisions that produce equitable outcomes
- **Affordability** – energy decisions that produce affordable outcomes
- **Economic development** – workforce development; economic competitiveness
- **Reliability & Resilience** – energy system improvements and load balancing

Key Strategies

- Build on and/or modify findings and recommendations of 2013 and 2018 CESs
- Consider emerging issues not addressed in a prior CES
- Rely on results from recent, major quantitative studies where appropriate rather than duplicate efforts

3 Key Factors

- The carbon intensity of the electric grid
- Need for emission-reduction solutions that facilitate climate change adaptation, resilience, and energy security
- Fuel price volatility

Tentative CES Development Timeline

- **September 2022** – Technical Sessions 1-3
- **November 2022** – Technical Sessions 5-8
- **November 2022 – January 2023** – Drafting & Public Comment Periods for at least 3 White Papers
  - White papers to be based on topics covered in technical sessions
- **Q1 & Q2 of 2023** – CES Drafting, Public Comment Opportunities, & Listening Sessions

Technical Session Topics

1. Hard-to-Decarbonize End Uses
2. Heat Pump Market Barriers & Strategies
3. Building Thermal Decarbonization Support Strategies
4. Building Thermal Decarbonization – Economic Potential & Technology Targets [written comment opportunity only – no live technical session]
5. Electric Demand Response
6. Alternative Fuels
7. Natural Gas Planning & Policies
8. Carbon Pricing & Low-Carbon Incentives

Why devote a CES technical meeting to active demand response?

Connecticut's Commitments:

Conn. Gen. Stat. 22a-200a (2019)

- Requires economy-wide greenhouse gas emission reductions of 45% by 2030 and 80% by 2050 below 2001 levels

Public Act 22-5 (2022)

- Requires 100% zero emission electricity supplied to in-state electric customers by 2040

Executive Order 21-3

- Directs DEEP to include in the next Comprehensive Energy Strategy strategies to improve the resilience of the state's energy sector (among other things)

Potential Benefits of Active Demand Response

Potential to enhance carbon reductions

Grid safety & reliability

Support energy affordability

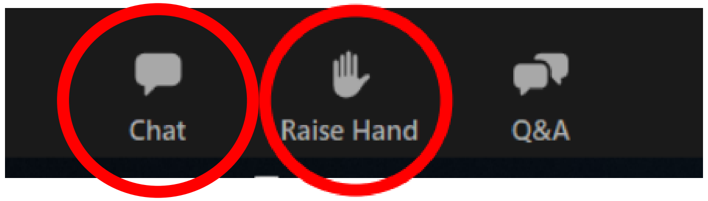
What is Active Demand Response

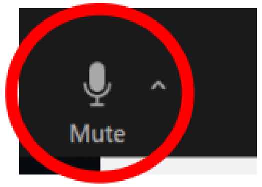
- Reduction, increases, or shifts in electricity consumption by customers in response to economic signals
  - How are economic signals communicated?
  - What is included in economic signals
    - Price arbitrage of existing markets?
    - Reliability signals not included in price?
    - Environmental signals not included in price?

Goal of CES – Active Demand Response

- Common definition of Active Demand Response
  - With Common definition we can distinguish and optimize programs
- Identify and categorize existing programs
- Identify successes and barriers of existing programs
  - What's happening with FERC Order 2222 (and other Orders)
- Identify problems ADR can solve beyond peak shaving
  - Helping intermittent resources?
  - Can it help with winter reliability?
  - Managing increasing electrification
- Identify policy goals that ADR can help achieve
- All the above viewed through the five lenses:
  - Climate
  - Equity
  - Affordability
  - Economic development
  - Reliability & Resilience

Questions and Comments





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If you have a question for a presenter, please drop it into the chat to Jeff Howard. DEEP will pose as many questions as time allows to the speakers. Clarifying questions will be prioritized. Leading questions will not be accepted.

If you would like to make a comment during the public comment periods:

- Please use the “Raise Hand” feature if you would like to speak
- After any interested elected officials have provided their comments, you will be invited to provide your comment in the order the hands were raised
- Please unmute yourself, state your name and affiliation
- Given time limitations, please limit your comment to 2 minutes.
- After your comments, please remember to click the “Mute” button

General Public Comment

Topic Introduction

Paul Gray – Avangrid

Amy Findlay – Eversource

Josh Ryor – CT Public Utilities Regulatory Authority (PURA)

(speaker order may vary)

Click on an agenda section heading to jump to the relevant slides

BUREAU OF ENERGY AND TECHNOLOGY POLICY

Avangrid & Eversource

2022 CES Technical Session #5: Active Demand Response (ADR)

November 3, 2022

Amy Findlay, Eversource
Paul Gray, Avangrid

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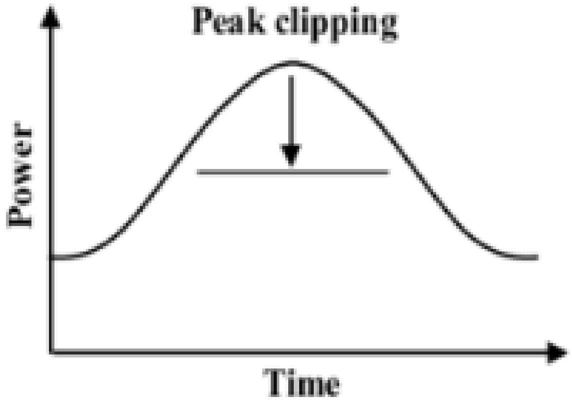
What is ADR?

What do we currently offer?

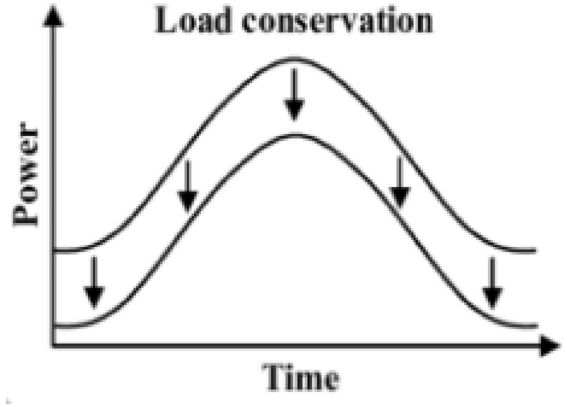
ADR vs. EE

Active demand response

- **Manual Dispatch** – upon receiving dispatch signal, customer manually adjust equipment or initiates automated process
- **Auto Dispatch** – predetermined DR strategy automatically initiated for customer by the EDC

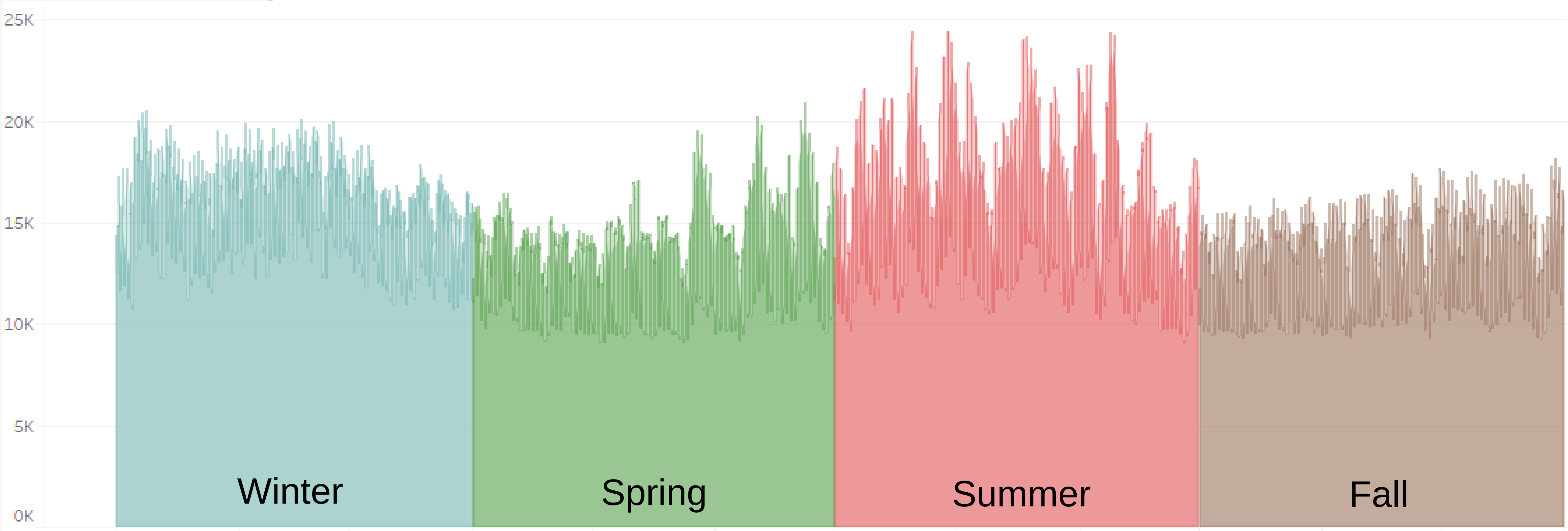


Passive demand resources are designed to save electricity over the life of the measure and cannot change the amount saved in response to a dispatch instruction (ex: energy-efficiency measures)



What is demand response and why do we do it?

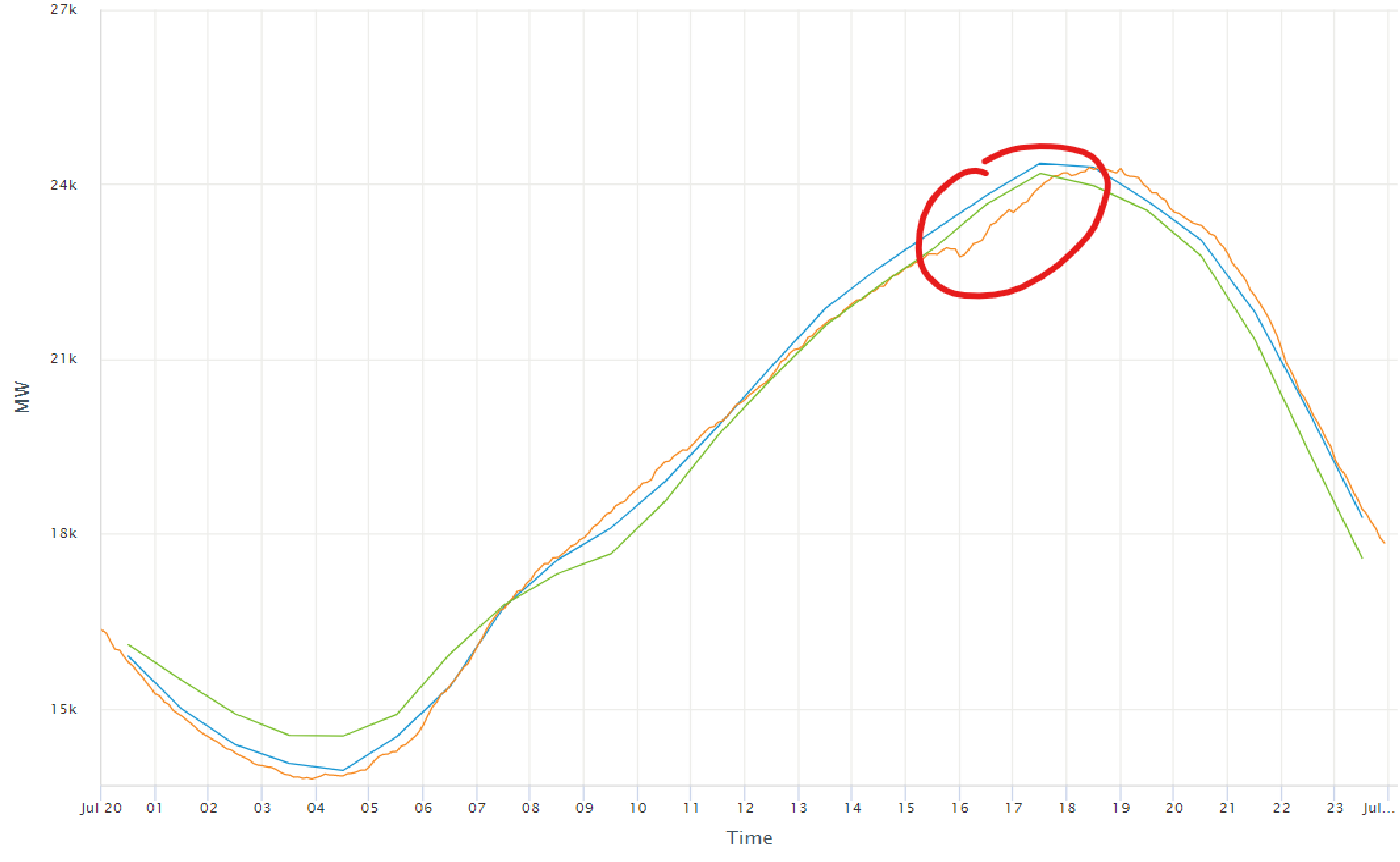
“The top 10% of hours during the year, on average, accounted for 40% of the annual electricity spend…”



The whole grid is sized to meet the peak.

Source: [State of Charge – MA Energy Storage Initiative]()

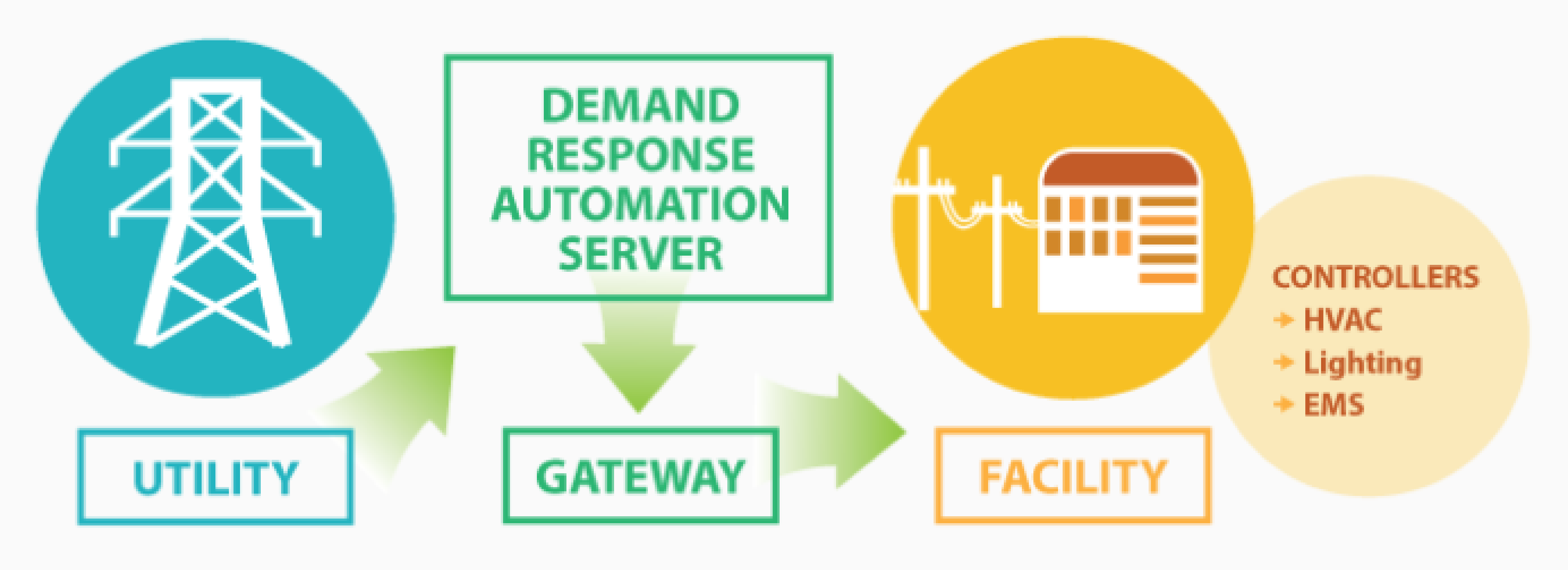
July 20, 2022 – ISO-NE Peak Day



Programs across New England take approximately 300 MW off the grid (~85 MW in CT) during DR events

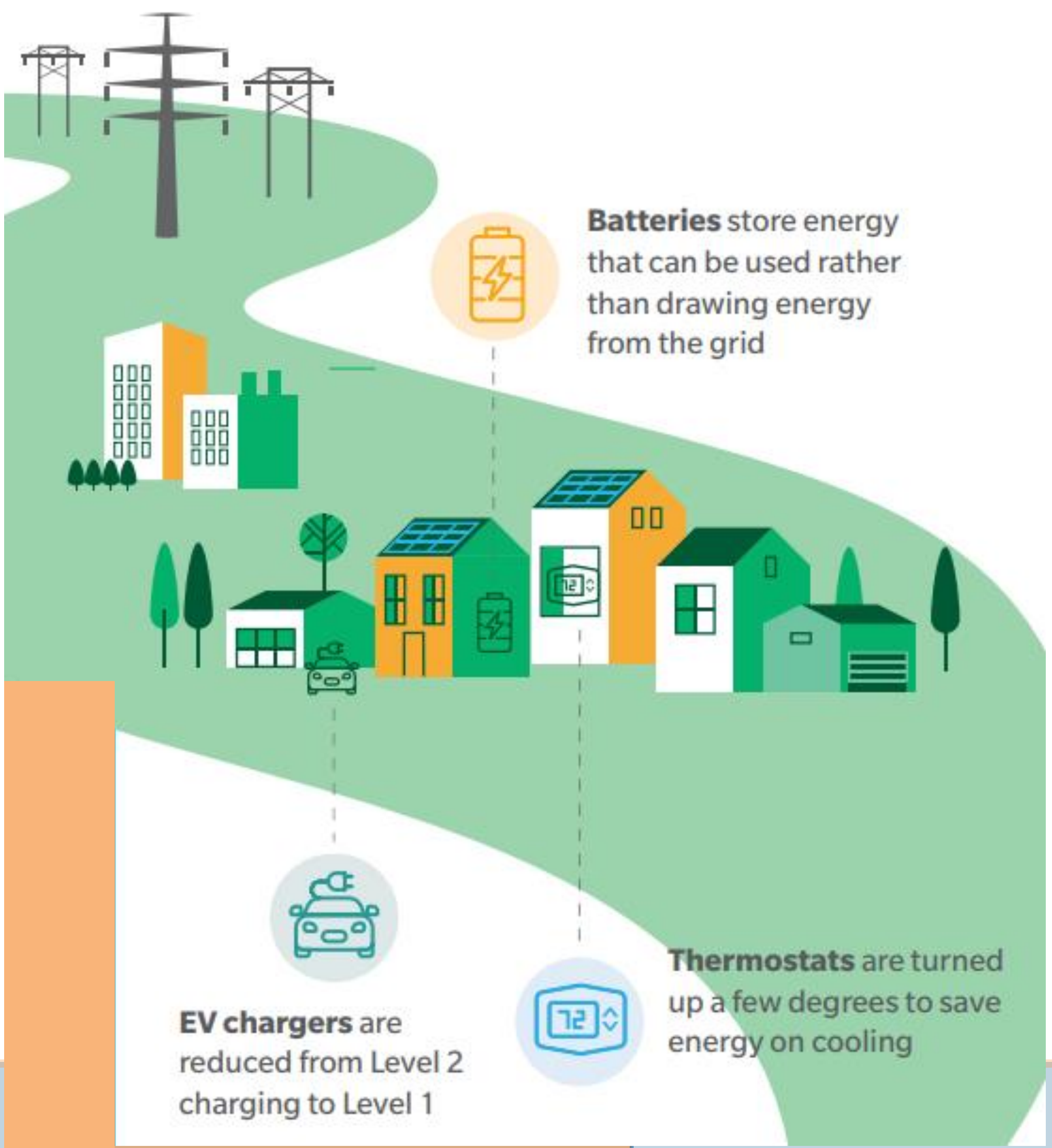
Source: https://www.iso-ne.com/isoexpress/

How do we connect to devices?



Source: https://sites.energycenter.org/demand-response/about

Residential customer experience during a DR event



Residential Programs
Bring-your-own-device (BYOD)

Thermostats (36,000 thermostats, 24 MW)

Around 15 events per season (June – Sept)

Batteries (800 customers, 11 MW)

Daily events in June & July

Majority of new enrollments pursuing Energy Storage Solutions (PURA)

EVs (250 chargers)

Legacy ConnectedSolutions participants will be converted to PURA managed charging in 2023

C&I Programs
Enroll through third parties

Targeted curtailment (136 customers, 90 MW)

Manual temperature control, process changes

Daily storage (2 customers, 0.5 MW)

Automatic control of batteries, thermal storage, industrial freezers

New enrollments pursuing Energy Storage Solutions (PURA)

Auto DR (29 customers, 1 MW)

Automated system to control HVAC, lighting and non-critical processes

PURA

Active Demand Response

Past, Present, & Future

2022 CES Technical Meeting 5
November 3, 2022



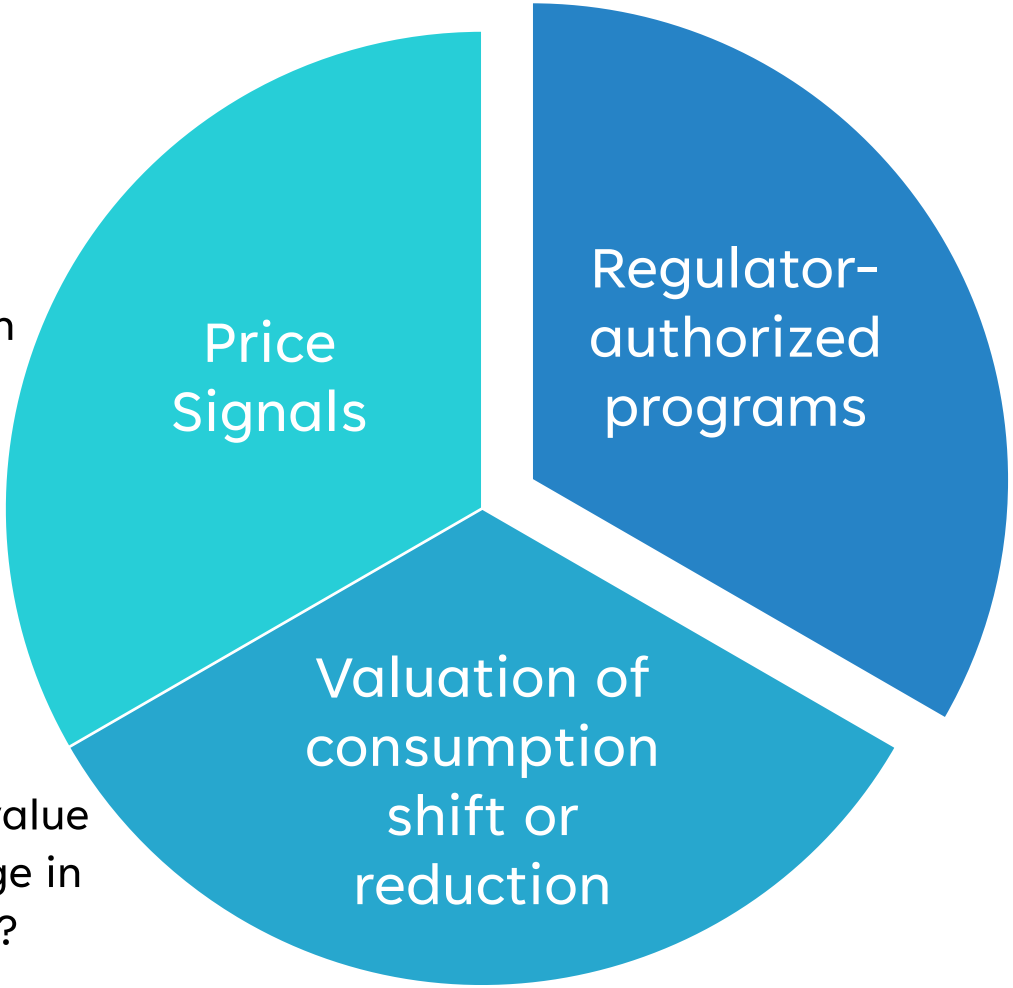


What is Active Demand Response (ADR)?

Standard ADR

Designed to motivate a change in consumption

What is the value of that change in consumption?



Designed to address market gaps or barriers for certain applications or use cases.

The Evolution of ADR

Past

- Price signal sent to customers to achieve peak shaving and mitigate emergency constraint conditions.

Present

- Additional programs designed to avoid distribution system upgrades and balance power system and DERs.

Future

- Wholesale & distribution level markets to monetize more ADR use cases.
- Customers responding to dynamic &/or real-time price signals.

CT's Current ADR Landscape

ADR

Existing TOU Rates[1]	• Standard, simple on-peak/off-peak signals
AMI Deployment[2]	• Increased data granularity and meter read intervals can enable more dynamic, real-time price signals
Energy Storage Solutions[3]	• Strategic charge/discharge in response to day-ahead price signals to reduce system peak (plus increases customer resilience)
EV Managed Charging[3]	• Can optimize the distribution system and maximize grid level benefits of transportation electrification for ratepayers

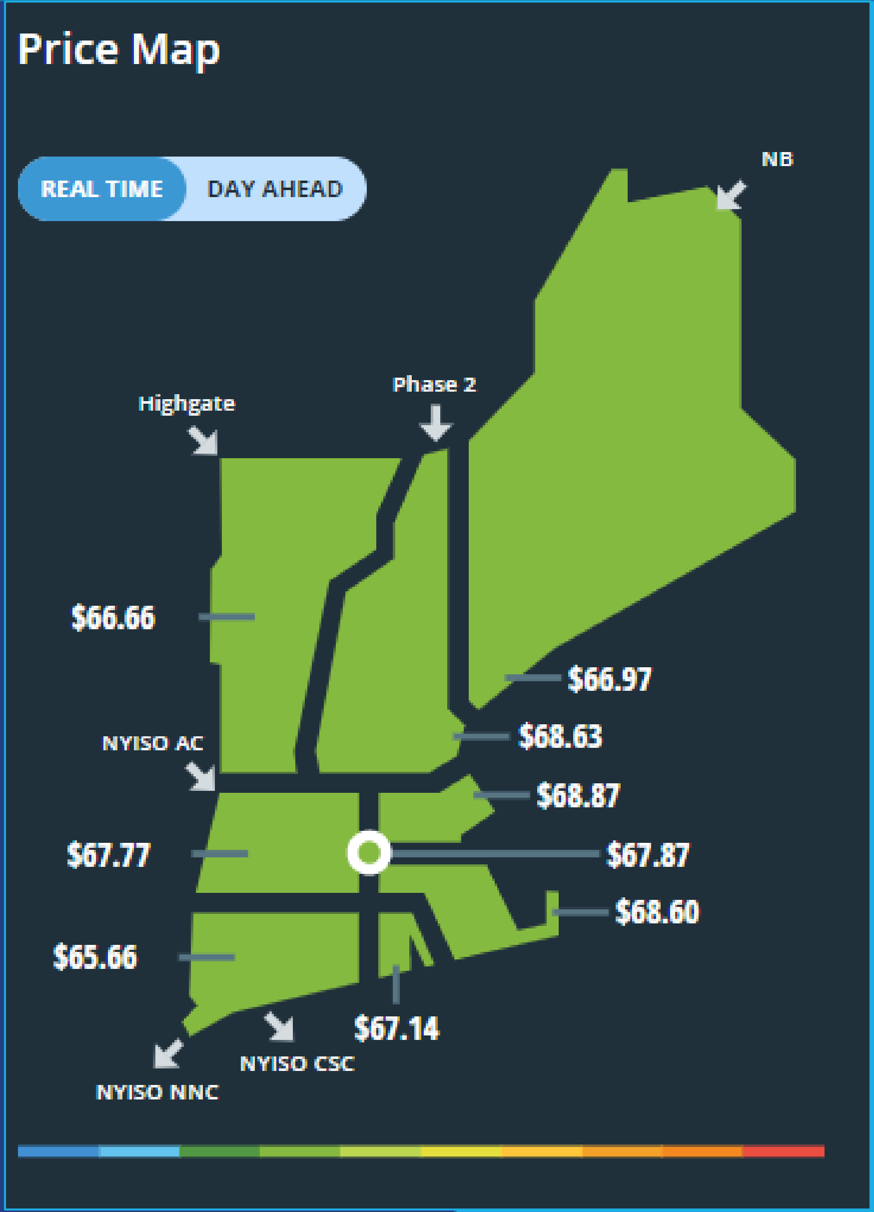
[1]ADR adjacent; [2]ADR enabling; [3]ADR Program

Regulatory Next Steps

PBR	FERC Order 2022	FTM Storage
• Priority Outcome: distribution system utilization • Framework to ensure regulatory policies and programs are aligned and incent value optimization of all grid assets	• FERC Order 2222 authorized aggregated DERs to participate in wholesale markets • Many of the associated processes will run through the electric utilities and be governed by PURA	• Energy Storage Solutions Program currently focus on BTM • FTM storage can perform additional grid functions and provide ratepayer value • Exploring through Docket No. 22-08-05

Potential needs of a market-based future

1. Data transparency
2. Flexible and interoperable systems
3. Dynamic markets to monetize both wholesale and distribution system value of demand reduction
4. Realistic customer price signals
5. Robust customer offerings



Active Demand Response Potential

Vipul Agrawal – Independent Electric System Operator (IESO) Ontario

Paul Gray – Avangrid

Amy Findlay – Eversource

(speaker order may vary)

Click on an agenda section heading to jump to the relevant slides

BUREAU OF ENERGY AND TECHNOLOGY POLICY

IESO - Ontario

NOVEMBER 3, 2022

Capacity Auction

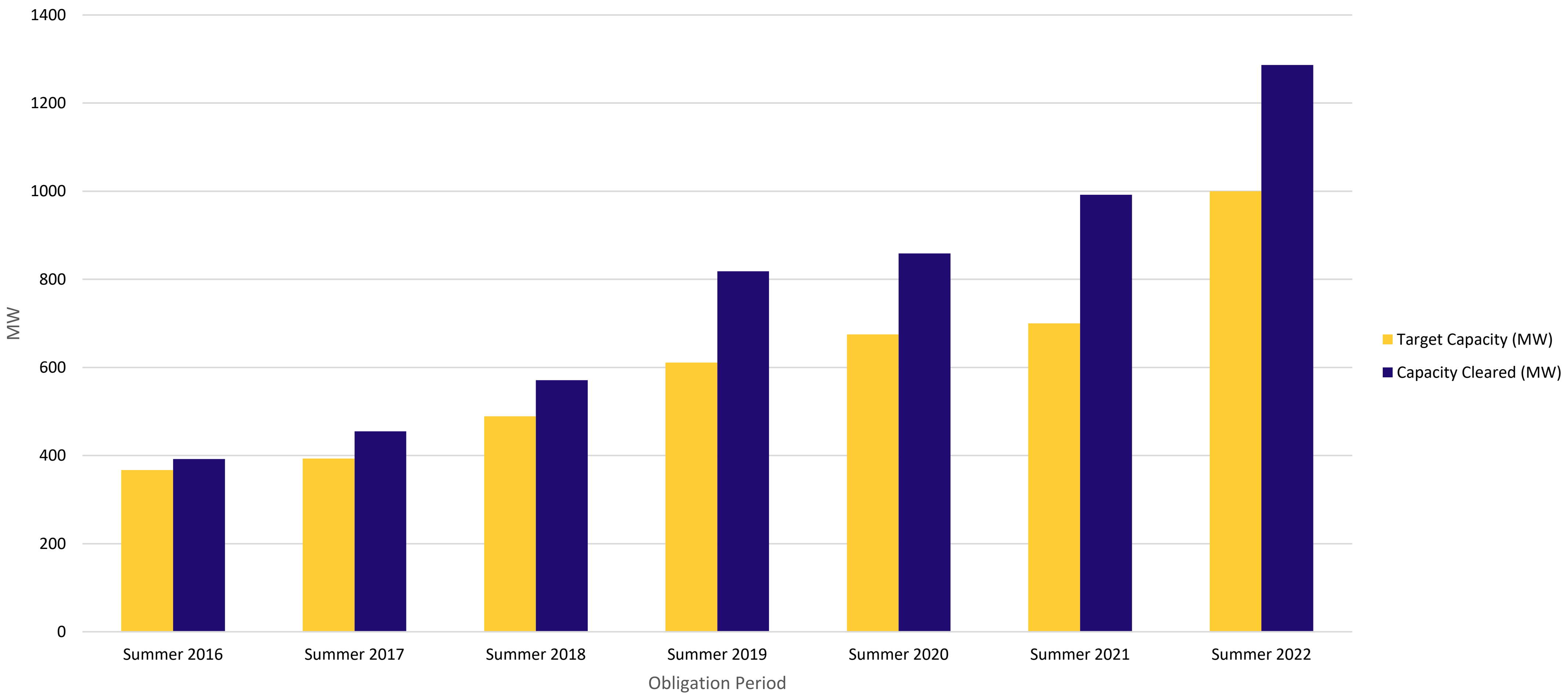
Independent Electricity System Operator - Ontario

ieso
Connecting Today. Powering Tomorrow.

Background

- Ontario procures Demand Response through an annual Capacity Auction
- Capacity Auction serves as a balancing mechanism, within the broader Resource Adequacy framework
- Capacity Auction secures for two 6-month obligation periods –
  - **Summer:** May-October
  - **Winter:** November – April

Historical Comparison: Cleared Capacity (Summer)



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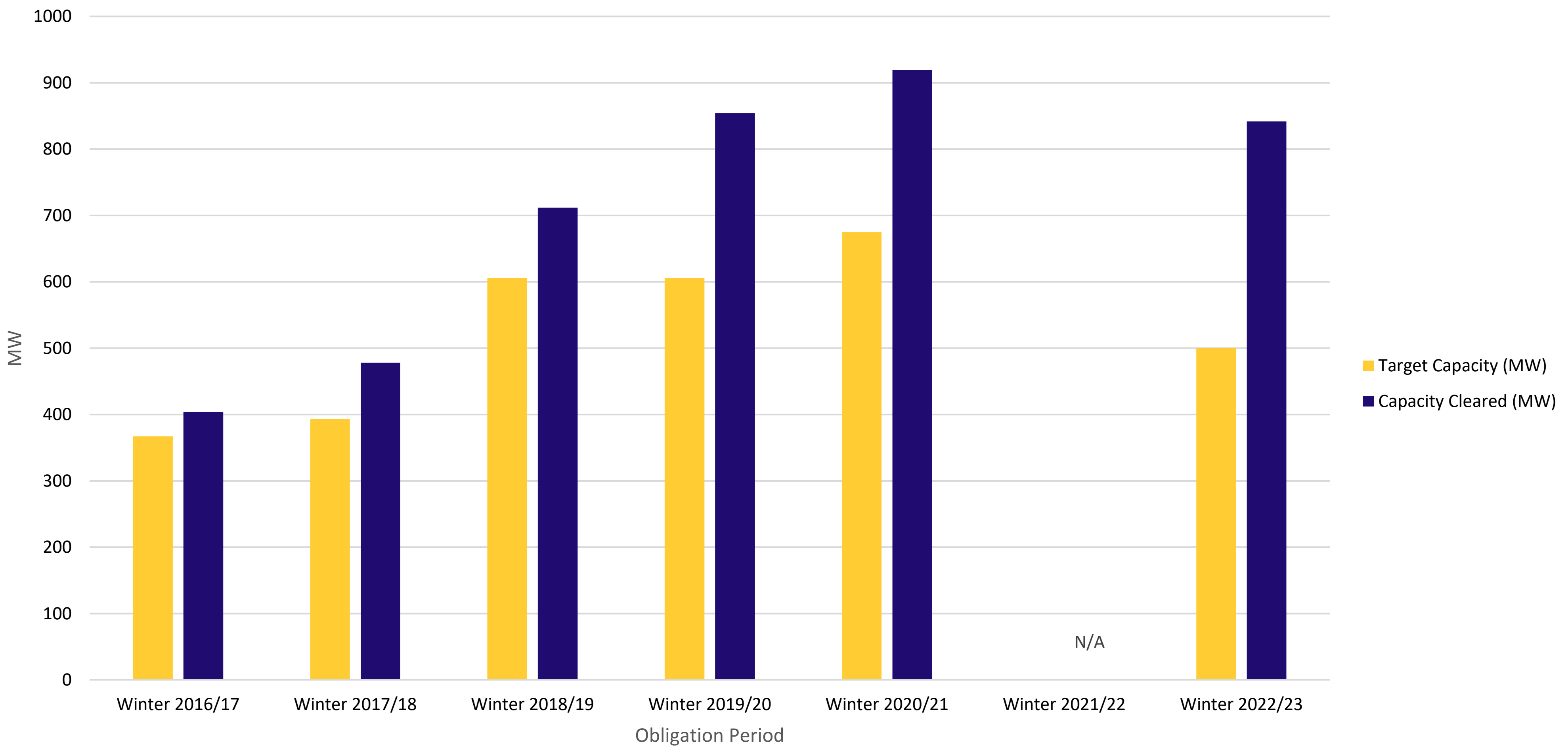
Historical Comparison: Cleared Capacity (Winter)



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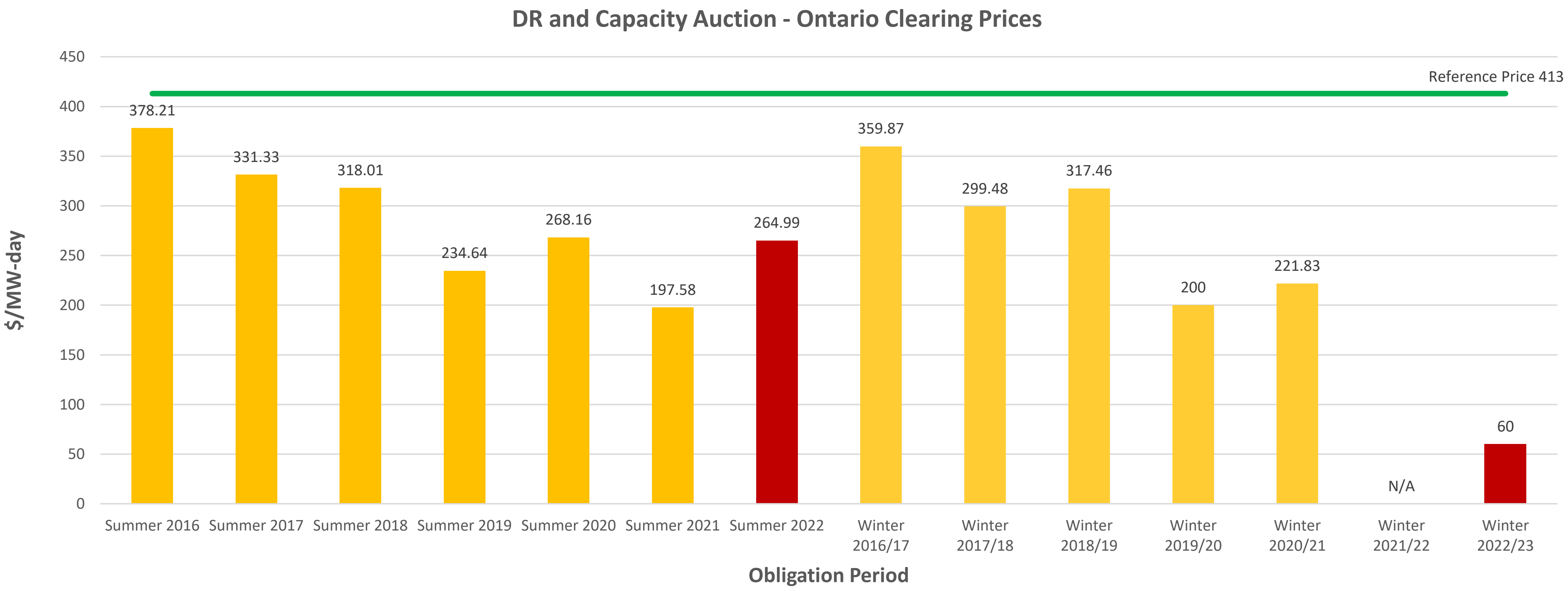
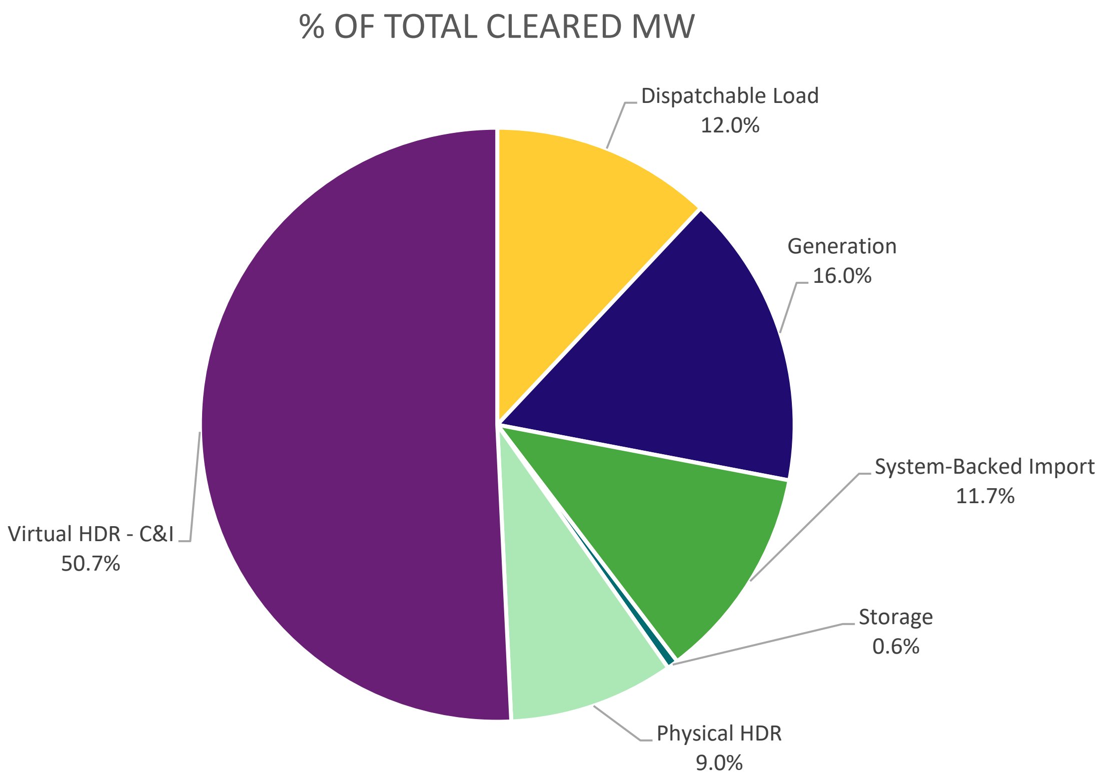
Historical Comparison: System-wide Clearing Price

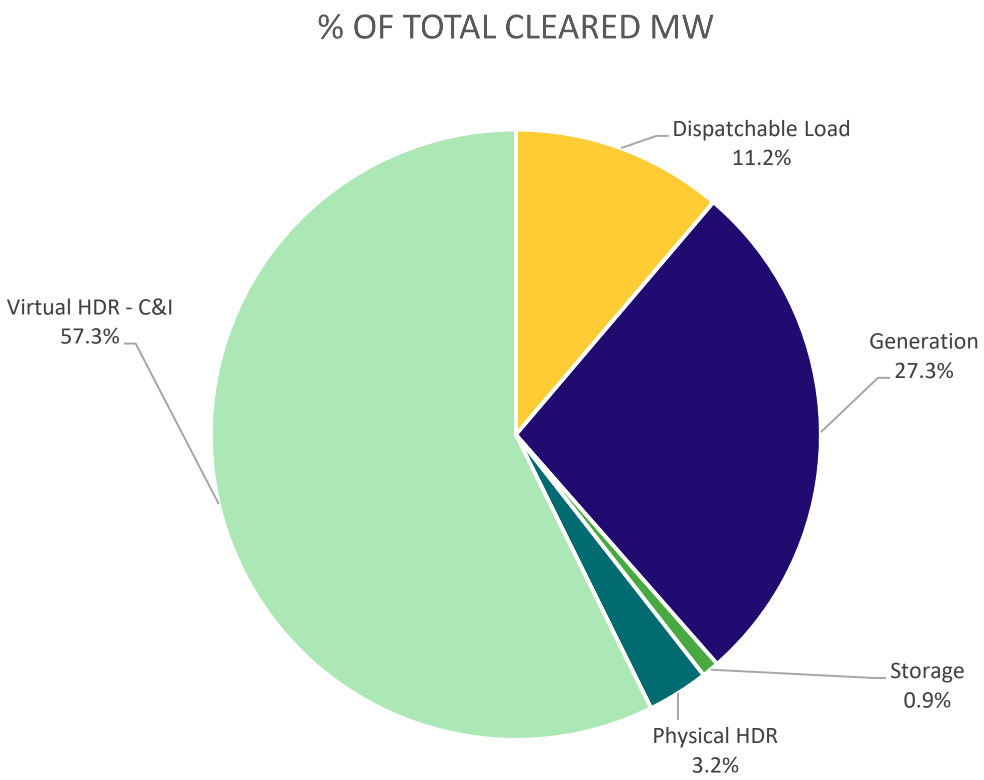


Resource Breakdown

[Summer]



[Winter]



Target Capacity Projections

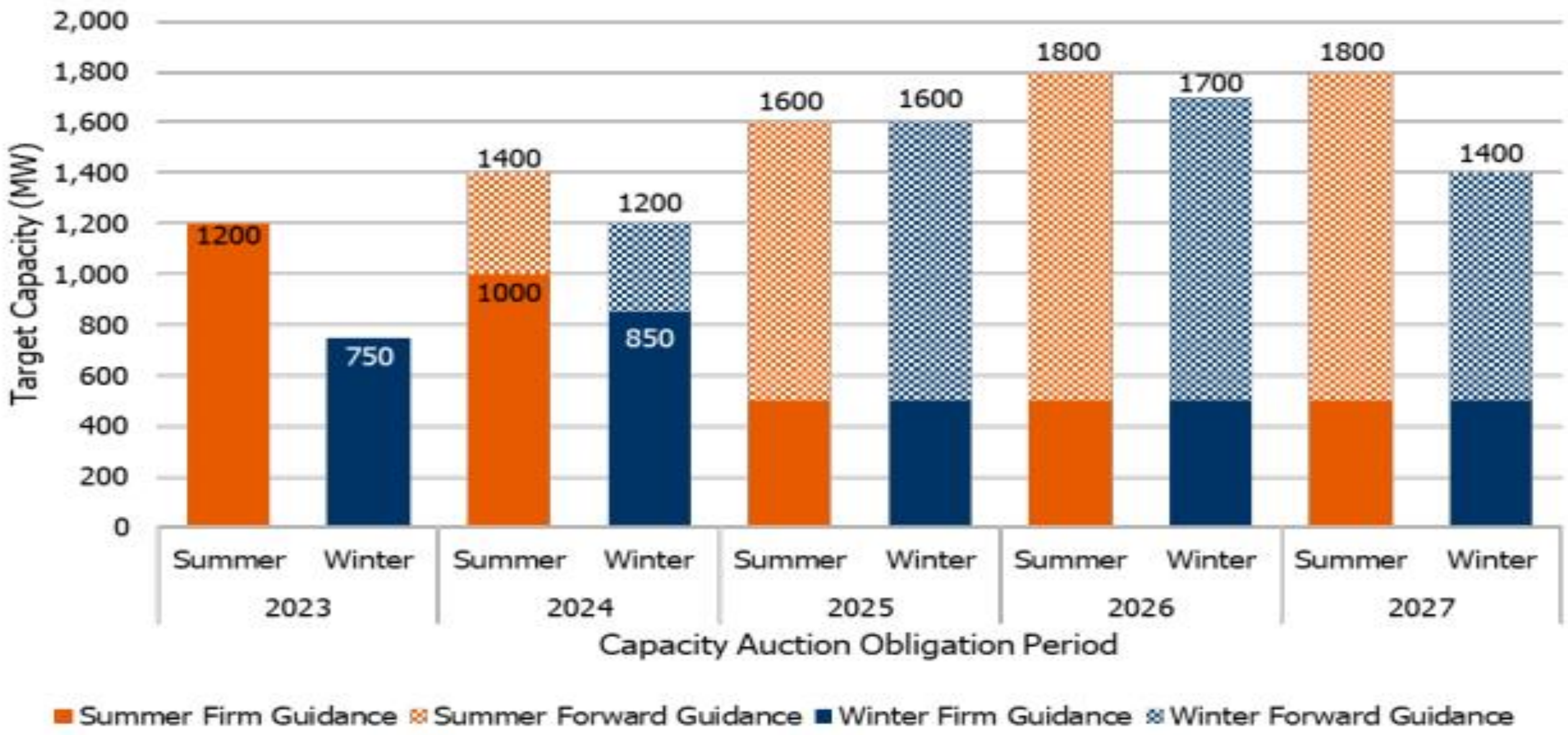


Figure 10 | Capacity Auction Forward Guidance

Source: 2022 Annual Acquisitions Report

Enhancements: Drivers

Ensure Reliability:

Ontario will be emerging from a decade of surplus to a period of acute capacity need starting mid-decade, and capacity secured in the Capacity Auction will be increasingly relied upon for resource adequacy.

- Enhancements to pre-auction qualification and performance assessment framework will collectively ensure that capacity secured in the Auction, from all resource types, is **available and reliable at times of need**

Maintain Competition:

Enabling and expanding participation from different resources helps to ensure continued competitive and cost-effective outcomes

Proposed Auction Enhancements

Enhancement #1: Capacity Qualification

- Adopt transparent methodologies to derive an Unforced Capacity (UCAP) value for all resources while accounting for unique resource participation frameworks and characteristics

Enhancement #2: Performance Assessment Modifications

- Changes to performance assessment obligation and assessment framework to ensure alignment with qualification methodology, to incent availability and reliable performance from acquired capacity resources

Enhancement #3: Expand Participation

- Increase competition and cost effectiveness through enabling participation from generator-backed capacity imports

Qualified Capacity (QC)

UCAP reflects the amount of capacity a resource can be expected to provide during peak hours by accounting for historic availability and/or forced outages

- Aims to equalize the contribution of each MW across all resource types towards satisfying resource adequacy needs
- Methodologies provide for fairness while accounting for the characteristics of different resource types
- Work with performance assessments to incent resources to maximize availability and be reliable at times of need.

Performance Assessment Enhancements

Consistent Capacity Tests

- **Assess to Capability (ICAP)**
  All resources will be assessed to their actual capability (or cleared ICAP) when tested
- **Revised Performance Thresholds**
  For HDR, reduce the performance threshold from 20% to 10% beginning with the December 2022 Auction; allow a 5% threshold for all other resources
- **Capacity Test Scheduling**
  All resources will be required to successfully schedule their resource to demonstrate its ICAP/cleared ICAP capability within an IESO-determined 5-day testing window

Performance Assessment Enhancements

Improve Performance

- **Future De-rates based on performance**

  If a resource fails a capacity test, in addition to settlement charges, their UCAP value in the subsequent auction will be de-rated through the application of a Performance Adjustment Factor (PAF)

- **Dispatch Testing**

  IESO will continue to have the discretion to test resources by scheduling them in the energy market to verify their ability to comply with dispatch based on submitted bids and offers.

Thank You

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ADR Potential

November 3, 2022

Amy Findlay, Eversource
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ADR Potential

Reach customers who have eligible devices but have not enrolled

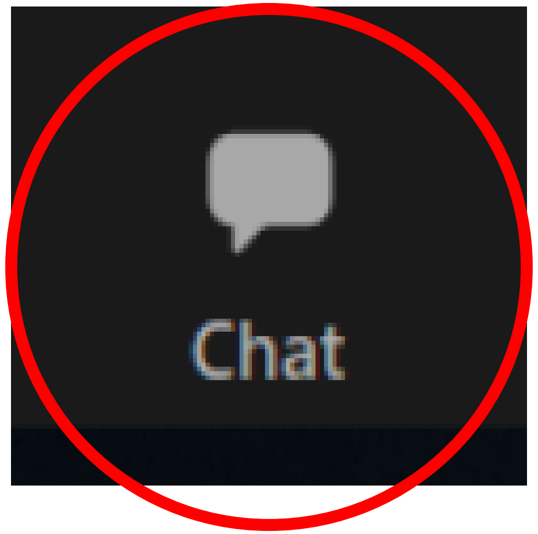
Encourage manufacturers to enable device connectivity and pursue integrations to support utility programs

Possible opportunity with smaller C&I customers who may not be participating through third parties

Improved efficiency standards limit impact of DR

ADR Potential

Questions



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Barriers to Active Demand Response

Caitlin Marquis – Advanced Energy Economy

Nancy Chafetz – CPower

Amy Findlay & Paul Gray – Eversource & Avangrid

Maria Belenky – OhmConnect

(speaker order may vary)

Click on an agenda section heading to jump to the relevant slides

BUREAU OF ENERGY AND TECHNOLOGY POLICY

Advanced Energy Economy (AEE)

ACTIVE DEMAND RESPONSE: BARRIERS TO PARTICIPATION

CT DEEP Technical Session Nov. 3, 2022

Caitlin Marquis, Advanced Energy Economy

About AEE

- Advanced Energy Economy (AEE) is a national association of businesses that are making the energy we use secure, clean, and affordable. We work to accelerate the move to 100% clean energy and electrified transportation in the U.S.
- Advanced energy encompasses a broad range of products and services that constitute the best available technologies for meeting energy needs today and tomorrow. These include energy efficiency, demand response, energy storage, solar, wind, hydro, nuclear, electric vehicles, biofuels and smart grid.
- AEE represents more than 100 companies in the $238 billion U.S. advanced energy industry, which employs 3.2 million U.S. workers.

Active Demand Response: Context

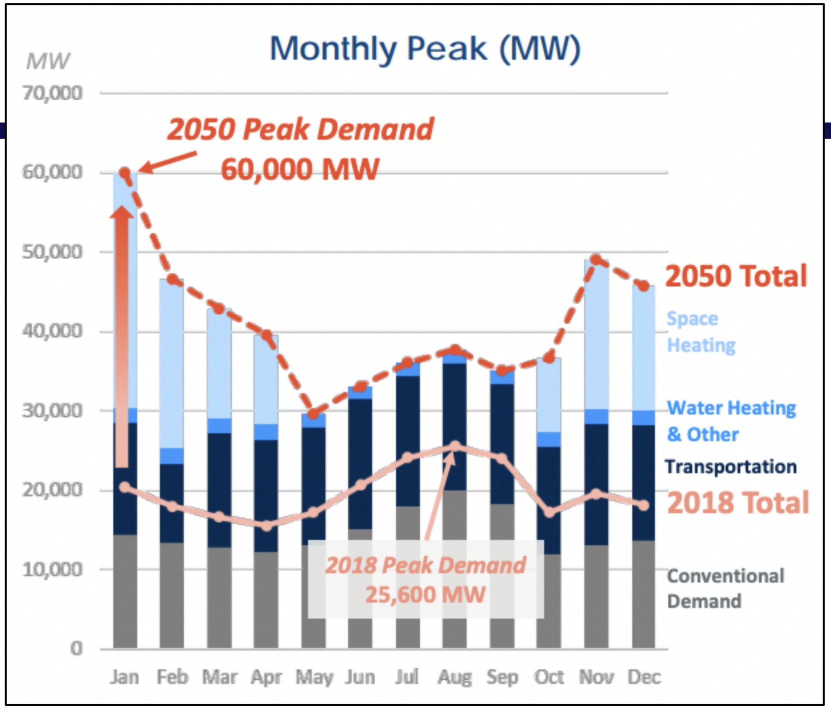
- Demand response provides **cost and reliability** benefits to **all customers**
- Demand Response in New England has worked, but **only for certain use cases**
  - Select commercial and industrial customers that respond to infrequent events, e.g., by turning off unessential equipment or pre-cooling
- **DR capabilities have evolved** since ISO-NE DR model was developed in 2011
  - Proliferation of technologies capable of providing demand response (e.g., battery storage, solar+storage, EVs, smart thermostats, smart water heaters, heat pumps)
  - Affordability and accessibility of these technologies, especially for residential customers
  - Ability to respond more frequently and rapidly with automated and responsive technologies



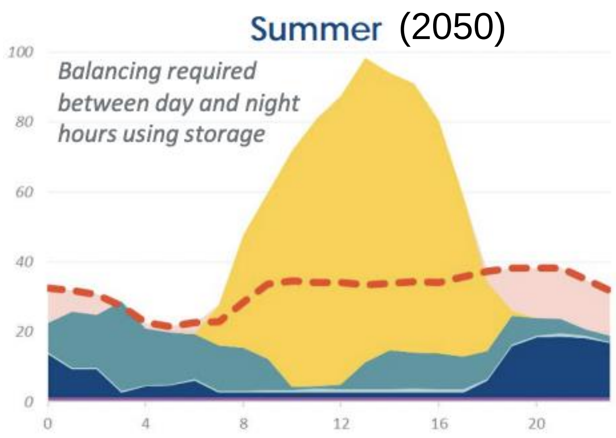

Images credit: MassCEC

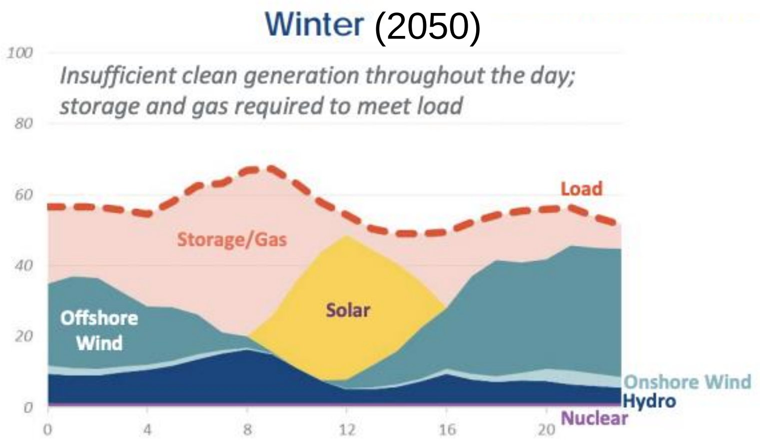
Active Demand Response: Needs

- Meanwhile, the need for DR—particularly active DR—has **grown and evolved**
  - Electrification of buildings and transportation will increase the importance of load flexibility
  - Growth in variable renewable generation necessitates building a more responsive system
  - Persistent winter reliability challenges require consideration of both supply and demand solutions



Market rules have not evolved alongside these shifts in technology, price, consumer interest, and system needs





Graphs: https://www.brattle.com/wp-content/uploads/2021/05/17233_achieving_80_percent_ghg_reduction_in_new_england_by_20150_september_2019.pdf

Current barriers in ISO-NE DR participation model

- Historical baseline methodology works well for infrequently dispatched resources, but not for more responsive technologies that can be deployed frequently
  - Baseline is set based on historical data within a set time period
  - For frequently dispatched resources, baseline already reflects demand reduction performance
- Lack of Advanced Metering Infrastructure (AMI) in CT and across New England prevents residential and even some C&I customers from enrolling without costly metering upgrades

As a result, most residential use cases and many newer technologies have no opportunities to participate despite technical capability. Addressing these barriers and enabling more DR and DER participation will bring cost and reliability benefits to all customers.

Order No. 2222 presented an opportunity to address barriers to active DR

- **Commission determination:** “we find that existing RTO/ISO market rules are unjust and unreasonable in light of barriers that they present to the participation of distributed energy resource aggregations in the RTO/ISO markets, which reduce competition and fail to ensure just and reasonable rates.”
- **Commission directive:** that “each RTO/ISO… revise its tariff to ensure that its market rules facilitate the participation of distributed energy resource aggregations”
- **Definition of DER:** “any resource located on the distribution system, any subsystem thereof or behind a customer meter. These resources may include, but are not limited to, electric storage resources, distributed generation, demand response, energy efficiency, thermal storage, and electric vehicles and their supply equipment.”

Vision of Successful Order No. 2222 Implementation

Wholesale market participation/compensation *complements* other values and revenue streams that DERs currently access (e.g., customer benefits and retail programs). This means:

- **Customers can deploy DERs more affordably,** because DERs receive compensation for *all* the services they can provide
- **DERs already being deployed add more value to the grid** by offering all the services they are technically capable of providing
- **DERs are deployed more rapidly and more efficiently,** because they are responding to transparent market signals
- **Reliability improves,** because grid operators gain visibility and control as DERs participate in wholesale markets
- **Wholesale competition is enhanced** as DERs participate

ISO-NE failed to meaningfully address barriers to ADR in its compliance filing in response to FERC Order No. 2222

- FERC included DR in its non-exclusive definition of DERs, and allowed RTOs/ISOs to comply either by revising existing participation models or by creating new models
- ISO-NE's compliance filing failed to address the barriers to participation in its current DR participation model, or unlock participation by behind-the-meter DERs through new participation models
  - ISO-NE declined to adopt new baseline methodologies that would better capture performance of new forms of DR, especially frequently dispatched resources
  - ISO-NE did not provide workable options for device-level measurement of behind-the-meter DERs (e.g., residential batteries)
- ISO-NE's compliance filing is awaiting a final Order from FERC; ISO requested a decision by Nov. 1, 2022

Other challenges for active demand response

- Lack of consideration as a solution to address winter reliability needs
  - ISO-NE winter programs either exclude or fail to provide a meaningful incentive for DR
  - State-level programs such as ConnectedSolutions are designed to lower utility costs in the summer-peaking ISO-NE capacity market, and therefore do not include winter participation
- Lack of support as a solution to address decarbonization
  - Not eligible for incentive payments under current state programs
  - Appears likely to be excluded from energy-based state or regional procurement mechanisms such as a Forward Clean Energy Market
- Need for capacity market reform
  - FCM payments are critical to the viability of DR; current oversupply in capacity market has led to low prices that are likely to persist
  - Impact of ISO-NE's current effort to overhaul capacity accreditation TBD
  - Other reforms, e.g., addressing barriers to retirement, may also help

Thank you!

Caitlin Marquis
Managing Director, Advanced Energy Economy
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781.261.6047

CPower

The Bridge to Energy's Future

CPower

Barriers to Demand Response

CT DEEP Technical Meeting – Comprehensive Energy Strategy

Nancy Chafetz, CPower

November 3, 2022

About CPower

- CPower is a leading Demand Response and Distributed Energy Resource (DER) Provider.
- Dedicated to guiding customers toward a cleaner and dependable energy future.
- Over 6 GW of capacity under management across the United States.
- Participates in the ISO-NE market and NE state retail programs with demand response and distributed energy resources

Brief Review – Current State of Demand Response in ISO-NE

- In ISO-NE, the Active Demand Response participation model favors large commercial customers that dispatch infrequently. No significant changes proposed to this model for compliance with Order 2222.
  - Baseline methodology not conducive to customers that curtail frequently
  - Required interval metering is expensive; generally not cost-effective for small customers to install

At the retail level, demand response programs differ between utilities

- Two retail (electricity) DR programs are in place in CT
  - Eversource Connected Solutions
  - UI Automated Demand Response (ADR)
- Connected Solutions provides incentives for load reductions in response to dispatches during the months of June - September
  - Has been effective in reducing annual coincident peak load -> in turn reducing capacity requirements/costs
  - No Connected Solutions program during the winter months.
- UI ADR program allows customers with automated methods for curtailing load to earn incentives
  - Utility curtails the load using automated process, provides customer with 24 hour notice and ability to opt out of events.

Barrier 1 – Baseline Calculation

Baseline Calculation

- Baseline is meant to approximate customer's "normal consumption" absent a demand response event
- Customer's performance is calculated as the difference between their metered load and their baseline.
- Baseline is developed based on historical consumption during a set period of non-event days. For example, for weekday, non-holidays, baseline is average of most recent 10 non-event days in last 30 days (ISO-NE method)
  - If the requisite non-event days are not available (e.g. due to frequent events), event day data is included in the baseline
  - Results in *baseline erosion*

Baseline Calculation - Examples

(Some simplifications have been made to the calculations for illustrative purposes)

EXAMPLE 1: 'Customer A' - curtails infrequently

DR actions could include, among other things:

Shutting off non-essential lighting

Stopping a manufacturing process

Turning down heat/AC

Interval 15:00 – 15:05	Metered Load (kW)	DR Event?
Week 1		
Monday	100	NO
Tuesday	100	NO
Wednesday	100	NO
Thursday	20	YES
Friday	100	NO
Week 2		
Monday	100	NO
Tuesday	100	NO
Wednesday	20	YES
Thursday	20	YES
Friday	100	NO
Week 3		
Monday	20	YES
Tuesday	100	NO
Wednesday	100	NO
Thursday	20	YES
Friday	100	NO
Week 4		
Monday	100	NO
Tuesday	20	YES
Wednesday	100	NO
Thursday	100	NO
Friday	100	NO

CPower

Customer A
Baseline Calculation

Baseline = avg of last 10 non-event days in 30 days (weekday, non-holiday baseline)

Days noted in blue make up baseline

Baseline for this interval equals 100 kW

Interval 15:00 – 15:05	Metered Load (kW)	DR Event?
Week 1		
Monday	100	NO
Tuesday	100	NO
Wednesday	100	NO
Thursday	20	YES
Friday	100	NO
Week 2		
Monday	100	NO
Tuesday	100	NO
Wednesday	20	YES
Thursday	20	YES
Friday	100	NO
Week 3		
Monday	20	YES
Tuesday	100	NO
Wednesday	100	NO
Thursday	20	YES
Friday	100	NO
Week 4		
Monday	100	NO
Tuesday	20	YES
Wednesday	100	NO
Thursday	100	NO
Friday	100	NO

CPower

Customer A (*infrequent* curtailer) - Performance Calculation

- On Day 1 of week 5, Customer A receives a dispatch instruction in Interval 15:00-15:05 and curtails down to 20 kW (from 100 kW).
- Baseline = 100 kW
- Metered Load = 20 kW
- Calculated Load Reduction = 80 kW

✓ *All is good*

EXAMPLE 2: ‘Customer B’ - curtails *frequently*

DR actions could include, among other things:

Discharging a battery

Adjusting their thermostat

Interval 15:00 – 15:05	Metered Load (kW)	DR Event?
Week 1		
Monday	20	YES
Tuesday	20	YES
Wednesday	100	NO
Thursday	20	YES
Friday	100	NO
Week 2		
Monday	20	YES
Tuesday	20	YES
Wednesday	20	YES
Thursday	20	YES
Friday	100	NO
Week 3		
Monday	20	YES
Tuesday	20	YES
Wednesday	100	NO
Thursday	20	YES
Friday	100	NO
Week 4		
Monday	100	NO
Tuesday	20	YES
Wednesday	20	YES
Thursday	20	YES
Friday	20	YES

CPower

Customer B
Baseline Calculation

Baseline = avg of last 10 non-event days in 30 days (weekday, non-holiday baseline)

10 non-event days are not available in this case; most recent event days are included.

Days noted in blue make up baseline

Baseline for this interval equals 68 kW

Interval 15:00 – 15:05	Metered Load (kW)	DR Event?
Week 1		
Monday	20	YES
Tuesday	20	YES
Wednesday	100	NO
Thursday	20	YES
Friday	100	NO
Week 2		
Monday	20	YES
Tuesday	20	YES
Wednesday	20	YES
Thursday	20	YES
Friday	100	NO
Week 3		
Monday	20	YES
Tuesday	20	YES
Wednesday	100	NO
Thursday	20	YES
Friday	100	NO
Week 4		
Monday	100	NO
Tuesday	20	YES
Wednesday	20	YES
Thursday	20	YES
Friday	20	YES

CPower

Customer B (*frequent* curtailer) - Performance Calculation

- On Day 1 of week 5, Customer B receives a dispatch instruction in Interval 15:00-15:05 and curtails down to 20 kW (from 100 kW).
- Baseline = 68 kW
- Metered Load = 20 kW
- Calculated Load Reduction = 48 kW
- Same action as Customer A, but different result

✗ *All is not good*

Barrier 2 – Metering Requirements

Metering Requirements

- Barrier: ISO-NE requires interval metering at Retail Delivery Point (customer meter). This is prohibitively expensive for small customers. Additionally, some utilities do not allow customers to use utility meter data to measure performance in Connected Solutions.
- A real life example: CPower was approached by a building developer who was building a low income apartment building and wanted to see if it would be economic to install batteries in each unit.
- Our conclusion was that it would be cost prohibitive to put an interval meter on each of these units so that they could participate under ISO-NE’s active DR model.
  - Metering at the battery would be much more cost effective; this is allowed under Connected Solutions but not ISO-NE
  - Another solution is to use statistical sampling to measure performance when participating aggregations of many small, similar customers.

Barrier 3 – Lack of Incentives for Winter Load Reductions

Incentives for Winter load reductions are lacking

- In recent winters, energy costs have skyrocketed due to higher fuel prices.
  - Feb 2022 energy costs totaled $1.2 billion (compared to Feb 2019 energy costs of $366 million)
- Concerns about winter energy security continue to grow.
- Participation by Price Responsive Demand in the ISO-NE market has been anemic. In January 2022 it peaked at 13,500 MWh (less than 20 MW on average)
- Connected Solutions provides incentives during the summer only.
- There is untapped DR potential in the winter that could deliver cost savings, emissions reductions, and improved reliability

Connected Solutions should be extended to winter season

- Justification for Connected Solutions program has historically rested heavily on its ability to reduce the annual system peak, and therefore reduce capacity requirements/costs.
- This is not the appropriate metric to measure the benefit of winter load reductions.
- Winter load reductions have little to no effect on capacity requirements (under the current paradigm) but they provide significant benefits:
  - Energy cost savings
  - Emissions reductions
  - Improved reliability
- The cost-benefit test used in evaluating retail programs should be adjusted to incorporate benefits provided by winter DR

One Final Note

No Connected Solutions Program in UI’s CT territory

- While UI does have an ADR program it caters to customers who can provide automated load reductions
- This leaves untapped potential on the table

Summary

Barriers to DR have kept the region from realizing its full potential in this area

- Barriers include: baseline calculation, metering requirements, and lack of a winter incentive for DR
- It will become even more important to address these barriers as the number of behind the meter Distributed Energy Resources (DERs) continues to grow.
- Failing to harness the load flexibility that comes with the proliferation of DERs leaves benefits on the table:
  - Cost savings
  - Reliability benefits
  - Emissions reductions

QUESTIONS?

Avangrid & Eversource

Barriers to ADR

November 3, 2022

Amy Findlay, Eversource
Paul Gray, Avangrid

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EVERSOURCE

UI
An AVANGRID Company

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energize CONNECTICUT

Smart meters can assist with identifying ADR opportunities and marketing

Availability of broadband, namely WiFi, is key

- Installation for SMB thermostats
- Device location for pool pumps, water heaters

Barriers to ADR

OhmConnect

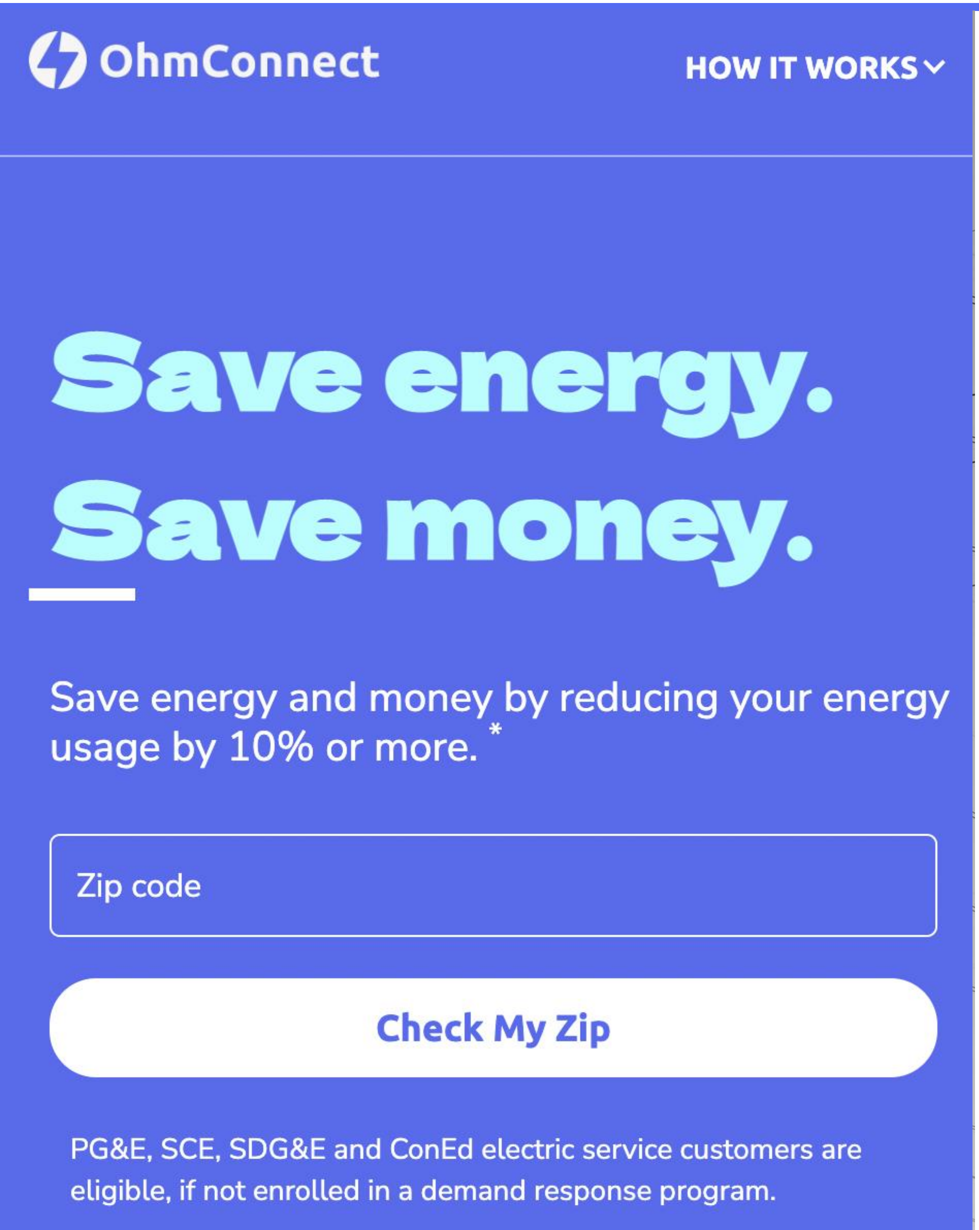
Barriers to ADR: Lessons from CA

November 3, 2022

OhmConnect

What is OhmConnect?

Quick overview of OhmConnect



Residential Demand Response

OhmConnect's 200k+ CA customers save energy during hundreds of DR events ("OhmHours") per year

Behavioral & Automated Participation Options

OhmConnect's customers reduce energy behaviorally and by connecting smart devices that are toggled during events

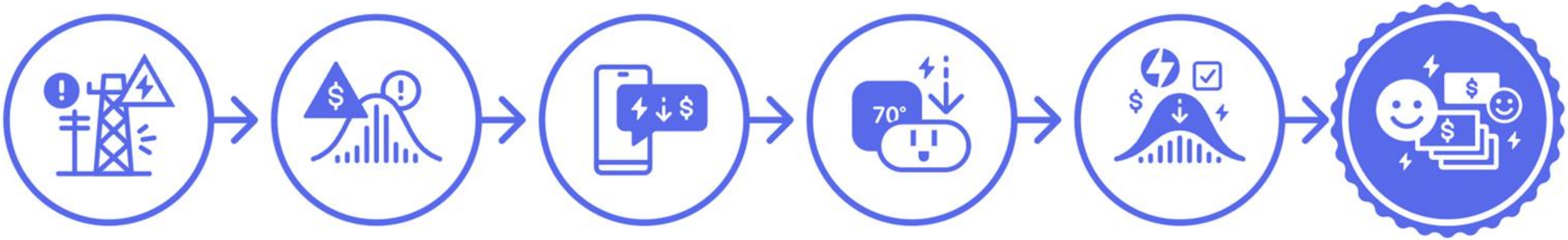
Market Integrated Resource

OhmConnect bids aggregated load drop directly into CAISO's wholesale market & dispatches customers based on market awards

OhmConnect Customer Experience

Our gamified platform rewards users for saving energy during peak times.

OhmConnect aggregates residential customer load drop and bids it into the wholesale energy market. If our bids clear, we notify customers that they will have an event. Customers earn rewards for saving energy.



OhmConnect **Bids into CAISO market**

Bid clears and CAISO **dispatches OhmConnect**

OhmConnect **Alerts Members**

- Email notification
- Text notification

Members **Power Down**

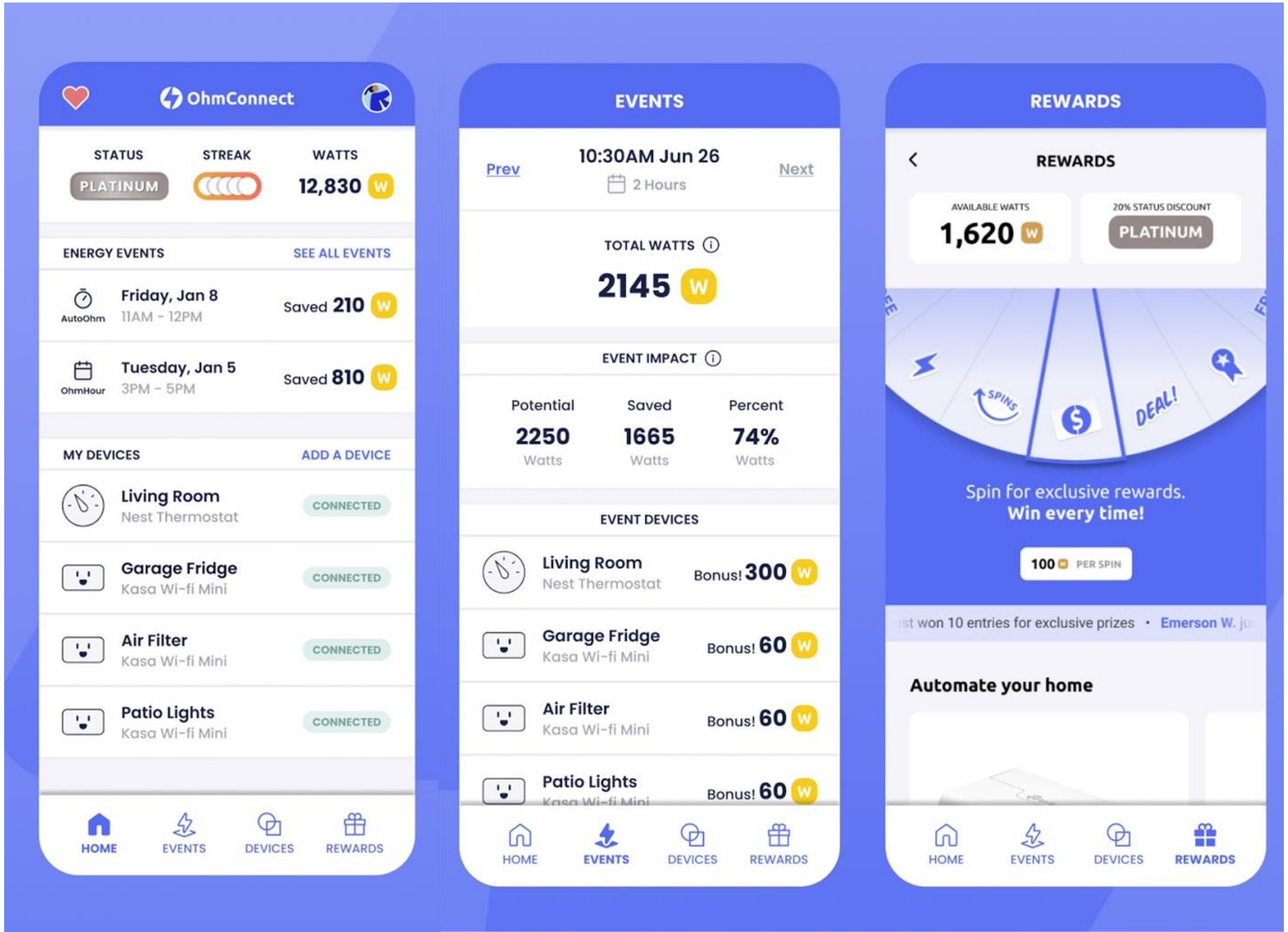
- Behavioral response
- Automated response

Grid Operator Pays for **Unused Power**

OhmConnect **Pays Members**

OhmConnect Customer Experience

Our gamified platform rewards users for saving energy during peak times.



- Customers earn "**Watts**" for 1) reducing their energy use during events, and 2) allowing OhmConnect to control eligible devices
- Continuous and deeper reductions boost customer **status** and **streak**
- Higher **status** and longer **streak** adds value to the earned Watts
- **Watts** can be redeemed for prizes and cash

OhmConnect

Barriers to Demand Response

Primary Challenges to DR Growth in California

01 **Meter data authorization & delivery**

Non-utility DR providers lose customers in the meter data authorization process; data delivery by utilities is inconsistent

02 **Customer choice in DR providers**

Disenrolling from a utility DR program is confusing and slow, restricting customer movement between programs

03 **Level playing field between utility & independent providers**

Preferential rules for utility DR programs makes entering market and competing more difficult

04 **Regulatory certainty**

Stop-start pilot programs and years' long uncertainty around DR capacity valuation makes planning challenging

Meter Data Authorization & Delivery

Data authorization process has improved but many gaps remain

"DR customers shall have the right to provide DR through a service provider of their choice and **Utilities shall support their choice by eliminating barriers to data access**" *(2016 CPUC Decision)*

- Customers must authorize meter data access through their utility
- **The authorization process has improved since 2018…**
  - Paper form → online process
  - Introduced in 2018, the "two clicks" online authorization helped unlock residential DR participation
- **… but many challenges remain**
  - >40% of customers that click through to authorize data access don't complete process
  - Potential causes:
    - Utility authorization websites are frequently down
    - Most require customer's utility credentials or account number
    - Pages contain long and confusing boilerplate legal terms
  - Interval meter data is often delayed and/or contains errors

Solutions exist and have been proposed in many venues. Regulators should adopt policies that better enable secure and reliable data sharing.

Customer Choice in DR Providers

Customers must navigate confusing disenrollment processes to leave utility programs

> **"DR customers shall have the right to provide DR through a service provider of their choice** and Utilities shall support their choice by eliminating barriers to data access" *(2016 CPUC Decision)*

- A customer generally cannot be enrolled in more than one DR program
- Customers enrolled in utility programs must navigate confusing disenrollment processes to switch to a third-party provider (e.g., phone calls or emails to customer service, prolonged wait times)
  - Tens of thousands of customers enrolled in OhmConnect only to be "stuck" because they cannot/have not successfully disenrolled from utility programs
  - Complex enrollment/disenrollment can cause attrition from DR altogether
- Data authorization platform provides an ideal touchpoint to streamline disenrollment
  - Upon sharing data with third-party provider, customers should also be able to disenroll from any competing programs, or proactively select to remain enrolled

Regulators must push utilities to simplify the process of switching DR providers and improve the customer experience around demand response.

Level Playing Field Between Utility & Independent Providers

Harsher rules for third-party providers make competition with legacy utility programs difficult

"Utilities and third-party providers should fairly compete on a level playing field to vie for customers to enroll in their demand response programs." (2016 CPUC Decision)

- Utility demand response programs continue to have many advantages, making market entry and competition for independent providers difficult.
- **Marketing advantages**:
  - Name recognition leads to built-in credibility
  - Data on customer loads, habits and behaviors allows better targeting
- **Favorable market participation rules:**
  - Less rigorous testing requirements make programs more attractive for customers
  - No must-offer obligation at the CAISO reduces financial penalties
- **Systemic advantages:**
  - Use of ratepayer funds provides financial advantage
  - Lack of competition with other resource types ensures continuous "carve-out"

Regulators must proactively review differences in treatment in order to ensure compliance with Commission decisions and intent.

Regulatory Certainty

Constant regulatory uncertainty makes it difficult to plan ahead.

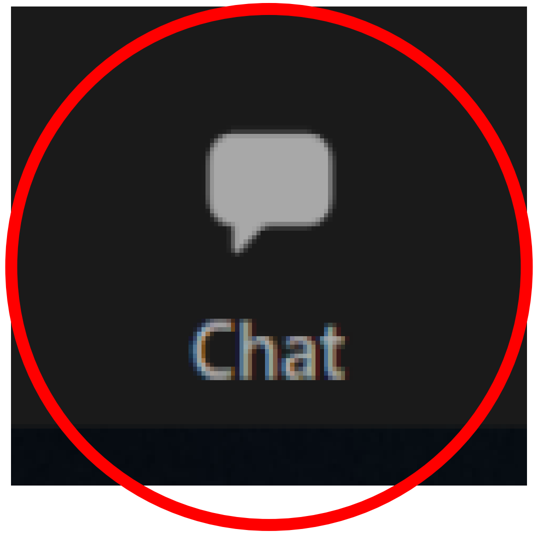
- DR needs a stable and supportive regulatory environment in order to grow
- Pilot to build a competitive marketplace for demand response—the Demand Response Auction Mechanism—has been plagued by a stop-and-start approach and rising administrative costs
- The valuation methodology for DR capacity has been under review for years
    - DR providers face year-to-year uncertainty regarding how their capacity value will be determined
    - Lack of transparency around capacity determination erodes trust
- Rules around treatment of DR resources within the Resource Adequacy program change frequently, making it challenging for load serving entities to procure DR resources

Regulator should strive to provide a stable and predictable environment in which DR providers can not only operate, but plan for the future and thrive.

Thank You!

Maria Belenky
maria@ohmconnect.com

Questions



At the conclusion of each panel DEEP will hold a brief question and answer period.

If you have a question for a presenter, please drop it into the chat to **Jeff Howard**. DEEP will pose as many questions as time allows to the speakers. Clarifying questions will be prioritized. Leading questions will not be accepted.

Lunch Break

(we'll restart at 1:00 p.m. ET)

BUREAU OF ENERGY AND
TECHNOLOGY POLICY

Solution Strategies

Travis Kavulla – NRG

Henry Yoshimura – ISO New England

Erin Cosgrove – Northeast Energy Efficiency Partnerships (NEEP)

Carmen Best – Recurve

Ben Clarin – EPRI

Steve Bright – WeaveGrid

Ryan Hledik – The Brattle Group

BUREAU OF ENERGY AND
TECHNOLOGY POLICY

(speaker order may vary)

NRG

Four Reforms for a More Active Demand Side in Connecticut

2022 Comprehensive Energy Strategy: Technical Session 5 on Active Demand Response

Connecticut Dept. of Energy & Environmental Protection

Travis Kavulla, NRG

Nov. 3, 2022

Real & Potential Sources of Value for Demand Response Providers

- ISO-NE capacity markets – tied to auction outcomes

Resource ID	Resource Name	Load Zone	Resource Type	Price ($/kW-month) FCA10 2019-2020	FCA11 2020-2021	FCA12 2021-2022	FCA13 2022-2023	FCA14 2023-2024	FCA15 2024-2025
40867	CT West	CT	ADCR	$ 7.03	$ 5.30	$ 4.63	$ 3.80	$ 2.00	$ 2.61
40865	CT East	CT	ADCR	$ 7.03	$ 5.30	$ 4.63	$ 3.80	$ 2.00	$ 2.61
40866	CT North	CT	ADCR	$ 7.03	$ 5.30	$ 4.63	$ 3.80	$ 2.00	$ 2.61

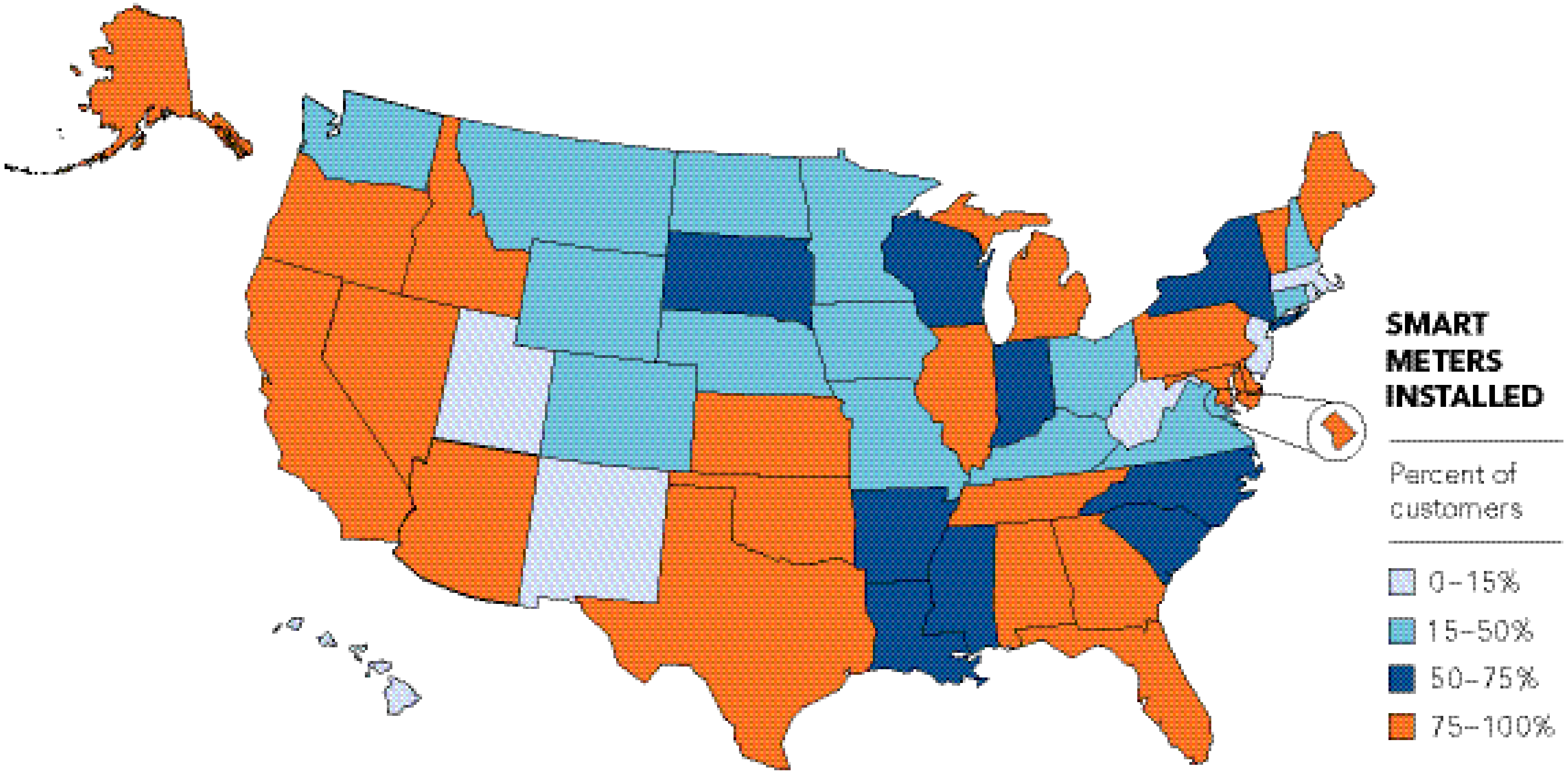
Resource ID	Resource Name	Load Zone	Resource Type	Annual Price ($/kW) FCA10 2019-2020	FCA11 2020-2021	FCA12 2021-2022	FCA13 2022-2023	FCA14 2023-2024	FCA15 2024-2025
40867	CT West	CT	ADCR	$ 84.36	$ 63.56	$ 55.57	$ 45.60	$ 24.01	$ 31.33
40865	CT East	CT	ADCR	$ 84.36	$ 63.56	$ 55.57	$ 45.60	$ 24.01	$ 31.33
40866	CT North	CT	ADCR	$ 84.36	$ 63.56	$ 55.57	$ 45.60	$ 24.01	$ 31.33

- Avoided transmission costs – tied to 12-CP billing

- Avoided energy costs – dependent on time-varying retail energy rates that reflect savings from wholesale market

- Supplemental utility incentive programs (e.g., “Connected Solutions”) – program rules around number, duration, and timing of calls for Winter & Summer

Smart Meter Deployment – 2022



Don’t do Smart Meters just to have Dumb Rates

- Former Commissioner Rob Powelson (PA PUC/FERC): “To be frank, it is pointless to have smart meters if you are still going to have ‘dumb’ rates.” (2009)
- By statute in Connecticut, United Illuminating and Eversource are required to offer a Time-of-Use rate option, as are competitive energy suppliers
  - This requirement applies only to C&I Eversource, due to 1M residential & 120k bus. customers lacking smart meters.*
  - UI/Eversource TOU tariff (Rate 7) has 2 tiers. Trans & Generation costs time variable; distribution is not.
  - Rate design doesn’t express strong on-/off-peak ratio ~3:2
- TOU products are opt-in and adoption is extremely low, even where AMI metering is available
- Without universal AMI deployment and default adoption of TOU, demand response unlikely to be robust

*PURA Docket 13-07-18,

Why are Time-of-Use Rates important?

1. If retail rate design does not contain signals for an "active demand response," then DR more likely is relegated to ISO markets
   - Unhealthy dependency on capacity revenues
   - Demand should be demand, and in retail markets. Demand should not only find its expression as jerry-rigged supply

2. TOU is a foundation for retail product differentiation
   - DER products marketed to customers on the basis of savings under TOU
   - Retailers offering flat-rate or hedges
   - Should not be up to third parties to persuade customers to opt-in to a more cost-reflective TOU rate

Why is TOU important? (cont'd)

3. Demand flexibility can shape load, reducing need & cost for capacity & transmission, including both *incremental cap-ex* & *allocation of sunk costs to load*

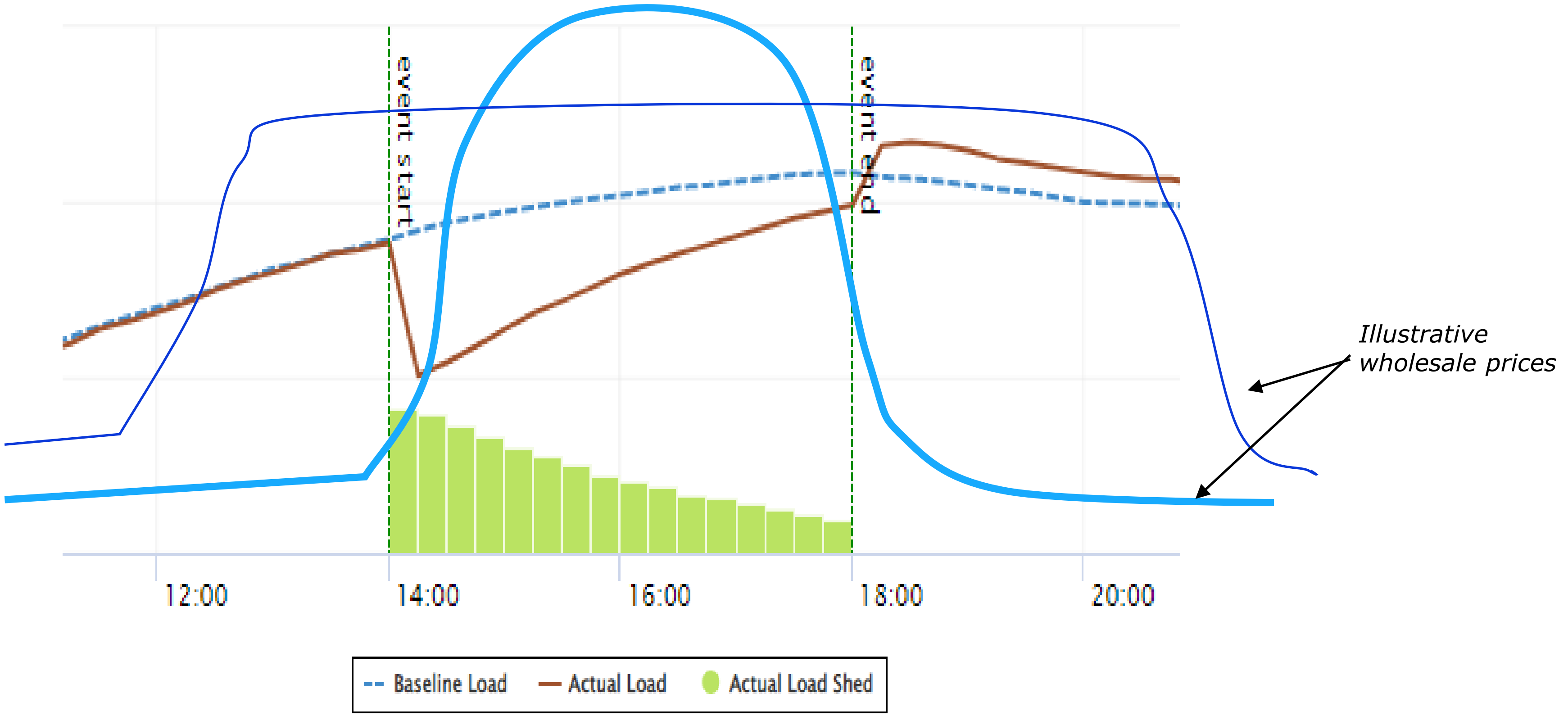
- Shifting to off-peak well-documented when strong incentives exist. In MD pilot, 4:1 to 6:1 ratios between on-/off-peak led to "9.3 percent to 13.7 percent in the summer months and by 4.9 percent to 5.4 percent in the winter months." Staff, MD PSC, *Re: PC44 Rate Design Work Group Leader's Report and Recommendations on Full-Scale Time of Use Rate Offerings* (June 3, 2022)

4. TOU may be a more equitable approach

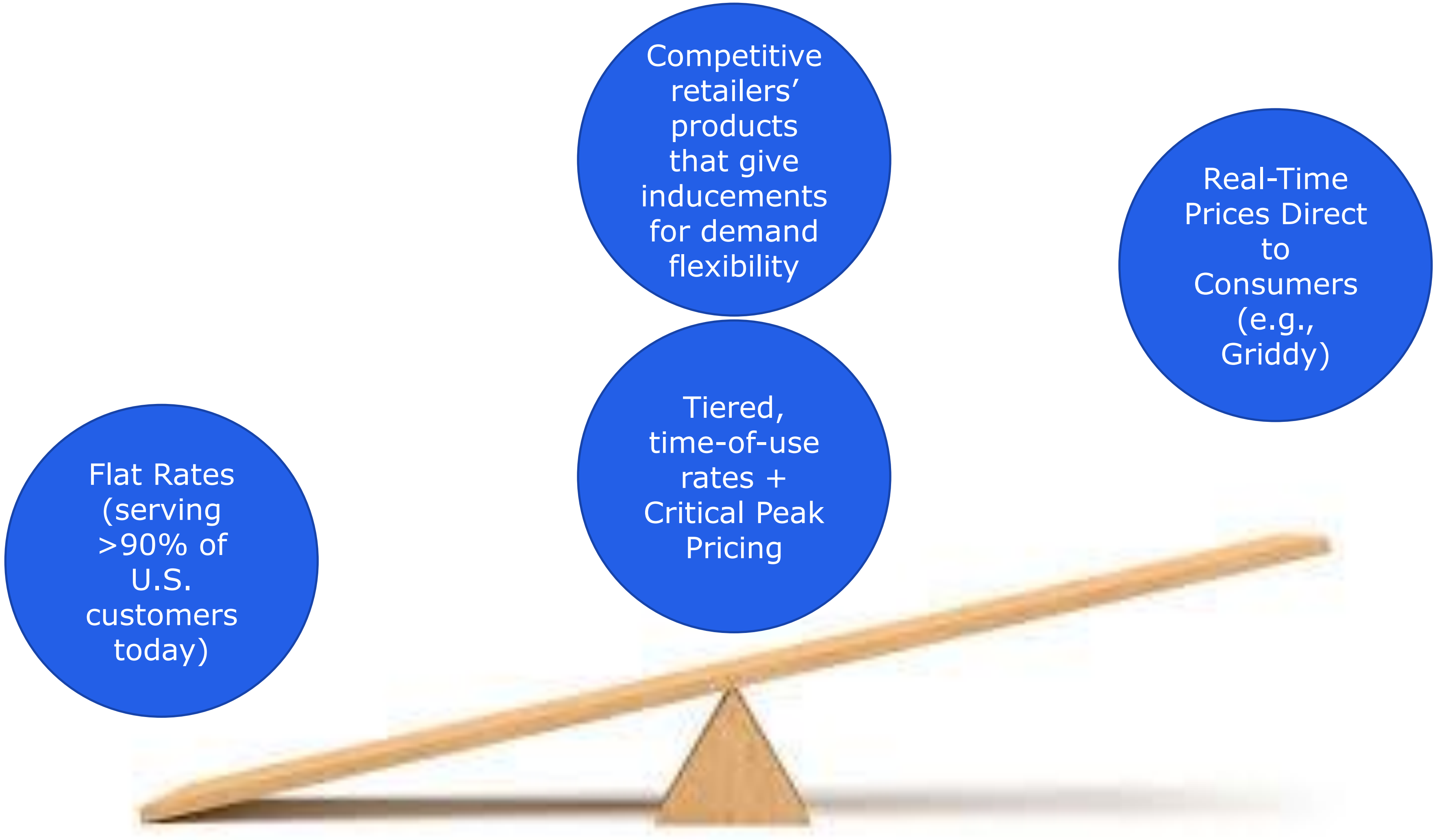
- Research suggests LMI customers perform no worse than any other customers classes in presence of TOU, and in some circumstances are advantaged by it
- "The Pilot results indicated that customers, both overall and low- and moderate-income customers specifically, responded to the rate by shifting usage off-peak." MD PSC Staff in PC44

Example of a Third-Party Retail Program (with Active DR Characteristics)

- NRG's Reliant Degrees of Difference ("DOD") Program: device control DR using smart thermostat, offered through retailer program
- DOD results in a demand decrease of 20% to 30%. So if 1,000 customers participated, potential for ~1 MW total reduction in demand when deployed.
- It would be highly beneficial to evaluate ways to facilitate supplier programs that incentivize behavioral demand response.



Two Extremes of Retail Rate Design for Mass Market



Reform: Regulated Utilities

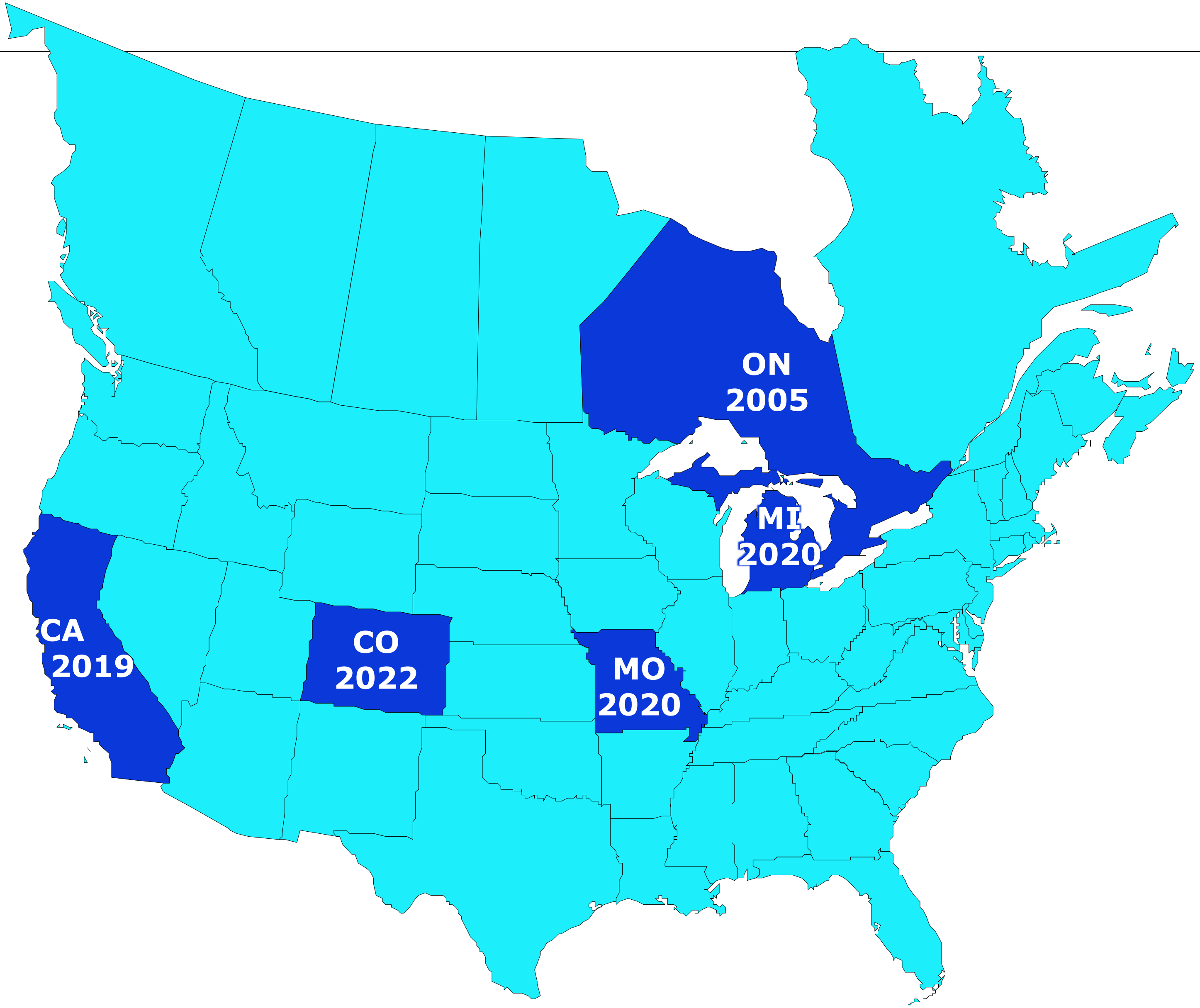
- ***Reform #1: Complete rollout of AMI hardware & functionality***
  - Before Connecticut can have robust demand response or wide adoption of time-of-use rates, they must complete the rollout of smart meters to all customers
  - Ensure utility back office is capable of settling load-serving entities' customer accounts based on *actual load data* and not load profiles
  - In tandem with hardware installation, default customers who are on utility service to Time-of-Use rate, to prevent the "smart meter but dumb rate" phenomenon

Reform: Regulated Utilities cont.

- *Someone, somewhere* should have a consistent, price-based incentive for demand to respond to supply.

- ***Reform #2: Opt-out time-varying rates***
  - Regulated rate should reflect both routine (e.g., tiered TOU) and extraordinary (e.g., "Oil Peak Day") wholesale-market & long-run marginal cost dynamics
  - Like in Colorado (Xcel) & Missouri (Ameren), when a customer gets a smart meter installed, they should be defaulted to TOU.
  - Ontario, California, Michigan all provide additional examples for TOU as the default rate
  - Customers who prefer something other than TOU can opt-out by selecting a third party product

Smart by default: Some states have made time-of-use rates the opt-out standard rate



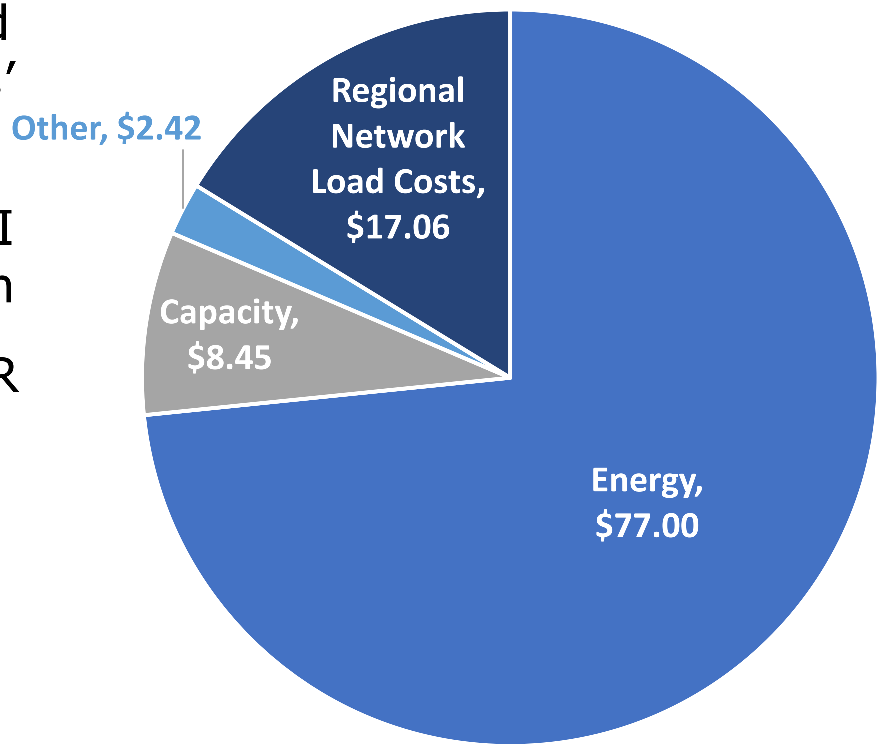
Reform #3: ***<u>Create direct relationship between customer & "demand" providers</u>***

- Customer billing continues to occur through T&D utilities.
- Supplier-consolidated billing is a complement to allow third parties to actively intermediate TOU rate elements (which in presence of successful retail/DER offerings may never be seen by retail customers, even while they create incentives for demand flexibility).
- Consider whether transmission & capacity costs should be billed to Generation Services. Ensure that retailers have opportunity to intermediate these costs

The Pieces of the Pie that aren't on the Table

- Retailers would have a more profound incentive to deploy DR to residential customers if billed ISO charges on their customers' actual, cumulative demand
  - again, only possible with AMI & back-office implementation
- In our estimation, successful DR programs can save
  - ~2-3% of energy costs
  - ~10% of transmission costs
  - All capacity costs
  - (Since CT Distribution rates are not time-varying, no opportunity to save)

Average Connecticut ISO-NE Costs, Sept '21 – Aug '22



Information compiled from: *ISO New England Wholesale Load Cost Report September 2022*. https://www.iso-ne.com/static-assets/documents/2022/10/2022_09_wlc.pdf and *ISO New England Monthly Regional Network Load Cost Report August 2022*. Table 8-1. https://www.iso-ne.com/static-assets/documents/2022/10/2022_08_nlcr_final.pdf

Reform: Nudge Automated Devices

Though results suggest Customers are behaviorally responsive to TOU, they can be further empowered to respond to price signals through home automation.

Just like rates aren't smart by default, many major appliances also not 'smart' by default

Reform #4: ***<u>Nudge Smart Devices</u>***

- Standards for certain demand-flexible appliances (e.g., West Coast states)
- Regulatory programs for Energy Efficiency should target subsidizing cost of smart thermostats and other devices that can be interoperable across retail providers

Concluding Thought: The Role of Demand in Modern Electricity Markets

- Regulation’s attempts to date to activate demand have often been to jerry-rig demand as a supply resource

- The goal should be a two-sided market where demand acts as demand. That happens when either:
  - Retail prices mirror a utility’s cost structure
  - A competitive retail market structure exists to take full responsibility for the full cost to serve demand

ISO-NE

Demand Response Implementation in New England and the Growing Need for Demand Flexibility

Connecticut Department of Energy and Environmental Protection

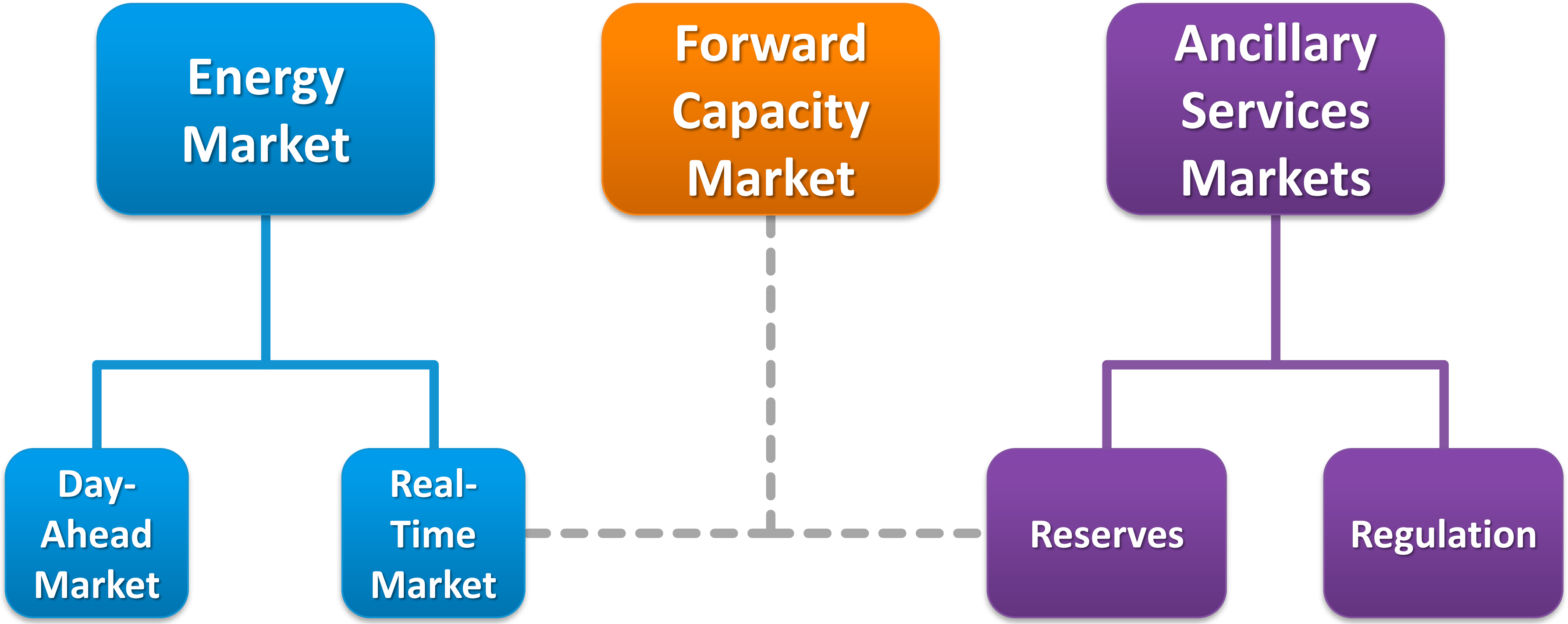
2022 Comprehensive Energy Strategy Technical Session #5 Active Demand Response

Henry Yoshimura

DIRECTOR, DEMAND RESOURCE STRATEGY

DEMAND RESPONSE IN NEW ENGLAND: DEMAND RESPONSE ASSETS (DRAs) AND DEMAND RESPONSE RESOURCES (DRRs)

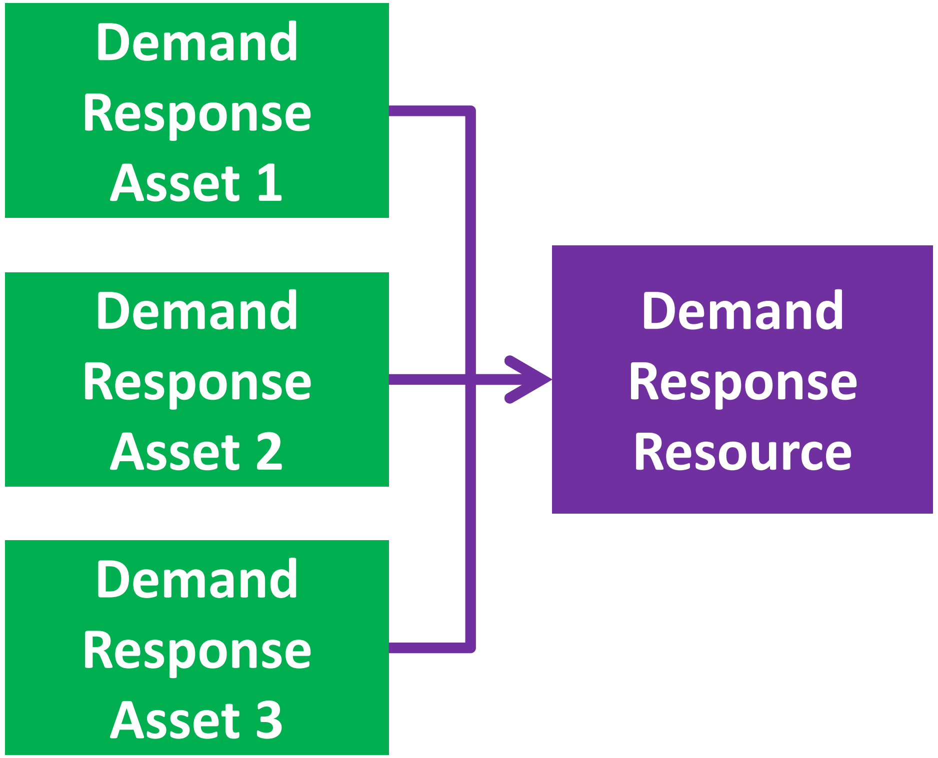
New England Wholesale Markets



Demand Response Resources participate in energy, capacity, and ancillary services markets

What are Demand Response Assets (DRAs) and Demand Response Resources (DRRs)?

- A DRA is an individual end-use customer facility, which may be aggregated and mapped to a DRR
- DRR can consist of multiple DRAs located in the same zone
  - A DRA with a capability of 5 MW or greater must be mapped to its own DRR
- DRRs participate in energy and reserve markets
  - Supply offers are associated with DRRs, not with specific DRAs
- DRRs can be further aggregated into capacity resources (Active Demand Capacity Resources)



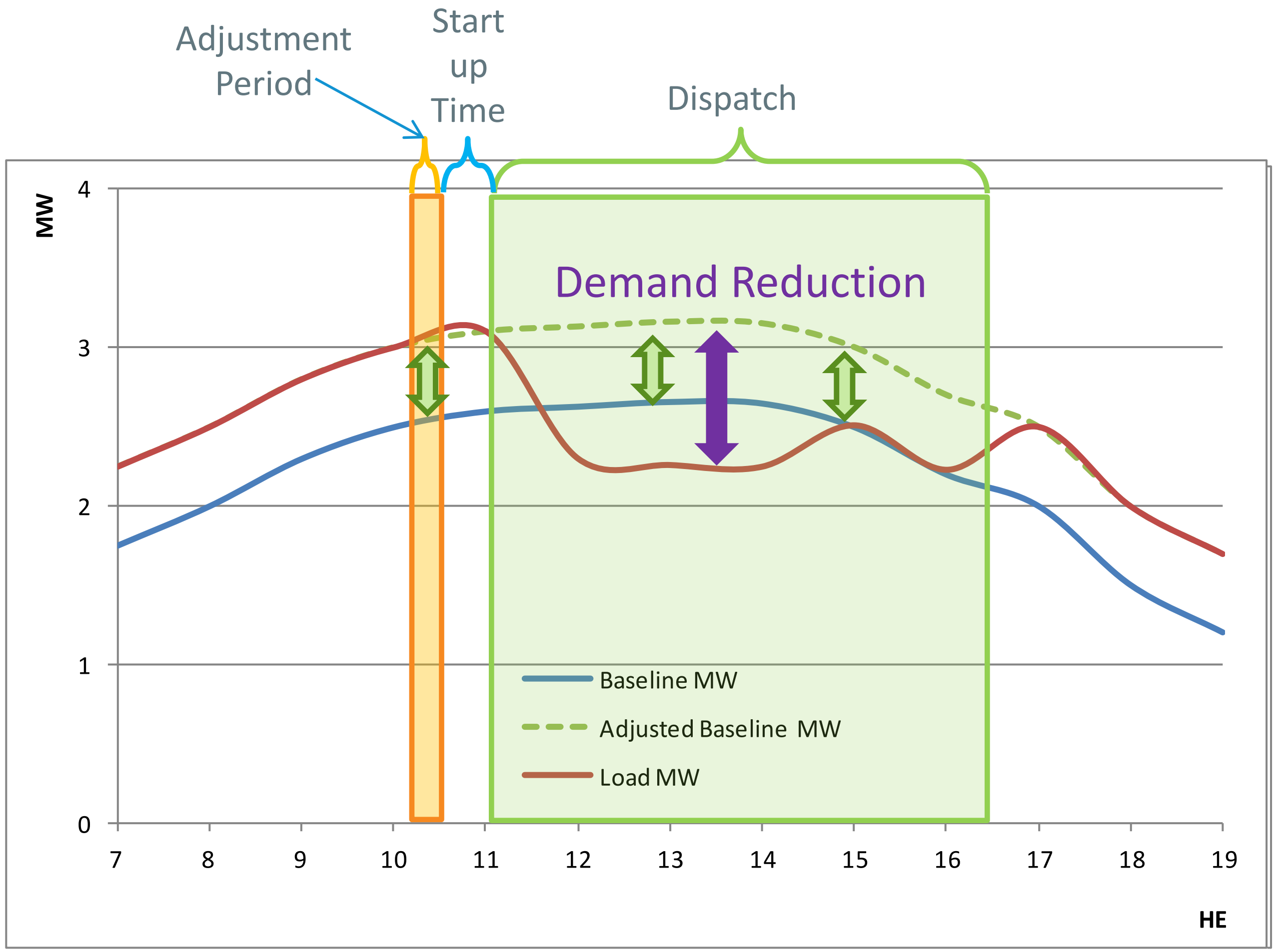
Performance Measurement Example

Dispatch instruction received at 10:29 with a 0 minute notification and 30 minute startup time

Adjustment period 10:10 to 10:25

Actual load is much higher than the baseline during the adjustment period

Baseline adjustment will increase the baseline to accurately calculate the demand reduction MW



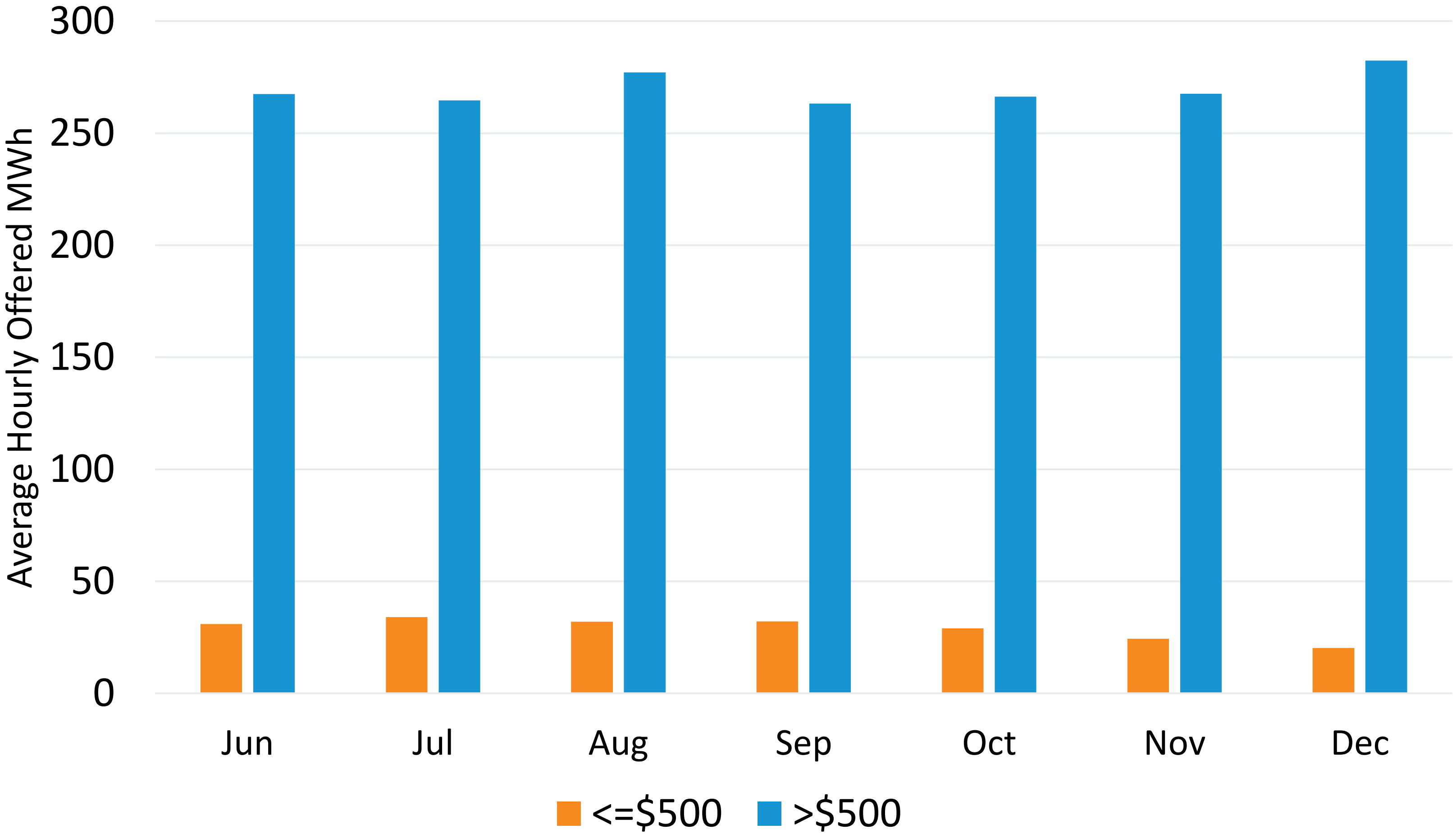
Note that at the 30 minute point in this example (10:59), the load = the adjusted baseline, so based on this dispatch, this asset was not capable of providing 30 minute reserves.

Capacity Supply Obligation (CSO) MW by Demand Resource Type for November 2022

Load Zone	ADCR*	On Peak	Seasonal Peak	Total
ME	90.9	214.1	0.0	305.0
NH	40.5	169.4	0.0	209.9
VT	37.4	132.5	0.0	169.8
CT	147.5	227.2	614.4	989.0
RI	37.6	345.8	0.0	383.4
SEMA	41.4	531.8	0.0	573.2
WCMA	81.3	566.7	35.2	683.2
NEMA	68.6	880.2	0.0	948.8
Total	**545.2**	**3,067.7**	**649.5**	**4,262.4**

* Active Demand Capacity Resources
NOTE: CSO values include T&D loss factor (8%).

90% of DRR MWh have been offered above $500/MWh



Note: Average hourly offered MWh was 301; see: https://www.iso-ne.com/static-assets/documents/2019/01/a6_presentation_review_of_prd_implementation.pptx

Observations

- DRRs are aggregations of DRAs (i.e., end-use customer facilities)
- DRRs are fully integrated into the ISO's capacity, energy, and ancillary service markets and receive market payments
- DRRs are compensated for reducing demand below expected (baseline) demand
- Most DRRs are offered extra-marginally in the energy market – i.e., they offer at a very high energy price
- DRR inclusion in economic dispatch has improved price formation
  - DRR integration improves the accuracy of economic dispatch
- Most DRR revenue is derived from the capacity market, and DRRs provide mostly Operating Reserves rather than energy in real-time

See Appendix slides for more detail

GENERATION AND PRICING DYNAMICS OF THE FUTURE GRID

Electricity Pricing Dynamics in a De-carbonized Economy

- To de-carbonize the economy, electricity will be generated by renewable resources (e.g., solar, wind), and end-uses (e.g., transportation and space-heating) will be electrified
- Renewable resources like solar and wind do not respond to supply/demand conditions as reflected in market prices, leading to periods of over- and under-generation and increased price volatility
  - Periods of zero or negative Locational Marginal Prices (LMPs) resulting from renewable resource over-generation, and periods of high LMPs resulting from renewable resource under-generation
    - Out-of-market revenues give resources the incentive to submit negative bids into the market, which could result in negative LMPs
- Price volatility provides an opportunity for energy storage and "demand flexibility"
  - *Increase demand* during periods of renewable resource over generation with low prices
  - Decrease demand during periods of renewable resource under generation with high prices
  - Such demand flexibility reduces overall system costs and carbon emissions, and addresses system reliability from renewable generation intermittency

Can Demand Response Encourage Demand Flexibility?

- Demand response resources are given incentives to reduce load, which addresses only half of the problem
  - "Demand response means *a reduction in the consumption of electric energy* by customers from their expected consumption in response to an increase in the price of electric energy or to incentive payments designed to induce lower consumption of electric energy" [18 CFR 35.28(b)(4) (emphasis added)]
  - Demand response is treated like a supply resource in the markets – like a generator increasing output, demand response is paid for decreasing consumption
- Demand response does not consider the positive implications of *increasing demand* at the right times

States Have An Opportunity to Leverage Demand Flexibility if Consumers are Given the Tools to Act

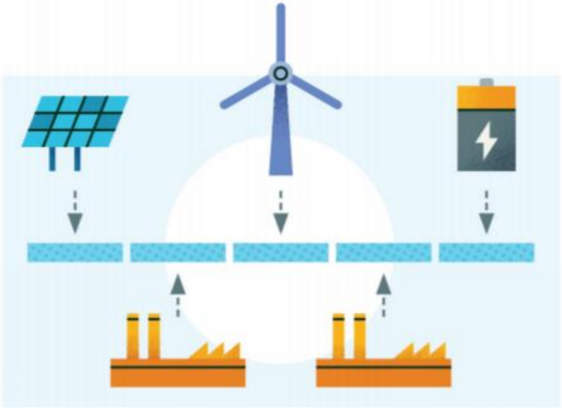
- Retail rates that reflect time-varying costs can enable demand flexibility
  - Prices will be high when marginal costs are high
  - Prices will be low when marginal prices are low
  - Embedding fixed costs in the rate – which increases the rate – would be a disincentive for electrification
- While **real-time pricing** is most efficient, **time-of-use** and **critical peak pricing** have other desirable rate design properties – i.e., price predictability and bill stability
- Rate designs that encourage demand flexibility require **advanced metering functionality** so that real-time hourly usage can be measured and used by customers or their aggregators to adjust load as renewable generation (and the associated retail rate) fluctuates

FERC ORDER NO. 2222: ISO NEW ENGLAND’S COMPLIANCE APPROACH

ISO's Proposal Builds Upon Region's History of DER Market Participation

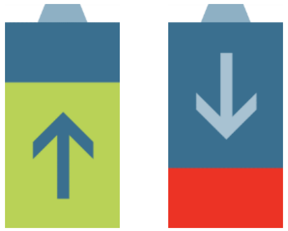
- The ISO's Order No. 2222 proposal creates opportunities for Distributed Energy Resources (DERs), bundled together through DER Aggregation (DERA) to respond to market prices.
  - The ISO's proposal allows DERA's to provide flexibility by reducing demand, injecting energy, withdrawing energy, and providing regulation in response to market prices.
- The ISO's proposal creates two new market participation models and amends several existing models in order to allow the participation of DERAs in the region's energy and ancillary services markets as well allow DERAs to participate as capacity resources in the Forward Capacity Market (FCM).
- In addition, to comply with the order, the proposal:
  - sets a minimum size of 100 kilowatts (kW) for DERAs;
  - includes an opt-in provision for small electric distribution companies;
  - creates a registration process to allow electric distribution companies to determine whether DERA participation in wholesale markets may pose risks to the safe and reliable operation of the distribution system; and
  - creates a framework to coordinate the real-time operation of DERAs and DERs with electric distribution companies and aggregators.
- Timeline:
  - The ISO has proposed that FCM-related changes go into effect in the fourth quarter of 2022, in order to allow the ISO to complete changes necessary for DERAs to participate in Forward Capacity Auction (FCA) #18.
  - The energy and ancillary services market changes would be effective in the fourth quarter of 2026, such that resources can be commercial and integrated ahead of the FCA #18 Capacity Commitment Period that begins on June 1, 2027.

Customers and the Environment will Benefit from Greater Demand Flexibility



- To encourage demand flexibility, DER Aggregators and their customers must have better access to wholesale market LMPs so the supply and demand of the DERA is priced at the LMP
  - When LMPs are negative, a DERA withdrawing energy from the system should be paid for the amount withdrawn – *increasing consumption yields higher payment*
  - When LMPs are positive, a DERA reducing its withdrawal of energy should avoid paying high prices – and should receive payment if it injects energy into the system
- Customers that are part of a DERA with flexible demand priced at the LMP pay a lower average rate

Customers and the Environment will Benefit from Greater Demand Flexibility *(Cont.)*



- This approach encourages DER Aggregators to serve customer energy needs by installing, aggregating, and/or operating any set of devices – e.g., heating/cooling systems, electrical or thermal storage, water heating, distributed generation, electric vehicle charging – at customer facilities and lower customer costs by taking advantage of price volatility
- Shifting load from high-priced periods to zero- (or negative) priced periods utilizes renewable resource over-generation, and reduces the use of fossil-fuel resources, which reduces carbon emissions

Questions

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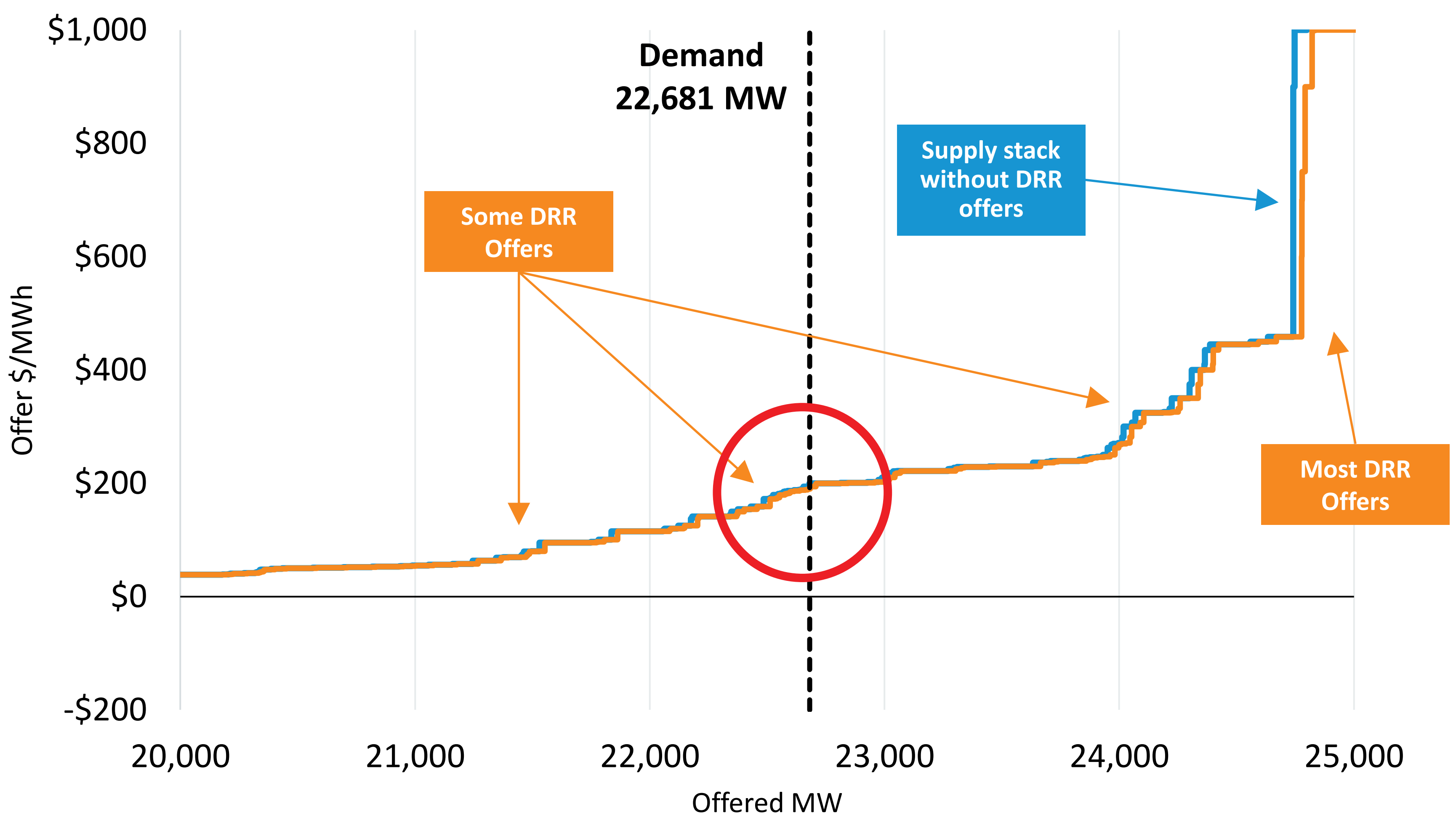
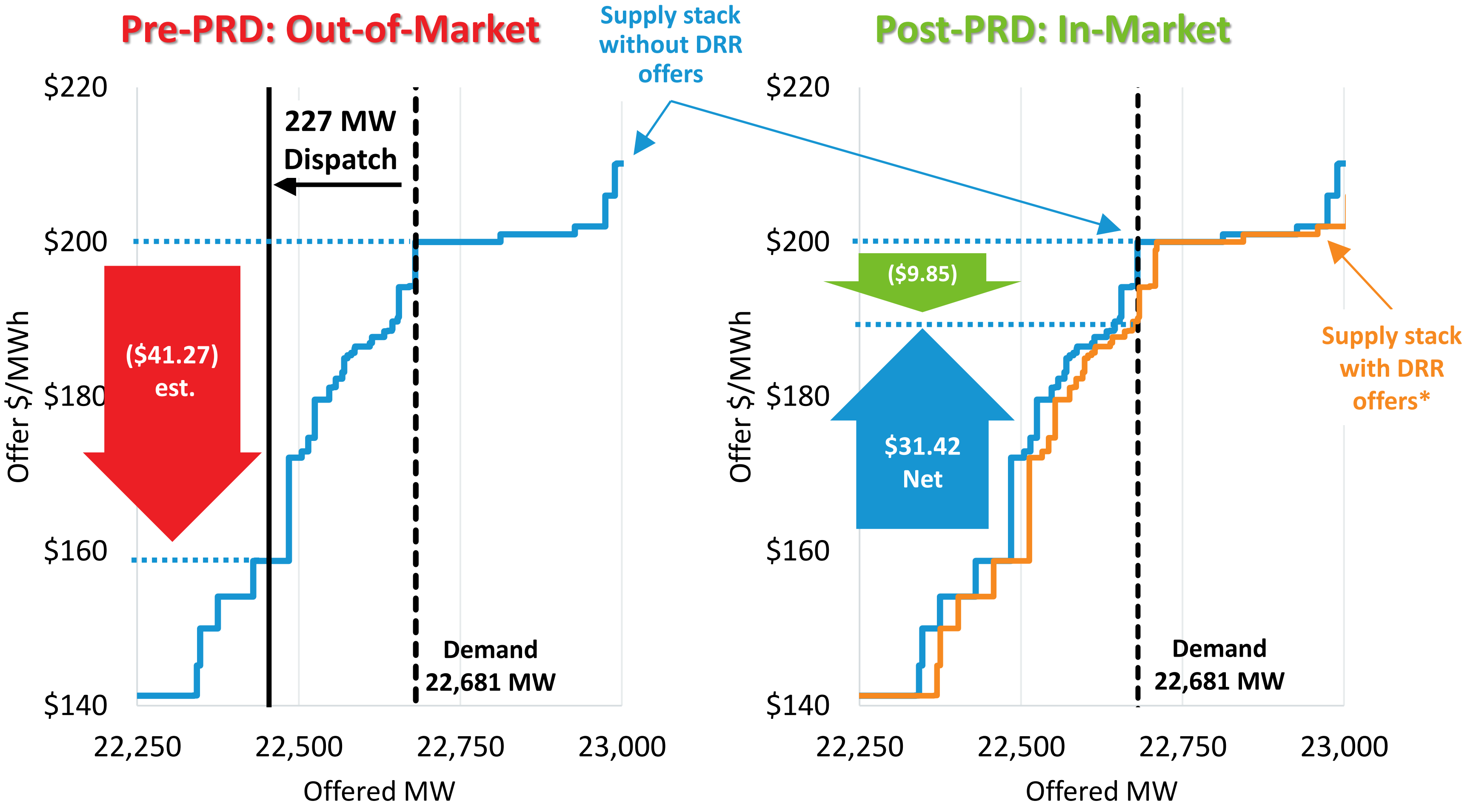
APPENDIX

DRR offers affect the supply stack



* *Observed real-time (RT) supply stack with DRR offers on 9/3/2018, hour ending 7:00 pm*

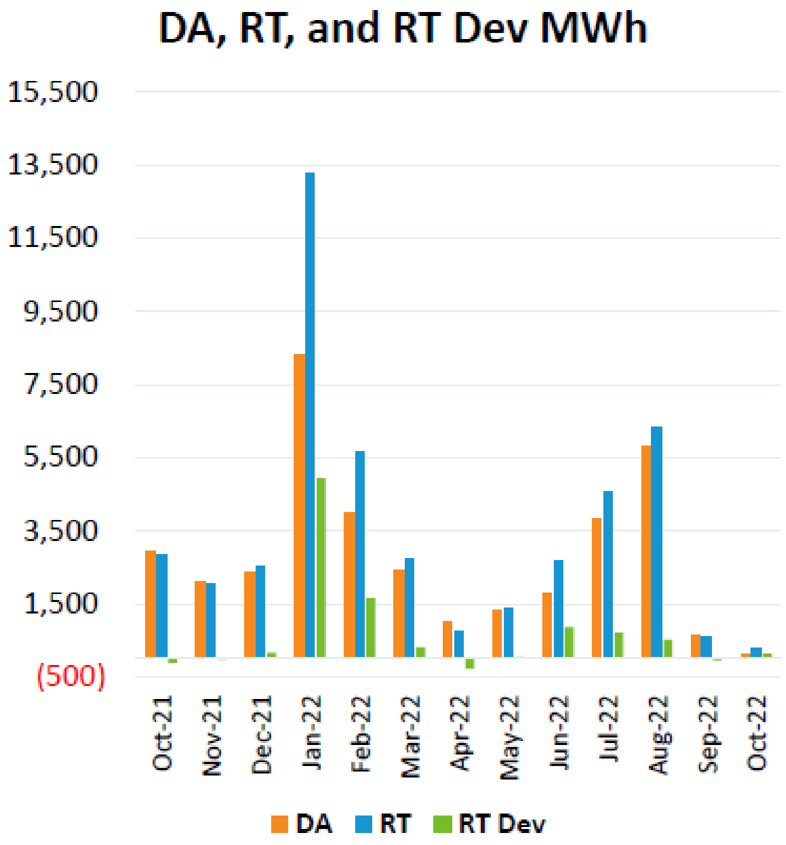
DRR offers in supply stack improve accuracy of economic dispatch compared to pre-DRR

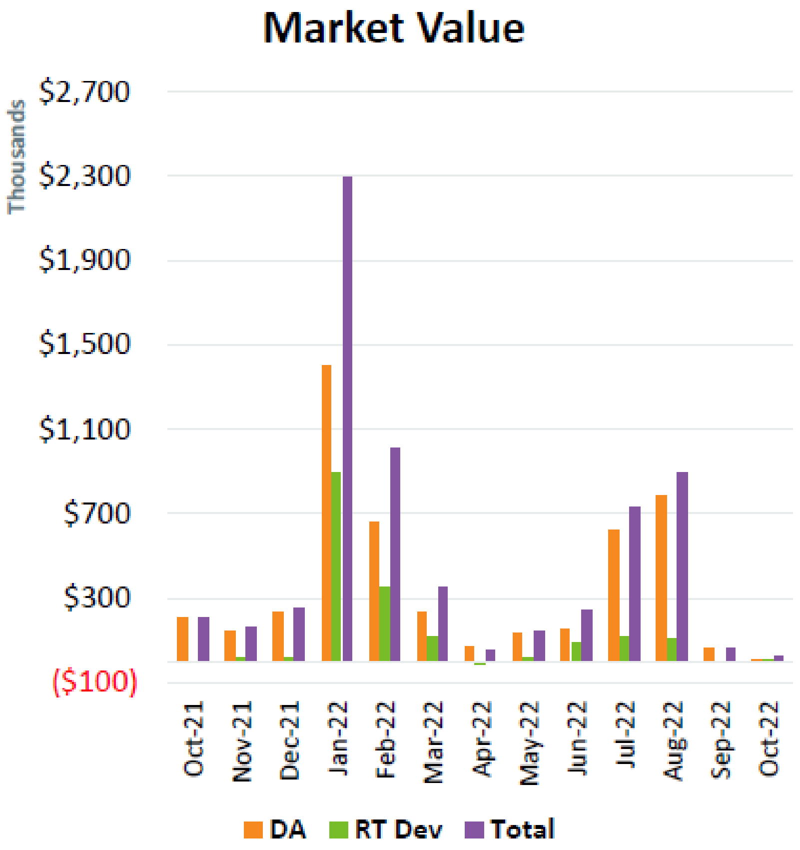


** Observed RT supply stack with DRR offers on 9/3/2018, hour ending 7:00 pm*

Content on this slide was not presented during the live session but was submitted by the presenter for posting

Price Responsive Demand (PRD) Energy Market Activity by Month





Note: DA and RT (deviation) MWh are settlement obligations and reflect appropriate gross-ups for distribution losses.

DRRs produced about 13,500 MWh in January 2022. The January COO report showed that DRRs had a CSO of 529.5 MW. So 13,500 MWh ÷ (529.5 MW x 744 hours in January) = 0.03, i.e., a 3% monthly capacity factor.

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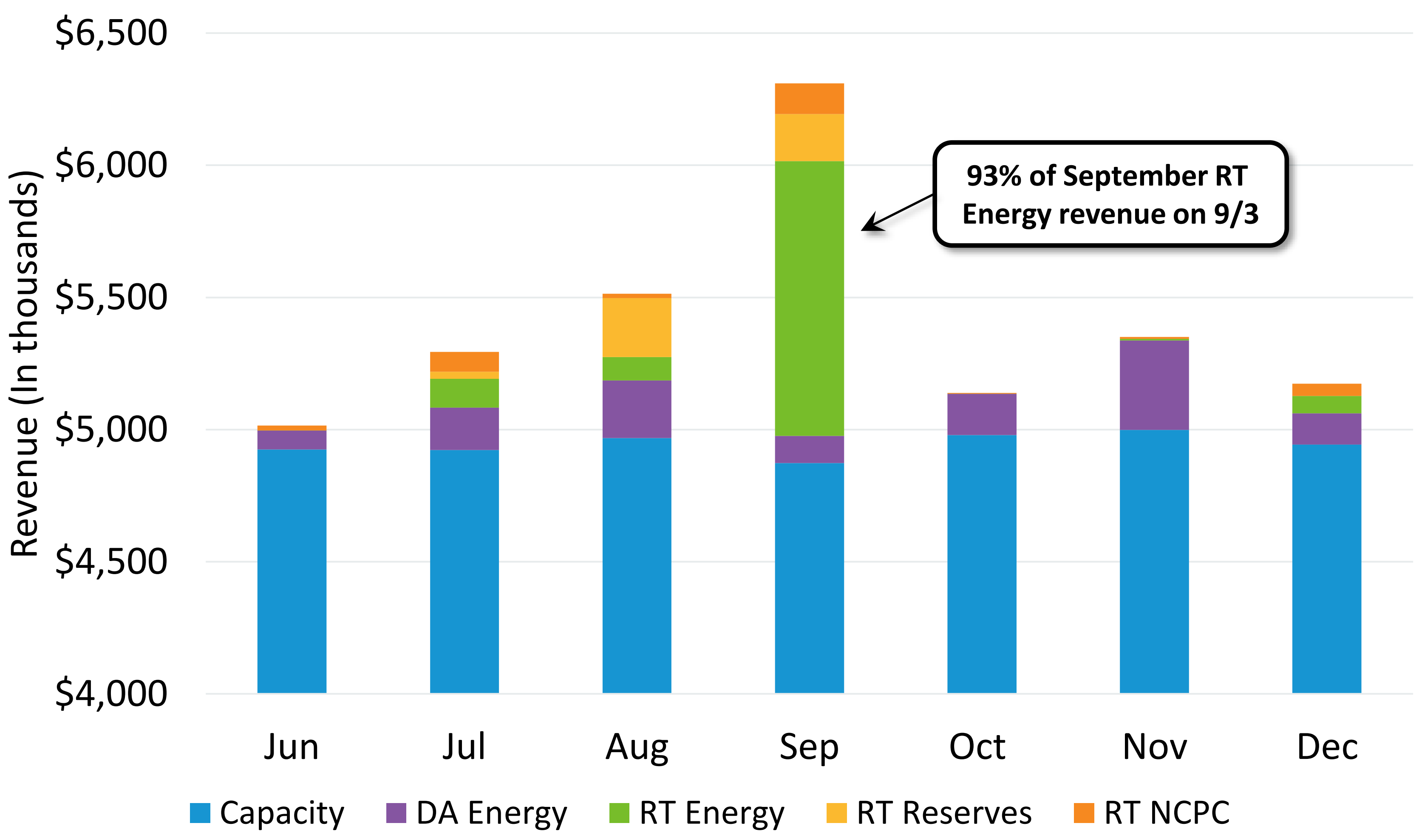
92% of DRR revenues derived from capacity



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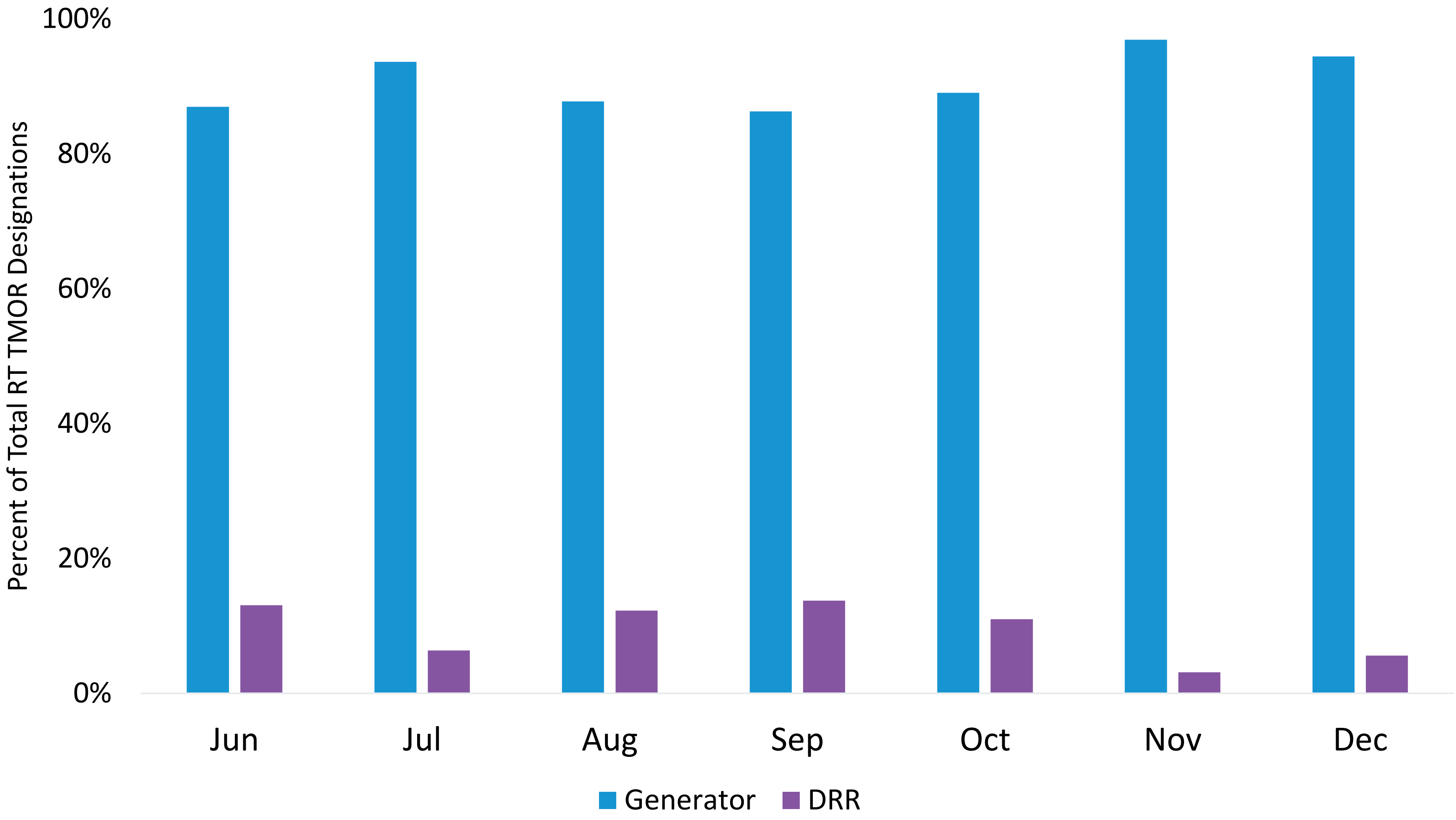
DRRs comprised 3% of system 30-minute reserve capability, and have supplied 9% of designated TMOR



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NEEP

Total Systems Benefit Goal:

A New Program Goal to Incentivize Active Demand Response

Erin Cosgrove
Public Policy Manager
Northeast Energy Efficiency Partnerships

Shifting Goals for Energy Efficiency Programs

Save Energy Costs

- Energy Savings Goals

Beneficial Electrification

- Fuel Neutral Goals

Decarbonization of Grid

- Energy Optimization Goals

Total Systems Benefit Goal

- **What**: Single goal expressed in dollars that represents the value of energy efficiency, demand response, and distributed energy resources to the grid on an hourly basis.

- **How**: Calculates the savings and load shape of an energy efficiency resource by applying hourly values for energy, capacity, and GHG benefits (carbon and high global-warming potential gasses).

- **Result**: Identification of benefits of programs that reduce peak demand such as active demand response and utilize storage or off grid services.

Hourly Energy Costs

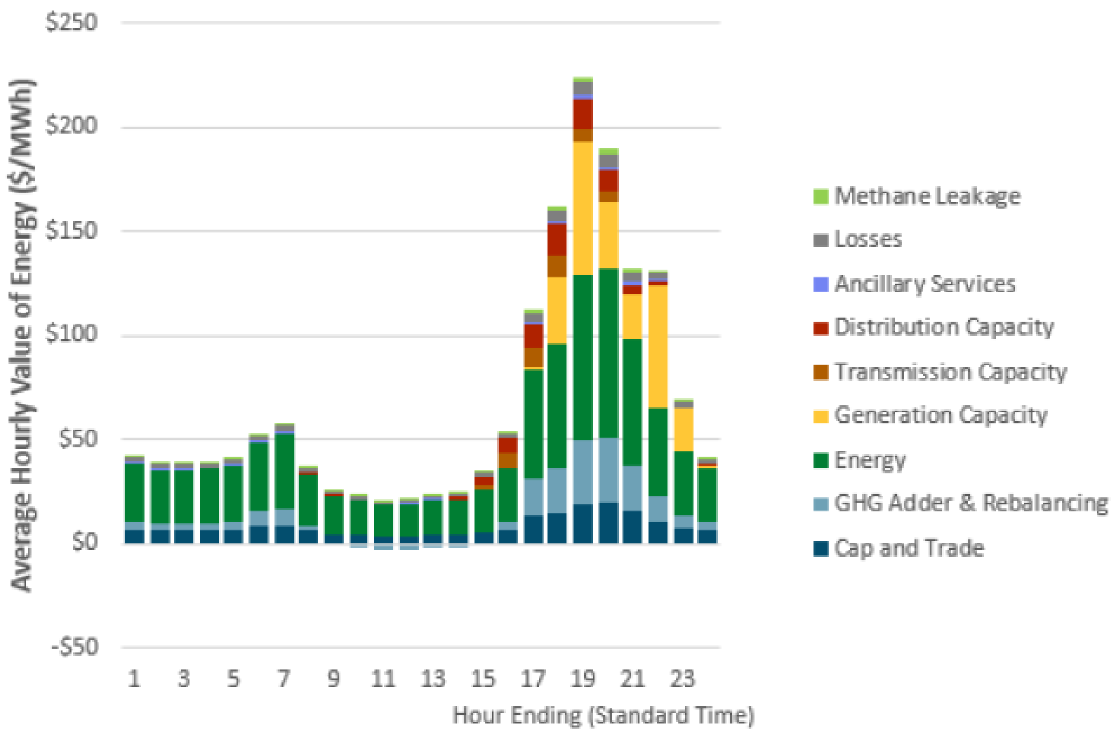


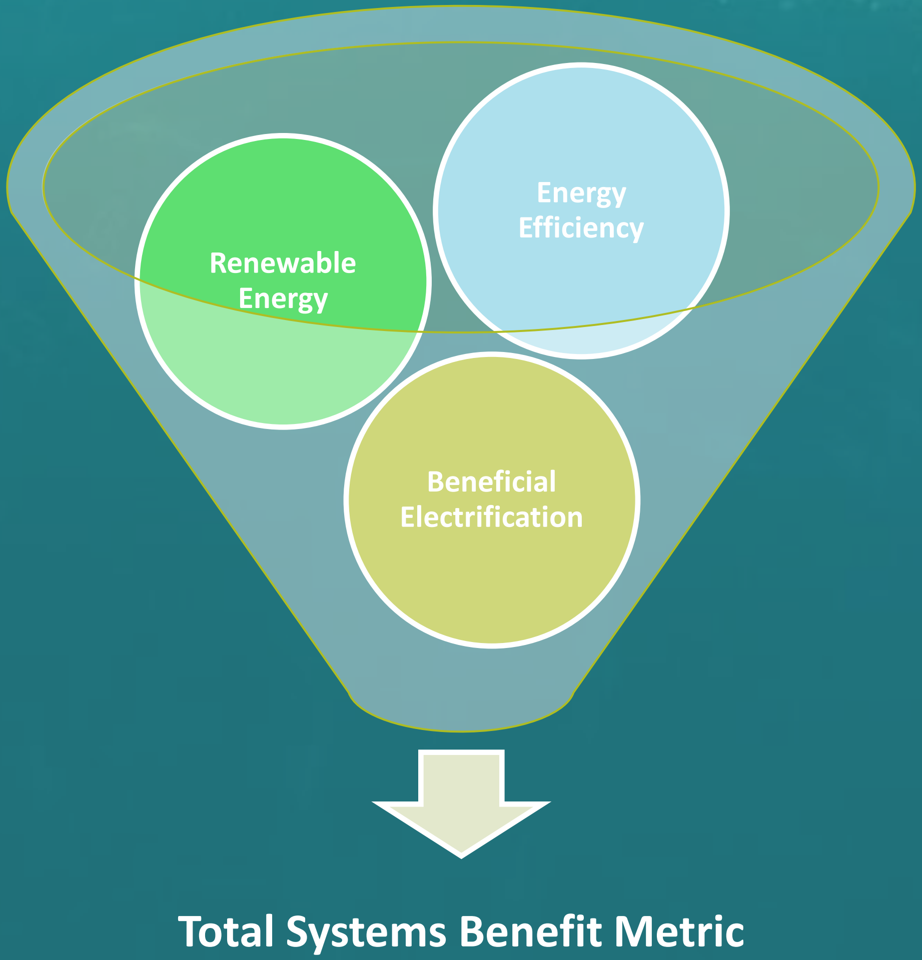
Figure 3: 2021 Avoided Cost Calculator, v.1a

Image Source: https://pda.energydataweb.com/api/view/2530/DRAFT%20TSB%20Tech%20Guidance%20081621.pdf

How TSB Benefits Connecticut

- **For Program Implementers**: Identifies when savings will be most valuable to the grid and encourages programs designed around times of higher usage.

- **For Regulators**: Properly values the benefits of active demand response programs, load shifting programs, and distributed energy resources programs so that they can be be fully realized.



For more information, contact:
ecosgrove@neep.org

Recurve

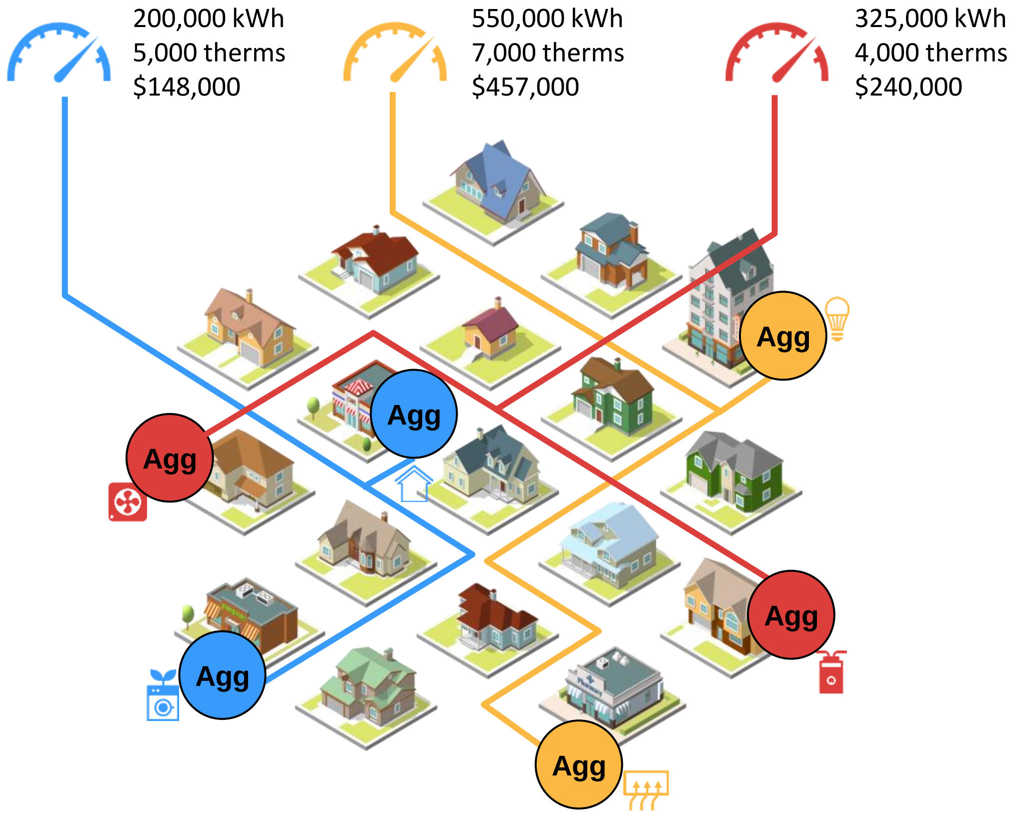
RECURVE

SHAPE THE FUTURE OF ENERGY

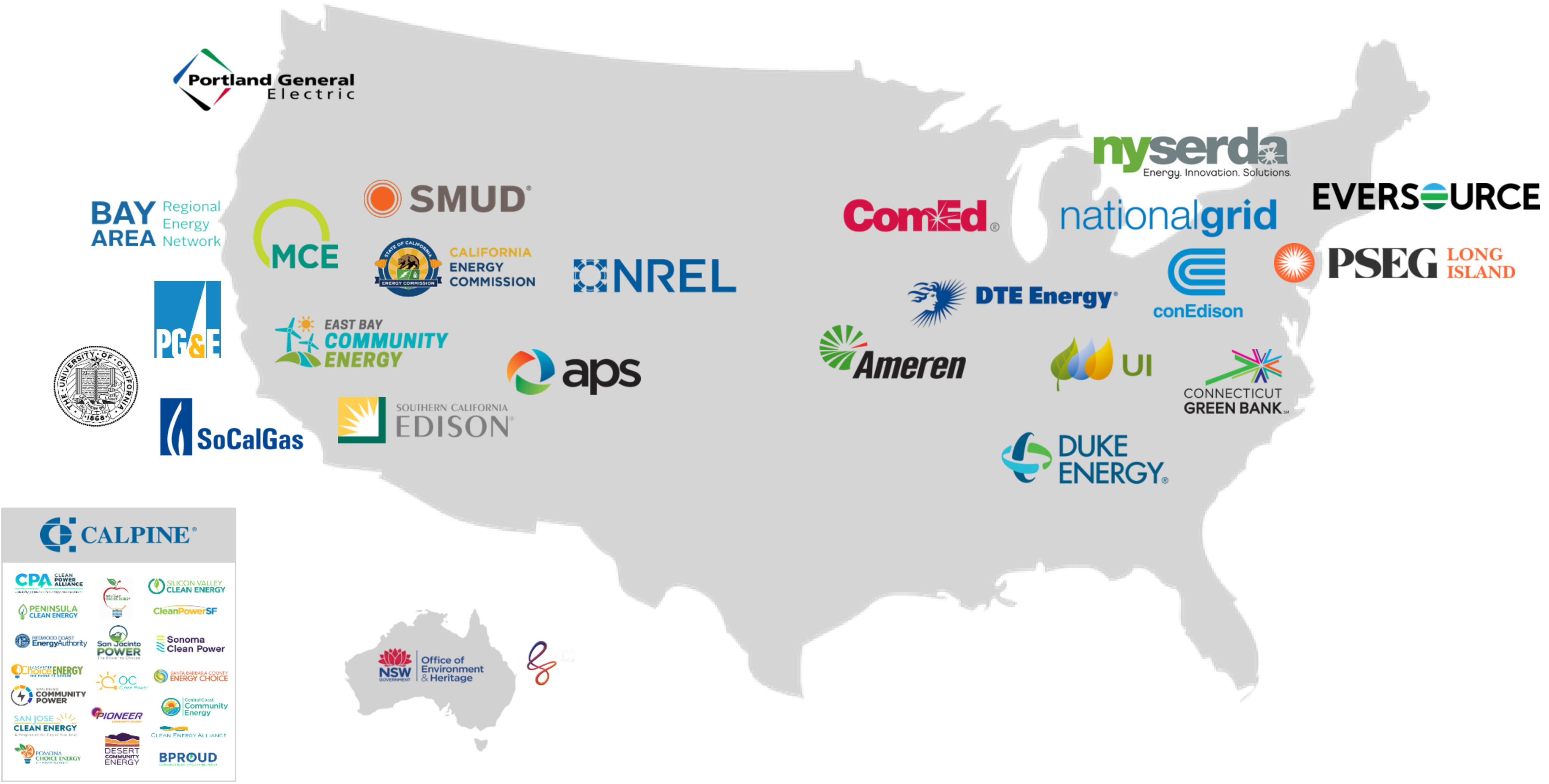
What Does Recurve Do?

1. Demand Flexibility Analytics Platform

2. Market for Virtual Power Plants

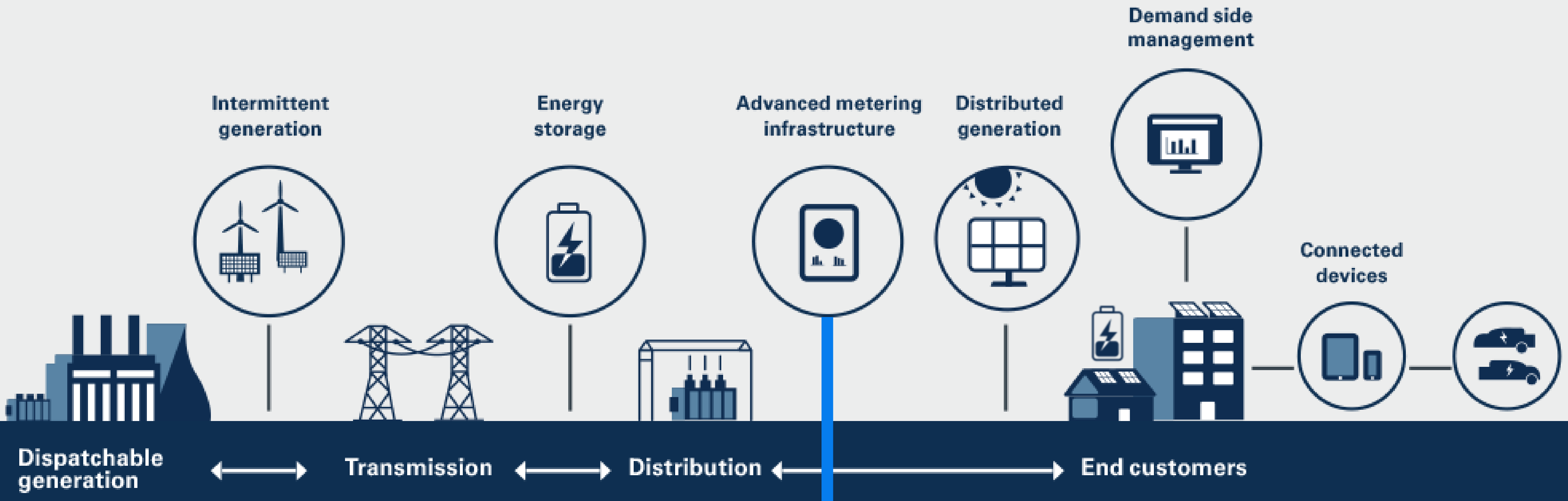


Recurve Customers



The Grid is a Balance of Supply and Demand

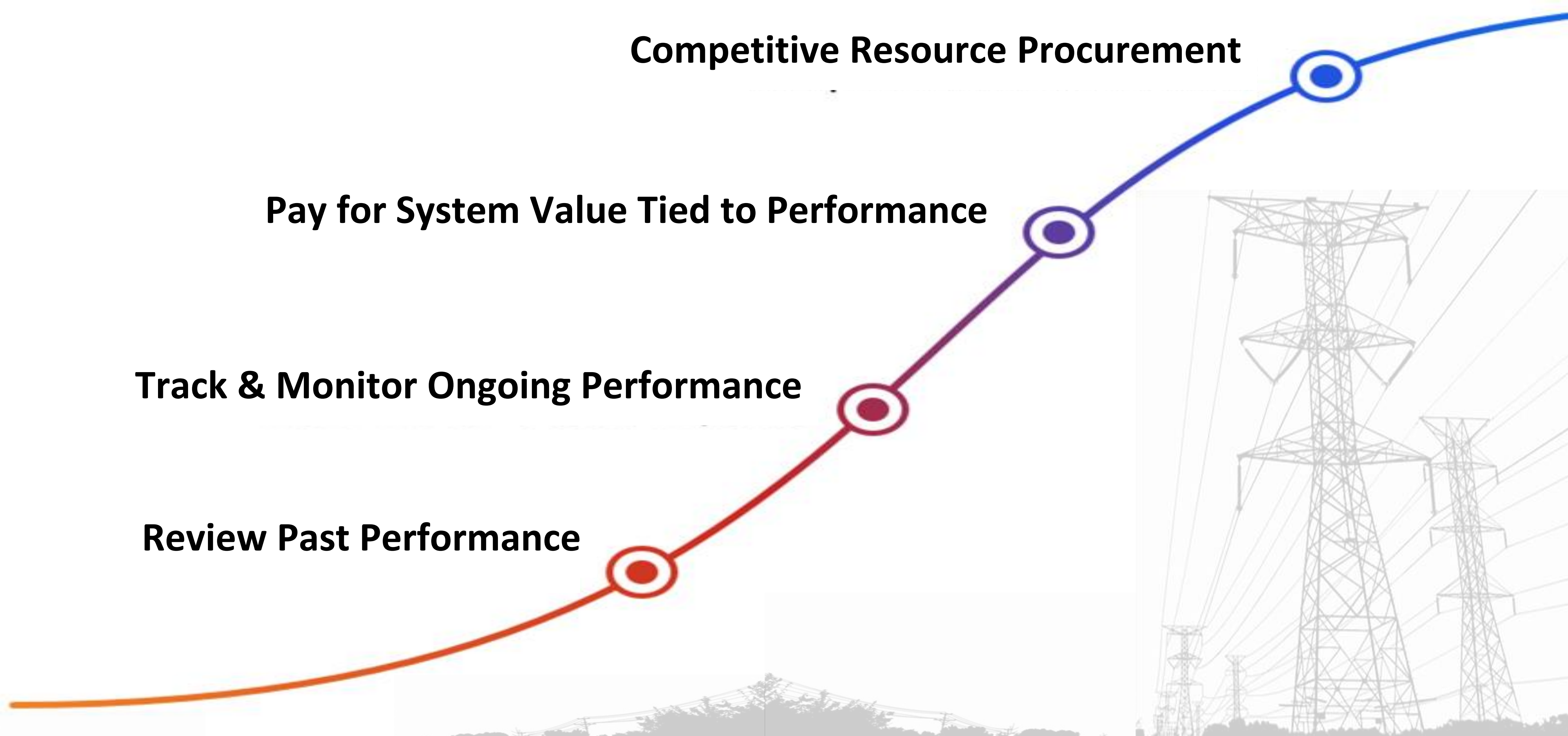
Supply = Demand



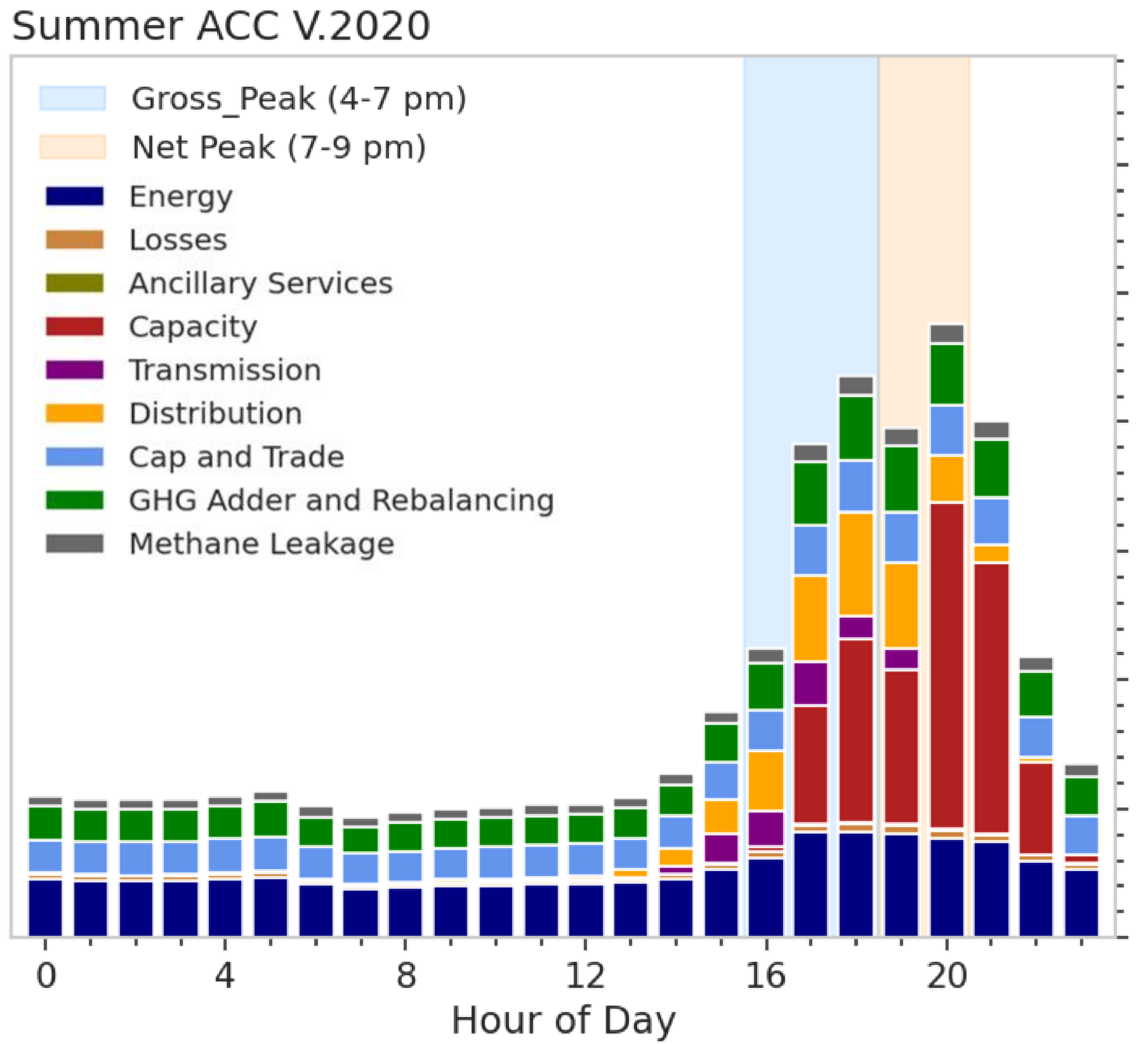
Supply: Energy Resources

Demand: Load Modifying Resources

A Path to Integrating Flexibility As Resource

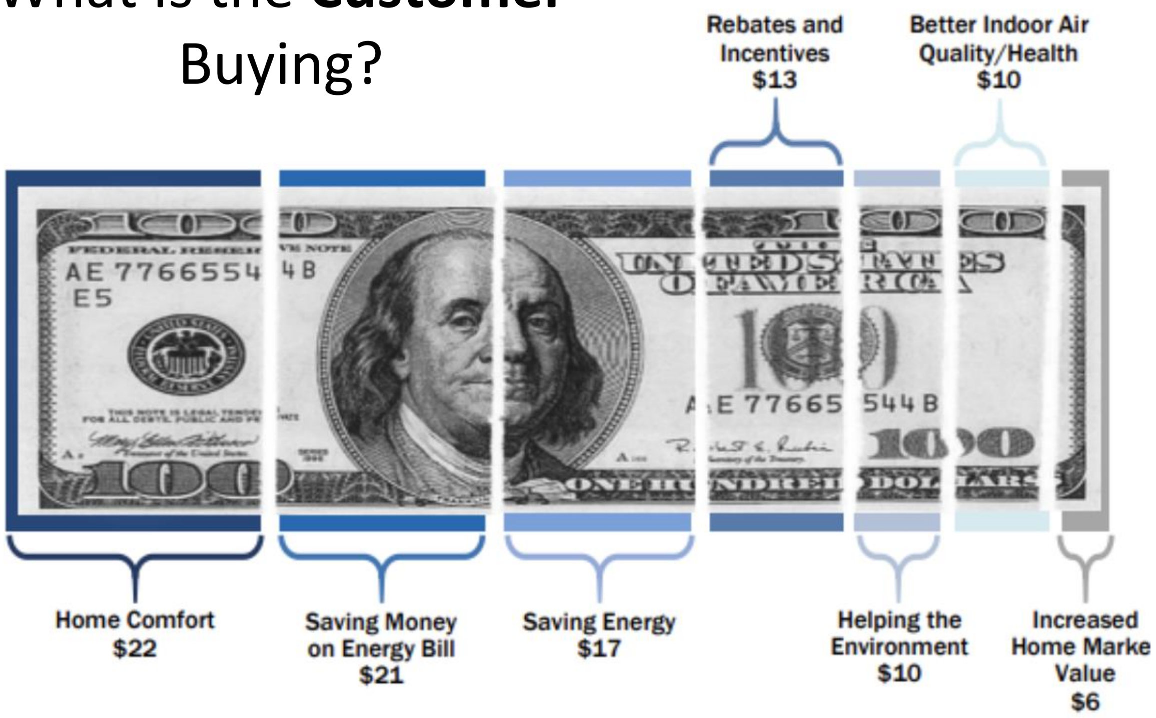


System Benefits From Demand-Side Resources



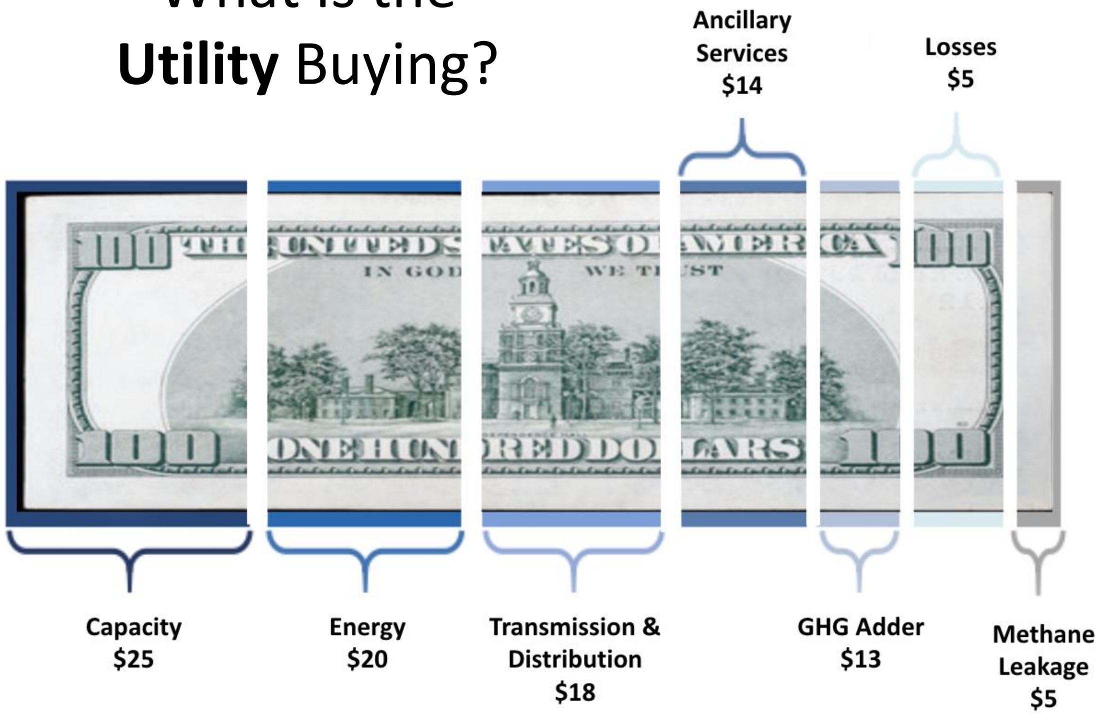
Customer Benefits From Demand-Side Resources

What Is the **Customer** Buying?



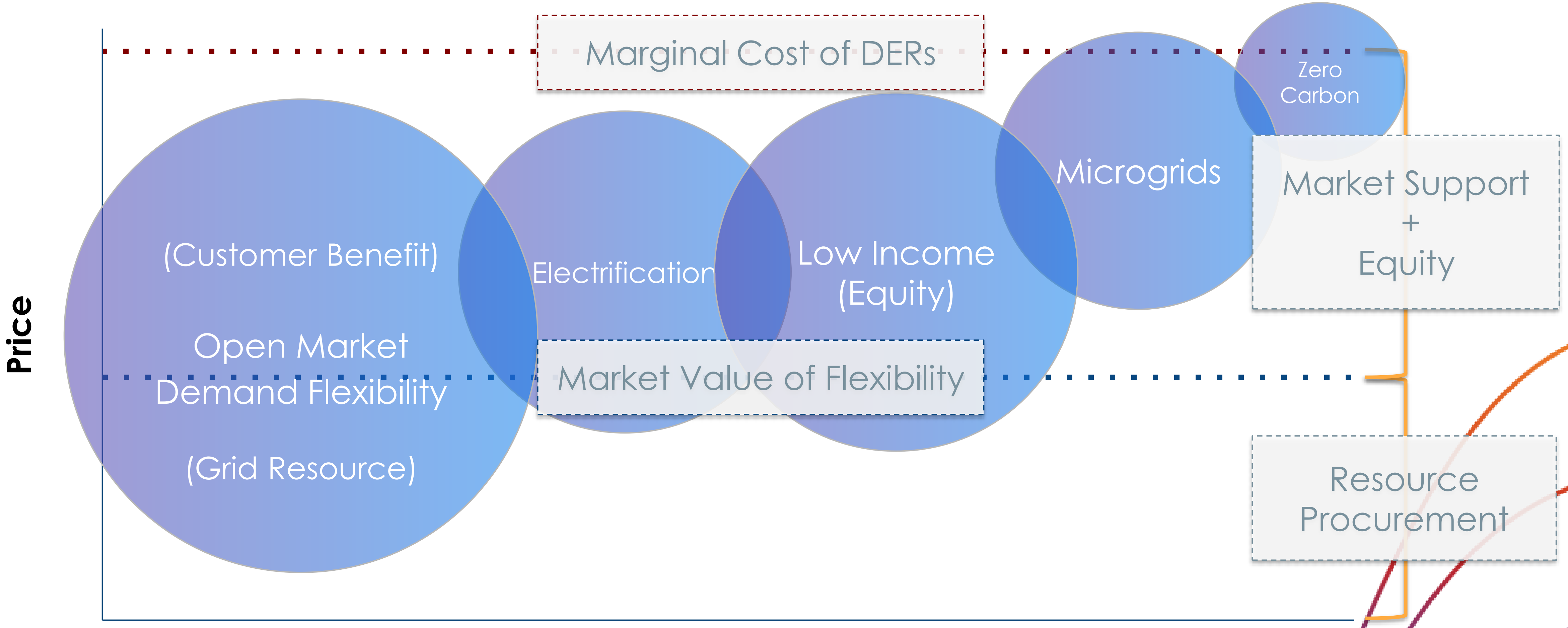
"Considering the cost of your recent retrofit and these main benefits that you experienced, if you were to express the value of each of these benefits by distributing 100 dollars across your list – how much out of 100 dollars would you pay for...?"

What Is the **Utility** Buying?



Who should be deciding for whom?

Multiple Goals & Objectives of Investment



Aligns with TSB Metric + Segmentation Strategies Proposed by NRDC in "[A Roadmap to Better Energy Efficiency Policy](#)"

DEMAND FLEXMARKET

Utility

Marketplace Contract

Recurve

Flexibility Purchase Agreements

Aggregators

Procures
Cost Effective System
Benefit

Provides Demand
FLEXmarket Platform

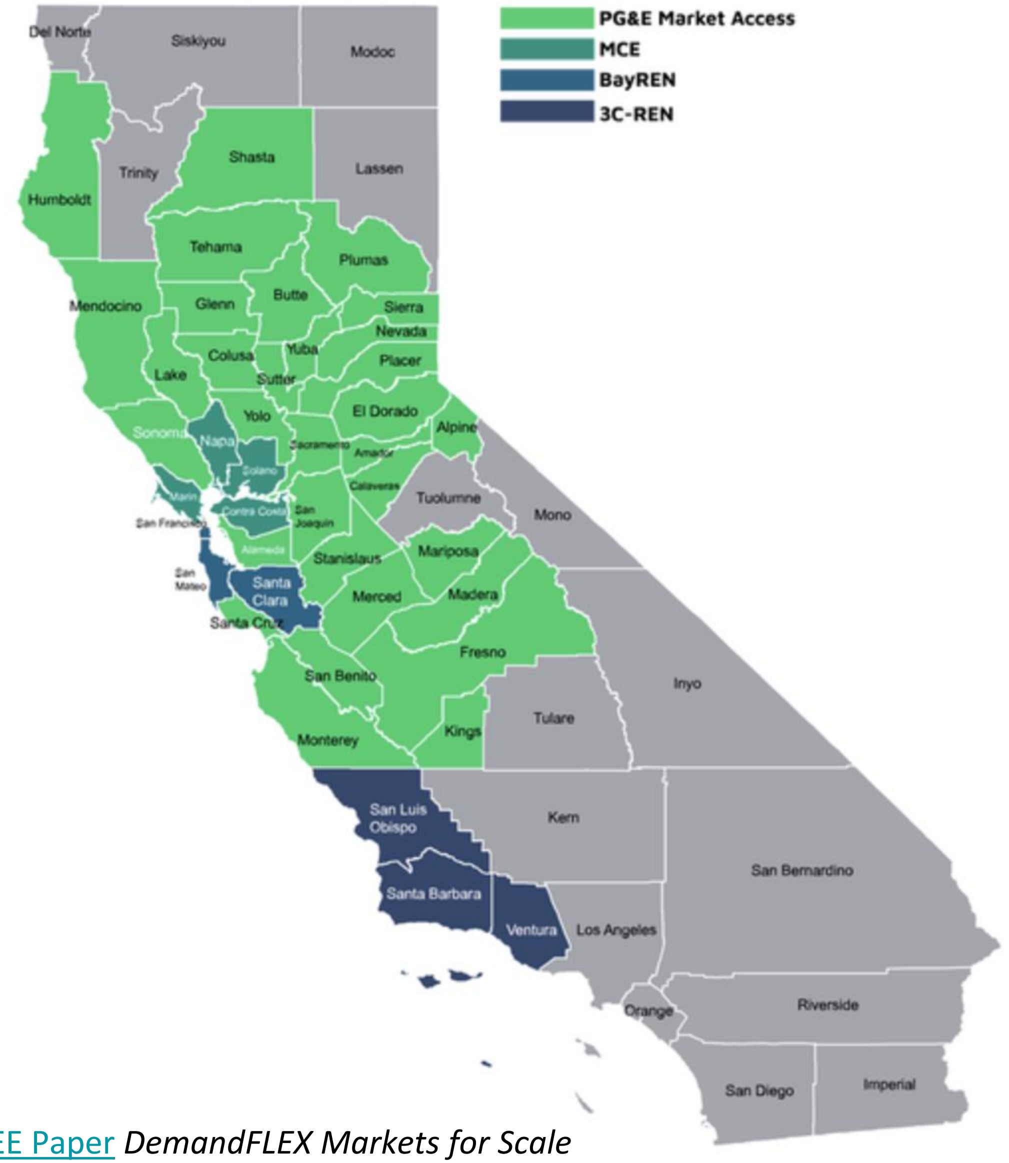
Paid for cost effective hourly **grid value based on metered performance** (base)

+ **Equity** bonus

+ Access to **Market Support**

+ **Resiliency** bonus

DEMAND FLEXMARKET = Market Access Model

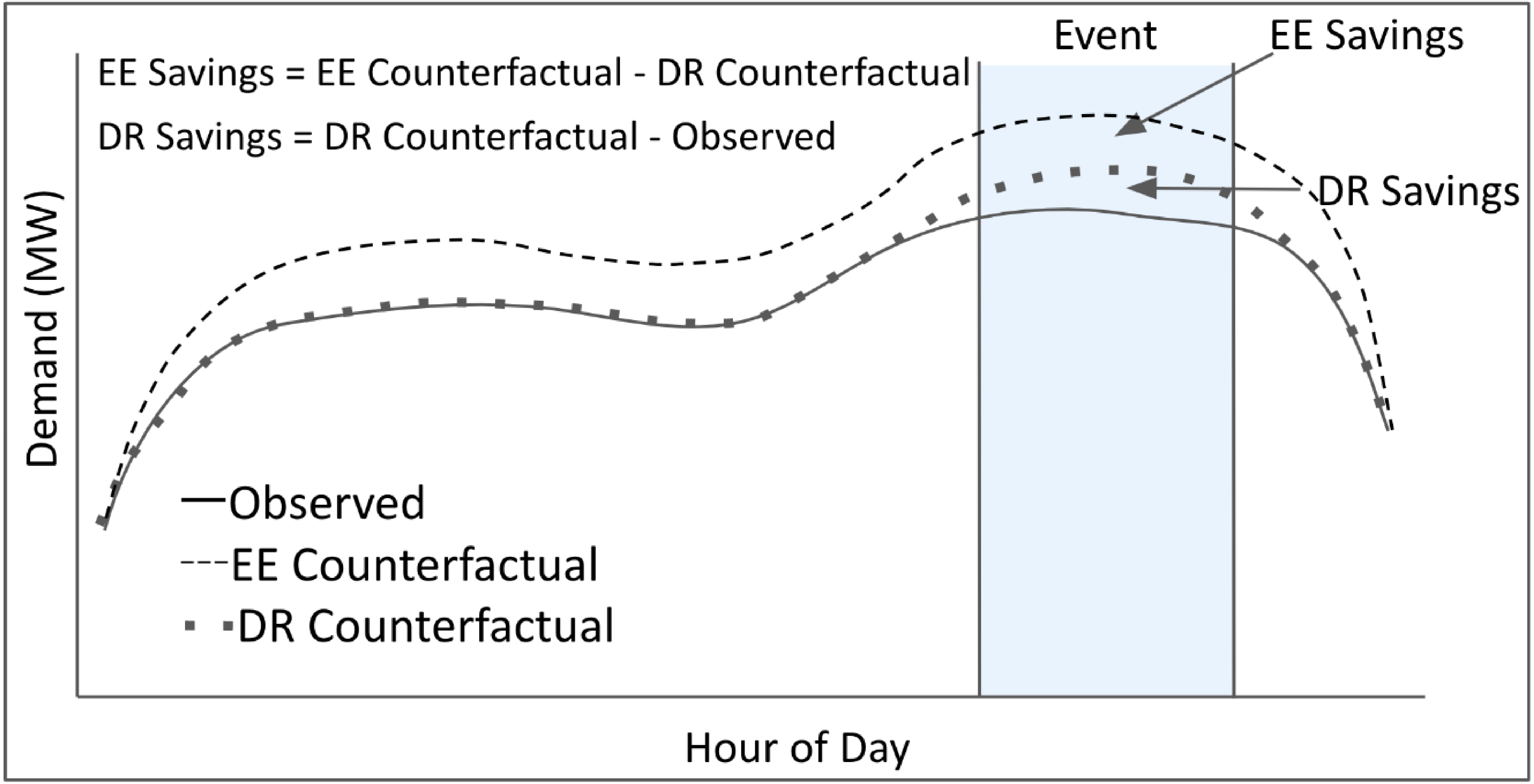


- Meter-based quantification to track impacts and payments
- Pay-for-Performance
- Deliver Measurable Peak Savings
- Open to any Aggregator that Meets Standard Eligibility Requirements
- Aggregators Paid Based on System Benefits Delivered - Adjusted to Include a Peak Savings "Kicker"

ACEEE Paper *DemandFLEX Markets for Scale*

Decision Link: D.21-12-011

Demand Flexibility = Efficiency & Demand Response



ACEEE Paper *Expanding Energy Efficiency Open Source Measurement Methods to Incorporate Demand Response for Grid Stability*

Demand Flexibility = Efficiency & Demand Response

Treatment % Difference

Event = -28.7%

Comparison Group % Difference

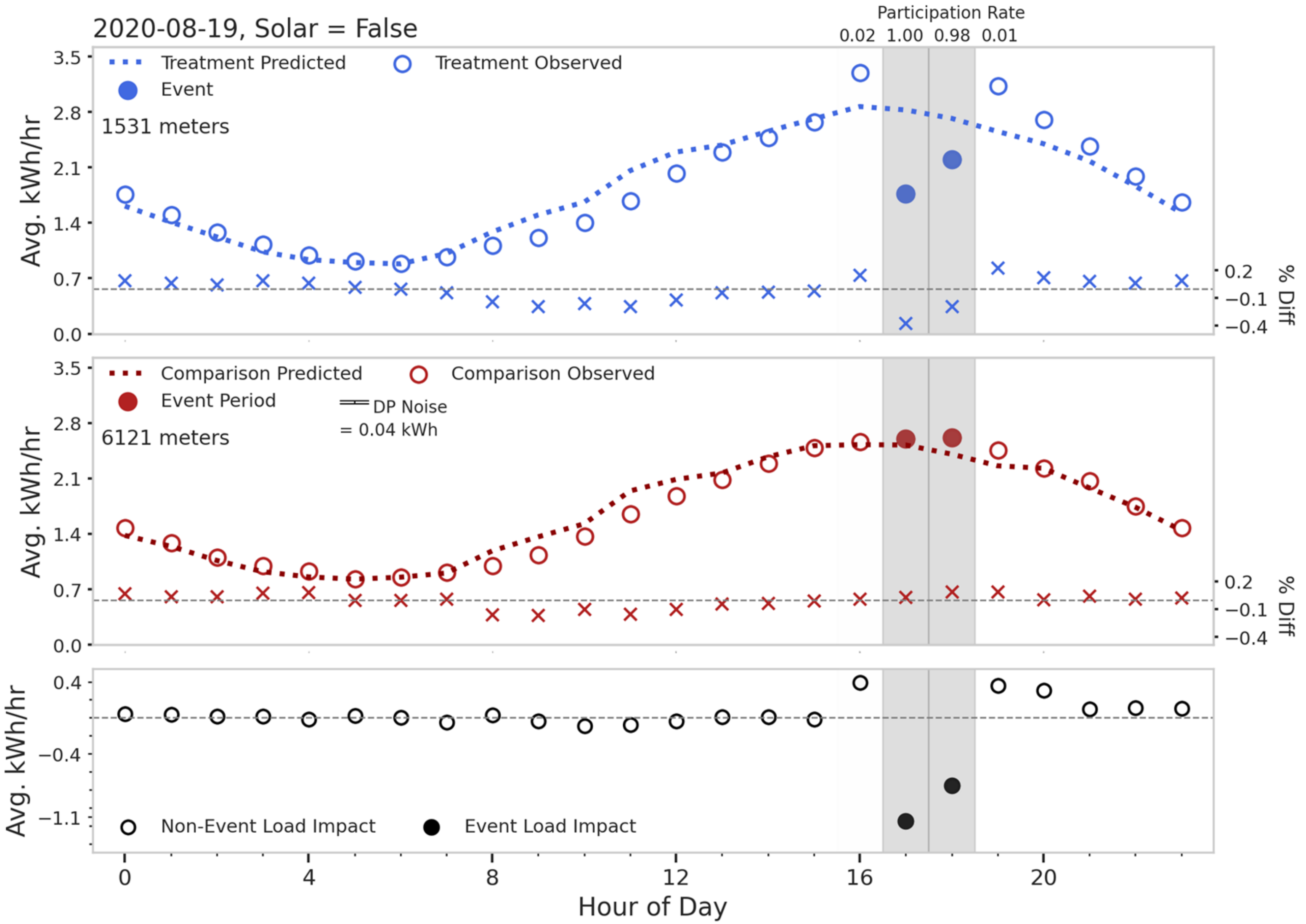
Event = 5.1%

% Difference of Difference

Event = -33.8%

Avg. Event Load Impact

= -0.94 kW



CAISO Study: *Demand Response Advanced Measurement Methodolgoy*

HOMES - Inflation Reduction Act

Measured Performance Pathway

State agencies, regulators and utilities will be able to track quantifiable impacts from the $3.5 B federal investment, including:

- Improving **resilience** for customers adapting to extreme weather
- Addressing **grid reliability** and **carbon goal attainment**
- **Reducing energy burden** via customer bill impacts

✓ Fast, efficient deployment including geographic and demographic **targeting**

✓ **Compatible with existing programs** and/or can be deployed as a "market"

✓ **Values the full impact** of home performance and grid optimization

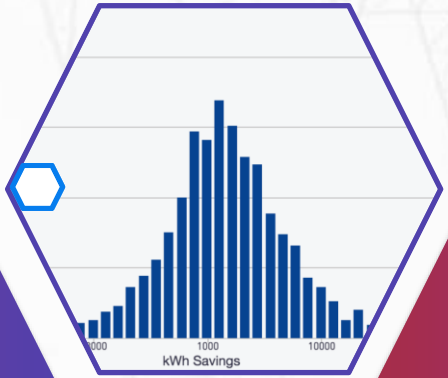
✓ **Technology-agnostic** and **business friendly** to drive innovation

✓ **Open-Source Transparent Measurement**

LF ENERGY OPENEEMETER

Accelerate Investment in Our Most Important Energy Infrastructure: Our Homes.

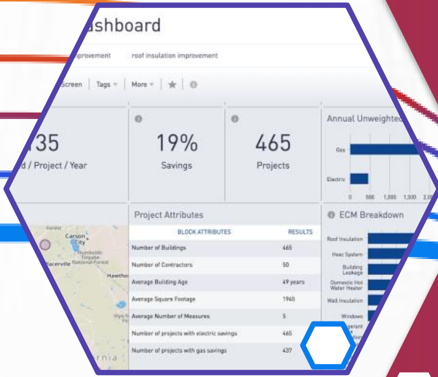
SHAPE THE FUTURE OF ENERGY



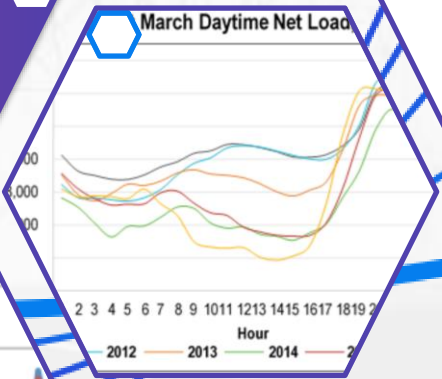
FLEXmarket

Demand Flexibility

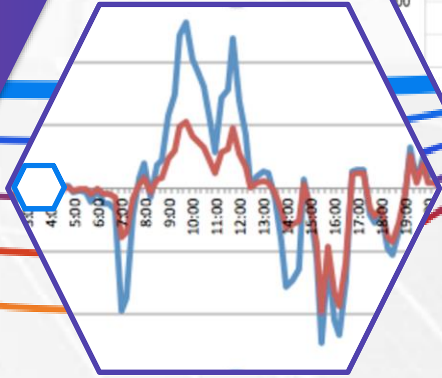
Reliability



Resource Curve



Market Access



Carmen Best

carmen@recurve.com

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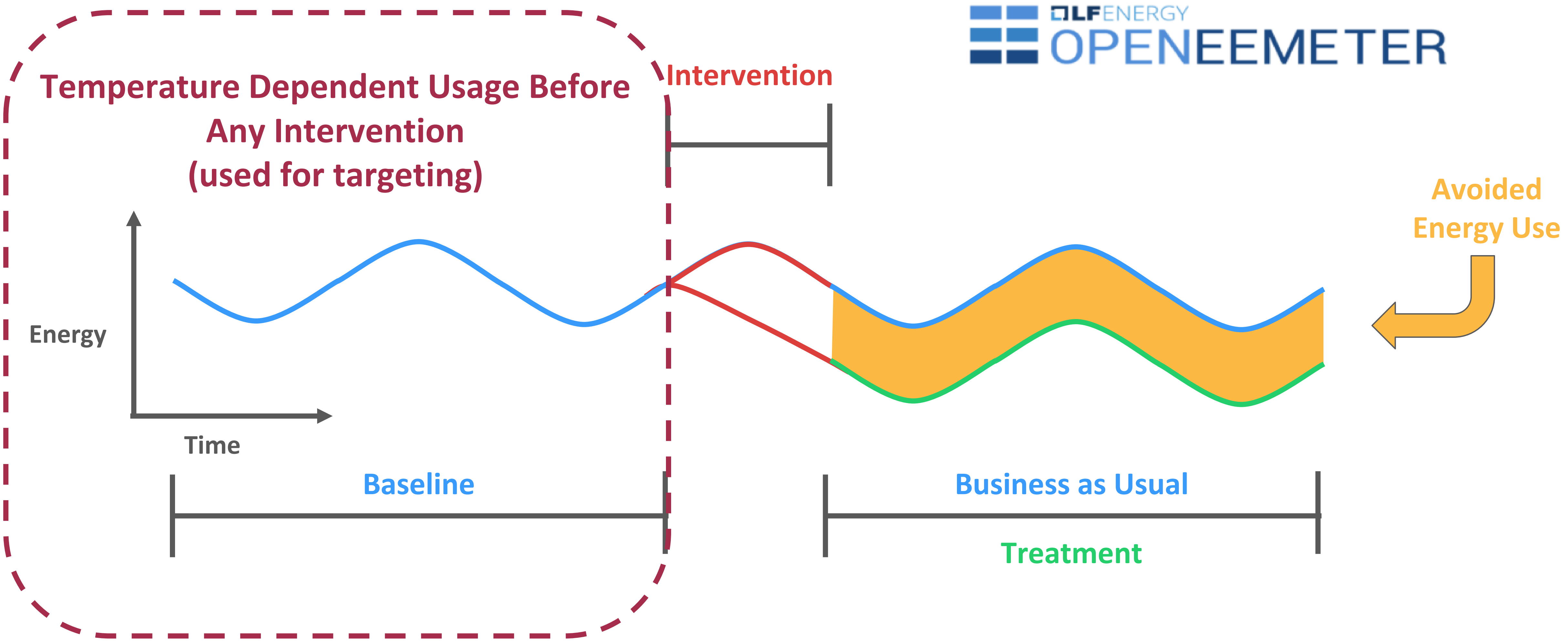
Appendix Slides

OpenEEmeter & Targeting

RECURVE

OpenEEmeter Measures Changes in Consumption



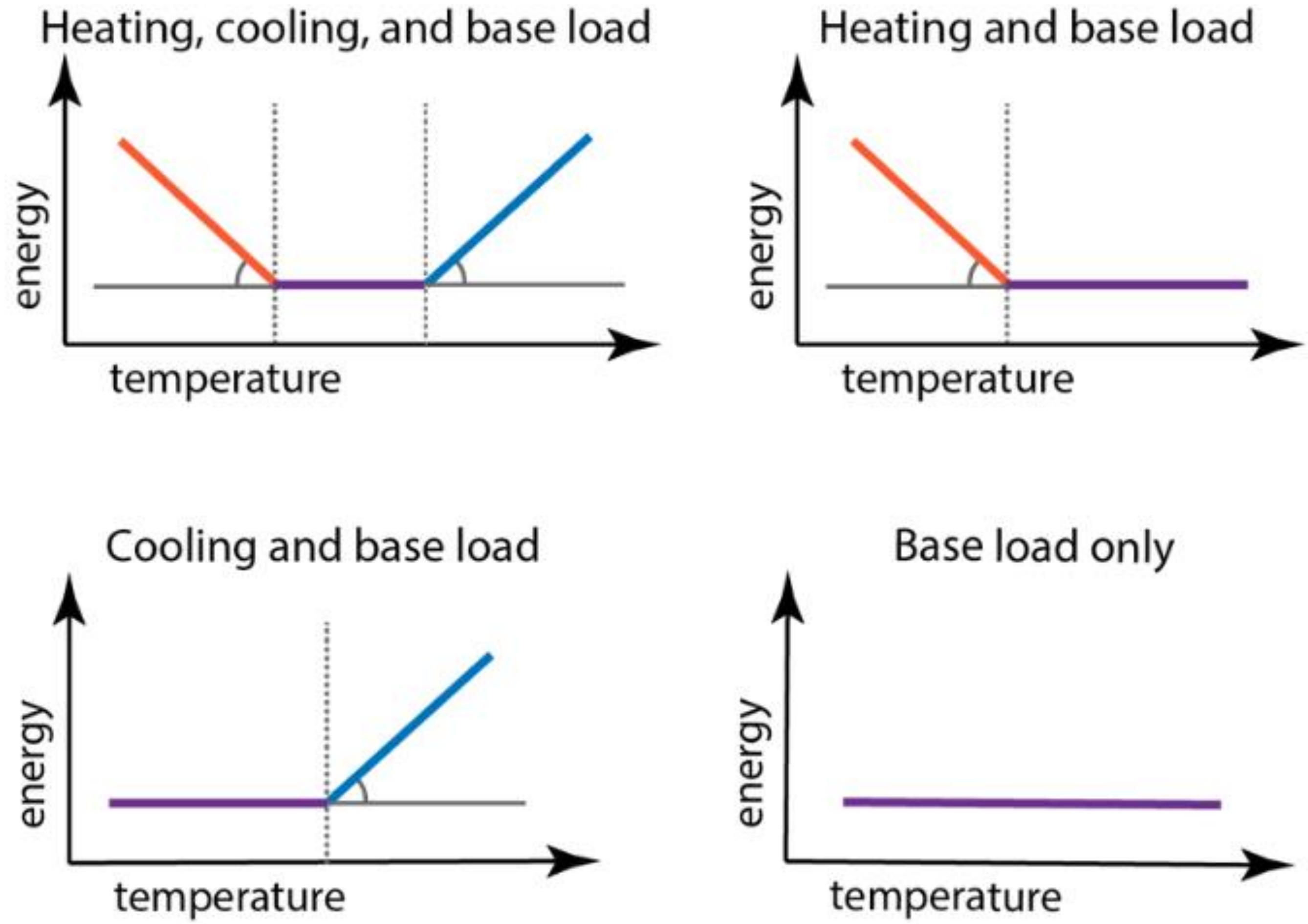
Content on this slide was not presented during the live session but was submitted by the presenter for posting

OpenEEmeter Model Implementation

Content on this slide was not presented during the live session but was submitted by the presenter for posting

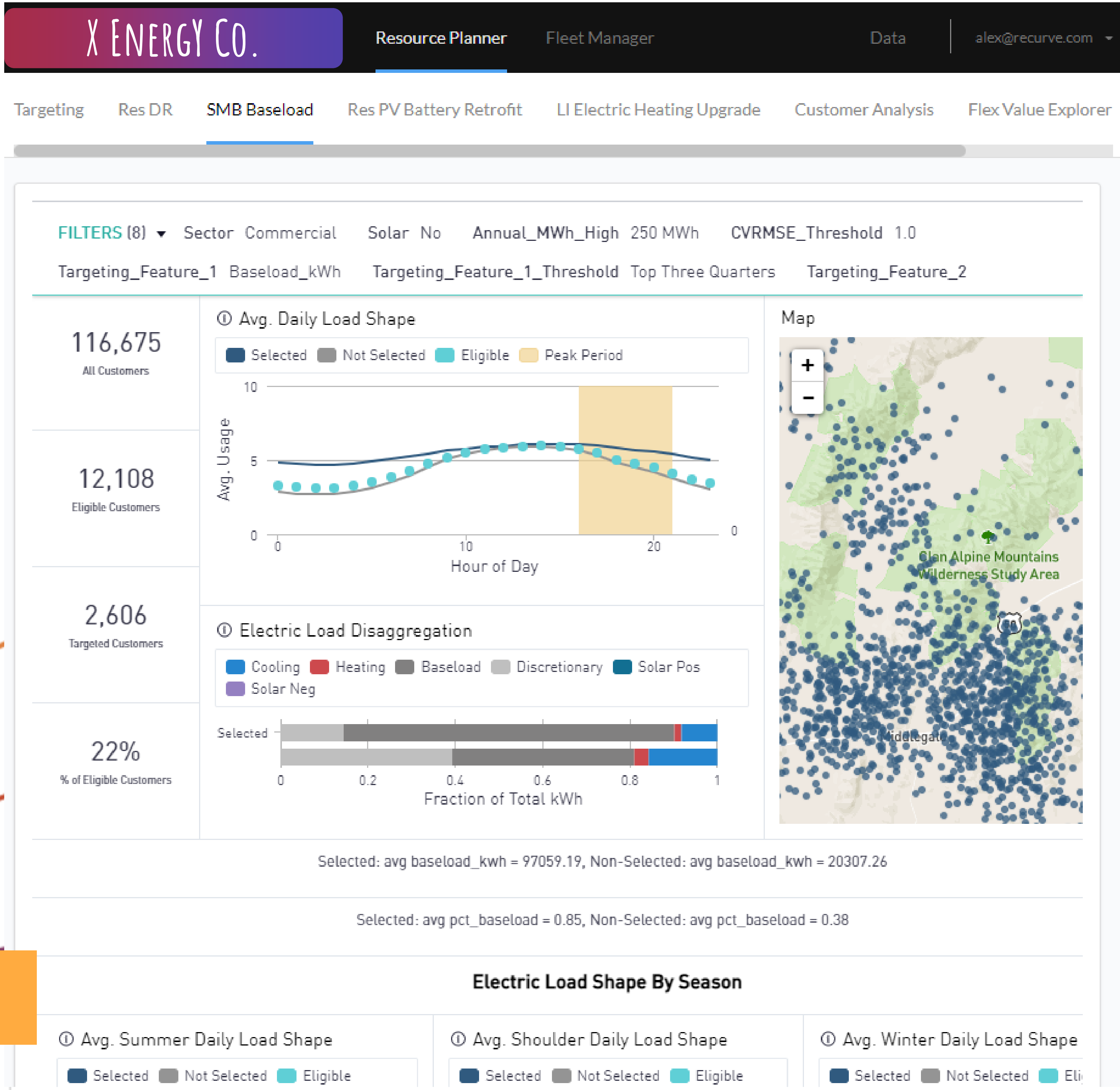
OPENEEMETER

- Four candidate models:
  - No heating or cooling load
  - Heating and temp independent load only
  - Cooling and temp independent load only
  - Heating & cooling load
- Heating and cooling loads assumed to have a linear relationship with heating and cooling demand



Targeting Platform

1. Recurve processes customer data - the output is customer usage characteristics
2. Select a group of eligible customers
   a. E.g. residential non solar, grocery, etc.
3. Select customer usage characteristics and thresholds to meet program goals
   a. Peak usage %, Cooling MWh, Evening ramp
4. Download list of customers for program implementation



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Optimizing Energy Efficiency to Serve Small Businesses in Disadvantaged Communities

https://www.youtube.com/watch?v=CIDGP1d0Q2Y

EPRI

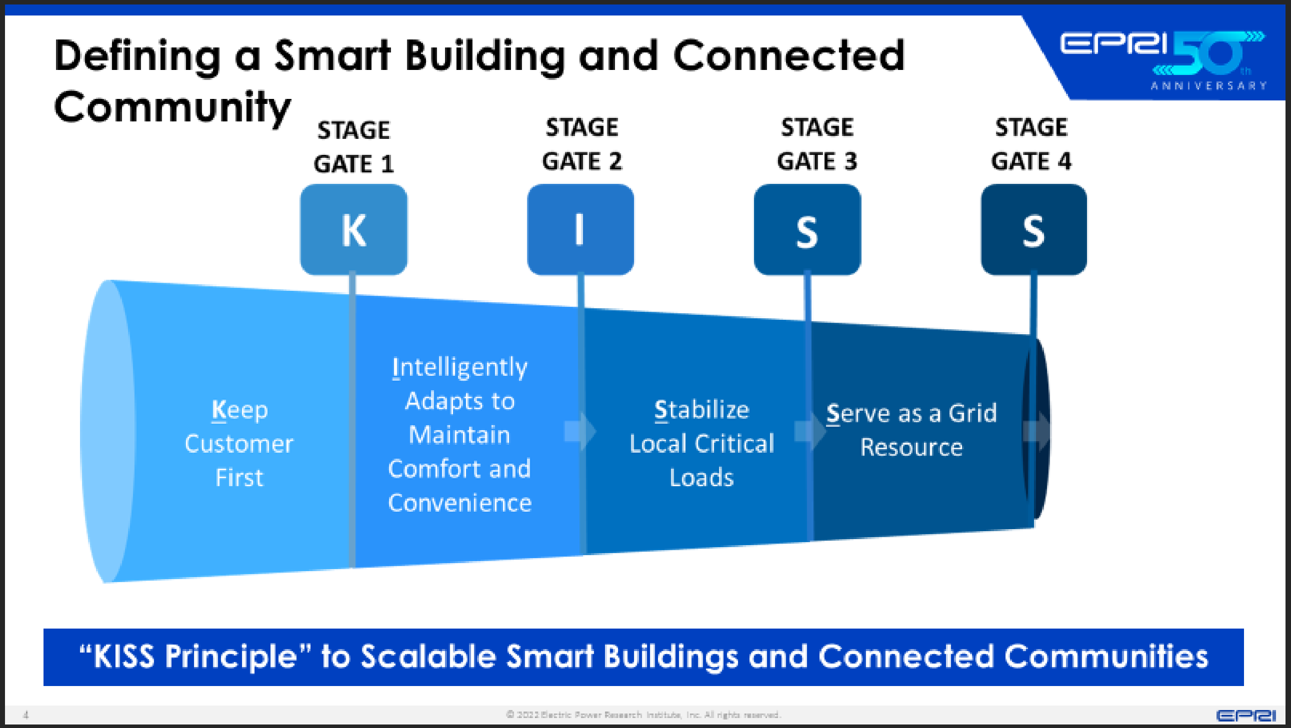
Active Demand Response from the Customer Lens

Presentation for Connecticut's Comprehensive Energy Strategy Technical Session – Session 5 (Active Demand Response)

November 3, 2022

Presented by: Ben Clarin – Principal Manager at EPRI

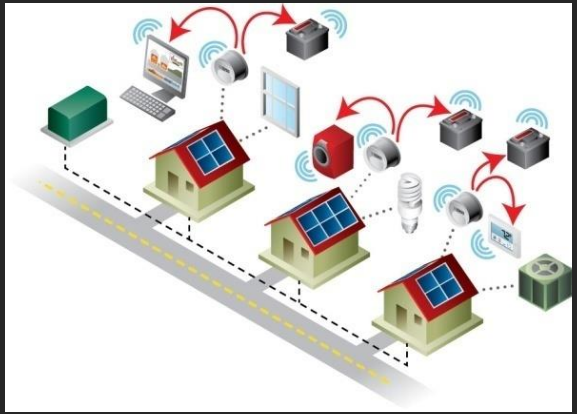
Assessing Active Demand Response Leveraging Customer End-Use Technologies



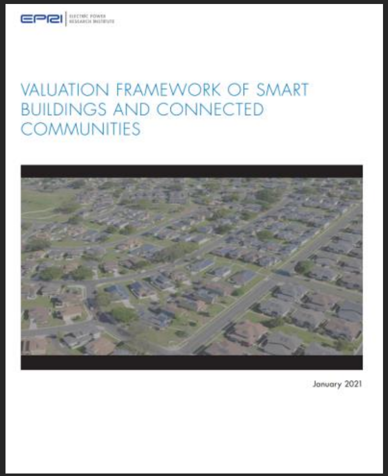
- 200 gigawatt resource[1] from 1 billion machines[2]
- Energy impacting vs. energy resource
- " KISS Principle"
- Enablement and scale
- Innovative vs. Industry Innovation?

Sources:
[1] Hledik, Ryan et. al. The National Potential for Load Flexibility. The Brattle Group. Washington, DC. 2019.
[2] https://www.rewiringamerica.org/policy/one-billion-machines

EPRI Project Portfolio - Demand Response from the Customer Lens



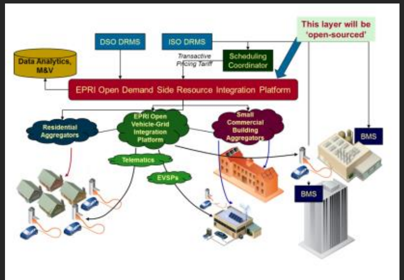
Technology Scouting and Assessment



EPRI | ELECTRIC POWER RESEARCH INSTITUTE

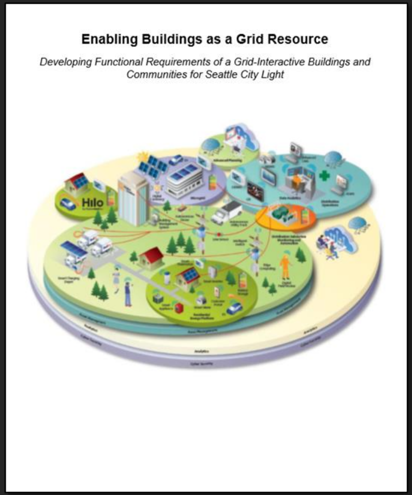
VALUATION FRAMEWORK OF SMART BUILDINGS AND CONNECTED COMMUNITIES

January 2021



Value Frameworks and Tools

Webcasts and Stakeholder Discussion

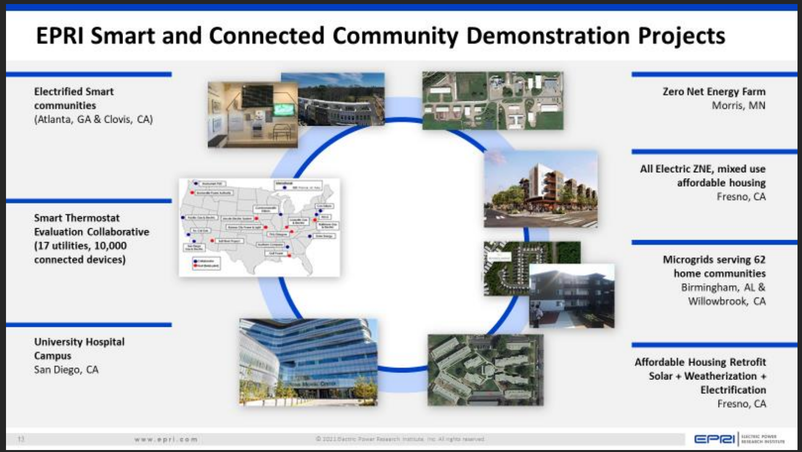


Enabling Buildings as a Grid Resource

Developing Functional Requirements of a Grid-Interactive Buildings and Communities for Seattle City Light

Functional Requirements and Standards Activities

Market Assessment and Feasibility Studies



Demonstration and Deployment

Main Takeaways – Active Demand Response

- Demand response and active demand management is a tool and not “the tool” – enablement and scale (when and where).
- Non-industry players are still “unboxing” demand response
- Building technologies = (1) rapid technology change and (2) energy “impacting” decisions.
- The devils are in the details…. And the details are in data
- With interoperability comes interdependency

Together...Shaping the Future of Energy™

WeaveGrid

WeaveGrid

October 2022

WeaveGrid Presentation - Comprehensive Energy Strategy Technical Session

Enabling new connections to better support the EV transition

UTILITY

Access to visibility, control, and customer engagement

Resilience & Affordability

DRIVER

Direct incentives, better rates, lower EV cost of ownership

Savings & Satisfaction

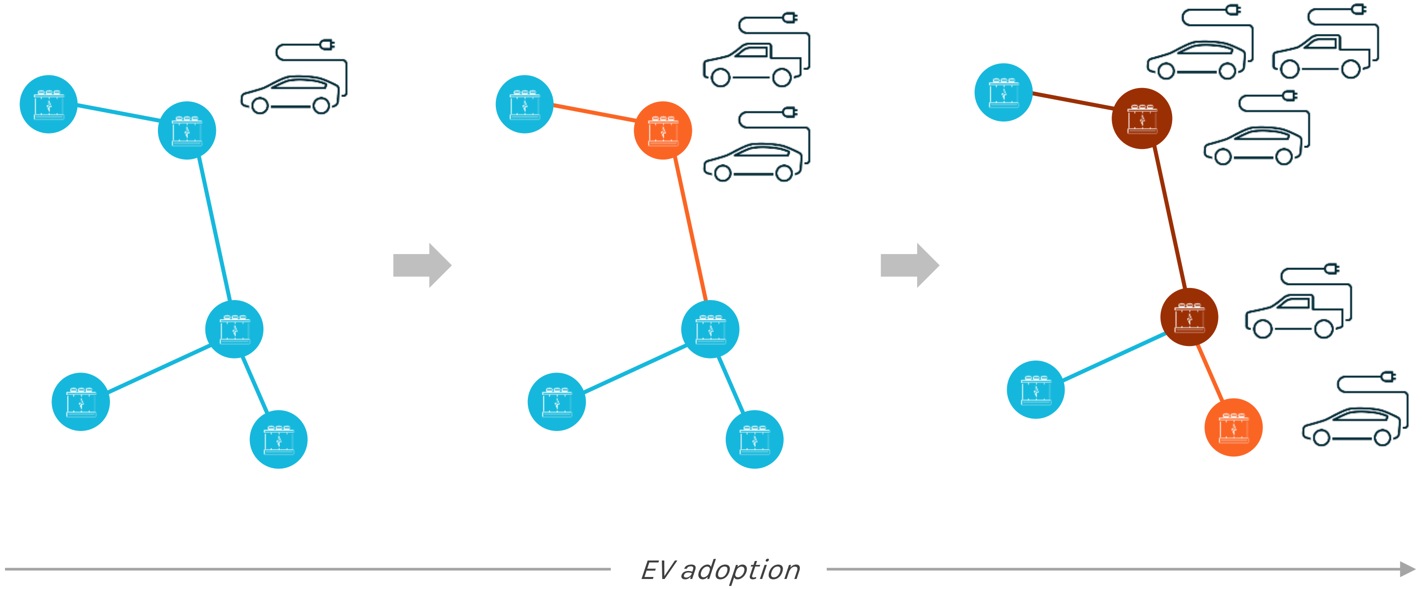
AUTO OEM

EV market uptake and better customer experience

Higher Sales & Loyalty

Complex challenges for utilities at the grid edge

OVERLOADING FROM EVs LEADS TO DISTRIBUTION ASSET AGING AND FAILURE



Distribution node (e.g., transformer)

Distribution wiring

1x EV

The grid was not designed with EVs in mind.

80% of charging happens at home

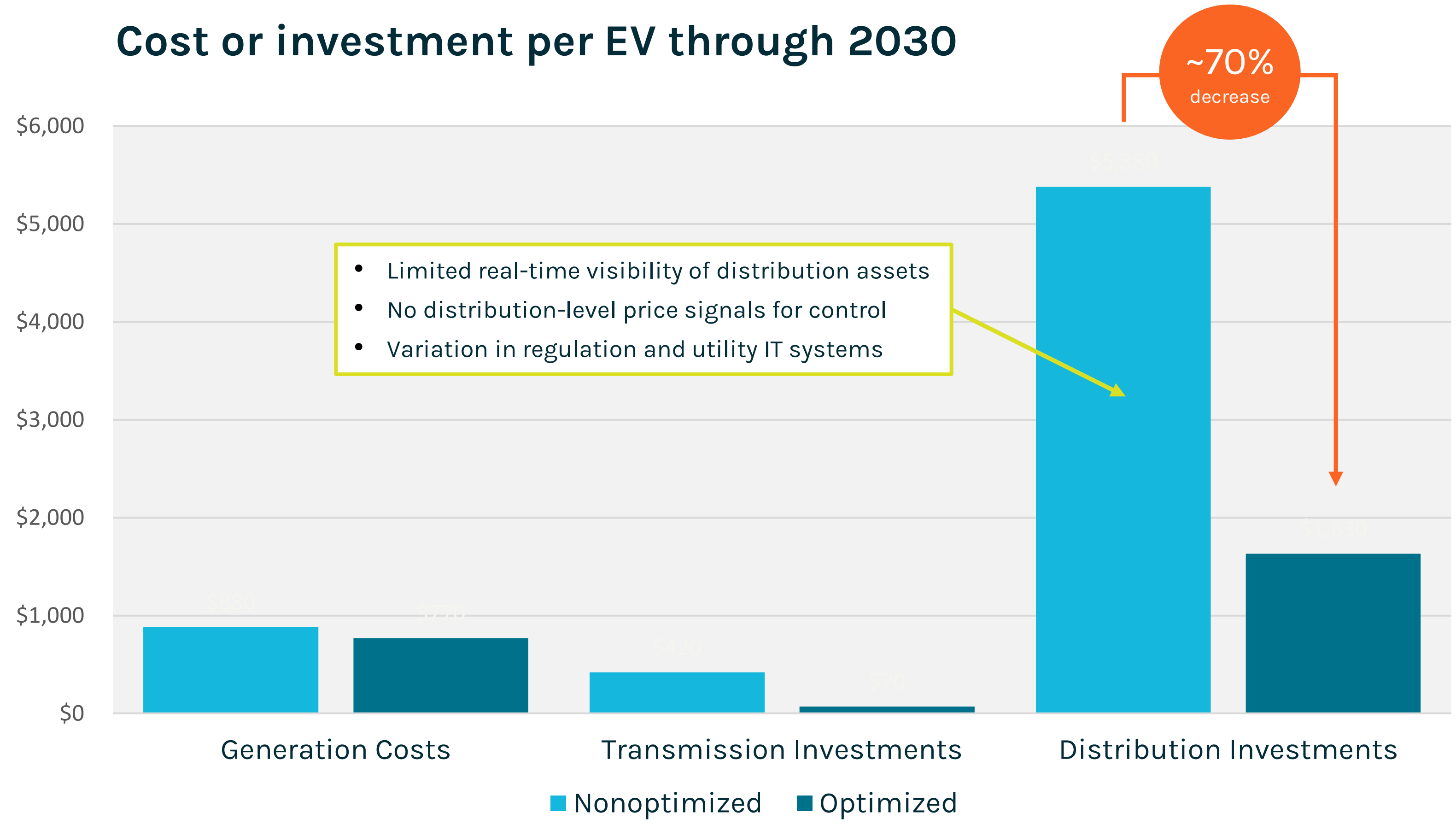
Level 2 charger = 2-3 homes' demand

EV adoption is very clustered

Local transformer supports 4-8 homes

WeaveGrid

Managed and optimized charging can reduce EV-related costs for the distribution system



[1]https://www.bcg.com/publications/2019/electric-vehicles-multibillion-dollar-opportunity-utilities

80% of charging happens at home

Level 2 charger = 2-3 homes' demand

EV adoption is very clustered

Local transformer supports 4-8 homes

WeaveGrid

WeaveGrid’s core principles for managed charging programs: focus on drivers’ experience and grid benefits

DRIVER FIRST

- Consider mobility as customer need first and foremost
- Avoid assumptions based on EV first adopter behavior
- Promote rewards, not penalties

DRIVER EXPERIENCE MEETS UTILITY NEED

- Keep industry complexity and terms away from customers
- Simplify experience across multiple program types
- Minimize balkanizing EV experience by utility territory

MAXIMIZE GRID BENEFITS

- Focus on continuous optimization
- Optimize for local and bulk system constraints
- Transition from reactive to proactive

Utilities are designing and implementing managed charging programs based on capabilities and system needs

SOLUTION	OBJECTIVES	CASE STUDY
Passive Managed Charging	• Understand charging patterns • Identify risks to grid • Shape charging behavior • Enable billing for EV-only rates	bge, pepco
Active Managed Charging	• Activate load shifting • Meet driver preferences • Manage for EV/TOU rates	Xcel Energy, Portland General Electric
Advanced Value Streams	• Integrate with AMI, GIS, DMS • Co-optimize for bulk & distribution system constraints • Unlock full EV-grid value	exelon, U.S. Department of Energy, Pacific Gas and Electric Company, SRP

WeaveGrid

October 2022

Thank you!

Steve Bright

Policy and Regulatory Affairs Manager, East
steve@weavegrid.com

The Brattle Group

The National Potential for Load Flexibility

VALUE AND MARKET POTENTIAL THROUGH 2030

PRESENTED BY

Ryan Hledik

Connecticut DEEP Technical Session on Active Demand Response

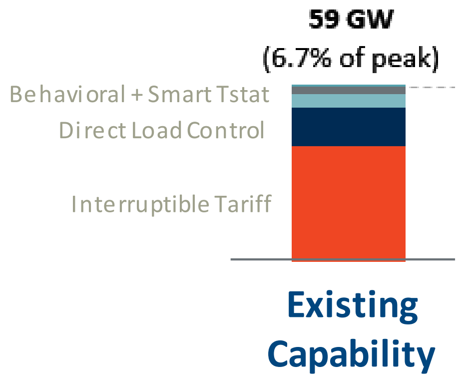
November 3, 2022

THE Brattle GROUP

The national potential for load flexibility

You can't spell "DER" without DR. It's one of the largest DRs available in the US today.

U.S. Cost-Effective Load Flexibility Potential

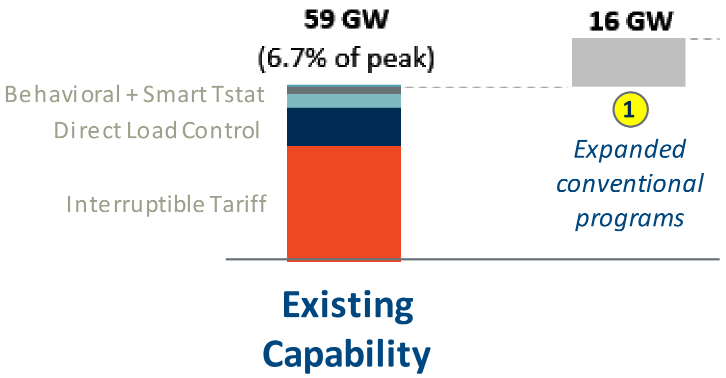


Notes: Existing DR capability does not account for impacts of retail pricing programs, as fewer than 1% of customers are currently enrolled in dynamic pricing rates and the impacts of long-standing TOU rates are already embedded in utility load forecasts. See appendix for summary of key modeling assumptions.

The national potential for load flexibility

Existing DR programs can be modernized and expanded to attract new participants.

U.S. Cost-Effective Load Flexibility Potential



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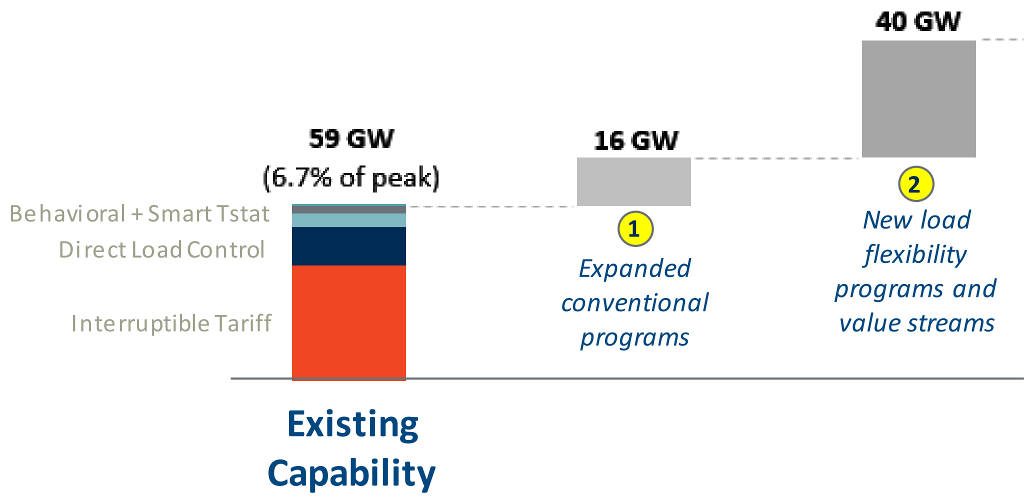
The national potential for load flexibility

New load flexibility programs will incorporate emerging technologies and capture additional value streams.

U.S. Cost-Effective Load Flexibility Potential



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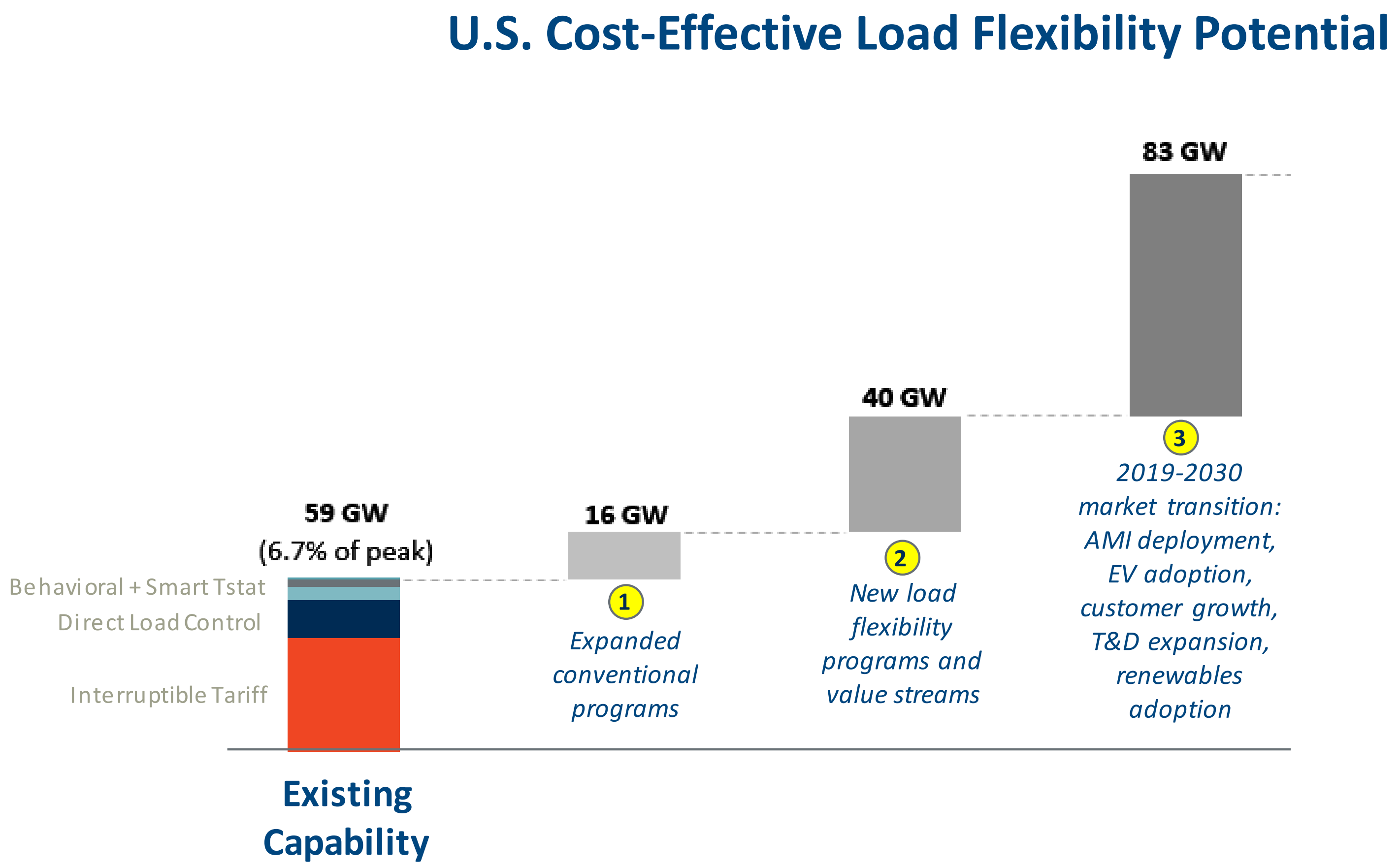
The national potential for load flexibility

The energy transition will improve the economic attractiveness of load flexibility.



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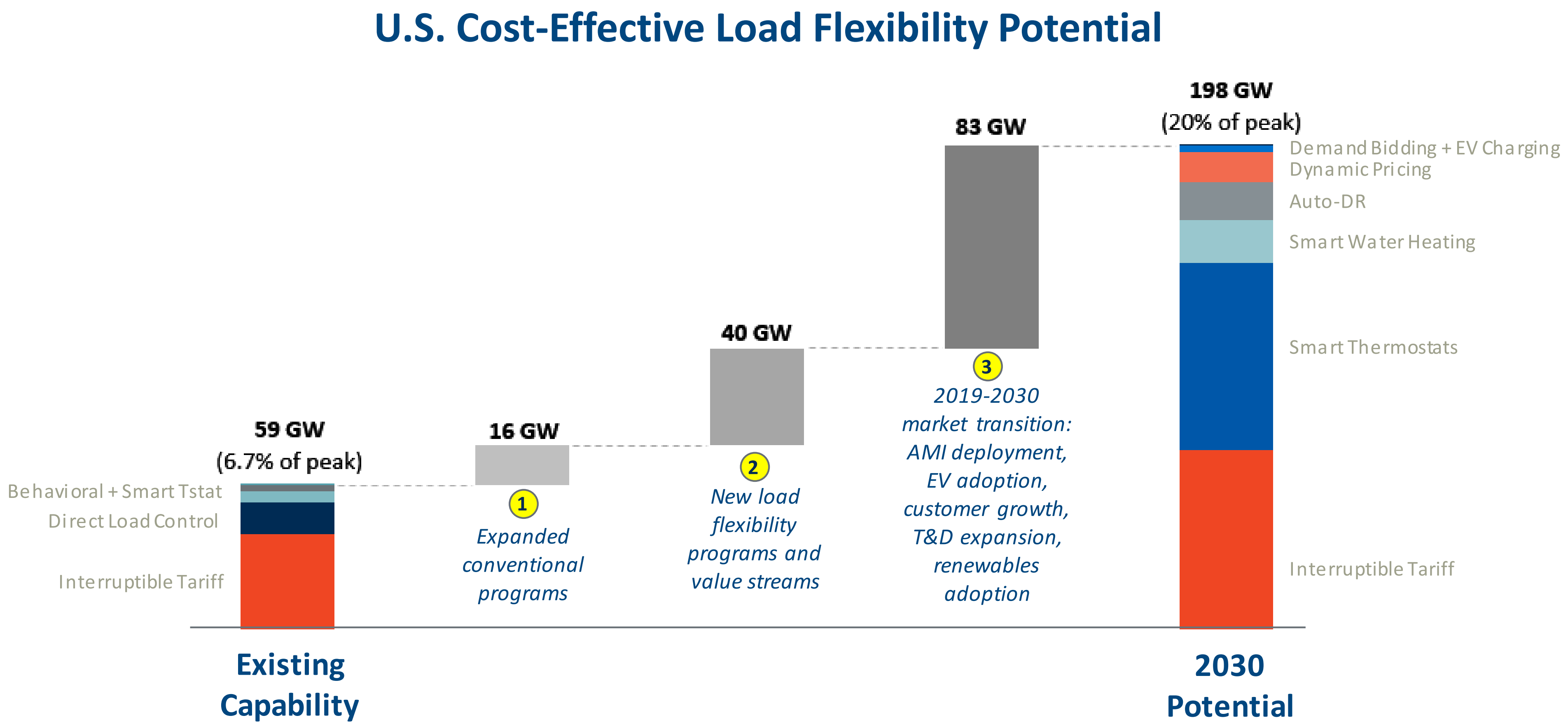
The national potential for load flexibility

A portfolio of load flexibility programs could triple existing DR capability, approaching 200 GW (20% of system peak) by 2030, with annual benefits exceeding $15 billion



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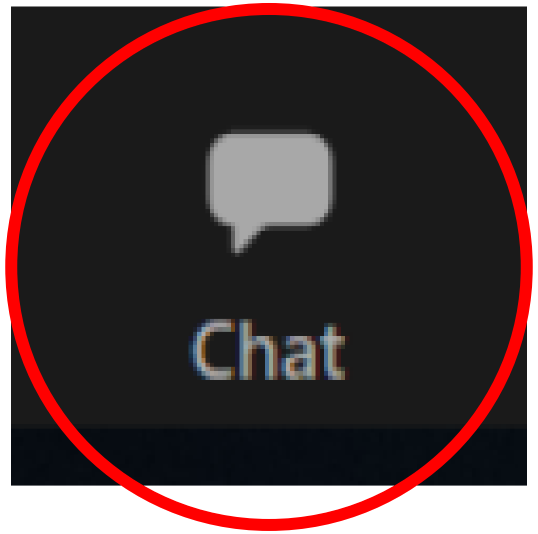
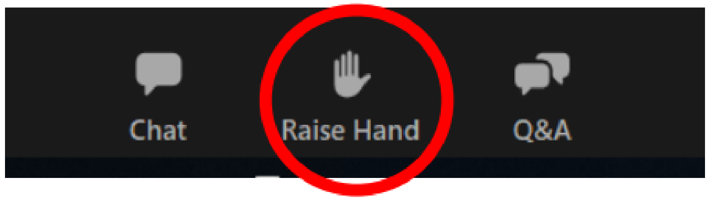
Questions

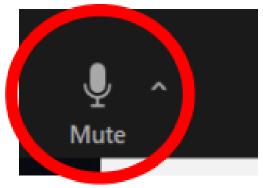


At the conclusion of each panel DEEP will hold a brief question and answer period.

If you have a question for a presenter, please drop it into the chat to **Jeff Howard**. DEEP will pose as many questions as time allows to the speakers. Clarifying questions will be prioritized. Leading questions will not be accepted.

Public Comments





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If you would like to make a comment during the public comment periods:

- Please use the “Raise Hand” feature if you would like to speak
- After any interested elected officials have provided their comments, you will be invited to provide your comment in the order the hands were raised
- Please unmute yourself, state your name and affiliation
- Given time limitations, please limit your comment to 2 minutes.
- After your comments, please remember to click the “Mute” button

General Public Comment

BUREAU OF ENERGY AND TECHNOLOGY POLICY

WRAP UP

Thanks for joining our technical session today!

Written comments related to this session, or the general Comprehensive Energy Strategy can be submitted to:

1. BETP's Energy Filings web page – or –
2. Via email to DEEP.EnergyBureau@ct.gov

All information on upcoming Comprehensive Energy Strategy technical sessions and written comment opportunities can be found on the CES webpage

This slide deck and a recording of this session will be posted on the CES webpage

Written Comments related to this technical session are due
Monday, November 21, 2022, at 5:00 p.m. ET

Thank you for joining!

Questions? DEEP.EnergyBureau@ct.gov

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