ORRICK
ENERGY STORAGE UPDATE

2024

Including Special Updates on the Inflation Reduction Act and Revenue Trends

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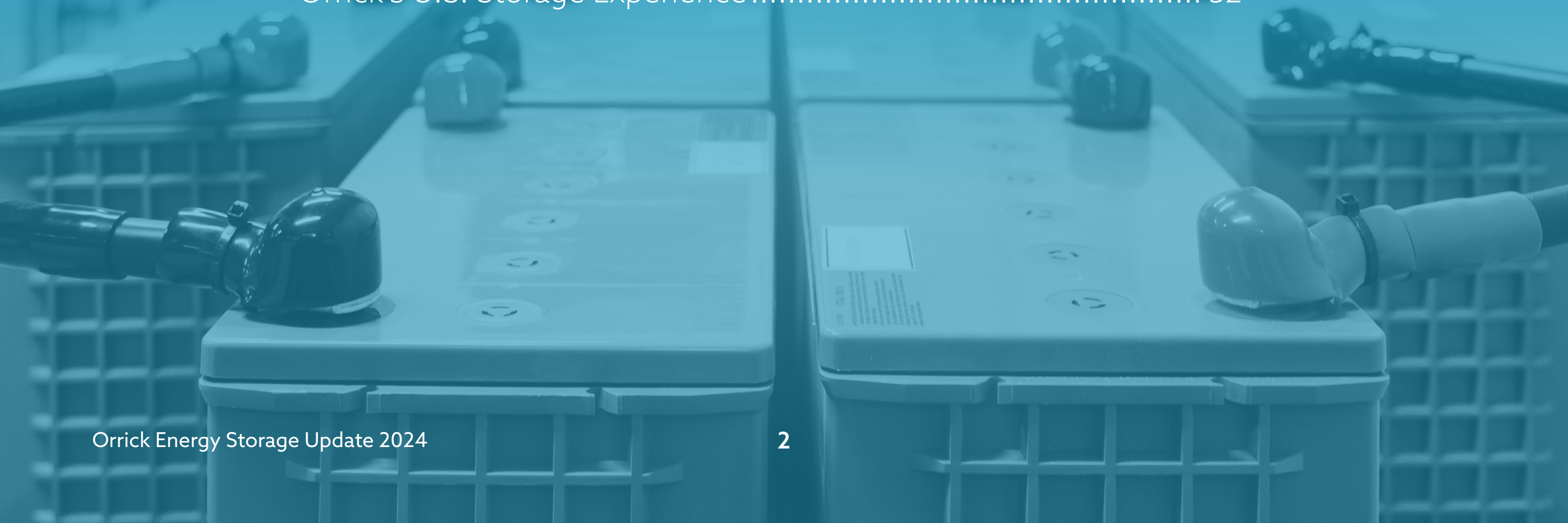
Contents



INTRODUCTION

The battery storage market has continued its incredible growth since we published our last Orrick Energy Storage Update 2021-22.

In the United States, developers installed 8.7 GWs of battery storage capacity in 2023, a 90% increase from the prior year. Operating and planned utility scale battery storage projects totaled approximately 16 GWs of installed capacity at the end of the year, with an additional 15 GWs expected to be installed in 2024. California leads the way with 7.3 GWs of battery storage capacity installed, and Texas with 3.2 GWs, as of the end of 2023.

The global storage sector followed a similar trajectory. The global market grew by 110 GWhs of energy storage capacity in 2023, an increase of 149% from the previous year. The United States, China and Europe accounted for most of the increased demand. Investment in the global storage sector grew 76% in 2023, to $36 billion.

Over the next few years, this growth pattern is expected to continue, including for the following reasons:

1. The continuing expansion worldwide of installed intermittent renewables generation (including solar and wind capacity) requires increasing amounts of battery storage to effectively **integrate the additional renewables while maintaining grid reliability**.
2. In the United States, the **Inflation Reduction Act created several incentives** that continue to transform the stand-alone storage and co-located battery storage finance markets, while **capacity markets are expanding** and driving additional utility procurement of storage in certain jurisdictions.
3. Developers, financing parties and load-serving entities are becoming **more comfortable with technology risks** associated with grid-tied battery storage projects, resulting in the consummation of many more offtake, procurement, financing and M&A transactions.
4. Although market disruptions for lithium-ion and battery systems hit their peak during the COVID-19 pandemic, the supply chain issues and related factors creating **market disruptions have decreased and markets are operating more predictability**, which facilitates procurement and financing.

In this latest Orrick Energy Storage Update 2024, we present the latest trends and issues accompanying this sector growth and maturity, including:

- **Transaction Trends:** Updates on deal structures and trends across offtake, procurement and O&M, build-transfer, financing and M&A.
- **Tax, Trade and Regulatory Updates:** Opportunities created for storage by the Inflation Reduction Act – including the latest trade, tariff, ESG and regulatory issues.
- **International Developments:** Global perspectives of energy storage in the United States, Europe and Asia.

We hope this latest edition is helpful to our clients and readers. Please don't hesitate to reach out to any of our team members with questions.

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OFFTAKE AND HEDGES

In prior Orrick Energy Storage Updates,[1] we provided a summary of the most common offtake structures for front-of-meter, grid-tied energy storage projects in the market today, including Energy Storage Tolling Agreements, Capacity Sales Agreements, Hybrid PPAs (Solar-Plus-Storage PPAs), Shared Savings Contracts and other recent contract and hedge structures including multiple contracted revenue streams, fixed-shaped solar-plus-storage PPAs and "TB4" contracts.

Since the publication of our most recent Orrick Energy Storage Update 2021–2022, several new trends, issues and contract structures relating to the sales of products and services from energy storage projects have emerged. They include the following:

- IRA and Supply Chain Impacts
- "Virtual" Tolling Agreements
- Developments in Resource Adequacy and CAISO Deliverability
- Hedge Transactions for Storage Projects
- Corporate Procurement of Storage

IRA and Supply Chain Impacts

Inflation Reduction Act

As we describe in more detail in the "Tax and the Inflation Reduction Act" section of this report, the Inflation Reduction Act ("IRA") has now made it possible for a qualifying energy storage project to obtain the Investment Tax Credit ("ITC") independent of any relationship it may have to a renewable energy facility.

1 See Orrick Energy Storage Update 2021-2022; Energy Storage Update 2018; Energy Storage Update – 2014 California Storage RFO.

As a result, hybrid power purchase agreements ("PPAs") (for solar-plus-storage projects) no longer need to include complicated limits on the storage project's grid-charging capabilities during the ITC recapture period. This development has also increased the economic optionality for co-located solar and storage projects by allowing the solar facility to obtain the Production Tax Credit, and for each of the solar facility and storage facility to pursue separate tax equity financings. To facilitate such distinct financings, developers will often prefer to execute individual offtake contracts for each facility: a PPA for the solar facility and a tolling agreement for the storage facility. From commercial and tax perspectives, the interface between the two contracts must be carefully crafted. In a circumstance where a single hybrid PPA is utilized for a solar-plus-storage project, the hybrid PPA may include provisions requiring both parties to implement amendments and modifications required to facilitate the project sponsor's achievement of tax equity financing.

> Developers will often prefer to execute individual offtake contracts for each facility: a PPA for the solar facility and a tolling agreement for the storage facility. The interface between the two contracts must be carefully crafted.

Supply Chain Impacts

Recent supply chain dynamics relating to energy storage equipment have had three primary impacts on energy storage offtake contracts. First, project sponsors today often negotiate price protection in the offtake contract. Extreme commodity and equipment price volatility in recent years has trickled upward—as original equipment manufacturers ("OEMs") and suppliers increasingly sell battery energy storage system ("BESS") equipment on a cost-plus basis, developers have frequently required price adjustment provisions, whereby the increase (or decrease) in engineering, procurement and construction ("EPC") costs, commodity prices or other metrics will result in an increase (or decrease) in storage or other capacity prices under the offtake agreement. These price changes are often subject to ceilings and floors and can also result in termination rights for either or both parties.

> Project sponsors today often negotiate price protection and supply chain related schedule protections into the offtake contract.

Second, due to global equipment shortages, variability in supply and transportation and Uyghur Forced Labor Prevention Act ("UFLPA") / U.S. Customs and Border Protection ("CBP") investigations[2] since the commencement of the COVID-19 pandemic, project sponsors often negotiate supply chain related schedule protections into the offtake contract. These may appear in the forms of additional schedule extension rights or cure periods, off-ramps or termination rights and/or robust force majeure provisions. Certain offtakers anticipate these dynamics and will proactively include in their pro forma agreements express limitations on the project sponsor's ability to claim such relief (*e.g.*, a comprehensive list of force majeure exclusions).

Finally, due to the risks described above, energy storage offtake agreements today will often include a combination of representations, warranties and/or covenants imposed on the project sponsor.[3] The intention of these provisions is to mitigate the offtaker's exposure to supply chain-related development risks. For instance, the offtake agreement may contain project sponsor representations regarding the use of forced labor in the project's supply chain, or project sponsor covenants to audit the project's supply chain. The offtaker may also have termination rights or other express, accelerated remedies upon a breach of any such provision.

"Virtual" Tolling Agreement

One of the newest offtake contract structures for front-of-meter energy storage projects is the "virtual" tolling agreement. As in the traditional energy storage tolling agreement (which we describe in detail in our Orrick Energy Storage Update 2018[4]), the project sponsor owns and operates a stand-alone, grid-interconnected energy storage project (typically a battery energy storage project) for the benefit of the offtaker. This traditional tolling structure has been used in both deregulated (Independent System Operators ("ISO") / Regional Transmission Organizations ("RTO"))[5] and regulated energy markets throughout the country over the past decade. In most of those arrangements, the offtaker (typically a load serving entity) has scheduling/market participant authority for the project, retains any market revenues for itself, and pays the project sponsor a capacity payment and/or a variable O&M payment for the use of the project.

In recent months, a new variant of the energy storage tolling agreement has emerged, primarily in ERCOT: the "virtual" tolling agreement. As in the traditional tolling structure, the project sponsor is seeking a financeable, fixed-revenue stream in exchange for constructing and operating the project over many years based on the offtaker's dispatch instructions and the project's operating limitations. In contrast to the traditional tolling structure, where utilities and other load serving entities typically serve as the offtaker; however, the offtaker in a "virtual" tolling agreement is more commonly a financial player or itself a project developer.

Two primary differences exist between the structures. First, in the "virtual" tolling arrangement, the project sponsor, not the offtaker, is responsible for securing the physical charging energy for the project. As a related matter, in the "virtual" context, the offtaker does not take title to, or responsibility for, charging energy or discharging energy. Scheduling responsibilities vary among transactions and parties, with the Qualified Scheduling Entity ("QSE") role (for projects in ERCOT) designated or served by one of the parties.

Second, the payment structure varies. In both "physical" and "virtual" tolling agreements, the project sponsor will typically be due a fixed monthly capacity payment from the offtaker. If the project sponsor collects the market revenues directly in the "virtual" context, however, the offtaker pays to the project sponsor a financial settlement instead. In addition, these "virtual" agreements will commonly involve some measure of revenue sharing. The offtaker is often a financial or energy markets player seeking to maximize arbitrage opportunities based on energy and/or ancillary services prices, which it does by issuing instructions to the project sponsor and/or through the QSE to implement. Based on both the market revenues achieved and the project's performance, the offtaker may share market revenues or profits with the project sponsor under agreed formulas.

> "Virtual" tolling agreements will commonly involve some measure of revenue sharing. The offtaker is often a financial or energy markets player seeking to maximize arbitrage opportunities.

Project sponsors may also enter into "optimization agreements" with revenue optimization firms. In these agreements, the optimizer provides scheduling and other services for the purpose of maximizing the project's market revenues. As in the "virtual" tolling agreement, the optimizer may receive some portion of market revenues/profits in addition to a fixed fee.

Developments in Resource Adequacy and CAISO Deliverability

Since the publication of our latest Orrick Energy Storage Update 2021–2022,[6] California's reliability-driven procurement mandates, CPUC regulatory reforms and the overwhelming size of the CAISO's generator interconnection queue have all played an important role in shaping offtake contracts and risk allocation for both stand-alone energy storage and hybrid generation + storage projects. Storage projects are playing an increasingly critical role in the state's plan to increase renewable penetration while maintaining system reliability.

2 See "International Trade and Investment" section of this report.

3 See "Procurement, O&M and Build-Transfer Arrangements" section for additional detail.

4 See Orrick Energy Storage Update 2018.

5 For reference, the ISOs/RTOs are: California Independent System Operator ("CAISO"), Electric Reliability Council of Texas ("ERCOT"), ISO New England ("ISO-NE"), Midwest Independent System Operator ("MISO"), New York Independent System Operator ("NYISO"), Southwest Power Pool ("SPP") and PJM Interconnection LLC ("PJM").

6 See Orrick Energy Storage Update 2021-2022.

Resource Adequacy (RA) Developments and Contracting

California has made several recent advancements related to resource adequacy ("RA") to achieve the reliable, carbon-free electrical grid mandated by California state energy policy. Over the past few years, the California Public Utilities Commission ("CPUC") has issued a succession of large procurement orders which have driven gigawatts of offtaker contracting by investor-owned utilities, municipal utilities and community choice aggregators. This reliability procurement has already added thousands of megawatts ("MW") of new, clean generating capacity to the grid, including unprecedented amounts of energy storage to help balance supply and demand during the summer's net peak. As a result, the CAISO has not experienced any supply-related outages since 2020 despite the increasing demands for electricity throughout the state. Of course, the state's challenges will continue for the foreseeable future as transportation electrification, green hydrogen production and data center expansion will all increase California's appetite for renewable electricity.

The CPUC and other local regulatory agencies are responsible for ensuring sufficient resources are contracted and available to the CAISO to reliably operate the grid. The CPUC's latest adopted resource plan for 2025 includes an additional 54 GW of renewable resources and 28 GW of batteries. Additionally, an expected increase in the planning reserve margin for 2026 and 2027, if adopted, will likely increase the demand for RA attributes and grow the overall RA market. As the planning reserve margin increases, load serving entities will be required to procure additional capacity, thereby putting upward pressure on the demand for RA attributes.

RA Slice-of-Day Counting Reform

The CPUC's new "Slice-of-Day" reform is intended to serve as a more precise measurement of a load serving entity's compliance with the RA program. It will significantly change the way in which energy storage resources (as well as co-located resources) are used to provide RA capacity.

The Slice-of-Day framework is designed to ensure that load serving entities procure sufficient resources to meet peak demand and charge system batteries after solar energy declines at the end of the day. Specifically, the CPUC's 24-hour Slice-of-Day framework requires each load serving entity to demonstrate enough capacity to satisfy its specific gross load profile—including a planning reserve margin—in all 24 hours on the CAISO's "worst day" of each month. "Worst day" is defined as the day of the month that contains the hour with the highest peak load forecast.

Under the Slice-of-Day framework, energy storage resources will be assigned a value based on Pmax, restricted to daily resource capabilities (*e.g.*, maximum daily run hours, maximum continuous energy and storage efficiency). Energy storage resources that are operationally and contractually able to provide multiple cycles in a 24-hour cycle may be shown for multiple cycles per day, provided that the load serving entity shows sufficient excess energy and time between discharge cycles to charge the battery. To the extent a load serving entity uses energy storage to meet its load requirements plus a planning reserve margin, the load serving entity must demonstrate it has excess hourly capacity (*i.e.*, capacity that exceeds its hourly RA requirement) that offsets the storage capacity plus efficiency losses. In other words, load serving entities must bring enough extra capacity to serve their own batteries. A co-located energy-only resource can be used to provide charging sufficiency. If the energy resource is not co-located with the storage, the energy resource needs to have a RA deliverability status.

The Slice-of-Day framework impacts storage in part because the shift from a peak-hour focus to a broader 12-month x 24-hour plan makes it so that load serving entities must now account for storage charging requirements in their RA plans. Energy storage resources that cycle multiple times per day may benefit since they can now count each cycle towards their RA obligations. For example, if an energy storage resource has a four-hour duration and is contracted with the load serving entity to cycle two times per day, it could count towards meeting eight hours of RA obligations assuming a sufficient amount of time between the showing periods to allow for charging.

> The CPUC's new "Slice-of-Day" reform will significantly change the way in which energy storage resources (as well as co-located resources) are used to provide RA capacity. The shift from a peak-hour focus to a broader 12-month x 24-hour plan makes it so that load serving entities must now account for storage charging requirements in their RA plans.

Grid charging restrictions may impact the value of the energy storage resource for RA purposes under Slice-of-Day rules. To the extent the charging restrictions imposed in an interconnection agreement affect the energy storage resource's daily storage cycle physical capability, storage efficiency, maximum continuous energy and storage maximum daily MWh, they could impact how the load serving entity is able to show the net qualifying capacity from the energy storage resource across the 24-hour slices.

Additionally, storage resources have the potential for being compensated for operating flexibility since they can address gaps in RA plans, including varying the delivery window month to month to when it is most valuable for the load serving entity. With the flexibility of the Slice-of-Day framework, long-duration energy storage resources may also have a way to monetize additional hours of duration beyond four hours.

While existing storage offtake contracts are expected to continue without modification or with minor changes under the Slice-of-Day framework, considerations for energy storage resources may include evaluating alternate must-offer windows, evaluating the impact on existing RA agreements to the extent risk is posed to the settlement or benchmarking provisions and evaluating the interconnection agreement for charging restrictions that could affect the storage resource's value, depending on how the load serving entity's showing tool's optimization tool will work.

Unforced Capacity Evaluation ("UCAP")

Alongside the implementation of the Slice-of-Day framework, the CPUC and CAISO are considering more accurate methods for calculating a generator's RA attributes. One such method is Unforced Capacity Evaluation ("UCAP"), which derates the RA value of a resource by discounting its deliverable qualifying capacity value to account for historical unit forced outage rates during RA supply hours. The CPUC had previously deferred the decision on whether to require the use of UCAP as a RA counting method, pending implementation of the Slice-of-Day framework. However, in 2024, the CPUC will reconsider the use of the UCAP methodology in determining the RA value of a given generator. The use of UCAP could change the commercial value of different resources in a more particularized fashion. With respect to energy storage, it is anticipated the CPUC will consider the differentiation in the UCAP policy between storage resources that charge from the grid versus those that cannot charge from the grid.

RA Regulatory Risk in Offtake Contracts

The developments in the RA regulatory framework discussed above are relevant to a primary commercial issue that arises in offtake contract negotiations for storage projects in California: how to properly and fairly allocate RA regulatory risk between the project sponsor and the offtaker. The risk of regulatory change (or "change in law") and its impact on a project's ability to supply agreed products and services under an offtake agreement is traditionally borne by the project sponsor. Where there exists a substantial degree of confidence in the ongoing or anticipated occurrence of regulatory changes affecting the project, however, failure to properly limit or reallocate such regulatory risk can potentially result in adverse economic impacts under the offtake contract and render it unfinanceable. RA regulatory risk fits neatly into this category.

The Orrick Energy Storage Update 2021–2022[7] summarizes change-in-law and RA regulatory risk and the common contractual methods for allocating this risk. While the contractual solutions have not changed meaningfully, there are new methods for allocating the unique risks posed by Slice-of-Day rules in particular. In addition, due to increased RA regulatory risk in recent years, California load serving entities have introduced new and additional penalty, indemnity and liquidated damage structures that need to be carefully vetted during the negotiation process. For optimal commercial viability and financeability of a California energy storage project, project sponsors will typically seek to more accurately define and/or limit these exposures.

> There are new methods for allocating the unique risks posed by Slice-of-Day rules. California load serving entities have introduced new and additional penalty, indemnity and liquidated damage structures that need to be carefully vetted during the negotiation process.

CAISO Deliverability

Energy storage projects cannot provide RA without receiving a deliverability allocation from the CAISO pursuant to the CAISO's generator interconnection and deliverability allocation procedures. Under the CAISO Tariff and CPUC rules, resources can only provide RA capacity as a result of full capacity deliverability status ("FCDS"), partial capacity deliverability status ("PCDS") or interim deliverability status ("IDS") if network upgrades are still pending when the resource achieves commercial operation. Energy-only resources are not permitted to provide RA capacity.

Navigating the deliverability process has been a challenge for energy storage developers in recent years, given that the CAISO deliverability assessments are delayed as a result of CAISO queues being overloaded and backlogged from the large volume of new projects seeking deliverability status. There is widespread industry concern about access to deliverability for resources seeking to compete in load serving entity procurement processes, particularly because the state has increased the importance of RA by limiting major procurement mandates to resources that can provide RA capacity.

Developers are also experiencing problems under interconnection agreements, given that some transmission utilities are requiring the completion of network upgrades and centralized remedial action schemes as a precursor to finalizing RA deliverability. Generally, a project cannot provide RA until the required remedial action network upgrades are complete. In many offtake contracts, the developer assumes the schedule and delay risk with respect to this issue, including potentially indemnifying the offtaker for any compliance penalties associated with failure to timely reach commercial operation. The utility's delay as a transmission provider with completing network upgrades does not typically result in an extension of a contract's RA guarantee date or guaranteed commercial operations date ("COD"), which is a significant risk and exposure that developers should track closely and, where possible, attempt to negotiate for permitted extensions associated with network upgrade delays.

7 See California section in Orrick Energy Storage Update 2021–2022.

Hedge Transactions for Storage Projects

Defining the Hedge

BESS hedges have the following characteristics:[8]

- They constitute some version of a swap in order to hedge the BESS project against the volatility of the power markets.
- The swap may take the form of (1) a fixed-price swap, which swaps a fixed price under the hedge agreement as against the variable, market-based price and/or (2) a fixed-quantity swap, which swaps a fixed (notional) quantity under the hedge agreement as against a market-based quantity. A hedge that contains elements of both swaps would not be uncommon.
- In addition, hedges must occur in "liquid" power markets.

Market Considerations

While it is theoretically possible to arrange a hedge in any power market, hedges are, in practice, only available for projects located in "liquid" power markets. Liquid power markets (1) have numerous participants—*e.g.*, generators, power marketers and end-users (including utilities), (2) enable trades amongst all of these participants and (3) publish prices for power attributes at specific intervals. In the United States, ISOs and RTOs manage liquid power markets.

CAISO, ERCOT and PJM are the ISOs/RTOs in which the bulk of U.S. power hedges are transacted. Those hedges have included power trades associated with fossil-fueled power generators, wind power generators and solar power generators. BESS project hedges are the newest entry to the power hedge landscape and have drawn principles from these other technologies. However, since BESS projects charge and then discharge electricity rather than generate electricity, power generation hedging models have to be modified for BESS projects.

Hedgeable Attributes

BESS projects have three classes of attributes that can be hedged—capacity attributes, ancillary services and energy. Both ancillary services and energy are currently traded in liquid power markets and have been the subject of power hedges. PJM hosted the earliest BESS project hedges, centered around ancillary services; CAISO initiated the Top 4 Bottom 4 ("TB4") hedge, centered around arbitrage between charging and discharging electricity prices; and ERCOT has migrated the TB4 hedge to a Top 2 Bottom 2 ("TB2") hedge and is innovating novel energy-based hedge transactions, including fixed-shape hedges and call/put options.

8 A broad interpretation of a hedge would include many agreements commonly used in the BESS industry to secure revenues—*e.g.*, certain energy services agreements, certain tolling agreements, resource adequacy agreements, etc. But for purposes of this report, we define hedges in line with the narrower, more common usage in the energy industry.

Ancillary Services Hedges

Ancillary services-based hedges for BESS projects have a relatively long track record. While particular ancillary services differ from market to market depending on which such services can be performed by BESS projects,[9] the hedges tend to be similar to fixed-for-floating swaps constructs. Again, in these arrangements, the BESS project swaps are variable, market-based revenues received from the market operator for providing ancillary services against a fixed amount of revenue from the hedge provider. These hedges may be either physical or financial in nature.

> Ancillary services-based hedges for BESS projects have a relatively long track record.

Energy Hedges

Energy-based hedges trades are more nascent in the BESS project market. While ancillary services-based hedges swap revenues, energy-based hedges must account for both (1) revenues from the sale of discharging electricity and (2) costs of purchasing charging electricity. The CAISO TB4 hedge documents this construct for a four-hour duration BESS project by calculating the difference between revenues earned from sale of discharging electricity in the four highest-priced hours of a day and the purchase of charging electricity in the four (or five) lowest-priced hours of a day. The ERCOT TB2 hedge is similar in nature but is used in the context of a two-hour duration BESS.

> Energy-based hedges trades are more nascent in the BESS project market.

Other energy-based hedge constructs have included call options sold by the BESS project operator to monetize upside volatility in electricity markets and put options purchased by the BESS project operator to protect against downside volatility in electricity markets. In call option hedges, the hedge provider pays the BESS project operator a premium in exchange for net revenues exceeding a specified threshold. By contrast in put option hedges, the BESS project operator pays the hedge provider a premium and the hedge provider pays an amount to the BESS project operator if net revenues fall below a specified value.

Finally, more novel energy-based hedge constructs have included sophisticated financial trades more frequently used for other technologies. As BESS projects continue to be commissioned to address volatility concerns in the liquid power markets, the novelty and sophistication of these trades is likely to grow.

9 Ancillary services include: frequency regulation, ramp up/down and voltage support.

Documenting the Hedge

Parties document power hedges in a number of ways. The International Swaps and Derivatives Association ("ISDA") agreement is likely the most prolific, as it is the common trading form used by power trading desks. The Edison Electric Institute's ("EEI") master power purchase & sale agreement is another commonly used form in power hedges. And, of course, the parties may choose to draft more bespoke contracting arrangements. No matter the form of documentation, a properly constructed hedge for a BESS project should include the following broad elements: (1) the hedge/trade; (2) covenants relating to operational requirements; and (3) collateral requirements.

Hedge/Trade

Properly documenting the commercial terms of a power hedge requires careful drafting. In documenting the actual trade—*e.g.*, fixed-for-floating swap, put option, etc.—the parties need to define the following: (1) tenor of the trade; (2) price, including by reference to liquid trading points; (3) calculation methodology; (4) any premia in connection with the trade; (5) in the context of options, whether the options are automatically exercisable; and (6) the details of any tracking accounts.

Operational Covenants

The effectiveness of power hedges is often dependent upon one or more assets being developed, commissioned and properly operating.[10] In addition, hedge providers are often concerned about impairments to the financial wherewithal of the power assets—whether that is due solely to operational concerns or because of excessive leverage and/or liens. As such, the hedge documentation will specify in detail associated conditions and covenants. The following may be a part of hedges for BESS projects: (1) achievement of commercial operation and associated milestones; (2) performance metrics, including availability guarantees and degradation factors; (3) maintenance of insurance coverage; (4) restrictions on incurrence of debt and liens; (5) requirements relating to operational uptime, scheduled outages and forced outages; and (6) maintenance of certain contractual obligations with third parties—particularly construction contracts, operations and maintenance agreements and energy management agreements.

Collateral Requirements

The final element of power hedges is a properly constructed collateral package. Hedges may or may not be secured by a lien on the assets of the BESS project. A structure with a lien requires significant documentation that creates both personal property security interests and real property security interests on the BESS project—and often on the upstream ownership interests in the project. In addition, lien structures may require subordination and intercreditor agreements with financing parties.

By contrast, structures without liens are generally much easier to document. Even without a lien, the parties often nevertheless require posting of some security in favor of each other. The instruments available can include: cash, letters of credit and parent guaranties. After those instruments are chosen, the parties must make various elections as to: (1) the quantum of security posting; (2) the eligibility of the various instruments for security posting, including credit quality requirements of each of the posting entities; and (3) the timing of security posting.

10 These are contrasted with power hedges that "simply" trade power without being associated to any particular asset.

Corporate Procurement of Storage

The demand for corporate offtake agreements in recent years has primarily been driven by corporate procurement of renewable energy credits ("RECs"), which typically may only be issued by resources that *generate* and deliver renewable energy. Since battery storage resources are not currently eligible to issue RECs, relatively few corporate offtake agreements for front-of-meter projects contemplate battery storage, other than perhaps an offtaker consent right or right of first offer with respect to any future project modifications or product associated with battery storage. Pairing battery storage with a generating resource nevertheless provides multiple unique applications for corporate offtake agreements, including the ability to "shift" and "shape" generation, as well as provide backup power.

In corporate offtake agreements, a project sponsor's ability to "shift" the delivery of generation from one period of the day to another is not only beneficial for price arbitrage (*e.g.*, to sell electricity during the highest-priced hours), but also as a mitigant to "basis risk." Basis risk is a common issue addressed in virtual power purchase agreements ("VPPAs"), one of the most prevalent contract structures for corporate offtake agreements, and refers to the risk of a difference between the price of energy at the liquid market hub, which is often the price used for the financial settlement under the VPPA, and the price at the project's point of interconnection ("POI"), which is used to determine a project sponsor's market revenues from the sale of energy into the grid. The financial settlement in VPPAs guarantees a project sponsor a fixed price for the energy it delivers, but any price at the hub above the price at the POI results in a payment to the offtaker. If the *hub* price is very high (*e.g.*, during an extreme weather event) but the POI price is very low or negative (*e.g.*, as a result of congestion), a project sponsor may be required to make a substantial payment to the offtaker without the benefit of revenues at the POI to offset such payment. These losses may be compounded in the event prices at the POI are negative.

Basis risk is customarily borne by project sponsors who will frequently negotiate caps, curtailment rights, price adjusters or other contractual mechanisms to reduce their financial losses during such volatile periods. Pairing a generating resource with battery storage allows project sponsors to mitigate these losses by instructing the battery to charge from the generating facility during periods of high basis risk. Corporate offtakers may also benefit from this arrangement, particularly if the generating resource is subject to fewer basis curtailments during the delivery term, which may ultimately result in more RECs being issued from the generating facility.

> Pairing a generating resource with battery storage allows project sponsors to mitigate losses by instructing the battery to charge from the generating facility during periods of high basis risk.

For certain corporate offtakers, the appeal of pairing battery storage with a generating resource may stem from the battery's ability to "shape" the amount of energy delivered over any given time period. Under these arrangements, a project sponsor may be required to deliver a fixed amount of energy over certain hours of the day, either based on a predetermined schedule or a more variable schedule intended to align with a corporate offtaker's load profile. Fixed-shape offtake agreements provide offtakers greater certainty regarding the amount of generation (and RECs) they are procuring and may also provide a compelling marketing benefit by matching a corporate offtaker's actual emissions with an equal amount of zero-carbon energy

> For certain corporate offtakers, the appeal of pairing battery storage with a generating resource may stem from the battery's ability to "shape" the amount of energy delivered over any given time period.

delivered to the grid. Note that project sponsors can "shape" the *delivery* of electricity with a battery, but the underlying RECs associated with that electricity will still be temporally tied to the period during which they were generated by the generating resource, rather than discharged from the battery.

Pairing battery storage with a generating resource may also be desirable for reliability purposes, particularly in the context of behind-the-meter physical power purchase agreements. If a corporate offtaker is procuring generation to power a data center or other non-interruptible assets (*e.g.*, a hospital), battery storage may provide critical backup power during periods when electricity from the grid is unavailable.

Integrating these battery storage applications into a corporate offtake agreement may introduce new risks and complexities to a transaction. If the generating resource and battery storage resource are being developed and constructed at the same time, corporate offtakers may desire new schedule milestones or higher delay damages to mitigate a potential increase in the project's development risk. Corporate offtakers may also require contractual protections to ensure the battery resource does not decrease the metered quantity of electricity (and RECs) delivered under the agreement (*e.g.*, as a result of the battery's parasitic load).[11] For certain market participants, the unique benefits (including those discussed herein) derived from pairing battery storage with a generating resource may outweigh any perceived complexities in negotiating a corporate offtake agreement.

11 Center for Resource Solutions, "Green-e Renewable Energy Standard for Canada and the United States."

PROCUREMENT, O&M AND BUILD-TRANSFER ARRANGEMENTS

The IRA and Other Recent Developments

Due to the passage of the IRA in 2022 and other recent legislative and geopolitical changes, certain new issues have become more prominent in the negotiation of procurement, construction and Operation and Maintenance ("O&M") (long-term service) contracts for energy storage projects. Below we discuss four pertinent and timely developments and their impact on the allocation of risk among owners, contractors, manufacturers, and service providers in today's market for battery storage projects:

- Domestic Content Bonus under the IRA
- Prevailing Wage and Apprenticeship under the IRA
- Tariff and Change in Law Risk
- UFLPA, Forced Labor Considerations and Supply Chain Disruptions

Background: Contract Structures and Performance Testing/Guarantees

Prior Orrick Energy Storage Updates[1] have provided a detailed overview of the primary contract structures and testing regimes for commissioning and long-term performance guarantees for energy storage projects. Although these structures and regimes have matured incrementally over the past couple of years, they remain fundamentally the same, at least for battery storage projects. Most utility-scale battery storage projects are purchased directly from the manufacturer by the project developer/owner, installed under another engineering and construction agreement, then commissioned by the manufacturer who must meet certain performance tests to achieve its completion milestone. Some of those tests are backstopped by liquidated damages or "buy-downs" to allow for small variations in performance that do not jeopardize the project's ability to satisfy its offtake requirements. Most battery storage projects also have long-term performance guarantees from the manufacturer, which often require the project to engage the manufacturer to perform preventive and corrective maintenance, though third-party service providers are making inroads into the industry for basic maintenance, monitoring, and software support.

> Most utility-scale battery storage projects are purchased directly from the manufacturer by the project developer/owner, installed under another engineering and construction agreement, then commissioned by the manufacturer who must meet certain performance tests to achieve its completion milestone.

Background: Inflation Reduction Act

The IRA advanced two important trends for battery storage projects (see also "Tax and the Inflation Reduction Act" section of this report for additional background). First, energy storage systems are considered "energy property" in their own right for purposes of the energy investment tax credit ("ITC"). As such, in order to receive the ITC for the battery storage project, developers are no longer required to structure hybrid projects to co-locate battery storage projects with another renewable energy project nor do they have to prevent battery storage projects from being charged with grid power (including for commissioning) during the five-year recapture period. Thus, most of the battery storage projects under construction post-IRA are AC-connected and are, even when paired with a renewable energy project, effectively stand-alone battery storage projects from a procurement and construction standpoint.

> To receive the ITC for a battery storage project, developers are no longer required to structure hybrid projects to co-locate battery storage projects with another renewable energy project nor do they have to prevent battery storage projects from being charged with grid power.

1 See Orrick Energy Storage Update 2021-2022; Energy Storage Update 2018; Energy Storage Update – 2014 California Storage RFO.

> These longer pipelines have encouraged the use of "master" agreements intended to cover multiple projects in which a developer and manufacturer agree to minimum volumes of purchases and supply.

Second, by extending the ITC through 2032 at a consistent credit rate, the IRA provides longer-term stability and predictability to the tax credit regime, allowing developers to stretch the duration of their pipelines with less concern about tax credits or other important federal incentives being eliminated or substantially reduced. However, there always remains risk that the law will change due to political changes or other future events. Consequently, the "change in law" risk remains an important area of negotiation. These longer pipelines have encouraged the use of "master" agreements intended to cover multiple projects in which a developer and manufacturer agree to minimum volumes of purchases and supply, with penalties for not achieving those volume commitments, and parameters around pricing for orders far beyond the time horizon that parties would typically negotiate in one-off procurement agreements. These master agreements can also be tied to, and provide indirect financing for, development of new or expanded manufacturing facilities (or new products), including new U.S. domestic manufacturing facilities that take advantage of manufacturing credits for the manufacturer and domestic content bonuses for the project developer. This provides developers with more certainty of supply availability and some predictability on pricing so they can more confidently structure projects and bid for offtake, while manufacturers can use early deposits and future, credit-supported financial commitments to secure funding for its operations or development/financing of new or expanded facilities.

Domestic Content Bonus Under the IRA

As described in more detail in the "Tax and the Inflation Reduction Act" section of this report, a project owner is entitled to additional tax credits — the domestic content bonus — if it can establish that a certain minimum percentage of the manufactured products and 100% of the U.S. structural steel and iron used in the project were produced within the United States. Energy storage projects being built now or in the near future pose a challenge in this respect because there is currently a limited capacity for battery storage equipment with a significant portion of U.S. domestic content. Given that the battery storage equipment typically constitutes a large portion of the manufactured products being incorporated into a battery storage project, if the battery storage equipment does not meet the domestic content threshold, the project will likely not meet the required threshold. This can be contrasted to a solar project, where there is more U.S. manufacturing capacity (and more being built every day), and the solar modules are a smaller portion of the solar project's overall cost. However, domestic content requirements under energy storage procurement agreements are becoming a more prominent part of negotiation as battery manufacturers explore new domestic mining, processing, manufacturing, and assembly facilities. It is helpful to understand the key commercial considerations in negotiations in this area which are based largely upon lessons learned from contracting for the supply of domestic solar modules.

> A project owner is entitled to additional tax credits — the domestic content bonus — if it can establish that a certain minimum percentage of the manufactured products and 100% of the U.S. structural steel and iron used in the project were produced within the United States.

First, to show the minimum percentage of manufactured products were domestically produced, a project owner must calculate and show to the IRS the percentage of the overall project's cost for manufactured products that were attributable to the cost of domestically manufactured products using the manufacturer's, rather than the project owner's, costs. This requires manufacturers to disclose proprietary cost and supply chain information that they typically would not disclose to their customers. An approach to this dilemma in the solar module space appears to be coalescing around disclosure of cost information to independent third-party auditors who then produce a report that the project owner can share with the IRS for purposes of claiming their domestic content bonus. However, until there is further IRS guidance in this very new area of the law and some projects have tested the process, it is unclear whether and in what form the IRS will accept these third-party reports as conclusive proof for meeting the domestic content requirements.

> Manufacturers often do not know the exact percentage of domestic content in their product when they execute a procurement agreement.

Another commercial issue is that manufacturers often do not know the exact percentage of domestic content in their product when they execute a procurement agreement. Not only can supply chains shift, but costs of various commodities and other inputs may also change relative to each other. As a result, the parties will need to negotiate a process whereby the manufacturer provides updates to the buyer on the domestic content percentage, along with guardrails to ensure that the project owner does not slip below the required threshold needed to claim the domestic content bonus on each project.

> Manufacturers are highly resistant to taking on liability for losses to a project arising from the loss of a domestic content bonus.

Finally, there is uncertainty in the event the manufacturer fails to meet its promised domestic content percentage. Manufacturers are highly resistant to taking on liability for losses to a project arising from the loss of a domestic content bonus, which can amount to approximately 10% of the value of the project. Manufacturers argue that this degree of exposure and risk is out of line with the benefit they are getting from a particular contract, especially if the cause of a decreased domestic content percentage is, for example, an unexpected change in commodity prices. Parties often agree on some level of liquidated damages that are substantial for the manufacturer but also do not fully compensate the project owner for a loss of the domestic content bonus.

Prevailing Wage and Apprenticeship Under the IRA

As described in more detail in the "Tax and the Inflation Reduction Act" section of this report, projects with a maximum net output of 1 MWac or greater that commence construction after January 28, 2023, must comply with the IRA's requirement to pay prevailing wages and involve apprentices in work being performed on the project. These requirements mostly impact construction contractors installing the battery storage project and doing most of the other site work but also impact manufacturers who typically have personnel on-site for commissioning and testing before the project is placed in service.

These prevailing wage and apprenticeship ("PWA") requirements can be distinguished from the domestic content requirements in two key respects. First, all projects must meet the PWA requirements to obtain the increased 30% ITC that nearly all projects rely on, unless the project begins construction before January 29, 2023, or has a maximum net output of less than 1 MWac. As such, the PWA requirements are not to be considered an optional bonus that project owners can pursue, but instead, a fundamental project and financing requirement. Second, unlike the domestic content percentage of a project, which is effectively unchangeable once the project is completed, failure to meet the PWA requirements can be cured by paying back wages and other penalties, which can be significant but well short of the loss of a 10% domestic content bonus.

> PWA requirements are not to be considered an optional bonus that project owners can pursue, but instead they are a fundamental project and financing requirement.

Several key issues factor prominently in imposing the PWA requirements on contractors and manufacturers. First, contractors assert that determining prevailing wages can be difficult because data is often missing or hard to come by, and they do not want to be held liable for incomplete or incorrect governmental data. Second, tracking the PWA requirements is data and document intensive, and contractors resist strict recordkeeping and audit requirements, including the duration that they are required to retain the documentation. Third, there is often a negotiation around whether the project owner or the contractor is primarily responsible for handling claims by the IRS that the PWA requirements were not met, with the contractor often wanting to be able to negotiate and settle directly with the IRS rather than the project owner resolving the issue and coming back to the contractor for an indemnity. Finally, the indemnity itself is often heavily negotiated, with contractors commonly insisting that their liability for failing to meet the PWA requirements should be limited to a small percentage of the contract, reasoning that they are willing to pay back wages and penalties to some degree for a limited period of time, but beyond that period, contractors prefer not to be liable. Under those circumstances, the developer would be responsible for curing a potential IRS audit if the penalties are higher than expected or due to a loss of ITC or bonus credit adders resulting from noncompliance with the PWA requirements—even though existing guidance is unclear as to whether violations can be uncurable and what type of violations would be uncurable.

Another issue related to the PWA requirements is a lack of clarity around the extent to which the PWA requirements apply to the operations and maintenance of the project. Proposed regulations issued by the U.S. Department of the Treasury have indicated that the PWA requirements do not apply to work that is ordinary and regular in nature that is designed to maintain and preserve existing functionalities of a facility after it is placed in service. This type of work performed after the project is placed in service may include regular inspections of the facility, regular cleaning and janitorial work, calibration of equipment and replacing materials with limited life spans. However, if this same type of work is performed before the project is placed in service, it may be considered part of the construction activities subject to the PWA requirements.

Tariff and Change in Law Risk

In any project development arrangement—including procurement—construction and O&M agreements, parties must consider the impacts of the enactment of any new laws or amendments or modifications to existing law that may affect the contractual terms of the agreement or the schedule or cost to perform the work, including any new or increased tariffs. Contractors and suppliers are expected to factor compliance with existing laws and payment of existing tariffs into the schedule and price. However, contractors and suppliers are usually entitled to an adjustment in the schedule and/or price to account for any change in law.

> In recent years developers have assumed the risk of any new or increased tariffs.

Although changes in tariffs used to be a customary exception to this paradigm in project development arrangements for both renewables and battery storage projects (whereby the contractor or supplier would absorb the risk of changes in tariffs), in recent years developers have assumed the risk of any new or increased tariffs. Customary exceptions to contractor's right to change in law relief include changes in tax law relating to income taxes and other taxes that contractor is responsible for and changes in laws that have been enacted prior to the execution of the construction or procurement agreement but become effective later. Developers also often request that changes in foreign laws do not qualify for change in law relief, particularly where contractors and suppliers have control over their supply chain sourcing locations and transportation routes.

Tariffs under Section 301 of the Trade Act of 1974 ("Section 301 Tariffs") apply to imports of a variety of products from China, including battery energy storage system equipment produced in China. Such tariffs are 7.5%, 15%, or 25%, depending on the type of product being imported.

In addition, tariffs under Section 232 of the Trade Expansion Act of 1962 ("Section 232 Tariffs") apply to imports of many steel and aluminum products. Section 232 steel tariffs are 25%, while Section 232 aluminum tariffs are 10%. These tariffs can raise costs associated with, among other things, steel and aluminum products used in the construction of battery energy storage systems in the United States. Section 232 Tariffs only apply to imported steel and aluminum products and not to imported BESS equipment.

It is not expected that Section 301 Tariffs or Section 232 Tariffs will be discontinued in the near future.

UFLPA, Forced Labor Considerations and Other Supply Chain Disruptions

Suppliers are working toward increasing domestic manufacture of energy storage systems, but the majority of key equipment required to build energy storage projects is still sourced outside the United States. As a result, global supply chain disruptions in recent years, caused by events like COVID-19 and the Russia-Ukraine War, have impacted the ability of developers to build their projects on schedule and under budget. Contractors and suppliers want broad cost and schedule relief for supply chain disruptions and logistics issues, including for events of which the parties are aware but the impacts of which might not be fully realized. Developers typically push back on including such broad relief, especially for known events like COVID-19 and the Russia-Ukraine War, which developers believe should be factored into the cost and schedule.

> Contractors and suppliers want broad cost and schedule relief for supply chain disruptions and logistics issues.
>
> Developers often prohibit contractors and suppliers from procuring, directly or indirectly, materials or equipment from Xinjiang, or alternatively require contractors and suppliers to comply with the UFLPA.

The UFLPA[2] impacts importers and the supply chain for certain battery storage equipment and materials. As a result, developers are scrutinizing supply chains more than ever and should pay extra attention to any equipment or materials sourced from China to minimize delays. In procurement agreements, developers often prohibit contractors and suppliers from procuring, directly or indirectly, materials or equipment from Xinjiang, or alternatively require contractors and suppliers to comply with the UFLPA. Equipment suppliers, on the other hand, are seeking cost and schedule relief for delays resulting from goods being detained by the United States Customs and Border Patrol.

Furthermore, developers, offtakers and financing parties are increasingly concerned with and focused on ensuring that there is no forced labor in all projects that they develop or invest in, irrespective of the technology. As a result, offtakers, including many corporate offtakers, are requiring developers to flow down certain environmental, social and governance ("ESG") requirements relating to forced labor. Some offtakers and financing parties include related representations, warranties, covenants, and often require the ability to audit the supply chain for the project, which then must also be flown down by developers to their contractors and suppliers. Such terms and audit provisions may be difficult to negotiate with contractors and suppliers who have already entered into long-term master supply agreements with their supply chain partners that do not provide the audit rights being sought by offtakers and financing parties.

Build-Transfer Arrangements

With the passage of the IRA and the advent of stand-alone ITCs for storage projects, utilities are increasingly active in the M&A market, acquiring storage projects for long-term ownership, rather than contracting only for offtake. Developers should be aware, though, of certain complexities that arise with utility buyers that are not present with strategic M&A.

Contract Structuring

The majority of utilities participating in the storage M&A market are acquiring projects through "build-transfer" or "build-own-transfer" agreements ("BTAs"). Under the BTA structure, the utility selects projects to purchase through a request for proposals ("RFP") process. The utility and the developer enter into the BTA very early in the development process, and close on the sale of the storage project at mechanical completion. BTAs can be structured as asset purchases or purchases of the equity interests in a project company, with some utilities requiring an asset purchase agreement in order to include the storage project in the asset base upon which it can earn a rate of return.

Regulatory Approval Requirements

One unique consideration with all BTAs is that the utility cannot be bound by the terms of the BTA until it receives approval from its public utility commission ("PUC"). Depending on the jurisdiction, this can take anywhere from a few months to over a year. If the PUC does not approve the BTA, or imposes unreasonable conditions on the utility's execution of the BTA, then the utility typically has a unilateral right to terminate the BTA, typically without any penalty or compensation to the seller. During negotiations between the utility and the developer, the utility will be mindful of its PUC's concerns and try to reduce any risk of the BTA being rejected. As a result, it is uncommon for a PUC to reject a BTA or impose onerous conditions on it, but developers should be aware of this termination risk when bidding their storage projects into BTA RFPs.

2 See "International Trade and Investment" and "ESG and Sustainability" sections of this report for more detailed descriptions of the UFLPA.

Interim Milestones and Covenants

Because of the time period that the regulatory approval process can take, along with the resulting lengthy period between the execution and closing of a BTA, both developers and utilities typically seek exit options before the project incurs significant development and construction costs. As a result,

BTAs contain a concept frequently referred to as the "firm date", which requires the seller to achieve significant development milestones by a certain date, subject to limited extensions for excusable events like force majeure. The firm date milestones align with the typical conditions precedent to a financing, and therefore, by the firm date, the storage project must have obtained all of the necessary permits for construction, full site control and title insurance commitments, full interconnection rights, satisfactory reports and studies, title insurance commitments, executed equipment and construction contracts on terms approved by the utility and a cost segregation report as to the portion of the project that is eligible for the ITC.

Both before and after the firm date, the utility purchaser will require approval rights over the project's development and construction process. Generally, the same issues that need to be negotiated with a project's construction contractors and equipment suppliers will likewise need to be negotiated with the utility purchaser, including prevailing wage and apprenticeship compliance, tariff and commodity price risk and compliance with laws prohibiting the use of forced labor in the project's supply chain. These issues are discussed in more detail above. With storage in particular, utilities are sensitive to approval rights over major equipment suppliers, to reduce risks with respect to the reliability of the product, as many utilities have less experience with ownership of BESS projects than they have historically had with solar and wind. This lower level of familiarity also plays into the contracting structure generally, and the developer and utility will need to align on the integrator's and storage equipment suppliers' respective scopes of work, to reduce the risk of scope gaps.

Particular Utility Perspectives

Another consideration specific to BTAs is the utility purchaser's view of post-closing construction and warranty obligations. Under a storage project's BTA, where the project is eligible for the stand-alone investment tax credit, it must be sold to the utility at mechanical completion. Because that is the case, the seller will be responsible for the completion of all construction work after closing, notwithstanding that title to the project itself has passed to the utility. As a result, the utility purchaser frequently is willing to acquire only the construction contract and equipment supply warranties, and not the contracts themselves. The utility may additionally require the seller to warrant the work performed by its construction contractors, BESS integrators and other equipment suppliers in a "full wrap" structure. This would include owing performance liquidated damages directly to the utility, to cover the fact that frequently the responsibility for performance warranties may be divided between the integrator and the BESS equipment supplier, depending on their respective scope of work. In many cases, it is not possible to mirror a BTA's warranty obligations identically with those provided by seller's contractors and BESS suppliers, which imposes additional risk on developers that needs to be factored into the project's financial modeling.

Market Outlook

As utilities seek to increase their ability to respond to electricity demand and provide grid stability, there are, and will continue to be, new utility entrants into the BTA market looking to acquire both stand-alone storage projects and storage systems co-located with other renewable energy projects. With these new entrants, we anticipate an overall trend toward more reasonable BTA terms than in recent years' RFPs, which should reduce time and costs of transacting these structures.

TAX AND THE INFLATION REDUCTION ACT

The primary U.S. federal income tax incentive for a BESS project is the ability to claim the ITC under Section 48 of the Internal Revenue Code of 1986, as amended (the "Code"), and for projects placed in service beginning in 2025, the technology-neutral clean electricity investment credit under Section 48E. The IRA provides that an ITC for "energy storage technology" can now be claimed for stand-alone BESS projects. For ITC purposes, energy storage technology includes thermal energy storage property and property (other than property primarily used in the transportation of goods or individuals and not for the production of electricity) which receives, stores and delivers energy for conversion to electricity (or, in the case of hydrogen, which stores energy) that has a nameplate capacity of not less than 5 kilowatt hours.

ITC Changes Following Enactment of the Inflation Reduction Act

Under the IRA, the ITC was modified to provide a 6% base credit with an increase to 30% for projects that (i) have a maximum net output of less than 1 MW (as measured on an AC basis) of electrical or thermal energy, (ii) begin construction before January 29, 2023, or (iii) satisfy specific "prevailing wage" and "apprenticeship" requirements. Projects with a maximum net output of less than 1 MW of electrical or thermal energy or which began construction prior to January 29, 2023, qualify for the increased ITC rate without meeting the prevailing wage and apprenticeship requirements.

The prevailing wage requirements can be satisfied by requiring all laborers and mechanics employed during construction and for any repairs or alterations during the applicable tax credit period to be paid "prevailing wages." The term "prevailing wages" means wages at rates for similar work in the locality of the project as determined by the U.S. Secretary of Labor (generally from a wage determination available on the U.S. Department of Labor ("DOL") website or as provided to the taxpayer or contractor through a request to the DOL).

The apprenticeship requirement requires a percentage of the total labor hours spent to construct a project to be performed by "qualified apprentices" who participate in a registered apprenticeship program that complies with federal requirements. The percentage of labor hours is 12.5% for projects beginning construction in 2023 and 15% if construction begins in 2024 or later. This labor hour requirement is subject to applicable requirements for apprentice-to-journey worker ratios of the DOL or the applicable state apprenticeship agency. Each taxpayer, contractor or subcontractor that employs four or more individuals to perform construction, alteration or repair work with respect to the construction of the facility must employ one or more qualified apprentices to perform such work.

Failures to satisfy the prevailing wage requirements may be remedied through correction and penalty payments. The apprenticeship requirement can be deemed to have been satisfied through a good-faith effort exception or by paying penalties to the IRS for any failure to satisfy the requirement.

The prevailing wage requirements can be satisfied by requiring all laborers and mechanics employed during construction and for any repairs or alterations during the applicable tax credit period to be paid "prevailing wages."

Bonus Credit Adders

The IRA amends the ITC to provide several new incentives including bonus credit adders, which increase the amount of ITC available to eligible taxpayers. Adders are available for projects that meet certain domestic content requirements and for projects located in certain energy communities. Projects can now qualify for a 50% ITC by satisfying prevailing wage and apprenticeship requirements as well as the domestic content and energy community adders.

The Code provides for a 10% ITC adder if the energy property meets certain domestic content benchmarks, and the taxpayer timely submits a certification to the IRS. To satisfy the domestic content requirement and qualify for the domestic content adder, the project must satisfy the steel or iron requirement (*i.e.*, structural steel and iron must be produced in the United States) and the manufactured products requirement (*i.e.*, manufactured products must contain an adjusted percentage of domestic content). The steel or iron requirement applies to applicable project components that are construction materials made primarily of steel or iron and are structural in function. Manufactured products are considered produced in the United States if all of the manufacturing processes for the manufactured product take place in the United States, and all of the manufactured product components of the manufactured product are of U.S. origin. If a manufactured product is not of U.S. origin, but some of the manufactured product components are, the cost of these components can be used towards satisfying the adjusted percentage. The adjusted percentage of domestic content required in BESS projects is 40%. The adjusted percentage is calculated using the direct material and labor costs of the manufacturer.

The Code provides for an additional 10% ITC adder to locate energy storage technology in specific geographical locations in 2023 or later. The Code defines an energy community as any one of the following categories: (i) brownfield sites, (ii) metropolitan statistical areas ("MSAs") or non-MSAs with 0.17% or greater direct employment or 25% or greater local tax revenues related to certain fossil fuel-related activities (at any time after 2009) and an unemployment rate above the national average rate for the previous year and (iii) census tracts or directly adjoining census tracts in which a coal mine has closed after 1999 or a coal-fired electric generating unit was retired after 2009. A notable safe harbor under the energy community guidance is that if construction begins on a project on or after January 1, 2023, in a location that is an energy community as of the beginning of construction date, then, for that project, the location will continue to be considered an energy community on the date the project is placed in service for purposes of the ITC.

Direct Pay and Transferability

The IRA created new opportunities for credit monetization for BESS projects claiming the ITC, which allow for financing from new parties and simpler capital investment in BESS projects compared to traditional tax equity investments. Section 6417 allows certain tax-exempt organizations, government entities, tribal entities, the Tennessee Valley Authority and rural electric cooperatives to elect to receive cash payments from the federal government in lieu of energy tax credits. Section 6418 allows the transfer of energy tax credits to unrelated parties in exchange for cash payments.

Treasury and IRS Proposed Regulations

The Department of the Treasury and the IRS issued proposed regulations for Section 48 to update the types of energy properties eligible for the ITC that reflect changes in the energy industry, technological advances and updates from the IRA. In addition, the Section 48 proposed regulations include a new "energy project" concept for purposes of the prevailing wage and apprenticeship requirements, the domestic content adder and the energy community adder. This concept treats multiple energy properties as one energy project if at any time they are owned by a single taxpayer and meet two additional factors (*e.g.*, constructed on contiguous pieces of land or constructed pursuant to a single master construction contract). Although the applicability of this rule applies to projects that begin construction after the publication of the proposed regulations, this rule lowers the threshold for co-located projects to be treated as a single project.

Proposed regulations have also been issued to provide guidance for entities interested in electing direct pay or transfer tax credits. To so elect, an entity must preregister through the IRS pre-filing registration portal and make the relevant election on its tax return for the tax year in which the project is placed in service, including the relevant registration number, required forms and attachments. For tax credit transfers, the transferee must include the relevant information with its tax return on which it claims the tax credit. To prevent fraud, there are certain reporting requirements, restrictions and penalties associated with direct pay and tax credit transfers to prevent multiple or excessive transfers of tax credits.

FINANCING AND M&A

The energy storage landscape is undergoing a significant transformation, driven by the availability of ITCs under the IRA for stand-alone energy storage projects. The opportunity for monetization of ITCs through direct sale transactions is a dynamic trend which is attracting new capital providers, increasing the availability of financing and accelerating the deployment of crucial energy storage infrastructure. Understanding key trends for energy storage project financing in this context is critical as the demand for energy storage continues to rise.

Finance Readiness

Finance parties evaluate energy storage projects based on many of the same criteria as other renewable energy projects, subject to some exceptions. Projects that are best positioned for financing have well-organized development documentation, including (i) site control, offtake, interconnection agreements and major permits in place, prior to launching term sheet discussions with finance parties and (ii) other material project documents and third-party consents in process such that execution is likely on or shortly after finance parties are mandated. Ideally, developers have flexibility to negotiate change orders to construction contracts as well as align deadlines imposed under offtake or other material project documents with financing date certain requirements and termination provisions.

Energy Storage Technology and Equipment

Finance parties continue to focus on the viability of major energy storage equipment, with consideration for supply chain delays, tariffs and other trade barriers and warranty and performance guarantee protections, with an emphasis on use of tier 1 equipment suppliers. While lithium-ion battery technology has been thoroughly diligenced by the market, nascent storage technologies will be subject to additional scrutiny. Finance parties and independent engineers focus on battery degradation, useful life and the ability to charge storage equipment in the context of existing legal and contractual restrictions such as charging limitations during energy constrained periods and compliance with requirements under interconnection agreements, including ancillary services such as reactive power requirements.

> Finance parties continue to focus on the viability of major energy storage equipment, with an emphasis on use of tier 1 equipment suppliers.

Financing Energy Storage Systems Using Merchant Sales vs. Contracted Revenue Streams

While the preference remains for contracted revenue streams (with capacity and tolling contracts being the simplest from a lender's perspective), there is some appetite in the financing markets for financing merchant revenues that constitute all or some percentage

> While the preference remains for contracted revenue streams, there is some appetite in the financing markets for financing merchant revenues. For transactions structured with all or a higher percentage of merchant revenues, lenders will typically require higher pricing, conservative sizing and additional structural protections.

of overall revenues of a battery energy storage system, such as when a project with a long-term resource adequacy contract arbitrages energy and sells ancillary services on the spot market. For transactions structured with all or a higher percentage of merchant revenues, lenders will typically require higher pricing, conservative sizing and additional structural protections such as cash sweeps to a fixed target debt balance schedule and/or additional sweeps for liquidity events or other nonrecurrent revenues. Some transactions may utilize revenue puts, price floors or other hedging strategies to obtain more favorable pricing or sizing. Additional lender diligence and more conservative terms are also likely where the developer is bearing operational risk and damages are not fixed or capped. That said, the ability to monetize ITCs through direct transfers may increase acceptance of merchant deals overall because lenders can rely on the value of project tax credits in the absence of traditional tax equity financing.

Tax Equity and Tax Credit Transfer Markets

The ITC is playing a pivotal role in accelerating deployment of energy storage technology in the United States (see further discussion in the "[Tax and the Inflation Reduction Act]" section of this report regarding specific provisions of the IRA). Monetization of ITCs involves converting tax credits into committed capital for energy storage projects, either through traditional tax equity transactions or, as a result of the IRA, through direct tax credit sale transactions between developers and third parties under Section 6418 of the Internal Revenue Code. The scope of participants engaging in Section 6418 transactions is diverse and often includes tax credit buyers that are new to energy investment, which is contributing to the development of a dynamic and robust tax credit monetization market for energy storage. Specifically, these new tax credit buyers include corporations, institutional investors, private equity firms and traditional financial institutions.

Hybrid Tax Equity Structures

Developers and tax equity investors are reevaluating existing, traditional tax equity transactions and negotiating new terms to allow tax equity partnerships to directly sell tax credits to third parties in Section 6418 transactions, thereby allowing developers to monetize depreciation and the "step up" in tax basis (which is not possible in direct tax credit sale transactions). In addition, in the absence of a tax equity partnership, some developers are creating cash equity "op-co" partnerships to serve as the seller of the tax credit to accomplish these same goals.

Asset Management

Asset management software is a critical component of energy storage projects and is increasingly sophisticated with the integration of artificial intelligence to optimize battery dispatch, charging and revenue generation based on many factors, including wholesale market prices, warranty limitations and weather patterns. Given the proprietary nature of energy management system ("EMS") software used by many service providers, concerns have arisen regarding the ability to replace service providers and ensure uninterrupted asset operations. Accordingly, finance parties may require "lockbox" protections for the intellectual property in EMS software, whereby the source code is placed in escrow and released to the project owner or finance party upon certain trigger events, such as service provider default or bankruptcy.

M&A Developments

Recent trends in the M&A landscape for energy storage projects have largely tracked the broader renewables market.

- The use of representations and warranties insurance continues to become more prevalent in the renewable and storage M&A industry, not only in platform sales but also in portfolio and large project sales (where the purchase price can justify the premium costs).
- Post-closing capacity-based milestone payments remain a customary feature in sales of development-stage energy storage projects which require close attention to defining capacity and the applicable milestone triggers and negotiating ongoing development covenants.
- Given that a significant portion of the consideration in development-stage sales is pushed to post closing (in comparison to sales of operational projects, which typically contemplate the payment of all or a significant portion of the purchase price at the closing), in sales with traditional indemnity structures, the indemnity cap is often materially higher (as a percentage of the closing payment) in development-stage project sales than in operational project sales.
- In 2023, as the result of higher supply costs and increasing interest rates, and consistent with the broader M&A market in the United States, prospective buyers of energy storage projects were more cautious than in prior years. However, in 2024, we expect to see (and anecdotally are already starting to see) an uptick in deal volume due to improving market conditions.

INTERNATIONAL TRADE AND INVESTMENT

The U.S. government's national security and related legal requirements policy concerns associated with international trade and investment have continued to intensify, particularly as they relate to China and Russia. These requirements continue to have important effects on the solar and energy storage sectors, including many solar-plus-storage projects. In this section, we discuss the following developments and their impact on energy storage:

- Import tariffs;
- New legislation targeting imports of goods made with forced labor; and
- U.S. government's focus on foreign investments in the U.S. energy sector, especially renewable energy and battery storage sponsors and investors.

Import Tariffs – Section 301, Section 232 and Section 201

The Biden administration has preserved import duties established by the Trump administration (2017-2021) that can bear heavily on energy storage project cost structures.

Tariffs under Section 301 of the Trade Act of 1974 apply to imports of a variety of products from China, including photovoltaic ("PV") cells, modules and inverters used in solar energy projects and battery storage project equipment produced in China. Such tariffs are one of 7.5%, 15% or 25%, depending on the type of product being imported.

Tariffs under Section 232 of the Trade Expansion Act of 1962 apply to imports of many steel and aluminum products. Section 232 steel tariffs are 25%, while Section 232 aluminum tariffs are 10%. These tariffs can raise costs associated with, among other things, solar racking, wiring and ground-mount posts used in solar energy projects, as well as steel and aluminum products used in the construction of battery storage projects.

Tariffs under Section 201 of the Trade Act of 1974 apply to most imports of solar PV cells and modules (excluding imports from Cambodia and various other "developing countries"). Section 201 tariffs are scheduled to expire on February 6, 2026. The Section 201 tariff is 14.25% between February 7, 2024, and February 6, 2025, and 14% between February 7, 2025, and February 6, 2026. In light of recent court action, it appears that an exemption for bifacial modules will likely be overturned potentially resulting in retroactive collection of Section 201 tariffs on imports of bifacial modules between October 25, 2020 and February 7, 2022. Section 201 tariffs apply only to solar cells and modules and do not apply to battery storage project equipment.

The Biden administration has preserved import duties established by the Trump administration (2017-2021) that can bear heavily on energy storage project cost structures.

Finally, there are antidumping ("AD") duties that apply to most solar PV cells and modules made in China and Taiwan, countervailing duty ("CVD") duties that apply to most solar PV cells and modules made in China and, beginning in June 2024, AD and CVD duties that apply to many solar PV cells and modules made in Cambodia, Malaysia, Thailand and Vietnam. The U.S. Department of Commerce generally revises AD and CVD levels annually. To date, AD and CVD duties do not apply to battery storage project equipment.

Forced Labor Considerations for the Solar Industry

The UFLPA entered into force in June 2022. It strengthens the prohibition against the importation of goods made wholly or in part with forced labor into the United States set out in Section 307 of the Tariff Act of 1930, as amended. The UFLPA establishes a rebuttable presumption that the importation of any goods mined, produced or manufactured wholly or in part in China's Xinjiang Uyghur Autonomous Region ("Xinjiang") or by designated entities were made with forced labor. Such goods are prohibited from entry into the United States. This presumption also applies to goods made in, or shipped through, China and other countries that include inputs made in Xinjiang. The presumption does not apply if imported goods are sourced entirely from outside Xinjiang. UFLPA restrictions resulting in detentions of solar panels and, more recently, lithium-ion batteries at the U.S. border, as described below, have significantly impacted storage and solar-plus-storage projects.

Importers have two options to respond to a CBP enforcement action (*i.e.*, detention, exclusion or seizure) under the UFLPA (other than seeking permission from the port director to export detained shipments at any point prior to exclusion or seizure):

- **Option 1:** *Applicability Review.* Importers provide information to CBP demonstrating that the imported merchandise is fully outside the scope of the UFLPA because the imported goods, including all inputs thereto, are sourced entirely from outside Xinjiang and have no connection to the designated entities; or
- **Option 2:** *Request an Exception.* If the imported items fall within the scope of the UFLPA, importers may seek an exception to the rebuttable presumption.

> Importers have two options to respond to a CBP enforcement action (*i.e.*, detention, exclusion or seizure) under the UFLPA.

In Option 1, importers generally must provide documentation that details the order, purchase, manufacture and transportation of inputs, including raw materials, throughout their supply chain. Recognizing that supply chains vary dramatically, CBP has sought to avoid prescriptive requirements for the types of documentation and information it will accept. However, CBP indicated in its February 2023 "Best Practices for Applicability Reviews: Importer Responsibilities" publication[1] that a proper applicability review package submitted by a solar panel importer includes all transactional, financial and transportation documents for all stages of the solar-panel manufacturing process, from solar panel modules and solar cells to wafers, ingots, polysilicon, silicon and quartzite. If, after reviewing an importer's applicability review submission, CBP determines that the merchandise is outside the scope of the UFLPA, CBP will release such shipments, provided they are otherwise in compliance with U.S. law.

In Option 2, where the imported items fall within the scope of the UFLPA, CBP may grant an exception to the presumption if an importer demonstrates by clear and convincing evidence that the goods mined, produced or manufactured in Xinjiang are not the product of forced labor. Any exceptions must be made public and be reported to Congress. In practice, it is nearly impossible to provide such positive evidence. CBP has not granted or denied any UFLPA exception to date.

Since the UFLPA became effective, CBP has been focused on polysilicon imports as one of the high priority sectors for enforcement. However, in a development relevant for the energy storage sector, in July 2023 the Forced Labor Enforcement Task Force, an interagency task force, identified lithium-ion batteries as a potential risk area, following the U.S. Department of Labor's addition of cobalt—an input in such batteries—to its list of goods produced by child or forced labor in 2022. Although CBP does not generally publicize specific detentions, there have been media reports that lithium-ion batteries are increasingly subject to detentions by CBP.[2]

UFLPA-related constraints on the U.S. solar market have impacted solar and solar-plus-storage projects, creating unpredictable delays clearing customs and affecting the supply chain balance. Multiple solar manufacturers have had significant numbers of modules detained at U.S. ports. CBP statistics do not specify the number of solar panels detained pursuant to UFLPA, but the number of detentions in the "Electronics" industry is a good approximation. Between June 2022 and the date hereof, CBP has detained over 2,900 "Electronics" industry shipments for review, of which 30% were denied entry and 50% were released. Notably, only a small percentage of these shipments were of Chinese origin—approximately 63% originated in Malaysia, 28% in Vietnam and 9% in Thailand.

Given the substantial UFLPA risks, many U.S. developers have begun implementing additional controls and compliance programs. For example, the CBP's Operational Guidance for Importers[3] provides guidance on measures to help comply with UFLPA requirements, including supply chain mapping and monitoring, development of traceability audit programs, engagement of third-party investigators/auditors to verify compliance and creation of internal codes of conduct.

> Given the substantial UFLPA risks, many U.S. developers have begun implementing additional controls and compliance programs.

CFIUS Developments Affecting the Energy Storage Industry

As discussed in the Orrick Energy Storage Update 2021–2022, to protect U.S. national security, the Committee on Foreign Investment in the United States ("CFIUS") has the authority to review and disrupt certain foreign investments in U.S. businesses.[4] President Biden issued Executive Order 14083 on September 15, 2022 (the "CFIUS Executive Order"), which provides formal direction on the risks that CFIUS should consider when reviewing transactions within its jurisdiction. The CFIUS Executive Order specifically directs CFIUS to focus on, among other things, a transaction's effect on U.S. technological leadership and supply chain resilience and security in areas affecting U.S. national security, including advanced clean energy (such as battery storage), and whether a foreign person involved in the transaction has ties to third parties that may pose a threat to U.S. national security.

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1 U.S. Customs and Border Protection, "Best Practices for Applicability Reviews: Importer Responsibilities."

2 See Reuters, "EV battery imports face scrutiny under US law on Chinese forced labor," August 19, 2023.

3 See U.S. Customs and Border Protection, "UFLPA Operational Guidance for Importers."

4 For further background on CFIUS's authority and the examination process, including when CFIUS filings are mandatory, please see the Orrick Energy Storage Update 2021–2022.

The order also instructs CFIUS to consider cybersecurity risks posed by a transaction. These include risks posed by access to information databases and systems on which threat actors could engage in malicious cyber-enabled activities, such as the sabotage of critical energy infrastructure, including smart grids. In addition, the CFIUS Executive Order provides that CFIUS shall consider aggregate industry investment trends, including, as appropriate, the risks arising from a transaction in the context of multiple acquisitions or investments in a single sector or in related sectors.

Demonstrating its focus on clean energy technology, in December 2022, CFIUS mandated that Borqs Technologies Inc. ("Borqs"), a China-based global provider of 5G wireless and Internet of Things ("IoT") solutions and clean energy, divest its ownership in the U.S. solar energy storage company Holu Hou Energy LLC ("HHE") due to national security concerns. HHE, a provider of solar energy storage and energy sharing systems for residential and commercial properties in Hawaii, focuses on multifamily dwelling units ("MDUs"), which are common in military housing. Borqs had acquired a 51% ownership stake in HHE in October 2021. According to HHE,[5] CFIUS found that HHE's solar energy storage system and EnergyShare technology for MDUs were "critical technology." HHE's press release disclosed that CFIUS was concerned that through Borqs, China "could gain significant visibility and exert influence over HHE's business operations and get access to HHE critical technology,"[6] due to Borqs' IoT software development and hardware sourcing capabilities in China. These concerns align with those highlighted in the CFIUS Executive Order.

5 See Press Release, "Borqs to Establish with the U.S. Government a Plan to Divest its Ownership of Holu Hou Energy Due to Deemed Critical Technology," December 19, 2022.

6 *Id.*

It is important that U.S. energy storage project developers analyze CFIUS risk if they plan to source financing from foreign persons, including entities directly or indirectly controlled by foreign individuals, entities or governments. To resolve whether a CFIUS filing could be mandatory, U.S. companies should determine whether they design, develop, produce, manufacture, fabricate or test any critical technologies, including certain export-controlled hardware, software or technology. It is also useful to understand whether the company owns or operates any "covered investment critical infrastructure," as defined in CFIUS' regulations, including any electric storage resource that is physically connected to the bulk-power system. Certain foreign investments in U.S. businesses that have involvement with critical technology or covered investment critical infrastructure trigger mandatory CFIUS filings.

U.S. energy storage developers should conduct due diligence on potential foreign investors, including their ownership and control, as well as their commercial relationships and other connections to China and Russia. In May 2023, CFIUS issued guidance confirming its position that it has the authority to request information "with respect to all foreign investors that are involved, directly or indirectly, in a transaction, including limited partners in an investment fund" and about "governance rights and other contractual rights that investors collectively or individually may have in an indirect or direct acquirer or the U.S. business."[7]

> U.S. energy storage developers should conduct due diligence on potential foreign investors, including their ownership and control, as well as their commercial relationships and other connections to China and Russia.

CFIUS continues to expand its efforts to identify transactions within its jurisdiction that parties have not notified to CFIUS and that may present national security risks. CFIUS may contact transaction parties post-closing, even years later, to request information and potentially a filing. As the Borqs-HHE case demonstrates, transactions that are not cleared by CFIUS remain indefinitely susceptible of possible future CFIUS interference. According to CFIUS' Annual Report for 2022,[8] CFIUS requested filings in 2022 for 19 non-notified transactions. Assistant Secretary for Investment Security Paul Rosen noted at a CFIUS conference in 2023 that many of these resulted in mitigation or voluntary divestment.

7 See U.S. Department of the Treasury, "CFIUS Frequently Asked Questions."

8 See U.S. Department of the Treasury, "Treasury Releases CFIUS Annual Report for 2022."

ESG AND SUSTAINABILITY

The energy storage industry has been impacted by both significant commercial pressures with respect to responsible sourcing requirements as well as a host of existing and new sustainability-related legal requirements that apply to energy storage project developers' business operations and commercial transactions.

U.S. Uyghur Forced Labor Prevention Act[1]

Raw materials and component parts for energy storage projects are sourced from all over the world, including from jurisdictions with minimal protections for workers. While forced labor and human trafficking have long existed in complex, global supply chains, there is now a heightened risk that products sourced from China may contain materials or component parts resulting from the forced labor of ethnic Uyghur workers from the Xinjiang Uyghur Autonomous Region (Xinjiang). This is certainly the case with respect to the photovoltaic solar industry, as a dominant portion of the world's polysilicon used in solar panels hails from Xinjiang. But China is also a significant exporter of Lithium, and approximately 60% of the world's cobalt is sourced from the Democratic Republic of the Congo,[2] where human rights abuses and labor violations are common in the cobalt mining industry.

As a result of the passage of the UFLPA in late 2021 and the recognition by commercial parties of the supply chain risks detailed above, buyers are increasingly (i) insisting on full supply chain traceability, from finished goods back to raw materials, in order to comply with the documentation requirements of the UFLPA to mitigate risks associated with the origin of goods and (ii) requiring suppliers to adhere to a supplier code of conduct that sets forth robust environmental and social requirements and mandates the implementation of "management systems" to ensure compliance. These management systems also play a significant role in rebutting the presumption of forced labor under the UFLPA and generally consist of measures such as risk assessment and risk management, training and audits. By flowing down traceability requirements, substantive ESG requirements and management systems requirements, buyers seek to force suppliers to both agree to adhere to these ESG principles and adopt processes and procedures that support compliance with those principles.

> As a result of the passage of the UFLPA in late 2021, buyers are increasingly insisting on full supply chain traceability and requiring suppliers to adhere to a supplier code of conduct.

Importantly, it is frequently the case that a buyer supplier code of conduct will apply not only to the operations of the supplier, but also to the operations of its subcontractors/sub-tier suppliers, as well as those suppliers' suppliers, as part of a full-supply chain regime. Project developers are therefore faced with the difficult task of assessing whether their own suppliers are in compliance with supplier codes of conduct flowed down from buyers. This is rendered more difficult by the fact that suppliers often claim that their own code of conduct is materially consistent with a buyer code and will resist agreeing to additional obligations. Project developers are working to develop methods of assessing supplier codes to determine whether they meet buyer requirements.

Recent California Climate Legislation

In addition to the UFLPA, project developers are contending with a new set of climate-related California laws that were passed in October 2023 – SB 253, SB 261 and AB 1305. SB 253 requires companies that do business in California and that have over US$1 billion in revenue to disclose Scope 1, 2 and 3 greenhouse gas emissions and obtain assurances regarding these metrics, with phased-in requirements for Scope 3 greenhouse gas emissions and assurances. SB 261 requires companies that do business in California and that have over US$500 million in revenue to disclose material climate-related risks. With respect to both SB 253 and SB 261, companies have time to disclose – initial disclosures aren't due until 2026 for SB 253, and initial disclosures under SB 261 must be made on or before January 1, 2026. However, AB 1305, which was also passed in October 2023, requires companies that operate in California to make what can be significant disclosures regarding net zero,

1 See also our discussion of the UFLPA in the "International Trade and Investment" section.

2 See The Faraday Institution, Faraday Insights – Issue 6 Update: December 2020, "Lithium, Cobalt and Nickel: The Gold Rush of the 21st Century."

carbon neutrality, and importantly, greenhouse gas emission reduction claims since AB 1305 became effective January 1, 2024. Net zero commitments in line with the Paris Agreement are becoming more common—based on Orrick research, as of June 2023, with 673 U.S. companies setting or committed to setting a near-term SBTi climate target. Under AB 1305, companies need to disclose how they are measuring interim progress against these targets. However, AB 1305 does not apply only to net zero goals – it applies to any goals that involve significant greenhouse gas reductions, either for the business itself or for products. Because project developers, by the nature of their business, are developing projects and products that reduce emissions, it is common for such businesses to make greenhouse gas emissions-related claims. For this reason, it is important for project developers to conduct an inventory to determine whether they have made relevant claims, and if they have, to assess whether they are in compliance with AB 1305 and whether additional disclosure must be made.

In addition, the FTC recently solicited input regarding whether it should amend its "Green Guides" – its published guidance regarding the use of claims related to environmental benefits. The FTC has asked whether it should revise its carbon offset guidance and add additional specific guidance on claims about climate change. It has also asked for comment on the substantiation for currently widely used (and previously unaddressed) terms such as "net zero," "carbon neutral," "sustainable" and "low carbon," and has asked if it should add guidance on energy use and efficiency. Project developers should monitor any updates to the FTC's Green Guides and ensure that such guidance is considered when making climate-related claims.

> In addition to the UFLPA, project developers are contending with a new set of climate-related California laws that were passed in October 2023.

EU Corporate Sustainability Reporting Directive

Also, potentially relevant for European project developers and U.S.-based project developers with significant operations in Europe is the EU Corporate Sustainability Reporting Directive ("CSRD"). The CSRD entered into force on January 5, 2023, and the related European Sustainability Reporting Standards were adopted on July 31, 2023. The CSRD expands existing sustainability disclosure requirements in the EU by increasing the number of companies that must report and introducing much more rigorous and burdensome sustainability reporting obligations. EU member states have until June 2024 to transpose the CSRD directive into national law. For U.S.-based project developers with operations in Europe, the developer will have to comply with the CSRD disclosure requirements if it has subsidiaries or branches in Europe that meet certain thresholds with respect to turnover, assets or number of employees. Disclosure must be made on an entity-by-entity basis, and for entities that must disclose, the process of determining relevant disclosure topics and preparing the required disclosures can be extensive and cost-intensive. Disclosure for the entities or branches of U.S. entities will need to be made in 2026 for the 2025 financial year.

What Can My Company Do?

Assess Your Company ESG Policies and Supplier Code of Conduct

Given that buyers will commonly flow down supplier codes of conduct that require both the project developer and the developer's suppliers to comply with an extensive set of ESG requirements, project developers should assess their company's ESG policies and their own supplier code of conduct to ensure that in both cases, the policies in place are consistent with industry standards, such as those published by the Solar Energy Industries Association ("SEIA") or Responsible Business Alliance and are effectively flowed down to the developers' own suppliers by means of appropriate contractual provisions.

Conduct an Inventory of Entity-Level and Product Climate-Related Claims

Project developers frequently make claims regarding the climate-related benefits of their technology and projects. Given the passage of AB 1305 and the FTC's request for comment regarding the Green Guides, project developers should consider conducting an inventory of climate-related claims and assessing those claims under relevant legal standards and guidance.

Determine Whether the Company Will Be Subject to the CSRD

The EU CSRD requires sustainability disclosures that are different in both type and extent than the sustainability disclosures currently required under U.S. legal regimes. Project developers should consider conducting an applicability assessment with respect to the developers' EU subsidiaries and branches. If a subsidiary or branch is required to comply with the CSRD, it is likely that multiple advisors, both legal and non-legal, will need to be engaged to determine relevant disclosure topics to prepare the required disclosure. Even though disclosure for EU subsidiaries and branches will not be required until 2026 covering the 2025 financial year, developers should begin to identify potential advisors now in preparation for the compliance process.

U.S. JURISDICTIONS

In 2018, the Federal Energy Regulatory Commission ("FERC") issued Order No. 841, which opened wholesale energy, capacity and ancillary markets for "energy storage resources," defined as any resource capable of receiving electric energy from the grid and storing it for later injection back to the grid. Before Order No. 841, some FERC-regulated RTOs, notably CAISO, had developed market rules that allowed energy storage resources to participate in wholesale markets. However, Order No. 841 attempted to level the playing field by requiring all RTOs – namely PJM, NYISO, ISO-NE, MISO, SPP and CAISO – to revise their tariffs and market rules to enable owners of storage projects to offer all energy, capacity and ancillary services that they are technically capable of providing, while accommodating the "physical and operational" characteristics of storage projects.

In 2020, FERC issued Order No. 2222, which directed RTOs to develop participation models that will enable aggregators of distributed energy resources ("DERs") to participate in organized energy, capacity and ancillary service markets. FERC defined DERs broadly to include "any resource located on the distribution system, any subsystem thereof or behind a customer meter." Although FERC's definition is resource-neutral, FERC clarified that DERs may include energy storage, distributed generation and demand response. Although some RTOs have developed participation models to address FERC's directives in Order No. 2222, others have lagged, including MISO and SPP.

Orders 841 and 2222 apply only to FERC-jurisdictional RTOs and ISOs, which are organized markets subject to FERC jurisdiction. Accordingly, they do not apply to utilities that do not participate in RTOs, primarily utilities in the southeastern United States and in the Pacific Northwest. In addition, they do not apply within the ERCOT region of Texas.

Since issuing Orders 841 and 2222, FERC has turned its attention to transmission expansion and interconnection queue reform. In July 2023, FERC issued Order No. 2023, which directs reforms aimed at streamlining the interconnection process and addressing the nationwide backlog of interconnection requests that have delayed efforts to connect new resources to the grid. The reforms favor a new "first-ready, first-served" approach where developers must pay commercial readiness milestones to proceed with interconnection studies. Higher deposit and security requirements are intended to weed out speculative requests, thereby allowing transmission providers to focus on more commercially viable projects. Transmission providers have until April 2024 to file tariff revisions with FERC to implement the queue reforms. As with other FERC reforms, ERCOT is exempt from these new requirements.

CAISO

Among the RTOs, CAISO has been a leader in the integration of energy storage resources even before FERC issued Order No. 841. In July 2023, CAISO reported that it had the largest concentration of lithium ion battery storage in the world – approximately 5,600 MW. In the CAISO market, owners of storage resources participate as Non-Generator Resources ("NGRs"), which are treated as generation when discharging or load when charging and then bid into the market with a single supply curve. To manage state-of-charge values, NGRs can use a variety of operational parameters in submitting bids, including upper and lower charge limits for each trading day and initial state of charge.

Although many NGRs operate as stand-alone projects, developers that choose to combine batteries with generation can operate under either the hybrid or co-located resource model. Under the hybrid model, the combined generation and storage resource is modeled as a single resource with a single bid curve. In contrast, the co-located model treats the storage and generation resources as separate resources with separate bid curves. The distinction between these two models can have consequences in how the market values capacity (resource adequacy) from the combined projects. Under the hybrid model, CAISO uses a single net qualifying capacity for the combined facility. Under the co-located model, CAISO attributes a net qualifying capacity to each of the generation and storage components, subject to the aggregate interconnection limit for the projects. Accordingly, co-located resources have the potential for greater capacity values.

DERs were eligible to participate in the CAISO markets for a decade before FERC issued Order No. 2222. Initially, CAISO attempted to maintain its existing DER program, which did not allow aggregators to register DER aggregations under one or more participation models. Through a series of compliance filings, the last of which being accepted by FERC in May 2023, CAISO has implemented reforms in compliance with Order No. 2222 to allow aggregations of DERs to participate in one or more participation models within the CAISO markets.

ISO-NE

In response to Order No. 841, ISO-NE implemented an initial set of reforms in 2019 to integrate energy storage resources into ISO-NE's energy, capacity and ancillary service markets. Energy storage resources can participate as either a dispatchable generator asset or as a Dispatchable Asset Related Demand ("DARD") resource. However, due to software limitations, ISO-NE will not account for storage resources' state of charge or duration characteristics in the day-ahead market until 2026. As of February 2023, storage projects made up slightly more than a third of the generating capacity in the ISO NE interconnection queue. In addition, more than one gigawatt of storage capacity secured supply obligations in the March 2023 Forward Capacity Auction.

As with other RTOs, projects requesting interconnection in ISO-NE are experiencing significant, multi-year delays relating to the completion of interconnection studies. ISO-NE is working to develop tariff revisions to address FERC's interconnection queue reform directives in Order No. 2023. Among its challenges, ISO-NE has flagged that moving to a first-ready, first-served approach will complicate how ISO-NE identifies capacity network resource interconnection rights, which could inhibit the ability of a planned generating or storage resource to participate in Forward Capacity Auctions.

NYISO

In 2022, the New York State Energy Resource and Development Authority ("NYSERDA") and Staff of the New York State Department of Public Service published a roadmap to develop 6 GWs of energy storage by 2030, which could ramp up to 12 GWs by 2040. However, backlogs in interconnection queues and the need for additional transmission capacity represent barriers to entry within the New York market.

NYISO has long facilitated participation of energy storage resources in its energy, capacity and ancillary service markets. Before FERC Order No. 841, energy storage resources within NYISO could participate as a generating resource, "Energy Limited Resource," or "Limited Energy Storage Resource." However, as NYISO acknowledged in its compliance filing to Order No. 841, market rules for generators are not tailored to the operating characteristics of storage facilities. Similarly, market participation rules designed for Energy Limited Resources and Limited Energy Storage Resources did not allow battery storage facilities to fully participate in the NYISO markets.

In 2020, in response to Order No. 841, NYISO implemented revisions to its Market Administration and Control Area Services Tariff ("Market Services Tariff") and Open Access Transmission Tariff ("OATT") to establish a new participation model for energy storage resources that recognizes their physical and operational characteristics and facilitates their participation in the NYISO energy, capacity and ancillary services markets. Today, energy storage companies can participate as suppliers in the NYISO wholesale market. Owners of energy storage resources receive economic dispatch instructions to inject energy into, or to withdraw energy from, the grid.

Since implementing its market participation reforms, NYISO has focused on reforms to streamline project interconnection. As noted above, transmission providers have until April 2024 to submit tariff revisions implementing FERC's queue reforms. However, NYISO has been working to improve transparency and efficiency of its interconnection process, including by implementing upgrades to its online portal. In addition, NYISO has expanded its planning and stakeholder services teams to improve coordination with project developers.

On November 3, 2023, NYISO filed with FERC proposed revisions to its Large Facility Interconnection Procedures ("LFIP") set forth in its OATT to establish an interim transition mechanism that will allow a developer to elect, based on its project's progress in the interconnection process, to commence or complete an ongoing interconnection study, to withdraw from an ongoing study without financial penalty, or to not commence a study. Projects that remain in the interconnection process after implementation of these interim reforms will be subject to further changes in the interconnection procedures that NYISO will effectuate through future tariff revisions in compliance with FERC Order No. 2023.[1]

Separately, NYISO has been working on reforms to integrate DERs, including storage resources connected to distribution systems, into wholesale markets. In 2020, FERC accepted revisions to NYISO's Market Services Tariff and OATT to establish a new participation model for aggregations of DERs whereby an "Aggregator" would act as the wholesale market participant for two or more resources connected to the retail distribution system, where no single resource can inject more than 20 MW into the grid. In 2021, NYISO filed with FERC further revisions to its Services Tariff and OATT to comply with Order No. 2222, but due to software limitations, those revisions might not become effective until 2026.

PJM

Prior to Order No. 841, energy storage resources had access to PJM's energy, capacity and ancillary services markets. PJM enhanced its market rules in compliance with Order No. 841 to compensate energy storage resources in the same manner as other resources and to recognize the unique physical and operational characteristics of energy storage facilities. PJM's Order No. 841 reforms took effect in December 2019. Following a dispute regarding PJM's proposed minimum run-time requirements for energy storage resources to participate in the

1 New York Indep. Sys. Operator, Inc., 186 FERC ¶ 61,085 (2024).

capacity market, FERC approved PJM's Effective Load Carrying Capability method to measure the capacity benefits of storage resources. Separately, in 2023, PJM adopted new rules to limit Capacity Interconnection Rights, which determine the amount of energy capacity that resources can provide to the grid, to a resource's historical output in the summer and winter months.

Developers have experienced significant delays in interconnecting within the PJM region, with over 14 GW of energy storage pending in the queue. In November 2022, FERC approved revisions to the PJM OATT to reform PJM's interconnection process ("PJM Queue Reform") to address the significant interconnection delays and queue backlog. Like the reforms adopted in Order No. 2023, the PJM Queue Reform revised PJM's interconnection procedures from a "first-come, first-served" approach to a "first-ready, first-served approach" to prioritize interconnection of projects that demonstrate commercial readiness. Under this new model, PJM processes interconnection requests in three study phases with three decision points at the conclusion of each phase. To proceed through the interconnection process, an interconnection customer must satisfy certain site control requirements and submit increasing readiness deposits at each decision point.

PJM adopted transition procedures to implement the PJM Queue Reform, which has resulted in reprioritizing groups of existing requests in the PJM interconnection queue based on their maturity. The approximately 740 interconnection requests that were subject to the transition rules were required to demonstrate readiness by September 8, 2023, to remain in the queue. While PJM continues to process interconnection requests under the Queue Reform procedures, PJM is required to submit its Order No. 2023 compliance filing by April 2024, which will result in additional reforms to the PJM interconnection process.

MISO

In November 2019, FERC issued an order largely accepting MISO's Order No. 841 compliance filing. MISO requested, and was granted, deferral of implementation related to the development of software to accommodate energy storage resources. In September 2022, MISO opened its energy and operating reserve markets to energy storage resource participation. By 2021, interconnection requests for energy storage resources surpassed requests for wind resources. There is currently over 34,000 MW of energy storage pending in the MISO interconnection queue.

MISO is the only grid operator that prohibits dispatchable intermittent resources ("DIRs"), including wind, solar and battery hybrid resources from providing ancillary services. In August 2023, FERC issued separate orders upholding MISO's "ban" on DIRs providing ancillary services. The orders were issued in response to (1) a complaint by SEIA requesting that FERC order MISO to reform its Open Access Transmission, Energy and Operating Reserve Markets Tariff to allow DIRs to provide ancillary services, and (2) MISO's proposal to prohibit DIRs from providing ramping services. In upholding the ban, FERC found that DIRs clearing the market when they are not deliverable would present a reliability issue.

Like other RTOs, MISO has proposed an overhaul of its generator interconnection procedures. In two separate filings, MISO has proposed reforms consisting of (1) increased milestone payments, more stringent site control requirements and automatic withdrawal penalties, and (2) a cap to limit the MW amount of interconnection requests that may be included in a cluster or cycle on a "first-come, first-served" basis, with limited exemptions from the cap. The proposed reforms are currently pending before FERC. Separately, MISO must comply with the interconnection reforms adopted in Order No. 2023 by April 2024.

SPP

In 2019, FERC adopted SPP's Order No. 841 compliance proposal, finding that it allowed energy storage resources to provide all services they are technically capable of providing, compensated energy storage resources in the same manner as other resources, and recognized their unique physical and operational characteristics. Of the approximately 104,000 MW of projects in the SPP interconnection queue at the end of 2022, 14,000 MW were energy storage resources.

Separately, in May 2023, FERC accepted SPP's proposed revisions to its OATT to allow energy storage resources to be considered a transmission asset. To be designated as a Storage as a Transmission-Only Asset ("SATOA"), the resource must be under SPP's operational control and connected to the transmission system as a transmission facility for the sole purpose of supporting the transmission system. In addition, the SATOA is selected as the preferred solution to a transmission need in SPP's transmission planning process only when the need cannot be resolved by a market solution.

SPP has grappled with interconnection backlogs since the late 2000s. In 2009, SPP first initiated interconnection process reforms to transition from a "first-come, first-served" serial approach to a "first ready, first-served" cluster approach. SPP also separated its interconnection queue into three queues: (1) the feasibility study queue, (2) the preliminary interconnection system impact study queue, and (3) the definitive interconnection system impact study queue. In 2013, SPP introduced additional reforms to increase milestone requirements to enter the definitive queue and continue with the facilities study, and to post a deposit upon execution of a Generator Interconnection Agreement. In 2019, SPP moved to a sequential, three-stage study process, requiring posting of financial security at each "Decision Point" to enter the next stage of the process. In 2022, FERC approved additional reforms to SPP's interconnection process to remove Decision Point 3, reduce study timelines, and increase financial commitments. SPP is required to submit additional reforms to its interconnection process by April 2024 to comply with Order No. 2023.

ERCOT

The wholesale markets administered by ERCOT are not subject to FERC's jurisdiction because they are, with the exception of four direct current ties, electrically isolated from the interstate grid. Nevertheless, ERCOT has been an active area for development of energy storage resources.[2]

Under the ERCOT protocols, energy storage resources are modeled as both generation resources when discharging and as controllable load resources when charging. Purchases and sales of charging and discharging energy from an energy storage resource are settled at the nodal (wholesale) price. When charging an energy storage resource, owners pay the equivalent of a real-time energy bid, but also must pay transmission charges for the charging energy pursuant to the transmission owner's tariff. In mid-2024, ERCOT expects to move to a model whereby scheduling coordinators for energy storage resources submit a single bid curve for charging and discharging energy, but the resources must be able to transition nearly instantaneously between charging and discharging.

Within ERCOT, energy storage resources can sell ancillary services, including Regulation Up, Regulation Down, Contingency Reserve, Non-Spinning Reserve, and Responsive Reserve Service. In 2023, ERCOT proposed to amend its protocols to require an energy storage resource to maintain a one-hour minimum state of charge to offer Contingency Reserve or Non-Spinning Reserve service. Violations of the minimum state of charge rule would be subject to penalties of up to $25,000 per violation. ERCOT claimed that the rule change was necessary because of the failure rate of energy storage resources. However, in January 2024, the Public Utility Commission of Texas rejected the rule as discriminatory, stating that all resources fail from time to time.

2 See our discussion of the "virtual" tolling agreement and BESS hedges in the "Offtake and Hedges" section.

INTERNATIONAL JURISDICTIONS
EUROPEAN UNION

Green Deal for Climate Neutrality

The integrated European electricity market is currently undergoing a fundamental transformation. As part of the European Green Deal to make Europe the first climate-neutral continent by 2050, the transition to a clean and efficient energy system is a key priority.

The regulatory framework for delivering the EU's climate goals is set by the "Fit for 55" package, implementing measures to reduce emissions by at least 55% by 2030.[1] The recent energy crisis has unveiled the necessity for a diversified and secure energy supply. In response, the REPowerEU plan was implemented, promoting a significant boost for investments in renewable energy.

Renewables Increase Flexibility Needs

So far, the efforts have proven successful. It is expected that almost 50% of the gross electricity production across the 27 EU member states will be from variable sources like wind and solar by 2030.[2]

The simultaneous decarbonization of the energy system and securing affordable energy supply entails a number of challenges for the European energy market. To keep demand and supply in balance under the changing conditions, the European Union Agency for the Cooperation of Energy Regulators ("ACER") has assessed that flexibility needs of the electricity grid will double by 2030.[3]

1 See European Commission, "Fit for 55: Delivering on the proposals."

2 See European Environment Agency, "Share of energy consumption from renewable sources in Europe," October 24, 2023.

3 See ACER-EEA Flexibility Infographic.

Revision of Electricity Market Design

On March 14, 2023, the European Commission published its proposal for a Regulation to Improve the Union's Electricity Market Design (COM(2023) 148 final). The main objective is to enhance the stability of the energy system and the integration of a growing share of renewables into the grid.

Electricity storage is considered a key element for the provision of flexibility solutions required for the seamless integration of additional renewable energy resources into the grid.

Price signals at the intraday and day-ahead markets provide short-term incentives for the provision of flexibility solutions. The regulation proposal allows flexibility support schemes as long-term incentives for investments in flexibility solutions from electricity storage.

Recommendations for Energy Storage

Concurrently with the proposed regulation, the European Commission has published "best practices" in relation to energy storage, recommending the member states to:[4]

- consider the double role of energy storage as generator and consumer to remove barriers resulting from double taxation, network charges or tariff schemes;
- identify the flexibility needs of their energy systems to cost effectively promote the deployment of energy storage, both utility-scale and behind-the-meter storage;
- assess whether energy storage can be a more cost-effective alternative to grid investments;
- identify potential financing gaps for energy storage and consider financing instruments for visibility and predictability of revenues;
- consider the sufficient remuneration of flexibility and non-frequency ancillary services;
- consider competitive bidding processes to reach a sufficient level of storage flexibility;
- remove barriers to the deployment of demand response and behind-the-meter storage;
- accelerate the deployment of storage in islands, remote areas and regions with insufficient grid capacity;
- make available real time data on congestion, curtailments, market prices and installed storage capacity to facilitate investment decisions; and
- support research and innovation in energy storage.

4 See Official Journal of the European Union, "Commission Recommendation on Energy Storage – Underpinning a decarbonized and secure EU energy system," March 14, 2023.

> The European Commission has published "best practices" in relation to energy storage.

Although not binding, it can be expected that member states will at least partially reflect these recommendations in their national regulations.

INTERNATIONAL JURISDICTIONS
FRANCE

France's current energy storage landscape is dominated by pumped-storage hydroelectricity plants (*Stations de transfert d'énergie par pompage*) ("STEP") that represent roughly 5 GW[1] of installed storage capacity, with little evolution in recent years. Still, the French multiannual energy programming (*Programmation pluriannuelle de l'énergie*) ("PPE") — an executive regulation adopted by the prime minister that provides for planning targets for a 10-year period—anticipates an increase of 1.5 GW between 2030 and 2035.

However, other storage technologies—in particular, battery storage—emerged in the last five years in mainland France[2] and are now undergoing vigorous development. At the end of October 2023, the interconnected capacity of battery storage reached nearly 786 MW,[3] while in 2022, it was approximately 500 MW,[4] and in 2020, it was around only 40 MW.[5]

Given that energy storage is an economic activity subject to competition, grid operators in France are not allowed to own storage facilities that are used for balancing or for congestion management purposes pursuant to Article L 352-2 of the French Energy Code (in French, *code de l'énergie*).[6] This would, in principle, allow economic operators to develop their storage projects with no unjustified competition from grid operators.

France's Energy Storage Objectives

The PPE for the period 2019-2028 sets an objective of 1.5 GW of additional STEP capacity to be commissioned between 2030 and 2035.[7] Beside this, on the matter of electricity storage, the PPE focuses on prospective actions without setting, except for STEP, quantified targets.[8]

Following a legislative process, the PPE is now also planned to be completed with an energy-climate programming law (in French, *Loi de programmation énergie-climat*) ("LPEC") to be enacted every five years and whose purpose is to define the objectives and priority actions related to French energy policy to respond to ecological and climate emergency circumstances.[9]

> The PPE for the period 2019-2028 sets an objective of 1.5 GW of additional STEP capacity to be commissioned between 2030 and 2035.

In November 2023, public consultation on the potential content of the LPEC and the next PPE for the 2024-2035 period was launched by the Ministry of Energy.[10] The consultation paper mentions a rise of the target concerning STEP from 1.5 GW to 1.7 GW of capacity to be commissioned between 2030 and 2035. The document also addresses the development of battery storage, including hybrid powerplants, and the opportunity of deploying technologies that are currently underused, such as inertial systems. At this stage, however, there are no quantified targets for the development of energy storage technologies other than STEP.

Regulatory Framework for Battery Storage Projects

Article L. 352-1 of the French Energy Code defines energy storage in the electricity system as "deferring the final use of electricity to a moment later than it was generated, or the conversion of electrical

1 See Forecast 2023–2035 – Electricity generation and storage (in French, *Bilan prévisionnel 2023–2035 – La production et le stockage de l'électricité*), p. 12, chart 3.3.

2 Battery storage is already used in French overseas territories (including Corsica) that are not connected to the mainland grid (in French, *zones non interconnectées*).

3 See CRE, Public consultation no. 2023-13 of December 14, 2023, on the tariff structure of the next tariff for the use of electrical grid "TURPE 7" (in French, *Consultation publique n° 2023-13 du 14 décembre 2023 portant sur la structure tarifaire des prochains tarifs d'utilisation des réseaux publics d'électricité* "TURPE 7") ("Consultation TURPE 7").

4 See Forecast 2023–2035 – Electricity generation and storage (in French, *Bilan prévisionnel 2023–2035 – La production et le stockage de l'électricité*), p. 55.

5 *Id.*

6 An exception is set forth for the CRE if (i) storage facilities are fully integrated into the networks and (ii) following an open, transparent and nondiscriminatory tendering procedure, there is a lack of supply of the facilities necessary for system operators to fulfil their obligations regarding the efficient, reliable and secure operation of the distribution system, and these facilities are not used to buy or sell electricity on the electricity markets.

7 *See* Ministère De La Transition Énergétique, Multiannual Energy Programming for 2019–2028, page 192.

8 *Id.*, refer to point 5.3.6 on electricity storage, page 189.

9 This new requirement has been enacted by Law no. 2021 1104 of August 22, 2021, combating climate change and building resilience to its effects (the so-called "Climate and Resilience Law").

10 See Ministère De La Transition Énergétique, "*Stratégie française pour l'énergie et le climat*."

energy into a form of energy which can be stored, the storing of such energy, and the subsequent reconversion of such energy into electrical energy or use as another energy carrier".[11]

A 2016 ministerial decree provides details on this definition and sets out that energy storage covers, among other technologies, "*pumped storage hydroelectricity, compressed air storage, storage through the conversion of electricity into hydrogen, electrochemical batteries and inertia flywheels*".[12]

Battery storage is thus one of the technologies that is encompassed in the definition of energy storage.

When it comes to permitting, there is however no single regulatory framework for energy storage in France but rather multiple frameworks depending on the type of storage that is contemplated to be installed.

Energy storage projects may indeed be governed by planning laws, environmental laws and other specific regulations linked to the characteristics of the energy storage project and with procedural lengths that may greatly vary.

With respect to battery storage, this technology may be categorized under environmental laws as an installation classified for environmental protection (in French, *installation classée pour la protection de l'environnement*) ("ICPE") which is subject to a declaration to be carried out by the developer when the cumulative deliverable charging power is greater than 600kW.[13]

Depending on the size of the battery storage installation, a permit under planning laws may also be required.

Finally, if the battery storage facility is installed on public land, an additional permit may also be required and, if any, only after a competitive tender process has been carried out by the competent authority.

With respect to the grid connection, a specific procedure for storage facilities has been implemented by the French operator of the public power transmission system, *Réseau de Transport d'Electricité* ("RTE") early 2023.[14]

Given the multiple layers of the regulatory framework related to permitting for battery storage projects, many stakeholders of the sector call for more clarity with the creation of an *ad hoc* status for storage facility operators.[15] The French national regulatory authority for energy, the *Commission de Régulation de l'Energie* ("CRE"), supports the idea of having a unique regulatory framework applicable to energy storage.[16] This position is also backed by the French Senate (*Sénat*).[17]

> The French national regulatory authority for energy, the *Commission de Régulation de l'Energie*, supports the idea of having a unique regulatory framework applicable to energy storage. The financial outlets for battery storage projects in France today remain rather limited.

Revenue Streams

The financial outlets for battery storage projects in France today remain rather limited.

Indeed, storage by battery is not included in the public financial support mechanism set forth for renewable energy projects on mainland France[18] and, therefore, a battery storage facility that may be co-located with a renewable energy asset is not covered by the feed-in-tariff ("FIT") which is only granted to the electricity produced by the renewable energy asset.[19] Therefore, the co-located battery storage project does not receive any additional revenue, and renewable energy producers need to ensure that the storage project will be economically profitable without any additional revenue.

Given the lack of public financial support for battery storage projects, the economic model for stand-alone battery projects depends on the existence of other revenue streams. For these stand-alone battery projects, one possibility is to participate in the seven-year term tenders for the capacity mechanism of RTE[20] to obtain a FIT.[21] Another possibility is to be granted an aid from a public authority to cover part of the construction costs, provided that such project was eligible.

11 This definition is identical to the one provided in Article 2, §59 of the Directive (EU) 2019/944 of the European parliament and of the Council of June 5 of 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU.

12 Article 1 of order of July 7, 2016, taken for the application of Articles D. 141-12-5, D. 142-9-2, D. 142-9-3 et D. 142 9 5 of the French energy code.

13 Cf. Section 2925 of Appendix 4 to Article R. 511-9 of the French Environment Code.

14 The CRE approved the grid connection procedure for storage facilities in its deliberation no. 2023-22 of January 19, 2023 (in French, *Délibération de la CRE du janvier 19, 2023 portant approbation de la procédure de traitement des demandes de raccordement des installations de production et de stockage au réseau public de transport d'électricité*).

15 CRE, September 11, 2019, "Reflection and contribution document: electricity storage in France" (in French, *Document de réflexion et de contribution: le stockage de l'électricité en France*), p. 6.

16 *Id.*

17 Sénat, 2022, "Information Report – Five plans to rebuild economic sovereignty" (in French, *Rapport d'information – Cinq plans pour reconstruire la souveraineté économique*), n.°755, p. 136.

18 Given the specificities of the grid in the French overseas territories, project developers of storage infrastructure, in collaboration with the local grid operator, can apply for specific public support under Article R. 121-28, III, of the French Energy Code. However, this public support is limited to the additional production costs they help to avoid, as calculated by the CRE (Article L. 121-7 2° b of the French Energy Code). A specific calculation of the remuneration allowed to the storage operator is set forth by the CRE (for the latest, please refer to the deliberation of the CRE N°2023-13 of January 12, 2023).

19 Cf. for instance, with respect to wind farms, Article 4 of Order May 6, 2017, setting the conditions for additional remuneration for electricity produced by wind-powered electricity generation facilities with a maximum of six turbines.

20 See Deliberation of the CRE no. 2022-226 of July 28, 2022, approving the System Frequency Services Rules proposed by RTE (in French, *Délibération de la CRE n 2022-226 du juillet 28, 2022 portant approbation des Règles Services Système fréquence proposées par RTE*), p. 4.

21 Art. L. 321-16 and L. 321-17, as well as Art. R. 335-71 and seq. of the French Energy Code.

An additional tendering mechanism may also promote the development of battery storage projects in the upcoming years. Indeed, pursuant to Article L. 352-1-1 of the French Energy Code, (i) if the objectives set by the PPE regarding storage capacities are not met or, alternatively, (ii) if the multiannual forecasted balances prepared by RTE highlight flexibility needs, the Minister of Energy Transition has the option to initiate a specific tendering procedure. This procedure is conducted by RTE which is to enter into a contract to pay the storage capacities of the selected candidates. The duration and the financial terms of these contracts are not known. As of today, this procedure has not yet been carried out, and it remains uncertain whether such calls for tenders will be launched in 2024.

However, the revenues generated by battery storage operators are hindered by the current tariff and tax structure which does not consider the specifics of the storage activity and even generates financial burdens for operators. Indeed, battery storage facilities behave alternatively as installations drawing electricity from the electrical grid when charging and as installations injecting electricity into the electrical grid when discharging. This technical aspect leads, as of today, to a double payment of the tariff for the use of the electrical grid (in French, *tarif d'utilisation du réseau public d'électricité*) ("TURPE") from the battery storage operator,[22] thereby decreasing total project revenues.[23]

This dilemma may, however, be resolved with the upcoming adoption of the new TURPE structure on August 1, 2025. Indeed, the CRE is proposing, for the first time, the implementation of a special optional tariff for storage.[24] The tariff would be designed to send pricing signals that reflect the contribution of storage capacity in reducing peaks on the grid, potentially resulting in significant savings on the TURPE for operators.[25]

> The CRE is proposing, for the first time, the implementation of a special optional tariff for storage.

22 In France, the TURPE is paid by the end-users to their electricity suppliers which then pays the collected TURPE to the distribution and transmission system operators.

23 In this respect, it can be highlighted that the European Commission identified this difficulty in its latest recommendation regarding energy storage and called Member States to eliminate this barrier (see Recommendation 1, Commission Recommendation of March 14, 2023, on Energy Storage – Underpinning a decarbonized and secure EU energy system 2023/C 103/01).

24 CRE, Consultation TURPE 7, op. cit., pp. 43 and seq.

25 A simulation conducted by the CRE suggests that, for installations subscribing to this option and adjusting their behavior in response to TURPE signals, potential savings on the paid tariff could range up to 25% for withdrawal and 75% for injection, depending on the connection voltage level in the current situation (see above, pp. 50–51).

Future Prospects

As underlined by RTE, "regardless of the technologies considered, the prospects for the development of storage remain highly dependent on the business models likely to emerge in the long term,"[26] and for utility-scale batteries the business model remains "uncertain."[27]

Until now, storage projects—irrespective of the technology—tended to target the segment of network stability services within the framework of organized tenders carried out by RTE. If storage projects will surely continue to target network stability services in the upcoming years, new opportunities now appear for storage operators.

Indeed, renewable energy plants co-located with a battery storage project are emerging in France. One of the first sizable solar-plus-storage projects was commissioned in 2014 in la Réunion, France.[28] Recently, several developers coupled their renewable energy assets (either solar or wind) with a battery storage facility.[29]

> Renewable energy plants co-located with a battery storage project are emerging in France.

Finally, the development of new storage technologies has also been announced. In French Guiana, for instance, the first hybrid solar power plant project to include hydrogen storage is currently under construction with a production capacity of 10 MW.[30] Its opening is planned for 2024.[31]

Some operators in the electric vehicle (EV) charging sector also consider the use of battery storage charging as an opportunity to charge overcapacity energy at low prices (at night) and delivering higher price energy during the day. The use of EV itself as a decentralized battery storage facility that could be used to stabilize the electricity network, for example, is also under study.

The French energy storage market is increasingly dynamic, and the upcoming years may see a boom of energy storage projects.

26 RTE, Forecast 2023–2035 – Electricity generation and storage (in French, *Bilan prévisionnel 2023-2035 – La production et le stockage de l'électricité*), p. 55.

27 *Id.*, p. 56.

28 The Bardzour solar farm is the first of its generation to include lithium-ion battery storage with a capacity of 9 MWh *cf*.

29 For instance, Total Energies commissioned in 2023 a PV farm with a battery storage facility of 43 MWh with the battery lithium-ion technology of its subsidiary Saft (in French). Boralex also developed a wind farm with a battery storage facility of 3.3 MWh in Brittany.

30 *See* Centrale Electrique de l'Est Guyanais' project website.

31 *Id.*

INTERNATIONAL JURISDICTIONS
GERMANY

Germany is one of the largest BESS markets in the EU and globally, with a total installed battery storage capacity of 11.4 GWh in 2023—representing an impressive year-on-year growth of 87% compared to 6.1 GWh of installed capacity in 2022 and an average annual growth rate of 64% compared to 1 GWh of installed capacity in 2018.[1]

The numbers show that the rapid growth is largely attributable to the popularity of small-scale household storage systems with a capacity below 30 kWh, whereas the uptake of mid-scale storage systems below 1 MWh and large-scale storage systems above 1 MWh has been rather slow.[2]

Government Support as Growth Accelerator

For many years, the German government has incentivized the installation of household battery and PV combinations by end consumers and small entities. The intention behind this promotion of decentralized electricity generation was to reduce grid load and avoid investment needs of the transmission system.

This led to a rapid uptake of small-scale BESS in Germany, with the installed capacity increasing from 503 MWh in 2018 to 9.5 GWh in 2023.[3]

Slow Start for Large-Scale BESS

Absent comparable government support, the growth rate of large-scale BESS in Germany had been rather moderate, resulting in an increase from 390 MWh to 680 MWh in a period of 4 years between 2018 and 2022.[4]

There has since been movement in the German large-scale BESS market on account of rising demand for flexibility and the implementation of government incentives. As a result, the growth rate has increased substantially, and additional capacity in the amount of 720 MWh was installed between May 2022 and December 2023.[5] In November 2023, developer Kyon Energy received the permit for a large-scale BESS project with a capacity of 275 MWh, making it Europe's then largest permitted BESS project.[6]

However, there is still room for improvement, given that, as of December 2023, large-scale BESS with 1.4 GWh accounted for only 12% of the total BESS capacity in Germany.[7]

Regulatory Framework

There is no comprehensive regulatory framework for energy storage, and the definition of energy storage is not fully consistent throughout the relevant legislation for the German energy market, including the Energy Industry Act ("EnWG"), the Renewable Energies Act ("EEG"), the Energy Financing Act ("EnFG") and the Electricity Tax Act ("StromStG").

There is no comprehensive regulatory framework for energy storage, and the definition of energy storage is not fully consistent throughout the relevant legislation for the German energy market.

BESS is considered energy consumption facilities when drawing electricity from the grid and generation facilities when injecting electricity into the grid. This formal approach had been criticized increasingly as not sufficiently reflecting the special role of BESS in the electricity system. In December 2023, however, the higher regional court of Düsseldorf (which, due to its jurisdiction over decisions by the German energy regulator, the Federal Network Agency (*Bundesnetzagentur* "BNetzA"), is the most experienced court in energy-related matters in Germany), confirmed this dual approach.

Generally, the German regulatory framework stipulates that grid utilization results from withdrawals and, accordingly, allocates the costs for grid connection and grid usage to the consumption of electricity. As a result, grid usage fees, statutory levies and taxes are generally only payable by the final customer and neither apply to electricity generation nor to wholesale trading.

1 See Bundesnetzagentur Marktstammdatenregister, "Battery Charts," based on data from the public asset data registry.
2 *Id.* (specifically "Battery Charts – Battery Status")
3 *Id.*
4 *Id.*
5 *Id.*
6 See Renewables Now, "Kyon Energy gets nod for 134.5-MW/275-MWh battery in Germany."
7 See Bundesnetzagentur Marktstammdatenregister, "Battery Charts," based on data from the public asset data registry.

As a consequence, electricity only delivered to a final customer once would ultimately be subject to the payment of grid usage fees, taxes and levies, as well as costs for metering, balancing and other services twice—once when withdrawn by the BESS for charging and again when reinjected and delivered to the final customer.

Exemption From Taxes, Fees and Levies

To avoid the BESS's 'double role' resulting in an unwanted 'double charging', the applicable legislation provides various exemptions:

- According to section 118(6) EnWG, withdrawals from the grid by BESS will be exempt from grid usage fees for a period of 20 years provided that commercial operation is achieved before August 4, 2029.
- Section 21(2) EnFG stipulates an exemption for BESS from statutory levies applied to withdrawals from the grid to finance the expansion of offshore wind facilities as well as combined heat and power facilities.
- Additionally, from an electricity tax perspective, section 5(4) StromStG qualifies BESS as part of the grid by ensuring that electricity supplied to BESS for charging is tax-exempt.

This preferential treatment is based on the assumption that—although legally considered consumption— the withdrawal of electricity by BESS for charging is not comparable to the withdrawal by final customers for 'electricity usage'. This holds true under the condition that the electricity is only temporarily stored in the BESS. Therefore, the exemptions are granted only if and to the extent the electricity withdrawn from the grid by the BESS is also reinjected into the same grid with a time lag.

Grid Connection and Cost-Sharing

Every operator of an energy generation or consumption facility has a legal claim against the distribution system operators ("DSO") to be connected to the electricity grid in a non-discriminating manner and on reasonable, economically viable conditions. Conversely, DSOs have the right to be compensated by the operator for a share of the installation costs, usually calculated on the basis of the anticipated capacity.

Absent any specific exemption, BESS is generally subject to the compensation requirement. For cost-calculation purposes, however, the specific usage profile of BESS as generation and consumption facility needs to be considered once again: It is not even possible in theory that a battery storage system continuously withdraws electricity from the grid at full connection capacity. Since the electricity is only stored and not 'used', there needs to be a full discharging cycle for every charging cycle. In simplified terms, BESS uses the grid only half as much as consumption facilities with the same capacity. In its aforementioned decision, the higher regional court of Düsseldorf decided that it would therefore be discriminating behavior and not lead to economically reasonable terms if DSOs applied the same cost-calculation method for BESS as is applied for consumption assets. The court did not define any threshold or a level of discount that needs to be granted to BESS in connection with the cost-sharing, so guidelines will have to be developed in practice.

Permitting

Under the REPowerEU program, member states are required to ensure that permitting processes for renewables assets are streamlined and any administrative barriers delaying the deployment of renewable energy are eliminated. In Germany, this is of particular relevance for environmental compliance assessment processes. Due to the involvement of various local and municipal authorities as well as mandatory public participation, permitting processes would often take several years and lead to great uncertainty for asset operators.

In response, renewable energy assets and BESS projects have been declared to be of overriding public interest and to serve national security. This means that the burden of proof has been shifted for the benefit of asset owners when weighing diverging legal interests. The goal was to avoid administrative bottlenecks in relation to environmental compliance assessments for renewables and BESS projects.

The applicable permitting process for a specific BESS project depends on various factors, most importantly, installed capacity, but also proximity to residential areas or nature conservation areas, use of toxic substances, etc. Due to its size and potentially far-reaching effects, large-scale BESS projects with a capacity of more than 50 MW are subject to regional planning processes.

Revenue Streams

When it comes to revenue generation, BESS may take advantage of its double role as generation and consumption asset by providing solutions to generators, consumers and grid providers on either side of the meter.

Trading vs. Self-Consumption

The difference between small-scale BESS and large-scale BESS becomes most apparent in individual-use cases.

Operators of front-of-meter BESS, whether stand-alone or co-located, are mainly taking advantage of the flexibility provided by BESS for trading spreads at the intraday markets.

Household storage systems, on the other hand, are typically not actively used for revenue generation but to maximize the self-consumption potential of home PV systems.

Balancing Reserve for Grid Stabilization

With the growing need for stability and flexibility solutions in the electricity market, the provision of grid support services is regarded as an even more important area of application for BESS.

Already today, BESS is a cornerstone for the provision of balancing reserve service used by transmission system operators ("TSOs") for grid frequency stabilization purposes.

Balancing reserves are procured by TSOs via daily auction processes on an open market platform. Providers need to fulfill defined prequalification criteria and pass certain reactivity tests before being permitted to the market.

Due to its fast reaction time, BESS is well-suited as a part of the Frequency Containment Reserve ("FCR"), the active power reserve to contain system frequency after the occurrence of an imbalance that needs to be fully activated within 30 seconds. FCR is procured as a symmetric auction product, meaning that 'positive' (upward flexibility) and 'negative' (downward flexibility) FCR are procured together, with a bid size resolution of 1 MW.

After the rapid response through FCR has stopped extreme frequency drifts, it is replaced by Frequency Restoration Reserve with automatic activation ("aFRR"), which needs to be fully available within 5 minutes of activation and must be provided continuously for 15 minutes. In case the imbalance has not been resolved after 12.5 minutes, the aFRR is replaced by the Frequency Restoration Reserve with manual activation ("mFRR").

Although the share of BESS in the total prequalified aFRR capacity is continuously growing, the market for aFRR and mFRR is more challenging for BESS. The main reason is stricter requirements for the stable and continuous provision of balancing energy over a longer period as well as a more competitive environment with lower margins.

It is expected that FCR will remain the most important balancing reserve market for BESS in the near term. However, value stacking of different balancing products is also possible.

> When it comes to revenue generation, BESS may take advantage of its double role as generation and consumption asset by providing solutions to generators, consumers and grid providers on either side of the meter.

Ancillary Services

In addition to balancing services, BESS may also be used by TSOs and DSOs for congestion management purposes, mainly in connection with redispatch measures. Since no remuneration is paid to operators in addition to the compensation of actual costs, redispatch cannot be considered a use case for BESS in revenue generation.

BESS may also be suitable for blackout restoration. These services will prospectively also be procured in open market auction processes. In January 2024, German TSOs called first tenders for certain regions. A nationwide auction of blackout restoration services is not foreseen before 2027. Absent any historic data, the attractiveness of this market for BESS cannot yet be assessed.

Behind-the-Meter Services

While classical load management is primarily used for adjusting the timeline of electricity consumption to benefit from the best market environments, industrial-scale electricity consumers with a baseload delivery profile typically put their focus on another price element: one of the biggest cost factors for large electricity consumers is the amount of grid usage fees.

Annual grid usage fees are generally calculated on the basis of a commodity price for the amount of electricity drawn from the grid throughout a year and a capacity charge for the maximum load in that year. That is because the grid capacity is sized to accommodate the maximum load that is likely to occur within the grid. The contribution to the total grid costs by a consumer is, for the most part, determined by its peak consumption rather than by its total consumption.

Peak shaving by using withdrawals from a BESS to replace a part of the required grid load may be a significant cost-saving strategy, especially for large electricity consumers with fewer options for demand-side management.

Peak shifting is another way in which BESS can reduce grid usage fees: the German Electricity Grid Fee Ordinance foresees a mandatory grid usage fee reduction by up to 80% for electricity consumers with a low 'coincidence factor', representing a highly non-simultaneous grid usage with other customers. By using withdrawals from a BESS for support in time periods of high overall load, consumers can actively shift their grid usage to off-peak times, thereby contributing to a more efficient use of total grid capacity.

Support Scheme for Colocation Assets

In 2021, Germany introduced a new tender mechanism for combinations of renewables assets and BESS.

Structured as a "reverse auction", asset operators may secure a guaranteed minimum price of up to EUR/MWh 91.80 through market premium top-up payments for all electricity generated by the renewables asset, whether fed directly into the grid or stored temporarily in the BESS. There are a few additional requirements on the combination, including that BESS capacity must be at least one-third of the renewables' capacity and that the BESS must be charged only from the renewables asset but not from the grid.

In a colocation scenario, BESS is considered part of an asset combination with renewables and thereby benefits from prioritized grid connection and exemption from cost-sharing obligations. Also, the steady and secure revenue streams make it much more feasible to obtain debt financing for developing a BESS.

> In 2021, Germany introduced a new tender mechanism for combinations of renewables assets and BESS. Structured as a "reverse auction", asset operators may secure a guaranteed minimum price.

On the other hand, BESS in asset combinations benefitting from support payments is restricted in some of its other use cases.

Since charging from the grid is not possible, BESS in colocation scenarios can provide only a limited degree of balancing and other grid services. This excludes any kind of negative balancing energy which would require a BESS to withdraw electricity from the grid. In consequence, the FCR balancing reserve market is not open to BESS benefitting from payment support under the innovation scheme.

Also, any electricity amounts for which market premium payments are claimed will not be eligible for the issuance of guarantees of origin under the European renewable energy certification mechanism.

Outlook

Growth in Large-Scale BESS

A look into the future shows that Germany's BESS landscape is slowly changing shape: Large-scale BESS projects with a total capacity of 2.1 GWh are scheduled for completion by the end of 2025, including two projects with a capacity of 600 MWh each.[8] This means that more than 90% of the total planned additional capacity of 2.3 GWh will be from large-scale BESS.

Removing Existing Barriers

On December 8, 2023, the German Federal Ministry for Economy and Climate Protection published a discussion paper for a future energy storage strategy (*Stromspeicher-Strategie*). The goal is to jumpstart discussions with stakeholders to analyze existing barriers and find potential solutions. The paper has identified a number of focus areas for improvement, including:

- Analyzing possibilities to allow BESS to be charged from the grid in colocation situations with renewables assets without jeopardizing the eligibility for payment support;
- Furthering the integration of household storage systems into the market for grid stability and flexibility services;
- Accelerating the grid connection of large-scale BESS; and
- Removing still existing permit-related barriers for the expansion of BESS.

The paper is still in the consultation process, and it is too early to speculate on any specific actions or legal amendments resulting from these discussions or on any designated timeline.

8 See "Battery Charts – Battery Status" with data of public asset data register

INTERNATIONAL JURISDICTIONS
UNITED KINGDOM

In the United Kingdom, battery storage is still a nascent market in its infancy, with the regulatory regime developing alongside it. Nevertheless, there is increasing deal flow for battery storage projects in the United Kingdom. The deals have typically followed alternative structures as opposed to the traditional nonrecourse project financing route. 2023 has seen the introduction of new legislation and guidance by the UK government to help clarify the role of batteries and application of the regulatory regime in the United Kingdom.

The United Kingdom could require up to 29 GW of battery storage by 2030 and 51 GW by 2050 (up from around 5 GW in place today)[1] in order to meet its 2050 net-zero targets. The market is therefore likely to see significant uptake and modification in the coming years. 2023 has seen important steps taken by the UK government to develop the UK battery storage market and increase the current capacity to meet the foreseen needs of the 2050 net-zero targets.

> The deals have typically followed alternative structures as opposed to the traditional nonrecourse project financing route.

The highly anticipated Energy Act 2023 (the "Act") received Royal Ascent on December 18, 2023. The Act, among other things, sought to codify and clarify the definition of "Stored Energy"—and therefore what constitutes a battery for the purposes of the regulatory regime. The Act defined "Stored Energy" as energy that was converted from electricity and is stored for the purpose of its future reconversion into electricity. Importantly, this new legal definition excludes some battery-type technologies that are present in the market, for example, batteries that store electricity and convert it into a different state for distribution (*i.e.*, heat batteries). Consequently, it remains unclear how such technologies will be treated by the regulatory regime going forward.

> As part of the continued steps to achieving its net-zero target, the UK government released the United Kingdom's first battery strategy (the "UK Battery Strategy") in November 2023.

As part of the continued steps to achieving its net-zero target, the UK government released the United Kingdom's first battery strategy (the "UK Battery Strategy") in November 2023. While the UK Battery Strategy focuses on the development of batteries generally and not specifically battery storage, the UK Battery Strategy is aimed at, among other things, strengthening the manufacturing supply chains for battery storage, encouraging the development of batteries through providing support for innovation and unlocking both private and public investment into the market.

1 See UK Infrastructure Bank, "Bank investment provides significant boost to UK battery storage sector," November 3, 2023.

Market Opportunities

Co-Location and Revenue Support Schemes

While there is not currently a separate revenue support mechanism for battery storage-only projects, a battery project could benefit from a revenue support scheme, such as a feed-in tariff, renewables obligation or a Contract for Difference ("CfD"), where it is co-located with an accredited renewables project that benefits under such revenue schemes.[2] In the latest Round of Allocation for the Contract for Difference (2023), over a third of all CfDs awarded solar capacity will be co-located.

Co-location can address the concerns regarding uncertain and complex revenue streams (which are explored below) by allowing the battery storage projects to benefit from the revenue support mechanism linked with the co-located generation asset. This may allow batteries to form part of project financed portfolios which could assist with their increasing deployment.

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2 See ofgem Guidance, November 21, 2023.

Co-Location and Hybrid Power Purchase Agreements ("PPAs")

As co-location becomes increasingly popular, we have seen the emergence of "hybrid PPAs" in the United Kingdom. Hybrid PPAs consist of two separate contracts: the conventional PPA for the generation asset and either an "optimisation agreement" or a "storage capacity agreement" for the storage asset.

As revenue streams for co-located technologies are often complex, a hybrid PPA simplifies the revenue stack by condensing it to one contractual arrangement, thus, addressing concerns regarding uncertain and complex revenue streams.

Proven Technology and Portfolio Financings

As battery storage technology is advancing and becoming more proven, we have seen financings of entire portfolios of battery storage projects in the United Kingdom. Financing of entire portfolios addresses certain bankability issues by limiting a lender's exposure to a specific portfolio and therefore issues at one project may be mitigated by the other projects in the portfolio.

Market Challenges

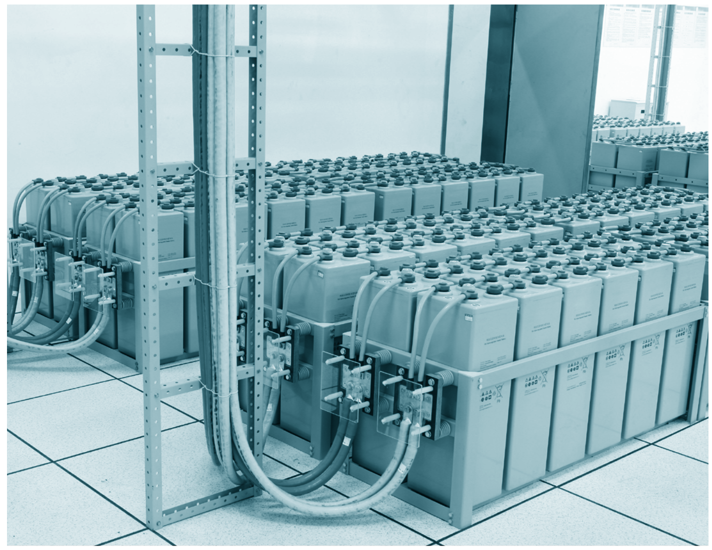
Uncertain Revenue Streams

One major challenge facing the battery storage market in the United Kingdom is uncertainty surrounding revenue streams. The United Kingdom does not currently have a revenue support scheme for battery storage-only projects, and revenues for projects are typically drawn from a stack of revenue streams, including the wholesale market and the capacity market. Newbuild projects in the United Kingdom currently face long grid connection times (as mentioned below) which can lead to greater uncertainty in modeling revenue streams, as it is unclear what the wholesale market will look like when the project becomes operational. It has therefore proven difficult to find project financing for battery projects in the United Kingdom given the uncertain and dynamic revenue streams and the complexity of the revenue stream stack. Therefore, most projects to date have been equity-funded.

> The United Kingdom does not currently have a revenue support scheme for battery storage-only projects, and revenues for projects are typically drawn from a stack of revenue streams, including the wholesale market and the capacity market.

While there haven't been many large-scale nonrecourse project financings of battery storage projects due to the above reasons, innovative structures that fund projects through a mixture of equity and debt or platform structures have emerged.

The UK Infrastructure Bank, a state-owned development bank whose goal is to help the United Kingdom reach net-zero, provided a £60 million loan (as part of a £120 million debt package alongside NatWest) to support Pacific Green in its development of a 249 MW electricity storage park. With the assistance of the UK government, battery storage projects are becoming increasingly bankable.[3]



Grid Connection Issues

Another key issue facing the battery storage market in the United Kingdom is the lack of grid capacity. Developers may have to wait up to 15 years before they can connect a project to the grid. Around 40% (which equates to approximately 120 GW) of new connection requests have been offered dates of 2030 or beyond, and there are now 280 GW of projects holding connection agreements.[4] New policies have recently been implemented to address grid delay, and we anticipate that 2024 will see allocated capacity freed up as National Grid seeks to terminate connection agreements for significantly delayed projects.

National Grid, the British multinational electricity and gas utility company, announced in November 2023 as part of its plan to accelerate 20 GW of grid connections that 19 battery storage projects worth around 10 GW will be offered dates to plug in to the grid—averaging four years earlier than their current agreement. This is based on a new approach which removes the need for nonessential engineering works prior to connecting the battery storage projects.

3 See UK Infrastructure Bank, "Bank investment provides significant boost to UK battery storage sector," November 3, 2023

4 See ofgem News, "Ofgem launches policy review on reforming the electricity connections system," May 17, 2023.

Structuring Considerations

The UK market does not have a settled approach to BESS transaction structures, with many being innovative and first of a kind. However, there are some commonalities across all transactions and there are, importantly, key commercial points for developers and other industry participants to consider:

1. **Route to Revenues** – The revenue stack for BESS can be complex. There are generally two approaches to accessing the market: A developer may elect to sell on the spot market via an optimizer or alternatively through an offtaker. Each option offers a wide range of commercial structures and there is currently no settled approach. The key commercial driver to which option is selected is likely to be the developer's risk appetite and whether any downside protection is required (which offtakers commonly offer a degree of).
2. **Procurement (EPC) and O&M** – The EPC market offers a range of structures which are dependent on the EPC contractor's relationship with the BESS OEM. In our experience, the commercial offerings for BESS vary from a fully wrapped offering—where the EPC is also the OEM and has a deep understanding of the plant to be constructed and maintained—to a pass-through of OEM risk based on what the EPC has been able to procure with its BESS supplier (via a subcontract) or a handover of the direct relationship with the OEM post-Taking Over (such that the EPC is only taking construction risk). Within each model, the current pressures of the global market subsist, and therefore detailed discussions must be had about wider supply chain risk, transportation and material costs.
3. **Project Finance** – The main challenge to securing project financing remains the uncertainty associated with the revenue stacks. However, as the technology becomes proven and the market becomes familiar with successful BESS projects, it is likely that funders will see the assets as less "risky." As with other projects where lenders take merchant risk, there are a number of structures that could be seen as bankable as they provide sufficient mitigation to the foreseen risks (for example, through portfolio disaggregation).

INTERNATIONAL JURISDICTIONS
INDIA

Policy reforms are underway to create a favorable business environment for the Indian ESS market. Despite challenges in the sector, there is optimism that the Indian storage market will continue to accelerate and that ESS will play a critical role in the nation's goal of achieving a net-zero economy by the year 2070.

India's Commitment to Energy Storage

In light of the Indian Government's growing focus on clean energy and globally announced renewable energy commitments at the 26th and 28th sessions of the Conference of the Parties to the United Nations Framework Convention on Climate Change, the Niti Aayog (Indian Government's apex public policy think tank) has recognized Energy Storage Systems ("ESS") as playing a critical role in grid integration and management of renewable energy as the share of renewable energy in the grid increases over the coming years.

The energy storage capacity in India for 2029-30 is anticipated to be 336.4 GWh, with 208.25 GWh derived from BESS alone.[1] There are several notable BESS projects in India that are in construction and operational. These include the Phyang Solar PV-BESS plant (the first instance of a co-located large scale BESS solution in India), the AES-Mitsubishi Rohini BESS (India's pioneer grid-scale BESS with a lithium-ion battery capacity of 10,000 kW) and the Modhera Sun Temple Town Solar PV Park BESS (which incorporates a BESS with a lithium-ion battery capacity of 6,000 kW and a rated storage capacity of 15,000 kWh).

1 Central Electricity Authority, M. o. (2023). Report on Optimal Generation Capacity Mix 2030 2.0.

Energy Storage Roadmap for India 2019-2032

The India Smart Grid Forum, an Indian Government think tank established as a public private partnership, prepared the 'Energy Storage Roadmap for India 2019 – 2032' in August 2019 ("Energy Storage Roadmap"), in association with India Energy Storage Alliance ("IESA"), with the primary objective of estimating India's ESS requirements for grid support for integration of renewable energy into the grid for the period 2019-32. The Energy Storage Roadmap records key drivers and study findings for India's ESS technical requirements and feasibility and will form an initial reference point in India's ESS from a technical feasibility perspective.

> The Indian Government announced the National Framework on ESS ("National ESS Framework") in August 2023 to support the development and deployment of ESS through policy and regulatory measures, financial and fiscal incentives and performance-based incentives.

The National ESS Framework

The Indian Government announced the National Framework on ESS ("National ESS Framework") in August 2023 to support the development and deployment of ESS through policy and regulatory measures, financial and fiscal incentives and performance-based incentives. It also aims to redesign energy markets to incentivize participation of ESS in the markets and to establish market mechanisms through the introduction of products and compensation methods for storage services and to develop technical standards for ESS that ensure interoperability with the grid and to monitor and evaluate the performance and impact of ESS.

The National ESS Framework requires energy storage capacity of 16.13 GW (with "Pumped Storage Hydro Plants ("PSP") of 7.45 GW capacity and BESS-based storage of 8.68 GW) by the year 2026-27.

The storage capacity requirement increases to 73.93 GW (26.69 GW PSP and 47.24 GW BESS) by the year 2031-32. In order to develop this storage capacity from 2022-27, the estimated fund requirements for PSP and BESS are ~INR 542 billion (USD 6.5 billion) and ~INR 566.47 billion (USD 6.8 billion) respectively. The National ESS Framework does not clarify if these are funding amounts required by the government to be invested or investments required to implement such installations. Further, for the period 2027-32, estimated fund requirements for PSP and BESS have been identified to be ~INR 752.4 billion (USD 9 billion) and ~INR 2926.37 billion (USD 35 billion) respectively.

Regulatory Framework and Government Support

The Indian Government has issued guidelines for the two primary types of ESS:

- **BESS:** On March 10, 2022, detailed guidelines for procurement and utilization of BESS as part of generation, transmission or distribution assets, or along with ancillary services, were issued by the Indian Government. The guidelines provide standardization and uniformity in procurement of BESS and a risk-sharing framework among various stakeholders involved in energy storage and storage capacity procurement. Recently, based on these guidelines, Solar Energy Corporation of India (SECI) carried out bidding of a 500 MW/1,000 MWh BESS project which has been awarded to JSW Renew Energy Five Limited at a cost of ~INR 1 Million/MW/month (USD 12,000/MW/month).
- **Pumped Storage Hydro Plants ("PSP"):** On April 10, 2023, the Indian Government came out with measures in the form of "Guidelines to Promote the Development of Pumped Storage Projects". These guidelines provide for, amongst others, transparent criteria for awarding project sites, self-identification of off-river PSP sites, removal of upfront premium for project allotment, market reforms for monetization of ancillary services provided by PSPs, exemption of PSPs from free power obligation, and the rationalization of environmental clearances for off-river PSP sites and utilization of exhausted mines for development of PSPs.

These guidelines outline financial mechanisms and policies designed to establish a market that enhances the viability of projects by assigning a monetary value to the reliability and flexibility of the technology beyond its electricity generation. This approach ensures fair compensation for project developers and operators. Additionally, the guidelines propose potential tax and land exemptions that could further bolster the financial feasibility of pumped hydro projects.

Government Support for ESS

Energy Storage Obligation, ISTS Waiver and Viability Gap Funding

ESO: The Indian Government announced a long-term trajectory for mandatory Energy Storage Obligations ("ESO") on July 22, 2022, to ensure that sufficient storage capacity is available with entities obligated to procure renewable energy (such as distribution companies, open access consumers and captive power producers). The trajectory specifies a minimum percentage of electricity consumption within a power distribution licensee's area that must be procured from renewable energy through ESS. The trajectory also provides that the ESO of obligated entities will gradually increase from 1% in FY 2023-24 to 4% by FY 2029-30, with an annual increase of 0.5%.

ISTS Waiver: The Indian Government has declared a complete waiver of transmission charges (such transmission charges varying from state to state) for using Inter-State Transmission System ("ISTS") to ESS (including BESS and PSPs). The waiver of ISTS charges has been made applicable to BESS and PSP projects commissioned up to June 30, 2025. Transmission charges for ISTS networks may be levied gradually for the projects commissioned after June 30, 2025.

VGF: The Indian Government has approved Viability Gap Funding ("VGF") of INR 37.6 billion (USD 450 million), covering up to 40% of the capital cost for private entities establishing BESS. This is expected to spur the development of 4,000 MWh of BESS projects, according to the Ministry of Power. By providing VGF support, the scheme aims to achieve a Levelized Cost of Storage ranging from INR 5.50 to INR 6.60 per kWh (USD 0.07 to 0.08 per kWh). The selection of BESS developers for VGF grants will be carried out through a transparent competitive bidding process and a minimum of 85% of the BESS project capacity will be made available to distribution companies.

The approval of VGF for BESS, coupled with the anticipated production-linked incentive scheme amounting to ~INR 150 billion (USD 1.8 billion) for stationary storage, is anticipated to significantly boost the adoption and scaling-up of BESS throughout the country.

> The Indian Government has approved Viability Gap Funding ("VGF") of INR 37.6 billion (USD 450 million), covering up to 40% of the capital cost for private entities establishing BESS.

The Indian Government's decision to include Lithium in the critical mineral list is a welcome step. This identification aims to reduce the risk of disruptions that could impact industries and sectors reliant on Lithium. By securing a stable and reliable supply, proactive measures can be taken to ensure its continuous availability, supporting the smooth functioning of the supply chain. The critical minerals list serves as a framework to guide policy, strategy and investment decisions. To build competitive value chains in India, the discovery of mineral wealth and identifying areas of its potential by use of advanced technologies is essential. Identifying critical minerals helps the country plan for the acquisition and preservation of such mineral assets, taking into account the long-term needs of the country. This in turn reduces dependency on imports as India is currently 100% import dependent for certain components. It also provides direction on resource allocation and development priorities, allowing policymakers and stakeholders to make informed choices.

ESS and E-Mobility

India's shift towards e-mobility, inspired by the global EV30@30 initiative, is now a tangible goal. The nation has set a target for EVs to constitute at least 30% of total vehicle sales by 2030. ESS will play an important role in establishing a widespread and stable network of EV charging infrastructure and realizing this ambitious transition.

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ESS offers a straightforward and sophisticated solution to address the challenges associated with the future of EV infrastructure in the country. With the rapid cost reduction of lithium-ion batteries due to global scaling up of manufacturing capacity as well as the anticipated launch of giga-scale lithium-ion battery factories in India, the reduced total cost of ownership for most user segments will drive the adoption of EVs in the country. The resulting projected battery requirement for EVs by 2032 is likely to be around 1,721 GWh, according to the India Energy Storage Alliance.

Challenges in the Indian ESS Ecosystem

Setting up an ESS project in India comes with various challenges, some of which are characteristic of the broader energy sector and others specific to the Indian context. Some of these key challenges include:

- **Market Mechanisms and Procurement Processes:** Established conventional sources often receive preferential treatment in competitive procurement processes which, in turn, inhibits the market share growth for ESS technologies. Standardized contracts, clear guidelines for project procurement and mechanisms for fair and competitive bidding can enhance investor confidence.
- **Government Support:** As is the case for new sectors, support for tax incentives should be considered particularly in the context of Goods and Services Tax on batteries. This would significantly balance the overall cost of storage systems, making them a more feasible investment for investors. Another example of an important incentive is custom duty exemption, a measure that has already proven effective in reducing the cost of manufacturing lithium-ion batteries used in EVs.
- **Technological Advancement:** In addition to policy measures, ongoing technological evolutions in batteries, including sodium-ion and flow battery technologies, are gaining traction. These advancements address current hurdles related to cost, performance and safety faced by lithium-ion batteries in India. The adoption of these technologies will expedite the integration of large-scale storage systems, enabling massive integration of renewable energy into the grid. Scaling up battery production for BESS is equally critical, and this can only be achieved through the provision of the right low-cost financing schemes and dedicated research and development efforts.
- **Policy Consistency and Long-Term Planning:** A stable policy environment that aligns with India's long-term energy goals is crucial for attracting sustained investments in energy storage infrastructure. While initial steps have been taken by the Indian Government with the announcements of ESS-focused policies and action plans, how the government implements these policies will determine if an ESS ecosystem takes off.
- **Land Acquisition and Permitting:** Land ownership in India is known to be plagued by a glaring disconnect between official documentation and ground reality. Securing land for storage projects, obtaining necessary permits, and navigating through the complexities of environmental clearances pose challenges to project development. Streamlining the permitting process and providing incentives for land acquisition can facilitate project development. The acquisition of land should be approached differently, depending on the ESS infrastructure, either through government channels or private owners.

Structuring ESS Projects in India

As stated above, ESS in India is at a nascent stage, with very few established ESS projects in place. However, the abovementioned framework and roadmaps are helping transaction structures fall into place. The most popular structure with investors is an integrated PSP with renewable energy generation projects. As part of this transaction structure, investors may consider investing either in the special purpose company which generates renewable energy power and has PSP arrangements either within the group itself or with a third party or at a level above the special purpose company (*i.e.* at the group level).

> The most popular structure with investors is an integrated PSP with renewable energy generation projects.

Renewable energy players are also integrating renewable energy facilities with PSP facilities within the power developer group itself, which proves to be an attractive overall package for investors. These would typically include execution of PPAs, PSP supply agreements and electrolyzer supply agreements (in the event that electrolyzer is not sourced within the group). A notable example is the world's largest PSP of 1,680 MW in Andhra Pradesh by Greenko, which also involves developing 3,314 MW of power projects in collaboration with Greenko's subsidiary, AM Green.

ESS may also be integrated with transmission infrastructure to maximize asset usage, extending grid stability and duration of transmission assets. Operating independently, stand-alone ESS can engage in energy trading, supply off-grid applications or enhance EV charging infrastructure. ESS with fast ramp rates provides frequency and voltage control, fast response, peak shifting and ancillary services over short time periods, allowing stakeholders (including licensees, developers and procurers) to utilize ESS effectively. Developers can additionally sell, or lease, ESS capacity based on specific requirements and periods.

Developing ESS Projects in India

ESS engineering, procurement and construction in India involves various stages. The specifics vary based on project scale and technology, among other factors.

A general approach would be to first identify the need for energy storage by the 'Procurers', considering factors such as grid stability, renewable energy integration and demand management. A Procurer will first identify the area of land to locate the project and review documents/agreements to ensure 100% availability of the identified land. The Procurer may invite bids for the procurement in terms of BESS capacity. The Procurer will then constitute a committee for evaluation of the bids, with at least three members, including at least one member with expertise in financial matters / bid evaluation. After successful evaluation of bids and finalization of the

> The financial models for energy storage services can vary, with some projects being implemented through public-private partnerships, while others may involve independent power producers and private investment.

winning bid, the Procurer and the ESS provider will enter into a Battery Storage Purchase Agreement and Land Lease/right to use agreement. The Procurer/ESS provider will then apply for grant of connectivity and open access by the State Transmission Unit /Central Transmission Unit, as applicable, and other legal clearances before the scheduled commissioning date.

A notable example of development and sale of ESS is the partnership of Adani Group and energy transition company Greenko Group. Under the partnership, firm and dispatchable renewable energy solutions including round-the-clock power supply of up to 1 GW will be supplied to Adani Group's proposed industrial complex. Greenko has offered 6 GWh of long duration hydro storage capacity from its proprietary, under-development 'Off-Stream Closed Loop Pumped Storage Project' at Madhya Pradesh and Rajasthan.

Financing ESS Projects in India

Storage solutions have the potential to accelerate India's energy transition. To leverage this opportunity and meet the estimated demand, a mix of solutions across the value chain is required. The financial models for energy storage services can vary, with some projects being implemented through public-private partnerships, while others may involve independent power producers and private investment. To give impetus to India's energy storage market, the following financial models are highlighted as financing and investment options:

- **Public sector units ("PSUs")** with substantial financial strength, such as NTPC and GAIL, have the potential to lead the storage solutions transition, akin to global counterparts like Shell and BP. These PSUs can explore business opportunities within the storage value chain for mobile and stationary purposes, diversifying and creating new avenues. Once a track record is established, balance sheet deleveraging using instruments like Infrastructure Investment Trusts become feasible, paving the way for significant private sector involvement.
- **Financial intermediation**, through mechanisms like credit guarantees, can de-risk and facilitate bank lending to entities entering the energy storage sector, particularly those lacking bankable credit ratings. Multilateral or concessional lines of credit, like the World Bank–SBI line for rooftop solar, showcase the viability and business case of such solutions for private finance.
- **Additional policy support** focusing on research, development, manufacturing of storage solutions and domestic value chain creation is essential for sustained growth. Incentives like tax breaks and subsidies, similar to those under the Faster Adoption and Manufacturing of Electric Vehicles ("FAME") scheme and VGF, along with budgetary allocations, can spur the expansion of storage solutions across diverse applications.
- **Innovative business models** like leasing or a focus on second-life batteries are crucial to address the high initial cost hurdle to widespread adoption. For example, with PSP being added to the renewable energy facility, the overall project would be viewed as more bankable by the lenders due to the higher reliability of continuous supply of renewable energy power. While ESS in India is still at a nascent stage, it is likely that banks will look to create security on the PSP assets (in the event that PSP is held within the group) and/or create a typical assignment charge provision in the PSP agreements to gain access to the PSP facility in the event of default in debt servicing.

INTERNATIONAL JURISDICTIONS
JAPAN

Japan's battery storage market has been growing rapidly, and this trend is expected to continue. Amidst the era of large renewables projects, the Japanese government is now keen to accelerate the introduction of battery storage to provide more flexibility to the grid and to accommodate additional renewables.

Stand-alone Battery Projects

Japan's Electricity Business Act previously did not have any provisions specifically applicable to stand-alone battery projects and, therefore, storage batteries were installed only incidental to other power facilities. Existing battery storage projects connected directly to the grid were mainly those owned by transmission and distribution system operators ("TDSOs") at their substations on an experimental basis for the purpose of stabilizing frequency fluctuation or balancing demand and supply in the region. For instance, batteries were installed at two substations (20 MWh[1] and 40 MWh[2]) in the Tohoku area: a 60 MWh storage battery was installed in 2015[3] (51 MWh in 2022[4]) at a substation in the Hokkaido area and a substation with 300 MWh storage battery was constructed in the Kyushu area.[5]

1 See Tohoku Electric Power Co., Inc., "Commencement of Operation of Large-Capacity Battery Storage System at Nishi-Sendai Substation," February 20, 2015.

2 See Tohoku Electric Power Co., Inc., "Commencement of Operation of Large-Capacity Battery Storage System at Minami-Sōma Substation," February 26, 2016.

3 See Hokkaido Electric Power Co., Inc., "Commencement of Pilot Project of Large-Scale Battery Storage System at Minami-Sarai Substation," December 25, 2015.

4 See Hokkaido Electric Power Network, Inc., "Commencement of Operation of Grid-Side Storage Battery Installed Under the 'Solicitation Process for Wind Power Generation Projects Utilizing Grid Side Storage Battery,'" April 1, 2022.

5 See Kyushu Electric Power Co., Inc., "Commencement of Operation of Buzen Storage Battery Substation," March 3, 2016.

The Electricity Business Act, amended in April 2023, now explicitly recognizes stand-alone storage batteries connected directly to the grid as independent facilities and treats such storage projects similar to power plants. As a result, many merchant battery storage projects are now being developed in Japan.

This paradigm changed completely in 2023. The Electricity Business Act, amended in April 2023, now explicitly recognizes stand-alone storage batteries connected directly to the grid as independent facilities and treats such storage projects similar to power plants. As a result, many merchant battery storage projects are now being developed in Japan. The combined capacity of interconnection study applications and interconnection agreement applications submitted to TDSOs exceeded 13 GW at the end of May/June 2023, and the first merchant storage battery project achieved COD in June 2023.[6] The rules for grid connection and utilization for storage batteries are under development as well.

6 See Agency for Natural Resources and Energy, "Measures to Mitigate Curtailment on Renewables etc.," August 3, 2023, p. 31.

The introduction of the Long-Term Decarbonization Auction (the "LTDA") scheme is expected to further accelerate battery storage adoption. The LTDA is a scheme under the Capacity Market, where power resources can receive capacity payments per installed kW of storage capacity from the Organization for Cross-Regional Coordination of Transmission Operators ("OCCTO") in exchange for their provision of capacity to the market, satisfying certain requirements. Stand-alone storage battery projects with installed capacity of 10,000 kW or more are eligible under the LTDA. While resources in the Main Auction of the Capacity Market can only receive a capacity payment for a specific single year awarded, resources awarded in the LTDA are entitled to receive capacity payments from OCCTO for a continuous 20 years.

Battery storage resources can earn merchant revenues for their provision of energy through the wholesale market or bilateral wholesale transactions, though they are required to pay approximately 90% of the profit to OCCTO.

Battery storage resources can earn merchant revenues for their provision of energy through the wholesale market or bilateral wholesale transactions, though they are required to pay approximately 90% of the profit (merchant income less variable costs) to OCCTO. For the next 20 years, resources are thus expected to receive capacity payments from OCCTO and approximately 10% of the merchant profit earned outside of the LTDA framework. The first LTDA took place in January 2024 and attracted the attention and interest of many project developers in the market.

Hybrid Projects (Renewables + Battery)

The Japanese government has also taken measures to support the installation of batteries co-located with renewable projects.

The government has incentivized renewables through the FIT scheme by the Renewable Energy Special Measures Act (the "REA") implemented in July 2012. The Feed-in Premium ("FIP") scheme was newly introduced as a support measure by the amendment to the REA, effective as of April 2022, where FIP-certified renewable projects can receive monthly FIP premiums from OCCTO for the quantity of energy they have successfully sold on a merchant basis through the wholesale market or bilateral transactions. Large-scale solar and onshore wind are no longer eligible for new FIT certificates and only eligible for FIP.

> The Japanese government has also taken measures to support the installation of batteries co-located with renewable projects.

As more and more renewable projects have started to sell their energy on a merchant basis—FIP or non-FIP—project developers have considered installing storage batteries at the project site with the hopes of additional project revenue. Although the installation of storage batteries to solar projects after FIT-certification can jeopardize the already-obtained FIT price, the government set rules (1) allowing projects newly FIP-certified in FY 2022 or later to install batteries without impacting their applicable FIP price, and (2) mitigating the impact on an applicable FIP price for projects previously FIT-approved but converted to FIP. The goal is to promote installation of storage batteries encouraging more projects to consider battery installation as battery prices fall.

> As more and more renewable projects have started to sell their energy on a merchant basis—FIP or non-FIP—project developers have considered installing storage batteries at the project site with the hopes of additional project revenue.

Furthermore, the government is now planning to change the current rule prohibiting FIT/FIP projects to charge from the grid and will allow certain FIP projects to charge from the grid in order to promote increased installation of storage batteries.

INTERNATIONAL JURISDICTIONS
PHILIPPINES

The current Philippine administration has recognized the importance of ESS in guaranteeing a stable power supply.[1] Notably, through the Department's Circular No. DC2023-04-0008 (ESS Policy), the Department of Energy ("DOE") has updated the Philippine ESS policy in light of the country's goal to increase the renewable energy portion of the country's energy mix to 35% by 2030 and 40% by 2040.

The private sector also takes a positive outlook on ESS in the Philippines, with conglomerates increasingly investing in ESS projects—one such company already has BESS facilities installed with a total capacity of 1,000 MW and intends to install more nationwide with a total capacity of 2,000 MW. Another conglomerate intends to establish BESS facilities with a total capacity of 40 MW.[2] In 2023, the Energy Regulatory Commission ("ERC") received or processed several applications for Certificates of Compliance ("COC"), a prerequisite for the operation of ESS facilities, for ESS projects with a total capacity of 284 MW.[3]

Recognition of ESS Technologies

ESS is defined under the ESS Policy as "a facility capable of absorbing energy directly from the grid or distribution system, or from a renewable energy plant or from a conventional plant connected to the grid or distribution system and storing it for a time period, and injecting stored energy system when prompted, needed to ensure reliability and balanced power system[.]"[4] ESS technologies recognized in the ESS Policy include BESS, compressed air energy storage ("CAES"), flywheel energy storage (FES) and pumped-storage hydropower ("PSH").[5]

> The private sector also takes a positive outlook on ESS in the Philippines, with conglomerates increasingly investing in ESS projects.

In the early drafts of the ESS Policy, hydrogen energy storage ("HES") was included, but the absence of pilot projects and deployments in the Philippines for HES resulted in its removal from the final draft. It must be noted that the language of the ESS Policy does not limit ESS technologies to BESS, CAES, FES and PSH."[6] As such, HES developers can avail themselves of the incentives under the ESS Policy.

ESS proponents must apply and register their ESS for any of the following purposes:[7]

1. To support transmission capacity and electricity essential to maintaining power quality and reliability of the electric grid;
2. For Generation Companies ("GenCos") to utilize ESS to sell power through contracts or energy trading in the Wholesale Electricity Spot Market ("WESM");
3. For GenCos to integrate ESS in variable renewable energy facilities for the purpose of mitigating variable generation output and to support the grid in maintaining power quality and reliability;[8]
4. To augment supply needed during peak demand hours enabling higher energy dispatch into the power system of a GenCo;
5. To defer the need for additional transmission and distribution facility upgrades by supplying peak demand of grid/end-users through ESS when connected to appropriate nodes;
6. To improve the power quality of a transmission and distribution system;
7. To manage end-user energy requirements; and
8. To include the process of storing energy available during off-peak periods and discharging the stored energy in the power system during peak periods, thereby reducing consumption from the grid during peak hours.

An ESS may be (i) stand-alone or connected to—and store energy sourced from—the transmission or distribution system; (ii) integrated with non-renewable energy or a combination of conventional power and ESS, where

1 See Philippine News Agency, "Battery energy storage system vital for power security: PBBM," March 31, 2023.

2 *Id.*; Business World, "EDC targets energy storage projects to be finished by 2025," December 11, 2023. and Inquirer.net, "EDC putting up more solar power plants, energy storage systems," December 11, 2023.

3 See Energy Regulatory Commission, Issuances.

4 ESS Policy, Section 2.11.

5 *Id.*

6 ESS Policy, Section 2.11.

7 *Id.* Section 4.

8 The installation of ESS to a FIT-eligible variable RE should not in any way increase the VRE plant's capacity and generation entitled to FIT. The ESS shall only be charged from the VRE facilities' output.

the ESS will not charge from the grid or distribution system and its Pmax limited to the plant capacity; (iii) integrated with renewable energy projects or a combination of renewable energy project and ESS, where the ESS is solely charged by the renewable energy project; and (iv) "Generation Plant and ESS" or a combination of Conventional Plant(s) and/or RE plant(s) and ESS, where the ESS is charged either from the generation plant(s) or from the grid or distribution system.[9]

Incentives for ESS Technologies

A renewable energy developer with an integrated ESS in its renewable energy plant may avail itself of fiscal incentives under the Renewable Energy Act for both the renewable energy plant and the ESS that is integrated with such renewable energy plant. The power produced by an integrated renewable energy plant and ESS will have a preferential dispatch (depending on the type of renewable energy, it may either be a required or a priority dispatch), but it can opt to be registered as a scheduled generating unit.

> A renewable energy developer with an integrated ESS in its renewable energy plant may avail itself of fiscal incentives under the Renewable Energy Act for both the renewable energy plant and the ESS that is integrated with such renewable energy plant.

Challenges

The permitting requirements for ESS would depend on whether they are stand-alone or integrated with—or separate from—a generation plant. For stand-alone and "Generation Plant and ESS", the ESS must obtain a COC from the ERC.

All ESS must comply with the rules and regulations relating to safety, health, environmental, proper disposal, and recycling of ESS standards that are enforced by government agencies.

All ESS must also secure an Environmental Compliance Certificate or an equivalent document from the Department of Environment and Natural Resources and other requirements by relevant government agencies pursuant to their guidelines.

WESM registration is necessary for (i) ESS connected to the transmission system and absorbing and injecting energy into it and (ii) ESS connected to the distribution system and absorbing and injecting energy into it, with a capacity of 10 MW for Luzon Grid and 5 MW for Visayas and Mindanao Grids.

Where applicable, ESS must also comply with the Philippine Grid Code, Wholesale Electricity Spot Market Rules and relevant market manuals, Philippine Distribution Code, Omnibus Guidelines on Enhancing Off-Grid Power Development and Operation and other relevant DOE and ERC rules.

Depending on the owner or purpose of the ESS, accreditation or testing and commissioning of a third party is required.

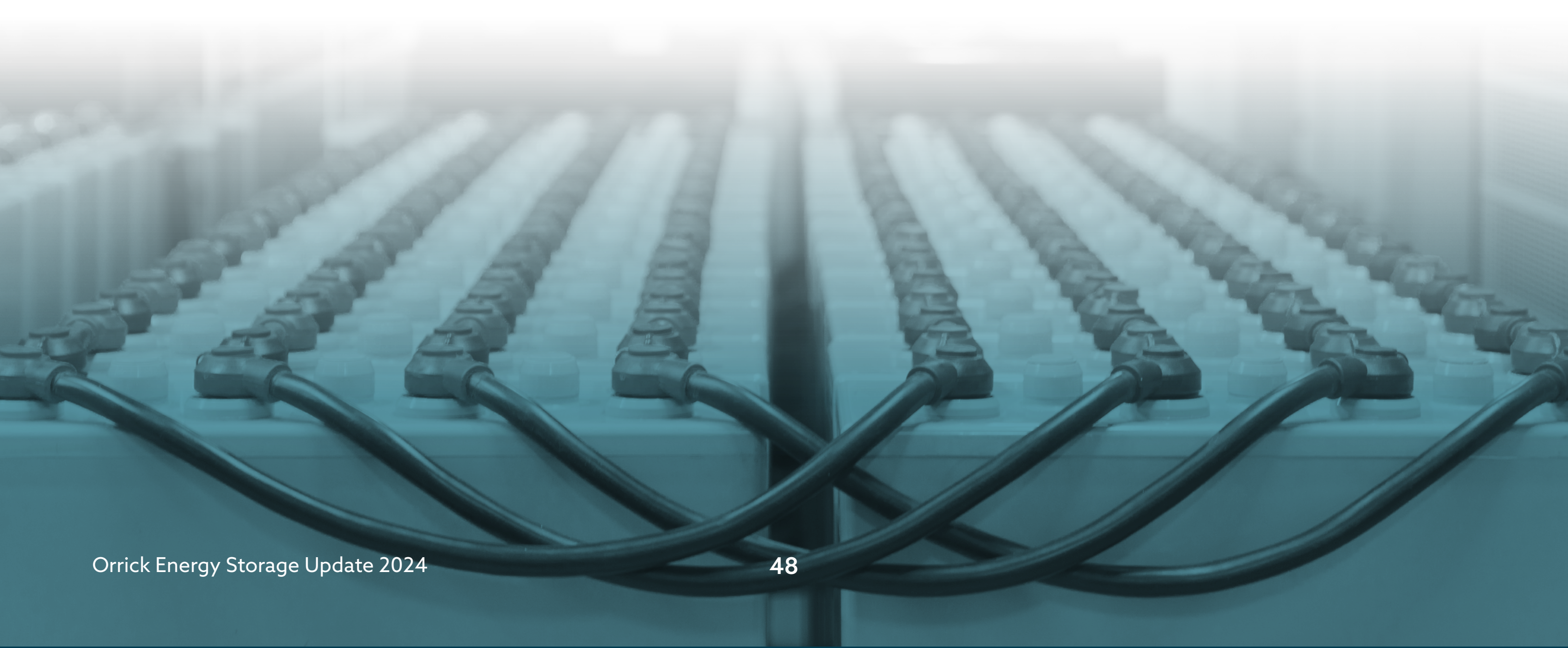
The ESS Policy also imposes specific duties and responsibilities to the following entities that intend to have ESS: (i) GenCos, (ii) end-users that own and operate "Generation Plants and ESS", (iii) microgrid service provider with ESS and (iv) system operator and small grid system operator.

Future of ESS in the Philippines

As mandated by ESS Policy, it is expected that more definitive regulations on ESS will be promulgated soon, *e.g.*, amendments to the WESM Rules.

There are newer and more complex ESS technologies, such as HES and sodium-based ESS, that are not specifically mentioned by the ESS Policy. However, the non-exclusionary language of the ESS Policy indicates that such ESS technologies could possibly be accommodated. It can be implied from the language of the DOE in removing HES in the ESS Policy that specific regulations applicable to these technologies may be adopted sooner if they are introduced in the Philippines.

9 *Id.* Section 2.



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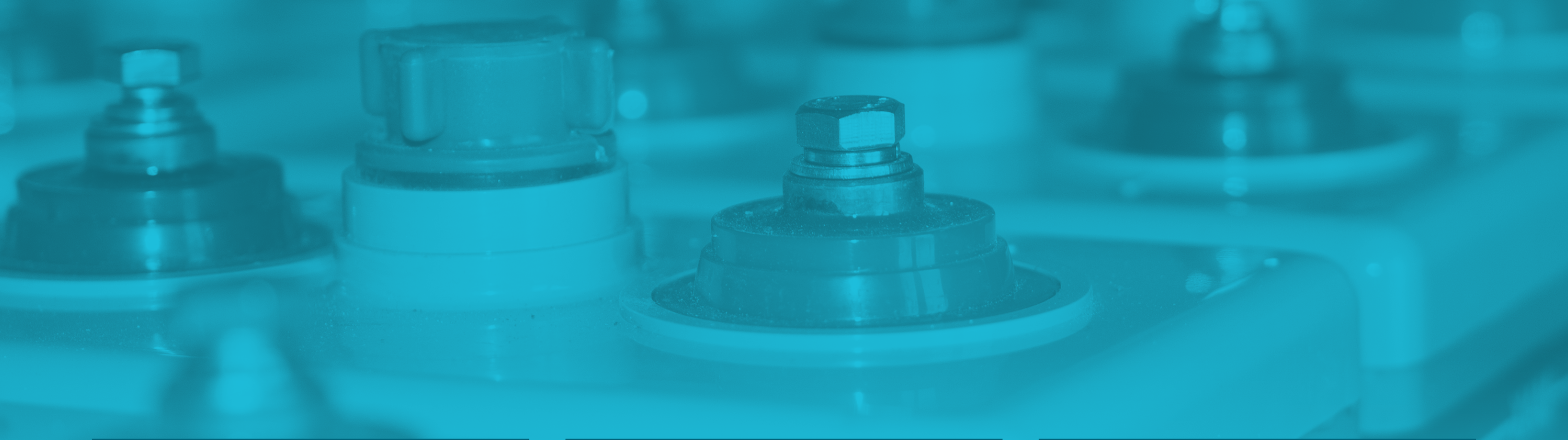

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