WELCOME TO TODAY’S WEBINAR!

Cost-Effectiveness Reform

July 23, 2020
Today’s Speakers

- Julie Michals, E4theFuture and Steve Schiller, Schiller Consulting
- Courtney Welch and Gabe Cuadra, eSource
- Christa Heavey, E3

Webinar Moderator: Terry Fry, Cadmus Group
National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources

CEDMC's Summer Lunch & Learn Series
July: Cost-Effectiveness Reform

Julie Michals – E4TheFuture
Steve Schiller – Schiller Consulting

July 23, 2020
Why an NSPM for DERs?

Traditional cost-effectiveness tests often do not address pertinent state policies

Traditional tests are often modified by states in an ad-hoc manner, without clear principles or guidelines

DERs are treated inconsistently in many BCAs

DERs are often not accurately valued

There is a lack of transparency on why tests are chosen and how they are applied

The National Energy Screening Project (NESP) is a stakeholder organization and is open to all organizations and individuals with an interest in working collaboratively to improve cost-effectiveness screening practices.
NSPM for EE
May 2017

NSPM for DERs
Summer 2020

# NSPM State Interest and Use
(July 2020)

## # States Referencing/Applying the NSPM

- **4** PUC Order (final/tentative) on use of NSPM
- **3** Actively applying NSPM to review current test
- **5** In process of learning about the NSPM
- **25** References made in PUC/legislative proceedings

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![Map of NSPM State Interest and Use](image-url)
NSPM for DERs - Development

- Managed by E4TheFuture
- Funded by E4TheFuture and US DOE (via LBNL)
- Multiple co-authors
  - Extensive understanding of regulatory economics
  - Specialized expertise with different DERs
- Advisory Group
  - 45+ individuals
  - Diversity of perspectives
  - Input on Manual outline and drafts
NSPM for DERs – Audience and Uses

**Audience:** All entities overseeing/guiding DER decision (PUCs, SEOs, utilities, DER reps, evaluators, consumer advocates, and others)

**Purpose:** Guidance for valuing DER opportunities to inform policies and strategies that support state goals/objectives, such as:

- Expanding EE/DR plans, strategies, and programs to broader set of DERs.
- Evaluating and planning for non-wires/pipes solutions.
- Incorporating DERs into distribution system planning.
- Achieving electrification goals, including EV goals.
- Achieving environmental and carbon emission objectives.

**Applies to:**

- **Programs:** including initiatives and policies implemented by utilities or other entities to encourage the adoption of DERs.
- **Procurements:** including initiatives to procure DERs, whether built by a utility or procured from third-party vendors e.g., competitive procurement.
- **Pricing Mechanisms:** including those designed to compensate DERs for their value to the grid or to achieve other policy objectives, such as time-based pricing (time-of-use rates, peak time rebates, critical peak pricing).
NSPM for DERs: Scope

Presents a comprehensive BCA Framework

Provides guidance on single and Multi-DER BCA:

- **Single-DER analysis** - where one type of DER is assessed relative to a fixed (i.e., static) set of alternative resources
- **Multiple-DER analysis** - where multiple DERs are assessed and optimized relative to a fixed set of alternative resources
- **Dynamic DER analysis** - where all electric resources, both distributed and utility-scale, are optimized
NSPM for DERs - Outline

- **Part I:** presents Benefit-Cost Analysis Framework, including fundamental principles and guidance on development of primary and secondary BCA tests

- **Part II:** describes full range of potentially relevant DER benefits and costs and presents range of cross-cutting considerations

- **Part III:** chapters provide guidance on single-DER analysis for various DER types, and identify key factors/issues that affect BCA for each DER type

- **Part IV:** provides guidance on multiple-DER, with case studies, addressing 3 main ways that multiple-DER analysis can be conducted:
  - for a customer on-site
  - for a geographic region (e.g., non-wires solution)
  - for an entire utility service territory

- **Appendices:** provide further detail on various topics that warrant additional explanation, and which are referenced in Parts I-IV
NSPM for DERs – PART I

The NSPM Benefit-Cost Analysis Framework
NSPM BCA Framework

- Fundamental BCA Principles
- Multi-Step Process to Develop a Primary Cost-effectiveness Test
- When and How to Use Secondary Cost-Effectiveness Tests
NSPM BCA Principles

1. Recognize that EE and other DERs can provide energy or power system needs, and therefore should be compared with other energy resources and treated consistently for benefit-cost analyses.

2. Align primary test with applicable policy goals.

3. Ensure symmetry across costs and benefits

4. Account for all relevant, material impacts (based on applicable policies), even if hard to quantify.

5. Conduct a forward-looking, long-term analysis that captures incremental impacts of the DER investment.

6. Avoid double-counting through clearly defined impacts.

7. Ensure transparency in presenting the analysis and the results.

8. Conduct BCA separate from Rate Impact Analyses because they answer different questions.
Cost-Effectiveness Perspectives

- Three perspectives define the scope of impacts to include in the most common traditional cost-effectiveness tests.

- Perspective of public utility commissions, legislators, muni/coop boards, public power authorities, and other relevant decision-makers.
- Accounts for utility system plus impacts relevant to a jurisdiction’s applicable policy goals (which may or may not include host customer impacts).
- Can align with one of the traditional test perspectives, but not necessarily.
# Process for Defining Primary Cost-Effectiveness Test

## STEP 1: Articulate Applicable Policy Goals
Articulate the jurisdiction’s applicable policy goals related to DERs.

## STEP 2: Include All Utility System Impacts
Identify and include the full range of utility system impacts in the primary test, and all BCA tests.

## STEP 3: Decide Which Non-Utility System Impacts to Include
Identify those non-utility system impacts to include in the primary test based on applicable policy goals identified in Step 1:
- Determine whether to include host customer impacts, low-income impacts, other fuel and water impacts, and/or societal impacts.

## STEP 4: Ensure that Benefits and Costs are Properly Addressed
Ensure that the impacts identified in Steps 2 and 3 are properly addressed, where:
- Benefits and costs are treated symmetrically;
- Relevant and material impacts are included, even if hard to quantify;
- Benefits and costs are not double-counted; and
- Benefits and costs are treated consistently across DER types

## STEP 5: Establish Comprehensive, Transparent Documentation
Establish comprehensive, transparent documentation and reporting, whereby:
- The process used to determine the primary test is fully documented; and
- Reporting requirements and/or use of templates for presenting assumptions and results are developed.
NSPM for DERs – PART II

DER Benefits & Costs and Cross-Cutting Issues
## Ch 4. DER Benefits & Costs

### Electric Utility System Impacts

<table>
<thead>
<tr>
<th>Type</th>
<th>Utility System Impact</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Generation</td>
<td>Energy Generation</td>
<td>The production or procurement of energy (kWh) from generation resources on behalf of customers</td>
</tr>
<tr>
<td></td>
<td>Capacity</td>
<td>The generation capacity (kW) required to meet the forecasted system peak load</td>
</tr>
<tr>
<td></td>
<td>Environmental Compliance</td>
<td>Actions to comply with environmental regulations</td>
</tr>
<tr>
<td></td>
<td>RPS/CES Compliance</td>
<td>Actions to comply with renewable portfolio standards or clean energy standards</td>
</tr>
<tr>
<td></td>
<td>Market Price Effects</td>
<td>The decrease (or increase) in wholesale market prices as a result of reduced (or increased) customer consumption</td>
</tr>
<tr>
<td></td>
<td>Ancillary Services</td>
<td>Services required to maintain electric grid stability and power quality</td>
</tr>
<tr>
<td>Transmission</td>
<td>Transmission Capacity</td>
<td>Maintaining the availability of the transmission system to transport electricity safely and reliably</td>
</tr>
<tr>
<td></td>
<td>Transmission System Losses</td>
<td>Electricity or gas lost through the transmission system</td>
</tr>
<tr>
<td>Distribution</td>
<td>Distribution Capacity</td>
<td>Maintaining the availability of the distribution system to transport electricity or gas safely and reliably</td>
</tr>
<tr>
<td></td>
<td>Distribution System Losses</td>
<td>Electricity lost through the distribution system</td>
</tr>
<tr>
<td></td>
<td>Distribution O&amp;M</td>
<td>Operating and maintaining the distribution system</td>
</tr>
<tr>
<td></td>
<td>Distribution Voltage</td>
<td>Maintaining voltage levels within an acceptable range to ensure that both real and reactive power production are matched with demand</td>
</tr>
<tr>
<td>General</td>
<td>Financial Incentives</td>
<td>Utility financial support provided to DER host customers or other market actors to encourage DER implementation</td>
</tr>
<tr>
<td></td>
<td>Program Administration</td>
<td>Utility outreach to trade allies, technical training, marketing, and administration and management of DERs</td>
</tr>
<tr>
<td></td>
<td>Utility Performance Incentives</td>
<td>Incentives offered to utilities to encourage successful, effective implementation of DER programs</td>
</tr>
<tr>
<td></td>
<td>Credit and Collection</td>
<td>Bad debt, disconnections, reconnections</td>
</tr>
<tr>
<td></td>
<td>Risk</td>
<td>Uncertainty including operational, technology, cybersecurity, financial, legal, reputational, and regulatory risks</td>
</tr>
<tr>
<td></td>
<td>Reliability</td>
<td>Maintaining generation, transmission, and distribution system to withstand instability, uncontrolled events, cascading failures, or unanticipated loss of system components</td>
</tr>
<tr>
<td></td>
<td>Resilience</td>
<td>The ability to anticipate, prepare for, and adapt to changing conditions and withstand, respond to, and recover rapidly from disruptions</td>
</tr>
</tbody>
</table>
## Ch 4. DER
Benefits & Costs

### Host Customer Impacts

<table>
<thead>
<tr>
<th>Type</th>
<th>Host Customer Impact</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Host portion of DER costs</td>
<td>Costs incurred to install and operate DERs</td>
<td></td>
</tr>
<tr>
<td>Host transaction costs</td>
<td>Other costs incurred to install and operate DERs</td>
<td></td>
</tr>
<tr>
<td>Interconnection fees</td>
<td>Costs paid by host customer to interconnect DERs to the electricity grid</td>
<td></td>
</tr>
<tr>
<td>Risk</td>
<td>Uncertainty including price volatility, power quality, outages, and operational risk related to failure of installed DER equipment and user error; this type of risk may depend on the type of DER</td>
<td></td>
</tr>
<tr>
<td>Reliability</td>
<td>The ability to prevent or reduce the duration of host customer outages</td>
<td></td>
</tr>
<tr>
<td>Resilience</td>
<td>The ability to anticipate, prepare for, and adapt to changing conditions and withstand, respond to, and recover rapidly from disruptions</td>
<td></td>
</tr>
<tr>
<td>Tax incentives</td>
<td>Federal, state, and local tax incentives provided to host customers to defray the costs of some DERs</td>
<td></td>
</tr>
<tr>
<td>Host Customer NEIs</td>
<td>Benefits and costs of DERs that are separate from energy-related impacts</td>
<td></td>
</tr>
<tr>
<td>Low-income NEIs</td>
<td>Non-energy benefits and costs that affect low-income DER host customers</td>
<td></td>
</tr>
</tbody>
</table>

### Summary Description

<table>
<thead>
<tr>
<th>Host Customer NEI</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Transaction costs</td>
<td>Costs incurred to adopt DERs, beyond those related to the technology or service itself (e.g., application fees, time spent researching, paperwork)</td>
</tr>
<tr>
<td>Asset value</td>
<td>Changes in the value of a home or business as a result of the DER (e.g., increased building value, improved equipment value, extended equipment life)</td>
</tr>
<tr>
<td>Productivity</td>
<td>Changes in a customer's productivity (e.g., changes in labor costs, operational flexibility, O&amp;M costs, reduced waste streams, reduced spoilage)</td>
</tr>
<tr>
<td>Economic well-being</td>
<td>Economic impacts beyond bill savings (e.g., reduced complaints about bills, reduced terminations and reconnections, reduced foreclosures—especially for low-income customers)</td>
</tr>
<tr>
<td>Comfort</td>
<td>Changes in comfort level (e.g., thermal, noise, and lighting impacts)</td>
</tr>
<tr>
<td>Health &amp; safety</td>
<td>Changes in customer health or safety (e.g., fewer sick days from work or school, reduced medical costs, improved indoor air quality, reduced deaths)</td>
</tr>
<tr>
<td>Empowerment &amp; control</td>
<td>The satisfaction of being able to control one’s energy consumption and energy bill</td>
</tr>
<tr>
<td>Satisfaction &amp; pride</td>
<td>The satisfaction of helping to reduce environmental impacts (e.g., one of the reasons why residential customers install rooftop PV)</td>
</tr>
</tbody>
</table>
## Ch 4. DER Benefits & Costs
### Societal Impacts

<table>
<thead>
<tr>
<th>Type</th>
<th>Societal Impact</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Societal</td>
<td>Resilience</td>
<td>Resilience impacts beyond those experienced by utilities or host customers</td>
</tr>
<tr>
<td></td>
<td>GHG Emissions</td>
<td>GHG emissions created by fossil-fueled energy resources</td>
</tr>
<tr>
<td></td>
<td>Other Environmental</td>
<td>Other air emissions, solid waste, land, water, and other environmental impacts</td>
</tr>
<tr>
<td></td>
<td>Economic and Jobs</td>
<td>Incremental economic development and job impacts</td>
</tr>
<tr>
<td></td>
<td>Public Health</td>
<td>Health impacts, medical costs, and productivity affected by health</td>
</tr>
<tr>
<td></td>
<td>Low Income: Society</td>
<td>Poverty alleviation, environmental justice, and reduced home foreclosures</td>
</tr>
<tr>
<td></td>
<td>Energy Security</td>
<td>Energy imports and energy independence</td>
</tr>
</tbody>
</table>
Ch 5. Cross-cutting DER Considerations

- Temporal Impacts
- Locational Impacts
- Interactive Effects
- Behind-the-Meter Versus Front-of-the-Meter
- Air Emission Impacts
- Transfer Payments and Offsetting Impacts
- Variable Renewable Generation Impacts
- Wholesale Market Revenues
- Free Riders and Spillover Impacts
- Discount Rates
Temporal Impacts on EE Benefits
Hypothetical Example

Location Impacts on DR Benefits
Hypothetical Example
NSPM for DERs – PART III

Benefit-Cost Analysis for Specific DER Technologies
NSPM for DERs
DER Specific Chapters 6-10

- Energy Efficiency Resources
- Demand Response Resources
- Distributed Generation Resources
- Distributed Storage Resources
- Electrification

Each chapter covers:
- Benefits and costs of the specific resource
- Key factors that affect impacts
- Common challenges in estimating benefits and costs
Example: Demand Response chapter content

7. Demand Response Resources
   7.1 Summary of Key Points
   7.2 Introduction
      Demand Response Services
      Demand Response Classifications
   7.3 Benefits and Costs of Demand Response Resource
   7.4 Key Factors that Affect Demand Response Benefits
      7.4.1 Technology Characteristics
      7.4.2 Technology Operating Profile
      7.4.3 Other Fuel Impacts
         7.4.4 Host Customer Impacts
         7.4.5 Air Emissions Impacts
   7.5 Common Challenges in Determining Demand Resource
      7.5.1 Determining the Operating Profile
      7.5.2 Determining the Counter-Factual Baseline
      7.5.3 Accounting for Provision of Multiple Service
   7.6 Lost Revenues and Rate Impacts
      Lost Revenues and Rate Impacts of Non-Demand Response
Example: Demand Response Impacts

Benefit or Cost (or ‘Depends’)

<table>
<thead>
<tr>
<th>Type</th>
<th>Utility System Impact</th>
<th>Benefit or Cost</th>
<th>Notes on Applicability</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gen.</td>
<td>Energy Generation</td>
<td>●</td>
<td>Usually a benefit, but potential net impacts of load-shifting and total load increases must also be accounted for</td>
</tr>
<tr>
<td></td>
<td>Generation Capacity</td>
<td>●</td>
<td>This is frequently the primary objective of DR</td>
</tr>
<tr>
<td></td>
<td>Environmental Compliance</td>
<td>●</td>
<td>Usually a benefit due to reduction in use of peaker generation, but cumulative and marginal emissions impacts, including those associated with shifted load, must also be accounted for</td>
</tr>
<tr>
<td></td>
<td>RPS/CES Compliance</td>
<td>●</td>
<td>Typically, the demand reduction targets a marginal fossil generator, creating a benefit; impacts of load-shifting or load increases at other times must be accounted for; DR may also improve the ability of the system to accept higher deployment of variable renewable resources</td>
</tr>
<tr>
<td></td>
<td>Market Price Response</td>
<td>●</td>
<td>Usually a benefit since DR tends to target higher-priced supply in wholesale markets; depends on generation market operation</td>
</tr>
<tr>
<td></td>
<td>Ancillary Services</td>
<td>○</td>
<td>Usually a benefit due to load reductions when the system is stressed</td>
</tr>
<tr>
<td>Trans.</td>
<td>Transmission Capacity</td>
<td>●</td>
<td>Usually a benefit due to load reductions during periods of peak demand</td>
</tr>
<tr>
<td></td>
<td>Transmission System Losses</td>
<td>●</td>
<td>Usually a benefit due to load reductions during periods of peak demand, when losses tend to be disproportionately higher</td>
</tr>
<tr>
<td>Dist.</td>
<td>Distribution Capacity</td>
<td>●</td>
<td>Usually a benefit due to load reductions during periods of peak demand; however, circuit-level peaks are not always aligned with system peaks, and thus load-shifting to address system peaks could result in increased peak demand at the circuit or substation level, and vice versa</td>
</tr>
<tr>
<td></td>
<td>Distribution System Losses</td>
<td>●</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Distribution O&amp;M</td>
<td>●</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Distribution Voltage</td>
<td>●</td>
<td>DR can be used to manage voltage fluctuations on the grid</td>
</tr>
<tr>
<td>General</td>
<td>Financial Incentives</td>
<td>●</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Program Administrative Costs</td>
<td>●</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Utility Performance Incentives</td>
<td>●</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Credit and Collection</td>
<td>●</td>
<td>Indirect benefit due to reduced overall system costs</td>
</tr>
<tr>
<td></td>
<td>Risk</td>
<td>●</td>
<td>Usually a benefit due to reduced load when the system is stressed</td>
</tr>
<tr>
<td></td>
<td>Reliability</td>
<td>●</td>
<td>Usually a benefit due to better asset utilization of generation resources and enhanced grid flexibility</td>
</tr>
<tr>
<td></td>
<td>Resilience</td>
<td>●</td>
<td>Potentially a benefit due to reduced restart load</td>
</tr>
</tbody>
</table>
NSPM for DERs
Multi-DER Chapters 11-14

Four chapters addressing different approaches for combining multiple DER types

**Chapters**
- Multiple on-site DER types, such as grid-integrated efficient buildings (GEBs)
- Multiple DER types in a specific geographic location in the form of a non-wires solution (NWS);
- Multiple DER types across a utility service territory
- Dynamic system planning practices that can be used to optimize DERs and alternative resources (IGP, IDP, IRP)

**Content**
- Summary of key points
- Description of how the multiple DER types might be used together
- Discussion of key factors in determining benefits and costs for each approach
- Guidance on how to address common challenges in determining benefits and costs
- Case studies (for some of chapters)
Ch 11: Multi On-site DERs

Analyzing multiple DERs implemented at the building, facility, campus, or even neighborhood level - *Grid-Interactive Efficient Buildings*

Ch 11: Multi On-site DERs
Example of GEB Interactive Effects - Benefits

![Chart showing benefits of different DER combinations with interactive effects]

- **Total Benefits**
- **Combined**
- **Storage**
- **DPV**
- **DR**
- **EE**

Diagram illustrates the benefits of different DER combinations with and without interactive effects. The chart compares DPV + Storage + EE + DR with and without interactive effects, EE + DR with interactive effects, and the combined total benefits.
Ch 12: Non-Wires Solutions
Case Study – NWS Distribution Need

DERs: EE lighting and controls; DR Wi-Fi-enabled thermostats; DPV; and DS (thermal and battery storage)

- Assumes non-coincident with overall system peak (e.g., constrained distribution feeder peaks at 1-5pm, while system peaks at 5-9pm)
- Assumes system-peak hours entail higher marginal emissions rates than NWS = delivers GHG benefits.
- Assumes DER operating profiles where:
  - Storage charges and discharges during system off-peak hours
  - DR reduces and shifts load during system off-peak hours
  - Solar contributes to distribution and some system-peak needs
  - EE has a general downward trajectory on usage
Ch. 13: System-Wide DER Portfolios
# CH 14. Dynamic System Planning

<table>
<thead>
<tr>
<th>Type of Utility System</th>
<th>Planning Practice</th>
<th>Planning Practice Accounts for:</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Distribution System</td>
</tr>
<tr>
<td>Distribution-only &amp; vertically-integrated</td>
<td>Traditional distribution planning</td>
<td>✓</td>
</tr>
<tr>
<td>Integrated distribution planning</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>Vertically-integrated</td>
<td>Transmission planning</td>
<td>-</td>
</tr>
<tr>
<td>Integrated resource planning</td>
<td></td>
<td>-</td>
</tr>
<tr>
<td>Integrated grid planning</td>
<td></td>
<td>✓</td>
</tr>
</tbody>
</table>
Next steps

• Publication – August 2020

• Webinars and Training (2020-21)
  • National Regulatory Research Institute (NRRI) and Regulatory Training Initiative (RTI) – discussions underway to develop a BCA on-line training for the NSPM
  • Other training – TBD
  • Webinars/presentations

• NASEO outreach and state technical support

• NSPM is a ‘living document’ – plan is to update and improve over time, add case studies, etc…
For More Info…

Stay informed with the *NSPM Quarterly* Newsletter:

To download the NSPM and find supporting Resources visit:
http://www.nationalenergyscreening.org/

**Questions?** Email NSPM@nationalenergyscreening.org
or Jmichals@E4TheFuture.org
The role of cost-effectiveness testing in a framework for beneficial electrification

An E Source presentation at CEDMC Webinar
July 23, 2020
Who you’re speaking with today

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**Courtney Welch**
Associate Director  
Customer Energy Solutions  
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Who we are
A research and consulting firm focused exclusively on utilities and their customers

Clients
We work with over 300 utilities and their partners

Founded
Founded in 1986, we’ve been in the industry for over 30 years

Headquartered
Boulder, CO
A framework for beneficial electrification

- Environmentally beneficial electrification
- Grid-efficient electrification
- Economically efficient electrification
A framework for beneficial electrification

- Environmentally beneficial electrification
- Economically efficient electrification
- Grid-efficient electrification

Less carbon and lower rates for nonparticipants

Less carbon and lower bills

Carbon, rates, and bills are all reduced

Lower rates and lower bills
The role of cost effectiveness testing

Ensures electrification is beneficial

Allocates limited resources to most-effective programs

Offers policy makers a tool

Facilitates the creation of effective incentives
An evolution in cost effectiveness testing
## Adjusting cost-effectiveness rules to promote beneficial electrification

<table>
<thead>
<tr>
<th>Action Description</th>
<th>States</th>
<th>Details</th>
</tr>
</thead>
<tbody>
<tr>
<td>Modifying the cost-effectiveness test</td>
<td>CO</td>
<td>CO: smart charging pilot focused on peak savings, shift peak timing, and reduce wind curtailment</td>
</tr>
<tr>
<td>Shifting to a different cost/benefit methodology</td>
<td>MA</td>
<td>MA: CE test at sector-level</td>
</tr>
<tr>
<td>Changing “where” cost-effectiveness testing occurs</td>
<td>CA</td>
<td>CA: CE test at portfolio-level</td>
</tr>
<tr>
<td></td>
<td>MN</td>
<td>MN: possibility of creating EV or iDSM CE test</td>
</tr>
<tr>
<td></td>
<td>CO</td>
<td>CO: economic, grid, and environmental benefits of EVs</td>
</tr>
</tbody>
</table>
Using DSM shareholder incentives as a roadmap for beneficial electrification incentives

Like DSM, electrification has complex goals and poses new challenges to utilities.

Utilities are beginning to implement a range of incentive designs for electrification – varies by type of electrification initiative (e.g. buildings vs. vehicles).

Some utilities are proceeding without shareholder incentives, at least initially.
Structuring incentives

- Performance incentives
  - Btu reduction (residential and building electrification)
  - CO2 emission reductions

- Cost-effectiveness incentives
  - Value of benefits compared to costs
    - Challenge in defining benefits
    - Will require sophisticated evaluation protocols

- Innovation incentives
  - Innovation in electrification strategies and technologies over time
  - Incentives for expanding charging station networks
Getting buy-in from regulators to adopt shareholder incentives

- Regulatory buy-in is essential to ensure utilities and regulators are aligned in their principles and goals around shareholder incentives.
- Nationwide case studies of electrification provide evidence that electrification programs yield measurable, cost-effective results.
Regulators may push back on incentives

- Regulators may challenge the need for shareholder incentives as utilities are already receiving various benefits from electrification such as increased kilowatt-hour sales and significant CO2 reductions.

- A key objective of electrification is achieving major incremental CO2 reductions. Incentives may be instrumental for achieving these goals while balancing grid, environmental and economic benefits.
Thank you! For more information:

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Funding and cost recovery of electrification initiatives: expensing

- Core funding sources: funded through similar mechanisms used for DSM (e.g. system benefit chargers and supplemented through a variety of other sources)

- Cost recovery: expensing
  - Placing a surcharge on customers’ bills to recover the costs of electrification
  - Recover costs in the year the costs are incurred
  - Help utilities avoid accumulating costs over many years
Funding and cost recovery of electrification initiatives: rate-basing

- Cost recovery: rate-basing
  - Typically used for large capital investments such as power plants, transmission and distribution lines, etc.
  - Costs are incurred over 20 years or more and included in base rates with rate of return
  - Includes costs for electrification in base rates
- Other options and strategies are being explored but have not yet been implemented
CPUC Avoided Cost Calculator
CEDMC Webinar
July 23, 2020
Christa Heavey, Senior Consultant
Avoided Costs

+ Distributed energy resources (DERs) can be valued by considering the cost savings, or “avoided costs,” over a measure’s useful time.

+ Avoided cost components include:
  - Energy
  - Capacity
  - Transmission and distribution
  - Greenhouse gas emissions

+ The CPUC uses the Avoided Cost Calculator to evaluate savings of DER programs from the California IOUs.

+ The ACC calculates the 8,760 hourly avoided costs for PG&E, SCE, and SDG&E for 2020-2050.

+ Avoided cost methodology can also be applied to load increases, such as electrification.
  - For example, “avoided” costs can be used to evaluate the utility cost incurred to supply electricity to EVs, which can be compared to the gasoline cost savings.
Motivation for ACC Changes in 2020

• Previous versions of the Avoided Cost Calculator based values on historic energy prices
• SB100: California will be making rapid & bold changes to its energy supply from now to 2050  
  • 60% RPS by 2030  
  • 100% clean energy by 2045
• Given this changing environment, it is important to value and incent DERs based on the best and latest estimate of expected resource buildout and resulting energy, capacity & AS costs by time of day and location
• In order to do this, E3 and the CPUC modified the DER Avoided Cost Calculator to align with California’s current Integrated Resource Plan (IRP)
  • The IRP proceeding develops a long-term supply-side plan for what resources need to be procured for the state’s electricity supply needs, while meeting the state’s GHG and clean energy goals
Changing Avoided Cost Paradigm

+ 2019 ACC: CCGT and CT are marginal resource
  - ~ 60% Variable
  - Planning grid for peak capacity
  - Focus on efficient fossil generation and dispatch

+ 2020 ACC: Solar and Storage are marginal resource:
  - ~ 90% fixed cost
  - Planning grid for delivered renewable energy
  - Focus on efficient capital investment
IRP Modeling: “No New DER” Scenario

The IRP’s Reference System Plan has levels of DERs built into its load forecast.

The “No New DER” scenario removed those DER forecasts in order to see the counterfactual, “what would the system costs be without DERs?”

Used for the ACC to measure the value of new DERs.
## 2019 vs. 2020

<table>
<thead>
<tr>
<th>Avoided Cost</th>
<th>2019 ACC</th>
<th>2020 ACC</th>
<th>Data Source</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Generation Capacity</strong></td>
<td>Combustion Turbine Cost of New Entry</td>
<td>Battery Storage Net Cost of New Entry</td>
<td>RESOLVE input assumptions</td>
</tr>
<tr>
<td><strong>Energy</strong></td>
<td>Energy futures and gas turbine modeling</td>
<td>RESOLVE and SERVM modeling</td>
<td>SERVM outputs</td>
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<tr>
<td><strong>Ancillary Services</strong></td>
<td>Percentage of energy</td>
<td>RESOLVE and SERVM modeling</td>
<td>SERVM outputs</td>
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<tr>
<td><strong>GHG Value</strong></td>
<td>Based on RESOLVE GHG shadow price and cap &amp; trade price</td>
<td>Based on RESOLVE GHG shadow price and cap &amp; trade</td>
<td>RESOLVE outputs, cap &amp; trade prices</td>
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<tr>
<td><strong>GHG Emissions</strong></td>
<td>Implied market-heat rate short-run marginal emissions</td>
<td>SERVM short-run marginal emissions and RESOLVE long-run grid emissions intensity</td>
<td>RESOLVE and SERVM outputs, cap &amp; trade prices, annual GHG electric sector goals</td>
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<tr>
<td><strong>Transmission</strong></td>
<td>GRC marginal cost filings</td>
<td>From DRP guidance</td>
<td>GRC filings and historical utility cost and financial data</td>
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<tr>
<td><strong>Distribution</strong></td>
<td>GRC marginal cost filings</td>
<td>From DRP guidance</td>
<td>GNA data</td>
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<tr>
<td><strong>High GWP gases</strong></td>
<td>N/A</td>
<td>Methane &amp; refrigerant leakage modeling</td>
<td>CARB data</td>
</tr>
</tbody>
</table>
Changes in Value with 2020 Update

- Higher GHG value based on IRP’s RESOLVE shadow price, even with portfolio rebalancing adjustment
- Slightly higher energy prices from SERVM production simulation with scarcity pricing adjustment
- Higher generation capacity value in early years based on battery storage resource Net Cost of New Entry (Net CONE)
  - Generation capacity value is shifted to September due to increasing solar
- Distribution costs – now based on Distribution Resources Plan (DRP) – are lower in the near term, similar in the long term (based on GRC)
  - Distribution costs are more distributed across summer months with CTZ22 weather year
- New value for methane leakage – adds ~$2.25/MWh
Example for SCE, Climate Zone 9 (Los Angeles) in 2025:

**2019 ACC**

**2020 ACC**
Example for SCE, Climate Zone 9 (Los Angeles) in 2025:

2019 ACC

2020 ACC
Discussion and Q&A

Please ask your questions through the chat box, located on the control panel at the bottom of your screen.
Thank you for attending today’s webinar!

Upcoming Council Events:

• August 13th 1-4pm: Virtual Industry Training
• August 20th 12-1:30pm: Lunch & Learn Webinar: Decarbonization Update
• November 12th 12-5pm: Fall Virtual Conference (Note the date change)

For more information about all these events, please visit the Events page on our website at cedmc.org