K&L GATES

ENERGY STORAGE HANDBOOK

APRIL 2019

VERSION 4

NEW IN VERSION 4

- The latest in financing and solar + storage agreements
- New developments for California, and New York
- New insurance products to mitigate performance risk
- Reviews of the RTO/ISOs' FERC Order 841 compliance filings
- Review of FERC Order 845-A, clarifying and revising Order 845

TABLE OF CONTENTS

INTRODUCTION

As of today, at least 1 gigawatt (GW) of advanced energy storage technologies have been contracted for or 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. However, 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. Load, or electricity demand, generally increased year-over-year as the country prospered and Americans needed more power for their dishwashers, televisions, and refrigerators.

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, cities, and (increasingly) corporate actors 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 collocated 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, 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 by more than 25% 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 resulting in 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 continuing to update this Handbook as additional states and stakeholders continue to address the implementation of energy storage resources into the marketplace.

We hope you find it useful and welcome your feedback.

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 more than 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 2018, lithium ion solid state batteries made up most of the market share for energy storage while vanadium flow batteries and lead-acid solid state batteries represented a smaller portion of the market. Technological advancements have improved the reliability and output capacity of battery technology 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.

Power-to-Gas

Power-to-Gas storage converts electrical energy into stored chemical energy in the form of hydrogen gas by using electrical energy to split water into hydrogen and oxygen through the process of electrolysis. The resulting hydrogen (or, upon further conversion, methane) can be stored either in a dedicated storage facility or by injection into the gas grid and then used as a fuel for generating electrical energy at a later time. Power-to-Gas storage can have significant benefits when local gas infrastructure is more accessible than power infrastructure for transmission of stored energy. Storing energy in the form of natural gas can also result in benefits from its access to the vast storage capacity of the existing natural gas grid and lower losses during the transmission process. Increasingly, Power-to-Gas is viewed as a longer-duration, seasonal storage solution.

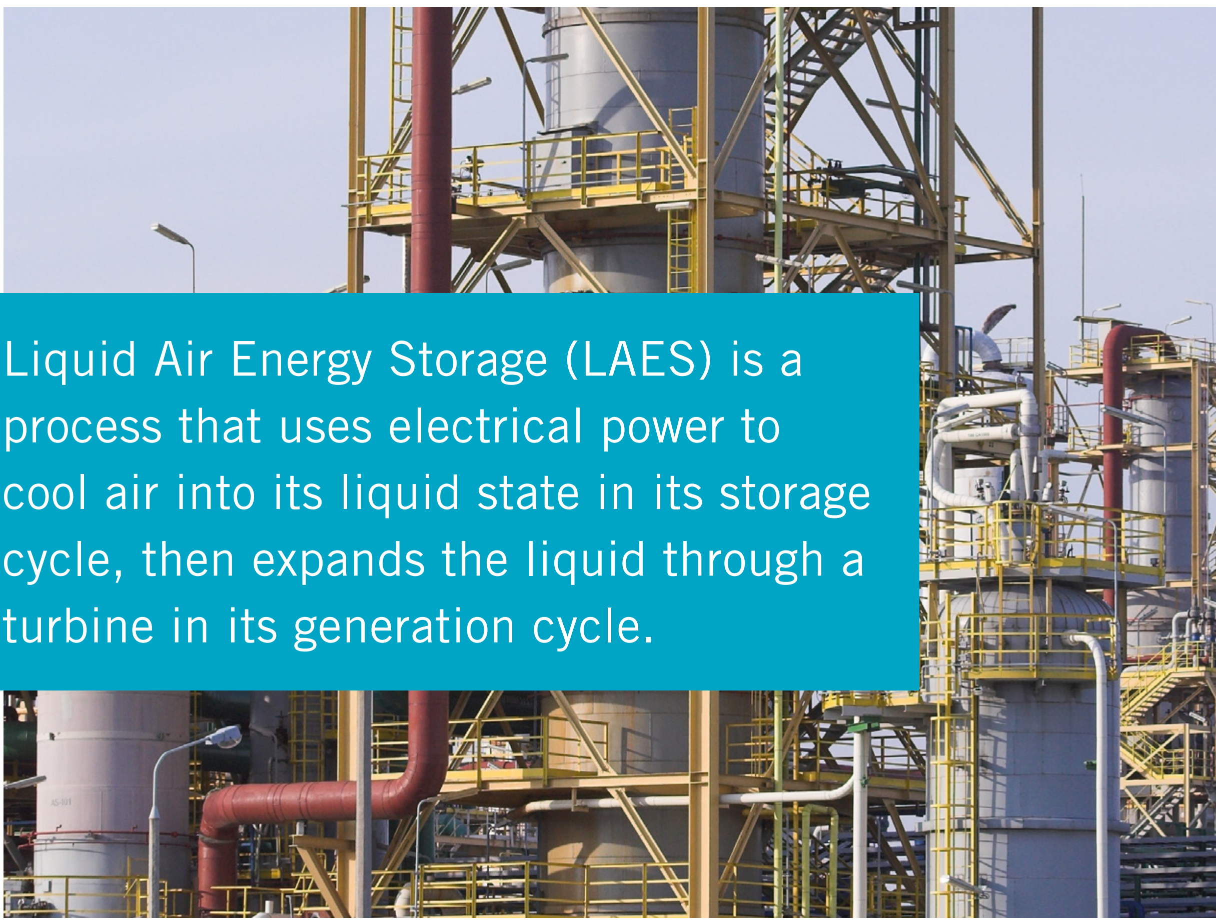
Thermal

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.

Thermal energy storage can be particularly effective for long-term storage, which is growing increasingly important in markets with greater reliance on renewable energy resources because those resources are often seasonal in nature. For example, over the last 10 years Denmark has installed a number of storage projects using water in underground pits as the storage medium, where the storage can be charged to 85° C during summer months when solar energy resources are plentiful and discharged to 10-15° C during winter months when the need for electricity is greater and the hours of sunshine are more limited.

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.



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. 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. Most importantly, FERC issued a rule in February 2018 to encourage deployment of energy storage projects in organized wholesale markets, creating opportunities to shape the implementation of these policies at the wholesale transmission operator level.

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.

Expanding Energy Storage Opportunities in Wholesale Markets – FERC Order 841

On February 15, 2018, FERC issued a Final Rule addressing participation of energy storage resources in electricity markets (Order 841) operated by Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs). Largely adopting the proposal issued in November 2016, Order 841 seeks to remove barriers for energy storage participation in wholesale capacity, energy, and ancillary services markets.

Order 841 directs RTOs and ISOs to revise their tariffs to develop a participation model that better incorporates energy storage into the market, including implementing processes that accommodate the physical and operational characteristics of energy storage systems. Recognizing that as of March 19, 2018, several parties have asked FERC to clarify and/or reconsider portions of Order 841, FERC mandates that such revisions should:

- Allow energy storage resources to be eligible to participate in all capacity, energy, and ancillary services markets that the resource is technically capable of providing;
- Ensure that storage resources under the participation model can be dispatched and establish the wholesale market clearing price as a wholesale seller and/or buyer;
- Account for electric energy storage's physical and operational characteristics (via bidding parameters or other means); and
- Set a minimum size requirement for storage resources' participation in the RTO and ISO markets of not more than 100 kilowatts (kW).

In addition to these market requirements, FERC also determined that electric storage resources should pay the wholesale locational marginal price (LMP) for electric energy that the resource buys from the RTO or ISO (presumably to charge the resource) that is then resold back into the RTO or ISO.

FERC deferred ruling on a companion proposal addressing participation of distributed energy resources (DERs) in wholesale markets, setting a technical conference on the topic for April 10-11, 2018, in Washington, DC. FERC plans to discuss the following topics:

- Economic dispatch, pricing, and settlement of DER aggregations;
- Operational implications of DER aggregations with state and local regulators;
- Participation of DERs in RTO/ISO markets;
- Collection and availability of data on DER installations;
- Incorporating DERs in modeling, planning, and operations studies;
- Coordination of DER aggregations participating in RTO/ISO markets; and
- Ongoing operational coordination.

The RTOs/ISOs began the stakeholder processes necessary to develop their compliance filings and have posted frequent updates on their progress on their respective websites. The compliance filings implementing the required tariff changes are due to be filed with FERC on or before December 3, 2018. FERC will notice the filings and give interested parties an opportunity to review and comment on the proposed changes to the RTO/ISO tariffs. Under Order No. 841, each RTO/ISO has until December 3, 2019 to implement the changes.

On December 3, 2018, the RTO/ISOs filed at FERC tariff revisions to reflect their compliance with Order No. 841. Below is a summary of key takeaways from each compliance filing:

- **CAISO:** CAISO proposed to maintain its existing rules for storage participation in its wholesale market with two key changes to comply with Order No. 841. Specifically, CAISO proposed: (1) to lower the minimum size for storage resources to participate from 500kW to 100 kW and (2) to exempt storage charging energy from transmission charges. CAISO's proposal has been cited by the Energy Storage Association (ESA) as the most compliant with the mandates of Order No. 841. As explained by CAISO, CAISO's existing policies are already aimed at achieving the goal of providing more opportunities for storage. For instance, in 2011 the CAISO established its "non-generator resource," or "NGR" model for storage resources, which is the CAISO's equivalent to Order No. 841's electric storage resource participation model. The NGR model was developed in response to the directives of FERC Order Nos. 719 and 890 to facilitate the provision of ancillary services by resources capable of both injecting and withdrawing energy. CAISO is also well under way on three phases of its Energy Storage and Distributed Energy Resource ("ESDER") initiative, which sought to solve the CAISO-related issues identified in the California Energy Storage Roadmap and solicit additional suggestions from stakeholders on storage-related issues. FERC approved phase two of its initiative in 2018. Consistent with Order No. 841, CAISO requested an effective date of December 3, 2019.
- **NYISO:** NYISO's proposal creates a new designation for Energy Storage Resources ("ESRs")--a subset of generators under the tariff. NYISO also revised its Installed Capacity market requirements to allow ESRs to spread their full capability over four hours to meet the minimum four consecutive hour run time qualification requirement. However, NYISO's proposal requires that NYISO manage a battery's state of charge in the day-ahead market, which has been criticized because it limits the flexibility of storage resources. Other stakeholders (including the New York Public Service Commission) have also criticized NYISO's proposal for creating barriers to entry for storage that allegedly violate Order No. 841. According to the protests, these barriers include NYISO's proposal to require separate wholesale metering for ESRs that are co-located with load behind the meter and NYISO's proposal to prohibit storage from participating in both wholesale markets and retail utility programs

until NYISO can develop rules for dual participation. NYISO requested that its implementation deadline be extended to May 1, 2020, because the software platform upon which the proposed revisions will be implemented is currently undergoing "a significant upgrade."

- **PJM:** PJM filed two separate proposals that together constitute its participation model for energy storage resources. Its "ESR Markets and Operations Proposal" expands ESR and Capacity Storage Resource designations to include all storage technologies. However, PJMs' proposal has been criticized for lacking state-of-charge parameters and requiring a ten-hour capacity duration requirement that makes it difficult for energy storage to participate in the capacity market. PJM requests approval for the ESR Participation Model by May 30, 2019 to have sufficient time to develop required software for a December 3, 2019 implementation. PJM also filed an ESR Accounting Proposal that allows PJM to test its proposed accounting methodologies and gather sufficient data before full deployment of the ESR Participation Model. On February 1, 2019, FERC issued a letter order accepting PJM's proposal, effective on February 3, 2019.
- **SPP:** SPP filed an Order 841 compliance plan that largely tracks the order's mandates. While SPP proposes a participation model for ESRs to participate in the market[1] under the resource registration name Market Storage Resources (MSRs), its proposal also allows ESRs to participate through existing participation models if they meet the requirements. SPP also proposes allowing ESRs to fulfill Load Serving Entity resource adequacy requirements if the ESR meets the continuous run time requirement applied to all resource types. Additionally, SPP assumes that the market participant (rather than system operator) will manage the ESR's state of charge. Several commenters sought clarification about certain aspects of the filing, including how ESRs would meet resource adequacy requirements and about distribution grid and participation issues. After originally requesting FERC's approval of the filing by March 1, 2019, SPP requested to defer FERC's approval until July 1, 2019 due to computer system infrastructure delays. The Energy Storage Association submitted a comment requesting that FERC order SPP to submit quarterly progress reports to ensure SPP's diligent effort to meet its deadlines.

1 Note that SPP manages the Integrated Marketplace, which is "a centralized day ahead and real-time energy and operation reserve market with locational marginal pricing and market-based congestion management." *SPP Compliance Filing*, Docket No. ER19-460 (Accession No. 20181203-5199).

- **MISO:** MISO's electric storage participation program will apply to all types of energy storage, including resources serving as non-wires alternatives to transmission and distribution needs. MISO proposed to alter the definition of "commitment status" for ESRs, allowing them to signal their availability and the manner in which they will provide products and services over time periods. MISO also requires execution of a new *pro forma* Distribution ESR Agreement for ESRs that connect to the distribution system. MISO requested approval by April 2, 2019 in order to implement its plans by December 3, 2019. Commenters have requested an explanation of whether and to what extent an ESR will be liable for transmission charges. MISO's effective date for implementation is December 3, 2019, at which time eligible ESRs can register for the quarterly update of MISO's proposed models, which will be effective on March 1, 2020.
- **ISO-NE:** ISO-NE's compliance filing explained how recent tariff changes,[2] including adding new categories of storage resources, meet Order No. 841 requirements. As part of its Order 841 compliance, ISO-NE also proposed revisions in October 2018 that were accepted by the FERC in February 2019.[3] The proposed revisions apply to resources that meet the requirements of a Continuous Storage Facility. Among other things, Continuous Storage Resources must be able to transition between the facility's maximum output and maximum consumption in ten minutes or less. The new rules provide mechanisms for Continuous Storage Resources to participate in ISO-NE's energy, reserves and regulation markets. The December 2019 Compliance filing proposed terms to distinguish between fast responding storage resources (i.e., Continuous Storage Facilities) and pumped-storage hydro-power (i.e., Binary Storage Facilities). Both types may participate in the ISO-NE's markets under different registration requirements and designations. ISO-NE's provisions stated that implementation would occur by December 3, 2019, except regarding Dispatchable Asset Related Demand ("DARD") regulation for which ISO-NE requested an implementation date of January 1, 2024. Among other issues, protests of the filing expressed concern over ISO-NE's proposed automatic de-rating of ESRs energy output capability, which ensures 60-minute availability to provide reserve, but protesters assert is inconsistent with Order No. 841.

[2] See FERC Docket No. ER19-84-000.

[3] *ISO New England Inc.*, 166 FERC ¶ 61,146 (2019).

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 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 primary frequency response service (as distinct from regulation service). Order 819 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 "nonwire" 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 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.

Reform of Generator Interconnection Procedures and Agreements - FERC Order 845

On April 19, 2018, FERC issued a Final Rule to amend the pro forma Large Generator Interconnection Procedures ("LGIP") and Large Generator Interconnection Agreement

("LGIA") to improve reliability, promote more informed interconnections, and enhance generators' interconnection processes by eliminating inefficiencies and bottlenecks. Order No. 845's reforms to the interconnection process create significant opportunity for energy storage resources. As an initial matter, Order No. 845 reforms the pro forma interconnection agreements and procedures to include energy storage in its relevant definitions. The Order also allows customers to connect at less than nameplate capacity and to take advantage of excess interconnection capacity already available on the transmission system. Both of these developments are expected to benefit energy storage resources because they will allow those resources to pair with existing generation with little or no additional interconnection costs. Similar to FERC's recent Order No. 841, with Order No. 845, FERC continues to unlock opportunities for energy storage to participate in the wholesale power markets.

On February 21, 2019, FERC issued Order No. 845-A that clarified and revised aspects of Order No. 845 based on the comments and issues that had been raised since its issuance. Relevant to energy storage, Order No. 845-A clarifies that for an entity to take advantage of surplus interconnection capacity, it can only do so if the surplus interconnection capacity can be accommodated without requiring the construction of new network upgrades. This will be relevant as the transmission provider analyzes the impacts of storage projects using excess interconnection capacity of a different type of generation resource. Order No. 845-A also clarified that transmission providers must develop a definition of permissible technology changes that the interconnection process will accommodate without the loss of a queue position pursuant to the material modification provisions of the LGIP. The effective date for Order No. 845-A is May 20, 2019.

Requirements to Provide Primary Frequency Response - FERC Order 842

On February 15, 2018, FERC issued a Final Rule that amends the pro forma Large Generator Interconnection Agreement ("LGIA") and the pro forma Small Generator Interconnection Agreement ("SGIA") to require all new large and small generating facilities, both synchronous and non-synchronous, to install, maintain, and operate equipment capable of providing primary frequency response as a condition of interconnection. FERC also establishes certain uniform minimum operating requirements in the pro forma LGIA and pro forma SGIA, including maximum droop and deadband parameters and provisions for timely and sustained response.

The Notice of Proposed Rulemaking that preceded the Final Rule included no provisions specific to electric storage resources. However, several commenters raised concerns that by failing to address electric storage resources' unique technical attributes, the proposed requirements could pose an unduly discriminatory burden on storage resources. As a result, the Final Rule adopted changes specific to electric storage resources. Specifically, the Final Rule required transmission providers to include in their LGIAs and SGIAs specific accommodations and limitations on when electric storage resources will be required to provide primary frequency response. For example, new interconnecting electric storage resources will be required to specify an operating range representing the minimum and maximum state of charge over which the resource will provide primary frequency response. The Final Rule became effective on May 15, 2018.

FERC Order on Southern California Edison's Wholesale Distribution Access Tariff Revisions - Ensuring Fairness for Energy Storage Customers

On August 23, 2018, FERC issued an Order that denied proposed revisions to Southern California Edison Company's ("SoCal Edison") Wholesale Distribution Access Tariff ("WDAT") that would have treated customers with energy storage devices differently from those without them. On March 30, 2018, SoCal Edison filed proposed revisions to its WDAT with a purpose of facilitating the interconnection of energy storage devices to SoCal Edison's system and updating the terms of its Generator Interconnection Procedures (GIP) to be consistent with CAISO's Tariff. Specifically, SoCal Edison proposed to modify its WDAT to allow it to curtail electricity service to customers with energy storage devices, "if necessary," before it did so with retail and wholesale distribution load "to maintain distribution system reliability."

FERC found that SoCal Edison failed to demonstrate that it was just and reasonable to curtail one class of an interconnection customer's load over another "without providing an opportunity to have the energy storage device's load studied and to pay for the system upgrades needed to allow its load to have the same curtailment priority as other wholesale loads." FERC encouraged SoCal to continue to develop procedures

to study energy storage devices' charging demands in a non-discriminatory manner. FERC approved other changes to SoCal Edison's WDAT not related to energy storage and directed SoCal Edison to submit a compliance filing by September 24, 2018 to remove the rejected language from its tariff records.

ISO-NE Proposes to Codify New Enhancements for Participation of Emerging Storage Technologies in the New England Markets

On October 10, 2018, ISO-NE submitted revisions to its tariff codifying a new design to enhance the ability of emerging storage technologies that will allow for easier participation in New England markets. ISO-NE has a history of experience with other storage resources, such as hydroelectric pumped-storage. ISO-NE has applied lessons from these experiences to help integrate the growing industry of battery storage. The revisions will, among other things, add definitions regarding available energy, available storage, and maximum daily energy limit; lower the minimum size requirement for Electric Storage Facilities (ESFs); enable all technologies to participate under ESF rules; and create an effective date for dispatchable-asset-related demands to participate in Regulation Market. These battery storage revisions will allow the new technologies to be dispatched in the Real-Time Energy Market, while utilizing their ability to transition continuously and rapidly between charging and discharging states. The revisions will also allow the technology to participate simultaneously in energy, reserves, and regulation markets.

If approved, the storage revisions move ISO-NE much further to meeting the compliance requirements of Order No. 841. ISO-NE noted the filing deadline for

revisions to comply with Order No. 841 as December 3, 2018 with an effective date of December 3, 2019. ISO-NE will file any remaining measures for complying with the order separately and no later than December 3, 2018.

NorthWestern Corporation Petition -- Combining Storage and Solar under PURPA

On August 31, 2018, FERC received a petition from NorthWestern Corporation to invalidate the QF status of four wind projects due to the proposed addition of battery storage to their sites. The claim arose under FERC's one-mile rule where FERC will aggregate the capacity of generating facilities that: (1) are located within a mile of each other; (2) use the same energy resource (e.g. solar or wind); and (3) are owned by the same persons or their affiliates. The question raised is whether the definition of co-located QFs should include battery storage facilities with wind and solar generation facilities or whether a battery storage facility will be treated separately. October 1, 2018 was the comment deadline for the petition.

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 that themselves qualify for federal tax incentives. 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. In addition, guidance released by the Internal Revenue Service (IRS) in March 2018 that concerns the residential tax credit available under Code Section 25D implies that storage installed for use with a facility that qualifies for the ITC after such facility has been placed in service *may* separately qualify for the ITC; however, the guidance does not state that conclusion directly. There are also arguments, but considerably less certainty, that storage installed after a PTC-qualified facility is placed in service may separately qualify for the ITC if such facility would have qualified for the ITC.

There is hope that Treasury will release additional guidance regarding the qualification of energy storage assets for the ITC. On September 20, 2018, Senators Tim Scott (R-SC) and Michael Bennet (D-Co) sent a letter to Treasury Secretary Mnuchin asking him to provide that guidance, particularly in regard to whether storage assets installed at operating ITC-eligible facilities qualify for the ITC. In addition, on April 4, 2019, U.S. Representative Mike Doyle (D-PA-18), together with co-sponsors, U.S. Representatives Linda Sánchez (D-CA-38) and Earl Blumenauer (D-OR-3), introduced the Energy Storage Tax Incentive and Deployment Act, which would authorize the ITC for standalone storage.

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, but is currently being phased out for most technologies. (The maximum PTC rate applies to facilities the construction of which began in 2016 or earlier and that meet certain other requirements.) The ITC will begin phasing out for solar projects that begin construction in 2020 or a later year. All solar projects must be placed in service by the end of 2023 to qualify for an ITC rate greater than 10%.

Qualification of Energy Storage Property for the ITC and PTC

Energy storage property generally should qualify for the ITC when the storage equipment is placed in service at the same time as an ITC-qualified facility (generally, solar) if at least 75% of the power stored in the battery comes from qualified resources.

YEAR CONSTRUCTION BEGAN	LAST YEAR TO PLACE FACILITY IN SERVICE	ITC RATE
2019	2023	30%
2020	2023	26%
2021	2023	22%
2022, and thereafter	N/A	10%

**If construction begins in 2019, the project should be placed in service within four years after the day on which construction begins.*

Energy storage property also should qualify for the ITC when the storage equipment is placed in service at the same time as a repowered facility, provided that the requirements above are met and 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 proven qualified energy facilities, which may be useful 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).

Standalone storage does not currently qualify for the ITC, but legislation was recently introduced to create a new category of ITC for standalone storage. In addition, see the discussion below about Opportunity Zones.

Although energy storage technologies that store electricity produced by a qualified energy facility should independently qualify the residential solar energy credit under Code Section 25D, it is not clear that they would qualify for the ITC. Private Letter Ruling 201809003,[1] which was released by the IRS on March 2, 2018, concludes that the cost of a battery installed to store power produced by a residential solar system the original installation of which had already been completed *separately* qualified for the Code Section 25D residential tax credit. Importantly, the IRS expressly stated in PLR 201809003 that it will treat the battery as property that "uses solar energy to generate electricity," provided that only solar energy is used to charge it. This is important because the same phrase is used in Code Section 48 to describe solar energy property that qualifies for the ITC. There are other similarities between the two credits that are also compelling. For example, both credits are only available in respect of the year in which the relevant property is first used. For Code Section 25D purposes, this is the year in which the original installation of the property is completed. For Code Section 48 purposes, this is the year in which the property is placed in service, a very similar test. In addition, Treasury Regulations applicable to Code Section 48 expressly contemplate storage as credit qualifying property. And, although not clear, these Regulations arguably apply even if the storage asset is not placed in service at the same time as the solar panels or similar property that input energy to the storage asset. Nonetheless, the qualification of any storage asset, particularly an asset installed after a related ITC-qualified facility has been placed in service, for the ITC should be evaluated carefully before claiming the ITC in respect of the relevant costs.

The PTC is available only for electricity produced by a "qualified facility," which generally includes all property that is functionally interdependent and is used to produce electricity using a qualified

[4] Private Letter Rulings are binding only in respect of the taxpayer who requested the ruling based exclusively on the facts represented in the ruling requested. Accordingly, other taxpayers may not rely on any conclusion in a Private Letter Ruling, but such rulings may be informative of IRS positions on certain matters.

resource (for example, wind). This property generally includes, for example, equipment used for power conditioning, which may include voltage regulation, which may in turn be provided by certain energy storage systems). However, because the PTC is available only for electricity produced by a qualified facility, 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. In addition, many offtakers will not pay for power lost during storage, which would reduce the amount of PTC available.

Given that PLR 201809003 concluded that a storage asset may qualify for the ITC independently of the facility that inputs energy to the storage asset if all the relevant criteria is met, it its possible--but far from certain--that the cost of a storage asset installed at a facility producing power that qualifies for the PTC may separately qualify for the ITC if such facility would also qualify for the ITC. This is a limited class of assets, particularly given the current sunset periods for "crossover" facilities that can qualify under both Code Sections 45 and 48 at the facility owner's election. In addition, although not certain, it seems the IRS would have very good arguments that the PTC would not be available in respect of power stored in a storage facility located "behind the meter" if the storage facility owner claims the ITC in respect of the cost of such storage facility. Ultimately, this argument is untested and should be evaluated very carefully before claiming the ITC in respect of any storage asset installed to store power at a *PTC-qualified 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 ("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. Otherwise, energy storage equipment is generally depreciated using the MACRS method over seven years.

Renewable energy property that is placed in service before 2023 generally should qualify for immediate expensing, sometimes referred to as "bonus" depreciation. After 2022, bonus depreciation will continue to be available through 2026, but at reduced rates. While bonus depreciation also applies to used property, used property may not account for 20% or more of the value of renewable energy property that is incorporated into a project that is intended to qualify for the ITC.

Energy Storage in Opportunity Zones

The Opportunity Zones ("OZ") incentive provides attractive tax benefits for investors with capital gains and, unlike the ITC, is technology agnostic and available for standalone storage. The program is available for investments in qualifying assets located in one of the more than 8,700 geographic areas that is designated as an OZ. For storage plus facilities, the OZ incentive also can be combined with the ITC and PTC. In addition, any U.S. person and certain non-U.S. persons can invest in a QOF and use the OZ incentive. This includes individuals, corporations, partnerships, and trusts. Partners investing capital gains from a partnership have a longer window to invest in a QOF than the partnership would.

The benefits of the OZ incentive are available when a taxpayer disposes of a capital asset and, within 180 days, invests the proceeds in a qualified opportunity fund ("QOF") that invests in OZ property, either through a direct investment in tangible business property ("QOZBP") or a newly-issued equity interest in a partnership (including an LLC) or corporation operating a business in an OZ ("QOZB"). A QOF can be a corporation or a partnership (including an LLC) for U.S. federal income tax purposes and can function as an investment fund, a private investment entity, or many options in between. A variety of requirements apply to QOFs and QOZBs. For example, at least 90 percent of the QOF's assets (measured by cost or value, depending on the applicable facts) must be invested in OZ property as described above and at least 70% of a QOZB's tangible assets must be located in one or more OZ areas.

The OZ incentive consists of three tax benefits for investors:

- First, federal taxes on capital gains invested in QOFs may be deferred up to the 2026 tax year.
- Second, if the taxpayer holds the QOF investment for at least five years, the gain ultimately recognized may be reduced by 10%. The gain may be further reduced by another 5% if the taxpayer holds the QOF investment for at least seven years.
- Third, if the taxpayer holds the QOF investment for at least 10 years, capital gains realized upon disposition of the investment are free from federal income tax due to a step up in basis of the investment to its fair market value at the time of disposition.

As attractive as the program is, owning storage and storage plus systems through a QOF must be carefully structured in order to ensure compliance with applicable regulations and maximize tax benefits and the investors' rate of return. In addition, the facts and circumstances applicable to each investor require that QOF structures be somewhat tailored to different investors to account for other U.S. federal income tax limitations.

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 and recently extended SGIP that provides consumer rebates worth approximately $800 million through 2026. California has also taken the lead in its efforts to properly value energy storage technologies' many contributions to grid stability and reliability.

In January 2018, the CPUC issued D.18-01-003, which included 12 rules governing how an energy storage resource could participate in several grid domains at the same time (also known as "Multiple Use Applications"). A CPUC working group has continued to explore emerging energy storage use cases, including compensation for CPUC-jurisdictional services, distribution-level energy storage aggregations, and metering and enforcement issues. This working group issued recommendations in August 2018 regarding utility cost recovery, costs for charging storage assets, resource adequacy refinements, and other issues. The CPUC continues to consider how behind-the-meter storage resources can contribute to grid reliability and how to refine interconnection and rate tariffs to enable additional storage and microgrid assets to address California's steep evening ramp.

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 the IOUs 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 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 (four-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. In addition to the Aliso Canyon RFO, SCE procured approximately 260 MW through its 2013 Local Capacity Requirements RFO and approximately 120 MW through its Preferred Resources Pilot 2 RFO. SCE is now seeking to use storage and other preferred resources to meet the Moorpark sub-area's local capacity need, which was until recently proposed to be met by building a new 262-MW gas-fired generator.

The CPUC has also approved PG&E's request to replace three natural-gas fired power plants in the Moss Landing area with 567.5 MW / 2,270 MWh of battery storage projects. The 300-MW project from Vistra Energy and the 182.5-MW project from Tesla would be the largest battery storage projects in the world.. . . PG&E is also planning to replace an aging 165 MW facility in Oakland with a mix of preferred resources, including energy storage. It is anticipated that these battery storage projects will be less expansive than the natural gas and oil peakers that they are replacing.

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.

In March 2018, SDG&E, PG&E, and SCE filed their AB 2868 procurement plans. SDG&E proposes seven storage projects focused on emergency response services (e.g., microgrids for remote fire and police stations) and an incentive program for nonprofit care facilities to install storage. SCE's plan focuses on distribution-connected storage solutions to better integrate distributed renewable resources, and incentivizes up to $10 million of storage development for low-income multifamily housing. PG&E's AB 2868 procurement plan emphasizes distributed resources to improve grid resilience to wildfires. In March 2019, the CPUC rejected many of the proposed projects, however, and issued guidelines intended to lower the barriers for third parties to participate in the development and ownership of front-of-the-meter storage. Storage must be procured via Requests for Proposals and must meet a "least cost, best fit" criteria. The CPUC also found that "heat pump hot water heating thermal storage is a viable behind the meter option for energy storage" and encouraged the utilities to explore thermal storage, which is consistent with the state's growing "electrify everything" movement.

Under AB 2514, AB 2868, and other procurement efforts, California's IOUs have procured approximately 1,620 MW of new California storage capacity, of which approximately 420 MW are online. California's Community Choice Aggregators (CCAs) are also beginning to procure storage, with East Bay Community Energy, Monterey Bay Community Power, Silicon Valley Clean Energy, and Marin Clean Energy all pursuing a variety of standalone storage or solar plus storage projects to provide capacity or defer distribution and transmission upgrades.

Several Energy Storage and Distributed Energy Resource Bills Were Signed Over the Last Two Legislative Sessions

Energy storage bills continue to gain traction in the California legislature. In September 2018, California passed SB 1369, a bill that aims to develop hydrogen as a strategy for seasonal energy storage and to flatten spikes in renewable energy production and late-afternoon demand. SB 1369 requires the CPUC, CEC, and CARB to consider "green electrolytic hydrogen," (i.e., hydrogen produced from electrolysis) as an eligible form of energy storage technology. California's SB 700 also extended the state's Self-Generation Incentive Program, described further below.

These efforts in 2018 built upon a very strong 2017 for energy storage in California. Signed in September 2017, SB 338 requires 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 generation, which can be expensive to run in short bursts and does not advance California's clean energy goals. SB 338 requires 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.

The Assembly passed another storage-oriented bill, AB 546, on September 7, 2017. AB 546 requires 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.

Finally, SB 801 increased 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 was required to complete a study analyzing the cost-effectiveness and feasibility of deploying 100 MW of energy storage in the Los Angeles Basin (the study suggested it would be cost effective starting around 2021). SB 801 also required 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."

2019 has seen additional proposed legislation. For instance, SB 288, the "Solar Bill of Rights Act," would solidify a customer's rights to generate and store energy on their own property and prohibit the utility or municipality from enacting any discriminatory fees for doing so. The bill would also require the CPUC to work with CAISO to facilitate the participation of behind-the-meter resources in the state's wholesale energy market.

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% of total funds are exhausted. 85% of funds are allocated to energy storage technologies, of which 90% are allocated for projects greater than 10 kW in size, and 10% are allocated to the existing carve-out for residential energy storage projects less than or equal to 10 kW 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, a quarter of SGIP funds reserved for energy storage will be reserved for low-income residents, government agencies, educational institutions, nonprofits, and other customers located in areas impacted by environmental concerns. In September 2018, the California legislature added more than $800 million in SGIP incentives and extended the program through 2026. One surprising factor, however, was a CPUC report indicating that behind-the-meter energy storage actually *increased GHG emissions because of insufficient price signals to incentivize charging during periods of peak midday solar generation.*

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

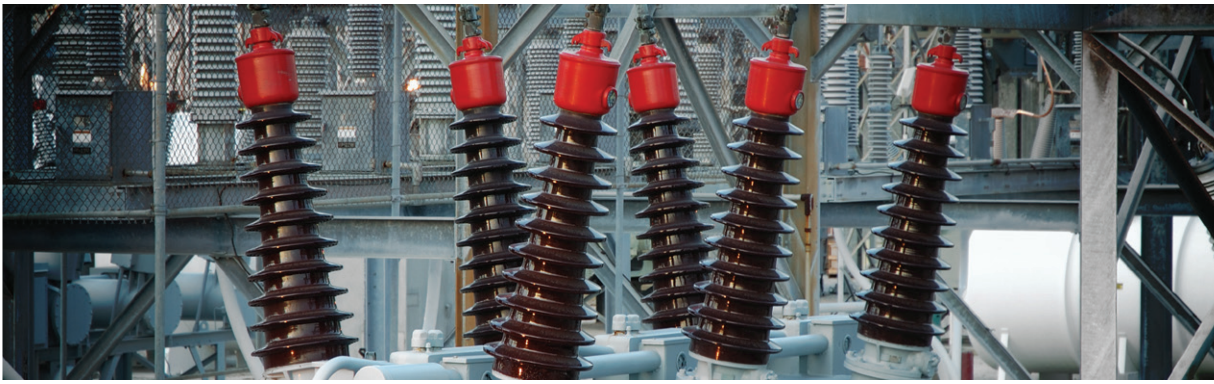
Massachusetts Governor Charlie Baker established the Commonwealth's Energy Storage Initiative (ESI) in May 2015 to incentivize energy storage companies to do business in Massachusetts, accelerate early-stage commercial energy storage technologies, expand the market for these technologies, and develop policy recommendations to advance these goals. The ESI has included extensive outreach, including a survey of storage industry stakeholders and 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.

MassCEC to Support Innovative Storage Use Cases and Business Models, Safety Development

As part of Massachusetts's 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, awarded 26 grants ranging between $243,000 and $1,250,000 to projects that have demonstrated a "clear and innovative business model" for a storage project sited in Massachusetts and secured at least 50% of the total project budget. The application evaluators also considered whether the applicants plan 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.

MassCEC is also coordinating a solicitation for an engineering design consultant for a solar plus storage or energy storage only facility that the Boston Fire Department can use for training and study for safety standards and training purposes.



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 published a Guideline on Energy Storage that better explains the formula used to calculate the SMART program's storage adder and approved the states' utilities' model tariff provisions to implement the SMART program on September 26, 2018.

One of the obstacles that concerned participants in the SMART program and net metering is the question of which party will control a storage asset's participation in the ISO New England's Forward Capacity Market (FCM). Under Massachusetts Department of Public Utilities (DPU) precedent, utilities hold the rights to bid net-metered solar capacity into ISO-NE's forward capacity market. Although the utilities have not availed themselves of that right to date, the utilities requested that they receive the rights to bid assets compensated under the SMART program, including associated storage assets, into the FCM. Project developers objected, arguing that losing FCM participation rights would undercut efforts to finance solar energy and energy storage projects under the SMART program.

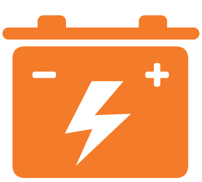
Following a series of meetings, stakeholders including utilities, solar and storage industry representatives, and Massachusetts DOER reached a compromise in July 2018. Under this compromise framework, project developers and/or host retail customer owners would retain FCM rights over energy storage systems that are paired with solar net metering or SMART facilities, with the exception for SMART projects operating under the Alternative On-Bill Credits arrangement in the SMART program rules. Utilities would control FCM rights for those storage facilities, although the project developer or host customer would have the option of buying out the utilities' FCM rights for these projects before approval of interconnection for those facilities. The stakeholders were not able to reach a compromise regarding treatment of behind the meter energy storage systems. DPU largely accepted the compromise approach, although DPU plans to provide additional details regarding the treatment of energy storage facilities when it issues its decision in a separate pending docket focusing on the eligibility of energy storage systems to participate in the state's net metering program.

Bill Suggests that Electricity and Natural Gas Efficiency Plans Should Consider Energy Storage

In March 2018, Governor Baker proposed legislation that encourages electricity and natural gas distribution companies to consider energy storage as part of their joint electric and natural gas efficiency plans. The bill, H. 4318, does not propose to require that the LDCs include energy storage in their analyses, instead suggesting that the LDCs include energy storage as part of their efficiency and load management programs. The bill remains pending in the Massachusetts House of Representatives.

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. The Commonwealth's Department of Public Utilities approved two energy storage projects with a total budget of $65 million as part of the rate case.

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 regulators 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 legislation that would require the state to set an energy storage procurement goal for 2030.

As the state encourages energy storage development, other agencies within New York are developing additional safety standards for energy storage systems. Both the New York City Fire Department and the New York State Energy Research and Development Authority (NYSERDA) are considering safety issues. New York Governor Andrew Cuomo established a roadmap (detailed below) to meet energy storage installation goals by 2030.

Regulatory Mandate Ffor Two Storage Projects by 2018, and 3,000 MW by 2030

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.

In December 2018, the NYSPSC established an energy storage goal of 3,000 MW by 2030 with an interim goal of 1,500 MW by 2025. These targets were based, in part, on an analysis of what it would take to retire vintage combustion turbine peakers in New York City and Long Island by 2025. NYSPSC plans to meet this goal through utility RFPs.

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, identified as Program Opportunity Notice (PON) 3541, NYSERDA is seeking proposals for field demonstration projects of "commercial distributed energy storage systems that leverage the flexibility of energy storage to 'stack' two or more value streams by performing multiple functions for retail electric customers, distributed generation, utilities and the New York State Independent System Operator (NYISO)."

NYSERDA will use a multi-step process to select projects for funding. First, applicants should submit a "concept paper" that outlines the values or services that the distributed storage project can demonstrate and monetize today, as well as the obstacles or complexities that the project will address. Or applicants may submit concept papers that propose pilot projects or other proposals that provide services that are not compensated and explain why such services are needed and why the proposed project's means of providing the service is better than alternative methods. NYSERDA will review the concept papers and invite selected applicants to propose either a feasibility study or direct the applicant to skip the intermediate

skip of a feasibility study and instead submit a full demonstration proposal. NYSERDA will fund up to 75% of the cost of the feasibility study up to $100,000 and may then select the project to submit a full demonstration proposal. Of the projects that submit full demonstration proposals, NYSERDA will then select full demonstration projects and fund up to 50% of the selected projects' costs.

NYSERDA requests that concept papers address the following:

- Describe the energy storage value-stacking concept and use-case;
- Explain the impact of the use-case on New York State;
- Describe the demonstration plan for the project;
- Explain why the use-case is "scalable and repeatable"; and
- Describe the applicant and team involved in the project.

NYSERDA will accept initial concept papers until December 31, 2019, or until it has committed its entire funding allocation.

Legislative Action and Roadmap

The New York State Legislature unanimously passed legislation supporting energy storage development by directing the 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, Governor Andrew Cuomo signed the bill on November 29, 2017. With his signature, Governor Cuomo issued a statement asserting that he has some concerns with the legislation's interaction with the state's Reforming the Energy Vision (REV) initiative and that he expects to work with the legislature to resolve his concerns with the legislation's fiscal commitments through the state's annual budget negotiations.

To meet the 2030 goal, in June 2018, Governor Cuomo announced the New York State Energy Storage Roadmap. The Roadmap proposes that stakeholders across New York State install 1,500 MW of energy storage capacity by 2025. The New York State Department of Public Service will coordinate solicitation of public comments and a series of technical conferences to finalize a storage installation target by the end of 2018. On September 12, 2018, NYSPSC accepted the environmental review of the Energy Storage Roadmap as complete.

To implement the Roadmap's goals, Governor Cuomo proposes making $350 million available for energy storage projects, adding energy storage to the NY-Sun program for solar-plus-storage projects, and additional regulatory and permitting changes to reflect the resilience and environmental benefits of energy storage systems.

Developing Safety Standards for Battery Storage Systems in New York and Beyond

As developers work to increase energy storage's penetration in the New York market, other New York authorities have undertaken a review of the safety standards for battery storage systems, particularly in densely populated areas like New York City. The New York Fire Department, in collaboration with NYSERDA, Con Ed and the National Fire Protection Association (NFPA), is developing a new set of standards for energy storage applications. NYSERDA and Con Ed commissioned a report on the fire risks surrounding energy storage systems, which concluded that the risks associated with energy storage systems are manageable. Separately, the NFPA has proposed its own safety standard for stationary energy storage systems, NFPA 855, which could limit the size of an energy storage system in an enclosed space.

New York City had only 4.8 MWh of energy storage capacity installed as of the start of 2017, so addressing these safety issues will be critical for growth of the energy storage market in New York, especially for the behind-the-meter residential market. Smart DG Hub, supported by NYSERDA and the City of New York, prepared a set of permitting and interconnection guidelines in April 2018 for outdoor lithium ion battery storage systems, and the NFPA expects to finalize its proposed standard by 2020, so stakeholders in addition to New York City itself are also working to address energy storage safety questions.

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 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. Portland General Electric (PGE) announced that it would spend up to $100 million to acquire approximately 39 MW of energy storage resources spread across existing generator sites, distribution sites, and customer sites. In 2018, PGE launched a "smart grid" project in Portland, Hillsboro, and Milwaukie. The project aims to increase decarbonization and to modernize by broadening and enhancing the microgrid system. One means by which to encourage the microgrid concept is by encouraging customers to install energy storage devices, a plan that these three Oregon cities are pursuing in earnest. Storage will play a significant role in Oregon's achievement of its 50% renewable energy target by 2040.

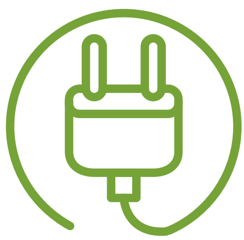
Energy Storage Pilot Project

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 the 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-kWh 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 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.

Washington has adopted aggressive renewable targets, and public-private partnerships have made significant efforts in this regard. Puget Sound Energy (PSE) launched the Glacier Battery Storage Project, which involved the installation of a 4.4-MWh lithium ion battery system to serve as a backup power source for the Glacier project area, a zone made up of an assortment of businesses and residences. PSE and the Washington State Department of Commerce (WADOC) contributed $7.4 million and $3.8 million to the project, respectively. Similarly, Avista and the WADOC commenced a 3.2 MWh large-scale battery storage project used to research and further develop the battery technology. Avista and WADOC each contributed around $3 million to the project. Governor Jay Inslee has signaled that the government will continue to support the development of energy storage projects in the state which has resulted in significant recent developments. Energy Northwest (EN), a Washington-based energy provider, has started building a combined 5-MW solar-plus-storage facility, which will be located in Richland, Washington. EN hopes to begin commercial operations in 2020. The Clean Energy Fund awarded half of the $6.5 million required to build the facility.

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. The PUCN is set to make a decision on the matter no later than December 31, 2018. 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.

In January 2018, NV Energy issued its first request for proposals for renewable energy projects including battery energy storage systems. As a result, NV Energy has contracted for three large-scale battery storage projects with 100 MW of battery energy capacity. The projects have yet to be approved by the PUCN.

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 considered 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. In January 2018, the ACC proposed a "clean peak" program that includes a 3,000-MW energy storage procurement target for 2030, with the goal of making renewable facilities dispatchable on command during periods of peak demand. Most recently, on March 12, 2018, the ACC instituted a moratorium on utilities procuring capacity from new gas plants over 150 MW for the remainder of 2018, and instead required the state's utilities to perform an independent analysis of the costs of "alternative energy storage options."

Salt River Project and TEPCO have also 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, and in January 2018 TEPCO issued a request for proposal for up to 150 MW of wind or wind plus energy storage and in June 2018 APS issued a request for proposal to equip existing solar farms with up to 106 MW of battery storage.

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. On the residential side, in November 2017 APS selected Sunverge Energy to participate in a pilot program that would analyze how integrating storage with solar and home energy management software could deliver increased customer value. Arizona will also be home to the country's first planned community microgrid that will integrate community-wide demand-response and energy storage systems with smart-home automation systems, which will allow homes to draw upon stored energy during peak periods while soaking up excess mid-day solar and early morning nuclear generation.

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.

80% 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 12 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. In addition, HECO is currently in negotiations with seven solar-plus-storage projects in Oahu, Maui, and Hawaii Island, resulting in contracts for approximately 260 MW. Each of the solar projects are connected to a four-hour battery storage system. The HECO projects are projected to displace 1.2 million barrels of oil each year. Hawaii's Kaua'i Island Electric Cooperative (KIUC), the top ranked utility for deploying energy storage in 2017, is currently paying $0.11 per kWh for the development of a solar-plus-storage facility. Specifically, 19.3 MW of solar will be paired with 70 MWh of battery energy storage capacity.

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.

Significantly, in addition to these public-private partnerships, HPUC has been busy promoting its independent storage agenda. At the start of 2018, HPUC launched "Smart Export," a program directed toward owners of combined rooftop PV–battery storage systems. Owners of these systems will be able to use their battery storage system to store the excess energy that is produced by their rooftop PV system during the day. This stored power will then be used to power their homes at night. Any excess stored electricity that the owners do not use will be exported to the grid, with monetary credits awarded to those who provide their excess generation during nighttime hours.

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 throughout 2018 and into 2019.

TEXAS

Texas has also become a leader 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 conducive to 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 collocated with wind generation facilities; Austin Energy's aggregated fleet of customer-sited energy storage; and Duke Energy's Notrees 36-MW storage project that operates as an ancillary services resource. At the time of its development, Notrees was the largest storage system paired with a wind farm in the United States. Most recently, Luminant, a subsidiary of Vistra Energy, began operating a 10-MW storage facility collocated at Luminant's existing 180-MW Upton 2 solar project on December 31, 2018. In February of 2019, Intersect Power proposed the construction of a hybrid 495-MW energy storage project and 495-MW solar farm in the Permian Basin to meet the energy demands of oil-field operations. If completed, it will be the largest battery storage facility in the world and would drastically increase the state's storage resources from the current 89 MW to 584 MW in 2021.

Legislative efforts:

In 2011, the Texas legislature passed SB 943 clarifying that energy storage facilities intended to be used to sell energy or ancillary services in ERCOT's 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 (discussed in greater detail, below).

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 co-located 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.

During the 2019 legislative session, HB 1012 was introduced in an effort to make clear that electric cooperatives and municipally-owned utilities can own or operate batteries without having to register as a power generation company. Sections 35.151 and 35.152 of the Texas Utilities Code currently require owners and operators of energy storage equipment to register even though cooperatives and municipally-owned utilities cannot qualify under the Section 11.003(14) definition of power generation company. In its 2019 Report on the Scope of Competition in Electric Markets in Texas to the 86th Legislature, the PUCT urged the legislature to provide clarity in this area, expressing concern that the existing language may lead to the unintended inference that cooperatives and municipally owned utilities cannot own or operate battery storage equipment.

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 Electric Reliability Council of Texas (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.

The Role of Storage as Distribution in Texas

In February 2018, the PUCT opened a new proceeding titled "Rulemaking to Address the Use of Non-Traditional Technologies in Electric Delivery Service" to consider whether energy storage resources can be owned by transmission and distribution utilities and serve as a replacement for traditional transmission and distribution infrastructure (February 2018 Rulemaking). The February 2018 Rulemaking stems from an application submitted by the transmission and distribution utility—AEP Texas—in September 2016, in which AEP Texas proposed to construct two energy storage resources in lieu of otherwise necessary traditional distribution upgrades, and to include the battery storage facilities in rate base. In connection with AEP Texas's request, which was highly contested, the PUCT considered: (1) whether energy storage resources would constitute "generation" or "competitive energy services," such that they could not be owned and operated by a regulated transmission utility; (2) whether battery storage facilities used to provide distribution-related services could be considered "distribution" and therefore be included in rate base; and (3) how the energy consumed by the battery storage facilities should be viewed under Texas law. Ultimately, the PUCT dismissed AEP Texas's request without prejudice, finding that it lacked sufficient information to make a final determination. As part of the dismissal however, the PUCT instituted the February 2018 Rulemaking to "develop a framework within which the [PUCT] can consider a broader range of technologies and study the potential impacts to the [energy markets] in ERCOT."

In October 2018, the PUCT issued a request for comments on the February 2018 Rulemaking. The PUCT's request primarily focuses on the issues raised during the AEP Texas proceeding, namely, whether transmission and distribution utilities can own and rate base energy storage resources that replace traditional transmission and distribution upgrades and that are used to support reliability. In November 2018, interested parties, including AEP Texas, submitted comments in response to the PUCT's request for comments. In early 2019, the PUCT announced it would defer further action until the conclusion of the 86th Legislature in May. However, the legislature does not look as if it will address these issues, forcing the PUCT to take them up again in the summer. While there is no clear timetable for a PUCT decision, the outcome of this proceeding will have a significant impact on the future and role of energy storage in Texas.

NEW JERSEY

In May 2018, New Jersey became the fifth state with an energy storage target and the first within the territory of the PJM Interconnection. The New Jersey Bill, A 3723, signed into law by Governor Phil Murphy requires that the New Jersey Board of Public Utilities ("BPU") conduct an energy storage analysis and submit a written report to the governor within one year of enactment. BPU must consult with PJM and other stakeholders in preparing the energy storage analysis. In addition to reviewing how energy storage systems can benefit ratepayers, BPU must also consider the need for integrating distributed energy resources into the electric distribution system.

The bill also requires BPU to initiate a proceeding to establish a process and mechanism for achieving a goal of 600 MW of energy storage by 2021 and 2,000 MW by 2030. With a 2,000 MW goal, the New Jersey legislation is currently one of the most aggressive energy storage mandates in the country.

COLORADO

In 2018, Colorado took two steps towards incorporating energy storage into the state's electric grid. First, in March, Governor Hickenlooper signed SB 9 that directed the Colorado Public Utilities Commission to develop rules allowing the installation, interconnection, and use of energy storage systems by utility customers. The legislation establishes that Colorado's electric consumers have a right to install, interconnect, and use energy storage systems without unnecessary restrictions or regulations and without discriminatory rates or fees.

In June 2018, Governor Hickenlooper signed HB 1270 into law, which directs the Colorado PUC to develop rules for integrating energy storage resources into the utility planning process. The legislation establishes a February 1, 2019 deadline for the PUC to develop these rules. HB 1270 specifically authorizes utilities to apply for rate-based energy storage projects (with a maximum capacity of 15 MW) during the pendency of the rulemaking.

INDEPENDENT SYSTEM OPERATORS AND REGIONAL TRANSMISSION OPERATORS

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 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 evaluated 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. Most recently, in September 2018, the CAISO Board of Governors approved ESDER Phase 3, which proposed a load shift product for behind-the-meter energy storage under the proxy demand response (PDR) participation model. The initial product will allow access to day-ahead and real-time energy markets for both load curtailment and load consumption by assigning behind-the-meter storage resources two distinct resource IDs. CAISO has designed the PDR product to help address over-supply, store negatively priced energy during times of abundant renewable energy, and deliver that energy back to the grid during the late-afternoon ramp.

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 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.

Changes to PJM's Regulation Market

As discussed above, PJM developed its frequency regulation market with two signals: a Regulation A signal (RegA) and a Regulation D (RegD) signal. The RegA signal was designed for slower-responding resources with limited ramp rates and unlimited duration of output (conventional generation), while the RegD signal was designed for faster resources with high ramp rates but limited duration (storage and demand response). PJM also designed the RegD signal to preserve a unit's energy neutrality over a 15-minute interval, meaning that a battery unit called on to inject power would subsequently be directed to withdraw power to return it to its neutral state. Following the implementation of the RegD signal and the favorable price signals associated with it, storage resources began to participate heavily in PJM's frequency regulation market.

Since 2015, however, PJM has implemented several changes to the RegD signal that PJM has stated are necessary to address operational and reliability issues in the regulation market resulting, in part, from a perceived oversupply of RegD resources. Many of these changes have been viewed by the storage industry as detrimental to the continued viability of storage participation in PJM. Notably, in December 2015, PJM instituted a cap on the total amount of RegD resources that could be dispatched during certain hours. In January 2017, PJM implemented additional operational changes to the RegD signal which, among other things, removed the requirement that the RegD signal respect the energy neutrality of RegD resources over a 15-minute interval. Following this change, the Energy Storage Association filed a complaint with FERC, arguing that both the December 2015 and January 2017 changes to the Regulation Market, and specifically to the RegD signal, were unduly discriminatory against limited-energy resources (April 2017 Complaint). Similarly, PJM filed proposed tariff revisions in October 2017 to further revise the means through which RegA and RegD resources are dispatched and compensated (October 2017 Filing). In support of the changes, PJM argued that the existing RegA and RegD signals are not well integrated, which creates compensation misalignments between the two resource types, impedes efficient price signals, and causes reliability issues. Various stakeholders protested PJM's October 2017 Filing, claiming that the majority of the changes had a disproportionate impact on storage resources, are inconsistent with FERC Order 755, and would limit the participation of energy storage resources in PJM's regulation market.

On March 30, 2018, FERC issued companion orders on the April 2017 Complaint and October 2017 Filing. FERC rejected the October 2017 Filing, finding that it failed to satisfy Order 755's requirement that storage resources participating in regulation markets be treated in a non-discriminatory manner. Similarly, FERC established hearing and settlement procedures to address parties' broader concerns in the April 2017 Complaint about the changes to the PJM Regulation Market since 2015. As of November 2018, settlement negotiations are ongoing, and it is not clear whether PJM will propose additional changes to the Regulation Market as part of its Order 841 compliance filing, or through a separate filing.

PJM's Market Implementation Committee Initiative and Response to Order 841

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 ("MIC") was established to study accommodating implementing storage in the PJM market. This special session has focused on making 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.

The special session of the MIC has been working on a proposal to remove barriers to storage participation in compliance with Order 841. On October 10, 2018, PJM presented a straw proposal outlining the guidelines for its "participation model" for energy storage resource participation in PJM markets. Changes proposed in the straw proposal include modeling energy storage resource as one continuous resource, regardless of whether withdrawing or injecting; allowing energy storage resources to manage their own state of charge; and allowing energy storage resources to opt in to provide synchronized reserve service. PJM also proposes to maintain its existing requirement that energy storage resources maintain a minimum duration of 10 hours to participate in the PJM capacity market. Like the other RTOs and ISOs, PJM's compliance filing is due on December 3, 2018.

Electric Reliability Council of Texas (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. The PUCT in particular 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 hydroelectric power, electrochemical 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.

The Midcontinent Independent System Operator (MISO)

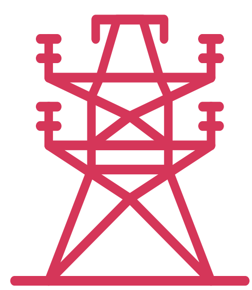
MISO assures unbiased grid management and open access to transmission facilities across 15 US states and Manitoba in Canada. In recent months, MISO has prioritized energy storage issues by establishing an Energy Storage Task Force (ESTF). The ESTF will bring together expertise from its various stakeholders to identify issues unique to the integration and realization of the benefits of energy storage for the grid, and recommend approaches to or solutions for the challenges these issues present to MISO's Steering Committee. In 2018, the ESTF expects to gather information regarding the status of energy storage in MISO and consider the following substantive topics: storage as transmission, storage offering market services, and distributed storage.

As part of its compliance effort with FERC Order 841, on August 21, 2018, MISO announced a framework to better integrate storage assets into the ISO's wholesale energy, capacity, and ancillary services markets. MISO proposes to measure the capacity of an energy storage resource in two ways, power and energy, to provide project operators more optionality to participate in capacity and energy markets. MISO is also considering additional steps to integrate storage into its system, including:

- "Make-whole payments" to address market fluctuations;
- Establishing dispatch and performance standards;
- Exempting storage from "lift charges," which grid operators impose when market revenues are insufficient to cover relevant operating costs; and
- Requiring transmission-connected storage assets to receive either network resource interconnection service or firm transmission service (to be determined on a case-by-case basis).

Beyond the ESTF, MISO has other active market adjustment initiatives related to energy storage. MISO is evaluating the Automated Generation Control (AGC) enhancement for fast ramping resources. MISO believes that adjusting its AGC logic could improve its system's reliability and efficiency, while also creating a more flexible system that better uses fast ramping resources to support a future grid with more variable resources and better accommodating the physical characteristics of energy-limited, fast-ramping resources like battery storage systems. MISO also is considering broader issues related to storage commitment and dispatch, such as state-of-charge, settlements, and state policy.

Most specifically, MISO is working through its response to FERC's order following a complaint by Indianapolis Power & Light Co. (IPL). After IPL alleged that MISO's treatment of IPL's battery storage facility was inappropriate, FERC concluded that MISO must accommodate energy storage resources' participation in all of the ISO's markets in which the resources are technically capable of participating (while considering the resource's specific physical and operational characteristics). To comply with FERC's order, MISO proposed a new resource category, termed the Stored Energy Resource – Type II (SER – Type II) that MISO will treat as a demand response resource except for settlement purposes, in which it will be treated as a regular generation resource. On August 15, 2018, FERC rejected IPL's challenge to MISO's SER-Type II, holding that IPL's criticisms of MISO' state of charge and allegations that FERC ignored ways that MISO's energy storage approach would harm one of IPL's energy storage facilities did not persuade the Commission to change in



its mind in this matter. However, FERC directed MISO to clarify further how the ISO will treat SER-Type II resources.

The New York Independent System Operator (NYISO)

NYISO operates the competitive electricity wholesale energy, ancillary services, and capacity markets in New York. The ISO has worked to accommodate storage resources into its markets and is considering additional measures to aid in the scheduling of storage resources.

In December 2017, NYISO released a report outlining a new plan to integrate energy storage resources into its markets. NYISO proposes a three-phase plan for increasing deployment of storage in New York, in advance of New York's legislated storage targets and the New York PSC's installation mandate. First, from 2017 to 2020: NYISO has established an Energy Storage Integration Phase to identify parameters important to include in an energy storage resource offer and to create a new energy storage participation model. To this end, NYISO, through its Market Issues Working Group, established an "Energy Storage Integration & Optimization Effort" in order to explore participation models for energy storage resources in the NYISO energy, ancillary services, and capacity markets.

In the second phase, from 2019 to 2022, NYISO envisions an Energy Storage Optimization Phase to more efficiently utilize energy storage services by analyzing the storage resource's operational constraints over the course of a day. During this second phase, storage operators may grant NYISO permission to maximize the resource's potential. Finally, in the third Renewable and Storage Aggregation Phase from 2020 to 2023: NYISO will analyze how storage resources can be matched with intermittent resources like solar and wind.

On September 21, 2018, NYISO's Market Issues Working Group presented its plan for an energy storage participation model in compliance with Order 841. The plan sets forth a "technology neutral" participation model and details the rules applicable to the registration, bidding, scheduling, and settlement of energy storage resources participating in the NYISO markets.[2] Like the other RTOs/ISOs, NYISO's Order 841 compliance filing is due on December 3, 2018.

ISO New England (ISO-NE)

On October 10, 2018, ISO-NE submitted revisions to its tariff codifying a new design to enhance the ability of emerging storage technologies that will allow for easier participation in New England markets. ISO-NE has a history of experience with other storage resources, such as hydroelectric pumped-storage. ISO-NE has applied lessons from these experiences to help integrate the growing industry of battery storage. These battery storage revisions will allow the new technologies to be dispatched in the Real-Time Energy Market, while utilizing

5 The entire 63-page proposal is available at https://www.nyiso.com/public/webdocs/markets_operations/committees/bic_prlwg/meeting_materials/2018-09-21/ESR%20Market%20Design%20MIWG%2009212018.pdf

their ability to transition continuously and rapidly between charging and discharging states. The revisions will also allow the technology to participate simultaneously in energy, reserves, and regulation markets.

If approved, the storage revisions move ISO-NE much further to meeting the compliance requirements of Order 841. From a practical perspective, however, ISO-NE began responding to the increasing interest in battery storage in early 2016. Designs for new storage capabilities and vetting processes were already underway in ISO-NE when FERC issued Order 841 in early 2018. ISO-NE requested for FERC to issue an order about the tariff revisions on storage by December 10, 2018. This means the changes could be effective by April 1, 2019, which is eight months prior to the effective date mandated by Order 841. ISO-NE will file the remaining measures for complying with the order separately and no later than December 3, 2018.

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, and this expansion 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 combine contracted long-term revenue streams produced by technology that is well proven and reliable with 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., kWh 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 usually 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 means facing 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.

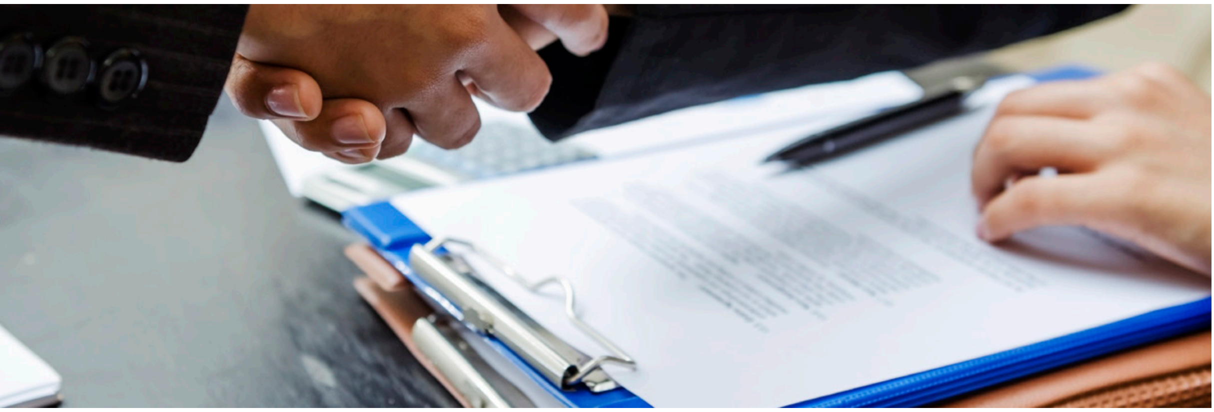
Given these inherent complexities, the cost of capital for storage project finance has yet to see substantial reductions. On the risk-return continuum, equity has, understandably, been the dominant source of financing for the nascent energy storage industry to date. Debt and tax equity are beginning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

Current Long-Term Energy Storage Agreements

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 is a 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 pioneered the use of 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 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 developing, installing, and operating the energy storage system and charges the system at its 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. The CSA typically allows the developer to market certain products from the energy storage system to third parties, as long as the delivery of such products does not interfere with the developer's obligation to deliver RA to the offtaker as and when required by the CSA. To enable the offtaking utility to monitor the multiple uses to which a given energy storage system is being put, the utility may require the developer to give notice of the market services being offered. CSAs are used for utility-scale energy storage projects that will be interconnected with the transmission or distribution systems.

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.

The DRESA is typically supported by agreements with each storage site host that also obligate the developer to provide on-site energy management services. Under these customer agreements, 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.

Hybrid Agreements

Energy storage systems can be combined with other renewable generators, most commonly solar systems but occasionally wind generators. For tax and other reasons, the storage system and generator are usually located at the same site and, in the case of solar and other ITC qualified facilities, more than 75% of the power used to charge and the storage system must be charged from the renewable generator rather than from the grid until the five-year recapture period has ended. In that case, the cost of the storage system should qualify for the ITC. There is less certainty regarding whether storing power generated by a PTC-qualified facility prior to sale of the power to a third party would prevent the seller from claiming the PTC. For more information, please see the general discussion about Federal Tax Incentives, above.

A hybrid agreement may be structured so that the developer is paid a per-MWh purchase price based on the electricity delivered at the interconnection point, in which case the developer will manage and pay for the charging and discharging of the energy storage system to maximize the revenue from the hybrid facility's output. If this structure is used, the developer does not receive a capacity payment and the offtaker does not control the charging or discharging of the storage system.

Other hybrid agreements are structured so that they more closely resemble tolling agreements. The offtaker purchases solar or wind energy on a per-MWh basis, and the developer delivers the generation to the offtaker and/or charges the storage system in accordance with the offtaker's charging instructions. The offtaker decides when to discharge the system. The agreement should include mechanisms for determining the amount of energy sold and stored, round-trip efficiency, the amount of energy discharged and the total amount of electricity delivered to the delivery point. In addition to a per-MWh payment for energy produced by the generator, the developer receives a capacity payment that is typically adjusted to reflect the actual availability, capacity, and round-trip efficiency of the storage system. The stored electricity is owned by the utility and thus is not available for station service. The developer's availability, capacity, and round-trip efficiency guarantees will affect the capacity payment received by the developer and will be tied to the system's operating parameters. The operating parameters are in turn structured to account for the system's expected uses case(s).

Energy storage agreements usually include a fairly detailed exhibit setting out the system's operating parameters. Among other things, the exhibit would define the maximum number of full cycles per day, the maximum number of full cycles per year, maximum daily discharge, maximum annual discharge, and maximum partial discharges, as well as procedures for issuing, accepting and executing discharge instructions or default charging/discharging strategies. These provisions are especially important in a tolling agreement or any other contract in which the buyer has the right to charge and dispatch the facility. If the storage system is operated within the agreed-upon operating parameters, the storage provider is required to meet the capacity, 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 may have the right to refuse a dispatch instruction or a contractual defense to damages or price adjustments imposed due to deficient performance. Careful consideration of the system's operating parameters are very important, as experience in the PJM and MISO teaches that tariff or rule changes that change the way a storage system operates in the market can adversely affect the system's performance and may also limit warranty claims under the storage system's procurement contracts.

The operating parameters set out in the energy storage agreement should also take into account the offtaker's expected use case(s) for the storage system. For example, if the system is being used to store peak solar generation for discharge during the evening hours, the determination of whether the number of full cycles conforms to what is allowed in the operating parameters will be fairly straightforward. If the offtaker plans to use the system to address multiple use cases, it may be more challenging to reconcile the system's actual use with the operating parameters. The uses case(s) may also change during the term of the agreement when new rules are adopted or new services are recognized, in which case the parties may want to include a process that allows the offtaker to implement new use cases, either by making appropriate adjustments to operating parameters or translating the new use case into existing parameters.

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 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 an 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 damages or price adjustments 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.

The operating parameters set out in the long-term agreement should also take into account the offtaker's expected use case(s) for the energy storage system. For example, if the system is being used to store peak solar generation for discharge during the evening hours, the determination of whether the number of full cycles conforms to what is allowed in the operating parameters will be fairly straightforward. If the offtaker plans to use the system to address multiple use cases, it may be more difficult to reconcile the system's actual use with the operating parameters. The uses case(s) may also change during the term of the agreement when new rules are adopted or new services are recognized, in which case the parties may want to include a process that allows the offtaker to implement new uses cases but ties each new case to the system's operating parameters.

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.

Build Transfer Agreements

For various reasons, including the desire to rate base assets, utilities may prefer to acquire and own the energy storage system. As in the wind and solar industries, utilities may sometimes seek to accomplish this result by entering into a build transfer agreement or similar arrangement (BTA). Under a BTA, the storage system developer takes the development risk of putting the storage project together. Depending upon the needs of the parties, the BTA may cause the developer to transfer the project assets to the utility at a relatively early stage pursuant to an asset purchase agreement, after which the developer will install the system in accordance with an EPC contract (see below) or other construction arrangement. Alternatively, the BTA may cause the developer to transfer the system to the utility only when the system has achieved substantial completion. In the second scenario, the BTA needs to include a "notice to proceed" mechanism that functions as a financial closing, allowing the parties to resolve all issues pertaining to title, permits, interconnection, equipment procurement and other matters as conditions to proceeding with the procurement and installation of the system. The utility is then obliged to pay for and purchase the storage asset, barring a material adverse effect such as a casualty that destroys the system.

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.

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 makes 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 ITC for standalone storage facilities. With or without the ITC, 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 can 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.

EPC contractors will generally support well-conceived performance guarantees that focus on objective equipment performance metrics, but may be reluctant to agree to arrangements that unreasonably transfer commercial market risk to the contractor through excessive large liquidated damages or overly long terms. Negotiation of appropriate warranties from a commercial standpoint is a balance between what is technically expected and achievable and appropriately respecting the risks and rewards associated with project development as opposed to EPC contracting.

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 from 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 warranties applicable to equipment, and even subcontractor work, are 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, collocating 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.

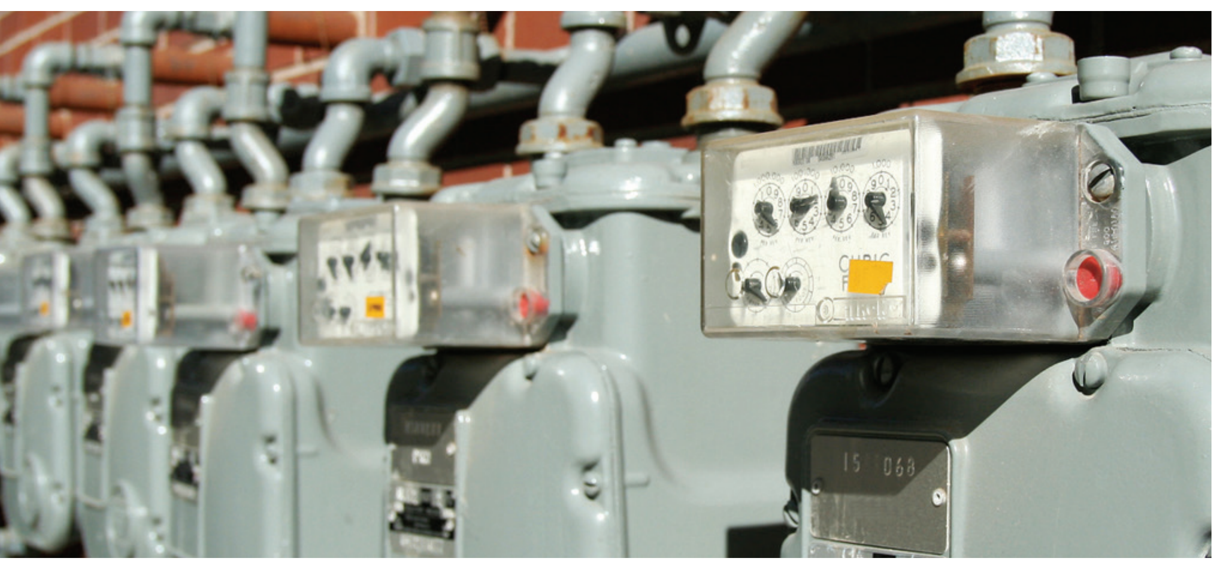
An indemnity is an obligation by one party to protect another party against loss or damage. Most EPC contracts contain several indemnity provisions. Some of the most common are for loss or damage incurred by the indemnified persons (usually Owner and related entities) related to personal injury, property 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 rise 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 require 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.

INSURANCE COVERAGE FOR ENERGY STORAGE PERFORMANCE

As the energy storage industry matures, secondary products and services continue to develop to support the storage sector. The insurance market is one of these secondary products, including insurance products that cover battery storage performance.

Insurance products can play an important role in managing risks for energy storage manufacturers, developers, and customers. Appropriate insurance products can help manufacturers spread out the risks



of the system warranties that they offer. System performance warranties or guarantees can be a considerable expense, especially in the case of long-term warranties or guarantees that manufacturers make to developers or operators of energy storage systems. Carrying the risks of servicing extended warranties on a balance sheet could inhibit a manufacturer's ability to secure financing for other activities or otherwise act as a drag on other business operations.

Likewise, insurance allows an energy storage system customer to mitigate the risk associated with relying on a manufacturer's battery performance warranty. Behind-the-meter energy storage customers usually use storage systems to reduce the volatility of energy costs or improve power reliability over a significant period of time. These customers rely on the manufacturer's warranty for storage performance to make sure that those savings and efficiencies are realized (i.e., the storage system provides adequate service during the term of the storage service contract, or the manufacturer makes up the difference if not).

By purchasing a storage solution from a manufacturer with a battery performance insurance policy, a customer can have more confidence that the manufacturer or its insurer will cover any performance deficit during the term of the insurance policy, particularly in an emerging technologies industry like energy storage. Where the parties extend the insurance contract to cover a specific storage system installation, the insurance company will pay for any performance deficiencies during the warranty period, even if the manufacturer is not able to honor the warranty due to insolvency or bankruptcy.

In March 2019, Munich Re announced that it has created the "world's first long-term insurance for battery performance" to cover battery manufacturers' battery performance warranties. Munich Re stated that ESS Inc., a manufacturer of a flow battery energy storage system, is the company's first customer for a 10-year battery performance insurance product and that Munich Re hopes to expand its coverage to performance of mobile battery systems in electric vehicles. In this scenario, ESS already offers a lifetime guarantee for its flow batteries' performance. But the Munich Re insurance policy would provide customers additional assurance that ESS or Munich Re will honor the terms of the performance warranty during the coverage period.

Munich Re and other insurers will likely continue to develop additional insurance products to help manage the risks associated with the growing storage sector generally and battery storage solutions specifically. Parties are negotiating these insurance contracts in an evolving and highly regulated environment with limited legal precedent and industry experience, indicating that battery performance insurance contracts may be bespoke agreements for some time. Issues like the scope of coverage, who controls battery dispatch, and the transferability of the insurance contract will need to be reviewed closely. Parties will be well served to consider these contracts carefully, and the risk allocations they have reduced to writing, so that neither the insured nor the insurer will be surprised about who bears the cost in case of a loss event.

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 (such as the ability to act as both generation and load). For instance, while certain behind-the-meter projects may be non-exporting or inject energy onto the grid during limited and predictable times, many state interconnection procedures subject these resources to the same level of scrutiny as traditional generators. Some states, like California, have fast-track procedures that recognize a storage resource's unique load and dispatch profile.

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 fewer than 12 months and can sometimes take 30 months or longer. It is often assumed that the storage resource will inject its maximum capacity at any particular time, which overlooks some of storage's key advantages.

Interconnection issues and confusion can delay energy storage projects, impact financing, and lead to higher energy costs for customers. 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 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 jurisdictions have raised concerns about the perceived fire hazards associated with the storage of large banks of lithium iron batteries.

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. For residential projects, California has required local jurisdictions to make available and accept online all applications for behind-the-meter advanced energy storage systems.

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 straightforward. 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 60 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 60-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 QFs can be applied to energy storage companies to qualify for the books and records exemption.

Exempt Wholesale Generator

An 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 an 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 an EWG, the particular operational characteristics of the facility will need to be examined.

Qualifying Facilities (QFs)

The Public Utility Regulatory Policies Act of 1978 established a new class of generating facilities known as QFs that receive special rates 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. In determining whether an energy storage facility can be a QF, the primary energy source behind the battery must be considered. If the primary energy source is one of those contemplated by the statue for conventional small power production then the storage system may qualify as a QF. 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.

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 fewer 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	Demand 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 and more quickly recoup investment costs, optimizing the system for multiuse applications that "stack" energy storage's contributions to the energy market. One issue, however, is how market participants should 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).

From a regulatory perspective, California is the first state to establish rules on how energy storage resources can participate in several market segments at once. In January 2018, the CPUC adopted 12 rules to evaluate multiuse storage applications and directed the state's utilities to comply with these rules. The 12 rules are listed below:

(1) Resources interconnected in the customer domain may provide services in any domain.

(2) Resources interconnected in the distribution domain may provide services in all domains except the customer domain, with the possible exception of community storage resources.

(3) Resources interconnected in the transmission domain may provide services in all domains except the customer or distribution domains.

(4) Resources interconnected in any grid domain may provide resource adequacy, transmission, and wholesale market services.

(5) If one of the services provided by a storage resource is a reliability service, then that service must have priority.

(6) A single storage resource may not contract for two or more different reliability services from the same capacity in a single or multiple domains over the same time interval for which the resource is committed to perform. The storage provider must not enter into multiple reliability service obligations such that the performance of one obligation renders the resource from being unable to perform the other obligation (except as provided in Rule 7).

(7) A single storage resource may contract for resource adequacy capacity and provide wholesale market reliability services using the same capacity, and over the same time interval. For example, if a storage resource is providing local resource adequacy capacity, it may meet its resource adequacy obligation by providing any service in the wholesale service domain using its resource adequacy capacity.

(8) If using different portions of capacity to perform services, storage providers must clearly demonstrate, when contracting for services, the total capacity of

the resource, with a guarantee that a certain, distinct capacity be dedicated and available to the capacity-differentiated reliability services.

(9) For each service, the program rules, contract, or tariff relevant to the domain in which the service is provided must specify enforcement of these rules, including any penalties for non-performance.

(10) In response to a utility request for offer, the storage provider is required to list any additional services it currently provides outside of the solicitation. In the event that a storage resource is enlisted to provide additional services at a later date, the storage provider is required to provide an updated list of all services provided by that resource to the entities that receive service from that resource. The intent of this rule is to provide transparency in the energy storage market.

(11) For all services, the storage resource must comply with availability and performance requirements specified in its contract with the relevant authority.

(12) In paying for performance of services, compensation and credit may only be permitted for those services which are incremental or distinct. Services provided must be measurable, and the same service only counted and compensated once to avoid double compensation.

The CPUC is also soliciting feedback from a stakeholder working group on certain issues, such as metering of time-differentiated multiuse applications, enforcement of certain contract provisions, and whether any CPUC-jurisdictional rules or tariffs must be modified to accommodate multiuse applications. The working group filed its report on August 9, 2018, providing comprehensive feedback across a range of issues. CPUC is considering this submission. Regulators and electricity system stakeholders in Hawaii, Massachusetts, Minnesota, New York, and Texas are all considering similar issues.

On the industry side of the value stacking question, utilities in Florida are considering methods to unlock additional value from energy storage facilities. Jacksonville Energy Authority (JEA), Jacksonville, Florida's municipal utility, is offering a rebate of up to $4,000 for residential or business customers who install qualifying energy storage systems to complement the customer's approved renewable energy system. JEA has also adjusted its net metering incentives to encourage its customers to install energy storage with distributed renewable generation. Other utilities in the state, including Florida Power & Light and Lakeland Electric are considering initiatives to unlock value associated with energy storage.

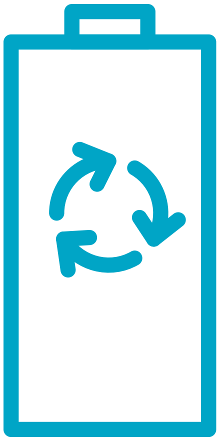
Given the financial benefits presented by multiple use storage applications, one can expect additional development of the technical, financial, regulatory, and legal changes necessary to unlock the full value of a storage resource. These structures will include, for example, lenders and borrowers coalescing 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 backup 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 100 MW of solar and a 30 MW, 120 MWh energy storage facility with a PPA rate of 4.5 cents per kWh over its 20-year life. In January 2018, Xcel Energy released information from its August 2017 RFP for Colorado, showing median bids of $36/MWh for solar-plus-storage and $21/MWh for wind-plus-storage.

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. 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. In anticipation, a number of U.S. utilities have already launched programs to procure or otherwise support hybrid storage projects. Moreover, generators are beginning to recognize the benefits of transforming existing wind or solar facilities into a hybrid system.

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, 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 MWh of storage (i.e., 13 MW of storage available for four 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 MW of solar PV with 20 MW 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. In 2019, the HPUC approved six grid-scale solar-plus-battery storage projects in Hawaii, adding a total 247 MW with almost 1 GWh of storage in the state. The estimated costs will range from 8 to 10 cents per kWh, already a slight improvement from the preceding AES project and a marked decrease from the 15 cents per kWh needed for fossil fuel generation on the island.

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, four-hour energy storage system (120 MWh), at a reported all-in price of 4.5 cents per kWh. The project is expected to be in service by the end of 2020.

Business Model and Regulatory Issues

While the benefits are clear, 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, the IRS indicated that the amount of the credits would be calculated over time, based on the percentage 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 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.

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 is gaining traction. Danish energy giant Ørsted has completed a project to add a 2-MW battery storage system to a 90-MW wind farm in the United Kingdom. In November 2018, BP installed a 212 kW battery storage system for the first time at one of the company's wind farms. The company intends to implement similar storage technology at its 12 other wind energy sites in the United States. 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. The UK government is targeting the achievement of 50% EV saturation by 2030 and "effectively zero emission" by 2040. In addition, Volkswagen is planning to build 50 million electric vehicles by expanding manufacturing to the US.

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 kWh of response during those events. Audi and Nissan have both launched pilot projects that link EV charging stations, rooftop solar panels, and stationary energy storage to balance services to the grid. BMW, Mercedes Benz, 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.

CONTRIBUTORS

Buck B. Endemann
Editor
Federal and State Regulatory, Project Finance, EPC, and Development
Partner, San Francisco
+1.415.882.8016
buck.endemann@klgates.com

Toks A. Arowojolu
Associate, Washington, DC
+1.202.778.9016
toks.arowojolu@klgates.com

Kristen A. Berry
Federal and State Regulatory; Project Finance, EPC, and Development
Associate, Seattle
+1.206.370.7636
kisten.berry@klgates.com

Elizabeth C. Crouse
Tax
Partner, Seattle
+1.206.370.6793
elizabeth.crouse@klgates.com

David P. Hattery
Project Finance, EPC, and Development
Partner, Seattle
+1.206.370.7823
david.hattery@klgates.com

Elias B. Hinckley
Project Finance, EPC, and Development
Partner, Washington DC
+1.202.778.9091
elias.hinckley@klgates.com

William H. Holmes
Project Finance, EPC, and Development
Partner, Portland
+1.503.226.5767
bill.holmes@klgates.com

Abe F. Johns
Associate, Washington DC
+1.202.778.9430
abe.johns@klgates.com

William M. Keyser
Federal and State Regulatory
Partner, Washington DC
+1.202.661.3863
william.keyser@klgates.com

Stan Lewandowski
Project Finance, EPC, and Development
Partner, Palo Alto
+1.650.798.6743
stan.lewandowski@klgates.com

Olivia B. Mora
Associate, Houston
+1.713.815.7369
olivia.mora@klgates.com

Nicholas R. Nahum
Federal and State Regulatory
Associate, Seattle
+1.206.370.7851
nicholas.nahum@klgates.com

Michael L. O’Neill
Federal and State Regulatory
Associate, Boston

+1.617.951.9190
mike.oneill@klgates.com

Charles H. Purcell
Tax
Partner, Seattle
+1.206.370.8369
charles.purcell@klgates.com

Benjamin L. Tejblum
Federal and State Regulatory
Associate, Washington DC
+1.202.778.9129
ben.tejblum@klgates.com

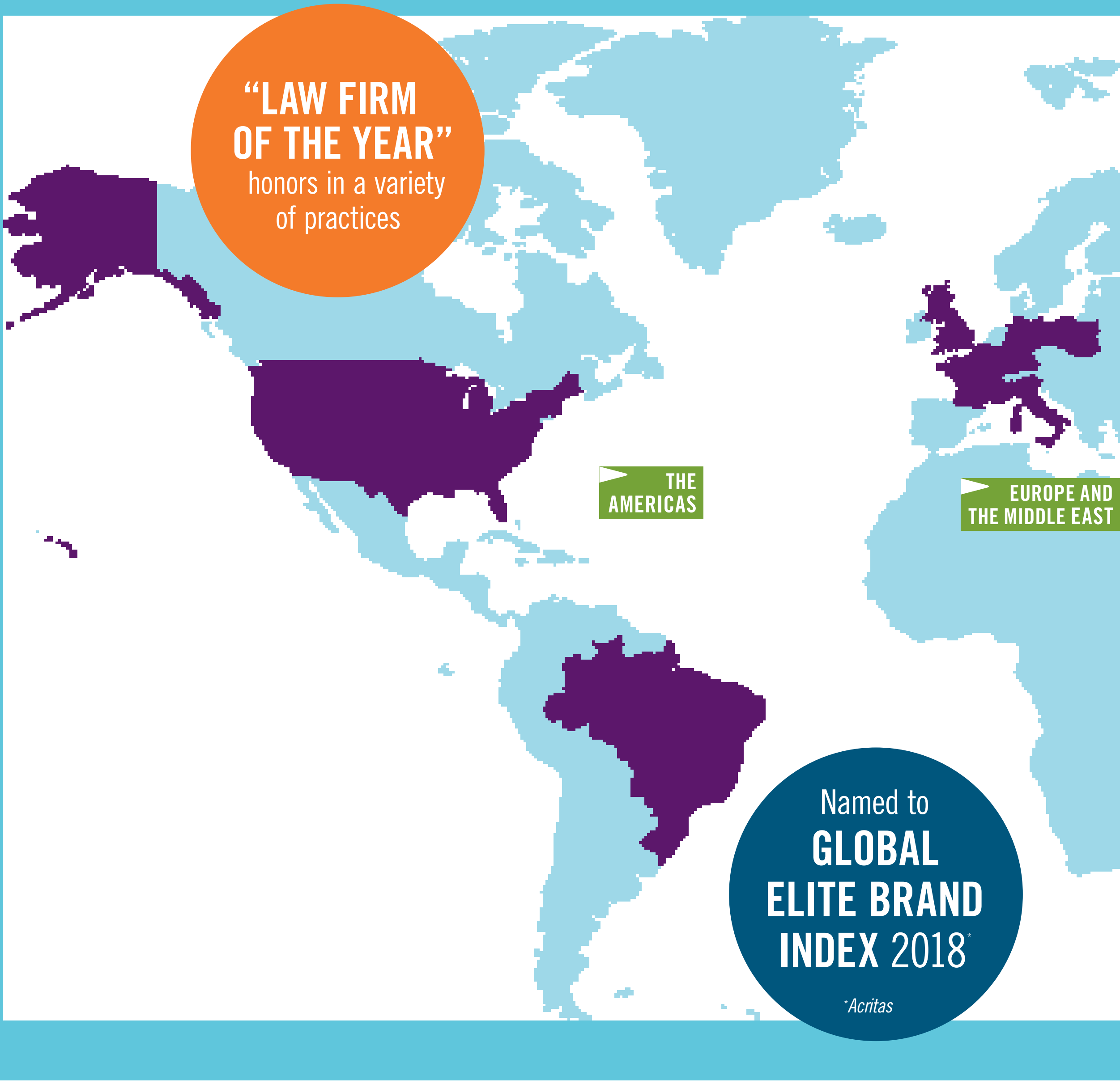
Elizabeth Thomas
Federal and State Regulatory
Partner, Seattle
+1.206.370.7631
liz.thomas@klgates.com

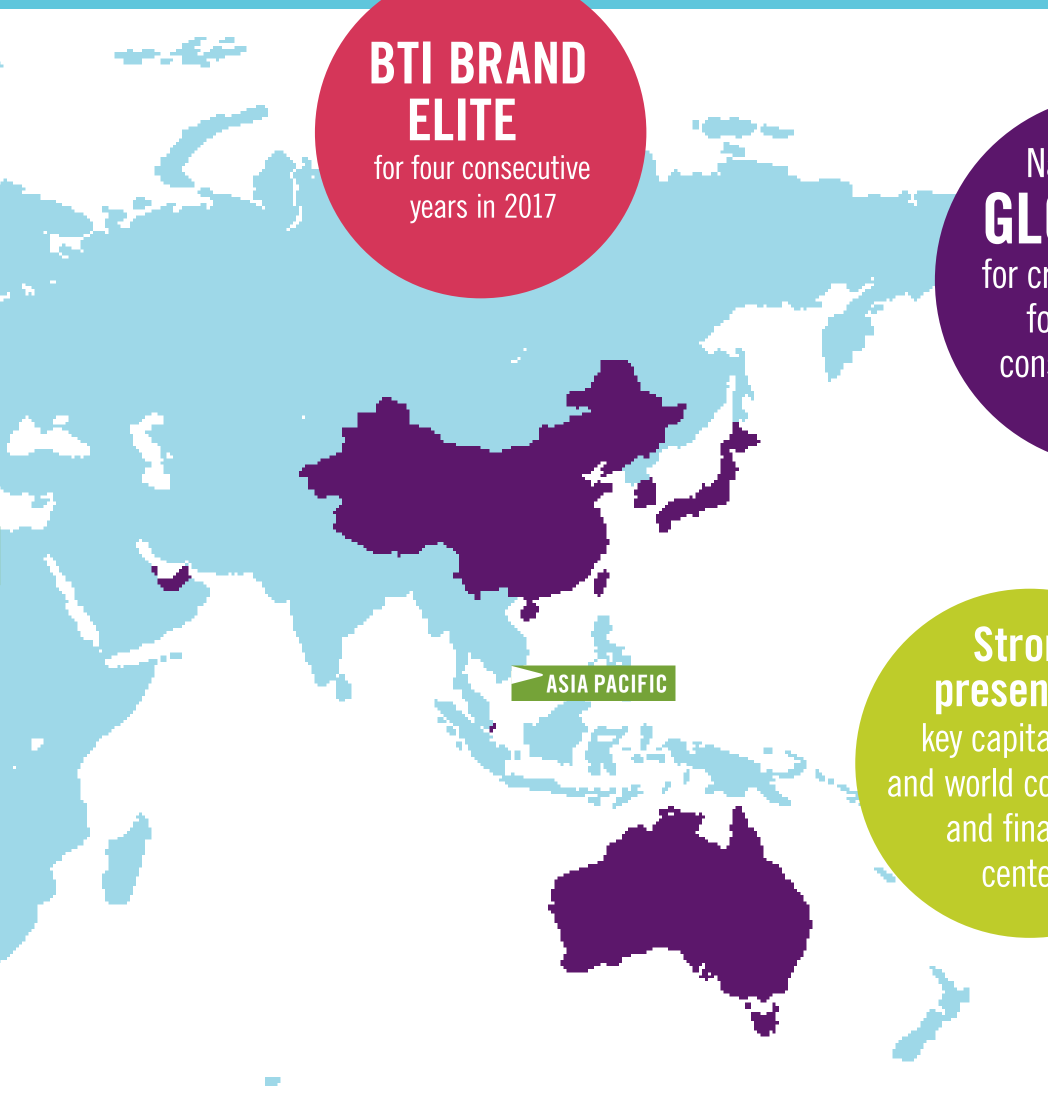
James R. Wrathall
Project Finance, EPC,
and Development
Counsel, Washington DC
+1.202.778.9092
jim.wrathall@klgates.com

Special thanks to the Energy Storage Association for their helpful thoughts and comments.

A GLOBAL PERSPECTIVE

Our broad global platform allows us to guide clients through the legal challenges of the ever-changing international landscape. With fully integrated offices on five continents, the deep latticework of relationships across our offices and practices enables our clients to respond to diverse legal issues and risks through the services of one law firm, with one communication.





BTI BRAND ELITE
for four consecutive years in 2017

Named to
GLOBAL 20
for cross-border work for **seven** consecutive years*

*Law360, 2017

Strong presence in key capital cities and world commercial and financial centers

Visit **KLGATESHUB.COM** for comprehensive industry-based digital content at the intersection of legal and business issues.

K&L GATES

K&L Gates is a fully integrated global law firm with lawyers located across five continents. The firm represents leading multinational corporations, growth and middle-market companies, capital markets participants, and entrepreneurs in every major industry group, as well as public sector entities, educational institutions, philanthropic organizations and individuals. For more information about K&L Gates or its locations, practices and registrations, visit klgates.com.

19435