DER INTEGRATION & COMPENSATION INITIATIVE

WEBINAR #3: COMPENSATION OPTIONS FOR AGGREGATED DER GRID SERVICES

January 8, 2024
Problem Statement

Current and anticipated growth of distributed energy resources (DERs) and introduction of aggregated DERs into wholesale markets as a result of Order 2222 is fundamentally changing the way the grid is planned and operated.

Policy makers and regulators will increasingly need to evaluate, consider, and establish the rules and requirements as well as enabling policies and programs to bring these resources online safely and fairly to provide retail and wholesale services.

New myriad technical and economic issues will require new information and tools to make informed decisions related to the connection, technical operation, and compensation of aggregated distributed energy resources---in the distribution, bulk power system, and wholesale energy markets.
Convene and support state members to understand the impact of their decision making related to the connection, operation, and compensation of aggregated DERs.

NARUC and NASEO will provide information, tools, access to experts, and peer sharing opportunities that assist members with FERC Order 2222 implementation in RTO/ISO regions and State oversight of transmission-distribution-customer (TDC) coordination outside of RTO/ISO regions.

**Objectives:**
- Inform key state decision makers
- Raise and evaluate risks and opportunities of different decision options
- Bring different perspectives to the table

**Advisory Group:**
An advisory group of 10 NARUC and NASEO members representing diverse regional perspectives help guide the project.
Curriculum Design 2023-24

The DER I&C Initiative 2023-24 curriculum is designed around three sequential modules:

1. **Module 1 – The modern landscape**
   - Learn best practices & lessons from what’s being done today
   - Dec '23 - Jan '24

2. **Module 2 – Hot topics**
   - Collectively explore cutting-edge applications
   - First Half 2024

3. **Module 3 – Deep dive**
   - Advance a pressing topic through intentional collaboration
   - Second Half 2024
Module 1: The Modern Landscape

Learn best practices & lessons from what’s being done today

Module 1 begins with three webinars in December 2023 and January 2024:

- **Webinar 1:** Aggregated DER Grid Services, December 4, 2023
- **Webinar 2:** Aggregated DER Valuation, December 18, 2023, 3:00-4:30pm ET
- **Webinar 3:** Compensation Options for Aggregated DER Grid Services, January 8, 2024, 3:00-4:30pm ET

Moderator: Commissioner Riley Allen, VT PUC
Expert: Travis Kavulla, NRG
Panelist: Pete Polonsky, Hawaii PUC
Panelist: Carmen Best, Recurve

Objective: Provide an overview of various compensation approaches, including their strengths and weaknesses, such that decision-makers can evaluate which approaches are best aligned with their context and objectives.

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<tr>
<th>Time (ET)</th>
<th>Agenda</th>
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<tbody>
<tr>
<td>3:00-3:10pm</td>
<td>Welcome and DER I&amp;C initiative</td>
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<td>Opening remarks: Moderator, Commissioner Allen (VT)</td>
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<td>3:10-3:35pm</td>
<td>Presentation on Compensation Options of ADER Grid Services: Travis Kavulla, NRG Q&amp;A</td>
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<td>3:35-3:55pm</td>
<td>Panelists:</td>
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<td>• Pete Polonsky, Hawaii PUC</td>
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<td>• Carmen Best, Recurve</td>
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<tr>
<td>3:55-4:25pm</td>
<td>Moderated and audience Q&amp;A</td>
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<tr>
<td>4:25-4:30pm</td>
<td>Closing</td>
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Perspectives on Compensating DER Aggregations

Travis Kavulla
Vice President of Regulatory Affairs, NRG

DER Integration & Compensation Initiative
NASEO & NARUC       Jan 8, 2024
Not the First Rodeo...
The idea that changing the shape of demand over time is a worthwhile undertaking for a consumer at all depends on supply prices that vary over time.

- Prices in the wholesale market are usually time-variable (e.g., energy & ancillary services) or demand-based (capacity & transmission).
- Prices in retail market are often flat—they don’t reflect the underlying cost characteristics of the wholesale market. But that is slowly changing...

If ADER doesn’t have access to ‘Prices’, then a regulator/utility can manufacture an indirect way to convey value for DERS’ demand-shaping services: A ‘Program’.
Supply Growing More Volatile and Peaky, as Demand Grows ...Will Prices Reflect That?

Demand side of market has increasingly obvious role to play

- “Retail rate design reduces the amount of capacity procured and triples the capacity contribution of solar in the electrification scenario.”
  - PJM, Energy Transition in PJM: Emerging Characteristics of a Decarbonizing Grid (May 17, 2022)

- “The Pilot results indicated that customers, both overall and low- and moderate-income customers specifically, responded to the rate by shifting usage off-peak ... by 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)

- New York’s Climate Leadership Council estimates a $41B cost to deep decarbonization with ‘uncontrolled’ electrification -- $28B with efficient rate design
Prices:
Retail Rates & Wholesale Markets
So What Are ‘Prices’?

Retail rates are prices

Ratemaking a process by which to collect a utility’s embedded cost structure

A century-old problem in utility regulation is how to align rates more to marginal cost to allow demand to participate

In places with retail competition, the supply portion of the bill is not subject to ratemaking & marginal-cost principles apply

Wholesale markets set price by auction, bilateral trade, or ratemaking

RTO energy auctions and bilateral trading usually are reflective of marginal costs

Transmission rates for wholesale service are based on embedded cost of service but are usually demand-based (e.g., billed based on a transmission customer’s peak demand)
• Time-of-use rates have been theorized for a century, and in effect in some places for many decades

• TOU rates are evolving to be peakier, reflective of evolving cost structure & new sources of demand (e.g., EVs)

• The deployment of Advanced Metering Infrastructure allows TOU to be billed more accurately, at more granular intervals, ubiquitously across the customer base

In USA, Smart Meters Widely Deployed... Only 5 States Use Them for Default Retail Pricing

Adapted from: Cooper and Shuster, “Electric Company Smart Meter Deployments: Foundation for a Smart Grid,” Institute for Electric Innovation, April 2021, p. 3.
What Goes Into a Time-of-Use Rate?

**Illustrative National Grid MA TOU Rate**

<table>
<thead>
<tr>
<th>On-Peak</th>
<th>Off-Peak</th>
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<td>Winter</td>
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<td>Supply</td>
<td>2.7:1</td>
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<td>Transmission</td>
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<td>Capacity</td>
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<table>
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<tr>
<th>Summer</th>
<th></th>
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</thead>
<tbody>
<tr>
<td>Supply</td>
<td>4.0:1</td>
</tr>
<tr>
<td>Transmission</td>
<td></td>
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<tr>
<td>Capacity</td>
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- 4 3-month pricing seasons and on-peak hours 7am-11 pm.
- The supply prices shown based on hourly 5x24 DA ISO-NE settlement prices at MASSHB, 2018-2022.
- Capacity prices from ISO-NE and allocated to on-peak hours.
- Transmission prices from National Grid, but adjusted to apply to on-peak hours.

**Oil-fired generation as a % of total supply in ISO-NE 01/21 to 03/23**

- 0.0%
- 2.0%
- 4.0%
- 6.0%
- 8.0%
- 10.0%
- 12.0%
Real-Time Pricing, a.k.a. Dynamic Rate

Sunday
25th February 2023

For electricity meter

Total cost
£ 1.05

Total consumption
4.17 kWh

Weighted average unit rate
25.14 p / kWh

Monday
1st May 2023

For electricity meter

Total rebate
£ -0.52

Total export
4.76 kWh

Weighted average unit rebate
-10.83 p / kWh
Griddy (not to be confused with Gritty) offers a cautionary tale.

Griddy, an ERCOT Retail Electric Provider, offered to pass through wholesale energy pricing directly to retail customers for a small monthly subscription fee.

- Catastrophically failed during Winter Storm Uri when wholesale prices = $9,000/MWh.
- Griddy, an exception that proves the rule: Intermediaries bear an important role standing between wholesale market & retail customers.
Monthly Subscriptions

- Subscriptions offered by utility

- Third party aggregators/brokers could evaluate offers and manage risk
  - Hedges
  - Comprehensive device management

Device-Specific Dynamic Rates

$0.0272 per kWh Lowest Energy Rate | $0.0569 per kWh Highest Energy Rate

TRANSACTIVE ENERGY RATES FOR WEEK STARTING SUN, DEC 24

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Reliant (NRG retailer) has been able to engage its customers in demand response through smart thermostats in two ways:

- **Direct Load Control**: Average 20-30% reduction in customer demand during the period thermostat is controlled.
- **Behavioral DR**: Customers who actively participate lower their demand by approximately 10-15%.

- Reliant’s standalone thermostat ADER program has grown 40% in 4 years.
- Customers are also increasingly adopting other DERs like battery storage. A customer in a detached single-family home that has smart HVAC controls paired with battery storage can reduce demand by up to 40-100% (on average) over a four-hour period, depending on the size of their battery.
So What About Wholesale Pricing?

- FERC Order 719 (2008) allows Demand Response to be aggregated for sale into RTOs
  - DR aggregators may sell energy, capacity, ancillary services into RTO auctions
- FERC allowed states to forbid third-party aggregators from participating in RTOs
  - MO recently lifted its ban, while MN recently decided not to lift its ban

Source: Sydney P. Forrester, Cole Triedman, Sam Kozel, Cameron Brooks, and Peter Cappers, Lawrence Berkeley National Laboratory, *Regulation of Third-Party Aggregation in the MISO and SPP Footprints*, p. iv. [Link](#).
Participation in eastern markets dominated by capacity products
  • Follow the money!

“Classic” revenue streams for demand products are trending down as capacity prices fall and energy markets are tempered.

Order 2222

- Extends Order 719 principles of market access for DR to ADER
- No state opt-out
- Applies *only* in RTO footprints (so not West or Southeast)
- RTOs all over the map on implementation timeline
The Price Is Right?

• ‘Price’-oriented ADER business models require prices that express marginal cost and grid needs – rather than being flat and non-time-varying
  • Most retail rates continue to be flat

• Requires that prices, collectively, express the full range of value of ADER
  • E.g., DER may not earn transmission avoided-cost benefit if regulator sets transmission retail pricing flat (regardless of upstream demand-related rate design)

• Retail competition and RTOs are useful, if not necessary, for ‘Price’-oriented ADER
  • Multiple competitive retailers will evolve to cater to and compete for DER-adopting customers, and pace of innovation > utility regulation
  • RTOs markets present some barriers, but more open than non-RTO, vertically-integrated utilities
  • If Retail Competition/RTOs don’t exist to express prices, then diverse and time-varying utility rate offerings can be a path for “Price”-based ADER
Programs
An Alternative or Supplement to Incomplete Prices

• So perhaps you don’t think that prices are a good way to efficiently allocate scarce resources

• You can always stand up a ‘Program’ instead to do what ‘Prices’ do
  • May be particularly appropriate where there are specific needs for ADER (like local distribution system congestion)

• Typically rely on incumbent utilities to finance them with ratepayer subsidies
  • Also examples where competitive retailers offer rebates for activating customer DER, or
  • Where RTOs solicit (outside the typical markets they run) for particular needs
Subsidy for Device in Exchange for Utility Control

- The most common type of ‘Program’ which uses ratepayer funding to incentivize customer adoption of DER (in this case, a smart thermostat)

- Compensation not directly aligned to value of energy, capacity, transmission

- Gives utility right in pre-specified conditions to dispatch ADER remotely through its DERMS provider

<table>
<thead>
<tr>
<th>CYCLING OPTION</th>
<th>TEMPERATURE INCREASE</th>
<th>ANNUAL REWARD*</th>
<th>INSTALLATION CREDIT**</th>
<th>TOTAL REWARDS FOR YOUR FIRST 12 MONTHS*</th>
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<tbody>
<tr>
<td>50%</td>
<td>1-3 DEGREES</td>
<td>$40</td>
<td>$40</td>
<td>UP TO $80</td>
</tr>
<tr>
<td>75%</td>
<td>2-4 DEGREES</td>
<td>$60</td>
<td>$60</td>
<td>UP TO $120</td>
</tr>
<tr>
<td>100%</td>
<td>4-7 DEGREES</td>
<td>$80</td>
<td>$80</td>
<td>UP TO $160</td>
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Some Utilities Also Extending this Program to Batteries

Benefiting you and Vermont

You save money by joining GMP’s BYOD program. If you enroll a battery for ten years, we’ll give you an upfront payment of $850 per kW of storage enrolled for three hour discharge, $950 per kW for four hour discharge. If you’re retrofitting an existing solar system in one of the areas of the state where extra storage will help the grid most, we’ll give you an extra $100 per kW. Plus, get the benefit of knowing your device is helping to cut carbon emissions and costs for all GMP customers!

Source: While the graph is illustrative, the One-Time Rebate column is based on the participation of a Powerwall 3 in Green Mountain Power’s BYOD program (link), and the Annual Incentive column is based on National Grid’s ConnectedSolutions program. The final column illustrates the different ways a battery could participate on the grid.
Pay for Performance

• An alternative to an up-front subsidy in exchange for capacity rights to ADER is a pay-for-performance model

• To the right is an example from National Grid’s “Connected Solutions”

• Again, the benefit paid under this program is a value approved by regulators based on an approximation, and not directly connected to more dynamic ‘Prices’

Connect with a battery storage partner.

Energy-sharing events through our ConnectedSolutions program call on your battery system to automatically discharge during peak demand days, which occur as follows:

- From June 1 – September 30
- Between 3pm - 8pm
- No more than 60 times each summer
- A maximum of 3 hours per event
- You can opt out at any time

Incentives

Participating customers will receive an incentive every year based on the performance of their battery system at a rate of $275 per kW performed between June 1 and September 30. On average, customers have received $1,500 per year.

The incentive rate is locked in place for the first five summers the customer is enrolled in ConnectedSolutions with all new systems. Your battery system performance will vary based on size, configuration, internet connectivity and other factors.
ERCOT has a small, standalone capacity market for Demand Response, known as Emergency Response Service (ERS), which exists outside its ordinary energy markets.

**EMERGENCY RESPONSE SERVICE (ERS)**

ERCOT offers two types of Emergency Response Service: 10 Minute and 30 Minute.

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<tr>
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<th>10 MINUTE DEMAND RESPONSE PROGRAM (ERS 10)</th>
<th>30 MINUTE DEMAND RESPONSE PROGRAM (ERS 30)</th>
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<tbody>
<tr>
<td><strong>Notification</strong></td>
<td>Customers will be notified of an event via email, phone, text and/or electronic signal per customers’ instructions and must fully curtail within 10 minutes of start of event.</td>
<td>Customers will be notified of an event via email, phone, text and/or electronic signal per customers’ instructions and must fully curtail within 30 minutes of start of event.</td>
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<tr>
<td><strong>Minimum Size</strong></td>
<td>No minimum size; accounts of under 100 kW curtailment will be aggregated.</td>
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<tr>
<td><strong>Participation</strong></td>
<td>4 month contract periods starting February, June and October. Each period contains 4 optional time slots: weekdays 5:00AM-11:00AM (Time Period 1), 11:00AM-5:00PM (Time Period 2), 5:00PM-11:00PM (Time Period 3), 11:00PM-5:00AM (Time Period 4), and weekends/holidays/other hours including ERCOT holidays (Time Period 5).</td>
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<tr>
<td><strong>Enrollment Deadline</strong></td>
<td>One month before each contract period (January 31st, May 31st, September 30th).</td>
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<tr>
<td><strong>Distributed Generation</strong></td>
<td>Can participate independently or in conjunction with Load.</td>
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<tr>
<td><strong>Metering/Direct Load Control (DLC)</strong></td>
<td>Each account must have at least a 15 minute interval or smart meter (per ERCOT) and may also require CPower’s monitoring solution, which provides one-minute usage data.</td>
<td>No DLC requirement</td>
</tr>
<tr>
<td><strong>Number &amp; Duration of Load Response Events</strong></td>
<td>Customers over 1 MW of curtailable load must have DLC via CPower’s monitoring solution (CPower’s requirement).</td>
<td>Customers may be called to curtail load for up to 12 hours per contract period.</td>
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<tr>
<td><strong>Testing</strong></td>
<td>At a minimum, a 15-30 minute test event will be called once per year absent successful event deployment.</td>
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<tr>
<td><strong>Capacity Payments</strong></td>
<td>Customers are paid based upon the clearing price, contract capacity and participation hours.</td>
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<tr>
<td><strong>Settlements</strong></td>
<td>Customers receive payments within 60 days of the end of the contract period.</td>
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<tr>
<td><strong>Compliance</strong></td>
<td>Customers must meet their performance obligations during events and test events, and must meet their availability requirements all other committed times.</td>
<td></td>
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<tr>
<td><strong>Consequence of Non-compliance</strong></td>
<td>Availability and performance factors are taken into consideration and can reduce payments.</td>
<td>Non-performance</td>
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Source: CPower
Comparing ‘Programs’ and ‘Prices’

<table>
<thead>
<tr>
<th>Programs</th>
<th>Prices</th>
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<tbody>
<tr>
<td><strong>What</strong></td>
<td><strong>How</strong></td>
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<tr>
<td>Utility subsidies for device adoption</td>
<td>Regulatory process defines avoided-cost value</td>
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<td>Procurements for targeted needs</td>
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<td><strong>Business Model</strong></td>
<td><strong>Pros &amp; Cons</strong></td>
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<td>ADER a utility vendor</td>
<td>A clear value target</td>
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<td>Limits to quantity and pace</td>
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The two can be complementary, especially when ‘Prices’ fail to convey ADER a particular value that is not appropriately priced (e.g., distribution or transmission)
Travis Kavulla
Vice President, Regulatory Affairs

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DER Grid Service Compensation in Hawaii

Pete Polonsky, Utility Analyst, Hawaii PUC
Presentation for the NARUC-NASEO DER I&C Initiative
January 8th, 2024
Disclaimer

This presentation does not represent the view of the Hawaii Public Utilities Commission in any capacity and is offered purely for educational purposes based on the development of DER policies in Hawaii. Information shared here is also publicly available via the Commission’s eServices website, largely in Docket No. 2019-0323.
The Hawaii Context

High rooftop solar penetration

Long way to go to get to 100% renewables by 2045

Battery Bonus Program

**Why?** An emergency need for replacement resources as the last coal plant on Oahu was required to retire in September 2022, and upcoming solar-plus-storage projects were significantly delayed, leading to concerns about reliability during the evening peak.

**What?** A customer program that provides incentives for customers installing a new battery, connected to rooftop solar, and requiring the customer to discharge the battery for two consecutive hours during the evening peak every day for 10 years.

**How?** Within the Commission’s proceeding to investigate distributed energy resource policies for Hawaiian Electric, the parties modeled a variety of program options to determine a range of values and incentives for the program.
Battery Bonus Incentives

1) Upfront incentive: $850/kW of customer’s capacity commitment

2) Monthly capacity payment: $5/kW of capacity

3) Retail rate energy export credit for exports during program for first 3 years of enrollment

Example: for a 5-kW battery system, a customer receives $4,250 upfront, $25/month for 10 years, and a bill credit of ~$60 per month for 3 years.
Next-Gen DER Programs, Launching March 1st

Smart DER Program

• Replaces all NEM and post-NEM DER programs as the basic program
• Non-export option and export option
• Open to all renewable customer-sited generation
• Export option provides time-varying compensation for export
• Oahu rates:
  • Daytime (9am-5pm): $0.135/kWh
  • Evening Peak (5pm-9pm): $0.329/kWh
  • Overnight (9pm-9am): $0.189/kWh

Decision & Order No. 40418, December 4th, 2023
Next-Gen DER Programs, Launching March 1st

Bring-Your-Own-Device Program

- Replaces Battery Bonus as a supplemental, optional tariff for grid service compensation
- Three “levels” with distinct operational requirements and incentives
  - Level 1: Flexible User Dispatch
  - Level 2: Utility Dispatch
  - Level 3: System Grid Services
- Similar incentive structure to Battery Bonus:
  - Upfront: $100/kW, up to 5 kW
  - Monthly: $5-10/kW
  - Energy Export Credit at the evening peak Smart DER rate
- Three-year customer commitment

Decision & Order No. 40418, December 4th, 2023
Compensation for Long-Term DER Programs

Modeling Efforts

- Hawaiian Electric adapted modeling efforts from the utility planning process for use in DER program development
- Several iterations of modeling occurred with feedback from the Commission and other stakeholders
- Modeling evaluated the impact on the grid of freezing DER installations at today’s levels

DER Value Streams

- The Commission outlined 8 applicable DER value streams that should be reflected in DER compensation:
  - Energy Generation Impacts
  - Capacity Impacts
  - RPS Compliance Impacts
  - GHG Emissions Impacts
  - Grid Services
  - Transmission System Impacts
  - Distribution System Impacts
  - Resilience Impacts
Compensation for Long-Term DER Programs

Finalizing Incentives

• The Commission “mapped” the results of the modeling efforts to the identified DER value streams, and used the modeling results to establish additional incentives

• Not all DER value streams are represented clearly in the incentives, so...

Update Framework

• ...the Commission established an update framework for the new programs

• Updates every three years after program launch

  • Export rates
  • Incentives
  • Interconnection requirements
  • Eligible technologies
  • Operational requirements
Alignment with Other Initiatives

Grid Service Purchase Agreements

Integrated Grid Planning Process

Energy Equity and Justice Docket
Key Takeaways: Program Design

- Develop DER incentives that balance the value DERs provide to the grid with the need to support a robust DER market.
- Embed iteration and evolution in program design, especially as electric grids are actively evolving.
- Acknowledge the role of DERs in utility planning processes and the role of utility planning in program development so that plans and programs are consistent.
Key Takeaways: Stakeholder Process

- Push for compromise between stakeholders (e.g., utilities and solar advocates).
- Get stakeholders together in the same room to address the merits of each other’s arguments.
- Engage stakeholders early and often to avoid delays in the process when stakeholders do not feel heard or consulted.
More Information

Hawaii PUC’s website on DER programs: https://puc.hawaii.gov/energy/der/programs/

Hawaiian Electric’s website on customer renewable programs: https://www.hawaiianelectric.com/products-and-services/customer-renewable-programs
Demand Flexibility Platform

VPP Marketplace

FLEXmarket
Compensation Should Recognize Supply and Demand

**Supply**

- Energy Resources
- Energy Storage
- Smart Meters
- Distributed Generation
- Renewables
- Energy Efficiency

**Demand**

- Load Modifying Resources
- Demand Response
- Generation
- Transmission
- Distribution
- Customers

*Supply: Energy Resources*

*Demand: Load Modifying Resources*
System Benefits from Demand-Side Resources

Load Modifying Resources (LMR)

- 15% price advantage over supply-side*
- Hedges market peak energy events
- Modifies forecast to support resource adequacy
- Provides benefits to local customers
- Incorporate the full value stack

Additional Benefits from Demand-Side Resources

Quantify value

Avoided Energy & Capacity Costs

Air Quality / Carbon

Equity / Resilience

Provide time-valued price signal

Enable Aggregators

Support Customers

Value

Hour of Day
Operationalize with Open "Market Access" Model

an open, pay-for-performance marketplace where aggregators receive incentive payments for demonstrated impacts at the customers energy meter using transparent consistent measurement & verification.

"The market access approach also allows for incorporating innovative measures into energy efficiency programs, since this approach allows experimentation with measures and customer offerings without going through lengthy solicitation processes. Also, the market access approach can be used to enable integrated demand side management (IDSM) opportunities." CPUC D.23-06-055
Open-Source Measurement & Verification at the Meter

Proven accurate methods and code available publicly

OpenEEmeter is an open source toolkit for implementing and developing standard methods for calculating normalized metered energy consumption (NMEC) and avoided energy use. The OpenEEmeter library contains routines for estimating energy efficiency savings at the meter.

OpenEEmeter includes the reference implementation of the CallTRACK methods for estimating normalized metered energy savings. CallTRACK is a working group under the Energy Market Methods Consortium (EM2).
Compensation to Providers Mirrors Avoided Cost++

Price Anchored in Hourly Avoided Cost

Summer ACC V.2020

- Gross_Peak (4-7 pm)
- Net Peak (7-9 pm)

+ Geographic
+ Demographic (LMI)
+ Event-based response

Virtual Power Plants
- Business Models
- Technologies
- Consumer Finance

Demand Flexibility
- Energy Savings
- Peak Reduction
- Carbon Reduction

Grid Value
- Metered Performance
- Payment for Grid Value
- Project Finance

Customers
Aggregators
Utilities
Performance Aligns Incentives

Price Anchored in Hourly Avoided Cost

Summer ACC V.2020

- Gross Peak (4-7 pm)
- Net Peak (7-9 pm)

+ Geographic
+ Demographic (LMI)
+ Event-based response
Enable Range of Technology Agnostic Impacts

**EV charging** load shifts out of the evening peak

**Smart thermostats** reduce load across all hours, focusing on the peak
Adaptable to Multiple Procurement Models

Vertically Integrated Utilities

- Non-Wires / Pipes Alternatives
- Integrated Resource Plans & Resource Adequacy
- Clean Energy Resource or Decarbonization Goals

Generation & Transmission Providers

- Wholesale Aggregation for member companies
- All Source Procurements
- Carbon Credit (Energy Attribution Credits)

Wholesale Markets

- Forward Capacity Markets
- Aggregated Distributed Energy Resource (ADER)
- Load Modifying Resource for Cooperatives & CCAs
- FERC 2222 Enabled DSM

Clean Energy Resource or Decarbonization Goals
Strategies and Examples for Action

Develop or **publish value** for pricing avoided energy usage and decarbonization

- New York's Valuation of Distributed Energy Resources (VDER)
- California's Avoided Cost Calculator (ACC)
- Efficiency cost test values

Establish **measured outcomes as the default** and utilize standardized measurement and verification

- IRA-HOMES programs measured pathway with open-source M&V
- Kansas efficiency **order** setting metered results as default

Streamline program designs for **technology-agnostic solutions** valuing short and long term load management

- Market Access model
- Integrated Demand Side Management strategies
- Outcome-based performance incentives
Thank you!
carmen@recurve.com
Thank you for joining today!

Upcoming:

- **In-Person: Integrated Distribution System Planning & Resilience Training, Jan 24-25, 2024** in Irvine, CA [state agencies only]
  
  [www.naruc.org/about-naruc/event-calendar/western-dspr-training/](www.naruc.org/about-naruc/event-calendar/western-dspr-training/)

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