2020 ACC Workshop

Greenhouse Gas Value and Emissions

5/8/2020
Introduction

Comparing 2019 and 2020 Vintage ACC Results

GHG Value
  • From RESOLVE modeling of Reference System Portfolio

GHG Emissions
  • From SERVM modeling of No New DER case
  • Marginal emissions and portfolio rebalancing

Example Calculations

https://www.ethree.com/cpuc-acc-downloads-page/
Please use the Q&A feature to ask questions.

Questions will be answered during the allotted discussion periods after each section.

If you have a longer question you would prefer to use your microphone for, you can request to be unmuted by clicking on the button with the phone icon:

- Once you are given speaking permissions, you will need to connect your audio by clicking on the phone icon on the main screen:
Comparing 2019 and 2020 ACC Results
Monthly Average Avoided Costs (excl. Capacity)

- Higher energy and GHG avoided costs in 2020 ACC except during July and August

SCE Climate Zone 9 (Los Angeles) in 2025

Hold your questions...
Higher mid-day and lower evening avoided costs in 2020 ACC

SCE Climate Zone 9 (Los Angeles) in 2025
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

Based on Integrated Resource Planning Proceeding
To meet emissions target by 2030, the RSP builds:

- 2.8 GW of in state wind and 0.6 GW of out of state wind
- 11 GW of utility scale solar
- 8.8 GW of battery storage
- 1 GW of pumped storage
- 0.2 GW of added Shed DR

2030 CAISO Emissions Target of 37.9 MtCO2/year
20+ weather years of 8760 hourly electric consumption demand data for each forecast area in California (currently 8 areas in California, 4 in CAISO and 4 outside CAISO)

+ Corresponding 8760 hourly shapes for the same weather years and the same forecast zones for weather dependent load modifiers (BTMPV, EV, TOU, AAEE)

$$\text{20 Weather Years} \times \text{5 Econ/Demo error points} = \text{100 Demand Scenarios}$$

Expected Value Across 100 Scenarios
LOLE, GHG, Production Cost
Use of RSP and No New DER Case

**Reference System Plan**
- IRP Least-cost portfolio to achieve GHG emissions targets
- ACC uses RESOLVE modeling of RSP for:
  - GHG value
  - planned grid emissions intensity

**No New DER Case**
- Counterfactual, what would system costs be without DER
- ACC uses SERVM Modeling of No New DER case for:
  - Marginal GHG emissions
GHG Value (from RSP)
To meet emissions target by 2030, the RSP builds:

- 2.8 GW of in state wind and 0.6 GW of out of state wind
- 11 GW of utility scale solar
- 8.8 GW of battery storage
- 1 GW of pumped storage
- 0.2 GW of added Shed DR

2030 CAISO Emissions Target of 37.9 MtCO2/year
RESOLVE GHG shadow price: cost of reducing an additional unit of GHGs

Near-term: RESOLVE price is very low, matching the cap and trade price because GHG is not a binding constraint in the model

Long-term: Price is very high, due to more stringent GHG targets
1) Discount 2030 Value at Utility WACC

**Rationale:**
represents 2030 RESOLVE shadow price, but discounted to today

Provides consistency with the 2019 ACC in the near-term, but results in higher prices long-term when GHG constraints are more stringent
Rationale: matching the area means that the average price will equal that of RESOLVE for the time period (2020-2045)

However, this method results in very high prices very early on relative to the 2019 ACC
3) Area Under the Curve 2020-2030

+ Rationale: same as Option #2 – by matching the area of the RESOLVE curve, the average price is the same for that time period (2020-2030)

+ However, only considering 2020-2030 results in very low long-term prices
Option 1 strikes a balance between aligning with the 2019 ACC in the near-term and generating higher prices in the long-term to more accurately value the cost of reducing GHGs.

Provides consistency with the IRP outputs by using RESOLVE 2030 value.
GHG Emissions
GHG Emissions Framework for Avoided Cost

Hourly marginal emissions

Average grid emissions intensity will decline

Portfolio rebalancing

Marginal emissions depend on DER load shapes

In long-run emissions from electricity will decline over time

Portfolio will be rebalanced to achieve emissions target

GHG target will be met, but portfolio cost will be higher or lower depending on shape of DER impacts
# Average Grid Intensity (from RSP)

<table>
<thead>
<tr>
<th></th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
<th>2023</th>
<th>2024</th>
<th>2026</th>
<th>2030</th>
<th>2045</th>
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<tbody>
<tr>
<td><strong>Load</strong></td>
<td>242,188</td>
<td>244,541</td>
<td>247,401</td>
<td>249,495</td>
<td>251,191</td>
<td>253,790</td>
<td>257,010</td>
<td>382,590</td>
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<td><strong>Retail sales</strong></td>
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<td>207,382</td>
<td>208,055</td>
<td>208,238</td>
<td>208,092</td>
<td>207,224</td>
<td>203,413</td>
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<td>41</td>
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<td>12</td>
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<tr>
<td><strong>Emissions</strong></td>
<td>0.21</td>
<td>0.19</td>
<td>0.18</td>
<td>0.18</td>
<td>0.19</td>
<td>0.20</td>
<td>0.19</td>
<td>0.04</td>
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<tr>
<td><strong>Allowable Heat Rate</strong></td>
<td>3,913</td>
<td>3,649</td>
<td>3,415</td>
<td>3,378</td>
<td>3,557</td>
<td>3,725</td>
<td>3,511</td>
<td>785</td>
</tr>
</tbody>
</table>

**Grid Emissions Intensity**

- 2020: 0.21 tCO2/MWh
- 2021: 0.19 tCO2/MWh
- 2022: 0.18 tCO2/MWh
- 2023: 0.18 tCO2/MWh
- 2024: 0.19 tCO2/MWh
- 2025: 0.20 tCO2/MWh
- 2026: 0.19 tCO2/MWh
- 2027: 0.04 tCO2/MWh

**Allowable Heat Rate**

- 2020: 3,913 Btu/kWh
- 2021: 3,649 Btu/kWh
- 2022: 3,415 Btu/kWh
- 2023: 3,378 Btu/kWh
- 2024: 3,557 Btu/kWh
- 2025: 3,725 Btu/kWh
- 2026: 3,511 Btu/kWh
- 2027: 785 Btu/kWh
Adding load increases GHGs at the marginal emission rate.

Re-optimized RPS portfolio reduces emission to hit SB100 goals.

Net effect

Emission intensity, set by reference system plan.
Increase in load and GHG emission

2019 ACC
$132,000

2020 ACC
$132,000 - $14,400 = $117,600

Step 1: Marginal Emissions
Step 2: Rebalancing = Net cost

Cap & Trade + GHG Adder ($110/ton) X

Hourly marginal emissions (1200 tons)

Cap & Trade + GHG Adder ($110/ton) X

Hourly marginal emissions (1200 tons)

GHG Adder ($30/ton) X

Portfolio Rebalancing (- 480 tons)

Net effect

Emission intensity, set by reference system plan

Portfolio Rebalancing

Net cost
Simple Example Calculations
Simple Example: Three Grid Resources

- **Combined Cycle Gas Turbine (CCGT)**
  - $50/MWh
  - 0.4 Tons/MWh

- **Solar**
  - $25/MWh
  - High marginal curtailment for new solar

- **Solar + Long-duration Storage**
  - $94/MWh
  - Marginal resource needed to deliver carbon free energy
Added Load – EV Charging

+ Add 3,000 MWh of Evening EV Charging
+ Hourly marginal impact – 1,200 tons GHG
  - Evening load is provided by CCGT
  - Increases emissions intensity from 0.16 to 0.22 tons/MWh
+ Portfolio Rebalancing
  - To achieve intensity of 0.16 tons/MWh
  - For additional 3,000 MWh, only 480 tons GHG is allowable to achieve intensity target
  - Additional 1,200 MWh is allowable from CCGT
    - (1,200 MWh x 0.40 tons/MWh = 480 tons)
  - Remaining 1,800 MWh to serve EV load must come from more expensive PV + long-duration storage

### Portfolio

<table>
<thead>
<tr>
<th>Portfolio</th>
<th>Cost MWh</th>
<th>IRP Plan MWh</th>
<th>Hourly Marginal Impact MWh</th>
<th>Portfolio Reblancing MWh</th>
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<tr>
<td>Combined Cycle Gas Turbine (CCGT)</td>
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<td>PV</td>
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<td>PV &amp; Long-duration Storage</td>
<td>$94</td>
<td>3,000</td>
<td>3,000</td>
<td>4,800</td>
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<td>Total MWh</td>
<td>10,000</td>
<td>13,000</td>
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<td>Total Cost of Generation</td>
<td>$557,000</td>
<td>$707,000</td>
<td>$786,200</td>
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### Allowable Tons

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<tr>
<th>GHG Intensity (Tons/MWh)</th>
<th>0.16</th>
<th>2.080</th>
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<tr>
<td>Total Tons</td>
<td>1,600</td>
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<td>Allowable Tons</td>
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<td>2,800</td>
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### Hourly Marginal Emissions:

<table>
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<th>$/Ton</th>
<th>Tons</th>
<th>Tons</th>
<th>Total $</th>
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<td>Hourly Marginal Emissions: Cap and</td>
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<td>1,200</td>
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<td>Trade Price</td>
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<tr>
<td>Hourly Marginal Emissions: GHG Adder</td>
<td>$30</td>
<td>1,200</td>
<td>1,200</td>
<td>$36,000</td>
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<td>Portfolio Rebalancing: GHG Adder</td>
<td>$30</td>
<td>(480)</td>
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<td>$(14,400)</td>
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<tr>
<td>Allowable increase in GHG Emissions</td>
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<td></td>
<td></td>
<td>$117,600</td>
</tr>
</tbody>
</table>

| Average $/Ton of incremental GHG    | $98/Ton |
| Average $/MWh GHG Value             | $39/MWh |

<table>
<thead>
<tr>
<th>Incremental Cost of Supply Rebalance</th>
<th>$79,200</th>
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<tbody>
<tr>
<td>CCGT GHG Intensity (Tons/MWh)</td>
<td>0.40</td>
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</table>
### Three Categories of GHG Emissions

- **$80/ton Cap & Trade Price**
- **$30/ton GHG Adder**
- **$110/ton GHG Value (Electric Sector)**

### Hourly Marginal Emissions – Cap & Trade

- 1,200 tons at $80/ton

### Hourly Marginal Emissions – GHG Adder

- 1,200 tons at (additional) $30/ton

### Portfolio Rebalancing – GHG Adder

- 480 tons of allowable emissions at $30/Ton

#### Total Cost: $117,000

- $98/Ton (for 1,200 tons)
- $39/MWh (for 3,000 MWh)
### Added Load – Daytime Cooling

**Add 3,000 MWh of Daytime Cooling**

**Hourly marginal impact – 200 tons GHG**
- 2,500 MWh from Solar PV (reducing curtailment)
- 500 MWh from CCGT

**Portfolio Rebalancing**
- To achieve intensity of 0.16 tons/MWh
- For additional 3,000 MWh, only 480 tons GHG is allowable to achieve intensity target
- Additional 1,200 MWh is allowable from CCGT
  - $(1,200 \text{ MWh} \times 0.40 \text{ tons/MWh} = 480 \text{ tons})$
- Procurement of more expensive PV + long-duration storage can be reduced by 700 MWh
### Added Load – Daytime Cooling (2)

#### Three Categories of GHG Emissions
- $80/ton Cap & Trade Price
- $30/ton GHG Adder
- $110/ton GHG Value (Electric Sector)

#### Hourly Marginal Emissions – Cap & Trade
- 200 tons at $80/ton

#### Hourly Marginal Emissions – GHG Adder
- 200 tons at (additional) $30/ton

#### Portfolio Rebalancing – GHG Adder (Minus)
- 480 tons of allowable emissions at $30/Ton

#### Total Cost: $7,600
- $38/Ton (for 200 tons)
- $3/MWh (for 3,000 MWh)
Load Shape Example Calculations
Added Load: Load Shapes

**kWh Added Load**

- Commercial Heat Pump (Cooling)
- Residential EV Charging (Unmanaged)

**GHG Emissions Impact Relative to Long Run Annual Grid Intensity**

- Commercial Heat Pump (Cooling)
- Residential EV Charging (Unmanaged)
### Summary Calculations

<table>
<thead>
<tr>
<th>Emissions Category</th>
<th>Emissions Valued at:</th>
<th>$/Ton</th>
<th>Residential EV Charging</th>
<th>Commercial Cooling</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>Tons GHG</td>
<td>$ GHG Value</td>
</tr>
<tr>
<td>Marginal Emissions</td>
<td>Cap and Trade</td>
<td>$80</td>
<td>931</td>
<td>$74,492</td>
</tr>
<tr>
<td></td>
<td>GHG Adder</td>
<td>$30</td>
<td>931</td>
<td>$27,934</td>
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<tr>
<td>Portfolio Rebalancing</td>
<td>GHG Adder</td>
<td>$30</td>
<td>(480)</td>
<td>($14,400)</td>
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<tr>
<td>Total Marginal Emissions</td>
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<td></td>
<td>931</td>
<td>$74,492</td>
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<td></td>
<td></td>
<td>448</td>
<td>$35,819</td>
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<td></td>
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<td>88,026</td>
<td>$34,852</td>
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<tr>
<td>Average $/Ton</td>
<td></td>
<td></td>
<td>$95</td>
<td>$78</td>
</tr>
<tr>
<td>Average $/MWh GHG Value</td>
<td></td>
<td></td>
<td>$29</td>
<td>$12</td>
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</table>

#### 3,000 MWh EV Charging

**931 Tons Hourly Marginal Emissions**
- 931 tons x $80/ton Cap and Trade
- 931 tons x $30/ton GHG Adder

**Portfolio Rebalancing (minus)**
- 480 tons x $30/ton GHG adder

**Average $/Ton** $95 | **Average $/MWh** $29

#### 3,000 MWh Cooling

**448 Tons Hourly Marginal Emissions**
- 448 tons x $80/ton Cap and Trade
- 448 tons x $30/ton GHG Adder

**Portfolio Rebalancing (minus)**
- 480 tons x $30/ton GHG adder

**Average $/Ton** $78 | **Average $/MWh** $12
## Two Ways to the Same Answer

<table>
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<tr>
<th>Emissions Category</th>
<th>Emissions Valued at:</th>
<th>$/Ton</th>
<th>Residential EV Charging</th>
<th>Commercial Cooling</th>
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<tr>
<td></td>
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<td>Tons GHG</td>
<td>$ GHG Value</td>
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<tr>
<td>Marginal Emissions</td>
<td>Cap and Trade</td>
<td>$80</td>
<td>931</td>
<td>$74,492</td>
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<tr>
<td></td>
<td>GHG Adder</td>
<td>$30</td>
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<td>$27,934</td>
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<td>Portfolio Rebalancing</td>
<td>GHG Adder</td>
<td>$30</td>
<td>(480)</td>
<td>($14,400)</td>
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<tr>
<td>Total Marginal Emissions</td>
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<td>$88,026</td>
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<tr>
<td></td>
<td>Average $/Ton</td>
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<td></td>
<td>Average $/MWh GHG Value</td>
<td></td>
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<td>$29</td>
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<table>
<thead>
<tr>
<th>Emissions Category</th>
<th>Emissions Valued at:</th>
<th>$/Ton</th>
<th>Residential EV Charging</th>
<th>Commercial Cooling</th>
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<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>Tons GHG Impact</td>
<td>$ GHG Value</td>
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<td>GHG Adder ($110 - $80)</td>
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<td>Allowable Emissions</td>
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<td>$88,026</td>
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<td>Average $/Ton</td>
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<td>$95</td>
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<td></td>
<td>Average $/MWh GHG Value</td>
<td></td>
<td></td>
<td>$29</td>
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</tbody>
</table>
Example GHG Avoided Costs for One Day

- 2025 SCE CZ 9 (Los Angeles)
  - 1 Day in April

- $40/ton Cap & Trade
- $100/ton GHG Adder
- $140/ton GHG Value
- Grid Intensity 0.19 tons/MWh
Three emissions cost streams for electricity

1. **Cap and Trade Emissions**: Direct plant emissions from directly serving load

2. **GHG Adder**: Additional cost of procuring the necessary supply-side resources to achieve the electricity-sector long run emissions intensity target. Replaces previous ‘RPS Adder’ field

3. **Emissions Abatement**: Economy-wide cost of abating remaining emissions after supply-side actions have been taken

Adding load from new buildings increases emissions

Re-optimized RPS portfolio reduces emissions to hit SB100 goals

Remaining emissions put pressure on the 80 x 50 GHG cap and therefore drive costs to meet statewide goal

Biofuels to reduce GHG content of pipeline gas

‘GHG Adder’ calculates cost of incremental renewables

Net long-run GHG emissions
Two emissions cost streams for natural gas

1. **Cap and Trade Emissions**: Direct emissions from non-renewable gas delivered (net of RNG)
   
   Additional cost of procuring renewable natural gas included in the commodity price.

2. **Emissions Abatement**: Economy-wide cost of abating remaining emissions after supply-side actions have been taken.
**Cap and Trade Emissions:** Cost from IEPR GHG Allowance Price forecast; direct cost of emissions from combusting natural gas, factored into retail rates

**Emissions Abatement:** Assumed that in a SB32-compliant future, cheapest economy-wide incremental emissions reduction is from electricity supply side, so RESOLVE GHG Abatement price is used. Represents cost of meeting state economy-wide emissions target.
No New DER Case
**Use of RSP and No New DER Case**

**Reference System Plan**
- IRP Least-cost portfolio to achieve GHG emissions targets
- Included CEC Integrated Energy Policy Report (IEPR) forecast of DER
- ACC uses RSP for:
  - GHG value
  - planned grid emissions intensity

**No New DER Case**
- Removes DER associated with utility programs
- Counterfactual, what would system costs be without DER
- ACC uses No New DER case for:
  - Marginal GHG emissions
Comparison of 2019 and 2020 ACC Curtailment
Looking Back 2019 ACC Underestimated Curtailment

2019 ACC understated the number of curtailment hours compared to actual curtailments in CAISO.

**Total Curtailment Hours**

<table>
<thead>
<tr>
<th></th>
<th>2019 ACC NP15 &amp; SP15 (all-year)</th>
<th>2019 CAISO (Jan – Aug)</th>
</tr>
</thead>
<tbody>
<tr>
<td>ACC NP15 and SP15 Curtailment 2019</td>
<td></td>
<td></td>
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<tr>
<td>CAISO System Curtailment 2019 (note that data from Sep - Dec was not available at the time of data collection)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Curtailment data from Sep to Dec was not available at the time of data collection.
Curtailment hours derived from SERVM prices are significantly lower in 2020 ACC, using implied heat rate methodology.

**Curtailment Hours Currently in 2020 ACC**

<table>
<thead>
<tr>
<th>ACC Curtailment Hours, SEVBM Implied Marginal Heat Rate</th>
<th>NP15 &amp; SP15</th>
</tr>
</thead>
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<tr>
<td>1</td>
<td>2 4 3 2 1 2</td>
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<tr>
<td>2</td>
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<table>
<thead>
<tr>
<th>Total Curtailment Hours</th>
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<tbody>
<tr>
<td>2020 ACC NP15 &amp; SP15</td>
</tr>
<tr>
<td>2030 ACC NP15 &amp; SP15</td>
</tr>
</tbody>
</table>

Keep holding your questions…
2030 No DER vs RSP SERVM Energy Prices

- Price duration curve shows approximately 2% of hours have negative prices in No DER case
- Approximately 10% of hours have negative prices in RSP case
- Difference due to difference in resource build, as both cases meet binding RPS, emissions targets

No New DER Case has less curtailment than RSP
Increased storage, decreased solar in No DER case limit curtailment hours in SERVM