ELECTRIC POWER RESEARCH INSTITUTE

Strategic Intelligence Update

Energy Storage & Distributed Generation

June 2017 Program 94

Highlights of this Issue:

- We focus on fuel cell markets, technologies, and applications—and potentially new opportunities from advancements in hybrid technologies and surging interest in microgrids (page 1)
- Utility integrated resource plans increasingly select energy storage. Arizona utilities' IRPs offer examples (page 9)
- Key findings from PG&E energy storage demonstration projects (page 10)

Fuel Cells for Distributed Generation: New Applications in a Changing Market

Since the 1990s, fuel cell manufacturers have been pursuing automobile, home, and business applications for their products. However, performance limitations, economic challenges, and competing energy generation and storage technologies have held back the market penetration of fuel cells. While stationary fuel cells are powering a sizable share of homes and businesses in European and Asian markets, the U.S. market has lagged in comparison. Now, the outlook could be starting to change with drivers for clean energy, advancements in hybrid technologies, and a surge in interest for microgrid application. As distributed energy resources (DERs) proliferate, fuel cells can be an environmentally beneficial, flexible, and economically viable power option in the new energy landscape.

Pioneered by European scientists in the 1800s, fuel cells were largely ignored as an electricity generation technology for nearly 100 years. In the 1950s, NASA recognized the potential for fuel cells as a power source for space missions, and fuel cell technologies were subsequently developed into a reliable source of energy for space applications. Corresponding with the growth of distributed generation in the 1970s and past efforts to reduce greenhouse gas emissions, government funding and incentives have enabled the continued development of fuel cells, primarily for transportation and stationary power generation. The focus of these developments has aimed at creating a more reliable and efficient technology while simultaneously reducing costs.

Fuel Cell Markets

There are three primary end-use markets for fuel cell technologies: portable systems, transportation, and stationary power. Table 1 outlines the major characteristics of each fuel cell market.

Portable fuel cell systems are most commonly used in remote areas, acting as a form of short-term backup power. Smaller portable fuel cells are also being evaluated as potential energy sources for common appliances such as cell phones and laptops.

Transportation fuel cells are used to power vehicles. Transportation applications are growing in popularity, with major automobile manufacturers, such as Toyota and Hyundai, beginning to produce commercially-available fuel cell vehicles. Transportation fuel cells are also used to power forklifts and other vehicles in warehouses and industrial operations.

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Table 1. Three Major Fuel Cell Markets (Source: GTM Research, CHP and Fuel Cells 2016-2026: Growth Opportunities, Markets, and Forecast)

Fuel Cell Market	Portable	Transportation	Stationary
Definition	Units that are built into products that are designed to be moved, including auxiliary power units (APUs)	Units that provide propulsive power or range extension to a vehicle	Units that provide electricity (and sometimes heat) but are not designed to be moved
Typical power range	5 W - 20 kW	1 kW - 100 kW	0.5 kW - 400 kW
Typical fuel cell technology*	• Proton exchange membrane Direct methanol Alkaline	• Proton exchange membrane • Direct methanol	• Molten carbonate • Phosphoric acid • Solid oxide • Proton exchange membrane
Examples	• Non-motive APUs (camper vans, boats, lighting) • Military applications	• Materials-handling vehicles • Fuel-cell electric automobiles • Trucks and buses	• Large stationary combined heat and power • Small stationary micro-CHP • Uninterruptible power supplies

**See Table 2 for description of technologies*

Stationary fuel cells are designed and built to provide permanent power at a single location. Stationary fuel cells can have much higher capacities compared to fuel cells designed for transportation or portable applications. They can also accept a wider range of fuels, which can include natural gas, biogas, methanol, and coal gas.

Fuel Cell Technologies

Fuel cells produce electricity through an electrochemical process that does not require combustion. Hydrogen ions travel through an electrolyte between two electrodes, releasing electrons that yield electric power, with water created as a byproduct. A single fuel cell produces a relatively small amount of electricity, and several fuel cells are typically "stacked" to create a practical fuel cell

Table 2. Fuel Cell Technologies

Fuel Cell Technology	Characteristics	Benefits
Alkaline (AFC)	• Operate at ~90°C • Used in military and space applications	• High efficiency • Low cost
Direct Methanol (DMFC)	• Operate at 60°C-130°C • Low efficiency • Used as portable power and in military applications	• Methanol is energy-dense, easy to transport • Low temperature requires less maintenance
Phosphoric Acid (PAFC)	• Operate at 150°C - 200°C • Used for stationary power • Relatively low efficiency, expensive catalyst required	• Fuel Flexibility • Well-suited for CHP
Proton Exchange Membrane (PEMFC)	• Operate ~80°C • Requires high-purity hydrogen Used most often in vehicles and portable applications	• Quick startup • Low temperature operation requires less maintenance
Molten Carbonate (MCFC)	• Operate >600°C • Long startup time, slow ramping • High temperature causes corrosion, leading to shorter life • Low power density	• High efficiency • Fuel flexibility • Well-suited for CHP
Solid Oxide (SOFC)	• Operate 700°C – 1,000°C • Long startup time • High temperature causes corrosion, leading to shorter life and more maintenance	• High efficiency • Fuel flexibility • High power density • Well-suited for CHP

system with the desired output. Stationary fuel cell power generators range from less than 1 to thousands of kilowatts, spanning residential, commercial, and industrial applications. The wide range of available capacities, along with negligible emissions, low noise, and limited mechanical wear, are factors that continue to drive fuel cell development and adoption.

There are six widely used fuel cell technologies with different electrolytes and operational characteristics: alkaline (AFC), direct methanol (DMFC), phosphoric acid (PAFC), proton exchange membrane (PEMFC), molten carbonate (MCFC), and solid oxide (SOFC). Four of these (DMFC, PAFC, PEMFC, and SOFC), are used in stationary fuel cell systems. While each of these fuel cell technologies share the same basic principles, they differ in their operating characteristics and benefits. Table 2 outlines the characteristics and benefits of each technology.

Fuel cells run on hydrogen, which can either be supplied to the fuel cell system, or the fuel cell system can include a reformer that creates hydrogen from a hydrocarbon source. Most of the currently available stationary fuel cell technologies operate on hydrocarbon fuels such as natural gas and biogas. Stationary fuel cells have higher electrical efficiencies and significantly lower emissions than other fuel-based DER technologies such as reciprocating engines and microturbines.

The Stationary Fuel Cell Market

Interest in fuel cells has been increasing, spurred by low natural gas prices, a stronger focus on grid resiliency and declining fuel cell equipment costs. Recent data from Japan suggests that the cost reduction from higher production volumes and technological advancements can significantly reduce fuel cell equipment prices. The data, from Japan's Ene-Farm [1] residential fuel cell program, shows prices declining faster than wind turbines and nearly as fast as PV equipment in recent years (see Figure 1).[2]

Currently, there are six fuel cell manufacturers in North America. The three largest -- Bloom Energy, Doosan Fuel Cell America, and FuelCell Energy – produce stationary fuel cell products that accounted for over 70 MW of new U.S. fuel cell capacity in 2015.[3] The other three manufacturers exclusively produce proton exchange membrane (PEM) fuel cells, which are primarily used for portable and transportation applications.

1 Ene-Farm was the nickname given to the first fuel cells for practical home use that made their debut in Japan.

2 Forni, Adam, Navigant Research, S*tationary Fuel Cell Prices Falling Faster Than Wind*, Close to PV, August 1, 2016, https://www.navigantresearch.com/blog/stationary-fuel-cell-prices-falling-faster-than-wind-close-to-pv

3 *Fuel Cell Technologies Market Report 2015*, United States Department of Energy, https://energy.gov/sites/prod/files/2016/10/f33/fcto_2015_market_report.pdf

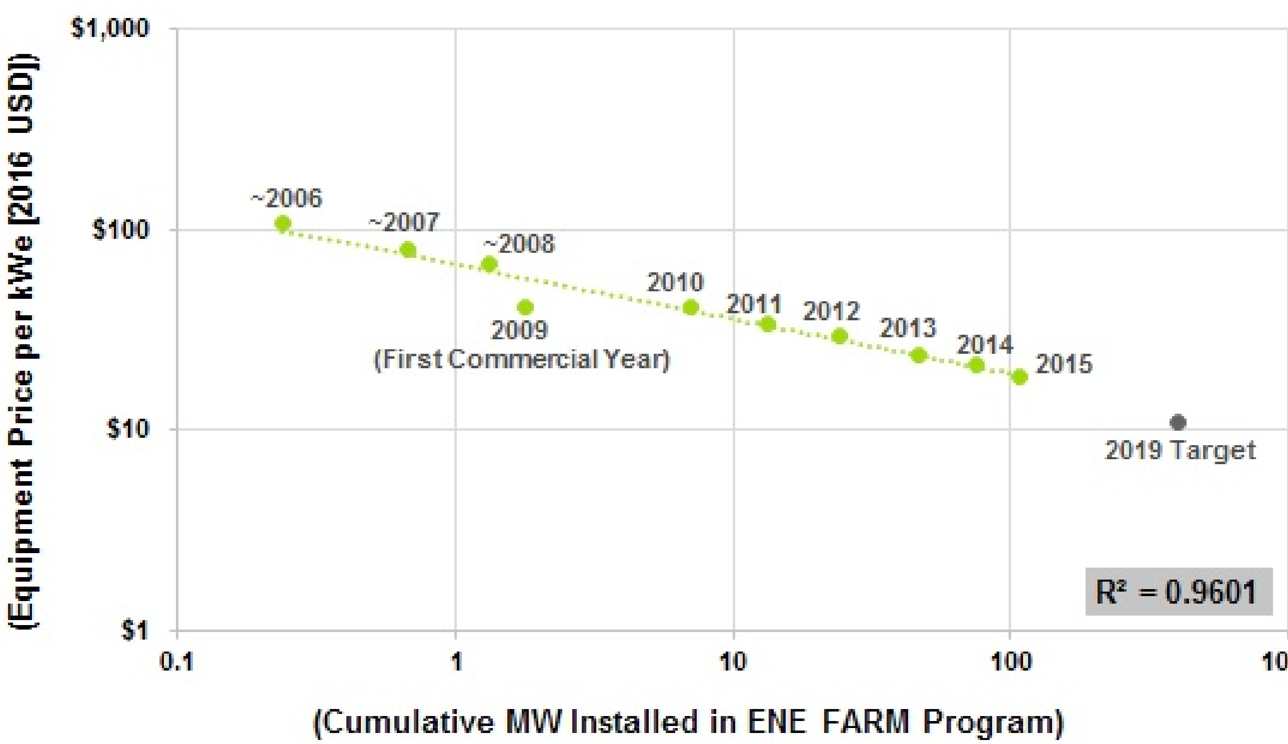

Figure 1. Fuel Cell Equipment Prices Compared to Installed MW for Japan's ENE FARM Program (Sources: Navigant Research; Imperial College London; Ministry of Economy, Trade and Industry)

Bloom Energy manufactures electricity-only solid oxide fuel cell (SOFC) systems ranging in size from 160 kW to 250 kW. Bloom's fuel cells recover and recuperate waste heat to improve electric efficiency, but they cannot be used for combined heat and power (CHP) applications. *Doosan Fuel Cell America*, which acquired UTC in 2014, offers a versatile natural gas-fueled, 460 kW phosphoric acid (PAFC) CHP fuel cell system. *FuelCell Energy* produces a fuel flexible, 1.4 MW molten carbonate (MCFC) CHP system, which can be sold in packages of one, two, or three units. Each manufacturer produces a distinct fuel cell system powered by a different technology.

Figure 2 shows the percent of installed capacity and the percent of units for the U.S. fuel cell market, by fuel cell technology. While many of the SOFCs, MCFCs and PAFCs have been installed by other companies in the past, current production is largely limited to Bloom, FuelCell Energy and Doosan. There are more companies involved with PEM fuel cell production, primarily for potential automobile or small residential power applications.

Increased energy density and high-volume production are bringing fuel cell costs down. The energy density for Bloom's current fuel cells is five times higher than their 2008 fuel cells, and more gains are expected in the near future.[4] Maintenance costs are also being reduced, and the modular design of fuel cells allows for higher availability during servicing. According to a representative at Doosan, their PureCell 400 package requires roughly \$100,000/year for all-inclusive maintenance, with a stack replacement at year 10, over a 20-year lifetime.[5] When utilized for baseload power, these maintenance costs are comparable to reciprocating engines. Still, installed capital costs for fuel cells remain significantly higher than conventional natural gas generation technologies, with the all-in cost for many installations exceeding \$5,000 per kW, compared to \$2,500-\$3,000 per kW for comparable reciprocating engines and microturbines. Incentive programs and PPA offerings can help to reduce or eliminate the high investment cost hurdle.

4 Discussion with Asim Hussain, VP Marketing & Customer Experience, Bloom Energy, May 23, 2017.

5 Discussion with Robert Broglio, Senior Sales Manager, Doosan Power Service Americas, May 15, 2017.

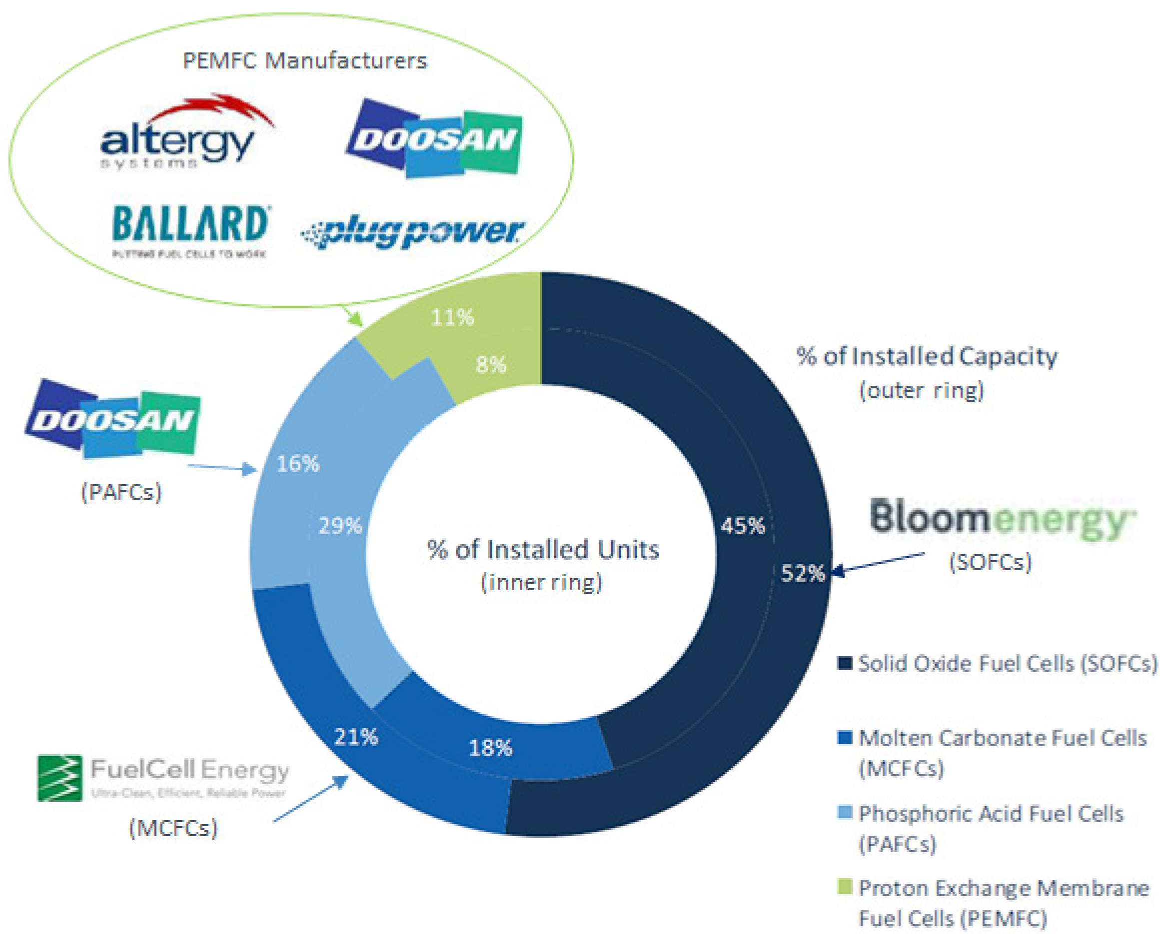

Figure 2. Market Share by Technology for U.S. Stationary Fuel Cell Market (source: GTM))

Current and Future Applications for Stationary Fuel Cells

To date, most stationary fuel cells have been deployed for baseload power operations, where the system runs 24 hours a day at full capacity. SOFC installations from Bloom, said to total 250 MW from over 300 sites[6], are deployed for these baseload power applications. About half of Bloom's customers are operating under a power purchase agreement (PPA), where Bloom owns and operates the fuel cell equipment. The customer signs a long-term contract to purchase the electricity, so they can benefit from clean and reliable on-site power with no capital investment required. This PPA model is becoming more common for all forms of DER, including other fuel cell options. Several technology firms including Google, Apple, and eBay have installed Bloom fuel cells for office and data center applications. While Bloom fuel cells have a high electric efficiency, averaging close to 60 percent, it is not possible to recover and utilize the waste heat in a CHP configuration.

Outside of Bloom's SOFCs, the majority of remaining stationary fuel cell installations in the U.S. consist of Doosan's PAFCs or FuelCell Energy's MCFCs. These fuel cells are configured to recover and utilize the waste heat from the fuel cell stacks, resulting in high CHP efficiencies (over 80 percent). The DOE CHP Installation Database (see Figure 3) shows fuel cell CHP systems currently in operation. As shown, there are an estimated 156 active fuel cell CHP installations across the U.S., totaling 106 MW of capacity. Over 80 percent of these installations are fueled by natural gas, with the remainder fueled primarily by biogas. [7]

CHP fuel cell installations showed an increasing trend from 2008 through 2012, and then declined from 2012 through 2015. Data for 2016 suggest another uptick in fuel cell activity, with ten installations totaling over 21 MW of CHP capacity in 2016.[8] Note that this data does not include Bloom units or any other power-only fuel cell offerings.

Historically, California has dominated the market for baseload and CHP fuel cell applications, largely due to favorable treatment from the Self Generation Incentive Program (SGIP). Over 60 percent of U.S. CHP fuel cell installations are currently located in California. Recent changes to SGIP have favored energy storage, and fewer fuel cell installations, along with other types of distributed generation technologies, will likely receive SGIP incentives in the future. Even with the SGIP changes, the California market is expected to remain strong, and the Northeastern market is on the rise, with fuel cell and microgrid incentive programs that are pushing new projects forward.

6 Discussion with Asim Hussain, VP Marketing & Customer Experience, Bloom Energy, May 23, 2017.

7 U.S. Department of Energy, Combined Heat and Power Installation Database, with preliminary 2016 updates from ICF. Official database updates will be published in June 2017.

8 Ibid.

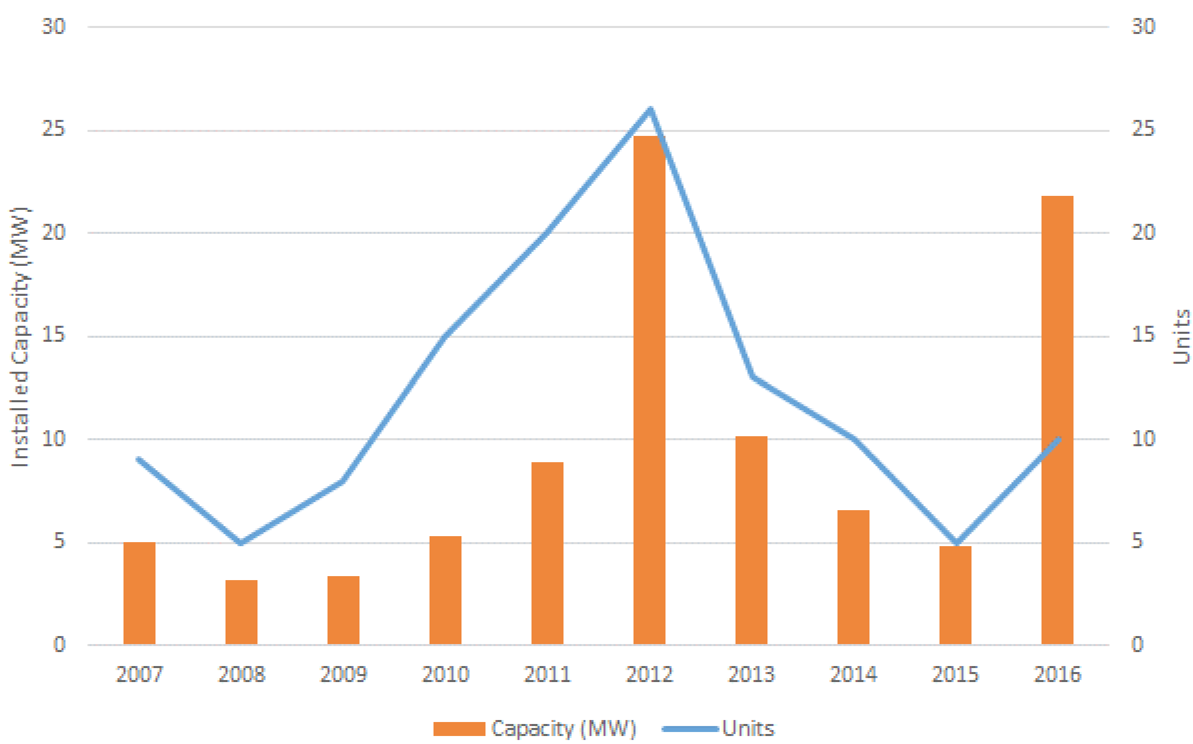

Figure 3. New Fuel Cell CHP Installations, Number of Units and Total Capacity, 2007 through 2016 (source: DOE CHP Installation Database, updated through December 31, 2016)

Fuel Cells for Microgrids

Interest in microgrids is growing, primarily due to the resiliency benefits of diverse on-site generation sources that can operate independent of the utility grid in a microgrid configuration. Microgrids can consist of multiple DERs serving multiple loads, including renewable technologies and energy storage, but they tend to be most resilient when gas-fueled generation systems are providing baseload power. Fuel cells can serve this role for microgrids, with the lowest emissions profile among all gas-fueled generation options.

Spurred by incentives, microgrid deployments are increasing in the Northeast, and many are implementing fuel cells. Incentives for both community microgrids and fuel cells are currently available in Connecticut, Massachusetts, New Jersey, and New York. A number of Northeastern microgrids under development in these states are incorporating fuel cells, including several that resulted from a 2015 agreement between Bloom and Constellation. Through the agreement, Bloom will provide 40 MW of fuel cells and equity financing for new projects developed by Constellation. Constellation has already secured customer offtake agreements for all 40 MW, and is about halfway through the installation of the fuel cells across "hundreds of sites" in California, Connecticut, New Jersey, and New York.[9]

Earlier this year, Constellation Energy, Bloom Energy, and the City of Hartford completed a community microgrid powered by an 800 kW fuel cell system. The microgrid will provide power to Hartford's Parkville Elementary School, Dwight Branch Library, Parkville Senior Center, and Charter Oak Health Center. In the event of utility outages, the microgrid will shift into islanding mode, allowing the buildings to act as places of refuge for the community. In addition to the four facilities covered under grid-connected operation, the microgrid will provide emergency power to a local gas station and grocery store during utility outages.[10]

The state of Connecticut helped fund the Hartford project with a $2 million grant from the Microgrid Grant Program. Additional incentives for fuel cell generation are provided through Connecticut's Low-Emission Renewable Credits program. The project earns credits for each megawatt-hour of energy produced, and Connecticut utilities purchase the credits to reduce their net emissions.

Fuel cells are well-suited to provide baseload power in microgrids, with high reliability, high efficiency, low emissions, and quiet operation. However, fuel cells can be sensitive to grid voltage fluctuations when interconnected, and they may not be able to support dynamic load following. It can take a long time for a MCFC or SOFC to shut down and restart, which is sometimes required after a utility outage. This long startup time could reduce resiliency benefits compared to technologies with faster startup times. However, the direct current (DC) bus used by fuel cells allows for two inverters to be installed and configured such that one of them operates independent from the utility grid, always serving the load. The other inverter runs in parallel with the grid, disconnecting when necessary, and only reconnecting when the load-connected inverter is in sync with the utility signal. This means that with proper electrical engineering, fuel cells can ride through grid outages without needing to shut down and restart, allowing them to act as a resilient baseload anchor for micrograms.

Depending on the technology and configuration, fuel cells may not be able to provide the same inertia and ramping capabilities as other prime movers in a microgrid. Engines can easily fluctuate their output as large loads come on and off, but ramp rates for fuel cells tend to be slower. This issue is most prominent for MCFC technologies, which are typically only capable of a 10 percent power swing. The extent to which fuel cells can provide the necessary inertia for the baseload anchor role in a microgrid is uncertain, and depends on several variables, but it is a consideration that microgrid developers and engineers must take into account.

In addition to the primary source of baseload power, fuel cells can also play a complementary role in microgrids, acting as a quiet, low-emission, small-footprint source of power for a particular building, while other microgrid resources are utilized strategically according to their advantages. An example of this can be found at the University of California San Diego campus microgrid, which contains a 2.8 MW biogas fuel cell at a wastewater treatment plant. This fuel cell has been integrated with a 30 MW CHP plant and 1.2 MW of solar panels distributed throughout the campus to form a resilient microgrid.

Hybrid Technologies

During operation, some hydrogen fuel typically passes through a fuel cell unreacted. Different approaches have been conceptualized to capture this unused fuel along with energy in the high-temperature exhaust stream. One concept, currently being developed by General Electric, is a Fuel Cell-Combined Cycle (FC-CC) design that consists of a SOFC and a Jenbacher reciprocating engine (see Figure 4). The electric efficiency of the FC-CC can reach 60-65 percent, with up to 90 percent CHP efficiency. With a simplified fuel cell design and a new thermal spraying process for SOFC manufacturing, the FC-CC system is expected to be significantly more affordable and long-lasting than comparable fuel cell options. "Fuel cells are made for hybridization," as stated by Robert Rose of the Breakthrough Technologies Institute.[11] "It's a natural fit because hybridization makes the fuel cell system more efficient and economical." The General Electric FC-CC is expected to be commercially available in 2018, with modular options in the range of 1-10 MW.

9 Maloney, Peter, *Utility Dive, Fuel Cells are a good partner for microgrids, but costs limit deployment*, May 10, 2016, http://www.utilitydive.com/news/fuel-cells-are-a-good-partner-for-microgrids-but-costs-limit-deployment/418891/

10 Wood, Elisa, Microgrid Knowledge, *Connecticut's Latest Microgrid and Fuel Cell Project Goes Live in Hartford*, April 25, 2017, http://microgridknowledge.com/microgrid-and-fuel-cell-hartford/

11 General Electric, *GE-Fuel Cells: The Power of Tomorrow*, 2015, https://www.ge.com/sites/default/files/GE_FuelCells.pdf

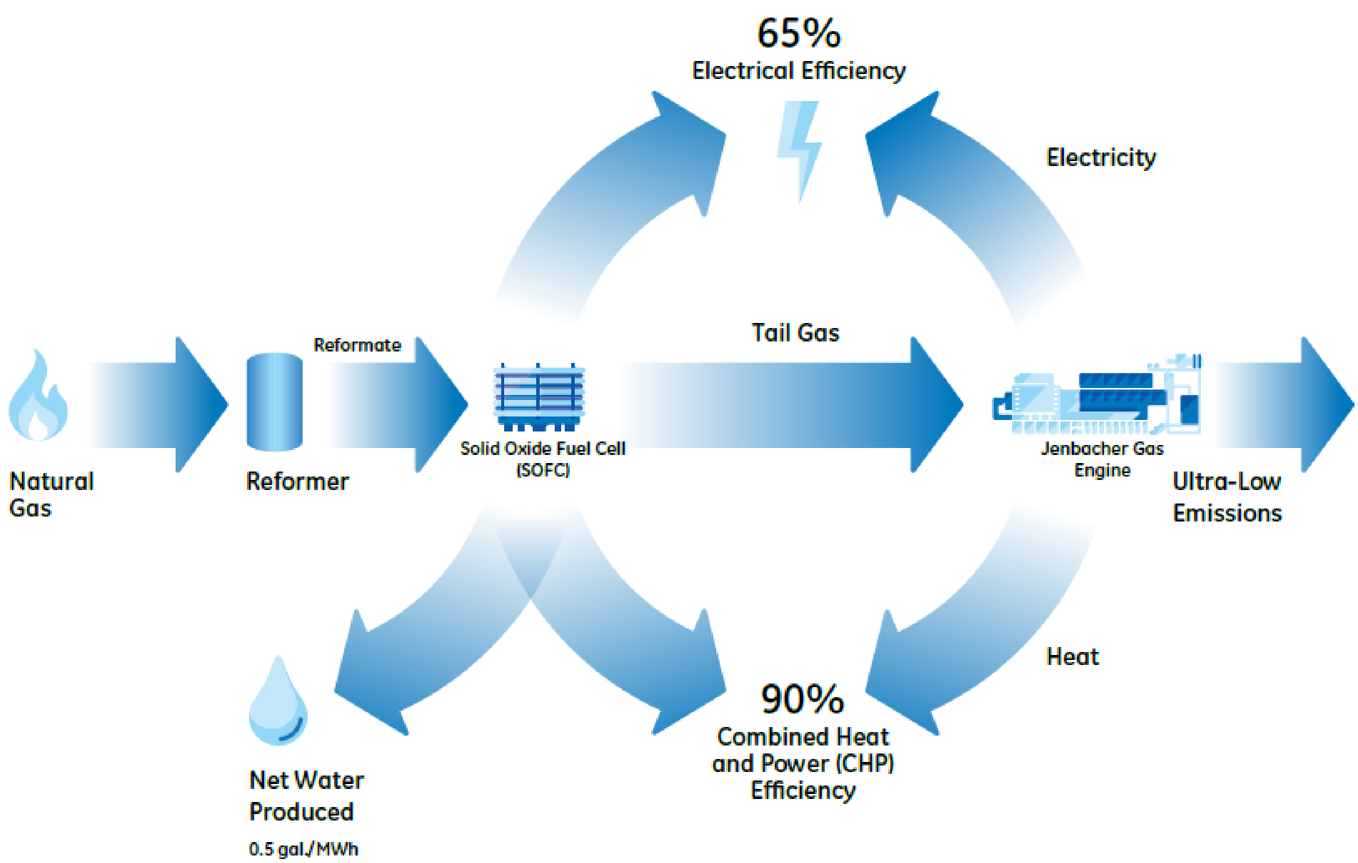

Figure 4. General Electric's Fuel Cell-Combined Cycle System (source: General Electric)

In addition to hybrid fuel cell systems that use reciprocating engines, there are hybrid designs that integrate gas turbines. Hybrid fuel cell-gas turbine (FC-GT) designs utilize the high-temperature exhaust gas (unused fuel) to power a gas turbine. Essentially, the fuel cell acts as the combustor for the turbine. Steam is then produced from the gas turbine exhaust and used in the fuel reformer as the systems are integrated with careful engineering. While experiments with hybrid FC-GT systems under several different configurations have been theorized and tested with promising results, the technology has not been commercialized. However, the success of General Electric's FC-CC system could incentivize equipment manufacturers to develop new hybrid FC-GT designs.

Another emerging hybrid technology for fuel cells involves integration of energy storage. Bloom recently introduced an energy server hybrid product that incorporates integrated storage systems. Retail establishments, office buildings, and many other applications have peak daytime loads and small nighttime loads. With energy storage, DC electricity from a fuel cell can charge batteries at night, and this electricity can then be used during peak daytime hours. A fuel cell integrated with energy storage can allow facilities to:

- Shift peak energy requirements and shave peak demand
- Allow for business continuity during outages
- Participate in demand response markets
- Allow the battery to be dispatched by utilities as needed

Bloom recently secured a deal with Home Depot to install 200 fuel cell servers in their stores, and 60 of these installations will incorporate the hybrid storage systems.[12]

With hybrid technologies, the high efficiency and low emissions profile of fuel cells can be combined with lower-cost engines and turbines to create affordable, low-emission power options. In the future, hybrid technologies with fuel cells and batteries could provide flexible and efficient operation, resiliency benefits for customers, and new dispatchable power options for utilities.

12 Discussion with Asim Hussain, VP Marketing & Customer Experience, Bloom Energy, May 23, 2017.

Dispatchable Fuel Cells

Utilities are starting to become involved in fuel cell deployments. As an example, Delmarva Power started deploying 30 MW of Bloom servers in Delaware in 2012 as new rate-based generation assets. In 2015, EPRI completed a performance and benefits assessment for one of the installations, identifying several benefits for Delmarva.[13] Exelon and Southern Company are currently working with Bloom to combine for over 100 MW of new capacity under power purchase agreements with customers. These systems will be installed at customer sites to provide baseload power, but companies like Bloom and Doosan hope that fuel cells will soon be deployed directly by utilities in strategic locations to reduce transmission congestion and allow for utility dispatch. Doosan is currently in talks with a large electric utility about potentially owning and operating their fuel cells at strategic grid locations.[14] When properly configured, fuel cells can provide power factor control, volt-ampere reactive power support, and other ancillary services for utilities. There are several advantages that fuel cells have over other distributed generation technologies (e.g., reciprocating engines and microturbines) and energy storage for utility dispatch applications, including:

- Reliable fuel-based generation with minimal emissions
- Low downtime for maintenance (compared to engines)
- High part-load efficiencies (compared to other fuel-based DER technologies)
- No conversion losses from discharging (compared to energy storage)
- Does not require downtime for charging (compared to energy storage)

Although fuel cells are generally dispatchable, their relatively high capital cost and fixed maintenance costs tend to make them more economical for baseload power applications. Compared to engines and turbines, they are not capable of fast ramping. Slow ramping is particularly true for molten carbonate technologies, which have the longest start-up times and are only capable of a 10 percent power swing. As fuel cell technologies improve and costs decline, dispatch options may become more prevalent, especially as hybrid storage systems become more available.

13 *Operational Performance and Benefits Assessment of a 3-MW Fuel Cell at a Utility Substation: Case Study: Delmarva Power/Bloom Energy Solid Oxide Fuel Cell*. EPRI, Palo Alto, CA: 2015. 3002004715

14 Discussion with Robert Broglio, Senior Sales Manager, Doosan Power Service Americas, May 15, 2017.

Fuel cells paired with energy storage as a hybrid technology have more flexibility than stand-alone fuel cells for utility dispatch applications. While fuel cells provide baseload power and charge the battery at night, utilities can dispatch the storage as needed during peak load hours for demand response, frequency regulation, and other ancillary services. The flexibility and functionality that energy storage adds to hybrid fuel cells could make them a valuable resource in the future for both utilities and their customers.

A Fuel Cell Future?

There are several reasons that stationary fuel cells could be poised for significant market growth in the U.S. The recent surge in interest and activity towards microgrids is driven by the desire for resiliency and clean energy, which fuel cells can provide. Resilient microgrids require a fuel-based anchor, and fuel cells have the highest electric efficiencies and lowest emissions of all fuel-based DG and CHP technologies. The combination of fuel cells with reciprocating engines, gas turbines, and energy storage devices as hybrid technologies could create new markets for fuel cells. However, the largest hurdle for fuel cells continues to be high installed costs, which are substantially higher than other fuel-based generation options.

While high efficiencies, high availability, and reliable operation can help recover the large initial investment for fuel cells, the payback periods and rates of return tend to be more favorable for other distributed generation technologies. But many customers are willing to pay a premium for low emissions and quiet operation, and PPA offerings can eliminate the investment cost hurdle. Energy densities and production methods are also improving for fuel cells, leading to lower costs for customers.

The promise of fuel cells has been around for a long time, and after many years of high expectations and low uptake in the market, many in the energy industry are skeptical that fuel cells may soon turn the corner and start gaining significant market share. While no game-changing cost reductions are expected, fuel cell costs are expected to decline as a result of incremental gains in energy density and high-volume production methods. In combination with lower costs, the demand for fuel cells is expected to grow, driven by policies and regulations that encourage clean distributed energy, utility interest in using fuel-based generation to enable intermittent renewable loads, and end-user interest in resiliency during grid outages. Additionally, the advantages of new hybrid technologies could create more markets for stationary fuel cells, with the potential to rejuvenate the fuel cell industry.

Quadrennial Energy Review (QER) – Second Installment

In 2015 Q2, the Update reviewed the first installment of the QER, an inter-agency initiative lead by the Department of Energy (DOE) to assess "energy challenges, needs, requirements and barriers" to inform policy and legislative options. The Update focus was on the role of distributed resources and energy storage in the assessment. On January 6, 2017, DOE released the second installment of the QER, an extensive report coupled with over 40 analytical studies developed in support. Much of the report and its associated studies address topics relevant to distributed resources, the distribution grid, smart grid, and energy storage. In later editions of the Update, we will examine the contents of these reports.

Both the first and second QERs and supporting documentation can be found here: https://energy.gov/epsa/quadrennial-energy-review-qer.

State Regulatory and Utility News

Arizona - Storage in Utility IRPs

One of the challenges faced historically by energy storage technologies has been the difficulty in modeling such technologies in utility resource planning. In part, this was because the high capital costs of storage and the structure of long-term capacity expansion models (most of which did not accurately value operational benefits or analyze multiple use applications) did not result in storage being selected for resource portfolios. In response to state policy requirements (which may include both requirements to include storage in planning and direct procurement mandates), some utilities began to conduct surveys of storage technologies, costs and benefits, and some conducted more detailed modeling studies coupling capacity expansion models with production cost models and other tools. Due to the combination of declining storage costs, other policy goals and market trends, such as renewable energy mandates and declining costs, and improved quantitative analysis, we are seeing energy storage being selected in utility resource plans on an accelerated basis.

As recent example is the integrated resource plans (IRPs) submitted by Arizona utilities in April 2017 for the target year of 2032. Three of the four utilities submitting these plans selected new storage projects.

Arizona Public Service (APS) identifies 507 MW of new energy storage in its "selected plan" scenario for 2032, and up to 1,107 MW in two other scenarios in which respond to potential higher policy requirements for renewable energy and storage. Peak load in 2032 is forecast as 10,066 MW (net of energy efficiency and demand side management), so in the high storage case, storage would be a significant component of utility resource capacity. We note also that APS has one of the world's largest concentrating solar power plants at 250 MW with 6 hours of thermal energy storage, under a 30 year contract which began in October 2013. Table 1 shows the storage resource capital costs ($/kW) assumed in the IRP analysis, excerpted from IRP Table 2-3.

Table 3. Assumptions About Current Storage Technology Costs in APS Integrated Resource Plan, 2017

Storage technology	Capital costs ($/kW)
CAES	$3, 246
Pumped Storage Hydro	$3, 139
Battery Energy Storage System (Li-ion)	$1,539
Flow Battery	$1,589
Battery Energy Storage System (Na-S)	$1,740
Battery Energy Storage System (Lead Acid)	$941
Battery Energy Storage System	$1,214
Flywheel	$3,008
Grid-Scale Solar – Parabolic Trough, Salt Storage	$5,481
Grid-Scale Solar – Central Receiver (Power Tower), Salt Storage	$8,301

To select energy storage technologies in the IRP, APS notes that it incorporated state policy goals and stakeholder input, and used a combination of modeling tools to optimize portfolios. APS is also evaluating risks of new storage technologies in its Solar Partner Program, with two 2 MW/2 MWh battery units co-located with a solar facilities being analyzed with EPRI support; in the IRP, it notes that these risks include:

> Resource risk - Batteries do not produce energy so they are reliant on other resources – often variable resources – the deployment of which has been driven by tax policies that may not be extended.
>
> Cost risk - As with other resources batteries will be considered for dispatch on a cost competitive basis against other resources.
>
> Integrative capabilities - Pairing storage with other resources, namely solar or wind, has limited operational experience and requires more "live" projects before these pairings can be viewed as seamless and reliable.

Tucson Electric Power (TEP) also selected significant new energy storage in its IRP, with its Reference Case Plan including the addition of a 50 MW battery project in 2019 and another 50 MW each 3 years up to 200 MW by 2032. TEP has a forecast peak load of 2,610 MW in 2032.

UNS Electric Inc., (UNSE) has a similar plan to TEP, at lower procurement levels. UNSE foresees procuring its first energy storage system as a 5 MW, 5 MWh system deployed in 2019, with similar systems procured each 3 years up to 20 MW capacity procured by 2028. UNSE forecasts a peak load of 527 MW in 2032.

The Arizona utility submitted IRPs can be found here: http://edocket.azcc.gov/Docket/DocketDetailSearch?docketId=18939#docket-detail-container2.

Wholesale Electric Power Market and Resource Integration News

FERC 2016 Staff Report on Assessment of Demand Response and Advanced Metering

In December 2016, the Federal Energy Regulatory Commission (FERC) released its annual staff report on demand response and advanced metering. While the Update is generally not focused on demand response, we note this report because it reflects the growing role of behind-the-meter energy storage and distributed energy resources in the demand response area. The report notes a large number of the energy storage initiatives around the country which are affecting the evolution of demand response programs.

The report can be found here: https://www.ferc.gov/legal/staff-reports/2016/DR-AM-Report2016.pdf.

PG&E Energy Storage Demonstration Project Results

California utilities have undertaken a number of demonstration or pilot projects utilizing different types of energy storage (stationary, mobile) in different applications. From initial authorization in September 2013 to September 2016, Pacific Gas & Electric (PG&E) conducted a California Energy Commission (CEC)-sponsored demonstration of battery operations in the California ISO (CAISO) wholesale markets. PG&E used two different Sodium Sulfur (NAS) Battery Energy Storage Systems (BESSs): the 2 MW Vaca-Dixon facility and the 4 MW Yerba Buena facility. Table 4 shows additional details and attributes of the storage devices. While the Vaca-Dixon device was dedicated fully to wholesale market operations, the Yerba Buena facility was half reserved for islanding and backup of a commercial customer.

The results of these experiences are summarized in a final report, *EPIC Project 1.01-Energy Storage End Uses: Energy Storage for Market Operations*. This report is particularly useful because it is a public document explaining wholesale market operations with some project level market revenue results that usually remain confidential.

The report contains a lot of details on operational requirements and software developed to facilitate operations. Some of the critical wholesale market findings are as summarized below:

"<u>CAISO Day-Ahead (DA) and Real-Time (RT) Energy revenues are not currently conducive to energy arbitrage</u>." PG&E finds that energy "price differentials were not large enough on a consistent basis to offset the inherent round trip efficiency of the BESSs, which averaged about 75 percent." In addition, PG&E notes that differentials in energy prices vary by location around the grid, such that storage economics might differ significantly whether the project is located in northern or southern California.

"<u>Frequency Regulation represented the best financial use of the BESSs.</u>" PG&E found that dedicating the devices to frequency regulation (FR) – called Regulation Up and Regulation Down in the CAISO markets – provided the highest revenues. In particular, the projects benefited substantially from a large increase in the CAISO FR prices in early 2016, but an increase which subsided later in 2016.

How the devices were modeled by the CAISO also made a significant difference to market revenues. In 2011, the CAISO implemented the Non-Generation Resource (NGR) model of market

Table 4. PG&E Battery Energy Storage System (BESS) Characteristics

	Vaca-Dixon	Yerba Buena
Facility size (rated by DC discharge power)	2 MW	4 MW
Location	Vaca-Dixon Substation	Customer R&D Facility, San Jose
Commercial operational start date	August 2012	May 2013
Max energy available	12.5 MWh	27. 8 MWh
Max energy for market operations	12.5 MWh	15.3 MWh
Max Discharge Rate	1.85 MW	3.85 MW
Max Charge Rate	-2.15 MW	-4.25 MW
Efficiency	75%	75%
Wholesale services provided in demonstration phase	Energy arbitrage, Energy and Ancillary Services in the same hour, Regulation, Spinning Reserve	Energy arbitrage, Energy and Ancillary Services in the same hour, Regulation, Spinning Reserve
Other customer services		Islanding, backup power

participation to facilitate operations of energy-limited devices such as batteries and flywheels which do not have transition times between charging and discharging. Such devices can participate in the frequency regulation markets either through the general NGR model, in which case the storage operator optimizes energy and manages state of charge when providing frequency regulation, or under a variant of the NGR model – the Regulation Energy Management (REM) participation model – under which the device participates in the FR markets only and the CAISO manages state of charge and attempts to maintain it at 50%. PG&E tested both participation models and found that the REM approach significantly improved market revenues compared to the NGR model.

Figure 5 , excerpted from the PG&E report, shows the Vaca-Dixon facility following the CAISO's REM control signal for a day in April 2016, and demonstrating also that state of charge is brought back to around 50%. The report also provides a comparative figure showing a less efficient utilization of the same device for FR under the NGR model.

"Spinning Reserve revenues can very modestly add to resource revenues." In contrast to FR, with average hourly prices for spin of around $4/MW, PG&E found that it "was not a significant revenue contributor during the project."

"Current market dynamics do not favor long-duration batteries." One of PG&E conclusions is that "given that the most significant revenues are from FR, and that FR is a power rather than energy product (meaning that FR requires resources to provide power for short periods), a 30-minute BESS might be able to provide the same FR capabilities as a 7-hour system, with presumably less capital investment." However, the report also notes later that future conditions on the grid, such as increased prevalence of low

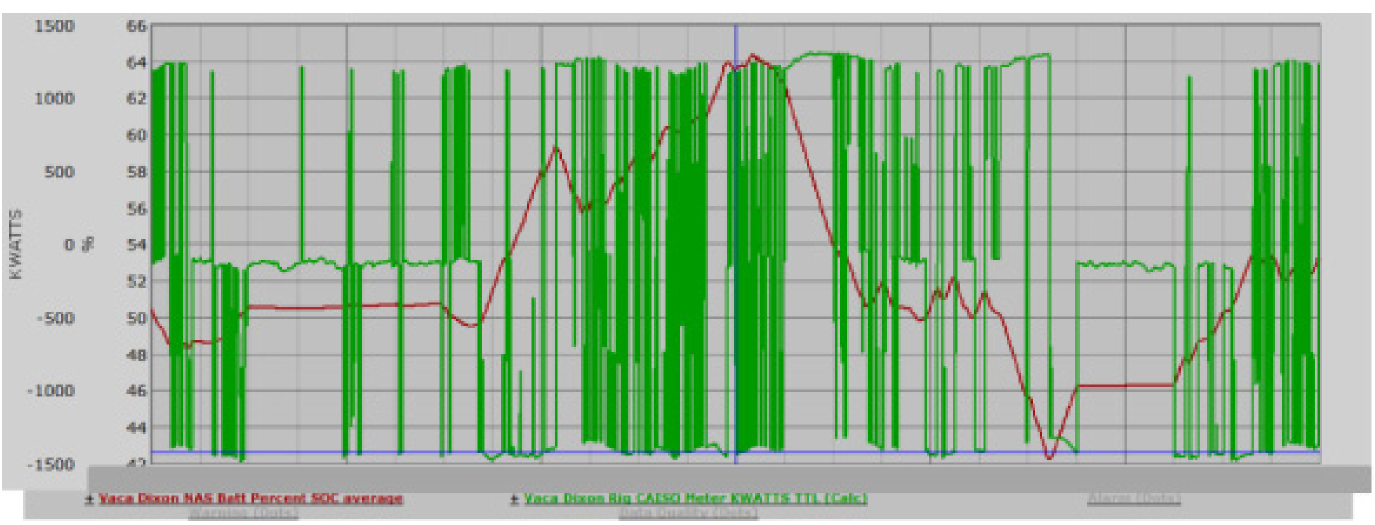

Figure 5. Vaca BESS Providing FR as NGR-REM Resource – Single Day April 2016 (pg. 41)

or negative energy prices, and new products, such as the CAISO flexible ramping product, may improve the revenues of long-duration devices.

"Overall, revenues from market participation seen during the project were less than those estimated by models filed [in 2013] with the CPUC and California Energy Commission (CEC)." PG&E compared the market revenue results to the modeled long-term storage revenue forecasts in 2013 studies by EPRI and DNV-GL, and found that actual market revenues were lower than predicted. Those prior studies are posted at http://www.cpuc.ca.gov/General.aspx?id=6442452867. PG&E notes that "using models to predict market values [can be] somewhat problematic to the extent that: They tend to assume "perfect" bids that would require more certainty about forward prices than is realistic; They do not necessarily capture operational challenges such as managing SOC, resource-specific limitations, and the many other challenges …" (pg. 56). PG&E notes that CAISO frequency regulation prices would have to be sustained at early 2016 prices to achieve the long-term revenue forecast in the 2013 studies. We agree, as discussed below, that further work needs to be done to compare simulation results to actual market results.

The PG&E report provides many details which can improve understanding of energy storage market value and operations. Following the pilot phase, PG&E plans to continue testing market operations to evaluate spinning reserves and the CAISO flexible ramping product. Among the limitations of the report are that measurement of market performance results are aggregated, and the reasons for them are not always clear. The actual months being analyzed are masked.

The PG&E report can be found at https://www.pge.com/pge_global/common/pdfs/about-pge/environment/what-we-are-doing/electric-program-investment-charge/PGE-EPIC-Project-1.01.pdf. We note that the report does not appear to be posted yet on the CEC website. We also note that EPRI's StorageVETTM tool (www.storagevet.com) can in principle replicate these historical market revenue results with reasonable accuracy; EPRI is working with the participants in the Energy Storage Integration Council (ESIC) to validate model results, in part by using the market revenues of actual projects. Interested parties should contact Giovanni Damato at EPRI at gdamato@epri.com. For additional information on CAISO market participation models, see EPRI, *Energy Storage Valuation in California: Policy, Planning and Market Information Relevant to the StorageVET™ Model*, Technical Update 3002008901, December 2016, also available at www.storagevet.com.

CEC Staff Paper on Bulk Energy Storage in California and CAISO Pumped Storage Modeling

Much of the attention in California has been on the rapid expansion in utility procurement of battery storage to meet the California storage policy requirements. As implemented by the California Public Utilities Commission (CPUC), the 1.325 GW target for new energy storage procured by 2020 for the state's three large investor-owned utilities (IOUs) specifically excluded large pumped storage plants (greater than 50 MW). Other initiatives to procure bulk storage, notably PG&E's 2015-16 request for offers (RFO) for compressed air energy storage (CAES) did not result in new projects. The state legislature and state energy agencies have been examining measures to facilitate development of new bulk storage over the past 2-3 years, with a range of different analyses produced to date, some of which are reviewed here. Project development also continues for a few large new bulk energy storage projects in the region, although the Sacramento Municipal Utilities District (SMUD)'s Iowa Hill 400 MW pumped storage plant was terminated in 2016 after 10 years of development, with higher updated costs and lower assessment of operational needs cited as the reasons.

In late 2015, the California Energy Commission (CEC) held a workshop to evaluate barriers to bulk energy storage, and in July 2016 issued a staff paper on *Bulk Energy Storage in California*, with recommendations on measures to facilitate bulk storage development. As general measures, the report recommends that the state agencies convene a statewide Bulk Storage User Committee for consideration of how to reduce barriers, streamline licensing to reduce the very long development times of large projects, conduct a cost-benefit analysis of bulk storage, particularly for renewable integration, and explore joint ventures that might facilitate financing.

The report focuses on pumped storage, as it "is a proven, efficient, and reliable technology." However, justifying investments to upgrade existing facilities or build new pumped storage projects remains very challenging under current regulatory structures and electricity market economics." With regard to pumped storage plants, the report identifies a series of research topics, both quantitative and with respect to policy and regulation, including: how such plants are compared to other resources in the CPUC's "least-cost/best-fit" requirements for utility procurement; how pumped storage can provide new operational requirements, such as fast ramping; appropriate valuation of black start capability; identification of new value streams; how to incorporate pumped storage into the state's resource and transmission planning processes; methods for allocation of benefits and costs to ratepayers in more than one utility; and how analysis of pumped storage compares to battery energy storage.

As part of the state energy agency initiatives to address these questions, for the past 2 years, the California Independent System Operator (CAISO) has been modeling pumped storage costs and benefits in 40% RPS and 50% RPS scenarios in California (using a production cost model which includes the entire Western Electricity Coordinating Council or WECC). The results to date have been inconclusive. In its *2015-2016 Transmission Plan* (issued on March 28, 2016), the CAISO presented results of modeling a new 500 MW pumped storage in a 40% RPS scenario, in which benefits included energy and ancillary services, as well as the avoided fixed costs of additional renewable generation which would be needed to meet policy goals given forecasts of curtailment (in other words, if the policy target was 40% RPS, but curtailment was found to be 5%, wind and solar "overbuild" scenarios were developed to achieve the 40% target). A new pumped storage plant's annualized costs were estimated at $383.62/kW-year, it was equipped with variable speed pumps, and its efficiency was assumed at 83.3%. The 40% RPS simulations found that the plant's modeled benefits exceeded its costs in the high solar scenarios, but were slightly less than its costs in the high wind scenarios. The primary value was due to energy time-shift of curtailed renewable generation.

The 50% RPS scenario results were presented subsequently in the CAISO *2016-2017 Transmission Plan* (issued on March 17, 2017), and included not only additional renewable overbuild in each scenario but a number of other changes to scenario assumptions. Notably, there is less inflexible non-renewable generation assumed, and, despite the higher RPS target, updated distributed solar estimates resulted in less transmission-connected additional renewables. Due to these assumptions and lower estimated costs of renewable curtailment, there is also lower renewable curtailment in the initial (pre-storage) solution. The scenarios included both 500 MW and 1,400 MW pumped storage plants. These differences in assumptions and other factors lead to a notable change in the cost-benefit results. In contrast to the 40% study, the CAISO finds that the pumped storage plants annualized revenue requirements are greater than annual operational benefits by a factor of about 4:1, due to the changes in the factors listed above. As such, any new plant will need "other sources of revenue streams, which could be developed through policy decisions." The CAISO results are not yet final, and analysis is continuing to evaluate other factors driving costs and benefits, such as assumed renewable curtailment costs.

The increasing conditions of excess generation supply in California – exacerbated in particular during the high hydro conditions of spring 2017, clearly create new opportunities for bulk energy storage. The CAISO analyses, and other studies, have pointed to how sensitive simulations of storage benefits are to changes in assumptions, even when additional renewables are added to the grid. Additional research is needed to verify the economic benefits of bulk energy storage of different types, and how they compare to more distributed energy storage solutions.

The CEC staff paper can be found at http://www.energy.ca.gov/2016publications/CEC-200-2016-006/CEC-200-2016-006.pdf. The CAISO annual transmission planning studies cited are found here: http://www.caiso.com/planning/Pages/TransmissionPlanning/Default.aspx.

CPUC-CAISO Joint Workshop Report on Multiple-Use Applications for Energy Storage

Many energy storage technologies can potentially provide multiple services simultaneously, including to the retail customer, the distribution network and to the bulk power system. The California Public Utilities Commission (CPUC) and the California ISO (CAISO) have labeled the provision of services across these multiple service domains at the same time, "multiple-use applications." On May 15, 2017, the two agencies released a *Joint Workshop Report and Framework: Multiple-Use Applications for Energy Storage*, and held a stakeholder workshop, under CPUC Rulemaking 15-03-011 and the CAISO's Energy Storage and Distributed Energy Resources (ESDER) 2 Stakeholder Initiative. The paper is organized around the following topics: principles for organizing the framework with respect to domain, service and time; principles for compensation; a list of proposed rules for multiple use applications and questions for parties; and a review of regulatory barriers. Some of the key points are reviewed here. We note that the contents of the report may change in response to stakeholder input.

Principles: Domain, Service, and Time

The report begins by expanding on some categorizations of different types of multiple use applications and adding clarifications which have been raised in prior stakeholder input. The paper uses the term "domain" first adopted in the CPUC's storage proceeding (in Decision (D.) 13-10-040) for categorization (1) of the physical point of interconnection of the storage device – customer-sited, distribution-connected, and transmission-connected – but then also adds (2) the services which the device can provide from its location (and respecting any regulatory or operational barriers). The set of service domains is categorized as the following: customer, distribution, transmission, wholesale market, and resource adequacy. There are 20 services within those service domains, which are listed in Table 5 (excerpted from the report). We include this table for comparison to other regions, where service definitions and procurement mechanisms may be different.

Table 5. Storage Service Domains and Primary Services

Service Domain	Service
Customer	TOU bill management
	Demand charge management
	Increased PV self-consumption
	Back-up power
Distribution	Distribution capacity/deferral
	Reliability (back-tie) services
	Voltage support
	Resiliency/microgrid/islanding
Transmission	Transmission deferral
	Black start
	Voltage Support
	Inertia
	Primary frequency response
Wholesale Market	Frequency regulation
	Imbalance energy
	Spinning Reserves
	Non-spinning reserves
Resource Adequacy	System RA capacity
	Local RA capacity
	Flexible RA capacity

The paper attempts to clarify how the two domains are related through a series of proposed rules. First, these rules identify that storage located at the customer domain has the capability, when eligible, to provide most of the services as devices in the distribution and transmission domains, but devices at the distribution domain can only provide services in that domain and the transmission domain, and devices at the transmission domain can only provide services in that domain. Going beyond these basic definitional rules, the paper proposes that resources "interconnected in any grid domain may provide resource adequacy, transmission and wholesale services." In addition, the rules note that resources providing T&D deferral will have specific performance and direct control constraints.

A common question in stakeholder discussions is the prioritization of obligations to provide certain services. To clarify the operating requirements on storage devices providing multiple use applications, the paper distinguishes between reliability and non-reliability services. In the reliability service category are local and flexible resource adequacy capacity, T&D deferral schedules, contingency reserves, frequency regulation, transmission voltage support, and primary frequency control. These services are considered to be crucial to reliability, such that provision "in real time should not be left entirely to the resource operator's financial optimization." This requires a strict hierarchy of uses from which the storage operator may not deviate, with principles delineated in the paper, although exact penalties are not discussed. The paper does note that additional penalties for resource adequacy resources which do not perform as expected in real-time operations may require consideration.

Non-reliability services include the customer-sided services, distribution voltage support, wholesale energy and system resource adequacy capacity. The intention is that these latter services do not directly impact reliability if the storage device deviates from schedules or obligations, or that if they do, the ISO has sufficient time to compensate for these deviations (for example, by procuring additional system capacity). In this case, the ISO and utilities will aim to design "effective market price signals, financial incentives and possibly penalties associated with each use in a multi-use application in order to drive prioritization of those services…"

The paper raises a number of questions for stakeholder consideration regarding these organizing principles. Of interest, the paper asks whether the 20 services is necessary, or whether a simpler categorization into just energy and capacity is sufficient. Also, the paper asks for scenarios where the device may get conflicting instructions from the ISO and the retail customer, for example during periods of excess supply on the grid, and how they can be prevented. As noted, the paper also asks whether stronger performance incentives are needed for bidding and scheduling of RA capacity. We note that these are questions specific to CAISO; other regions, notably PJM, have recently significantly increased performance penalties for capacity resources.

Compensation Principles

The second section of the paper addresses different issues associated with how compensation for multiple use applications should be structured. The paper notes that "We agree with the principle that storage devices may receive revenue from multiple services that are specific and measurable, if those services serve distinct system or customer needs." However, "if energy or capacity is sold twice to provide the same need, at the same time and in the same domain, we are concerned that this counts as double compensation."

As an initial proposition to prevent double compensation, the paper argues that a principle of "incrementality" should apply: "In paying for performance of services, compensation and credit may only be permitted for those services which are incremental and distinct." However, the paper further notes that identifying all specific scenarios to which this principle would apply will require further work. For example, for customer-sited devices, this principle would seek to prevent adding storage after the procurement of other resources (e.g., generation) to serve a need and then claim compensation for the avoided use of the other resource. The paper notes that this is intended to prevent stranded costs.

The paper raises but does not resolve a few other issues related to compensation, including station power rules for devices which provide wholesale services, and options for measuring and metering of such devices. On these topics, the paper asks for stakeholder input.

The CPUC-CAISO report provides a useful next step in organizing information relevant to how devices providing multiple uses are evaluated. The report is available here: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M187/K237/187237488.PDF. The CPUC's storage proceeding webpage is here: http://www.cpuc.ca.gov/General.aspx?id=3462. The CAISO's ESDER 2 stakeholder initiative can be found here: http://www.caiso.com/informed/Pages/StakeholderProcesses/EnergyStorage_DistributedEnergyResourcesPhase2.aspx.

ERCOT Report on DER and Power System Reliability

On March 22, 2017, the Electricity Reliability Council of Texas (ERCOT) issued a report on Distributed Energy Resources: Reliability Impacts and Recommended Changes. Based on filings at the Public Utilities Commission of Texas (PUCT), there are an estimated 900 MW of distributed generation, which include both fossil and renewable resources (some of which are backup power only), located in the retail choice transmission and distribution utility areas, and another 200 MW in the non-retail choice utility areas. Table 6, excerpted from the report, shows how these units are distributed by size and operations in the five competitive choice utilities (Oncor, CenterPoint Energy Houston Electric, LLC, Texas-New Mexico Power, Sharyland, and AEP). ERCOT finds that "based on installed capacity and current rates of growth, these resources do not pose an immediate or near-term reliability concern for the transmission grid." Further, "the environment for DERs in ERCOT is characterized by a combination

Table 6. DER Installations and Capacity in ERCOT Competitive Choice Utilities, 2016

	Self-Dispatched		Intermittent	
Unit Size	Installations	Megawatts	Installations	Megawatts
1 ≤ 10 MW	113	593.4	3	7.8
< 1MW	43	16.0	8,484	75.5
Totals	**156**	**609.4**	**8,487**	**83.3**

of low energy prices and an absence of region-wide regulatory incentives, leading to a penetration growth rate that is much slower than has been witnessed in other regions such as Germany, California, and Hawaii."

Nevertheless, trends in DER development suggest that the growth rate could increase substantially with declining costs and customer interest. The recent additional drivers for DERs observed within the ERCOT market have been demand response through the Emergency Response Service (ERS), mitigation of retail rate demand-charges through the Four Coincident Peak (4CP) rates, and participation in the real-time energy market through Load Zone-level wholesale price response. This report focuses on measures to address potential reliability and operational impacts of DERs, complementing other initiatives by ERCOT to facilitate market participation.

With respect to reliability, ERCOT foresees similar impacts to those identified in other regions and in NERC studies. In particular, the lack of DER visibility could affect operations through inaccuracies in net load forecasting; additional ancillary service reserve procurement; invalid State Estimator results due to incorrect data from distribution circuits; inaccurate load distribution factors in operational studies; reduced or limited reactive power, voltage control and dynamic response to faults; lack of coordination during system restoration; incorrect operation of voltage control equipment due to lack of coordination with the variable active output of solar PV; and potential damage to transmission surge arresters. Section 3 of the report reviews these factors, including experience in ERCOT and other regions.

The report concludes with a set of recommendations. ERCOT observes that "the foundation to the reliable and efficient management of this future distributed grid is visibility" and many of the initial measures are related to improving data collection on current and future DER from the utilities. This includes "a standardized method" for collecting data, and a process for distribution utilities to monitor clusters of unregistered DERs. ERCOT needs data on the "type, Operational Capacity, location, and operational abilities" of DERs. ERCOT will improve forecasting of intermittent DERs and update its short-term and long-term load forecasting tools. In addition, a new forecasting tool will be developed for analysis of self-dispatched DERs that are responsive to wholesale market prices or other signals.

Throughout the report, ERCOT notes that the "responsibility for operation of the distribution grid resides with the distribution service providers (DSPs)." ERCOT's objectives are to improve visibility and ensure reliability. The ERCOT DER reliability report can be found at http://www.ercot.com/content/wcm/lists/121384/DERs_Reliability_Impacts_FINAL.pdf. See also ERCOT's August 2015 concept paper on DERs, which is available here: http://www.ercot.com/calendar/2015/8/25/72783-DREAMTF.

2017 Energy Storage Association Conference: Industry Perspectives and EPRI Engagement

The annual conference of the Energy Storage Association, held in Denver on April 18-20, featured perspectives from senior executives, breakout sessions on specific aspects of energy storage, and a major product expo with over 70 exhibitors. Experts from EPRI's Energy Storage and Distributed Generation Program contributed to several conference sessions.

Industry Outlook

The conference plenary panel discussion explored high-level trends in the industry, with insights from David Eves, President of Xcel Energy; Michael O'Sullivan, Senior VP of Development at NextEra; and Lyndon Rive, President of Global Sales at Tesla Energy.

Eves (Xcel)—whose company is the largest provider of wind power nationwide—emphasized that high wind penetration makes energy storage a strategic priority for Xcel, which expects the share of wind in its generation portfolio to continue growing through 2030. O'Sullivan (NextEra) described energy storage as a "natural progression" of wind and solar, in which NextEra has a major role as a developer.

The panel agreed that pace of energy storage deployment is likely to increase. Eves predicted that "this will all happen faster than we think." Rive (Tesla Energy) highlighted that energy storage is already economic today in certain scenarios. EPRI's own research emphasizes that the value of stationary storage is highly site-specific, and can only be fully assessed with full understanding of both cost and full life cycle benefits.

NextEra's O'Sullivan suggested that we are now in "the second or third inning" of energy storage. While the rate of cost decrease in solar generation took the solar industry by surprise, O'Sullivan expects the cost of energy storage to decrease even faster.

Matt Roberts, executive director of the Energy Storage Association, laid out a vision for the future of the electric grid closely aligned with EPRI's Integrated Energy Network: an electric grid deepening its interaction with natural gas and communication networks. Roberts envisioned 35 GW of stationary storage deployed across the U.S. in 2025—approximately a sixty-fold increase from today's installed base of 575 MW.[15]

Technology Outlook and Maximizing Value

While the meeting was dominated by familiar battery technologies, several emerging technologies were also represented, including two solutions for bulk energy storage. Liquid air energy storage is being developed for deployment by a British company, Highview Power Storage, Inc.[16] A second approach, developed by the Toronto-based company HydroPower, is developing a compressed air energy storage solution that uses constant-pressure air caverns under hydrostatic pressure. Breakout sessions featured flow battery developer UniEnergy Technologies and ice-based cold storage developer CalMac.

While emerging technologies continue to develop and may identify suitable market niches, lithium-ion batteries constitute over 95% of recent storage deployments. Some technologies are inherently more competitive for longer-duration applications, and may gain wider attention if this segment of the market grows. EPRI monitors the performance and cost status of emerging storage technologies through the Technology Innovation Program and the Bulk Energy Storage Interest Group.

15 2013-2016 cumulative deployments in Arizona, California, Hawaii, Massachusetts, New Jersey, New York, PJM and Texas. Source: GTM Research.

16 Highview Power Storage, Inc. was featured during the inaugural quarterly webcast of the Bulk Energy Storage Interest Group, an initiative of the Transmission and Bulk Level Energy Storage project of EPRI's Energy Storage and Distributed Generation program.

A panel session examined the persistent challenge of fully characterizing opportunities for storage to provide value to asset owners across a wide array of tariff environments and potential revenue streams. Experts from EPRI, the National Renewable Energy Laboratory, and private-sector project developers discussed their approaches. Ben Kaun, EPRI storage program manager, demonstrated EPRI's publicly available software tool for energy storage project valuation, StorageVETTM. This recently launched tool allows the user to define detailed technology and application scenarios, and determines project value and asset operation forecasts.[17]

EPRI Engagement

EPRI's Energy Storage and Distributed Generation Program was deeply engaged in the ESA proceedings through participation in conference panels, an adjoining meeting of the Energy Storage Integration Council (ESIC), and selective travel scholarships to student attendees.

EPRI's Energy Storage Integration Council convened following the conference, hosted by Xcel Energy. Approximately 50 companies joined the discussion, representing the utility, supplier, consulting and research communities. Discussions focused on identifying the current industry gaps and prioritizing new research areas. Presentations from LG Chem, Southern California Edison, and Pacific Gas and Electric highlighted the practical application of published ESIC tools and guidelines in projects or incorporated into business practices. Five different breakout sessions focused on development of forthcoming ESIC publications and collected strategic direction feedback for ESIC. The sessions included new initiatives in communication and control, safety, procurement, testing and specification, and storage value analysis. Notes from the ESIC meeting are posted on the ESIC collaboration site (http://collab.epri.com/esic).

During the main conference, EPRI energy storage experts contributed to three conference sessions:

- "Energy Storage 101" workshop (Haresh Kamath, Brittany Westlake, Ben Kaun, Steve Willard)
- Breakout session: Resilient design of integrated microgrid systems (Steve Willard)
- Panel discussion: Determining value of energy storage systems (Ben Kaun)

EPRI also awarded several travel scholarships that enabled graduate students from a variety of disciplines to attend the conference, to engage talented early-career professionals in the opportunities and challenges of energy storage's growing role in the energy sector.

17 For more information on StorageVET, see http://www.storagevet.com/.

In Case You Missed It – News Bites

US Energy Storage Market Has Largest Quarter Ever

The United States deployed some 234 MWh of energy storage in the first three months of 2017, making it the biggest quarter in the history for the U.S. storage market, according to the Energy Storage Association (ESA) and GTM Research U.S. Energy Storage Monitor.

"Much of this growth can be attributed to a shift from short-duration projects to medium- and long-duration projects in the utility-scale market, along with a surge of deployments geared to offset the Aliso Canyon natural gas leak," said Ravi Manghani, GTM Research's director of energy storage. "Although, the industry shouldn't get too comfortable, as with fulfilment of Aliso Canyon deployments, there aren't that many 10+ megawatt-hour projects in the 2017 pipeline, indicating that the first quarter may be the largest quarter this year."

Front-of-meter deployments grew 591 percent year-over-year, boosted by a few large projects in Arizona, California and Hawaii. In all, front-of-meter energy storage represented 91 percent of all deployments for the quarter. The behind-the-meter market segment, which is made up of residential and commercial energy storage deployments, declined 27 percent year over year in megawatt-hour terms. The report attributes the slowdown to a pause in California's Self-Generation Incentive Program.

California will remain the leader of the U.S. storage market over the next five years, followed by Arizona, Hawaii, Massachusetts, New York and Texas.

GTM Research expects the U.S. energy storage market to grow to roughly 2.6 GW in 2022, almost 12 times the size of the 2016 market. By 2022, the U.S. energy storage market is expected to be worth $3.2 billion, a tenfold increase from 2016 and a fivefold increase from this year. Cumulative 2017-2022 storage market revenues will be $11 billion.

FuelCell Energy to Install 1.4 MW CHP Plant at Trinity College

Trinity College in Hartford, CT, and FuelCell Energy have announced an agreement to install a 1.4 megawatt fuel cell power plant on campus to generate both electricity and steam.

The combined heat and power (CHP) plant will enable Trinity to achieve a 39 percent reduction in CO2, to decrease fuel consumption by 35 percent, and to reduce annual energy costs, according to Trinity and FuelCell Energy.

"Trinity is committed to enhancing environmental awareness, responsibility, and sustainability throughout our College community and this on-site fuel cell power solution is a first step," said Dan Hitchell, vice president for finance and operations at Trinity.

FuelCell Energy, based in Groton, CT, will install power plant and provide long term operation and maintenance. Trinity College will pay for power as it is produced, avoiding a capital investment in power generation. The fuel cell plant can operate independently from the grid, allowing it to support future implementation of a campus micro-grid, the school reported.

FuelCell Energy says the power plant will allow the college to achieve "overall system efficiency upwards of 70%."

According to FuelCell Energy, fuel cell power plants are well-suited for schools as they are clean, quiet and efficient, and are easily sited because they don't require much land. Because they are located on-campus, no transmission is needed, which is an added cost to grid-delivered power. When configured for combined heat and power, the university can then lessen use of combustion-based boilers for heating which reduces their overall fuel usage.

Other learning institutions with fuel cell power plants include University of California, San Diego, Central Connecticut State University, California State University San Bernardino, and San Francisco State University.

Forecast: 2.1 GW of Hybrid Storage by 2026

Global deployment of hybrid energy storage systems (HESSs) that combine features of multiple technologies could grow from 78.6 MW in 2017 to 2.1GW in 2026, according to a report from Navigant Research, which said the deployments could "change the energy storage landscape."

HESSs integrate two or more energy storage technologies with complementary operating characteristics. These systems deliver power capacity, energy duration, and cycle life in a single system that is not achievable by any one energy storage technology.

"Much of the growth of the HESS industry is expected to occur alongside the maturation of pure-play battery energy storage technology," says Ian McClenny, research analyst with Navigant Research. "The future of the HESS industry in global markets will be largely decided by customer and grid operator needs, evolving market structures to value flexible resources favorably, and the local utilities' views on new technology."

The report, Hybrid Advanced Battery Markets, analyzes the global market for utility-scale and customer-sited HESSs. The study examines the market drivers and barriers and technological trends affecting the deployment of HESSs around the world. Global forecasts for power capacity, energy capacity, and revenue, segmented by region, technology, and market segment, extend through 2026. The report focuses on current and future technologies in the HESS market, including battery-battery, battery-capacitor, and other hybrid systems.

Calendar

June 26–30, 2017: ASME 2016 15th Fuel Cell Science, Engineering and Technology Conference, Charlotte, North Carolina. http://calendar.asme.org/EventDetail.cfm?EventID=32438

July 10-13, 2017, Intersolar North America Conference and Exhibition, San Francisco, California, www.intersolar.us/en/home.html

July 11–13, 2017: electrical energy storage Program at Intersolar North America, San Francisco, California. http://www.electrical-energy-storage.events/en/home.html

July 25 - 27, 2017, Grid Evolution Summit, Washington, D.C., https://sepapower.org/event-complex/grid-evolution-summit/

August 8-10, 2017: Energy Storage North America (ESNA), San Diego, California. http://www.esnaexpo.com/

September 10–13, 2017: Solar Power International, Las Vegas, Nevada. http://www.solarpowerinternational.com/

September 12–14, 2017: The Battery Show, Novi, Michigan. http://www.thebatteryshow.com/

October 11-13, 2017, Electrical Energy Storage Applications and Technologies (EESAT), San Diego, California, http://energystorage.org/events/2017-electrical-energy-storage-applications-and-technologies-eesat

November 7-9, 2017, Fuel Cell Seminar & Energy Exposition, Long Beach, California, www.fuelcellseminar.com/

December 12-13, U.S. Energy Storage Summit, San Francisco, California, https://www.greentechmedia.com/events/live/u.s.-energy-storage-summit-2017

EPRI Power Delivery & Utilization Advisory Meeting

- **September 11–13, 2017:** Denver, Colorado
- **February 5–7, 2018:** Coronado, California
- **September 17–19, 2018:** Atlanta, Georgia

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