Implications of Rate Design for the Customer-Economics of Behind-the-Meter Storage

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Rate design and the customer-economics of BTM storage: An essential piece of the rate reform puzzle

- Electricity bill savings from behind-the-meter (BTM) storage are intrinsically linked to retail electricity rate design.
- As regulators look to balance policy objectives related to rate reform and storage deployment, understanding how proposed changes in rate design may impact the customer economics of storage will be essential.
- Previous work (e.g., McKinsey & Co. 2018, NREL 2017) has focused primarily on the nominal $/kW demand charge rate as the key driver for bill savings from BTM storage.
  → Other aspects of demand charge design, as well as the details of time-varying energy rates and net billing rates for PV customers, may also be critical to BTM storage economics.
- This work aims to fill in these gaps and provide additional insights into which rate design elements are most important to the customer-economics and market potential of BTM storage.
Project overview

This analysis explores how the details of retail electricity rate design can impact customer bill savings from behind-the-meter (BTM) storage.

Scope

- **Focus is on the customer-economics**
  - Follow-on project will address alignment between customer-economics and utility value
- **Addresses just one aspect of the customer-economics: utility bill savings (demand and energy charges)**
  - Not considered here are other potential value/revenue streams for BTM storage owners (e.g., participation in wholesale markets, customer reliability and resilience benefits, voltage support, T&D deferral, etc.), though some of those are “implicit” in retail rates
  - We also do not address storage costs

**Approach:** Compute/compare utility bill savings from BTM storage across a range of rate structures and load shapes
Key rate design features impacting bill savings from BTM storage

Demand-charge savings depend on:
- Size of the demand charge rate ($/kW)
- Non-coincident vs. peak-period demand charges
- Timing and duration of peak period
- Averaging interval for measuring billing demand
- Seasonal variation in demand charge rates
- Ratchets

Energy-charge arbitrage savings depend on:
- Price differential between high/low price periods
- Daily/monthly structure of price variability
- Duration of high/low price periods

The analysis characterizes the relative significance and manner in which these rate design features impact BTM storage economics.

Vary among: Time-of-Use (TOU), Critical Peak Pricing (CPP), Real-Time Pricing (RTP), and Net Billing rate structures.
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Load data for demand charge analysis

- Demand charge analysis focuses on commercial customers, given much greater prevalence of demand charges in the commercial sector (and more readily available interval load data)
- 5-minute interval load data collected and published by EnerNOC, for 100 anonymized commercial customers over a single year (2012)
- Selected three representative customer loads: (1) a shopping center, (2) a shopping center with a PV system, and (3) a manufacturing plant—see next slide
  - For shopping center with PV, solar profile constructed from the National Renewable Energy Laboratory (NREL)'s National Solar Resource Database converted to solar generation data using NREL’s System Advisor Model
  - PV system sized to generate 50% of the building’s annual energy consumption
- The three individual customers selected are located in Chicago; previous analyses of commercial demand charges have shown that geographic location is secondary to building type
Selected customer types span range of customer characteristics and bill savings from storage

The three building loads selected for analysis capture the relevant range of load-shape attributes

- Shopping center: wide midday peak loads
- Shopping center with PV “skinny” peaks in net load, shifted to late afternoon/evening
- Manufacturing: relatively flat load shape
## Rate design and analytical methods

### Demand charge modeling

<table>
<thead>
<tr>
<th>Rate Design</th>
<th>Storage Modeling</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Demand charges calculated with and without storage</td>
<td>• Perfect foresight dispatch algorithm using HOMER</td>
</tr>
<tr>
<td>• Reference demand charge: $7/kW, non-coincident, 15 minute averaging window, no ratchet</td>
<td>• Storage dispatch optimized for demand charge reduction</td>
</tr>
</tbody>
</table>
  - Based on median demand charge level in the OpenEI Utility Rate Database (URDB) | - Though energy arbitrage could occur in conjunction if highest-priced hours coincide with peak demand |
| • We also calculate demand charge savings for alternative demand charge rate designs with: | • Storage capacity (in kW) sized to meet 20% of customer’s peak annual load |
  - Demand charge levels ranging from $2-$15/kW | • Various hours of storage modeled (1, 2, and 4 hours) |
  - Peak period demand charges with varying peak period definitions (8am-6pm, 12-6pm, 5-10pm) | • Compare demand charge savings across rate designs primarily in terms of *annual bill savings per kW of storage capacity* ($/kW-yr) |
  - Averaging intervals ranging from 5-60 minutes | |
  - Seasonal demand charge (summer and winter peak) | |
  - Ratchets (≥90% of max. billing demand of past 12 months, ≥60% of max. billing demand) | |
## Rate design and analytical methods

### Energy charge arbitrage

<table>
<thead>
<tr>
<th>Rate Design</th>
<th>Storage Modeling</th>
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</thead>
<tbody>
<tr>
<td><strong>Time-of-use (TOU):</strong> Analyzed a range of TOU structures, informed by review of rates in the URDB</td>
<td>Storage dispatch optimized for energy arbitrage</td>
</tr>
<tr>
<td><strong>Critical Peak Pricing (CPP):</strong> Analyzed specific CPP rates currently in place</td>
<td>Assume 85% round-trip efficiency</td>
</tr>
<tr>
<td><strong>Real-time pricing (RTP):</strong> Volumetric rate equal to hourly day-ahead wholesale market price, based on historical nodal data for nine markets</td>
<td><strong>TOU, CPP, and RTP:</strong> Assume the battery can be fully charged in the two lowest priced hours and fully discharged in the two highest priced hours</td>
</tr>
<tr>
<td><strong>Net billing:</strong> Exports from PV generation compensated at some price other than (typically less than) retail rates; considered export rates ranging from 1-10 cents/kWh below retail rates</td>
<td><strong>Net billing:</strong> Assume that storage can be fully charged from PV generation each day that would otherwise be exported to the grid</td>
</tr>
</tbody>
</table>

- Energy charge savings are largely independent of the underlying customer load shape; results are not specific to either residential or commercial customers
- Compare energy charge savings across rate designs primarily in terms of *annual bill savings per kWh of storage capacity* ($/kWh-yr)
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Demand charge savings from storage vary by load shape and storage duration

• Storage is most effective at reducing demand charges for customers with narrow peaky loads
  – For peaky loads (e.g. customers with PV), even storage with shorter durations can be effective at shaving the narrow load peaks
  – For flatter load profiles (e.g. manufacturing), storage cannot sustain the required discharge to reduce peak demand

• Longer duration storage can more effectively reduce demand charges than systems with shorter durations
  – Longer duration storage can sustain discharge rates longer, potentially reducing wider peaks, though there are diminishing returns to duration

• Cross-customer differences in demand charge reduction efficiency hold across most demand charge rate designs

* Demand Charge Reduction Efficiency

\[
\text{Demand Charge Reduction Efficiency} = \frac{\text{Demand Charge Reduction (kW)}}{\text{Storage System Size (kW)}}
\]

The focus of our analysis is on the change in demand charge savings from these baseline levels when modifying individual elements of demand charge design
Impact of demand charge design on bill savings from BTM storage

Example: Shopping center, 2-hour storage

- **Demand charge rate** is the most-critical design feature in terms of demand charge savings
  - Most demand charge rates range from $2-15/kW, but a few utilities have rates as high as $30/kW or more

- **Peak period demand charges** can boost demand charge savings (by ~80% in this example), if based on relatively narrow windows

- **Averaging intervals** also have a distinct impact (±20% in this example), with greater demand charge savings the shorter the averaging interval

- **Season rates** and **ratchets** have little effect on bill savings

The following set of slides delve more deeply into these demand charge design elements

Note: The corresponding figures for the other two building load profiles are in the Appendix.
What does this mean in terms of payback period?

While we present our results elsewhere in normalized terms (e.g., annual bill savings per kW of storage), it can also be instructive to show how these results translate into more-intuitive metrics, like payback period.

Using the same example as the previous slide, the payback period from BTM storage (assuming demand charge savings are the only source of customer value):

- **11 years** under our reference demand charge design
- **5–39 years**, depending on demand charge level
- **6–11 years**, depending on whether or not peak coincident demand charges are used, and how that peak period is defined
- **9–15 years**, depending on the averaging interval

These values are illustrative: intended simply to show how demand charge design details can potentially be decisive to BTM storage economics and adoption.

Example: Shopping center, 2-hour storage, system sized at 20% of annual peak, $250/kWh storage cost*

*Storage cost assumption based roughly on average 2017 costs for Li-Ion battery storage, as reported by GTM Research (2018).
Demand charge levels vary widely: At “borderline” levels, other rate design details can drive BTM storage cost-effectiveness

- Demand charge rates can vary significantly by utility and by customer class and size
  - Depending on: underlying utility costs, cost allocation across customer classes, and which specific cost elements are recovered through demand charges
  - For large C&I customers, 50% or more of the total bill is often based on demand charges
- Prior analyses (NREL 2017, McKinsey 2017) have identified demand charge rates of $10-15/kW as a typical threshold for BTM storage cost-effectiveness
  - Demand charge rates at this level occur in most states (at least on a limited basis—see figure)
  - Our analysis of NREL’s Utility Rate Database found that 80% of all demand charge rates fall between $2/kW and $15/kW (the 10th & 90th percentile values, respectively), with an overall median of $7/kW

Storage is generally more effective at reducing demand charges when based on “peak period” demand

- Peak period demand charges are an alternative to non-coincident demand charges; are based on maximum demand during designated peak periods
  - Typically beginning between 12pm-2pm and ending between 6-8 pm, though specific timing and duration can vary considerably
- Peak period demand charges create skinnier demand peaks, leading to greater bill savings from storage
- Demand charge reductions from storage are greater the shorter the peak period window
- Demand charge reductions also depend on timing and on the underlying load shape during the peak period
  - If the timing of the demand charge peak period coincides with when load is ramping up or down, the resulting sharp load peaks inside the window can more easily be clipped by storage

**Billing demand reduction from storage with peak period demand charges**
An illustration of how peak period timing and duration can impact demand charge savings from storage

- **Shopping center**: the 5pm-10pm window coincides with the down-ramp of the load profile, leading to a steep peak within the window that storage can effectively reduce.

- **Shopping center with PV**: net load profile has a skinny peak (and hence greater demand charge saving under a non-coincident design), so the incremental savings from moving to a peak period design are much smaller.

- **Manufacturing**: Demand charge savings from storage depend primarily on the duration of the peak period window.
Demand charge savings from storage are greater under demand charges with short averaging intervals

- Demand charges are typically based on demand averaged over 15-minute intervals, though averaging intervals can range from 5-60 minutes (depending in part on metering technology)

- Longer averaging intervals smooth out billing demand variability, leading to lower billing demand without storage (i.e., the blue vs. the red line in the figure)

- In effect, longer averaging intervals are a proxy for storage, thereby eroding the opportunity for further demand reductions from storage

- The significance of averaging interval differs across customers depending on the variability (“noisiness”) of their underlying load profile
Seasonal demand charge rates and ratchets have little impact on demand charge savings from storage

- Seasonal demand charge and ratchet definitions are diverse among utilities
  - Seasonal demand charges can either have higher priced summer or winter peak seasons

- For seasonal demand charges, impacts of storage on demand reduction is small regardless of seasonal definition
  - For customers with PV, storage is more effective at reducing the demand charge in the summer months, when PV is most reliable at creating the “skinny peaks”
  - Though the change in demand charge reduction efficiency can be positive or negative depending on the load profile, the overall impact remains small

- Ratchets can slightly increase the average demand charge reduction efficiency of storage for loads with large month-to-month variation in peak load
  - We also considered a less-binding ratchet (with a 60% threshold) but this had no impact on demand charge reduction efficiency relative to the reference design

Notes: Summer and winter peaks have demand charge level increased fourfold from June through August and November through February, respectively.
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Energy-charge arbitrage savings from BTM storage

Range in annual bill savings from energy arbitrage (some illustrative examples)

- **TOU**: Wide variation, depending on peak-to-off-peak differential and seasonal definition (i.e., number of summer vs. winter months)
- **CPP**: Savings driven by arbitrage from TOU differential + critical peak price events
- **RTP**: Limited arbitrage opportunities if based solely on wholesale energy market prices, given average peak-to-off-peak spreads
- **Net Billing**: Daily arbitrage savings driven by the delta between retail and PV grid-export rates, the latter potentially based on some construct of avoided costs

Notes: We use $/kWh-yr as the bill savings metric, rather than $/kW-yr, as in the case of demand charge savings. See appendix for utility abbreviations and tariff names.
Energy price differences enable storage to reduce electricity bills through arbitrage

**TOU, CPP, and RTP:** Bill savings from storage achieved by charging during low priced hours and discharging during high priced hours.

**Net billing:** Storage manages PV exports to the grid, arbitraging between retail rates and the PV grid export rate.
Under TOU rates, arbitrage value varies widely depending on differential between peak-period and off-peak rates

Annual value of bill savings from TOU arbitrage for commercial and residential rates

- Computed value of energy arbitrage from storage across large number of TOU rates
- Specific examples shown here illustrate the range in arbitrage-value (~$2-$53/kWh of storage capacity per year)
- Greater bill savings driven by peak-to-off-peak TOU rate differential
  - Differential varies widely across utilities and tariff schedules (<2 cents to >20 cents per kWh)
- Bill savings value from TOU arbitrage can occur disproportionately during May-October
  - Peak period rates may only apply (or are much higher) during these months

Notes: See Appendix for utility abbreviations and tariff names.
TOU arbitrage opportunities vary by state and utility, primarily reflecting retail rate design choices (more so than wholesale prices)

Annual value of bill savings from residential TOU arbitrage for the largest utility of each state

- Calculations use residential TOU rate from largest utility selected for each state (ranked by number of residential customers)
  - Optional TOU rates are offered for residential customers by the largest utility in 38 states

- Values shown not indicative of other utilities in state
  - Wide variety of TOU peak to off-peak differentials also exist within each of the states

- No geographic trends emerge from map as TOU rates are only loosely tied to regional wholesale electricity prices

- Map shown for residential customers only as commercial customer rate also have demand charge element which makes total bill savings dependent on load profile

Notes: See Appendix for utility and tariff names used for each state.
Arbitrage value under CPP rates derives mostly from underlying TOU structure, but also depends on level and frequency of critical peak prices.

• Aside from pilot tariffs, relatively few CPP rates are currently available
  – Figure shows a sample of commercial and residential CPP rates illustrating a general range in bill savings from storage

• Large range in critical peak price levels (~$0.30-1.40/kWh) and event days per year (~10-20)

• Arbitrage value from storage varies from ~$4-56 per kWh of storage per year
  – Arbitrage from CPP events typically comprises one-quarter to two-thirds of overall energy charge savings
  – Under many of the CPP rates, most of the bill savings are from TOU arbitrage during non-CPP-event days

• Arbitrage value on CPP days may be lower if customers reduce load below storage capacity during events, as storage then would not fully discharge
Arbitrage value under RTP rates is relatively low compared to the other time-varying rates

- RTP most common among industrial customers though overall number of customers small compared to TOU (Nezamoddini and Wang 2017)
- RTP arbitrage value has relatively low range and variability across years and markets
  - Typically $6-$14 per kWh of storage per year, though some nodes experience higher price volatility
- Reflects fairly limited differential between average peak and off-peak prices
- Greater hourly variability and arbitrage value possible if:
  - Retail RTP also reflects temporal variability in marginal transmission and distribution costs
  - Growing PV penetration leads to greater price volatility

Annual value of bill savings from RTP arbitrage

*Based on historical day-head hourly prices*

<table>
<thead>
<tr>
<th>ISO</th>
<th>Annual arbitrage value ($/kWh-yr)</th>
<th>Average daily peak to off-peak price differential ($/kWh)</th>
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<td>ISO-NE</td>
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<td>NYISO</td>
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Notes: Based on prices from 100 randomly selected price nodes for each ISO from 2009 or latest market redesign (whichever is later) through August 2018. Storage assumed to be able to charge and discharge fully in the two lowest and highest priced hours of each day, respectively. Box plots represent 5th, 25th, 50th, 75th, and 95th percentiles.
Arbitrage value under net billing is driven by differential between retail rate and grid export rate

- Net billing has become the successor to NEM in some states: PV exports to the grid are compensated at some designated grid export rate (rather than at retail rates)

- Grid export rates may be based on avoided cost value or in some cases may be more of a political compromise (e.g., during transitional periods away from NEM)

- Differentials between retail rate and grid export rate vary
  - CA Net Metering 2.0: ~$0.02-0.03/kWh differential
  - Rocky Mountain Power: ~$0.02-0.04/kWh differential
  - Arizona Public Service: ~$0.10/kWh differential

- Linear relationship between arbitrage value and retail-to-grid-export price differential (assuming enough grid exports every day to fully charge storage)—see figure

- More applicable to residential customers, which tend to have proportionally greater grid exports than commercial customers with PV

Annual value of bill savings from net billing arbitrage

Notes: Assumes enough PV grid exports every day to fully charge storage.
Energy arbitrage savings can rival demand charge savings, especially with longer-duration storage

- Some TOU rates and net billing rates offer bill savings on par with, or greater than, demand charge savings—depending on the details of the rate design
- The relative importance of demand vs. energy charge savings also depends on storage duration
  - Energy arbitrage savings scale more-or-less linearly with storage duration, while demand charge savings face diminishing returns to scale
  - This has implications for rate design and BTM storage adoption, as longer duration storage becomes more economically viable

Notes: Range in demand charge savings based on $2-15/kW range in demand charge rate. Range in energy arbitrage savings reflect the specific set of illustrative rates featured in previous slides. Energy charge savings shown here in terms of $ per kW of storage capacity in order to allow comparability to demand charge savings.
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Conclusions

• It’s not just about the size of the demand charge: other rate design features are also key to understanding the customer-economics of BTM storage
  – Peak-period demand charge designs, demand charge averaging intervals, and TOU peak-to-off-peak energy price differential are all significant to determining the customer bill savings from storage
  – The details of demand charge design are more important for some customers than others (e.g., depending on how peaky or variable the customer load shape is and the timing of load peaks)

• Among the rate design elements and customer types considered, demand charge savings range from $8-$143 per kW of storage capacity per year whereas arbitrage savings can range from $4-$112 per kW of storage capacity per year (for a 2 hour duration storage system)

• With longer duration storage, energy arbitrage savings can be (sometimes substantially) larger than demand charge savings
  – Arbitrage savings roughly scale with storage duration, whereas there are diminishing returns to demand charge reductions with increasing storage duration
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### Utility and rate abbreviations (slides 23 and 25)

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<th>utility</th>
<th>rate</th>
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<td>commercial</td>
<td><strong>RMP</strong> Rocky Montain Power - Utah</td>
<td>Large General Service (No. 8)</td>
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<td><strong>SRP</strong> Salt River Project</td>
<td>Time-of-Use General Service (E-32)</td>
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<td><strong>ConEd</strong> Consolidated Edison Company of NY</td>
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<td><strong>AEP</strong> AEP Ohio (Ohio Power Co)</td>
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<td><strong>APS</strong> Arizona Public Service</td>
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<td>commercial</td>
<td><strong>GMP</strong> Green Mountain Power</td>
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<td><strong>OG&amp;E</strong> Oklahoma Gas and Electric</td>
<td>General Service Variable Peak Pricing</td>
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<td><strong>SCE</strong> Southern California Edison</td>
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<td><strong>PG&amp;E</strong> Pacific Gas and Electric</td>
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<tr>
<td>MD</td>
<td>Baltimore Gas &amp; Electric Co</td>
<td>Residential Optional Time-of-Use (schedule RL)</td>
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<tr>
<td>ME</td>
<td>Central Maine Power Co</td>
<td>Residential Service - Optional Time-Of-Use</td>
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<tr>
<td>MI</td>
<td>DTE Electric Company</td>
<td>Residential Time-of-Day Service Rate (D1.2)</td>
</tr>
<tr>
<td>MN</td>
<td>Northern States Power Co (Xcel)</td>
<td>Residential Time of Day Service (A02)</td>
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<tr>
<td>MO</td>
<td>Union Electric Co - (MO)</td>
<td>Residential Service Rate (No 1(M))</td>
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<tr>
<td>MS</td>
<td>Entergy Mississippi Inc</td>
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### Utility and rate abbreviations (slide 24, continued)

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<th>State</th>
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<td>MT</td>
<td>NorthWestern Energy LLC - (MT)</td>
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<td>NC</td>
<td>Duke Energy Carolinas, LLC</td>
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<td>NE</td>
<td>Omaha Public Power District</td>
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<td>NH</td>
<td>New Hampshire Elec Coop Inc</td>
<td>Residential Time of Day (TOD)</td>
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<td>NJ</td>
<td>Public Service Elec &amp; Gas Co</td>
<td>Residential Load Management Service (RLM)</td>
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<td>NM</td>
<td>Public Service Co of NM</td>
<td>Residential Service Time-of-Use Rate</td>
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<tr>
<td>NY</td>
<td>Consolidated Edison Co-NY Inc</td>
<td>Residential and Religious - Voluntary Time-of-Day (Rate III)</td>
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<tr>
<td>OH</td>
<td>Ohio Power Co (AEP Ohio)</td>
<td>Residential Service - Time-of-Day (RS-TOD)</td>
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<td>OK</td>
<td>Oklahoma Gas &amp; Electric Co</td>
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<td>OR</td>
<td>Portland General Electric Co</td>
<td>Residential Service (Time-of-Use Portfolio)</td>
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<td>PA</td>
<td>PECO Energy Co</td>
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<td>RI</td>
<td>The Narragansett Electric Co</td>
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<td>South Carolina Electric &amp; Gas Company</td>
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<td>TXU Energy Retail Co, LLC</td>
<td>Free Nights and Solar Days 12</td>
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<td>UT</td>
<td>PacifiCorp (Rocky Mountain Power)</td>
<td>Residential Service + Optional Time-of-Day Rider -Experimental</td>
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<td>VA</td>
<td>Virginia Electric &amp; Power Co (Dominion Power)</td>
<td>Residential Service (1T)</td>
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<td>VT</td>
<td>Vermont Electric Cooperative, Inc.</td>
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<td>Puget Sound Energy Inc</td>
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<td>Wisconsin Electric Power Co</td>
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<td>WV</td>
<td>Appalachian Power Co</td>
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<td>WY</td>
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Results summary: Comparing demand charge reduction and energy arbitrage value for three customer types

Annual value of bill savings from BTM storage
2-hour storage, storage capacity = 20% of peak demand

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<tr>
<th>Reference demand charge</th>
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<th>Arbitrage Value</th>
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<td>Manufacturing</td>
<td>Shopping</td>
</tr>
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<td>Shopping + PV</td>
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<tr>
<td>TOU</td>
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<tr>
<td>CPP (+TOU)</td>
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<tr>
<td>CPP days only</td>
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<td>RTP</td>
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<tr>
<td>Net Billing</td>
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</tbody>
</table>

- **Manufacturing**
- **Shopping**
- **Shopping + PV**

|$ / kW-yr |

Dem charge rate
Coincident pk defin
Averaging interval
Seasonal rates
Ratchet

Seasonal rates
Ratchet

TOU
CPP (+TOU)
CPP days only
RTP
Net Billing