Business & Technology Advisory

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NRECA
America's Electric Cooperatives

Energy Storage Cost-Benefit Analysis with White River Valley EC

Key Findings

- New online tools (linked below) are available to co-ops to calculate the costs and benefits of deploying energy storage on the distribution system.
- These tools were developed by NRECA and recently tested and demonstrated with White River Valley EC.

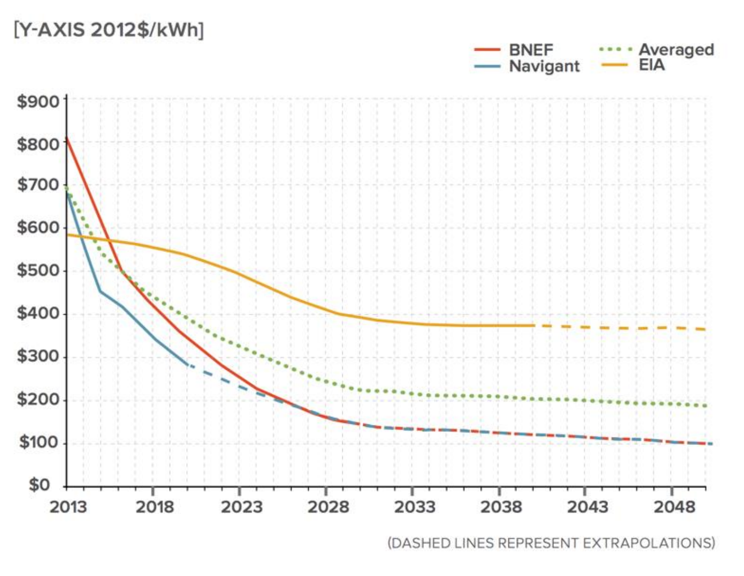
What has changed?

The price of energy storage is decreasing rapidly (Figure 1). This is making energy storage increasingly useful as a tool to manage peak demand, defer capital investments, and provide reserves services to the bulk power system.

What is the impact on cooperatives?

Cooperatives nationwide are evaluating where energy storage could be best applied in their systems. To assist with calculating the costs and benefits, NRECA has produced three analytical models to determine, for cooperatives, (1) the value of energy storage for peak demand management, (2) the value of storage for deferring capital investments, and (3) the value of storage for arbitraging different energy prices. These models were developed and tested with the help of White River EMC and the support of the U.S. Department of Energy (DE-AR-0000669).

***Figure 1.** Li-Ion Energy Storage Price Projections. From RMI Economics of Grid Defection Report, 2014, p. 24. https://rmi.org/wp-content/uploads/2017/04/RMIGridDefectionFull_2014-05-1-1.pdf*



What do cooperatives need to know or do about it?

Cooperatives are encouraged to try the models, send NRECA feedback (to David.Pinney@nreca.coop), and consider using them if you are planning to deploy energy storage. Your feedback will provide us with useful insights which will allow us to make updates to the tool to better serve cooperatives. Details on the models and how to run them follow.

Peak Demand Management Model

This model calculates the expected change in energy and demand costs a distribution co-op could anticipate if it deployed energy storage to reduce peak demand. Key inputs include time series hourly historical demand data, size of the energy storage system to model, costs of deployment, energy and demand prices. The dispatch of the battery can be calculated automatically to determine the optimal amount of peak shaving assuming perfect foreknowledge, or more conservative dispatch strategies such as daily dispatch or seasonally-adjusted dispatch can be specified. You can try the model online by going to https://omf.coop/newModel/storagePeakShave/advisoryShave2018, and the full model documentation is available at https://github.com/dpinney/omf/wiki/Models-~-storagePeakShave.

Capital Investment Deferral Model

This model calculates the cost savings that could be available by deferring an upgrade to increase the capacity of a transformer, transmission line, or distribution line. Using forecasted hourly demand data and the capacity limit of the current asset, it can calculate the amount of energy storage capacity needed to shift consumption to times that would not exceed the limit. By comparing the carrying cost of the asset to the amount of energy storage capacity needed, it can calculate the expected savings, if any. You can try the model online by going to https://omf.coop/newModel/storageDeferral/advisoryDefer2018, and the full model documentation is available at https://github.com/dpinney/omf/wiki/Models-~-storageDeferral.

Arbitrage Model

This model is similar to the Peak Demand Management Model, but instead of calculating cost reductions from peak demand management, it calculates cost reductions from time-shifting consumption from times when the cost of power is high in to times when it is lower. You can try the model online by going to https://omf.coop/newModel/storageArbitrage/advisoryArb2018, and the full model documentation is available at https://github.com/dpinney/omf/wiki/Models-~-storageArbitrage.

Analysis with White River Valley EC

White River Valley is investigating a megawatt-scale lithium ion battery system to manage peak demand, arbitrage energy prices, and provide backup power. They had worked with consultants to evaluate a system for peak demand management, but were interested in cross-checking those results, working with an open model where the inputs could be changed freely, and looking at arbitrage and backup applications in more detail. For the two substations analyzed, optimal dispatch led to sub-10-year simple payback periods for the demand management application with minimal battery degradation due to the low number of required charge-discharge cycles; a daily dispatch scheme using the time most likely to reduce peak demand resulted in a positive but very long payback period and a projected 15-year battery life. Although arbitrage analysis did not identify a valuable arbitrage scheme, and backup applications would be limited to 1-2 hours based on feeder load, additional work in these areas will be conducted to consider different energy sources to arbitrage, as well as switching options that could increase the duration of the backup power application.

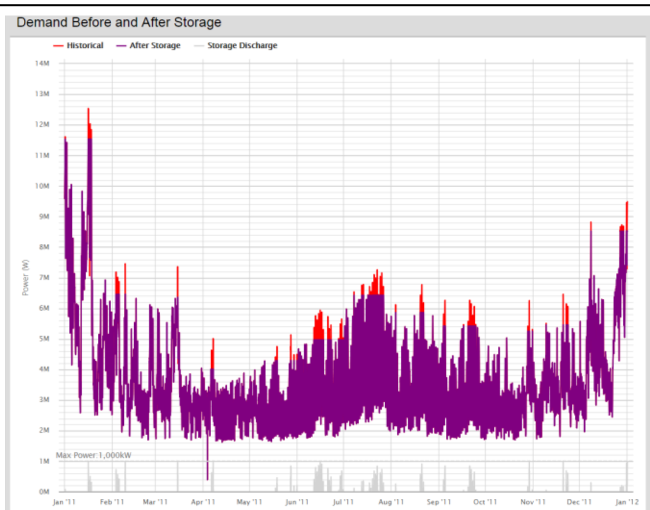


Figure 2. Model output showing peak reduction from optimal dispatch strategy and expected monthly peak shaving based on historical demand pattern.

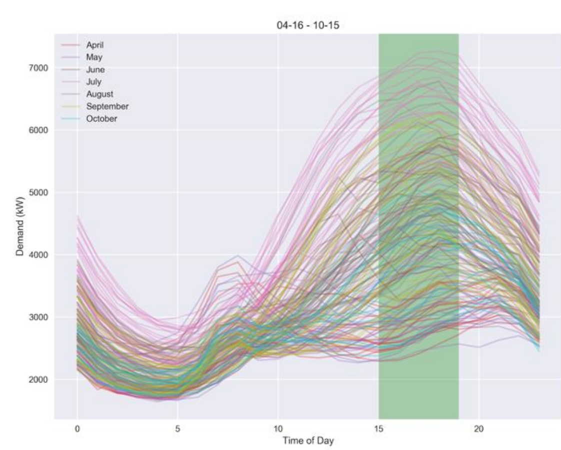


Figure 3. Overlay of daily demand curves for the same substation with green band indicating the daily dispatch window most likely to reduce system peaks.

Additional Resources

- **Energy Storage Overview Report:** https://www.cooperative.com/topics/distributed-energy-resources/Pages/Battery-Energy-Storage-Overview-Report.aspx
- **Energy Storage Toolkit:** https://www.cooperative.com/programs-services/bts/Pages/BTS-Reports/Energy-Storage-Toolkit-.aspx

Contact for Questions

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