Determining Optimal Storage Deployment Levels

INSIGHTS FROM NEVADA

PRESENTED BY
Ryan Hledik
Roger Lueken

Energy Storage Association Webinar
December 11, 2018
Key considerations for estimating optimal storage deployment levels

We focus on five critical – but complex – factors when estimating the economic potential for energy storage:

1. Technology cost uncertainty
2. Comprehensive identification of applicable value streams
3. Ability to “stack” multiple value streams
4. Decreasing incremental value of storage additions
5. Opportunity for T&D capacity investment deferral
1. Technology cost uncertainty

We analyzed a range of installed costs for 4-hour storage in 2020 and 2030 to reflect uncertainty in current cost projections.

2. Identifying applicable value streams

Assessments of storage potential must account for the full range of potential use cases

Quantified (primary) sources of value in the Nevada study

- Energy costs
- Ancillary services
- Avoided generation capacity costs
- T&D capacity investment deferral value
- Customer outage reduction value
- Environmental benefits

Additional (secondary) storage benefits

- Voltage support
- Reduced line losses
- Black start
3. “Stacking” multiple value streams

Storage can simultaneously capture multiple value streams; however, tradeoffs must be made in the dispatch decision.

Our dispatch modeling logic:

- Value of storage is optimized subject to the following assumptions
- Generation capacity value based on ability to dispatch storage during hours with high loss of load probability
- Outage events are not predictable; storage ability to mitigate outages is based on reduced state of charge (50% on average)
- T&D deferral and outage reduction are mutually exclusive benefits
- For storage providing T&D deferral, reducing local peak load is prioritized over reducing system peak load
- Operators have accurate forecasting 24 hours out, imperfect foresight thereafter
4. Declining incremental value of storage additions

An assessment of storage potential should reflect declines in incremental value of storage as more is added to the system.

Our approach:

- Add storage to the model in various capacity increments
- Quantify incremental reductions in system costs with each addition
- Identify point where benefit of incremental addition equals storage costs
5. T&D capacity investment deferral

T&D capacity benefits are based on an assessment of 260 individual planned upgrades in NV Energy’s service territory.

Marginal T&D Deferral Benefit of Storage for Individual T&D Projects ($/kW-year)

Our approach:
- Identify projects driven by peak growth
- Estimate load reduction required to provide 15-year deferral
- Require discharge of dedicated energy storage during hours when load reductions are needed

Notes:
Points reflect individual projects from NV Energy’s 2018 transmission and distribution capital expenditure outlook identified as deferrable by storage. Although NV Energy’s outlook is over a 10-year span, we annualize the size and value of opportunities. We order projects by $/kW-year value, and plot to estimate the marginal benefit for storage from T&D investment deferral. Values in nominal dollars.
The modeling platform

Brattle’s bSTORE model was used to address the previously discussed considerations

www.brattle.com/storage
Findings for Nevada
In 2020, storage costs exceed benefits for additions greater than 200 MW

Note: All values are in nominal dollars
System benefits and costs of storage: 2030

By 2030, storage benefits exceed costs up to NV Energy’s anticipated generation capacity need of 1,000 MW

Note: All values are in nominal dollars
4-hour storage can effectively offset need for new generation capacity in Nevada

Nevada Net Load Peak Day Reduction (July 27, 2020)

- Net load peaks concentrated in July and August
- Net load peaks are relatively short duration, due to high PV generation in summer months
- 1 MW of storage equivalent to 0.86 MW of capacity for simulated deployment of 1,000 MW
Sensitivity to alternative assumptions

The optimal deployment level will vary considerably depending on market definition and available value streams

Optimal Storage Deployment Levels for Alternative Cases

- Base Case
- Exclude outage mitigation benefits
- Nevada in regional market
- Exclude generation capacity value

Megawatts

- At low storage cost
- At high storage cost
Behind-the-meter (BTM) storage

BTM storage adoption is expected to be modest, but could more than double with the introduction of a utility incentive program.

Notes:
The potential estimates represent long-run adoption potential based on assumed storage costs for the years shown in the figure. It would take several years to reach these adoption levels.
Storage could be procured using an “optimal deployment curve” to account for cost uncertainty and changing system conditions.

1. At the lower bound of the 2020 storage cost range ($1,200/kW), the optimal storage deployment level is 175 MW.
2. Energy storage is not cost-effective at the upper-bound of the forecasted 2020 storage cost range ($1,800/kW).

1. At the upper-bound of the 2030 storage cost range ($1,310/kW), optimal deployment is around 700 MW.
2. At the lower-bound of the 2030 storage cost range ($880/kW), optimal storage deployment reaches the total system-wide need for new capacity (1,000 MW).

Notes:
Costs are shown in nominal dollars. Values are based on an assumed energy storage configuration of 10 MW / 40 MWh.
Closing observations

- 30% decline in storage costs $\rightarrow$ 200% to 500% increase cost-effective deployment levels
- Optimal deployment in 2030 is more than 2x the level in 2020 due, in part, to evolving system conditions
- The ability to mitigate distribution system outages potentially accounts for 20% to 40% of the total benefits, significantly impacting optimal storage deployment levels
- High-value opportunities can decline quickly; most opportunities for geographically-targeted T&D investment deferral are captured with ~200 MW of energy storage
- Stakeholder comments raise important question: Do existing resource planning practices sufficiently capture the benefits of emerging tech like energy storage? Or are new practices and/or policies needed?
For more information...

Link to the report:

PUCN Docket 17-07014:
http://pucweb1.state.nv.us/puc2/Dktinfo.aspx?Util=Rulemaking

Nevada Senate Bill 204:
https://www.leg.state.nv.us/Session/79th2017/Reports/history.cfm?ID=485
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This report was prepared for Public Utilities Commission of Nevada (PUCN) and the Nevada Governor’s Office of Energy (GOE) based on work supported by the Nevada Governor’s Office of Energy, and the Department of Energy, Office of Energy Efficiency and Renewable Energy (EERE), under Award Number DE-EE0006992. It is intended to be read and used as a whole and not in parts; it reflects the analyses and opinions of the authors and does not necessarily reflect those of The Brattle Group’s clients or other consultants.

The authors would like to acknowledge the valuable collaboration and insights of Donald Lomoljo and John Candelaria (PUCN), Angela Dykema (GOE), Patrick Balducci and Jeremy Twitchell (Pacific Northwest National Laboratory), and the contributions of NV Energy staff in providing necessary system data. We would also like to thank Brattle Group colleagues for supporting the preparation of this report, including Jesse Cohen for modeling of behind-the-meeting storage applications.

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Appendix
Comparison to Other Studies

Benchmarking the findings

Studies from other jurisdictions identify a range of potential estimates
### Comparison to Other Studies

#### Benefits Considered in Recent Storage Potential Studies

<table>
<thead>
<tr>
<th></th>
<th>Nevada</th>
<th>Massachusetts</th>
<th>New York</th>
<th>Texas (Brattle)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Avoided generation capacity costs</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Reduced energy (fuel) costs</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Deferred T&amp;D investment costs</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Ancillary services</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Environmental impacts</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>Discussed qualitatively</td>
</tr>
<tr>
<td>Outage mitigation</td>
<td>X</td>
<td></td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Distribution voltage support</td>
<td>Discussed qualitatively</td>
<td>X</td>
<td>Discussed qualitatively</td>
<td></td>
</tr>
<tr>
<td>Behind-the-meter value</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wholesale market cost reduction</td>
<td>N/A</td>
<td>X</td>
<td>X</td>
<td>X</td>
</tr>
</tbody>
</table>

**Notes:**
Table reflects Brattle’s interpretation of the modeled benefits in each study. Approximations have been made to accommodate differences in terminology across the studies. The analysis of Texas by Navigant Research is not included because insufficient detail was provided on specific categories of value streams. The modeling of cost-effective deployment levels in New York and Massachusetts do not specifically account for BTM adoption, but the studies acknowledge behind-the-meter deployment as one of several use cases.
Comparison to Other Studies

Comparison of Storage Costs Across Studies

Notes:
Battery duration shown in figure is 4-hours for Nevada and New York, 3-hours for Texas, and roughly 2-hours on average for Massachusetts. Massachusetts cost was calculated by dividing the midpoint of the range of total reported statewide storage costs by the total statewide economic storage capacity. Values are in nominal dollars.
Approach

Summary of Analytical Approach

Analysis Inputs

bSTORE

Analytical Results

**Develop Simulation Inputs**
- Nevada power system data
- WECC power system data
- Storage technical assumptions

**Simulate Storage With bSTORE**
- Simulate 2020 and 2030
- 200 MW and 1,000 MW storage at highest-value NV locations

**Identify Key Value Drivers**
- Reduction in production costs
- Avoided generation capacity
- T&D investment deferral
- Customer outage reduction

**Quantify Ratepayer Benefits**
- Compare customer costs with storage to Base Case without

**Develop Storage Cost Estimates**

**Compare Ratepayer Benefits to Storage Cost**

**Evaluate Additional Value**
- Reduced emissions
- Reduced renewable curtailment
- Provision of voltage support
- Reduced T&D losses

**Identify Cost-Effective Levels of Storage in 2020 and 2030**
## Approach

### Data Sources

We model Nevada consistent with NV Energy’s 2018 IRP and rest of WECC consistent with 2026 TEPPC database (adjusting for 2020 and 2030).

<table>
<thead>
<tr>
<th>Data Element</th>
<th>Source(s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Transmission Topology</td>
<td>2026 TEPPC Common Case (as updated in 2017 CAISO TPP)</td>
</tr>
<tr>
<td>NV and WECC Generator List</td>
<td>NV Energy’s 2018 IRP, 2026 TEPPC Common Case, SNL</td>
</tr>
<tr>
<td>NV and WECC Generator Characteristics</td>
<td>NV Energy’s 2018 IRP, 2026 TEPPC Common Case</td>
</tr>
<tr>
<td>Fuel Prices</td>
<td>NV Energy’s 2018 IRP, 2026 TEPPC Common Case, EIA</td>
</tr>
<tr>
<td>NV and WECC Demand</td>
<td>NV Energy’s 2018 IRP, 2026 TEPPC Common Case, SNL</td>
</tr>
<tr>
<td>NV and WECC Reserve Requirements</td>
<td>NV Energy’s 2018 IRP, 2026 TEPPC Common Case</td>
</tr>
<tr>
<td>NV and WECC RPS Requirements</td>
<td>NV Energy’s 2018 IRP, Database of State Incentives for Renewables &amp; Efficiency (DSIRE)</td>
</tr>
<tr>
<td>T&amp;D Deferral Analysis</td>
<td>NV Energy’s Transmission and Distribution Capital Expenditure Data</td>
</tr>
<tr>
<td>Distribution Reliability Analysis</td>
<td>NV Energy’s Distribution Outage Data</td>
</tr>
</tbody>
</table>
Although our analysis approach is technology agnostic, we simulate batteries with operational characteristics that resemble Li-Ion chemistry.

- **Configuration and siting**
  - Stand-alone storage, not co-located with solar PV or other generator
  - Distribution and transmission connected
  - Sited in front-of-meter (behind-the-meter use case evaluated separately)

- **Size of individual storage devices**: 5 to 10 MW

- **MWh:MW ratio**: 4:1
  - Four hour discharge capability at full output
  - Consistent with types of storage systems procured in many recent solicitations

- **Round-trip efficiency**: 85%

- **Lifespan**: 15 years

**Notes**: Assumptions developed with input from the PUCN and PNNL. Our fixed-cost and cost-levelization assumptions include the costs of replacing worn-out battery cells during the 15-year period. We do not assume degradation over time, consistent with the assumption that worn-out battery cells will be replaced throughout the 15-year period.
Levelization of Storage Costs

We assume levelized installed costs of $136-204/kW-yr in 2020 and $99-149/kW-yr in 2030 for 4-hour storage device.

### Financial Assumptions

<table>
<thead>
<tr>
<th>Financial Assumption</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fixed O&amp;M % of Installed</td>
<td>1%</td>
</tr>
<tr>
<td>Developer After-Tax WACC %</td>
<td>7%</td>
</tr>
<tr>
<td>Battery Asset Life yrs</td>
<td>15</td>
</tr>
<tr>
<td>Balance of Plant Asset Life yrs</td>
<td>15</td>
</tr>
<tr>
<td>Total Income Tax Rate %</td>
<td>21%</td>
</tr>
<tr>
<td>Depreciation Schedule 15-yr MACRS</td>
<td></td>
</tr>
<tr>
<td>Annual Inflation Rate %</td>
<td>2%</td>
</tr>
</tbody>
</table>

### Levelized and Installed Cost Assumptions

**For 10 MW (40 MWh) Storage Device**

<table>
<thead>
<tr>
<th>Assumed Installed Costs</th>
<th>Implied Levelized Costs</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>$/kW Installed</td>
</tr>
<tr>
<td><strong>Assumed Costs</strong></td>
<td></td>
</tr>
<tr>
<td>2020 Low</td>
<td>$1,200</td>
</tr>
<tr>
<td>2020 High</td>
<td>$1,800</td>
</tr>
<tr>
<td>2030 Low</td>
<td>$876</td>
</tr>
<tr>
<td>2030 High</td>
<td>$1,314</td>
</tr>
</tbody>
</table>

**Note:** Cost and financing assumptions indicative of new development costs in Nevada. All values in nominal dollars.
Cost Effectiveness Framework

The Ratepayer Impact Measure (RIM) test provides an indication of how average retail rates will change as the result of a new utility initiative:
- Includes all reductions in resource costs (e.g., reductions in fuel and capacity costs)
- Includes savings associated with procuring services more cheaply (e.g., ancillary services)

We also include as a benefit the ratepayer value of avoided distribution outages:
- Not traditionally included in RIM test (does not result a cost incurred by the utility), but reflects a benefit to ratepayers who experience fewer outages
- We separately report cost-effective storage levels excluding customer outage value

We quantify, but do not include as ratepayer benefits, the societal-cost impacts associated with changes in carbon and other emissions.

We utilize the RIM test to evaluate cost-effectiveness of energy storage, including the value of avoided customer outages.
Evaluation of Key Value Drivers

Reduction in Production Costs

Approach

We use a production cost model – Power System Optimizer (PSO) – to estimate cost of meeting Nevada’s energy and ancillary service needs.

- We simulate entirety of WECC, with focus on Nevada
- To account for changes in Nevada production costs, purchases, and sales, we calculated adjusted production costs (APC) for the Nevada footprint
- We simulate 3 scenarios: base case (no storage), 200 MW, and 1,000 MW of storage

Calculating Nevada Adjusted Production Costs (APC)

\[
\text{Nevada Adjusted Production Costs} = \text{Production Costs} + \text{Cost of Purchases} - \text{Revenue from Sales}
\]

Production Costs = Cost of Nevada owned generation
- Generation costs include fuel, emissions, variable operating, and startup costs

Cost of Purchases = Deficit in generation \times Price Hub
- Purchases priced at the Malin and Mead hubs for Northern and Southern Nevada, respectively.

Revenues from Sales = Surplus in generation \times Price Hub
- Sales priced at the Malin and Mead hubs for Northern and Southern Nevada, respectively.
**Evaluation of Key Value Drivers**

**Reduction in Production Costs**

**Findings**

We find APC savings of $4.5 to $16.5 million in 2020 (200 MW vs. 1,000 MW storage deployed), and $9.3 to $40.6 million in 2030.

- Savings due three factors:
  - Reduced costs of operating NV generators
  - Reduced imports during high priced hours
  - Increased revenues from sales

- Savings account for the value of storage providing ancillary services

- Incremental savings (savings due to adding 1 additional MW of storage) fall as more storage is added and highest-value opportunities saturate

### 2020 Adjusted Production Cost Savings (in nominal $million/year)

<table>
<thead>
<tr>
<th></th>
<th>Production Cost</th>
<th>Savings (Storage Case minus Base Case)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Base</td>
<td>200 MW</td>
</tr>
<tr>
<td>Production Cost</td>
<td>$421</td>
<td>$420</td>
</tr>
<tr>
<td>Cost of Market Purchases</td>
<td>$132</td>
<td>$129</td>
</tr>
<tr>
<td>Revenues from Sales</td>
<td>$(46)</td>
<td>$(46)</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$507</strong></td>
<td><strong>$502</strong></td>
</tr>
</tbody>
</table>

### Estimated Incremental Benefit from APC Savings

*Sources and Notes:*

All values in nominal dollars. The total APC savings from simulations with 200 MW and 1,000 MW were used to estimate a relationship between storage deployed and total savings, from which we can estimate the relationship between storage deployed and incremental APC savings.
Evaluation of Key Value Drivers
Transmission & Distribution Investment Deferral Approach

We used NV Energy capital expenditure data to identify high-value T&D deferral opportunities and evaluate how storage could defer investments.

- NV Energy provided cost data and descriptions for 260 capital projects from 2014-2027
- We estimate the subset that could be deferred by storage
  - We identified 35 projects (14% of total) are potentially deferrable by storage
  - Primarily transformer upgrades needed to support local load growth
  - We estimate the value of deferring each investment by 15 years
- We make several assumptions to approximate how much storage may be require to defer an investment
  - **Initial Peak Load:** based on NV Energy’s project descriptions
  - **Rate of Load Growth:** Assumed 2%
  - **Hourly Load Shape:** Based on average residential or C&I load shapes
- We size the storage to 15 year load growth

*Average of NPC and SPPC After Tax Weighted Average Cost of Capital (ATWAAC) per NV Energy 2018 IRP, weighted by each system’s contribution to total peak load.*
Evaluation of Key Value Drivers

Customer Outage Reduction Value Approach

We evaluate the reliability value to customers of deploying storage on specific feeders that historical experience relatively high levels of outages.

- NV Energy provided data on 43,000 distribution-level outages for 2014-2018
- We evaluate customer outage reduction benefits of siting storage at least-reliable feeders
  - We simulate storage deployed at each identified feeder, sized at average feeder peak load
  - Account for both the duration (hours) and magnitude (MWh) of each outage
  - Account for unpredictability of outages
  - Assume customers value improved reliability at $12,500/MWh value of lost load (VOLL)
- Analysis assumes feeders can be “islanded” in event of an outage
  - Requires grid modernization investments, e.g. microgrids, automated distribution switching
  - We separately report cost-effective storage levels if grid modernization efforts not made and customer outage value cannot be captured
The marginal benefit from avoided distribution outages declines as storage is added to the least-reliable feeders.

**Incremental Reliability Benefit of Storage ($/kW-year)**

- **Simulated Reliability Benefit** (noisy because least reliable feeders that are allocated storage may or may not actually experience outages)

**Note:**
All values in nominal dollars.
2020 cost-effective storage levels are up to 175 MW, depending on storage costs. In 2030, cost-effective levels are greater than 700 MW.

Note: All values are in nominal dollars.
Aggregate System-Wide Benefits
Renewable Integration and Emission Benefits

Storage reduces WECC-wide emissions in both 2020 and 2030. Storage also reduces Nevada solar curtailments in 2030.

**Reduction in Nevada Renewable Generation Curtailments, 2030**

<table>
<thead>
<tr>
<th></th>
<th>GWh</th>
<th>[Change] - [Base]</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Base</td>
<td>200 MW</td>
</tr>
<tr>
<td>Nevada</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total Solar Generation</td>
<td>6,630</td>
<td>6,633</td>
</tr>
<tr>
<td>Solar Curtailment</td>
<td>37</td>
<td>54</td>
</tr>
<tr>
<td>Percent Change in Curtailment</td>
<td>-5%</td>
<td>-51%</td>
</tr>
</tbody>
</table>

**Impact on WECC-Wide Emissions**

<table>
<thead>
<tr>
<th></th>
<th>Change in Emissions (tons)</th>
<th>Change in Emissions (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>200 MW</td>
<td>1,000 MW</td>
</tr>
<tr>
<td>2020 Cases</td>
<td></td>
<td></td>
</tr>
<tr>
<td>CO2</td>
<td>-46,974</td>
<td>-131,998</td>
</tr>
<tr>
<td>NOX</td>
<td>135</td>
<td>117</td>
</tr>
<tr>
<td>SO2</td>
<td>161</td>
<td>351</td>
</tr>
<tr>
<td>2030 Cases</td>
<td></td>
<td></td>
</tr>
<tr>
<td>CO2</td>
<td>-63,162</td>
<td>-234,955</td>
</tr>
<tr>
<td>NOX</td>
<td>-79</td>
<td>-455</td>
</tr>
<tr>
<td>SO2</td>
<td>8</td>
<td>-480</td>
</tr>
</tbody>
</table>

- In 2020, minimal curtailments with or without storage
- In 2030, 1,000 MW of storage significantly reduces curtailments
- Storage reduces WECC-wide CO₂ emissions in all cases
- Societal savings of $2.6 to $7.2 million in 2020 and $5.0 to $18.5 million in 2030*

Behind-the-Meter Storage Applications
We evaluate the economic potential for BTM storage adoption by C&I customers with and without a utility-administered program.

C&I customers most likely to adopt BTM storage in the near- to medium-term
- Uses include retail bill reduction, backup generation, and aggregation as DR
- Significant residential adoption unlikely, absent changes to retail rate design and NEM policy

The utility could incentivize further adoption of BTM storage
- Incentive could take the form of a cost-effective payment
- In return, utility would control device for a limited number of days per year to address resource adequacy needs
BTM Applications

Approach to Quantifying BTM Storage Potential

We use a 7-step process to evaluate BTM adoption with and without a utility-administered program:

1. Identify applicable retail rate design
2. Establish customer load patterns
3. Define BTM storage operational characteristics
4. Simulate storage dispatch using bSTORE
5. Calculate payback period
6. Quantify long-run BTM storage adoption
7. Impact of utility BTM storage incentive program

Bill savings
BTM storage costs
Customer investment payback period

We calculate the payback period, which is a measure of the time it takes for the savings from BTM storage to equal the original investment.
<table>
<thead>
<tr>
<th>Description</th>
<th>Charge</th>
</tr>
</thead>
<tbody>
<tr>
<td>Basic service charge ($/month)</td>
<td>193.10</td>
</tr>
<tr>
<td>Facilities charge ($/kW-month)</td>
<td>3.14</td>
</tr>
<tr>
<td>Demand charge</td>
<td></td>
</tr>
<tr>
<td>Winter ($/kW-month)</td>
<td>0.40</td>
</tr>
<tr>
<td>Summer on-peak ($/kW-month)</td>
<td>13.35</td>
</tr>
<tr>
<td>Summer mid-peak ($/kW-month)</td>
<td>2.04</td>
</tr>
<tr>
<td>Summer off-peak ($/kW-month)</td>
<td>0.00</td>
</tr>
<tr>
<td>Energy charge</td>
<td></td>
</tr>
<tr>
<td>Winter ($/kWh)</td>
<td>0.05213</td>
</tr>
<tr>
<td>Summer on-peak ($/kWh)</td>
<td>0.08508</td>
</tr>
<tr>
<td>Summer mid-peak ($/kWh)</td>
<td>0.06449</td>
</tr>
<tr>
<td>Summer off-peak ($/kWh)</td>
<td>0.04573</td>
</tr>
<tr>
<td>Riders ($/kWh)</td>
<td>0.00105</td>
</tr>
</tbody>
</table>

Notes: Summer season is June through September. On-peak period is 1 pm to 7 pm daily. Mid-peak period is 10 am to 1 pm and 7 pm to 10 pm. Off-peak period is 10 pm to 10 am.
Commercial & Industrial BTM Storage Adoption Function

The graph shows the long-term adoption rate as a function of the payback period. As the payback period increases, the long-term adoption rate decreases significantly. For example, in the first year, there is a near 100% adoption rate, but by the 15th year, the adoption rate has dropped to almost zero.
### Assumptions Behind BTM Storage Adoption Cases

<table>
<thead>
<tr>
<th></th>
<th>Low Adoption Case</th>
<th>Medium Adoption Case</th>
<th>High Adoption Case</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Battery cost</strong></td>
<td>2020: $700/kWh</td>
<td>2020: $575/kWh</td>
<td>2020: $450/kWh</td>
</tr>
<tr>
<td></td>
<td>2030: $400/kWh</td>
<td>2030: $325/kWh</td>
<td>2030: $250/kWh</td>
</tr>
<tr>
<td><strong>Adoption function</strong></td>
<td>20% reduction from Medium Case</td>
<td>Base adoption function based on investment payback period</td>
<td>20% increase from Medium Case</td>
</tr>
<tr>
<td><strong>Utility incentive payment</strong></td>
<td>50% of avoided generation capacity cost</td>
<td>75% of avoided generation capacity cost</td>
<td>100% of avoided generation capacity cost</td>
</tr>
<tr>
<td><strong>Customer mix</strong></td>
<td>Skewed toward segments with lower BTM storage value</td>
<td>Average customer mix</td>
<td>Skewed toward segments with higher BTM storage value</td>
</tr>
</tbody>
</table>
Summary of Sensitivity Analysis with BTM Storage

**Without Incentive**

- **2020**
  - Base = 2 MW

- **2030**
  - Base = 12 MW

**With Incentive**

- **2020**
  - Base = 8 MW

- **2030**
  - Base = 30 MW
Additional Supporting Material
Framework for Determining Value of Storage to Reduce Distribution Outages

4 Years of NV Energy Outage Events

Average customer load assumption (developed from NV Energy data) determines MWh of load impacted by interruption and VOLL.

2014
Select 2 years to evaluate most valuable locations to deploy storage based on non-storm outage events.

2015

2016
Use the subsequent 2 years of outage data to evaluate the outage costs avoided by storage (including storm events).

2017

Most valuable locations are based on the VOLL reduction each 100 kW of storage can realize.

Assume storage deployed on feeders with highest value of return with 5 MW at each feeder.

Consistent with output from production cost simulations, assume storage has 50% state of charge at time of each outage.

Estimate value of avoided distribution outages.
Change in WECC-Wide Generation Due to Storage
By Hour of Day (1,000 MW Case minus Base Case)

2020

2030
# Change in Societal Cost Associated with Carbon Emissions

<table>
<thead>
<tr>
<th></th>
<th>Change in Societal Costs ($M)</th>
<th>Change in Societal Cost ($/kW-yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>200 MW</td>
<td>1,000 MW</td>
</tr>
<tr>
<td><strong>2020 Cases</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Low</td>
<td>-$0.7</td>
<td>-$2.0</td>
</tr>
<tr>
<td>Baseline</td>
<td>-$2.6</td>
<td>-$7.2</td>
</tr>
<tr>
<td>High</td>
<td>-$3.8</td>
<td>-$10.6</td>
</tr>
<tr>
<td><strong>2030 Cases</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Low</td>
<td>-$1.6</td>
<td>-$5.9</td>
</tr>
<tr>
<td>Baseline</td>
<td>-$5.0</td>
<td>-$18.5</td>
</tr>
<tr>
<td>High</td>
<td>-$7.3</td>
<td>-$27.0</td>
</tr>
</tbody>
</table>

**Sources and Notes:**
Low estimate uses IWG’s 2.5% discount rate SCC estimate, baseline estimate uses IWG’s 3% discount rate SCC estimate, and high estimate uses IWG’s 5% discount rate SCC estimate. All values are in nominal dollars.
Nevada Average Daily Load Shapes, by Season

Sources and Notes: Hourly load data from 2026 TEPPC Common Case. Net load is net of renewables, distributed generation, and energy efficiency.
Average Peak Load Shapes by Customer Class

Sources and Notes: Load by Customer Class data, provided by NV Energy. Load Shapes are averaged over top 10 peak days.
Additional Reading

“Maximizing the Market Value of Flexible Hydro Generation,” Pablo Ruiz, James A. Read, Jr., Johannes Pfeifenberger, Roger Lueken, and Judy Chang, Comments in Response to DOE’s Request for Information DE-FOA-0001886, April 4, 2018

“Getting to 50 GW? The Role of FERC Order 841, RTOs, States, and Utilities in Unlocking Storage's Potential,” Roger Lueken, Judy Chang, Johannes P. Pfeifenberger, Pablo Ruiz, and Heidi Bishop, Presented at Infocast Storage Week, February 22, 2018

“Battery Storage Development: Regulatory and Market Environments,” Michael Hagerty and Judy Chang, Presented to the Philadelphia Area Municipal Analyst Society, January 18, 2018

“U.S. Federal and State Regulations: Opportunities and Challenges for Electricity Storage,” Romkaew Broehm, Presented at BITCongress, Inc.’s 7th World Congress of Smart Energy, November 2, 2017

“Stacked Benefits: Comprehensively Valuing Battery Storage in California,” Ryan Hledik, Roger Lueken, Colin McIntyre, and Heidi Bishop, Prepared for Eos Energy Storage, September 12, 2017

“The Hidden Battery: Opportunities in Electric Water Heating,” Ryan Hledik, Judy Chang, and Roger Lueken, Prepared for the National Rural Electric Cooperative Association (NRECA), the Natural Resources Defense Council (NRDC), and the Peak Load Management Alliance (PLMA), February 10, 2016


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