ELECTRIC POWER
RESEARCH INSTITUTE

Strategic Intelligence Update

Energy Storage & Distributed Generation

September 2014 **Program 94**

Highlights of Top Stories:

- The California Independent System Operator (CAISO) is holding workshops and hearings to help develop a roadmap for energy storage in California (Page 4).
- EPRI conducted a comprehensive Q&A with Stem, a company that offers "energy storage as a service" designed to benefit both end users and utilities (Page 9).
- Codes and Standards are the critical foundation to the use of energy storage and distributed generation. EPRI provides an overview and status update of this important topic (Page 13).
- Tesla Motors will build its lithium ion battery "Gigafactory" in Nevada, a decision that already impacts the industry (Page 15).
- The California Public Utilities Commission recently issued a proposed decision on storage procurement targets for the state's investor-owned utilities. Meanwhile, the Sacramento Municipal Utilities District (SMUD) has determined that current storage technologies are not cost effective for its needs (Page 16).

Market Initiatives in New York and California

New Regulatory Efforts on Planning, Operations, and Markets to Integrate Distributed Energy Resources

Distributed energy resource development is expanding rapidly in several U.S. regions, driven by market opportunities, financial incentives, other policies, and declining costs. Many observers believe that this technology trend will only accelerate. However, there is still limited capability in most distribution utilities to identify the highest value locations for resource interconnection, and there remain barriers to entry (which may differ by technology type), including the fact that compensation is not available for the full range of services that such resources may offer to the distribution system and the wholesale market. To significantly reduce these barriers could require new institutional frameworks, potentially including development of new distribution-level market designs, reforms to existing wholesale market designs, and corresponding changes to utility business models (for example, EPRI's Integrated Grid initiative).

Recently, several state regulatory initiatives have begun with the objective of implementing substantial reforms in distribution level planning, operations, and markets. As reviewed in this section, two of the most prominent of these are in New York and California. Both states have taken leadership in promoting distributed energy resources, and are already experiencing the operational and market impacts in some locations. In addition, both have single-state wholesale markets for electric power services operated by independent system operators, which could facilitate regulatory reform of the interface between federally-regulated wholesale markets and implementation of any new distribution-level markets subject to state regulatory jurisdiction.

The New York State Public Service Commission (PSC) began its "Reforming Energy Vision" (REV) initiative in early 2014. The initiative aims to foster a re-structuring of distribution utilities while harnessing customer choice and market competition around the shift to distributed energy resources. It has been

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supported by a robust stakeholder process and several detailed staff papers.

In California, where penetration of distributed energy resources is accelerating under a number of existing policies, California Public Utilities Commission (CPUC) proceedings with similar objectives to the REV initiative are beginning, including one initiated in August 2014 on distribution resource planning. In addition, an interagency California storage roadmap, which includes distribution-connected resources, is under development, as described in more detail in this *Strategic Intelligence Update* on Page 4.

These initiatives are still in the early phases and there are several years of development before new institutional and market frameworks are likely to proceed to implementation. However, if these initiatives achieve their stated policy goals, the implications for penetration of distributed energy resources are clearly potentially dramatic.

New York REV Initiative

The REV initiative began with a PSC order in December 2013 which identified the key objectives and established a study process. Commission staff then prepared a report issued on April 24, 2014, which provided a set of further substantive and process proposals, and the Commission issued an order instituting a proceeding (Proceeding 14-M-0101).

The staff report and the order aim to foster "a new business model for energy service providers in which distributed energy resources (DER) become a primary tool in the planning and operation of electricity systems, and in which customers are empowered to optimize their priorities with respect to reliability, cost, and sustainability." A key element in this industry restructuring is the development of distributed system providers, tasked with "actively managing and coordinating distributed resources and providing a market in which customers are able to optimize their priorities while providing, and being compensated for, system benefits." The REV proceeding is divided into two tracks, which will be discussed next with an emphasis on Track One, which has been higher priority in the first phase of the proceeding.

Track One

Track One is focused on the definition of the Distributed System Platform (DSP), which refers to both the technology needed for implementation and the entity serving this function, and issues related to customer engagement and market participation. From May to July 2014, the Track One process engaged a large number of stakeholders and generated several working papers and presentations. This report focuses on the resulting Staff straw proposal, "Developing the REV Market in New York: DPS Staff Straw Proposal on Track One Issues," issued on August 22, 2014.

The Staff straw proposal provides details and proposals on a range of topics, including a more detailed description of the DSP "market vision," surveying the potential customer engagement and market participants, evaluating technological and economic feasibility (including reviewing the state of technology needed for the DSP and defining a cost-benefit analysis framework), rules to prevent exercise of market power by distribution utilities, and phased steps to implement the vision.

A key question is which entities would be eligible to serve as the DSP. As shown in Table 1 below, excerpted from the straw proposal, the DSP would need to serve many of the same functions as the existing distribution utilities as well as providing some new ones to support the types of markets under consideration. After evaluating a number of considerations, Staff recommends that the utility takes on the DSP function, but subject to sufficient regulatory oversight and market design requirements to ensure that it operates efficiently and independently.

The straw proposal concludes that the DSP is technologically feasible; that distributed energy resources are sufficiently mature that the potential market will attract large numbers of providers,

Table 1: Comparison of Utility and DSP Roles and Responsibilities

Utility and DSP Roles and Responsibilities	Utility	DSP
Market Functions		
Administer distribution-level markets including:		
- Load Reduction Market		X
- Ancillary Services		X
Match load and generator bids to produce daily schedules		X
Schedule external transactions		X
Real-time commitment, dispatch, and voltage control		X
Economic demand response		X
Demand and energy forecasting	X	X
Bid load into the New York ISO	X	
Aggregate demand response for sale to NYISO	X	X
Purchase Commodity from NYISO	X	
Metering	X	
Billing	X	X
Customer service	X	X
System Operations and Reliability		
Monitor real-time power flows	X	X
Emergency demand response program	X	X
Ancillary services	X	X
Supervisory control and data acquisition (SCADA)	X	X
System maintenance	X	
Engineering and Planning		
Engineering	X	
Planning/forecasting	X	X
Capital investments	X	
Interconnection	X	X
Emergency Response		
Outage restoration/resiliency	X	X

service companies and entrepreneurs ready to participate; and that the potential net economic benefits are significant enough to support moving forward with planning and implementation efforts. As such, Staff made the following specific recommendations, excerpted directly from the straw proposal:

• The Commission should adopt the basic elements of the REV vision and proceed with implementation as proposed here;

• The DSP should enable broad market participation; the DSP function should be served by existing utilities, whose long-term status as DSP providers should be subject to performance reviews;

• Customers and energy service providers should have access to system information, to make transparent and readily available the economic value of time- and location-variable usage;

• Individual customer usage data should be made available, on an opt-out basis, to distributed energy resource providers that satisfy Commission requirements;

• Utilities should only be allowed to own distributed energy resources under certain clearly defined conditions, or pursuant to an approved plan;

• Where utility affiliates participate in DSP markets within the service territory operated by their parent company, appropriate market power protections must be in place;

• An immediate process should be undertaken to develop demand response tariffs for all service territories, including tariffs for storage and energy efficiency;

• Implementation plans should include proposals to encourage participation of low and moderate-income customers;

• To protect consumers and reliability of service, the Commission should exercise oversight of distributed energy resource providers;

• A benefit-cost framework should be defined appropriate to three different purposes: (1) utility DSP implementation plans; (2) periodic utility resource plans; and (3) pricing and procurement of distributed energy resources; and

• As a transition toward market-based approaches to increase levels of efficiency and renewables, utilities should integrate energy efficiency into their regular operations and should take responsibility for procurement of Main Tier renewables.

Initial comments on the Staff Straw Proposal on Track One Issues were due by September 22, 2014, and reply comments can be submitted until October 24, 2014.

Track Two

Track Two of the proceeding is focused on regulatory changes and ratemaking issues. The substantive element of this track was begun with a ruling issued May 1, 2014, which raised a number of questions for stakeholder comment, including evaluation of performance-based regulations, long-term rate plans, and design of existing rate structures. The current schedule, which could be further modified, is for a staff options paper issued by October 3, 2014, followed by stakeholder roundtables from October 20–December 15, 2014. Staff will issue a straw proposal by January 20, 2015, with stakeholder comments due by March 20, 2015.

The documents, webinars and other materials for this proceeding, including stakeholder comments, are all available here: http://www3.dps.ny.gov/W/PSCWeb.nsf/All/26BE8A93967E604785257CC40066B91A?OpenDocument.

California Initiatives

California has promulgated many policies over the years to promote distributed energy resources (and renewable generation generally), but similarly to other parts of the country, only recently has the rate of penetration begun to make questions about distribution planning, operations and the ability to derive value for energy services more prominent. Of note, prior editions of the *Strategic Intelligence Update* explained the targets on the California investor-owned utilities for distribution-connected and customer-side storage technologies.

Of the current efforts in California aiming to identify and resolve issues related to planning, operations, and access to wholesale markets for distributed energy resources, this *Strategic Intelligence Update* examines two new initiatives. The interagency storage roadmap is discussed on Page 4, below. The remainder of this section discusses the CPUC's proceeding (R.14-08-013) to implement new state legislative requirements on investor-owned utility distribution resource planning (DRP).

State Assembly Bill (AB) 327 requires that the utilities identify barriers to deployment and make investments needed to integrate cost-effective distributed resources. The bill also authorizes the CPUC to modify and approve these utilities plans "as appropriate to minimize overall system costs and maximize ratepayer benefit from investments in distributed resources."

To begin this process, the CPUC has issued a series of questions on DRP, including asking for comments on a framework paper authored by a group of researchers and industry stakeholders. This effort could, in principle, encompass many of the same issues as identified in the New York REV, but at present has not yet addressed the restructuring of the distribution utility and opening of competitive markets at the distribution level as directly as the latter initiative. The CPUC questions are as follows (excerpted directly):

1) What specific criteria should the Commission consider to guide the investor-owned utilities' development of DRPs, including what characteristics, requirements and specifications are necessary to enable a distribution grid that is at once reliable, safe, resilient, cost-efficient, open to distributed energy resources, and enables the achievement of California's energy and climate goals?

2) What specific elements must a DRP include to demonstrate compliance with the statutory requirements for the plan adopted in AB 327?

3) What specific criteria should be considered in the development of a calculation methodology for optimal locations of distributed energy resources?

4) What specific values should be considered in the development of a locational value of distributed energy resource calculus? What is optimal means of compensating DERs for this value?

5) What specific considerations and methods should be considered to support the integration of distributed energy resources into IOU distribution planning and operations?

6) What specific distribution planning and operations methods should be considered to support the provision of distribution reliability services by distributed energy resources?

7) What types of benefits should be considered when quantifying the value of distributed energy resource integration in distribution system planning and operations?

8) What criteria and inputs should be considered in the development of scenarios and/or guidelines to test the specific distributed energy resource integration strategies proposed in the DRPs?

9) What types of data and level of data access should be considered as part of the DRP?

10) Should the DRPs include specific measures or projects that serve to demonstrate how specific types of distributed energy resources can be integrated into distribution planning and operation? If so, what are some examples that IOUs should consider?

11) What considerations should the Commission take into account when defining how the DRPs should be monitored over time?

12) What principles should the Commission consider in setting criteria to govern the review and approval of the DRPs?

13) Should the DRPs include discussion of how ownership of the distribution may evolve as distributed energy resources start to provide distribution reliability services? If so, briefly discuss those areas where utility, customer and third party ownership are reasonable?

14) What specific concerns around safety should be addressed in the DRPs?

15) What, if any, further actions, should the Commission consider to comply with AB 327 Section 769 and to establish policy and performance guidelines that enable electric utilities to develop and implement DRPs?

The order also asks for comments on an attached paper by the Greentech Leadership Group, Energy Foundation and Resnick Institute titled "More Than Smart: A Framework to Make the Distribution Grid More Open, Efficient and Resilient," (http://greentechleadership.org/programs/smart-2014/). This paper addresses a range of institutional and design questions related to distribution planning and operations similar to the New York REV papers, including creation of distribution system operators and how they might relate to the wholesale markets run by independent system operators.

The CPUC's order instituting rulemaking was issued on August 14, 2014, with comments due in early September and a workshop on September 17. A staff proposal with guidance is due in November and subsequent workshops are likely. A ruling is expected in late January, and the investor-owned utilities will file their distribution resource plans by July 1, 2015.

California ISO Hosts Energy Storage Workshop

Roadmap to Guide Future Policymaking

On Thursday, September 4, the California Independent System Operator (CAISO) hosted a workshop to support roadmap development for energy storage in California. This effort, led by CAISO, is intended to coordinate the major relevant regulators—including CAISO, California Public Utilities Commission (CPUC), and California Energy Commission (CEC)—and industry to jointly identify the barriers associated with storage deployment. Approximately 200 people attended in person, including EPRI's Ben Kaun and several EPRI utility advisors, with at least another 100 participating via teleconference.

The CAISO roadmapping effort follows a survey that was distributed approximately one month ago to solicit feedback on the barriers associated with deployment of energy storage in California. The workshop covered several different categories of "barriers to energy storage" including:

- Financial and Ancillary Services Barriers
- Interconnection (Process) Barriers
- Market Rules and Regulatory Barriers
- Metering and Telemetry
- Modeling
- Standards.

Notes on each of those topics are provided below. In general, the discussion was very detailed and informative of the issues that vendor/developers of energy storage deal with in the development of commercial projects. The conversation was structured in a way to solicit the perspective of selling and installing energy storage, and it was primarily focused on regulations and related processes at the CAISO and CPUC proceedings, as well as understanding compliance requirements, interconnection requirements, and commercial details, such as financing and revenue certainty of new projects.

In opening remarks, the CPUC said that a draft decision for investor-owned utility (IOU) storage applications was expected in mid-September. Southern California Edison (SCE) and San

California Interagency Storage Roadmap

In August 2014, the CAISO, the CPUC and the CEC began a joint effort to establish a storage roadmap, with consulting support from DNV-GL and Olivine. The roadmap is intended to identify "needed policy, technical, and regulatory actions that will facilitate the development and utilization of electric grid energy storage in California." In addition, it will identify "the challenges and barriers for energy storage, prioritizing these, and identifying the appropriate venue(s) where each needs to be addressed."

The first step in this process was a detailed questionnaire circulated to particular organizations and also available for completion online. A summary paper based on this questionnaire and compiled by DNV-GL was issued prior to the first workshop, which was hosted by the CAISO on September 4, 2014. In addition, several entities submitted background information. There were 131 respondents in several categories, of which slightly more than half were identified as industry.

The summary paper identifies a large number of issues raised by the respondents. The following items were identified as general, cross-cutting themes (cited verbatim):

- A need to identify services, benefits and values storage can provide
- Need to develop market or regulatory structures for storage resources to monetize services provided and reduce risks to investing in storage
- A need to define how storage satisfies resource adequacy (RA) and flexible RA requirements
- Stand-alone storage and storage in combination with solar PV appear to be leading configurations regardless of point of interconnection (customer, distribution, transmission).

The schedule for the process, which is intended to be complete by December 2014, is shown below.

Step	Date	Activity
First phase of stakeholder outreach: Key issue identification/collection	July 21– Aug. 8, 2014	Online open survey
Publish survey results	Aug. 28, 2014	Summary of outreach findings and barriers
Stakeholder Workshop #1	Sept. 4, 2014	First workshop to present and discuss barriers and how to address each issue
Stakeholder comments due	Sept.18, 2014	Stakeholder comments on the Aug. 28 survey results and Sept. 4 Workshop discussion
Publish draft Roadmap	Oct. 2, 2014	Initial draft of the Roadmap
Stakeholder Workshop #2	Oct. 13, 2014	Second workshop to discuss draft roadmap
Stakeholder comments due	Oct. 30, 2014	Stakeholder comments on the draft Roadmap and Oct. 13 Workshop discussion
Publish final Roadmap	Mid-Dec. 2014	Final Roadmap

Diego Gas & Electric (SDG&E) are in the later stages of local capacity requirement (LCR) procurement, including energy storage. In fact, SCE said it may exceed its 50 MW minimum storage requirement.

CPUC stressed its goal that interconnection should not be a barrier to the energy storage business, and is holding workshops to explore how distribution planning can accommodate all new devices, including energy storage.

In its opening comments, CAISO said it had completed implementing new "pay for performance" policies as required by FERC 755, as well as its Flexible Resource Adequacy Criteria Must Offer Obligation (FRAC-MOO). An energy storage interconnection initiative is currently underway.

Financial and Ancillary Services Barriers

In the recent CAISO survey, the statement that drew the most agreement was that there is a "lack of electricity tariffs that allow all storage benefits to be monetized." For large-scale storage to succeed, workshop participants argued that utilities must enter into long-term power purchase agreements (PPAs) or other arrangements that provide certain revenue. For smaller distribution service, the reliability of energy storage devices is crucial.

Some suggested that ISOs could play a role in storage offering market products by providing forward fixed payments. More broadly, there are currently no well-defined markets or mechanisms to deliver many of the services energy storage could provide. More flexibility and better market product definition could help.

Interconnection Barriers

Workshop participants said that the biggest barrier to effective energy storage interconnection is widespread lack of clarity and knowledge regarding the rules for doing so. In particular, there is no transition process between Rule 21 and Wholesale Distribution Access Tariff (WDAT) processes. In addition, rate structures have not been updated to support storage interconnection and integration with the wholesale market.

A representative of the California Energy Storage Association (CESA) said that the "interconnection process should be different for different types of services provided by storage," which began a discussion of how many types of interconnection processes might emerge.

California ISO Control Center, Folsom (Source: CAISO)

The Northern California Power Agency (NCPA) identified a need to expand distribution interconnection processes, including deliverability, beyond energy storage to all distributed energy resources.

Market Rules and Regulatory Barriers

A key challenge is the fact that storage is often not defined as an asset, either in terms of generation, transmission and distribution (T&D), or its own unique class. ISOs often treat storage assets as conventional generation with respect to ancillary service certification quantities and maximum generation capacity.

In addition, minimum sizes are required to participate in market opportunities, excluding many distributed energy storage resources. Requiring one load-serving entity (LSE) per Proxy Demand Resource (PDR) prevents widespread deployment.

CESA co-founder Janice Lin said that one desired outcome of the workshop process would be a detailed one-line diagram, including metering requirements, of the high-priority use cases for energy storage.

Metering and Telemetry

Issues discussed on this subject included the inability to track where and how storage is being charged, the increased expense of duplicative metering, and the cost and complexity of required telemetry. Such issues have a larger impact on small energy storage projects than large one.

Modeling

Participants said that hybrid (dual-use) energy storage applications are not being accurately modeled, and their benefits are not being fully accounted for. They added that ISOs do not accurately model some storage technologies, and that in general the industry lacks a standard cost-effectiveness modeling too.

Standards

Several shortcomings in current standards were identified and discussed, including a lack of vetted safety and reliability standards that prevents storage from being readily installed and deployed. Fire codes have similar problems.

In addition, the industry lacks common communication protocols so that different types of devices can be integrated, and the absence of uniform local code and approval listings adds time and difficulty to commissioning projects.

The CPUC noted that EPRI and electric/hybrid automobile equipment manufacturers are working on control approaches for smart charging managed through vehicles' telematics systems.

Conclusions

The workshop had minimal focus on technical concerns or issues facing the customers and users of energy storage. Stakeholder comments on barriers and issues to consider in the roadmapping effort were due on September 18. A draft template will be released on October 2, and the final roadmap is planned for release in mid-December of this year.

Ben Kaun offered that the EPRI Energy Storage Integration Council (ESIC) could provide input related to energy storage technical and integration issues during their comment period. After the meeting, Kaun had initial discussions with CAISO personnel to begin coordinating these efforts.

CAISO has a homepage for its energy storage roadmap efforts at www.caiso.com/informed/Pages/CleanGrid/EnergyStorageRoadmap.aspx. EPRI members with questions or comments about the CAISO meeting are welcome to e-mail Ben Kaun directly at bkaun@epri.com.

California PUC Workshop Focuses on Distributed Resources

CPUC Workshop: Section 769 Distribution Resources Plan (R. 14-08-013)

On September 17, the California Public Utility Commission (CPUC) held a workshop to discuss a new rulemaking proceeding on the "Distribution Resources Plan." This proceeding was a result of 2013 California Assembly Bill AB327, Section 769, which directed utilities to develop a plan by July 2015 for incorporating distributed energy resources (DER) within the distribution planning process. EPRI's Ben Kaun attended and provided this report.

The workshop consisted of several presentations and discussions including:

- Opening comments by Commissioner Michael Picker
- Presentation summary of "More Than Smart" paper by Paul De Martini in collaboration with Caltech
- Presentation of initial frameworks for DER integration by the California IOUs and Interstate Renewable Energy Council (IREC)
- Panel discussion with representatives from UCSD, SolarCity, EPRI, Olivine, CESA, and CPUC regarding the different DER options, including microgrids, solar, electric vehicles, demand response, and energy storage.

Discussion focused primarily on the need for enhanced, standardized, and transparent methods and tools for distribution planning to identify locational value for different DER and opportunities for monetization. There was significant discussion about control or coordination of DER behavior and whose role it would be to manage—the utility, a new DSO entity, or the DER providers. There was also significant discussion about ways to develop a seamless, "plug and play" environment for diverse DER as well as the data needed to accomplish it.

Introduction and Opening Comments

This proceeding was a result of 2013 California Assembly Bill AB327, Section 769, which directed utilities to develop a plan by June 2015 for incorporating DER into their distribution planning process.

The workshop began with comments from CPUC Commissioner Michael Picker, who said that not only is electric power generation being distributed, so is the decision-making authority for grid planning and operations. He stated that it is important for DER to help achieve system level optimization, not just optimization from the customer perspective.

This includes identifying and understanding a range of locational values, including energy, capacity, power quality, voltage regulation, and resiliency. Picker said that the future is challenging to predict, so planning must consider and incorporate a number of possible future scenarios of how the grid may look and make decisions based on "least regrets" expenditures.

Picker envisions needs for new tools, data, and automation as well as what he called "scalable pilots": pilots large enough to incorporate a portfolio of DER and understand how they fit together. Finally, he expressed the need for policy equivalents of "net neutrality" for the operation of the distribution system.

"More Than Smart"

The first presentation session was provided by Paul De Martini, a visiting scholar with the Caltech Resnick Institute, and former VP of Advanced Technology of Southern California Edison. De Martini provided an overview of the paper he co-authored titled "More Than Smart: A Framework to Make the Distribution Grid More Open, Efficient, and Resilient."

The key objectives of this framework are to begin characterizing and defining locational benefits, optimal location, and value optimization. The framework envisions a new approach to distribution planning, which begins with a comprehensive, scenario driven, multi-stakeholder process that identifies location-specific costs and benefits of DER. It envisions that this process is enabled by a standard set of methods and analytical models based on a combination of utility grid operational data and DER market deployment information.

De Martini emphasized the importance of California's distribution system continuing to evolve towards an open and flexible "node-friendly" system that enables seamless DER integration. He also indicated that Utility Distribution System Operators (DSOs) need to evolve their roles to provide safe and reliable electric service across the distribution system and operational boundaries, while enabling seamless integration of DER and microgrids as part of overall system optimization to realize value.

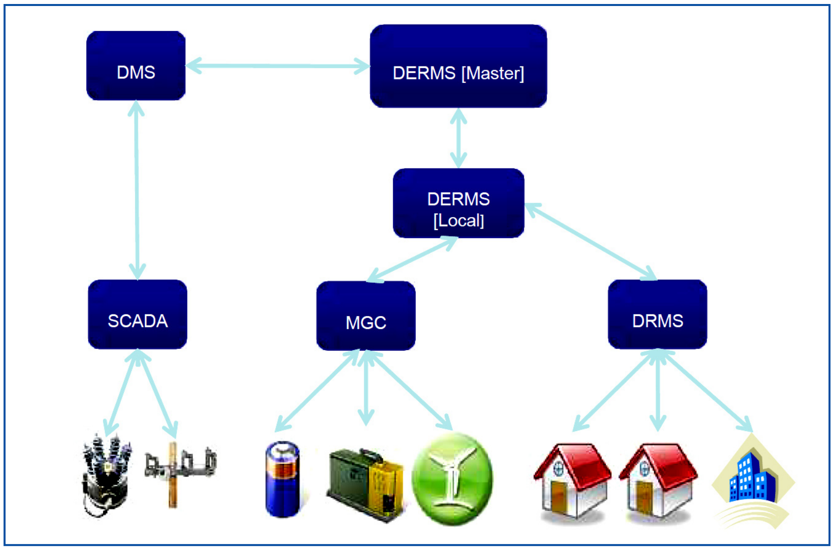
"More Than Smart" currently manages a working group to further this framework. Further information can be found at http://greentechleadership.org/june-2014-mts-2/.

California IOU Plans/IREC Presentation

The second presentation featured the three California IOUs—PG&E, SCE, and SDG&E—which discussed their current distribution planning process as well as their progress in developing the new distribution resource plans. The utilities emphasized the importance of safety, security, and physical assurance (availability) of the resources.

Additionally, IOUs mentioned the importance of cybersecurity considerations for DER. It was acknowledged that planning enhancements are required, particularly advanced load forecasting methods and new tools to assess variable behavior. Methods to identify optimal locations are needed, as well as reduced complexity and facilitated seamless integration of DER. The desire is to promote a more "plug and play" environment. The IOUs also discussed the need for distribution resource plans to incorporate a combination of "least regrets" investments and new technologies.

SDG&E emphasized the importance of appropriate rate structures as well as the implementation of a Distributed Energy Resources Management System (DERMS). The DERMS would consist of a Master and Local component. The existing Distribution Management System (DMS) talks to both SCADA and the DERMS (see figure). DERMS would issue set points to smart inverters, and aggregate data for the backhaul in their vision.



DERMS Schematic from SDG&E (MGC is Microgrid Controller; DRMS is Demand Response Management System)

The Interstate Renewable Energy Council (IREC) provided its perspective on the distribution resources planning process as well. IREC cites a changing paradigm. Traditional distribution planning is load centric; in most cases circuits have not been upgraded to respond to DG or other DER except in response to individual interconnection application. In IREC's view, utilities lack technology to enable easy visibility into their systems that enable proactive planning. They observe that wires-based solutions are the norm, with some consideration of alternatives but no evidence of a consistent practice, possibly due to economic incentives.

The foundations of the IREC proposal include: Specific DER Integration Goals and Metrics; a clear and consistent methodology developed with input from stakeholders for evaluating costs and benefits; multi-level data transparency to enable achievement of goals; procurement mechanisms to encourage innovation, lower costs, and use of optimal locations; and identification of interconnection process and cost allocation changes.

IREC's five steps of Integrated Distribution Planning (IDP) "Proactive" planning approach are:

1. Forecast DG growth on the circuit

2. Establish the hosting capacity and allowable penetration

3. Determine available capacity on the distribution circuit

4. Plan upgrades (or seek DERs) and expedite interconnection procedures based on IDP

5. Publish the results.

Afternoon Panel Session—DER Representatives

The afternoon session featured a discussion by panelists representing the different types of distributed energy resources, including solar, electric vehicles, demand response, energy storage, and microgrids. A representative of the CPUC staff was also on the panel.

In his comments, Byron Washom from the University of California San Diego (UCSD) stated that the cost of self-generation for UCSD is half the cost of being an energy importer. He also stated that the most disruptive actor on the distribution system is solar PV, with its cloud effects. He emphasized the virtues of synchrophasers and PMUs, which have been deployed at UCSD and can measure distribution system conditions with 60 hertz frequency. Washom said that the 2011 grid collapse could have been detected with a 10-minute warning with synchrophasers installed. On a later topic, Washom stated that DER are an orchestra requiring a "conductor," and that conductor may not be the electric utility. However, the utility may still provide the "sheet music."

Ryan Handley from SolarCity expressed the desire for a very detailed analysis of feeders with data transparency, and said that SolarCity and others could support the analysis. He argued that DERMS platforms are too centralized to handle a large number of endpoints. SolarCity also expressed that flexibility of resources needs to be emphasized going forward, and that dynamic granular control and ability to optimize and important characteristics of DER. Additionally, Handley emphasized that DER need "coordination," not necessarily "control."

Chris Edgette from the California Energy Storage Alliance (CESA) discussed the current "friction" of energy storage interconnection. However, he noted that supply-side demand response was making progress.

Mark Duvall of EPRI discussed the distinction between plug-in electric vehicles (PEV) and other DER, particularly in that PEV have a primary value proposition that is not related to any value offered to the power system. PEV cost of ownership is already better than gasoline vehicles in some instances, and is improving continuously to the point where PEV will even be able to compete on a first-cost basis with gasoline vehicles at some point. A fleet of electric vehicles has the potential to provide value to the electric system through smart charging alone.

The CPUC representative mentioned that there are currently advanced tool incorporating the visualization of geospatial data to inform opportunities for high-value efficiency projects. In addition, there are multiple CPUC proceedings related to this one, including Integrated Demand Side Management (DSM) and Zero Net Energy (ZNE) Buildings.

EPRI Q&A: Stem, Analytics-driven Energy Storage as a Service

Introduction

Based in Millbrae, California, Stem is one of an emerging cadre of companies that pairs customer-sited energy storage with intelligent energy management. Its innovative "storage-as-a-service" approach seeks to monetize benefits to both end-use customers and electric utilities via demand charge reductions and grid management efficiencies.

For commercial entities (e.g., hotels, big box retailers, etc.), the firm models electricity usage in the context of utility rate structures, and then utilizes sophisticated software algorithms that selectively employ lithium-ion battery-based systems and associated electronics to reduce peak demand. Clients pay nothing up front—assets are owned by a third party investment group—and over the course of an initial three-year service contract instead agree to a fixed monthly fee that is less than anticipated bill savings. A performance guarantee, a standard component of Stem's offering, serves as an additional enticement designed to emphasize the low-risk nature of program enrollment.

Stem's business model also targets revenues from ancillary services, such as frequency regulation and voltage support, which are intended to serve the interests of utilities and grid operators. Its offering provides utilities with access to the idle capacity available throughout the company's growing portfolio of distributed energy storage systems. In this way, power companies have the option of acquiring another resource, akin to a "demand response 2.0" scheme, for managing grid operations.

Stem's behind-the-meter commercial product underscores the increasing attention that distributed energy storage is receiving today, and the rising number of pathways that are being proposed to spur the technology's greater market traction.

EPRI's Nadav Enbar recently spoke with **Tad Glauthier, Stem's VP of Operations & Customer Development,** to better understand the inner workings of the company's novel business model, the status of its deployments—including uptake among utilities—and opportunities for furthering the storage-as-a-service concept. What follows is an edited transcript of the conversation.

Q&A Transcript

EPRI: I've heard Stem referred to as an "intelligent energy storage company." What does that mean? What is the company's core offering and business model?

Stem: We characterize ourselves in two ways. First, we're the leaders in the development of the control algorithms utilized for energy storage. These algorithms help … to derive the most out of the limited amount of energy stored in a storage unit, and to maximize the benefits the stored energy provides in a way that has low impact on the device's batteries and preserves their longevity.

Second, we build the most robust and flexible cloud-based operating center. Our devices respond to whatever the driving financial indicator happens to be—maybe a tariff or a market signal from the grid operator, for example. Our always-on operating platform manages storage and makes sense of sometimes conflicting signals; it efficiently chooses what to do with each distributed storage device in our portfolio.

EPRI: How does the company's cloud-based storage-as-a-service offering work? What are the technical and economic aspects of the offering?

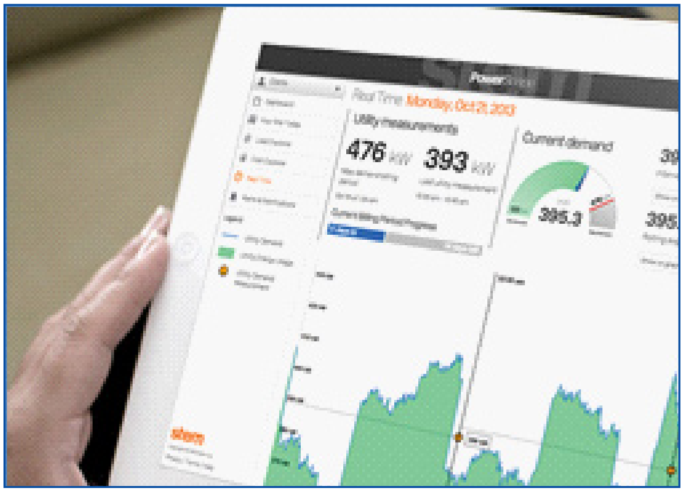
Stem: The Stem offering to a commercial customer is a service that looks like a fixed monthly fee. It's a save-more-than-you-pay offering. A customer signs up for a three-year term, and we have the system installed and interconnected with utility approval.

Our storage system (the PowerStore) is configured in 18-kW towers, each about the size of a gym locker, and multiple towers can be stacked to the appropriate size for a building's load. Once the system is up and running, we guarantee electricity bill savings primarily through demand charge reductions. Based on load analysis, electricity rates, and other factors such as weather, we reduce peak loads and provide a performance guarantee that customers will do better than break even.

A second value stream that we create is to offer the idle capacity available throughout our portfolio of systems to utilities. We can offer utilities a Demand Response 2.0 kind of resource. We provide a smart-grid dividend back to the commercial customer for allowing the utility to tap his box for its excess capacity.

36-kW Stem PowerStore Installation (Source: Stem)

We designed our system, with input from Jim Detmers (former COO of CAISO), for aggregated use by utilities. It's a way to maximize the value of our existing assets when they are idle by plugging them into frequency regulation and voltage support applications … using them as a demand resource.



Stem's Customer-facing Energy Use Interface (Source: Stem)

Stem Deploys 1 MW Grid Support with HECO

On September 11, Stem announced plans to deploy 1 MW of behind-the-meter energy storage in a demonstration project with Hawaiian Electric Co. (HECO) to support grid response services. Stem will integrate its own energy storage and data analytics with HECO's own renewable forecasting and monitoring capabilities to anticipate when additional grid capability is needed. Participating commercial and industrial customers with rooftop solar systems will receive financial incentives to install Stem's Li-ion batteries and control systems, and provide power on demand. Installations are expected to be completed by March 2015.

"Hawaii's renewable energy growth and isolated location present unique and significant challenges for local grid operators," said Stem CEO John Carrington. "Utilities and regulators are watching Hawaii to determine the viability of storage-enabled grid services."

The program is supported by $1 million in grant funding from Hawaii's Energy Excelerator, which was created to commercialize emerging energy technologies in Hawaii's unique market and help companies scale globally. In late 2013, the Energy Excelerator raised $30 million from the U.S. Department of Defense's Office of Naval Research to help the State of Hawaii achieve a goal of 70% clean energy by 2030. To this end, the outfit is investing in a range of start-ups—typically between $100,000 and $1 million per start-up—that show promise for helping Hawaii transition to the new energy paradigm. The program takes 1% in equity in exchange for funding.

EPRI: What have you found to be the level of customer savings necessary to drive adoption of Stem's storage service?

Stem: We present our offering as a bundled software/hardware package. It provides our customers with a finer resolution into their energy use in ways they've never seen before. And it also utilizes their installed battery systems to generate energy savings. The actual savings differ greatly by customer based on their load profile, but we find that if the payback period is around three years, then that's a compelling business case for the customer.

EPRI: How many kilowatts of storage has Stem installed so far?

Stem: We have a total of a couple dozen units currently in the ground—all of them in California. *[Editor's note: Stem is beginning to contract projects in New York and Hawaii.]* We started installing our UL-approved hardware product in November 2013. Installs were initially occurring at a pace of one to two per month, but have since increased in frequency to closer to one per week. So our deployment rate is going up.

EPRI: One of the unique features of Stem's business model is its lease financing component, which effectively allows customers to install energy storage systems at no upfront cost. How does this work?

Stem: We work with a third-party investment group, Clean Feet Investors I, LLC (www.cleanfeetinvestors.com), that finances the installation of Stem batteries at commercial and industrial (C&I) customer locations through a project finance fund.[1] Commercial customers pay nothing up front, and the asset is owned by the third-party investment group.

The financing is a three-year term, and if the customer isn't saving more than he's paying, we'll refund the difference and/or let him exit his three-year contract. At the end of three years, the expectation is that the customer will want to renew his service agreements. If not, because our systems are modular, we can remove them from the customer premises pretty easily.

[Editor's note: In mid-September, Stem closed a $100 million fund, provided by B Asset Manager, a New York City-based investment adviser in the insurance industry, to finance additional distributed energy storage projects at commercial and industrial customer sites.]

EPRI: How helpful is Stem's third party investment approach in spurring customer adoption? Is it a requirement to new adoption given current hardware price points and available markets?

1. In October 2013, Stem secured $5 million in funding from Clean Feet Investors I, LLC; it estimates that this level of funding could enable the deployment of up to 15 MW of energy storage.

Stem: The financing is helpful but not required for spurring customer adoption. Its greatest value is as a customer acquisition and lead generation tool. Once a customer sees the value in our storage system, they often opt to do an out-right cash purchase or use their own financing.

EPRI: To date, has Stem contracted with any utilities to sell them excess storage capacity?

Stem: We recently signed up our first through a grant from Hawaii's Energy Excelerator (www.energyexcelerator.com) that will fund a project with a Hawaiian utility (see sidebar).

There are multiple things that energy storage can do, and everyone understands that the potential of value-stacking is one of the most promising aspects of distributed storage. But one of the challenges for the industry has been creating a clear and simple path to a short-term business model to jumpstart deployments. We're trying to simplify the noise.

For commercial customers, it's about lowering their monthly bills. For utilities, we're designing our service to look like resources they've worked with before. When we aggregate behind-the-meter storage we want it to be treated like a fast responding, highly flexible generator.

EPRI: What has to happen to trigger further adoption of Stem's storage offering by utilities?

Stem: We're talking with a number of utilities who are interested in exploring behind-the-meter deployments. But utilities generally want to fit us into familiar buckets, like frequency regulation, generation, and demand response. So, it's about us ensuring that our aggregated systems can be accessed easily by system operators.

There's a longer sales cycle when working with utility customers compared to C&I customers, but when we look at new markets, we prefer to go into them in partnership with utilities. That's how our commercial customers are going to get the best economics. Why not let a utility rent their systems? Why not let the utility use a capital investment and get some benefit from the customer system?

The regulatory landscape could speed up adoption. The California Independent System Operator (CAISO) is piloting programs to allow behind-the-meter demand response. We could potentially participate in that without utility partnership. PJM is much more open to it.

On a related note, the capacity requirement for capacity procurement planning thresholds hurts us. Resources need to have a run time of 4 hours and that has a major implication on energy storage as an industry. Typically the energy is the expensive part, not the power.

EPRI: Stem has primarily been focused on bill reduction for C&I customers, like hotels. But as the company starts aggregating capacity, will its focus change? Also, the company's customers are entirely located in California, where there are relatively high demand charges and subsidies for energy storage. Is the company targeting other geographic areas?

Stem: Yes, we do expect that as our aggregated capacity target grows, we will be expanding our focus to additional verticals. As for geographies, Stem is actively involved in both the Hawaii and New York markets; both have high energy prices, tariffs with strong demand charge components, and favorable grid-side economics for aggregated systems.

EPRI: What synergistic opportunities does Stem see with solar?

Stem: Solar and storage have known synergies particularly at the individual customer level, in terms of solar firming, as well as at grid-scale, in terms of helping with volatility and ramp rates. We've identified some preferred solar partners that we're working with to address that target market.

EPRI: Stem is battery technology agnostic. But does the company have a battery preference based on performance and economics?

Stem: We work primarily with lithium iron phosphate. It's the safest of the lithium chemistries and has the lowest risk of thermal runaway. Our Li-ion battery modules are a little heavier than what you'd put in a car and they're price competitive. When you factor in total cost of ownership or cost over the life of the product, we find that lithium iron phosphate makes more sense than lead acid. We're offering 10-year warranty agreements and don't want to replace a lead acid battery every 1.5 years. *[Editor's note: Stem's warranty terms are tied to compliance with SGIP's 10-year warranty requirement.]*

What we're interested in are storage applications for the medium C&I market. For this segment, the batteries need to be smaller

Two Stem PowerMonitors at a Customer Site (Source: Stem) and located indoors in the basement of an office building … (and) GE's Durathon battery promises smaller form factor and better cycle life. Ambri, EOS and Aquion Energy produce compelling technologies. And a few start-ups are producing liquid metal batteries that can run pretty hot inside, are thermally insulated, and show potential.

EPRI: Have you identified alternative utility business models that could be instituted with Stem's offering?

Stem: In addition to our integrated storage systems, we've also installed our software offering and data collection device (the PowerMonitor)—about the size of a shoebox sited next to a smart meter—in four states. The collection device is able to sample data at a sub-second level and passes the information along to our network operations center.

With this data, we are able to model the impact of various types of tariffs against various scenarios of usage and renewables penetration. We believe this can be very useful for utilities to understand how to best serve their customers.

EPRI: What in the market landscape has changed that offers potential promise for accelerating energy storage uptake? What are the existing market/regulatory barriers that must be addressed to unlock energy storage's market potential, and Stem's offering, in particular?

Stem: Bringing down the cost of battery technology has the greatest potential for accelerating energy storage uptake. We're also very encouraged by the recent extension of the Self-Generation Incentive Program (SGIP) in California. We believe that the extension will help provide the cushion that will help battery cost curves get to the point where rapid acceleration will happen, just as we saw in the solar industry.

EPRI: Who are Stem's competitors?

Stem: There are some companies that are doing battery systems, like Samsung and Bosch; others who are doing energy software, such as Geli; and some who are effectively system integrators of third-party components, like Green Charge Networks. But we believe we're the only company who has an integrated off-the-shelf system. Our philosophy has always been that we need to have a product rather than project focus in order to build a truly scalable company.

EPRI: What, if any, lessons learned has the company accumulated in its short time selling storage as a service?

Stem: Simplicity of our offering is crucial to its adoption by commercial and utility customers. We are designing our service offering for our commercial customers, keeping in mind the "out of the box" experience. That's how signup with Stem should feel for our commercial customers. We're now trying to design a similar experience for our utility customers.

EPRI Perspective

Stem's service offering is emblematic of the increasing number of commercial strategies that aim to propagate the installation of greater distributed storage on the customer premise. Unlike more "disruptive" approaches, however, it aims to ease transition to a more decentralized grid by presenting power companies with a proposed means for harnessing behind-the-meter storage assets to serve utility operational needs.

In some ways, Stem's business model, and others like it, contribute to EPRI's vision of the Integrated Grid (www.epri.com/Our-Work/Pages/Integrated-Grid.aspx), in which distributed energy resources (DER) are more holistically incorporated into grid planning and operations to more fully leverage their value. Utilizing the pooled capacity offered by customer-sited storage assets offers utilities and grid operators one such avenue for reinforcing the transmission and distribution system through DER to meet projected load growth.

For its part, Stem appears to fully embrace utility partnership as a central component of its business model. Although it has thus far only inked one utility agreement through grant funding, time will tell if the reported interest expressed by utilities in Stem's service offering materializes into tangible business relationships.

Perhaps more fundamentally for Stem, however, is whether its no-money-down, analytics-driven storage service can sustainably meet customer and investor expectations, as well as bottom-line company goals. Demand charge reduction, currently the most lucrative distributed storage application—and an integral source of Stem's anticipated revenues—could, for example, be flattened through tariff restructuring (e.g., a movement to higher fixed charges) and upend one of the company's core value propositions.[2]

By contrast, changes in the regulatory and market rules could bolster the company's outlook through, for instance, the development of behind-the-meter demand response programs that allow energy storage participation. Ancillary services markets with more attractive pricing for fast-responding frequency regulation, akin to those offered by PJM, could also improve Stem's prospects. The company's ability to nimbly respond to the shifting dynamics of the nascent energy storage market and to monetize a growing number of service applications (the so-called "value stack") will likely determine the measure of its success.

At bottom, storage-as-a-service represents a novel business model for ramping demand for commercial energy storage products. Stem's business strategy, like others in the emerging segment, takes a page out of the solar leasing playbook in an effort to spur volume energy storage sales and realize associated benefits (e.g., reduced system costs, decreased cost of capital, investor certainty, etc.). We expect the next several years to clarify whether the concept can demonstrate long-term viability.

2. Stem claims that its commercial customers have been able to save up to 20% on their monthly bills, which would require up to a 40% reduction of their demand charges (assuming the demand charge comprises half of the customer's monthly retail bill).

Status Update: Energy Storage and DG Codes & Standards

An important and rapidly evolving key to enabling energy storage and distributed generation are codes and standards that recognize the technologies' unique characteristics and benefits. EPRI has compiled the following overview of the current status of this important topic.

IEEE 2030 Series: Smart Grid Strategy

The IEEE 2030 series classify energy storage as a "distributed energy resource. Other distributed energy resources include diesel generators, fuel cells, photovoltaic panels, and wind generation.

IEEE2030.2 is a subdocument to IEEE 2030 titled "Draft Guide for the Interoperability of Energy Storage Systems Integrated with the Electric Power Infrastructure"; **IEEE 2030** is titled "Draft Guide for Smart Grid Interoperability of Energy Technology and Information Technology Operation with the Electric Power System (EPS), and End-Use Applications and Loads."

These guides are IEEE's "strategy" guides to the Smart Grid, while IEEE 1547, "Standard for Interconnecting Distributed Resources with Electric Power Systems," is more tactical.

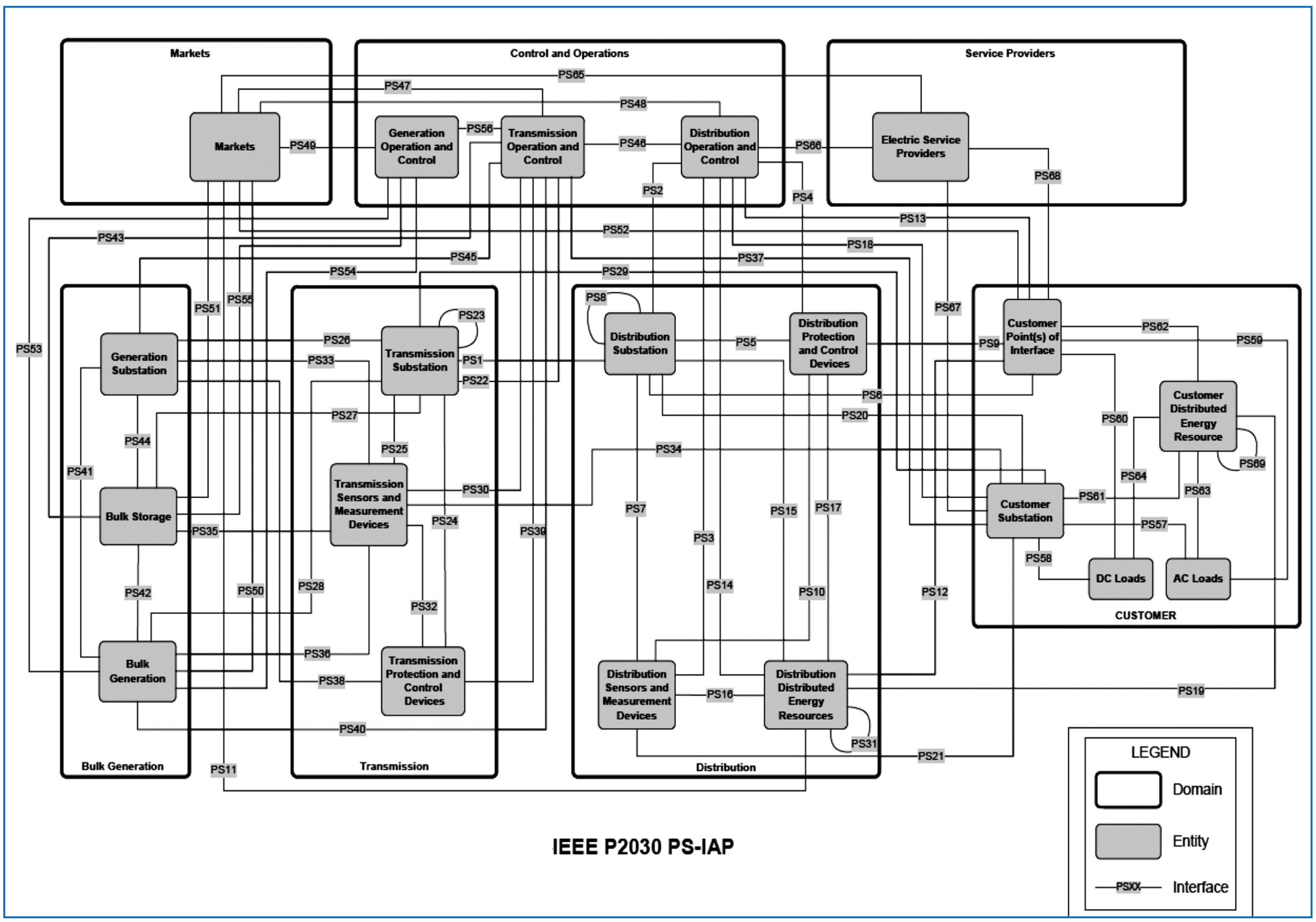
IEEE 2030.1, the "Draft Guide for Electric-Sourced Transportation Infrastructure," is transportation related, while **2030.3** is the "Standard for Test Procedures for Electric Energy Storage Equipment and Systems for Electric Power Systems Applications."

IEEE 2030 has three components: Hardware (utilities), Communication (companies like Intel are interested), and Data (companies like IBM are interested). The figure below shows this depth. Energy storage is considered a "Distributed Energy Resource" in the Customer box and the Distribution box, and "Bulk Storage" within the Bulk Generation box.

Each Interface (PSxx's) have both hardware, software and communication specifications associated with them. The 2030 series also references other IEEE specifications such as the 1547 series.

NEC National Electrical Code

The 2014 National Electrical Code (NEC) was published in the autumn of 2013. Managed by the National Fire Protection Agency (NFPA), the NEC is now in its revision cycle for the 2017 code. While this is not directly applicable to EPRI



Complex interrelated responsibilities for the IEEE 2030 series.

members, NEC will be important to utilities and grid operators with large-scale deployment of energy storage systems. Vehicle-to-grid (V2G) will introduce additional complications. The NEC addresses behind-the-meter applications, and changes in the code should be understood by ISOs and utilities.

The 2014 NEC addresses energy storage and distributed generation in the following sections:

- 480 Storage Batteries: Applies to all stationary installations of storage batteries.
- 490 Equipment Over 1000 Volts, Nominal
- 500 Special Occupancy: Classified Areas, Health Care Facilities, Trailer Parks, Theaters, Recreational Vehicles
- 625 Electric Vehicle Charging System
- 690 Solar Photovoltaic (PV) Systems
- 694 Wind Electric Systems
- 700 Emergency Systems
- 840 Premises-Powered Broadband Communications Systems

Numerous code proposals are being prepared to simplify and consolidate codes that apply to behind-the-meter energy storage systems. The National Electrical Manufacturers Association (NEMA) and Pacific Northwest National Laboratory are involved and offering a set of proposals. An initial meeting took place at the Energy Storage Association annual meeting in June.

The timetable for the 2017 NEC process is:

First Draft

- Public Input Closing Date for On-line Submission: 11/7/2014 Submit Public Input online
- Public Input Closing Date for Paper Submittal: 10/3/2014 Public Input form (word)
- First Draft Report Posting Date: 7/17/2015

First Draft Meeting Notices

- First Draft Panel Meeting Schedule
- NEC First Draft Panel Meetings, January 12-24, 2015, Hilton Head, South Carolina

Second Draft

- Public Comment Closing Date for Online Submission: 9/25/2015
- Public Comment Closing Date for Paper Submittal: 8/21/2015
- Second Draft Report Posting Date: 4/8/2016

International Electrotechnical Commission (IEC)

Founded in 1906, the IEC prepares and publishes international standards for electrical, electronic, and related technologies. Standards relevant to energy storage include IEC TC 120, "Electrical Energy Storage (EES) Systems."

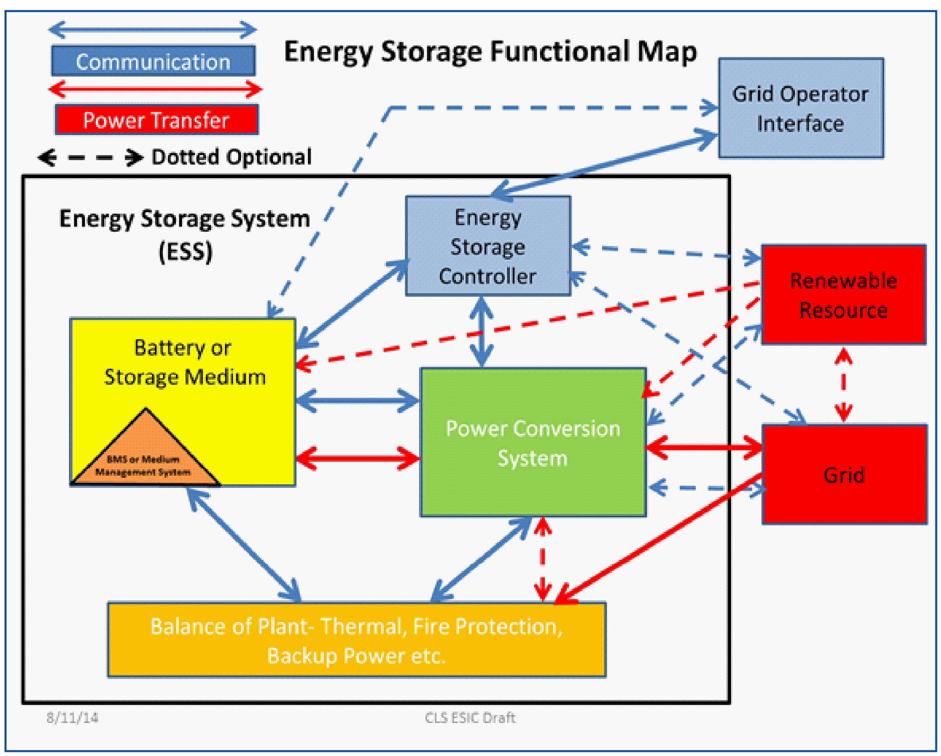
The scope of TC 120 is standardization in the field of grid-integrated energy storage systems, focusing on the *system* aspects of EES rather than particular energy storage devices. Any type of grid-connected energy storage that can both store electricity from the grid or any other source, and provide electricity to the grid, is within its scope. Unidirectional energy storage, such as uninterruptible power supplies (UPS), is not included. In general, TC 120 deals with defining unit parameters, testing methods, planning and installation, environmental guidelines, and system safety.

EPRI ESIC

The EPRI Energy Storage Integration Council (ESIC) is making good progress, and issues a monthly newsletter reviewing the efforts of the individual working groups. Definitions are important: an interesting discussion in one working group was the definition of an energy storage system. Figure TBD is a current draft of energy storage system functionality. For more information see the ESIC monthly newsletter mentioned above.

ESA

The Energy Storage Association (ESA) is the keeper of a common



Functions within an energy storage system as drafted by ESIC.

glossary that serves as a depository of common terms for energy storage. If more than one term is in common use, the first definition is the preferred with other definitions added for clarification. In recent months, ESA has redesigned its website to increase navigability and accessibility (http://energystorage.org/).

DOE Peer Review

The 2014 DOE/OE Energy Storage Program Peer Review and Update meeting was held September 17–19 in Washington D.C., and highlighted the breadth and diversity of the DOE Energy Storage Systems (ESS) program.

More than 360 people representing multiple countries attended the 2013 Peer Review, and more than 400 people were expected in 2014. Approximately 100 projects were presented, spanning electro-chemistry and materials development, component and system testing, economic and system analysis, and full demonstrations. Participants included Sandia National Laboratories, Pacific Northwest National Laboratory, Oak Ridge National Laboratory, ARRA, ARPA-E, SBIR, and university energy-storage projects. The event agenda is available at: https://share.sandia.gov/essPR12/2014_Peer_Review_Agenda.pdf.

Technology News: Energy Storage RD&D

Lithium Battery Energy Storage

Tesla Chooses Nevada for Gigafactory Site

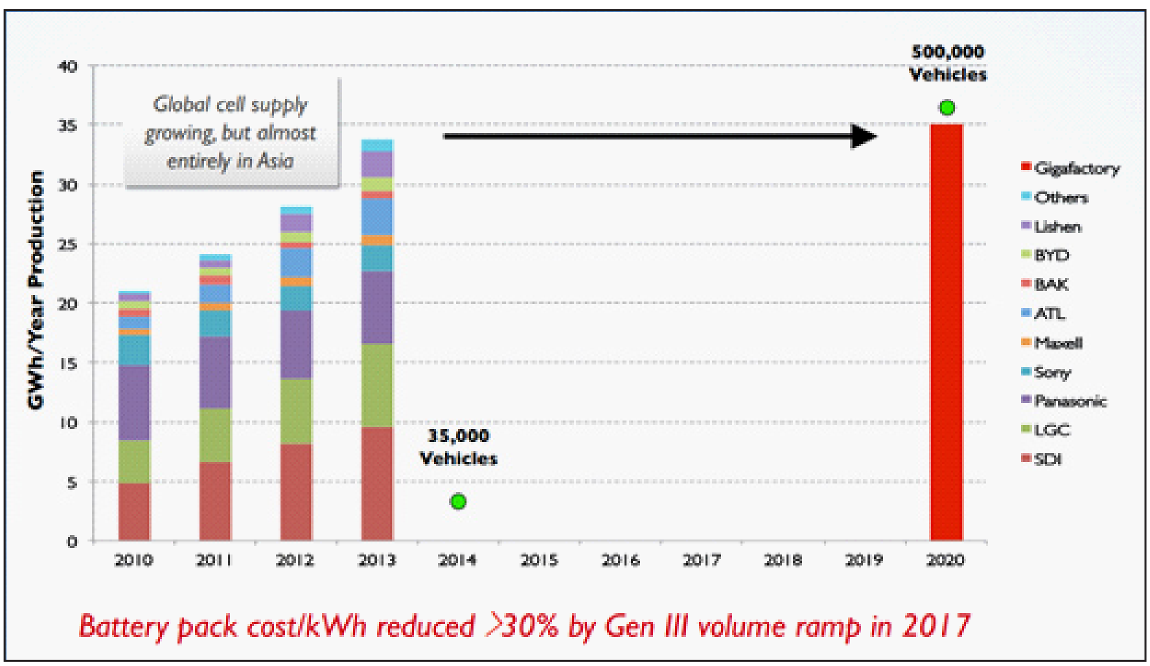
On September 4, Tesla Motors made the announcement five states had been waiting to hear: the company would be building the world's largest and most advanced lithium ion battery factory near Reno, Nevada.

Called the Tesla Gigafactory, the facility will single-handedly produce more watts of Li-ion capacity than all the factories currently operating in the world combined (see figure below). When built out, the plant will have the capacity to produce 50 GWh of battery packs per year, enough to supply 500,000 electric vehicles.

In addition to Nevada, the states vying to host the Gigafactory—which will primarily provide batteries to Tesla's auto plant in Fremont, California—were Nevada, Arizona, Texas and New Mexico. The contenders offered incentives and tax breaks to lure the facility; Nevada's package totals an estimated $1.25 billion over 20 years and includes a 100% abatement of some business taxes as well as real and personal property taxes until 2024, and sales tax abatement until 2034.

Other incentives included a transferable tax credit of $12,500 per permanent full-time job as well as transferable tax credits of 5% for the first $1 billion and 2.8% for the next $2.5 billion investment. Tesla, also committed $1 million to fund advanced battery research at the University of Nevada Las Vegas and $37.5 million for K-12 education beginning in August 2018. The Gigafactory is expected to cost about $5 billion to build, employ around 6500, and have $100 billion in economic impact over 20 years. The deal must still be approved by the state legislature.

Tesla CEO Elon Musk said his company will partner with Panasonic and several other companies to drive down the cost of Li ion batteries by 30% or more. Musk said that vertically integrating the battery production makes economic sense, and is the best way to scale up to the volume that Tesla says it will need to support its projected auto production. Tesla would also make its batteries available to external companies, such as solar photovoltaics developers Solarworld AG and SolarCity (see related story on next page).



Tesla's planned 2020 production volume exceeds 2013 global production (Source: Tesla Motors).

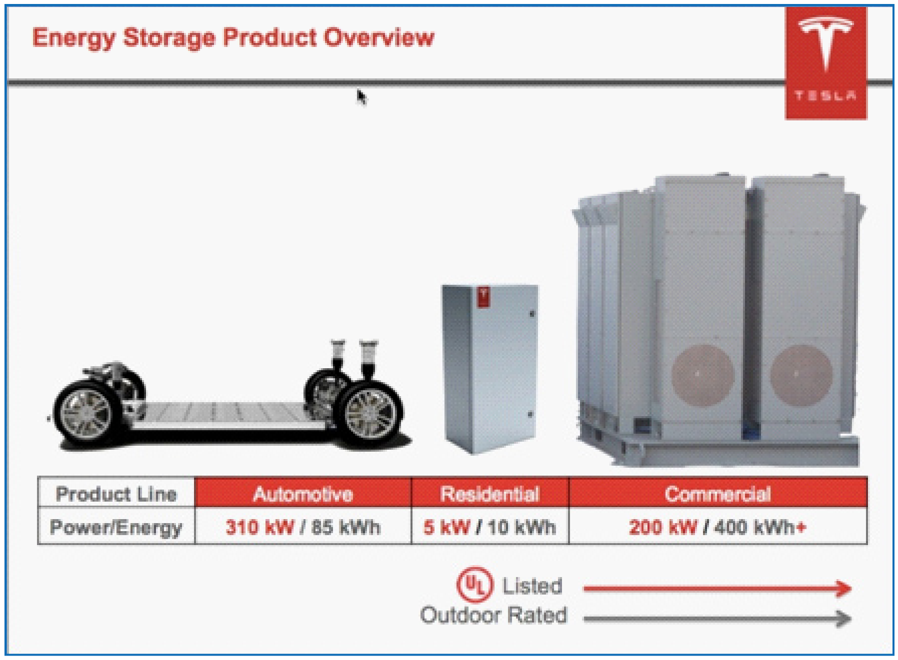
Tesla's Ambitions Affect the Industry

Tesla's plans are already influencing expectations in the grid storage world. In interview with Greentech Media, AES Energy Storage President Chris Shelton said that the Gigafactory has played an important role in the company's decision to concentrate on Li-ion as the battery chemistry of choice for the next seven to ten years.

In addition to electric vehicles, Tesla will have a big impact on distributed solar batteries. Tesla already has a partnership in place with SolarCity, a leading solar PV developer in the United States and Europe, to integrate PV and behind-the-meter batteries for residential and commercial customers. In late September, SolarCity said that it plans to include a Li-ion battery backup system with every rooftop solar power module within 5 to 10 years. The company stakes its plan on expectations that the cost of PV and Li-ion will continue to fall in the coming years via both technological improvements and economies of scale. SolarCity claims that even with battery backups, a SolarCity installation will deliver electricity that costs less than electricity from the grid.

SolarCity and Tesla are closely aligned. SolarCity CEO Lyndon Rive is a cousin of Tesla CEO Elon Musk, and Musk serves on the SolarCity board of directors. SolarCity will obtain many or most of its Li-ion batteries from Tesla's future Gigafactory.

If Tesla achieves its Li-ion cost-reduction targets, its batteries could become a cost-effective energy storage medium in more and more markets.



Tesla's vision for Li-ion battery applications extends beyond its own electric vehicles (Source: Tesla Motors).

Regulatory, Policy & Legislative News

California

CPUC Decision on IOU Storage Applications

On September 12, 2014, the CPUC issued a proposed decision on the investor-owned utility (IOU) storage procurement applications. Given the timeliness of this topic, a summary is included here. Any significant modifications will be noted in the next *Strategic Intelligence Update.*

The Proposed Decision covers a number of issues related to the IOU applications, including utilities' proposals for approval of existing projects, the definition of "storage," and clarification on the scope and specificity of approaches for cost-effectiveness evaluation (both utility proprietary and common methods).

Updated Eligible Projects and Remaining Needs for 2014 Procurement

The June 2014 *Strategic Intelligence Update* provided an estimate of the IOU procurements in 2014 based on the IOU applications and stakeholder comments. Those estimates are updated in the summary table on the next page, which is excerpted directly from the Proposed Decision. The main difference from the prior estimate is that the CPUC table clarifies that, due to its multiple procurement processes, Southern California Edison's (SCE) remaining procurement to meet 2014-2016 requirements will be no less than 16 MW. San Diego Gas and Electric (SDG&E) has the lowest remaining requirement, but has recently opened an RFO for 25 MW.

Definition of Energy Storage

Given extensive stakeholder debate and the views of the IOUs, the CPUC acknowledges challenges in clarifying the definition of energy storage and defers broad judgment, limiting its decision to the 2014 procurement cycle. The following technologies will be considered "storage" for the purposes of the procurement: in addition to batteries, compressed air energy storage (CAES), and small pumped hydro which are conventionally accepted as storage, the following additional clarifications were made.

Under the 2014 procurement, "energy storage" includes vehicle-to-grid (V2G) electric vehicle technologies (grid-connected electric vehicles that put power back on the grid), biogas with eligible

Estimated California IOU Storage Procurements for 2014 (MW)

	Transmission	Distribution	Customer	Total
San Diego Gas & Electric				
Storage Target	10	7	3	20
Existing/In Progress	40 (See Note 1)	6.15	--	56.15
Expected	--	--	4.66	4.66
Required Min. Procurement	--	0.85	--	0.85
Proposed 2014 Procurement	10	6	0	16
Pacific Gas & Electric				
Storage Target	50	30	10	90
Existing/In Progress	-- (See Note 2)	8.5 (See Note 3)	--	8.5
Expected	--	--	3.5	3.5
Required Min. Procurement	50	21.5	6.5	78
Proposed 2014 Procurement	50	21.5	6.5	78
Southern California Edison				
Storage Target	50	30	10	90
Existing/In Progress	--	13.68	--	13.68
Expected	50	--	16	66
Required Min. Procurement	--	16.3	--	16.3
Proposed 2014 Procurement	No min or max	16.3	--	>16.3
Total IOU				
Proposed 2014 Procurement	>60	43.8	6.5	>110.3

1) Includes 40 MW Lake Hodges Pumped Hydro

2) Excludes 150 MW Rice Solar CSP (to be counted in future solicitation)

3) Includes 2.5 MW biogas

(Note: Customer domain numbers indicate forecasted installations in the Self- Generation Incentive Program (SGIP) and Permanent Load Shifting (PLS) Program and are subject to true up in the biennial procurement period.)

storage component (i.e., tanks that allow storage of biogas after it is generated), solar thermal technologies (also known as concentrating solar power) with thermal energy storage, hybrid thermal generation with thermal energy storage. For the last three options, such installations will be allowed under the procurement where a storage component is added to existing generation systems; they cannot be used to justify purchases of additional generation.

For 2014, "energy storage" excludes V1G (grid-connected electric vehicles that do not put power back on the grid, even if they provide grid services through managed charging) and biogas (without eligible storage component).

This broadens the scope of storage beyond "electricity storage," which has historically defined the research of DOE and EPRI, to a cross-cutting set of technologies.

Cost-Effectiveness Assessment

The CPUC affirmed that the IOUs will have broad latitude to implement custom cost-effectiveness evaluation approaches for the 2014 procurement cycle. It defers common benchmarking of decision-making until a 2016 energy storage procurement program evaluation. While the IOUs will define standard scenario and input assumptions, no common evaluation tool or model has been clarified at this time, though the range of benefits identified by EPRI and DNV KEMA in the 2013 proceeding analyses are to be considered in the common evaluation protocol (CEP).

There are a lot of other clarifications in the Proposed Decision, including relating to cost allocation and milestones for procurement deferment.

Other CPUC Proceedings

The prior *Strategic Intelligence Update* noted the inclusion of a storage portfolio, including the 1.3 GW storage procurement target, in the California Independent System Operator (CAISO) models run for the CPUC *Long-term Procurement Planning (LTPP)* proceeding to determine operational needs. The initial scenarios' results have now been published, but there is no specific analysis of the role that storage has played in providing operational requirements and reducing system production costs when compared to a baseline without storage.

SMUD Staff Report on Storage

The municipal utilities in California must comply with AB 2514 by submitting storage procurement plans to the California Energy Commission (CEC) by October 2014. The next edition of the *Strategic Intelligence Update* will review these plans collectively; this edition reviews some of the details in the recent staff report by the Sacramento Municipal Utility District (SMUD), the *SMUD Energy Storage AB 2514 Report,* which provided the results of an assessment of storage technologies and recommendations to the SMUD Board of Directors.

The general finding is that all the storage applications studied are currently not cost-effective, with the exception of large-scale pumped hydro storage. The report includes a qualitative discussion of various "stand-alone" uses of the storage technologies evaluated, which are excerpted in the table on the next page.

Of interest, SMUD staff provide qualitative insight into their reasons for rejecting new storage projects for each of these uses, typically referring to the alternative provision of a particular service from existing SMUD resources or the CAISO wholesale market, or observing that particular system conditions which could merit storage, such as surplus generation from renewables, are not yet sufficiently problematic. Since many storage technologies can provide several of these stand-alone uses simultaneously (subject to operational constraints), SMUD staff also conducted valuation of five "bundled uses": Transportable Distribution Deferral, Distributed Energy Storage Systems, Commercial Energy Management, Aggregated Energy Management with Grid Support,

SMUD Staff Discussion of Storage Applications

Stand-alone Storage Application	Recommended as Currently Cost-effective Storage Use?	SMUD Staff Paper Assessment (with some edits)
Asset Management	No	Asset Management is the use of energy storage to defer investments in generation, distribution or transmission upgrades. This is applicable to SMUD; however SMUD is currently long on capacity. In addition, as part of its value analysis, SMUD conducted a comprehensive review of current distribution assets to see if energy storage could defer any investments. SMUD found that its distribution system is robust and could use energy storage for deferral in a very small number of locations and the dollar value of deferral was small relative to the cost of energy storage.
Renewable Energy Shifting	No	SMUD currently does not have an issue with excess renewable energy and would get little value from this application.
Wholesale Market Arbitrage and Cost Optimization	No	SMUD has analyzed this application in detail, but does not project a large enough, persistent (e.g. occurring over many hours a year) difference between on-peak and off-peak prices to make this cost effective.
Retail Market	No	A SMUD customer could own an energy storage system and use it to manage time of use rates and/or demand charges. However, given SMUD's current rate structures, staff's analysis shows that this is not cost effective for SMUD or the customer.
Load Following	No	SMUD currently uses its hydro resources for load following and they are very cost effective.
Operating Reserves	No	SMUD currently has enough reserves for the foreseeable future from its thermal and hydro assets.
Frequency Regulation	No	SMUD uses its hydro resources for this and they are cost effective.
Renewable Energy Capacity Firming	No	SMUD currently purchases firming services from the CAISO (using thermal resources) at a competitive price.
Black Start	No	SMUD currently has Black Start capability in existing power plants and does not need more capability.
Renewable Energy Ramping	No	SMUD does not have wind in its Balancing Authority (BA) that would require ramping support. SMUD does have PV in its BA, but at current penetrations and through post-2020, staff's current analysis indicates that SMUD can handle PV ramping with current assets.
Renewable Energy Smoothing		For SMUD's large solar feed-in tariff projects, energy storage could provide smoothing to mitigate the impacts (e.g. voltage violations, excessive equipment cycling, etc.) of large fluctuations in PV output. SMUD is currently demonstrating the technical viability of this but it has not proven cost effective as a standalone application.
Backup Power	No	Energy storage owned by SMUD or its customers could provide backup power during outages. However, SMUD has top tier SAIDI, SAIFI and CAIDI scores, so system uptime is very high and the need for backup power is low in SMUD's service territory. In addition, when outages do occur, staff research indicates that the value of having backup power is low for most customer segments. One exception is the industrial segment, but most industrial customers likely already have backup power systems in place.
Power Quality	No	Using energy storage to manage power quality on a feeder is applicable, but staff has not found it to be cost effective relative to traditional power quality control equipment (e.g. load tap changers, voltage regulators, etc.). Industrial customers and data centers have high power quality requirements that energy storage could help meet, but they likely already have equipment in place to manage power quality and would not need to add energy storage for this purpose.

and Bulk Energy Storage. In each case, the full bundle of uses was jointly evaluated, and the benefits compared to the costs.

Of these bundled uses, SMUD staff found that the most likely to be cost-effective are Transportable Distribution Deferral and Aggregated Energy Management with Grid Support. However, neither of these uses is found to be needed for SMUD at this time. On bulk storage, staff found a positive benefit-cost ratio for pumped storage. SMUD has been developing the Iowa Hill pumped hydro storage project for several years, but the date for commercial operations is expected after 2020, and hence is not being included to meet storage procurement targets before 2020.

Staff thus recommended that the SMUD Board of Directors decline to set storage procurement targets for December 2016 and December 2020, pursuant to AB 2514. SMUD will revisit this assessment every three years. SMUD staff anticipate that energy storage "will become cost effective for some applications within the next 10 years" and hence recommend "that SMUD continue investing in research to develop, demonstrate and pilot promising storage technologies."

Of interest to California users of EPRI's Energy Storage Valuation Tool (ESVT), the report notes that EPRI's report to the CPUC on storage cost-effectiveness found that many technologies did have a positive benefit-cost ratio. SMUD notes that several of the applications in that report "are not applicable to SMUD, such as using energy storage for ancillary services and peaker substitution." In addition, staff argued that the CPUC report used forecasts of 2020 costs, while this staff report is considering costs applicable to 2016 procurement targets.

The full report is attached to the SMUD board documents available online at www.smud.org/en/about-smud/company-information/board-of-directors/documents/documents-meetings/board-packet-09-04-2014.pdf

Calendar

September 30–October 2, 2014: Energy Storage North America (ESNA), San Jose, California. www.esnaexpo.com

October 23–24, 2014: Energy Storage Australia, Sydney, Australia. Focusing on battery energy storage systems. www.cdmc.org.cn/2014/esa/

November 10–13, 2014: Fuel Cell Seminar & Energy Exposition, Los Angeles, California. The expo theme is "The Power to Drive Change Today." www.fuelcellseminar.com

November 11–14, 2014: Lithium Battery Power 2014 and Battery Safety 2014, Washington D.C. www.knowledgefoundation.com

November 19–21, 2014: Energy Storage Global Conference 2014, Paris, France. Organized by the Energy Storage Association and the European Association for Energy Storage. http://energystorage.org/events/energy-storage-global-conference-2014

December 4–5, 2014: Second International Conference on Energy Storage and Microgrids, New Delhi, India. http://energystorage.org/events/2nd-international-conference-energy-storage-micro-grids

February 16–19, 2015: NAATBatt 2015 Annual Meeting & Conference, Phoenix, Arizona. This annual members' meeting of the National Alliance for Advanced Technology Batteries will focus on "Energy Storage: Electrifying the Future." www.naatbatt.org

March 2–5, 2015: EPRI Power Delivery & Utilization Advisory Meeting, Phoenix, Arizona

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September 2014

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