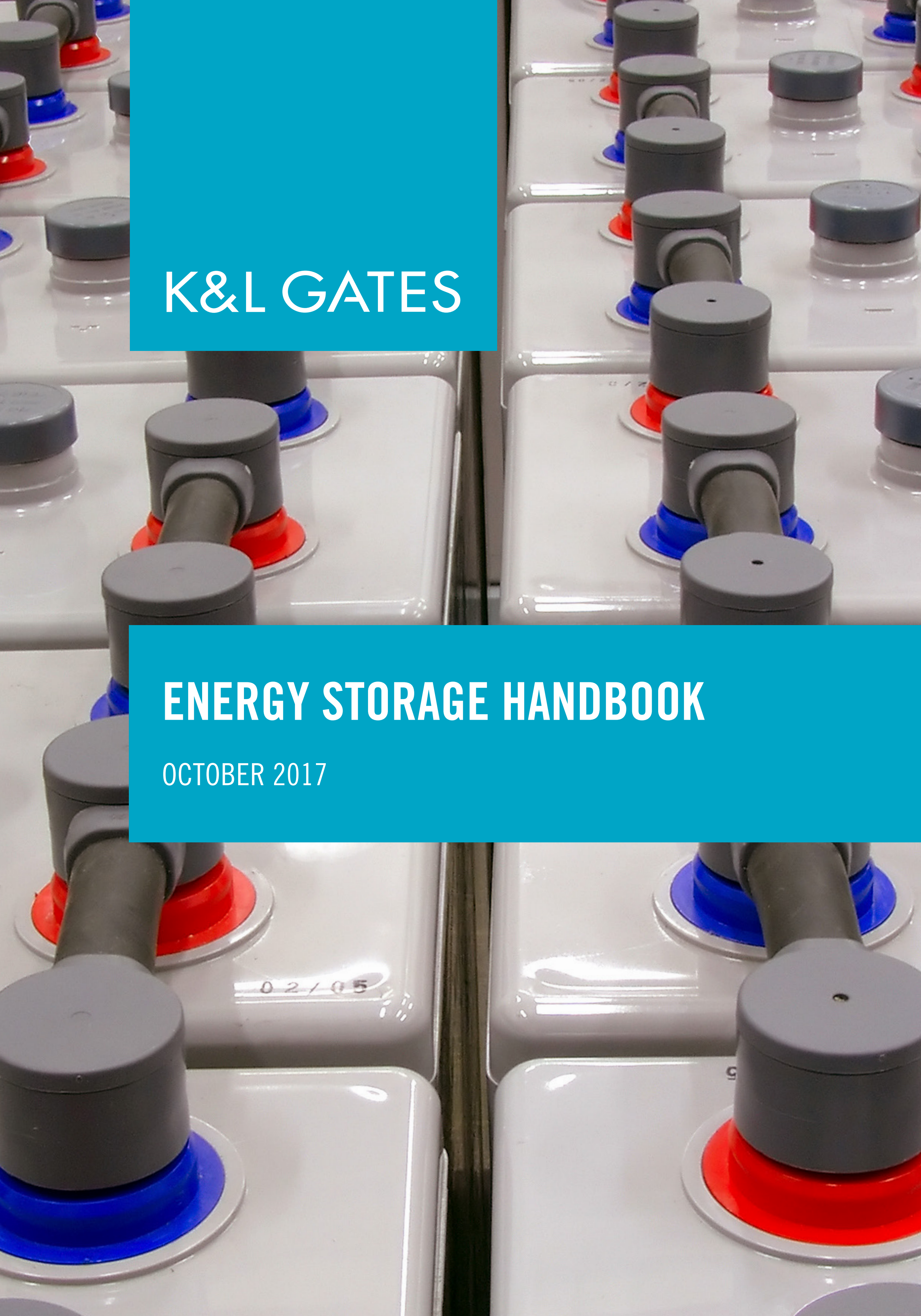
K&L GATES

ENERGY STORAGE HANDBOOK

OCTOBER 2017



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INTRODUCTION

As of today, approximately 800 MW of advanced energy storage technologies have been deployed in the United States, with nearly all of that capacity coming online in the last decade. New technologies, use cases, and storage-friendly policies and regulations seem to be announced on a weekly basis. But how did energy storage get here, and where is it going?

Starting in the late 1800s, the popularity of electric lighting spurred the development of small, independent electric grids across America, some using direct current to extend power just a few city blocks. Before long, centralized coal, gas, and other large fossil fuel-burning power stations were built, and it became economical to consolidate existing grids and transport electricity across long distances using high-voltage alternating-current transmission lines. Transmission lines began crossing state lines, and the Federal Energy Regulatory Commission (FERC) became responsible for regulating the transfer and sales of wholesale power flowing across the nation's transmission infrastructure while state public utilities commissions regulated private utilities that used lower-voltage distribution lines to service retail consumers. For many years, providing power was aided by the predictable electrical output of large, centrally located generators fired by steady supplies of fossil fuels, with hydropower and nuclear power plants eventually evolving to play a supporting role in ensuring a stable electricity supply.

By the late 20th century, policy makers concerned with power sector emissions and energy security issues began focusing on ways to decarbonize the grid. A combination of tax credits, mandates, grants, and other incentives (mostly lead by state governments) spurred the rapid development of carbon-free and renewable power generation assets, including wind and solar facilities. Technological advancements allowed these new renewable facilities to be large enough to provide hundreds of megawatts (MW) of electricity from a central location or to be small enough to power individual homes using solar panels on the roof. Many wind and solar technologies have become cost-competitive with fossil-fuel generators and do not require the operational expense of fuel to generate electricity. Several large coal and natural gas plants have ceased operations recently, citing competition from cheaper electricity produced by renewable energy resources.

While wind and solar facilities have obvious environmental advantages, they are “intermittent” resources, meaning that their electricity production varies when the sun does not shine and the wind does not blow. Wind- and solar-generated electricity is thus subject to the mercy of Mother Nature and tends not to be produced in exact quantities at the precise moment in time when consumers need it. Too much or too little power on the grid can lead to increased wear-and-tear, short circuits, outages, and high power bills for consumers. States are nevertheless pressing ahead with their goals to supply more electricity from renewable and distributed resources, which has the potential to stress the grid in unpredictable ways.

Energy storage resources help with the transition from traditional predictable resources to renewable, intermittent resources, and provide many other supplementary benefits to the grid. By capturing energy at the time it is generated and using it on demand at a later time, energy storage technologies are poised to play a key role in the United States’ move from large, centrally located power generation to a more distributed and renewable energy supply. The deployment of energy storage systems is expected to grow exponentially in the coming decades, either in stand-alone facilities or co-located with renewable resources to provide more consistent or on-demand power output. Energy storage advocates praise the technology’s flexibility, as variants can be installed from residential to utility scale, perform as generation or load, can provide several market products, and can be used even to defer massive investments in transmission and distribution infrastructure. With some industry watchers predicting the price of storage to drop 50% in the next few years, we expect to see consumers, businesses, regulators, and utilities continue to embrace energy storage technologies to meet their grid needs.

In sum, integrating energy storage technologies into our electric grid infrastructure promises a fundamental reconfiguration of how our nation produces and uses electricity with the hope of a more reliable, resilient, and cost-effective grid.

This Energy Storage Handbook (Handbook) is designed to be a basic primer on what energy storage is, how it is regulated by federal and state governments, and what sorts of issues are encountered when such projects are financed and developed. While this Handbook is not meant to be a definitive catalog of every energy storage law and issue existing in today’s marketplace, we have endeavored to highlight the most common regulatory and development issues faced by our clients and the industries that we serve. We anticipate updating this Handbook as additional states and stakeholders continue to implement energy storage resources into the marketplace.

We hope you find it useful, and welcome your feedback.

- *Buck Endemann, Partner*
K&L Gates LLP

ENERGY STORAGE TECHNOLOGIES

The term "energy storage" includes a wide array of technologies that capture energy at one point in time, store it, and release that energy later when it is needed or when it is profitable to do so. While some energy storage technologies have been in commercial use for over a hundred years (e.g., pumped hydro), many storage technologies are relatively new or are still in the development stage. Below are short descriptions of the most common forms of storage technologies.

BATTERIES

Battery energy storage technologies involve electrochemical processes that convert stored chemical energy into electrical energy. These different processes generally fall into one of two categories: solid-state batteries and flow batteries.

Solid-state batteries are variations on the conventional batteries that power consumer electronics all over the world. At its most basic level, the solid-state battery is a self-contained cell with one positively charged electrode (cathode) and one negatively charged electrode (anode), with a liquid or gel based electrolyte in between. When the anode and cathode are connected to an external circuit, the electrolyte allows ions to move from the anode to the cathode within the battery to generate a current that can flow out of the battery onto the external circuit and perform work.

Flow batteries accomplish the same conversion of stored chemical energy into electrical energy but use a completely different design. Rather than storing chemical energy within electrodes, flow batteries store chemical energy in fluid electrolytes that are kept in separate tanks—one positively charged (catholyte) and one negatively charged (anolyte)—and pumped past each other on either side of a permeable membrane. When electrodes on either side of the membrane are connected to an external circuit, the membrane allows ions to move from the anolyte to the catholyte to generate a current that can flow out of the battery onto the external circuit and perform work.

Because of the detached liquid tanks required for the electrolytes, flow batteries offer the potential of nearly unlimited longevity as the tanks can be continuously refilled with freshly charged electrolytes. The current technology for flow batteries, however, is comparatively less developed than solid-state batteries and more costly to build.

Both solid-state batteries and flow batteries have been developed using a variety of different chemical components. For example, solid-state batteries have been developed using lithium-ion, nickel-cadmium, and sodium-sulfur cells, and flow-battery technologies have included iron-chromium, vanadium, and zinc-bromine batteries. These different electrode and electrolytic materials, battery designs, and varying technological maturities each result in different operating and performance attributes as well as different costs.

Through the first half of 2017, lithium-ion solid state batteries made up nearly all the market share for energy storage while vanadium flow batteries and lead-acid solid state batteries represented a much smaller portion of the market.

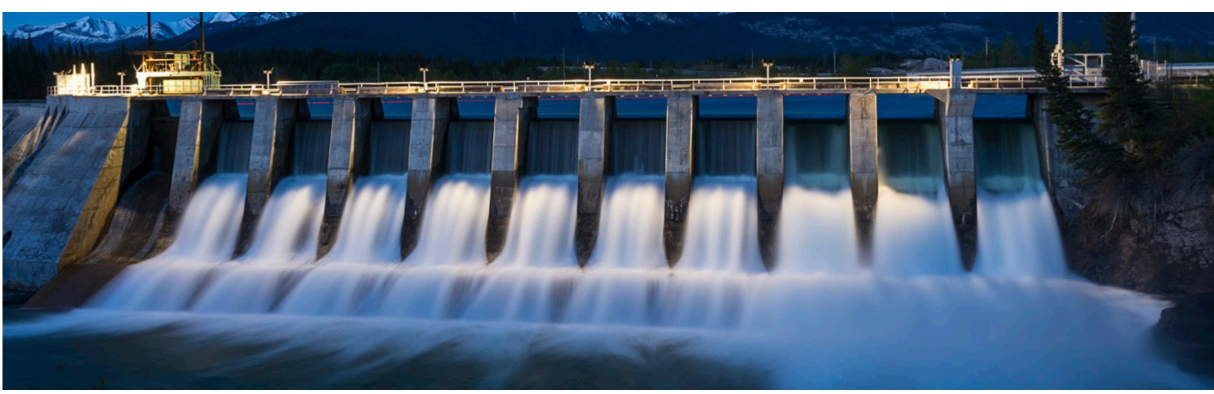
Technological advancements have improved the reliability and output capacity of and have reduced significantly battery technology costs in recent years.

FLYWHEELS

Flywheel storage technologies convert the energy of a rotating mechanical device into electrical energy. Flywheels use electrical energy to drive a motor that spins a mechanical device to increase its rotational speed, effectively storing electrical energy in the form of kinetic energy, which can then be called on instantaneously to discharge from the spinning rotational device as electricity. Flywheels have very fast response and ramp rates and can go from full discharge to full charge within a few seconds or less. They are well-suited to providing power quality and reliability services as well as fast regulation and frequency response, although their ability to provide long-discharge or capacity services is currently limited. Flywheels have traditionally been made of steel that rotates on conventional bearings; however, in recent years a wide variety of new materials have also been employed, including carbon fiber and magnetic bearings, which have enabled significantly increased rotational speeds and reduced resistance.

PUMPED HYDRO

Pumped hydroelectric storage converts the stored kinetic energy of water held in an elevated retaining pool into electrical energy. Pumped energy storage uses electric energy to power pumps that push water up to the elevated retaining pool, effectively and cheaply storing electrical energy in the form of potential energy.



When electricity is less abundant and more expensive, the water is converted back into kinetic and then electrical energy by flowing down from its elevated position through a turbine. Pumped energy storage facilities tend to be large-scale facilities with the ability to respond to large electrical load changes very quickly. Due to the mature state of pumped hydro technology, however, some jurisdictions limit the ability of large-scale pumped hydro facilities to satisfy energy storage mandates favoring new technologies instead.

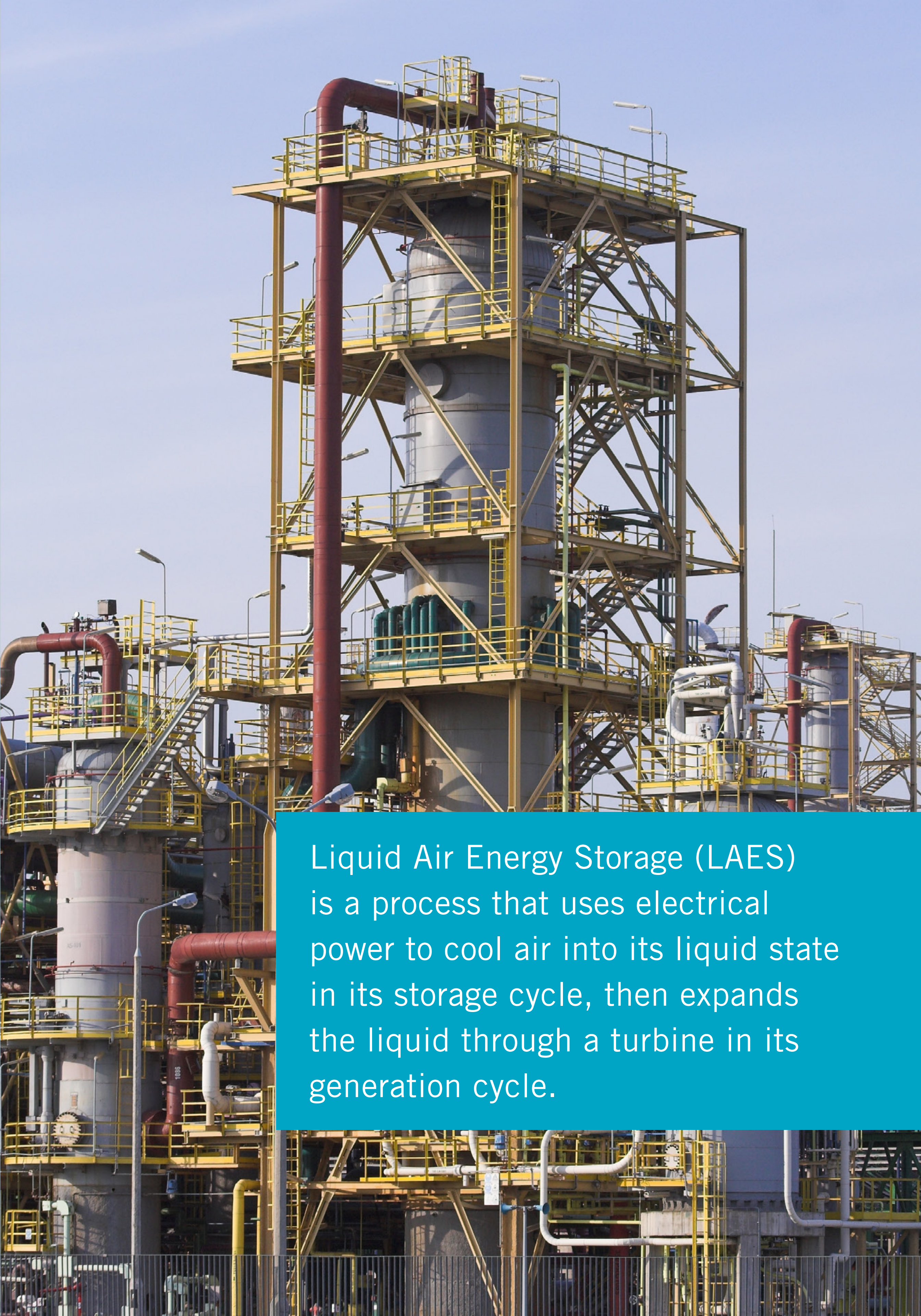
While using the force of falling water is by far the most common form of "gravitational" storage, other materials have also begun to be tested recently, including gravel or cement-filled railcars that are released from elevated positions to generate electricity following the same basic principles of physics.

COMPRESSED AIR ENERGY STORAGE (CAES)

CAES facilities compress ambient air and store it under pressure. When the CAES facility is needed to supply electricity, the pressurized air is heated and expanded to power turbines. CAES systems are similar to many pumped energy storage applications in terms of their broad range of applications, including balancing energy, ancillary services, and black start services, as well as CAES's large output and storage capabilities. CAES, however, is still in the early stages of its technological development, with less than a handful of large-scale projects currently in operation around the world.

THERMAL

Thermal energy storage can be achieved by a wide variety of technologies using resources that temporarily store energy in the form of heat or cold. For example, thermal energy technologies include using solar radiation to heat molten salt to store energy in the form of heat, which can then be used later to produce steam to power a turbine. Liquid Air Energy Storage (LAES) is a process that uses electrical power to cool air into its liquid state in its storage cycle, then expands the liquid through a turbine in its generation cycle. LAES can be effectively paired with industrial applications and use waste heat to boost efficiency and can provide long duration, large capacity energy storage. Thermal energy storage also encompasses technologies that allow buildings to use cheaper, off-peak electricity to power cooling equipment to produce ice or other cooled materials, which can then be used in the building's cooling system when electricity is more expensive. Thermal technologies can vary widely in storage media, facility size, progress of technological development, and cost.



Liquid Air Energy Storage (LAES) is a process that uses electrical power to cool air into its liquid state in its storage cycle, then expands the liquid through a turbine in its generation cycle.

LAWS AND REGULATIONS SHAPING ENERGY STORAGE DEVELOPMENT

FEDERAL LAWS AND REGULATIONS

Federal Energy Regulatory Commission Orders

Federal policy and regulatory treatment of energy storage resources recognizes the importance of this emerging and unique grid resource and provides opportunities to integrate energy storage into wholesale power markets. The FERC also appreciates that further change is necessary to fully recognize the value that energy storage provides. FERC continues to review rules governing compensation and interconnection to ensure that storage resources can efficiently interconnect with the grid and receive a just and reasonable rate for their services. This section provides an overview of relevant FERC orders and proposed rulemakings that have shaped energy storage development and outlines the regulatory requirements for energy storage resources to participate in the organized wholesale markets.

Significant FERC Orders and Policy Statements Affecting Energy Storage

FERC has issued several orders and policy statements creating opportunities for energy storage resources in ancillary services and other organized wholesale markets.

Opportunities for Non-Generation Resources - FERC Order 890

A key moment in the ability for energy storage resources to participate in wholesale markets began with the implementation of FERC Order 890. One aspect of Order 890's reforms to prevent undue discrimination and preference in transmission service involved changes to FERC's pro forma open access transmission tariff that opened energy and ancillary services markets to non-generation resources, including energy storage. In particular, the reforms opened markets for non-generation resources capable of providing reactive supply, voltage control, regulation, frequency response, imbalance, spinning and supplemental reserve services.

Frequency Regulation - FERC Order 755

Frequency regulation service is one of the tools used to balance short-term supply and demand on the transmission system. In 2011, FERC adjusted its frequency regulation compensation rules to recognize and properly reward the fast-ramping capabilities of resources like battery energy storage technologies. FERC determined that the existing frequency regulation compensation practices in regional transmission organizations (RTOs) and independent system operators (ISOs) resulted in unjust and discriminatory rates because the compensation methods in those markets failed to acknowledge frequency regulation services provided by faster-ramping resources. Order 755 required RTOs and ISOs to file compliance tariffs that would compensate frequency regulation resources based on the actual service that those resources provided. This new compensation system included a capacity payment accounting for the marginal unit's opportunity costs and a performance payment that rewarded a particular resource when it accurately followed a dispatch signal. Overall, Order 755 increased the pay for quick-response sources that bid into frequency regulation service markets, such as storage batteries or flywheels.

Opportunity for Ancillary Services Revenues - FERC Order 784

FERC Order 784 provided further revenue opportunities for energy storage resources by allowing such resources to sell imbalance and operating reserve services at market-based rates. Previously such services had been provided by the transmission operator at cost-of-service or by self supply. In addition to creating a new revenue opportunity in which energy storage resources could participate, Order 784 also required transmission providers to place greater value on speed, accuracy, and performance when procuring ancillary services

Interconnection of Storage Resources through Small Generator Interconnection Procedures (SGIP) - FERC Order 792

FERC amended its pro forma SGIP and pro forma Small Generation Interconnection Agreement to cover "storage for later injection of electricity." The SGIP applies to generating facilities and storage resources that are less than 20 MW and allows for fast track processing of interconnection requests for facilities that satisfy certain eligibility criteria. To determine whether a storage device can interconnect under the SGIP or whether it qualifies for the fast track process, the storage device's capacity is deemed to be equal to the maximum capacity that the device is capable of injecting into the transmission provider's system.

Additional Opportunities for Ancillary Services Revenues - FERC Order 819

Building on Order 784's reforms, FERC's Order 819 expanded the scope of ancillary services that can be provided by energy storage resources to include

Overall, Order 755 increased the pay for quick-response sources that bid into frequency regulation service markets, such as storage batteries or flywheels.

primary frequency response service (as distinct from regulation service). The order defines primary frequency response service as "a resource standing by to provide autonomous, pre-programmed changes in output to rapidly arrest large changes in frequency until dispatched resources can take over." As a result, energy storage resources that can capably provide such service have the ability to participate in a new revenue stream available to them.

Demand Response Opportunities - FERC Orders 719 and 745

Because behind-the-meter energy storage, in particular, can serve as an effective demand response resource, FERC's seminal demand response orders also opened revenue streams for energy storage systems. FERC issued Order 719 in 2008 and directed RTOs and ISOs to make several reforms to ensure comparable treatment of demand response resources in organized energy markets. The reforms included requiring RTOs and ISO to create new bidding parameters and accept bids from demand response resources for ancillary services. In 2011, FERC issued Order 745 to ensure that demand response resources participating in the organized markets were compensated at the same rate as generation. Although generators challenged FERC's authority to issue Order 745, in *EPSA v. FERC* the Supreme Court found that the Federal Power Act authorized Order 745's regulation of demand response, which did not impinge on state jurisdiction.

Shortage Pricing Reforms - FERC Order 825

In Order 825, FERC established settlement interval and shortage pricing requirements for organized markets. Order 825 requires each RTO/ISO to trigger shortage pricing for a dispatch interval during which a shortage of energy or operating reserves occurs. The shortage pricing requirement promulgated in Order 825 is expected to encourage investment in energy storage, as one of the primary goals of shortage pricing is to facilitate long-term market entry of new supply resources (i.e., storage resources) and exit of resources that are no longer economic.

Energy Storage Resources in Transmission Planning - FERC Order 1000

Energy storage resources are playing a greater role in transmission planning processes as "nonwires" alternatives. In Order 1000, FERC required transmission providers to consider proposed "nontransmission alternatives"—including energy storage, demand response, and distributed generation—on a comparable basis with transmission solutions as part of their regional transmission planning. Despite this requirement, Order 1000 did not provide concrete instructions on how to achieve comparable treatment for nontransmission alternatives in such planning efforts, and cost recovery issues for nontransmission alternatives remain unresolved. Accordingly, while Order No. 1000 attempted to create opportunities for energy storage resources to be considered in the regional planning processes, challenges and uncertainty remain in their actual deployment.

Policy Statement on Cost Recovery for Electric Storage Resources

In January 2017, FERC issued a policy statement clarifying that an electric storage resource may provide transmission or grid support services at a cost-based rate while also participating in the RTO/ISO markets and earning market-based revenues. The policy statement, however, acknowledged that implementation details would need to be addressed on a case-by-case basis. Energy storage resources seeking to provide transmission or grid support services at a cost-based rate while also recovering market-based revenues will need to address: (1) the potential for double recovery if the energy storage resource provides services at both cost-based and market-based rates; (2) the potential for the energy storage resource's combined rate recovery to cause adverse market impacts; and (3) the level of control an RTO/ISO may have over operating an electric storage resource without jeopardizing independence.

FERC Proposed Rules

Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators (Energy Storage NOPR)

In November 2016, FERC released the Energy Storage NOPR to develop compensation models and participation rules for energy storage resources and distributed energy resource aggregations in the organized wholesale electric markets.

In the Energy Storage NOPR, FERC noted that current participation models in the RTOs/ISOs may not sufficiently recognize energy storage resources' unique physical and operational characteristics and allow them to compete based on their technical abilities to provide traditionally defined grid services. The NOPR would require each RTO and ISO to revise its tariff to create a participation model that accommodates electric storage resources so they can effectively participate in the organized wholesale markets.

FERC also proposed requiring each RTO/ISO to revise its tariff to allow distributed energy resource aggregators—including but not limited to aggregations of electric storage resources—to enter as market participants. Using technology to integrate the power qualities of many small storage resources at disparate locations allows them to function as a "virtual power plant" to aid grid stability. Under the Energy Storage NOPR, each RTO/ISO would be required to establish market rules on eligibility, locational requirements, distribution factors, and data requirements, among other things, for distributed energy resource aggregators. Comments on FERC's proposal were filed in February 2017. As of the date of publication, an order from FERC to adopt a final rule had not been issued[1].

Reform of Generator Interconnection Procedures and Agreements (Interconnection NOPR)

FERC continues to review opportunities to enhance the interconnection process, including faster processes for interconnecting energy storage resources. In December 2016, FERC released the Interconnection NOPR in response to complaints from interconnection customers over systematic inefficiencies, discriminatory practices, and lack of transparency in the interconnection process. FERC's Interconnection NOPR sought comment on three broad categories of reform: (1) improving certainty and predictability in the interconnection process; (2) improving transparency by providing more information to interconnection customers; and (3) enhancing interconnection processes by promoting underutilized interconnections, providing interconnection service earlier, and/or accommodating changes in the development process.

FERC noted that expedited and more efficient interconnection processes may be particularly beneficial to energy storage resources because such resources can often be developed and constructed faster than existing processes allow. Additionally, in connection with potential enhancements to the interconnection process, FERC proposed a requirement for transmission providers to evaluate their methods for modeling energy storage resources in interconnection studies to identify whether current modeling and study practices adequately account for the unique operational characteristics of electric storage resources.

Requirements to Provide Primary Frequency Response (Primary Frequency Response NOPR)

In November 2016, FERC proposed modifications to the pro forma Large Generator Interconnection Agreement and the pro forma Small Generator Interconnection Agreement to require all new large and small generating

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[1] In 2016, the California Independent System Operator adopted tariff provisions allowing similar aggregations of distributed energy resources, and such aggregations are starting to be developed in California.

facilities, both synchronous and non-synchronous, to install, maintain, and operate equipment capable of providing primary frequency response as a condition of interconnection. The Primary Frequency Response NOPR did not include provisions specific to electric storage resources. Several commenters noted, however, that by failing to address electric storage resources' unique technical attributes the Primary Frequency Response NOPR's requirements could pose an unduly discriminatory burden on such resources.

In response to these concerns, FERC issued a request for supplemental comments in August 2017, seeking additional information to better understand (1) the performance characteristics and limitations of electric storage resources; (2) potential ramifications to electric storage resources from the proposed primary frequency response requirements; and (3) what changes are needed to address the issues raised by stakeholders. FERC also sought comments on whether there are reasonable parameters or requirements that could apply to electric storage resources' provision of primary frequency response.

FEDERAL TAX INCENTIVES

For many years, federal tax incentives have played an important role in developing preferred conventional and renewable energy resources. Energy storage resources can also benefit from certain federal tax incentives, particularly when those resources are paired with renewable energy facilities. Although federal legislative attempts have failed to provide the energy storage industry with its own tax credit, some energy storage may qualify for an investment tax credit (ITC) or a production tax credit (PTC) when developed alongside qualifying resources.

Tax Credits for Renewable Energy Property, Generally

Section 48 of the Internal Revenue Code (the Code) provides a 10% or 30% ITC for an investment in certain renewable energy facilities in the year in which such facilities are placed in service. Solar facilities currently qualify for a 30% ITC. Code Section 45 provides for PTCs when electricity produced by certain renewable energy facilities (usually wind) is sold to a third party during the ten years after the facility was "placed in service." The PTC rate is adjusted annually. The maximum PTC rate for electricity sold in 2017 is 2.4 cents per kilowatt hour of electricity sold. While the PTC is being phased out for wind facilities, the ITC will begin phasing out for solar in 2020.

Qualification of Energy Storage Property for the ITC and PTC

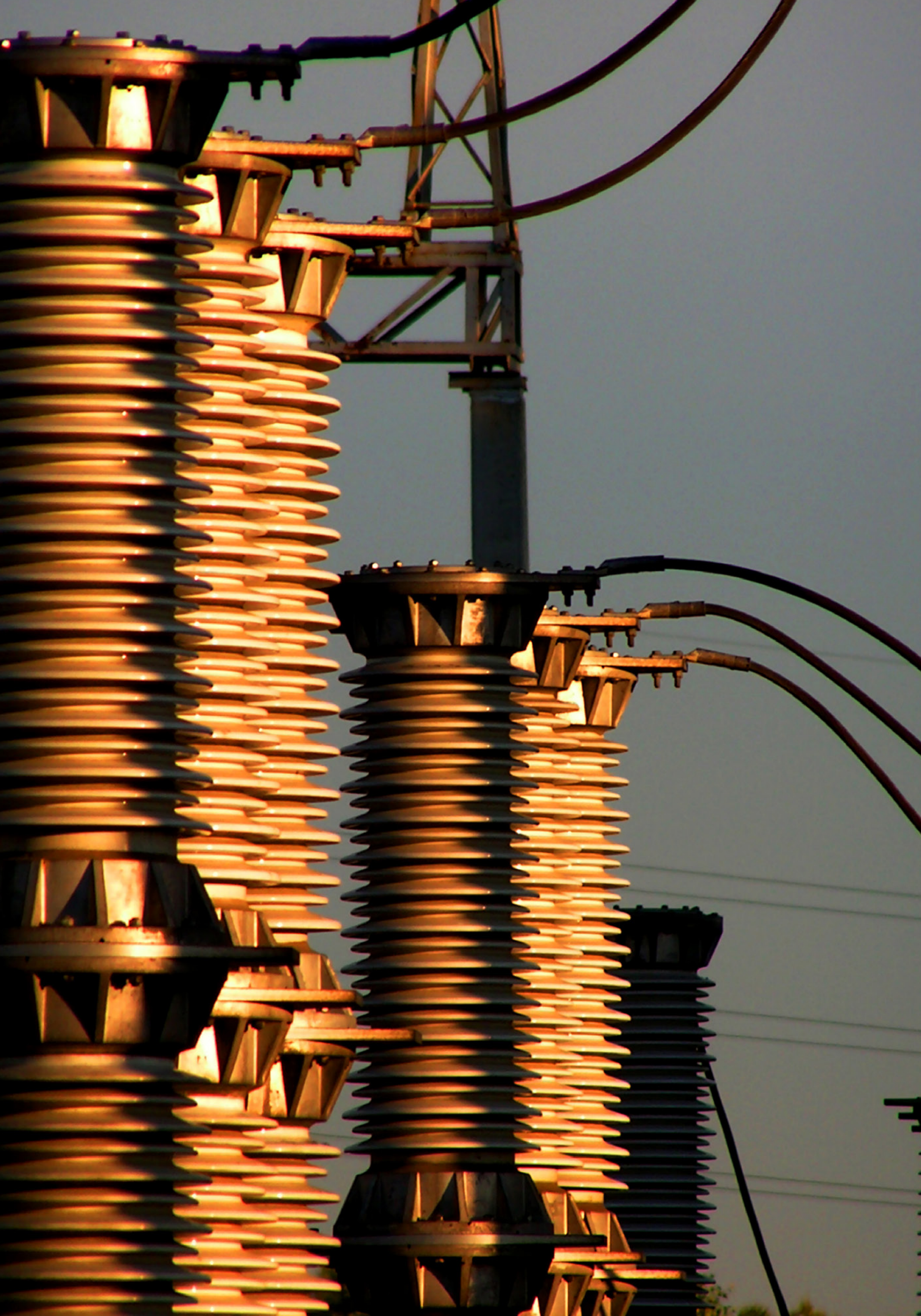
Unlike wind and solar generating facilities, stand-alone energy storage resources are not themselves eligible for the ITC or PTC. However, the ITC and PTC should generally be available for energy storage equipment that is incorporated into qualifying wind and solar (and other renewable energy) facilities.

The cost of energy storage equipment generally qualifies for the ITC if such equipment is incorporated into a facility that qualifies for the ITC, at least 70% of the power stored in the battery comes from qualified resources, and the facility and storage equipment are concurrently placed in service. The ITC is also available on the same basis for qualified energy facilities that are refurbished with energy storage technologies, provided that the value of the used equipment incorporated into the facility is worth no more than 20% of the total value of the facility. This provides opportunities to claim the ITC for energy storage devices installed at existing, proven qualified energy facilities. This may be of particular benefit in the secondary market for facilities that have been operating longer than the ITC or 1603 grant recapture period (five years following placement in service).

Although less certain, sales of electricity produced originally by a PTC-qualified facility and then stored in energy storage equipment should continue to qualify for the PTC if the facility is operated under certain technical parameters. This limitation arises from the requirement that the PTC is available only for electricity produced by a “qualified facility.” A qualified facility includes all property that is functionally interdependent and is used to produce electricity using a qualified resource (for example, wind). This property generally includes, for example, equipment used for power conditioning, which may include voltage regulation (power flow attributes sometimes provided by energy storage systems). Because the PTC is available only for electricity *produced* by a qualified facility, however, there is some uncertainty about whether the PTC is available for power stored in and later released from on-site energy storage equipment independent of the power generated from a qualifying facility.

Depreciation Deductions

For federal income tax purposes, the basis of tangible property, including energy storage equipment, is recovered over a specified useful life using one of several methods. The favored method is the modified accelerated cost recovery system or MACRS, which generally provides for accelerated depreciation deductions in the earlier years of a property’s useful life. Energy storage equipment incorporated into an ITC-qualified solar facility and placed in service concurrently with that facility can be depreciated using the MACRS method over five years. This five-year depreciation period could also potentially apply to energy storage equipment that is incorporated into a wind facility, if that wind facility would qualify for the ITC by reference to the requirements applicable to solar energy property. Absent these conditions, energy storage equipment is otherwise depreciated using the MACRS method over seven years.



STATE LAWS, REGULATIONS, AND POLICIES

California

California's Energy Storage Mandates and Rebates

California has several laws and incentives driving the adoption of large-scale and behind-the-meter energy storage resources, making it the clear leader in installed and procured energy storage systems. Many of these initiatives are set forth in the California Energy Storage Roadmap, an interagency guidance document jointly developed by the California Independent System Operator (CAISO), the California Energy Commission (CEC), and the California Public Utilities Commission (CPUC).

California's primary legislative efforts include two laws requiring utilities to procure significant amounts of energy storage resources and a revamped SGIP that provides consumer rebates worth approximately $450 million through 2019. California has also taken the lead in its efforts to properly value energy storage technologies' many contributions to grid stability and reliability.

California AB 2514 - The "Original" Energy Storage Procurement Bill

California Energy Storage Bill AB 2514 became law in September 2010. With the goal of encouraging widespread adoption of energy storage, the bill required the CPUC to determine appropriate targets for each large investor-owned utility (IOU) to procure viable and cost-effective energy storage systems. The bill also required the governing board of each local municipally owned electric utility to determine appropriate targets.

Under AB 2514 and related CPUC decision-making, California IOUs are required to collectively procure and install 1,325 MW of energy storage by 2024 (the deadlines are generally delayed about a year for municipally owned utilities, like the Los Angeles Department of Water and Power (LADWP)). For IOUs, the CPUC divided the 1,325 MW storage target into biennial procurement targets to be met in 2014, 2016, 2018, and 2020. For each year, the 1,325 MW is further broken down into separate requirements for transmission-connected, distribution-connected, and customer-side energy storage procurements, as listed in the below table:

Utility	*Storage Grid Domain Point of Interconnection*	*2014*	*2016*	*2018*	*2020*	*Total*
Southern California Edison	Transmission	50	65	85	110	310
	Distribution	30	40	50	65	185
	Customer	10	15	25	35	85
	Subtotal	90	120	160	210	580

Pacific Gas and Electric	Transmission	50	65	85	110	310
	Distribution	30	40	50	65	185
	Customer	10	15	25	35	85
	Subtotal	90	120	160	210	580
San Diego Gas and Electric	Transmission	10	15	22	33	80
	Distribution	7	10	15	23	55
	Customer	3	5	8	14	30
	Subtotal	20	30	45	70	165
Total		**200**	**270**	**365**	**490**	**1,325**

The CPUC's targets allow each IOU to defer up to 80% of its required storage targets to later periods if it is unable to find viable projects. To spur the research and development of new technologies, certain mature storage technologies, like pumped hydro over 50 MW, are ineligible to be counted toward these targets.

To guide the procurement processes, every two years each IOU is required to submit to the CPUC an energy storage procurement plan incorporating state mandates to, among other things, integrate renewable resources, reduce peak demand, reduce fossil fuel use, and avoid or delay transmission and distribution upgrades.

California utilities are meeting their storage targets in several different ways. While PG&E and SCE solicit projects through biennial, storage-specific Request for Offer (RFO) programs, most of the utilities have also procured significant storage resources through Local Capacity RFOs and Preferred Resources pilot programs. SCE also issued a special energy storage RFO to respond to the anticipated energy shortage arising from the shutdown of its Aliso Canyon natural gas storage facility. Within approximately six months, Greensmith Energy, AES Energy Storage, and other storage companies each successfully bid, installed, and interconnected three lithium-ion battery projects with a cumulative total of 70 MW (4-hour units), an effort that gave SCE and the CPUC confidence that significant amounts of energy storage could be added to the grid quickly and efficiently. Additional storage projects rounded out the Aliso Canyon effort to approximately 90 MW.

AB 2868 - California's "Additional" 500 MW Energy Storage Procurement Requirement

AB 2868, signed by California Governor Jerry Brown in 2016, requires PG&E, SCE, and SDG&E to propose programs and investments for an additional 500

MW of distribution-connected or behind-the-meter energy storage resources with a useful life of at least 10 years. While there is considerable overlap with the types of resources covered by AB 2514, this new 500 MW requirement excludes transmission-connected resources and is not subject to the 2020 procurement or 2024 installation deadlines and various other AB 2514 program requirements.

Under an April 2017 CPUC decision, each IOU is responsible for developing programs and investments for 166.66 MW of distributed energy storage systems. While the CPUC emphasized that these additional procurement obligations do not alter AB 2514's original targets, for practical purposes AB 2868 will facilitate the interconnection of an additional 500 MW of energy storage to the California grid, along the same general processes of AB 2514. The CPUC's existing limitations on large pumped-hydro, electric-vehicle charging, and gas-to-power storage resources remain in place, however. Consistent with other California energy storage initiatives, this CPUC decision continues California's focus on the customer and distribution-connected opportunities for battery energy storage systems.

Several Energy Storage and Distributed Energy Resource Bills Await Governor Brown's Signature

SB 338, passed by the California Senate on September 6, 2017, would require the CPUC and the governing boards of local publicly-owned electric utilities to consider how energy storage, energy efficiency strategies, and distributed energy resources can help utilities meet peak demand electricity needs while reducing the need for new electricity generation and transmission facilities.

Although California has plenty of renewable energy resources, it experiences a deep drop in solar electricity production in the late-afternoon and early evening just as people are returning home from work and causing energy demand to spike (i.e., the "duck curve"). This sudden surge in demand is met currently by gas-fired late-afternoon generation, which can be expensive to run in short bursts and does not advance California's clean energy goals. SB 338 would require utilities to consider how this period of peak demand could be met instead by resources that align more closely with California's climate and renewable energy goals, such as fast-ramping energy storage resources and efficiency and demand response strategies. SB 338 is on Governor Brown's desk awaiting signature.

The Assembly passed another storage-oriented bill, AB 546, on September 7. AB 546 will require all local governments to make available online all permitting applications for behind-the-meter advanced energy storage systems, and to accept such applications electronically. The law is meant to reduce the burden and costs on residential customers and prompt greater deployment of customer-sited energy storage systems. Like SB 338, AB 546 is enrolled and awaiting Governor Brown's signature.

Finally, SB 801, passed by the Senate on September 13, is the latest legislative effort to increase the deployment of energy storage and distributed energy resources to mitigate potential energy shortages caused by the Aliso Canyon gas leak. SB 801 specifically requires the "local publicly owned electric utility that provides electric service to 250,000 or more customers within the Los Angeles Basin" (i.e., LADWP) to do three things. First, LADWP must share electrical grid data with any persons interested in greater deployment of distributed energy resources. Second, SB 801 requires LADWP to undertake load reduction measures by favoring demand response, renewable energy resources, and energy efficiency strategies over simply meeting demand with increased gas-fired generation. Third, LADWP must determine by June 1, 2018, the cost-effectiveness and feasibility of deploying 100 MW of energy storage in the Los Angeles Basin. SB 801 also requires any private utility serving the Los Angeles Basin (e.g., SCE) to deploy at least 20 MW of energy storage "to the extent that doing so is cost effective and feasible and necessary to meet reliability requirements.

California's Self-Generation Incentive Program

California's SGIP was created in 2001 and received a significant regulatory overhaul in spring of 2017. In addition to doubling the annual surcharge amount collected by utilities, the new funding allocations prioritize the development of distributed energy storage resources. SGIP provides financial incentives for installing new qualifying technologies to meet all or a portion of the electric energy needs of a facility. Under the new SGIP regime, available funds have doubled to $166 million per year, while the incentive itself declines on a block basis at each point that 2 percent of total funds are exhausted. Eighty-five percent of funds are allocated to energy storage technologies, of which 90% are allocated for projects greater than 10 kilowatts in size, and 10% are allocated to the existing carve-out for residential energy storage projects less than or equal to 10 kilowatts in size. The remaining 15% of funds are available for renewable generation technologies. Any single developer/installer is limited to 20% of the available incentive funding for the generation, large energy storage, and residential energy storage categories. While historically SGIP funding has been used for large commercial and industrial projects, proposed legislation (SB 700) would direct additional funding toward residential and low-income projects. As of the date of this publication SB 700 is set to be re-introduced in 2018, although the CPUC is also in the process of instituting a carve out of 40% of SGIP funds for disadvantaged communities.

Massachusetts

Along with California, Massachusetts has emerged as one of the United States' most active energy storage markets. With one state-sponsored study suggesting that expanding state advanced energy storage programs could capture some $800 million in system benefits for

Massachusetts ratepayers, it is not surprising that Massachusetts considers energy storage developments a "game changer in the electric sector."

Energy Storage Initiative

Massachusetts Governor Charlie Baker established the Commonwealth's Energy Storage Initiative (ESI) in May 2015 to incentivize energy storage companies to do business in Massachusetts, accelerate early-stage commercial energy storage technologies, expand the market for these technologies, and develop policy recommendations to advance these goals. The ESI has included extensive outreach, including a survey of storage industry stakeholders, workshops to facilitate public input, and produced an in-depth analysis of energy storage issues, *State of Charge*, issued in September 2016.

In August 2016, the Massachusetts Legislature directed Governor Baker's administration to investigate whether it should set an energy storage procurement target for the state's electric utilities by 2020. Following extensive public input, the Massachusetts Department of Energy Resources (DOER) determined that Massachusetts should set targets for energy storage systems. On June 30, 2017, Governor Baker's administration announced that it has set an "aspirational" 200 MWh energy storage target for electric distribution companies to procure viable and cost-effective energy storage systems by January 1, 2020. In his June 30 announcement, Governor Baker also stated that his administration was evaluating programs to allow energy storage systems to be eligible in future Green Communities grants, which could expand the role of energy storage in complying with the state's Alternative Portfolio Standard.

ACES Program to Support Innovative Storage Use Cases and Business Models

As part of Massachusetts' broader ESI, the Massachusetts Clean Energy Center (MassCEC) established the Advancing Commonwealth Energy Storage (ACES) Program. Building on the more than $9 million MassCEC has invested in energy storage projects, MassCEC plans to award 10–15 energy storage projects between $100,000 and $1,250,000 each. Among meeting other eligibility requirements, awardees will need to demonstrate a "clear and innovative business model" for a storage project sited in Massachusetts and secure at least 50% of the total project budget. Another primary selection criteria is whether respondents are

It is not surprising that Massachusetts considers energy storage developments a "game changer in the electric sector."

seeking to collaborate with local utilities in project development. MassCEC is also interested in projects with "nonmonetizable benefits," like those providing flexible response to displace less efficient ramping generation, deferring transmission or distribution investment, or reducing peak capacity requirements. Winning projects must be commissioned within 18 months of contracting with MassCEC.

SMART Program Creates Storage "Adder" for Solar Projects Paired with Storage

Finalized in August 2017, the Solar Massachusetts Renewable Target (SMART) Program further incentivizes energy storage by encouraging solar project developers to pair their solar energy projects with storage. The program creates a financial "adder" above a solar project's base compensation rate for solar projects that co-locate with eligible energy storage projects. The DOER has pledged to publish a Guideline on Energy Storage that better explains the formula used to calculate the SMART program's storage adder.

Private Efforts for Utility-Scale Storage Deployments

Massachusetts utilities have advanced their own efforts to deploy energy storage projects. For example, Eversource Energy (Eversource) has proposed a series of thermal and battery storage demonstration projects designed to lower peak demand, which will be paid for by a $21 million energy efficiency surcharge. Opponents have criticized both efforts as presented. Eversource has also filed a general rate case proposing an additional $100 million of energy storage projects because DOER has not yet detailed its energy storage targets for Massachusetts utilities. Both proceedings are pending before the Massachusetts Department of Public Utilities.

New York

New York is following the lead of California, Massachusetts, and other states to spur investment in energy storage technology development and deployment. State regulations have directed utilities to install two storage projects each by 2018, the state has established a funding program, and the legislature has signaled its support for energy storage with proposed legislation that would require the state to set an energy storage procurement goal for 2030.

Regulatory Mandate Requiring Each Utility to Install Two Storage Projects by 2018

To encourage the state's utilities to more quickly deploy energy storage technologies, the New York State Public Service Commission (NYSPSC) used a March 2017 order to direct the state's utilities to "significantly increase the scope and speed of their energy storage endeavors." This order included a mandate requiring each individual utility to deploy and have operating energy storage projects at no fewer than two separate distribution substations or feeders by no later than December 31, 2018. NYSPSC states that the utilities should "strive to perform at least two types of grid functions" with each of the storage projects, such as increasing hosting capacity or peak load reduction, and notes that energy storage projects designed as nonwire alternatives or pilot projects will be considered for compliance with this directive. NYSPSC expects the utilities to meet this mandate using their existing budget authorities and reiterates that any incremental project with an incremental budget increase must be proposed to and approved by the NYSPSC.

Current Funding Opportunities

In April 2017, the New York State Energy Research and Development Authority (NYSERDA) established, as part of its Clean Energy Fund, a $15.5 million funding program for energy storage projects. Through the funding program, NYSERDA is seeking proposals for early stage product development (up to $200,000 per award), product development (no award limit), and product field testing (up to $1 million per award). NYSERDA proposes a multi-stage funding solicitation, offering to award $1.825 million by December 31, 2017, and up to a total of $6.3 million by December 31, 2018. NYSERDA will award the remaining $9.2 million under stage two of the solicitation, accepting concept papers through 2019.

NYSERDA's evaluation of the proposals will focus on several considerations:

- Whether the proposal identifies a core problem pertinent to New York, is feasible and will make significant progress toward solving the identified problem, and is testable, flexible and proposes a reasonable work schedule;
- Whether the proposal has the potential to significantly reduce GHG emissions or energy use, and whether a significant portion of the work will take place in New York;

- Whether the proposal offers wide-scale replicability;
- Whether the project team has relevant and necessary expertise to complete the proposed work; and
- Whether the expected benefits for the project strongly justify the cost.

Legislative Action

The New York State Legislature unanimously passed legislation supporting energy storage development by directing the New York Public Service Commission (NYPSC) to develop an Energy Storage Deployment Program (Deployment Program) to encourage the installation of storage facilities. As part of the Deployment Program, NYPSC must develop a target for storage procurement by 2030, and develop programs to help the state meet that target. Eligible storage technologies include any mechanical, chemical, or thermal process that stores energy generated at one time for use at a later time, including storing thermal energy for direct use in heating or cooling at a later time and that avoids using electricity for such heating or cooling. NYPSC has already ordered utilities to install two distribution-connected energy storage systems by the end of 2018.

Passed by the state Assembly on May 17 and by the state Senate on June 19, 2017, the bill awaits the signature or veto of Governor Andrew Cuomo.

Oregon

Legislation: HB 2193

Oregon has followed California in implementing a statewide energy storage mandate with HB 2193, passed in June 2015. The law requires each electric company with 25,000 or more retail customers to procure one or more storage systems with capacity to store at least 5 megawatt hours (MWh) of energy, with the total capacity procured by each company limited to 1% of that company's 2014 peak load.

The Public Utility Commission of Oregon (OPUC) recently released the guidelines for implementing the legislation, providing details on how the utilities must submit their proposals to meet the state's energy storage requirements. The guidelines direct Pacific Power and Portland General Electric, the state's privacy electricity providers, to submit proposals by January 2018 for qualifying energy storage systems, and public workshops are expected to follow. The energy storage projects must be operational by January 1, 2020.

OPUC has stated that it is seeking a balanced portfolio of storage projects that serve multiple applications and can defer or eliminate the need for system upgrades. It encouraged the utilities to submit multiple projects that test varying technologies or applications and to use a request for information process to identify suitable vendors.

Energy Storage Pilot Project

Oregon has also promoted energy storage technologies in connection with its initiatives to foster microgrid technology. In December 2015, the Oregon Department of Energy secured support from Sandia National Laboratories for an energy storage pilot project, granting a total of $295,000 in state and federal funds to the Eugene Water and Electric Board for its project demonstrating energy storage and microgrid technology. The Grid Edge Demonstration project aims to help Oregon better understand how different energy storage technologies can strengthen long-term grid resiliency. The project uses solar panels, advanced batteries, and smart grid technology to test the capability of microgrids to supply electrical power for crucial infrastructure and public emergency management services.

Washington

The state of Washington took a big step toward its grid modernization efforts in 2013 with the launch of the state's Department of Commerce's Clean Energy Fund. The Clean Energy Fund has provided two rounds of funding since its inception. In the first round, which took place from 2013 through 2015, the state awarded $14.5 million in matching "smart grid" grants for developing energy storage technologies, including: (i) $3.2 million to Avista Corp. (Avista) for testing of utility-scale battery developed by UniEnergy Technologies, (ii) $3.8 million to Puget Sound Energy to launch a utility-scale battery, and (iii) $7.3 million to Snohomish County Public Utility District (SnoPUD) for experimental projects using a 500 kilowatt-hour lithium-ion battery and a 6.4 megawatt-hour energy utility technology flow battery. In a requirement unique to Washington, eligible energy storage projects were required to incorporate a common technology standard to integrate energy storage system performance with grid operations (the Modular Energy Storage Architecture or MESA).

Following the success of the first round, the Clean Energy Fund launched additional grid modernization grants for projects from 2015 through 2017. One grantee, the Pacific Northwest National Laboratory, received funding to develop an integrated electrical system, a collaborative project with both the University of Washington and Washington State University. The other grants went toward projects proposed by Demand Energy Networks, Inc. and by Battery Informatics, Inc. to improve battery technologies and energy storage systems. Avista and SnoPUD

Washington's Clean Energy Fund has provided over $20 million in funding to energy storage projects.

received additional funding ($3.5 million each) too. Avista has developed a microgrid using solar panels and battery storage that employs a “sharing” concept, whereby grid users share power equitably among themselves as a means of cutting down on usage inefficiencies. In addition to its partnerships with private companies SnoPUD is working to create the Arlington Microgrid and Clean Energy Technology Center, which will use battery storage and microgrid technology to power one of its offices during grid outages and will educate the public on these areas of technological development.

On the regulatory side, the Washington Utilities and Transportation Commission (UTC) issued a draft policy statement in Spring 2017 recognizing that energy storage is a “key enabling technology” for decarbonizing the Washington grid. Washington’s IOUs were directed to use an integrated resource planning process to analyze energy storage options before committing to other resources, like gas-fired peakers. The UTC also made clear that it would apply ordinary cost recovery mechanisms to IOU acquisition of energy storage resources. Comments on the draft policy statement are presently under consideration by the UTC.

Nevada

Nevada has taken several recent steps to promote energy storage technologies within the state, including providing incentives for solar plus storage installations. In 2017, the Nevada legislature directed the Public Utilities Commission of Nevada (PUCN) to investigate whether it is in the public interest for electric utilities to procure energy storage systems, based on several statutory criteria. Stakeholders are currently investigating that question in a series of workshops. If the PUCN makes such a finding, then it will set annual energy storage procurement targets and require electric utilities to submit annual or biannual plans for energy storage procurement. Under AB 405, Nevada customers are guaranteed the right to interconnect solar plus storage systems in a “timely manner,” so long as all health and safety codes are complied with.

Arizona

While the Arizona legislature has not enacted any significant laws relating to energy storage, the Arizona Corporation Commission (ACC) has promoted energy storage technology development and deployment, particularly at the retail level.

In August 2016, the ACC began considering changes to the ACC’s Renewable Energy Standard and Tariff (REST) rules, which were originally established in 2007. ACC proposed an increase in Arizona’s Renewable Portfolio Standard from 15% by 2025 to 30% in 2030, and also proposed that the ACC consider revising the existing REST rules to incorporate the development and adoption of energy storage solutions to better benefit Arizona ratepayers. This proceeding remains ongoing.

Outside of the REST rule proceeding, the ACC has spurred the adoption of energy storage technology by using utility mandates. The ACC recently ordered Arizona Public Service Company (APS), Arizona's largest utility, to develop a $6 million residential demand response/load management program to facilitate residential energy storage technology. APS has proposed a "reverse demand response" program that would pay storage to charge at periods of electricity oversupply. In February 2017, the ACC ordered Tucson Electric Power Company (TEPCO) to develop a similar $1.3 million program.

Independent of ACC initiatives, Arizona utilities are investing in the development of utility-scale combined energy storage/solar facilities, in large part due to Arizona's favorable climate for solar generation. In late 2016, APS announced plans to develop 4 MW of energy storage in connection with its Solar Partner Program, through which APS intends to study the potential impact of batteries on its system. Since then, Salt River Project and TEPCO have each entered into power purchase agreements (PPAs) to buy power from two battery storage systems (10 MW and 30 MW, respectively), each of which will be paired with a corresponding solar facility. TEPCO also announced recently that its partner, E.On North America, has completed development of an additional 10 MW battery storage project, paired with a 2 MW solar array, that will provide frequency response and voltage control on TEPCO's system. APS, UNS Energy, and TEPCO have all included significant amounts of energy storage in their 2017 Integrated Resource Plans.

Hawaii

Hawaii's geography encourages the development of renewable energy sources, along with attendant storage capabilities. Hawaii has been an early adopter of energy storage-friendly policies and the state has several efforts underway to improve energy storage technology.

Eighty percent of Hawaii's energy is currently derived from imported oil supplies. Starting in 2008, Hawaii and the U.S. Department of Energy (DOE) began collaborating to reduce Hawaii's heavy dependence on imported fossil fuels by transitioning to local, clean, and renewable energy sources. In June 2015, Hawaii passed a law directing the state's utilities to generate 100% of their electricity sales from renewable energy resources by 2045. Hawaii's 100% RPS and various other energy independence laws and policies are known as the Hawaii Clean Energy Initiative (HCEI), which includes a public-private partnership between various industry players, the DOE, and Hawaii's Department of Business, Economic Development, and Tourism. Energy storage systems will play a key role in Hawaii's shift toward renewable generation, although the state does not yet have in place any comprehensive tax credit or procurement targets to drive demand.

To achieve the HCEI's objectives, Hawaiian Electric (HECO), Maui Electric, and Hawaii Electric Light Company must file joint annual reports with the Hawaii Public Utilities Commission (HPUC) that describe their renewable energy development projects. These reports describe twelve utility-scale battery projects proposed throughout the Hawaiian Islands. HECO's recent Power Supply Improvement Plan was recently updated to include 150 MW of energy storage. To facilitate the transition to a more distributed grid, HPUC has announced an expedited process for behind-the-meter storage interconnections.

To further advance battery storage technology, public-private partnerships between the utilities and the Hawaii Natural Energy Institute (HNEI), launched battery energy storage system (BESS) projects throughout the state. Four BESS projects exist presently, and are being used in frequency regulation, peak shifting, voltage support, and power smoothing applications. The long-term objective of HNEI's BESS program is to improve the science of battery storage technology, an important aspect to the development of Hawaii's broader energy scheme.

Energy storage-friendly bills have gained significant momentum in the Hawaii legislature. There have been nearly a dozen bills on storage incentives or rebates in last two legislative sessions, with more expected in 2018 and 2019.

Texas

Texas has also assumed a leading role in defining the role that energy storage can play in enhancing grid reliability and efficiency. Texas' unique dynamic of regulated and unregulated electric utilities, its own independent system operator (the Electric Reliability Council of Texas (ERCOT)), and a climate that encourages wind and solar generation have made Texas an ideal test site for energy storage technology. Texas projects have included utility-scale projects as well as microgrid and community

storage developments, including Oncor's advanced microgrid incorporating 25 kW of community energy storage systems; E.On's Texas Waves 20 MW battery storage project colocated with wind generation facilities; Austin Energy's aggregated fleet of customer-sited energy storage; and Duke's Notrees storage project that operates as an ancillary services resource.

Legislative efforts

In 2011, the Texas legislature passed a law clarifying that energy storage facilities wanting to participate in competitive markets are "generation assets" that must register with the Public Utility Commission of Texas (PUCT). This legislation allowed energy storage facilities to interconnect, to obtain transmission service, and to participate in ERCOT's wholesale energy market, although the "generator" label raises questions on whether such assets can be owned by regulated transmission providers.

In 2009 and 2013, Texas created the New Technology Implementation Grant (NTIG) fund as part of the Texas Emissions Reduction Plan. The NTIG fund allows grants for storage projects colocated with renewable energy generating facilities in air quality affected counties. To date, three utility-scale energy storage projects have received grants through the NTIG fund.

PUCT Rules

In connection with Texas legislative efforts, the PUCT has enacted several rules easing the ability of energy storage resources to participate in ERCOT's wholesale electricity markets. Under PUCT Substantive Rule 25.192, wholesale energy storage is exempt from transmission service rates and wholesale storage load is excluded from ERCOT's four coincident peak demand calculations. PUCT Substantive Rule 25.501(m) defines "wholesale storage" as something that occurs when electricity is used to charge a storage facility, the storage facility is separately metered from all other facilities including auxiliary facilities, and energy from the electricity is stored in the storage facility and subsequently regenerated and sold at wholesale as energy or ancillary services. Rule 25.501(m) further provides that wholesale storage is deemed to be wholesale load, and ERCOT is to settle it accordingly using the nodal energy price at the electrical bus that connects the storage facility to the transmission system (or if the storage facility is connected at distribution voltage, the nodal price of the nearest electrical bus that connects to the transmission system). The Rule also provides that wholesale storage is not subject to retail tariffs, rates, and charges or fees assessed in conjunction with the retail purchase of electricity. Collectively, these rules are thought to help ease storage into ERCOT's markets.

INDEPENDENT SYSTEM OPERATORS AND REGIONAL TRANSMISSION ORGANIZATIONS

The California Independent System Operator (CAISO)

CAISO is one of the largest ISOs in the nation, responsible for managing about 80% of California's electricity flow. In collaboration with CEC and CPUC, CAISO has been at the forefront of considering ways to incorporate energy storage resources into California's wholesale electricity market. Starting around 2011, CAISO began several stakeholder initiatives to address the ramping issues caused by California's abundant solar resources and the retirement of nuclear and once-through-cooling gas-fired generation assets. Energy storage technologies have a played a big role in shaping the policy decisions in CAISO's Flexible Resource Adequacy requirements, its Flexible Ramping Product, and Phases 1 and 2 of the Flexible Resource Adequacy Criteria and Must-Offer Obligation proceedings.

In 2014, CAISO (in collaboration with the CPUC and CEC) began its energy storage and distributed energy resources (ESDER) initiative. In 2016, CAISO updated its tariff to allow storage providers to self manage their state-of-charge and energy limits and to directly submit their state-of-charge status into the day ahead market to better reflect the actual conditions of the storage resource. In Phase 2 of the ESDER process, CAISO is evaluating tariff modifications to enhance demand response rules, provide more certainty on station power and multiple-use applications, and provide better modeling all of which are aimed to better capture storage's contribution toward grid reliability. Phase 3 of ESDER is exploring the development of a "load shifting" product to incentivize storage systems to soak up excess solar power in the middle of the day.

Also in 2016, CAISO adopted tariff provisions creating a new market participant category called a distributed energy resource provider (DER Provider). A DER Provider is a market participant that aggregates one or more small distribution-connected energy resources (like energy storage systems) totaling at least 0.5 MW. CAISO's DER aggregation program recognizes the difficulty in incorporating small distribution-connected resources into a market run by the transmission-level operator, and stakeholders are continuing to work toward improving communication at the transmission-distribution interface (i.e., at substations). Initial participants using the new DER aggregation tariff have had some success converting storage and electric vehicle resources from demand response resources to energy resources. It is worth noting that FERC's Energy Storage NOPR was modeled on some of the concepts in the CAISO tariff, although it is CAISO's view that each ISO and RTO retain the flexibility to enact policies that best represent the interests of their varied stakeholders and the region they serve.

PJM Interconnection

PJM Interconnection (PJM) is a RTO that operates the high-voltage transmission grid in all or parts of the mid-Atlantic states, the Midwest, and Appalachia. Unlike CAISO, PJM's policies must account for several state policies and perspectives to identify the most effective and cost-efficient grid improvements to ensure a reliable energy supply. While pumped storage hydropower resources have long participated in PJM's energy, capacity, and ancillary services markets, PJM has also recently integrated over 300 MW of battery and flywheel storage facilities. PJM is also evaluating the use of other technologies, including thermal storage and vehicle-to-grid integration, to further stabilize and improve the PJM grid.

The Role of Storage in PJM

Energy storage resources may inject energy onto the PJM grid as "generation" to participate in PJM's wholesale markets under PJM's existing market rules. Storage resources acting as generation may then provide energy, capacity or ancillary services (frequency regulation), provided they meet the standard parameters for participating in each market. In 2012, following the issuance of Order 755, PJM revised its frequency regulation market rules to differentiate between traditional generators with limited ramp rates (Regulation A resources) and energy-limited resources that have faster ramp rates, such as batteries (Regulation D resources). To date, and with the exception of pumped hydropower, the majority of energy storage resources operating as generators in PJM participate exclusively in PJM's frequency regulation market as Regulation D resources.

Energy storage resources may also participate as behind-the-meter "demand response"—a program that compensates retail customers for reducing their electric load when called upon by PJM. However, under PJM's existing market rules, such resources are generally unable to also participate in PJM's other wholesale markets. This is due in large part to PJM's existing demand response framework, which effectively prohibits demand response resources from also injecting energy onto the PJM grid.

PJM's Market Implementation Committee Initiative

In December 2015, PJM issued a problem statement outlining the need to develop more effective means to integrate energy storage resources into the PJM wholesale markets. The problem statement recognized that: (1) energy storage resources can provide value as both behind-the-meter "demand response" and as "generation" participating in PJM's wholesale markets, and (2) PJM's existing market rules made it difficult for energy storage to satisfy both these functions. After the problem statement was issued, a special session of PJM's Market Implementation Committee was established to study accommodating implementing storage in the PJM market. This special session has focused on changing changes to the existing market rules to provide an easier mechanism through which energy storage resources could participate both as behind-the-meter "demand response" and as "generation" in PJM's wholesale markets. Assuming a set of rules is developed through PJM's stakeholder process and approved by FERC, such rules could provide increased opportunity and incentive for electric storage to be developed and deployed in the PJM Region.

ERCOT

ERCOT is the ISO responsible for operating the transmission grid and energy-only wholesale markets in the state of Texas. Apart from a few interconnections to reach generating plants near bordering states, ERCOT's authority is entirely intrastate. This limitation makes ERCOT unique among ISOs, as its rates for wholesale power are exempt from FERC jurisdiction and are instead subject to the jurisdiction of the PUCT. Regarding the integration of energy storage, ERCOT's efforts are guided by state legislative mandates and the PUCT's regulatory directives. PUCT has enacted a number of rules intended to facilitate greater participation by energy storage resources in the ERCOT wholesale electricity markets.

In conjunction with the PUCT's efforts, ERCOT has revised its Nodal Protocols, which govern wholesale market participation. Nodal Protocol Revision Request 461 implemented the process for settling Energy Storage Resources (ESRs) in the energy markets. ESRs carry "Wholesale Storage Load," which in Texas is limited to the following technologies: batteries, flywheels, compressed air energy storage, pumped hydro-electric power, electro chemical capacitors, and thermal energy storage. Other Texas-specific definitions state the parameters that ESRs must meet to participate in the Regulation Services markets and outline the make-whole calculation processes for ESRs.

DEVELOPMENT ISSUES FOR ENERGY STORAGE

FINANCING AND MONETIZING ENERGY STORAGE PROJECTS

Installed capacity of energy storage is expected to reach 2.6 GW by 2022 in the United States, which will drive the need for sophisticated and cost-effective project financing. Unlocking sources of financing across the sector will be vitally important in realizing the monetary and societal benefits of energy storage.

Fundamentals and Challenges of Energy Storage Financing

Financing for energy storage projects shares some of the same fundamentals as solar and wind. Investors and lenders seek projects that can demonstrate: (1) contracted long term revenue streams; (2) produced by technology that is well proven and reliable; with (3) contractual performance assured by creditworthy counterparties or financial instruments such as performance insurance.

Beyond these fundamental similarities, however, energy storage projects are inherently more complex than solar and wind and typically face several additional types of challenges in seeking financing.

First, in contrast to the relatively simple metrics of renewable generation projects (e.g., kilowatt hours multiplied by PPA prices over time), energy storage projects may generate economic benefits through one or more different value streams. In preparing an economic model to support financing, the sponsor must clearly define the use cases for the project and link them to concrete and reliable future net revenue streams. Where a project benefit is in the form of cost savings, such as demand charge reduction, quantifying and monetizing that benefit will be a key step. Energy storage may also entail multiple concurrent benefits, such as providing grid-support services while at the same time serving as on-site energy supply. Deriving solid financial returns for these value streams—and ensuring that any potential conflicts and management issues among them are addressed—will be a necessary prerequisite to financing.

Second, compared to generation projects, energy storage technology requires significantly more active and sophisticated management over the life of the project, and has greater potential for change of use, than solar or wind. Operations and asset management for solar projects with a PPA are straightforward, well understood, and contractually defined. The framework generally needs to deliver energy on a steady stream over time, addressing only sporadic and mostly immaterial operations and maintenance issues. To achieve bottom-line results with a storage project, however, typically requires dynamic ongoing management and software controls to address changing circumstances and objectives. Where grid services are provided, those controls must mesh with the utility framework and meet applicable communications, technology, and contractual requirements. Realizing the revenue streams on which financing will be based thus faces significant additional ongoing uncertainties compared to traditional renewable energy generation projects.

Finally, the market and regulatory contexts for energy storage are rapidly evolving and may be unpredictable. Value streams may quickly change or dry up, as seen in PJM's recent decision to substantially decrease the Regulation D payment rates for frequency regulation services from energy storage. Utilities and state public utilities commissions in several major jurisdictions are in the process of reforming energy distribution and customer platforms. Interconnection rules, siting requirements, and market participation procedures are changing. New storage technologies are emerging, and software systems and transaction regimes such as blockchain are creating major new capabilities. All of these areas of change create potential risks and opportunities that must be assessed in considering financing terms.

Given these inherent complexities the cost of capital for storage project finance has yet to see substantial reductions. On the risk-return continuum, equity has, understandably, been the dominant source of financing for the nascent energy storage industry to date. Debt and tax equity are beginning to take on more active roles, however, as revenue streams, risk factors, and contract structures are becoming more clearly defined.

Current Project Financing Instruments

While many energy storage projects have been developed as merchant facilities, particularly in ERCOT, MISO and PJM, several energy storage projects have successfully entered into long term contracts for offtake of the storage resource or to assist in financing. Although these long-term agreements are sometimes referred to casually as energy storage "PPAs," this omnibus term bit of a misnomer because several forms of agreement have been developed to take advantage of energy storage systems as both generator and load (i.e., discharging and charging). While each form of energy storage agreement has its own peculiar features, several forms of agreement generally in use are summarized below.

Energy Storage Tolling Agreement (Tolling Agreement)

California utilities have used energy storage tolling agreements in connection with their procurement of utility-scale storage projects that are interconnected to the transmission or distribution system. Under a Tolling Agreement, the energy storage system developer is responsible for obtaining site control, permits, interconnection rights, equipment, and construction contracts and achieving agreed-upon milestones, usually including a target commercial operation date and a guaranteed commercial operation date. The buyer (here, the utility) pays for the electricity used to charge the battery storage system and receives the right to charge or discharge the system for energy and ancillary services, all within specified operating parameters. The storage provider receives a capacity payment, which is adjusted for the storage system's availability and round-trip efficiency, and a variable O&M payment for energy dispatched from the system. The buyer will usually insist on the right to dispatch the system to provide ancillary services like frequency regulation, usually without any additional compensation to the seller beyond the capacity and variable O&M payments. Because the buyer owns the energy stored in the battery, Tolling Agreements often prohibit or restrict the developer's use of the storage system for station service—a condition that requires the developer to enter into a retail service contract for the system's non-storage load. Energy storage Tolling Agreements are similar in many respects to gas tolling agreements, with "round-trip efficiency" being analogous to a heat rate and "availability" generally performing the same function under both types of agreement.

Capacity Services Agreement (CSA)

Under a CSA, the developer is responsible for most of the development activities associated with a Tolling Agreement but must charge the energy storage system at the developer's own expense. The offtaker (usually a utility) pays a capacity charge for the system, subject to adjustment for availability, and uses the storage system's capacity attributes to satisfy the offtaker's Resource Adequacy (RA) requirements. CSAs are used for utility-scale energy storage projects that will be interconnected with the transmission or distribution systems, and at least one California utility (PG&E) has used a CSA format for its most recent round of energy storage solicitations.

Demand Response Energy Storage Agreement (DRESA)

If a developer provides on-site, behind-the-meter storage to a number of customers, it may be able to aggregate the storage capabilities of those customers and enter into a DRESA. A DRESA between a local utility and an energy storage system developer allows utilities to compensate an energy storage system developer for providing the utility with energy storage system capacity and demand response energy storage ancillary services.

Each customer contractually allows the developer to make the storage systems available to reduce demand at the direction of the utility offtaker. The developer then enters into a long-term DRESA with a utility buyer under which the developer agrees to cause its customers to switch to energy storage as and for the duration requested by the utility, again subject to the operating parameters of the aggregate system. During this period, the developer's customers will rely on energy discharged from the storage system instead of electricity from the utility, thus reducing load on the grid. A DRESA may allow demand response assets to be deployed without capital expenditures by either the storage system host or the local utility, which provides advantages to several stakeholders at once.

Behind-the-Meter Projects

In states like Hawaii, California, and New York, energy storage systems have been installed on the customer's side of the meter, allowing the customer to charge the system in off-peak hours and then discharge it during peak hours. These systems can be dispatched in response to demand response price signals, to reduce the customer's usage of peak power, or to shave peaks and thus reduce peak demand charges. The agreement between the developer and its customer may take the form of a third-party PPA, particularly if the storage system is combined with a solar installation, with payments to the developer based on electricity delivered to the customer. Another type of agreement shares the savings that the customer achieves because it is able to shave its peak demand (and thus its peak demand charges). To date, such agreements exist primarily in states that offer one or more unique market conditions, such as a high retail electricity prices, time of use rates that allow charging at off-peak prices and discharging at on-peak prices, market design such as peak demand charges in California or demand response markets in New York, and incentive programs such as California's SGIP. Developers and utilities are continuing to create new forms of financeable agreements applicable to their fast-growing sectors, similar to where solar PV market players were ten years ago. A brief review of the most common behind-the-meter storage financing agreements available follows.

Operating Leases

An operating lease is an arrangement whereby the owner of an energy storage system grants the host the right to use the system in exchange for a monthly fee that covers the rental of the energy storage system and (in most instances) its operation and maintenance fees, software access fees, installation costs permitting costs, and sales and property taxes. The energy storage company, acting as the lessor, uses third-party financing to purchase the energy storage asset; therefore, it is essential that the lease provides for the owner's ability to assign the lease to its financing party.

During the lease period, which is usually 10 years from its commercial operation date (although terms as short as three years have been used), often with the option to extend the term for a additional 10 years subject to the particular lease terms, the energy storage system remains the property of the owner/lessor who will operate, manage, repair, and maintain it. The owner/lessor provides a long-term (again, often for 10 years) limited equipment warranty. The value proposition for the storage system typically will focus on reducing high time of use electricity rates or demand charges and providing backup power to the host/lessee in the event of grid outages. In most cases, the host/lessee will be granted an option to purchase the energy storage system before the lease terminates for its fair market value.

Concurrently, the energy storage system owner/lessor may operate the energy storage system to provide supporting services to the electrical grid, offering potential additional revenues from such activities. This operating lease model is used widely today by leaders in the energy storage market.

Demand Charge Shared Savings Agreements

Similar to the Energy Savings Performance Contract structure used for energy efficiency projects, a demand charge shared savings agreement (DCSSA) between a host (for instance, a hotel owner) and a third-party energy storage system owner or operator allows the host to enjoy lower energy consumption costs due to reduced demand charges achieved by discharging the energy storage system during peak hours and by performing energy arbitrage by drawing power during off-peak periods. With the DCSSA, the third-party financiers rely on an allocated portion of the energy cost savings from the reduced tariff-specific demand charges that will be distributed by the host to the project financing providers. The most significant advantage to the host is access to the energy cost-reducing third-party asset with zero upfront capital expenditure on the host's part. Under the DCSSA, the host is provided energy storage-related services on a Storage-as-a-Service basis. Several companies, including Stem, Advanced Microgrid Solutions, and Green Charge Networks utilize this model in their contractual arrangements with third-party C&I hosts.

Project Financing Risk Identification and Management

Energy storage agreements share many of the issues typical of any long-term PPA, such as force majeure, defaults, collateral assignment, and dispute resolution. Given the complexities of energy storage, however, project financing must effectively address a number of categories of risks associated with new technology, business management, market and regulatory evolution, and credit profiles.

Change in Law and Regulatory Risk

One of the most difficult issues in an energy storage agreement is allocating change in law risk. In California especially, utilities will often procure energy storage so that they can meet AB 2514 targets or other procurement mandates, as well as satisfy RA requirements. If, after the agreement is signed, there is a change in the laws or tariffs governing the targets, RA qualifications, or other key operational features or attributes of the energy storage facility, which party bears the risk of that change?

Developers prefer to shift the risk to the offtaker, arguing that the procuring utility is in the best position to manage changes in the laws, rules and tariffs governing energy storage systems and how they

count in meeting procurement targets or satisfying RA. A utility will often resist a full assumption of this risk, arguing that the small risk of an adverse change in law is better borne by the developer than the ratepayers. Developers, for their part, prefer to avoid provisions that merely excuse its performance and give it a right to terminate in the event the law changes--such language would increase the risk that the energy storage system will end up as a merchant plant, thus making it difficult to finance the system. Force majeure clauses are not adequate to the task of addressing this issue, and agreements need to address change of law risk allocation head on.

Not surprisingly, compromises are developing along the same lines as the change of law provisions affecting RPS compliance provisions in renewable energy PPAs. In some instances, utilities will agree to accept the risk of a change in law. In others, the parties will agree to allocate the risk such that the developer bears compliance costs up to a certain point, after which the utility may decide whether it wants to incur additional costs to cause the system to comply with the new law. From the developer's standpoint, the important outcome is that the utility cannot treat as a default the failure to comply with the new law after the cost threshold, if any, is reached, nor can it refuse to continue to receive and pay for the contracted energy storage services specified in the agreement.

Technology Risk

Energy storage agreements usually include a fairly detailed exhibit setting out the system's operating parameters. These provisions are especially important in a tolling agreement or any other contract in which a third party has the right to dispatch the facility. If the storage system is operated within the agreed-upon operating parameters, the storage provider is required to meet the availability and round-trip efficiency standards set forth in the agreement. On the other hand, if the system is operated outside its agreed-upon parameters, the developer will have a contractual defense to any penalties imposed due to non-performance. Experience in the PJM and MISO teach that tariff or rule changes that change the way a storage system operates can adversely affect the system's performance and may also limit warranty claims under the storage system's procurement contracts.

Behind the representations on operational performance is a concern that the energy storage technology will not perform as expected in the future and/or that operation and maintenance costs will be greater than anticipated. Today, lithium-ion batteries are perceived as safe and bankable. Because successful project financings depend on long-term manufacturer warranties backed by creditworthy entities, it is normal today for equipment manufacturers to stand behind their products with warranties that range from several to ten years. Performance ratings and performance guarantees are increasingly being used to mitigate the technology risk posed by the lack of long term performance energy storage system-related data.

Safety risks have also been a major area of focus. The DOE and Underwriters Laboratories are continuing to work on establishing codes and standards for avoiding project technology failures and resulting health and property impacts and financial liabilities. As in the solar industry, the practice of conducting bankability studies to support financing is taking root for storage. Performed by technical consultants with access to extensive databases of prior projects, such bankability studies can provide detailed due diligence on the project technology, reliability, and durability; the manufacturer and supply chain; and operations, asset management, software controls, and maintenance going forward.

Asset Management Risk

As discussed above, energy storage must be effectively managed and controlled to interface with generation sources and the grid. Software technology uncertainties and the need to rely on sophisticated asset management services over time create additional risks that must be assessed.

Credit Risk

There is always a risk of default by the borrower, who may be unable to service the debt as contracted. Prospective lenders are cautious about entering the market, as it is still considered immature despite the fact that several lenders have been actively supporting certain developers deploying energy storage systems in the past few years. Credit risk assessment for energy storage also extends beyond the project counter-parties to third parties, such as equipment manufacturers, software suppliers, and asset managers that the project may be relying on for warranties, guarantees, and operational effectiveness going forward. Insurance covering project assets and operations, as well as performance insurance supporting performance guarantees, often will be required.

One of the most difficult issues in an energy storage agreement is allocating change in law risk.

Trends Toward Standardization

A number of participants in the energy storage sector are actively working towards standardized approaches to risk management and contractual allocation. End-to-end contractual solutions are being developed by companies whose business models require ease of obtaining finance. Such efforts are being augmented by a number of non-governmental organizations, such as the Energy Storage Association and Rocky Mountain Institute's Business Renewables Center, that provide forums for finance experts to work with developers in overcoming common obstacles and streamlining financing processes. Sandia National Labs, the National Renewable Energy Laboratories, and others, are working under DOE programs seeking ways to reduce barriers for new lenders and to create trusted analytical benchmarks to assess and price risk in more systematic ways. Further rapid advances in these areas should be expected in the next few years, helping to open the spigot of financing for the energy storage sector.

In recent years, the energy storage industry has seen several significant and positive changes including equipment cost reductions, regulatory incentives, viable market structures, and proliferation of long-term agreements. Each of these make deploying energy storage systems more viable than ever before. As access to project financing is still an issue for many developers, however, it is encouraging to see project finance lenders taking a greater interest in financing large-scale energy storage projects in the United States and abroad.

In addition to more lenders entering the market, one of the main potential catalysts for the expedited deployment of additional energy storage systems would be Congress passing an Investment Tax Credit for stand-alone storage facilities. With or without the Investment Tax Credit, the fundamental economics and optimism in the energy storage industry indicate that energy storage can flourish in the coming years and the project financiers will have ample opportunities to make a significant contribution to this process. Each of the groups of participants in the storage ecosystem—sponsors, developers, financiers, and utilities—must work to streamline and standardize structures and contracts. The overarching commonality with solar and wind is that energy storage offers massive potential economic benefits that could be unlocked as these parties work on more effective approaches to financing. The question is not whether but when and how rapidly the sector can realize the kind of progress seen to date in renewable generation.

EPC AGREEMENTS

Energy Storage System developers use EPC agreements to accomplish two main goals: first, to clearly and concisely state the risks and obligations of the designer, the equipment suppliers, the contractor and the owner in a way that provides a foundation for a successful project, and second, to cover the main risk points in a way that attracts project financing from the lenders.

Most EPC agreements are turnkey agreements, meaning that the owner is relying on the contractor to design, construct, test, commission, and hand over a fully completed and functional plant. Having a single point of responsibility is, for most owners, the primary advantage of EPC contracts over other project delivery options. An EPC contractor, who is at once the designer, specification writer and builder, can make changes on the fly that the traditional design-bid-build format does not easily allow. Project lenders have historically preferred EPC contracts that aggressively shift as much risk as possible from the owner to the EPC contractor.

The EPC model seeks to take advantage of the specialized expertise of the contractor-engineer to provide an integrated approach to the planning, design, execution, and performance of the project.

Several key EPC risk points apply particularly to the energy storage market.

Performance Guarantees

One of the primary reasons an owner chooses a single-entity EPC contractor to deliver a project is to ensure that the project as constructed meets the owner's performance objectives. Project lenders want assurances that at the completion of the project, these expectations are met, as proven through performance testing and backed by performance liquidated damages. With respect to energy storage projects, the performance tests may include round-trip efficiency, overall capacity, speed of charge and discharge, and a demonstration of control system performance through a series of test case scenarios. The contract should directly and explicitly set forth the testing procedures, standards, methods, uncertainty principles, and consequences of an adverse test result.

Performance Guarantee Damages

Both the owner and the contractor will suffer consequences if an energy storage system fails the performance tests. One of the most closely negotiated aspects of the EPC contract is the amount of liquidated damages and what additional remedies the owner may have in this circumstance. Contractors typically seek a cap on liability with respect to performance liquidated damages. Agreement on a cap is typically based on a percentage of the Contract Price. Owners must of course carefully consider the extent to which such a cap may leave them with an underperforming resource and no remedy for the adverse economic impacts such as failing to live up to a PPA.

Many EPC contracts will require the contractor to both pay the owner liquidated damages at an agreed daily rate AND cure the performance shortfall. This "make good" obligation is often triggered only if the facility fails to reach a specified minimum level of performance. Contractors will typically resist a requirement that certain minimum performance levels be achieved no matter what.

Equipment Procurement Issues

It is not unusual for the cost to purchase specialized equipment, such as a particular type of battery or inverter to comprise a major percentage of an EPC contract price. Given this, it is imperative for the EPC contract to include all necessary and appropriate equipment purchase and sale terms, including, among others: delivery, title transfer, risk of loss, warranties, and intellectual property issues. These issues are heightened when dealing with new and potentially immature energy storage technologies.

Warranties

Project owners and lenders may require a "full wrap" warranty form the EPC, making it responsible for all defects in design, equipment and performance. Alternatively, an EPC may offer a cost advantage for an "unwrapped" warranty where the warrantes applicable to equipment, and even subcontractor work, as simply passed through to the owner for direct enforcement. Issues to negotiate include the term of the warranty, warranty exclusions, warranty claim process and restrictions, and the application of extended warranties for corrective work.

Intellectual Property

The design of an energy storage system and its software programs will incorporate proprietary processes and equipment configurations developed by parties who should be concerned about protecting their important knowledge from theft, misappropriation or loss of the exclusive right to such proprietary knowledge.
IP rights may be addressed in the EPC contract or may be the subject of a separate agreement. These provisions can be relatively simple or quite complex, depending on the size of the storage source, the type of batteries, the control technology to be used, and the extent of the contractor's design obligations (for instance, colocating the storage system with a renewable generator). A good general rule is that each party to an EPC agreement (and its respective design consultants and subcontractors) retains ownership of its respective pre-existing and non-project-specific IP and grants a nonexclusive limited license for use of such IP to other parties only to the extent necessary to complete the project, or in the case of the owner, to operate and maintain the plant upon completion.

Contract Payment Terms

Although the contract price is often one of the first material terms to be negotiated by the parties to any EPC contract, the pricing mechanisms under such contracts can be complex. The two main pricing mechanisms are "fixed lump sum" and "cost plus." Each has many variations.

Owners may prefer to enter into fixed lump sum contracts whenever possible in order to provide reasonable certainty of the owner's maximum exposure. Often, if the project is subject to third-party financing, the lenders insist on the EPC contract being performed for a fixed Contract Price. The point of this arrangement is that the contractor largely bears the risk of cost overruns but also gets the benefit of any cost savings, including through subcontractor and supplier discounts. Pricing is particularly dynamic in the battery storage industry, where the cost of lithium-ion technology is projected to continue to drop.

Cost plus pricing arrangements may be used where: (a) there remains significant uncertainty as to the scope of the project at the time the parties enter into the EPC contract, either because the design remains at an early stage or for other reasons; (b) the owner wants to avoid payment of contingencies unless such costs are actually incurred; and/or (c) the contractor is unwilling to commit to a fixed Contract Price due to uncertainty or the complexity of the project.

Other Key EPC Terms: Limitations of Liability, Indemnity and Termination

Owners almost universally prefer not to cap the contractor's liability under the contract; however, few EPC contractors will, as a commercial matter, enter into an EPC contract that leaves them exposed to unlimited liability. Therefore, in many cases the owner will agree to cap the contractor's overall liability to a specific amount; commonly, a percentage of the contract price, and most often 100%.

Owners will typically negotiate to exclude certain provisions of the contract or categories of liability from the applicability of the contractor's overall liability cap, such as for personal injury, death or third-party property damage. Generally, such liabilities should be fully or substantially covered by a policy of insurance, such as third-party personal injury or damage to real and tangible property. Other exclusions commonly sought by owners are exclusions related to the contractor's gross negligence, willful or intentional misconduct, violations of applicable law and permits, and intellectual property infringement liability.

An indemnity is an obligation by one party to protect another party against loss or damage. Most EPC contracts contain several indemnity provisions. Some of the most common are for loss or damage incurred by the indemnified persons (usually Owner and related entities) related to personal injury, property damage, breach of contract, liens arising from nonperformance, contamination and other environmental issues, or for tort claims. In most states/indemnity obligations are limited by state-law "Anti-Indemnification Statutes" that invalidate a clause in a construction contract that purports to indemnify a party for its sole negligence, and in many cases, prohibit indemnification to the extent that claims arise out of that party's comparative negligence. Most EPC contracts allow one or both parties to terminate the contract as a consequence of certain specified breaches, acts, or omissions of the other party (i.e., a termination for cause). Typical events of default giving rising to the right to terminate include insolvency, unauthorized assignment, change in control for either party, failure to maintain financial security, failure to make payment, failure to achieve milestones, and breach of any material contract provision. In Addition, Owners often requires a right to terminate the EPC contract for reasons unrelated to the contractor's performance under the contract. This is usually referred to as a "termination for convenience" or "T for C." Normally such entitlements are resisted strongly by contractors and are not reciprocal due primarily to the difficulty and cost associated with replacing a contractor during the project.

INTERCONNECTION

Energy storage projects generally undergo the same interconnection processes as same-sized renewable and traditional generation resources, despite the fact that most battery storage systems cannot operate at full capacity 24 hours a day and have many other significant technical and operational differences. For utility-scale storage projects, the owner must typically apply for interconnection to the transmission or distribution system owner or operator and then undergo a comprehensive independent or queue cluster study process, pay for any system upgrades necessary to ensure deliverability of energy, and negotiate an interconnection agreement. This process rarely takes less than 12 months and can sometimes take 30 months or longer.

Interconnection issues and confusion can delay energy storage projects. For behind-the-meter storage resources, or for storage resources that will not sell into FERC-jurisdictional wholesale markets, some state jurisdictional tariffs allow developers to fast-track or otherwise undergo a shorter interconnection procedure. Some states, like California, have begun proactively addressing these challenges in state public utility commission rulemaking proceedings, including establishing faster dispute resolution producers for interconnecting storage resources.

Interconnection issues may also arise when energy storage is either being added to or will replace all or a portion of an existing generating unit. Generally speaking, adding storage resources that will exceed the total MW of energy allowable under the existing interconnection agreement will require a developer to undergo a study process similar to that required for a brand new interconnection. But replacing, or "swapping out," all or part of an existing generator with some portion of energy storage may not necessarily require the time and expense of the full study process, assuming that the site's total MW capacity and electrical characteristics will not substantially change. Due to technological concerns about changing from synchronous to inverter-based energy, however, some ISO/RTOs require a new study process when battery storage will completely replace a traditional turbine-based generating asset.

Some generators may propose "limiting schemes" when incorporating energy storage into new or existing generation projects. For instance, an interconnection customer contemplating a combined generation and storage resource (e.g., storage paired with solar) may, with the transmission provider's agreement, propose to limit the maximum injection capacity to a lesser specified amount in its interconnection request. In that case, a combined resource may propose a control system, power relays, or both to limit the maximum amount of power that can be injected on to the grid at one time. Then, the transmission provider may measure the capacity of the energy storage device based on the capacity specified in the interconnection request, which may be less than device's maximum capacity.

PERMITTING AND FILING ISSUES

State and Local Permits

There are few, if any, states that require special storage-specific permits or applications for nonutility owned storage projects. Before constructing an energy storage system, developers will typically have to apply for a local conditional use, building, and/or grading permit, as well as comply with any generally applicable state and local zoning, building code, or environmental review laws (like the California Environmental Quality Act). Some states, like California, have passed laws requiring local jurisdiction to make permitting materials available online.

Storage projects proposed on federal land would have to undergo National Environmental Policy Act review, and may potentially involve the amendment of federal land use plans. Utility-owned storage projects will typically be approved using the standard state public utility commission methods, similar to the processes used for transmission lines, substations, and rate changes.

FERC FILINGS

Market-Based Rate Authority

Unless an exemption applies, entities that make wholesale sales of electric energy, capacity, or ancillary services, including energy storage resources, must obtain prior authorization from FERC. FERC allows sales of energy, capacity, and ancillary services at market-based rates if the seller and its affiliates lack, or have adequately mitigated, horizontal and vertical market power. For energy storage resources that are not affiliated with entities that own significant amounts of generation capacity or transmission facilities in the same market as the storage resource, the market power analysis is typically straight-forward. Market-based rate authority is also required before sales of test power. Accordingly, timing of the application to obtain market-based rate authority is an important consideration when developing energy storage resources. FERC regulations require that market-based rate applications be filed at least sixty days before the date on which the entity intends to begin selling at market-based rates. While it is possible to seek a waiver of this sixty-day requirement, such waivers are discretionary and FERC will not make such authorization effective any earlier than the day after filing. Thus, it is critical that market-based applications be filed before making any sales from an energy storage resource.

If market-based sales are allowed, sellers must notify FERC of any changes that alter the characteristics that FERC relied upon in reviewing the seller's market-based rate application. For example, a status filing charge may be required if the seller or its affiliates acquire or develop 100 MW or more of generation capacity, transmission facilities, or other inputs to electric power production not previously disclosed to FERC. Change in status filings must be made within 30 days of the change occurring. Energy storage companies with market-based rate authority must therefore, continually evaluate the need to file a change in status report with each new business change or new affiliation.

Certain entities are exempt from the requirement to obtain market-based rate authority. For example, qualifying small power production facilities that are 20 MW or smaller are exempt from the filing requirement and approval process.

Public Utility Holding Company Act of 2005 (PUHCA)

A public utility holding company is a company that directly or indirectly owns, controls, or holds, with power to vote, 10 % or more of the outstanding voting securities of a public utility company or a holding company of any public utility company. A public utility company includes companies that own or operate facilities used for the generation, transmission, or distribution of electric energy for sale.

Unless otherwise exempted, public utility holding companies must maintain and make available to FERC such books and other records as FERC determines are relevant to the costs incurred by an associate public utility or natural gas company and necessary or appropriate for the protection of customers with respect to jurisdictional rates. One possible exemption from FERC's books and records requirements for public utility holding companies is if the holding company owns only one or more of the following types of facilities: (1) qualifying facilities (QFs); (2) exempt wholesale generators (EWGs); and (3) foreign utility companies. The criteria for EWGs and qualifying facilities (QFs) can be applied to energy storage companies to qualify for the books and records exemption.

Exempt Wholesale Generator

A EWG is any person engaged in the business of owning or operating one or more eligible generating facilities and selling electric energy at wholesale. Although the EWG definition requires that the entity be "exclusively" in the business of selling electric energy at wholesale, FERC has recognized certain incidental activities, such as selling ancillary services, as permissible activities to retain EWG status.

An entity obtains EWG status by either filing a notice of self-certification with FERC demonstrating it satisfies the definition of a EWG or submitting a filing to request a FERC determination that it satisfies the definition. A self-certification notice will be deemed temporarily granted upon filing until further action is taken by FERC. If FERC takes no action within 60 days of filing, the self-certification status is final. All self-certification notices filed with FERC also need to be served on the state regulatory authority of the state in which the facility is located.

While FERC has acknowledged that electric storage devices do not readily fit into the traditional asset functions of generation, transmission, or distribution, it has accepted notices of EWG self-certification from energy storage resources that demonstrate that they will operate in such a manner that their facilities will be engaged directly and exclusively in selling electric energy at wholesale. Accordingly, to determine whether a particular energy storage facility will qualify as a EWG, the particular operational characteristics of the facility will need to be examined.

Qualifying Facilities

The Public Utility Regulatory Policies Act of 1978 established a new class of generating facilities known as QFs that receive special rate and regulatory treatment. QFs fall into two categories: qualifying small power production facilities and qualifying cogeneration facilities. Small power production QFs are 80 MW or less and have a primary energy source that is either renewable (hydro, wind, or solar), biomass, waste, or geothermal. Cogeneration QFs must meet certain operational and efficiency requirements and produce both electricity and another form of useful thermal energy (heat or steam) in a way that is more efficient than producing them separately.

In addition to being relevant to the PUHCA books and records exemption discussed above, QFs also benefit under federal law and FERC regulation by having, in certain circumstances, the option to require the electric utility with which they are directly interconnected to purchase their power. QFs also qualify for additional relief from certain other regulatory burdens.

An owner or operator of a generating facility with a maximum net power production capacity of more than 1 MW may obtain QF status by either submitting a self-certification or by applying for FERC certification. Eligible facilities that are 1 MW or less can obtain QF status without any filing. For an energy storage facility to be a QF, the facility must satisfy the QF fuel source requirements as well as the capacity limitations. For example, a battery storage facility could claim QF status by asserting that its battery system will take its input from 100% renewable energy resources. Whether FERC would agree with such an interpretation is unclear, however, particularly if the facility's configuration could later be changed to allow the battery to be charged with power sourced from the grid.

Transactions Involving Energy Storage Facilities

FERC has statutory authority to review and approve transactions involving public utilities, which may include transactions involving energy storage facilities. For transactions requiring FERC approval, FERC authorization must be obtained before completing the transaction. FERC must act on applications for transaction approval within 180 days, but can toll the time for an additional 180 days for good cause. Applicants can request expedited treatment, however, and in practice most applications are approved in less than 180 days. Nonetheless, energy storage companies engaged in transactions subject to FERC approval should factor in time for the approval process, particularly for transactions involving novel applications of energy storage technologies.

LOOKING AHEAD

MULTIUSE APPLICATIONS

When evaluating energy storage options at the wholesale, distribution, or behind-the-meter levels, sophisticated industry participants consider the multiple applications that energy storage systems can provide across the full electricity value chain. These multiple uses can include:

ISO/RTO Level	Utility Level	Customer Side ("Behind the Meter')
Energy Arbitrage	Resource Adequacy/Flexible Resource Adequacy	Time-of-Use bill management
Frequency Regulation	Distribution deferral	Increased PV self-consumption
Spinning/ Non-Spinning Reserves	Transmission congestion relief	Deman charge reduction
Voltage Support	Transmission deferral	Backup power
Black start	Peaker deferral	

Depending on the goal for the particular storage system, energy storage system operators can combine more than one of these energy storage applications to increase the system's value proposition more quickly recoup and investment costs. One issue, however, is how to separately value each use of an energy storage resource. For instance, while there is pricing for resource adequacy and spinning reserves services in most wholesale electricity markets, it's more difficult to value avoided transmission and distribution upgrades.

Moreover, due to structural or regulatory hurdles and barriers to entry, not all of these applications can be combined readily with each other. For instance, utility-level applications like transmission deferral cannot be combined easily with behind-the-meter applications like time-of-use bill management. Some state-level storage incentives are unavailable to storage resources that already participate in net-metering programs.

Most observers agree that regulatory charges are needed to unlock the full value of energy storage resources. Utilities and grid operators are considering different scenarios where storage systems can provide services along multiple parts of the electricity value chain. One example is in California, where utilities have considered the possibility of a retail energy storage system(s) providing wholesale demand response or permanent load reduction (which CAISO could treat as a supply resource under its tariff). Regulators and electricity system stakeholders in Hawaii, Massachusetts, Minnesota, New York, and Texas are all considering similar issues to bridge the transmission-distribution divide.

Given the financial benefits presented by multiple use storage applications, one can expect additional development of the financial, regulatory, and legal changes necessary to unlock the full value of a storage resource. These structures will include, for example, lenders and borrowers coalescing around financial modeling that incorporates stacking multiple uses for an energy storage system, grid regulators and operators addressing tariff barriers to multiple use applications for energy storage systems, and owners and operators of energy storage systems developing contractual and compliance processes to operate these storage systems for multiple customers across different regulatory programs. All of these issues, and many more, provide the opportunity to shape the energy storage market going forward and promise a more reliable resilient grid.

RENEWABLES PLUS STORAGE

Hybrid Projects: Integration of Energy Storage and Renewable Electricity Generation

The combination of renewables generation, cost-effective energy storage, and advanced power control technologies has been called a killer app for energy. Hybrid generation-storage solutions offer a wide range of benefits for both customers and grid operators. Applications for hybrid projects span the market, from microgrids and behind-the-meter hybrids for residential and commercial customers, to utility-scale projects serving as important additions to grid service offerings.

Costs for both energy storage and renewables generation have been steadily decreasing. With the improving economics, many use cases for solar-plus-storage and wind-plus-storage are coming into economic feasibility. Of the 13 different energy storage services identified in the recent Rocky Mountain Institute (RMI) report *The Economics of Battery Storage*, RMI states at least eight can now be achieved cost-effectively in renewable-storage combinations. These use cases include demand charge reduction and peak shaving to reduce costs resulting from time-of-use charges; frequency regulation; and grid services such as reactive power and voltage control. For commercial customers, distributed storage-generation hybrids can provide a reliable source of back up power, a need that is becoming more imperative as disruptive weather events become more common.

A global consultancy, Lux Research, has estimated that the global market for distributed storage for solar systems will reach $8 billion by 2026.

New integrated renewables generation and energy storage projects are coming online rapidly, with pricing that would have seemed years away as recently as 2016. In June 2017, Tucson Electric Power (TEP) announced a PPA for a project combining 100MW of solar and a 30MW, 120MWh energy storage facility, with a PPA rate of 4.5 cents per kWh over its 20-year life.

Other technologies may be poised to bring costs down even further. For example, ViZn Energy Systems offers a flow battery and solar hybrid that it asserts will be better suited to large scale storage firmed renewable power plants such as the TEP project. ViZn analyzed its flow battery solution using the metrics of the TEP project, and concluded that it could compete at the price of 4.0 cents per kWh, based on substantially lower battery replenishment costs over time.

The combination of solar and storage may eventually emerge as an economically superior alternative to natural gas peaking plants. A pending procurement in California, for the proposed 262 MW Puente natural gas plant, may bring these economics in direct competition. A recent study submitted to CAISO by the Clean Coalition estimates that the installation costs for a solar plus storage solution would be $267 million, versus $299 million for the currently proposed natural gas plant (it is worth noting, however, that CAISO's study estimated that a combination of grid-connected storage and distributed energy resources would cost $805 million or more). A number of other U.S. utilities have launched programs to procure or otherwise support hybrid storage projects.

When costs for integrated storage drop below a certain level, whether it is one half or even more of today's prices, a tipping point is likely to occur that could see this solution displace gas peakers on a widespread, even global basis.

Integrated Solar plus Storage Power Purchase Agreement (Solar plus Storage PPA)

Solar plus Storage PPAs are already common in places like Hawaii, where the cost of electricity supports the economics of combining renewable energy with storage technology. The Solar plus Storage PPA used in such behind-the-meter applications will be similar to the third-party PPA structure commonly used for the on-site solar projects.

Solar plus Storage PPAs have been used primarily for behind-the-meter projects in markets where the retail price of electricity is high and net metering may no longer be a viable option. Utility-scale integrated solar and storage systems, however, are also making an appearance. In 2015, Kaua'i Island Electric Cooperative's (KIUC) signed a 20-year PPA for such a project that would store solar energy from 17 MW of solar PV during the daytime and make 52 MWhs of storage (i.e., 13 MWs of storage available for 4 hours) to help meet the cooperative's evening peak. In 2017, KIUC entered into a PPA with AES Distributed Energy, which is expected to combine 28 MWs of solar PV with 20 MWs of batteries capable of five hours of discharge. The price tag for the output of the AES project is reported to be 11 cents per kWh, a decline from the 13.9 cents per kWh reported for the previous project.

Hawaii has been a logical proving ground for hybrid solar plus storage projects because the market price for electricity is set by imported fossil fuels, which results in the highest retail electricity prices in the United States. Nevertheless, integrated energy storage and renewable energy projects may prove a viable alternative to peaking resources on the mainland, at least where there is a strong solar resource. For example, Tucson Electric Power announced in 2017 that it had entered into a PPA with NextEra Energy for the output of a 100 MW solar PV project and a 30 MW, 4 hour energy storage system (120MWh), at a reported all-in price of 45 cents per kWH.

Business Model and Regulatory Issues

While the benefits are strong, integrated renewable plus storage projects pose regulatory and financing challenges. The theoretical returns available through the prospect of stacking multiple value streams can be difficult or impossible to attain in practice, given regulatory and utility constraints. They also present modeling challenges in assessing net present value of and projecting future cash flows.

Some of the key issues for project finance for renewables-storage hybrids include:

Tax Credit Uncertainties

The IRS has provided guidance regarding eligibility of storage to be considered part of a solar project to receive the federal Investment Tax Credit (ITC), stating that if the storage equipment is part of a single project with solar equipment, the storage investment will be eligible for the ITC provided at least 75% of the charging of the storage unit is through the solar generation. However, IRS indicated that the amount of the credits would be calculated over time, based on the percent of charging from solar versus charging from the grid. This approach is inconsistent with standard structures for tax equity financing, where the amount of the tax credits is locked in at the outset and certainty is required to assess the rate of return. The need to maintain eligibility for the ITC could also result in sacrificing potential economic gains that could be realized by charging from the grid through forms of energy arbitrage. On the other hand, the flexibility of storage systems to provide different grid services and economic use cases over time may serve to mitigate these concerns. Once the available tax credits are obtained, the project may then be reconfigured to provide other benefits.

Regulatory Compliance and State Public Utility Commission Requirements

Solar-plus-renewables projects can raise tricky issues for compliance with federal and state regulatory requirements. At the federal level, adding storage that may be charged from the grid can call into question a renewable generator's ability to meet Qualified Facility (QF) status for exemption from utility requirements. Owners must also evaluate whether storage facilities may subject them and any affiliates and investors to potential requirements under the Public Utilities Holding Company Act. At the state level, varying approaches to the regulation of "generation" facilities and "public utilities" can further contribute to the regulatory uncertainties. Finally, determining and meeting PUC interconnection requirements can become more challenging for hybrid storage projects, and can result in increased interconnection fees and delays in the study process.

Equipment Warranties, Software Systems, and Performance Guarantees

Combining generation and storage increases the matrix of operational risks and control issues that will impact performance. Developers and equipment and software suppliers will need to meet these additional challenges with financial backstops such as warranties and guaranties with assurance of financial resources standing behind them. These complications and risks add to the challenges for project financing.

Availability of State Incentives

A number of states, including California, Oregon, Massachusetts, and Maryland, are actively promoting storage and storage hybrids with incentives such as grant programs and procurement targets. Such incentives may make the difference for economic viability for many types of projects.

Role of Storage in Corporate PPAs

Large corporate power purchasers have been a major driver of renewables project development over the past three years. Several large corporates are showing active interest in hybrid projects adding storage. But for these buyers the ability to support sustainability claims is a key ingredient. Where storage is added that is intended to be charged both from renewables and the grid, the validity of renewable energy credits (RECs) that may be necessary to support sustainability claims may be called into question, or additional RECs may need to be procured.

Expanding the Types of Hybrid Combinations

While much of the focus has been on solar-plus-storage, combining storage with wind power or other generation such as natural gas or biomass are gaining traction. Danish energy giant DONG has a project to add a 2 MW battery storage system to a 90 MW wind farm in the United Kingdom. AES recently announced a $2 billion project to combine 100 MW of four-hour duration storage with a repowered 1.3

GW combined cycle gas plant, under a 20-year PPA with SCE. In fact, SCE has already installed a pair of 11 MW, 4.3 MWh battery storage systems at two existing 50 MW gas peaker plants in the Los Angeles basin. The batteries allow SCE's gas peakers to respond more quickly to frequency regulation signals and are expected to allow the peakers to avoid operating costs, reduce emissions, and cut water use.

AES also has combined storage with wind in prior projects, notably the 98 MW Laurel Mountain Wind Farm in West Virginia, which includes a 32 MW battery storage project. These are just some early examples, as the potential combinations are expanding rapidly with the improving technology and economics.

For a given project, the decision whether to combine storage and generation may turn on assessment of regulatory and financing issues. The potential benefits may be large, but the path to achieving them must be clear and viable. The industry has much work ahead in supporting market reforms and achieving financing models that will support widespread deployment of storage and renewables hybrids. With improving economics and more advanced technologies, however, the incentives to tackle and solve these problems are stronger than ever.

VEHICLE TO GRID

Vehicle-to-grid (V2G) technology is being studied as a means of addressing many of the inefficiencies of intermittency posed by renewable resources. V2G is characterized by the reciprocal flows of power between the grid and electric or plug-in hybrid vehicles (collectively, EVs). The goal of V2G technology is to transform EVs into mobile energy storage systems that can act as virtual distributed generators—storing excess wind and solar generation during off-peak periods, and then offering that power back to the grid during periods of peak demand.

Because most vehicles remain parked for an average of 23 hours each day, EV batteries can serve as temporary storage to soak up excess energy generated from renewable sources. By releasing energy during peak demand, a decentralized network of EV batteries can also alleviate transmission congestion and defer capital investment in distribution, transmission, and peaking assets that might otherwise be needed. V2G's stabilizing effects could also contribute to solving the problem of the "duck curve," where periods of peak renewable generation and of weak demand coincide (and vice versa).

The EV market is expected to accelerate over the next decade, posing several opportunities for V2G technology. By 2019, the United States is expected to be the home of 1 million EV drivers, spurred in part by federal and state incentives that recognize EVs lower carbon footprint. EVs are gaining similar market share in Europe and around the globe. China aims for EVs to comprise one-fifth of its annual car sales by 2025, while India is considering an even more ambitious goal of pivoting toward a total EV-based economy by 2032.

As the EV market continues to expand major corporations and universities are responding to market signals and have begun racing toward the broad implementation of V2G technology in EVs. For example, PG&E and BMW recently demonstrated the potential of V2G technology through their joint iChargeForward program. The program tested 100 EVs during 209 demand response events over an 18-month period, and found that EVs utilizing the V2G system provided 20% of the total 19,500 kilowatt-hours of response during those events. Nissan, Enel, Daimler AG, and others are also pursuing similar efforts and initiatives. The University of California, Los Angeles is researching improvements to attain maximum V2G power generation from each EV, while also improving response time and power sharing control significant investments are being made to incorporate EVs into the grid.

As V2G technology continues to develop, there will likely be new and novel relationships among vehicle owners, EV charging station owners, and local utilities. A legal framework will need to be developed to govern both the purchase and sale of energy among these entities and for integrating EVs with utility distribution systems. There are also implications for regulators, with FERC, RTO/ISOs, and state utility commissions all having a role to play in ensuring effective integration of V2G technology.

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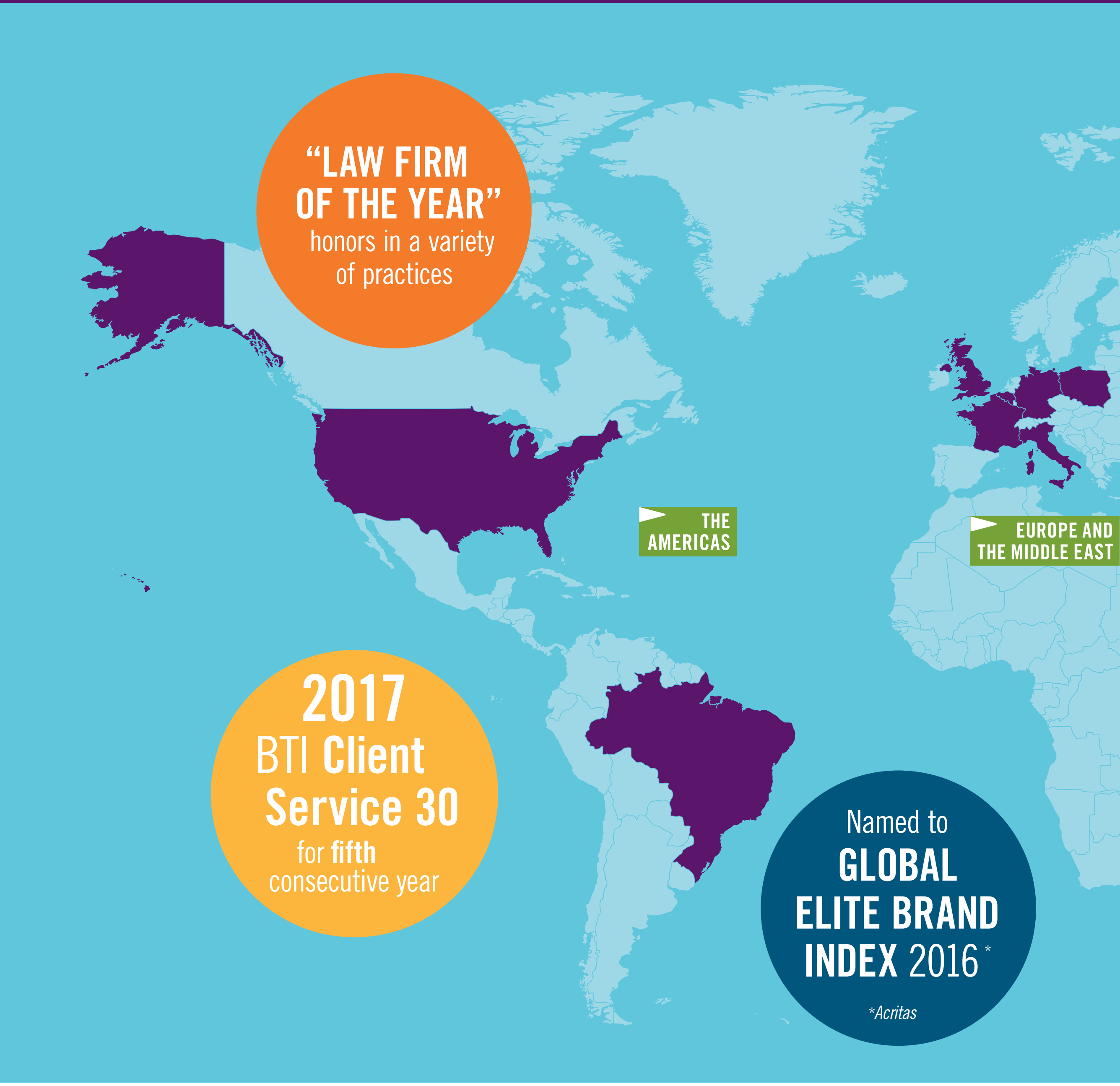

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