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PROJECT FINANCE
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Financing Projects With Community Choice Aggregators

by Deanne Barrow, in Washington

A report by the California Public Utilities Commission in May predicts that more than 85% of California's retail electric load will be served by sources other than investor-owned utilities by the middle of the 2020s.

IOUs are being replaced in large part by community choice aggregators. By the end of 2017, the number of customers in California who get power from community choice aggregators is expected to reach almost one million.

Amidst this backdrop, wind and solar developers and potential lenders are assessing the financeability of projects that have long-term power purchase agreements with CCA offtakers.

This article identifies some unique features with which they will have to grapple.

CCA Update

A CCA is a legal entity, usually a joint powers authority, formed by one or more counties, cities or towns for the purpose of purchasing power on behalf of the residents and businesses within local boundaries. The incumbent utility, which no longer provides the electricity, still remains responsible for transmitting and distributing the power, as well as for billing, collections and other customer services. Laws enabling this structure have been passed in California, Illinois, Massachusetts, New Jersey, New York, Ohio and */ continued page 2*

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SOLAR COMPANIES are evaluating what can be done to protect themselves against possible US tariffs on imported solar cells and panels.

Tariffs could be imposed later this year.

Suniva, a US solar cell and panel manufacturer in Georgia, asked the US International Trade Commission in late April to impose duties of 40¢ a watt on imported solar cells and a floor price of 78¢ a watt on imported solar panels. Solar panels are selling currently for roughly 37¢ a watt. Suniva is in bankruptcy. SQN Capital, an institutional asset manager that advanced Suniva money after the bankruptcy to let the company continue operating, made it a condition to the post-bankruptcy DIP loan that the company had to ask the US government for protective */ continued page 3*

CCAs

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Rhode Island.

California has seen a proliferation of CCAs since the first one launched in 2010. There are now eight operational CCAs, and at least 15 more are in various stages of planning, altogether covering 23 counties.

The Los Angeles County CCA, scheduled to launch in January 2018, will be the largest in the state. The total average annual energy use of all cities and unincorporated areas within LA County is around 3,440 megawatts, with a 7,900 megawatt peak. This amounts to more than 30% of Southern California Edison's total load. (SCE itself accounts for about 27% of aggregate state load.) LA County plans to procure power with at least 50% renewable energy content to meet this load, almost twice SCE's current 28%. The aggregator could end up procuring even more renewable power, depending on how many customers sign up for 100% renewable content.

Community choice aggregators present a huge new opportunity for developers of wind and solar projects because they are focused on purchasing renewable energy to serve customer load. CCAs have three unique features.

Creditworthiness

CCAs do not yet have credit ratings, although some of the older CCAs are actively working on establishing a credit rating.

One way to fill this gap is to set shadow metrics that signal possible trouble for a project whose power contract is with a CCA. They would act like tripwires, triggering cash traps, operating reserves and cash sweeps to backstop and pay down project-level debt more quickly.

These tripwires are the same credit metrics that rating agencies use to assess credit default risk. They typically include measures of cash flow, earnings, leverage and coverage. Using these building blocks, the parties can negotiate bespoke metrics for the transaction designed to give a picture of the CCA's financial health and signal vulnerability to default on financial obligations. An example of a CCA-specific metric would be opt-out rates, or the decrease in number of customers measured against a baseline.

If any of the credit metrics is not maintained, then protections are triggered under the loan agreement to reduce the exposure of the lenders. Possible protections include cash traps, cash sweeps and reserve accounts. In project finance, cash sweeps or distribution blocks are used to motivate the borrower to remedy violations of financial covenants. The difference here is that the trigger event relates to the financial health of the offtaker.

If tax equity is involved, back-levered lenders should take into account any protections the tax equity investor has built into the tax equity deal that may be triggered ahead of any protective measures on which the back-levered lender is counting. For example, in some partnership flip transactions, the tax equity investor is entitled to cumulative preferred cash distributions ahead of any distributions to the sponsor partner. This means that the sponsor member bears the risk that the CCA is not creditworthy and, by extension, so does any lender who lends at the sponsor level rather than the project level. In other deals, there may be a cash sweep starting on the projected flip date if the tax equity investor has failed to reach its target yield by that date.

Where tax equity will sit behind the lender in the capital stack, the tax equity investor will require the lender to enter into a forbearance agreement promising not to foreclose on the project after some kinds of defaults to give the tax equity investor time to reach its target yield. The lender can take over the sponsor position as managing member of the tax equity partnership in the meantime. Cash sweeps, reserve accounts and distribution blocks in favor of a project-level lender have not typically been addressed in forbearance agreements involving projects with utility PPAs. They may become a focus in projects contracting with CCAs. (The same issues

More than 85% of the retail electric load in California is expected to move to community choice aggregators and other alternative suppliers.

should be present in projects with corporate PPAs.)

Leveraged partnership flip transactions — where there is debt at the project level ahead of the tax equity — are rare in the current market.

A CCA may have a hard time offering credit support. Any such support would have to come from the municipalities inside the CCA service area and, thus, would require approval by the county board of supervisors or one or more city councils.

This requirement is rooted in the legal structure of a CCA. The California legislation that enables CCAs, AB 117, provides that a group of cities and counties can elect to combine their loads through the formation of a joint powers agency. A JPA is established pursuant to the Joint Exercise of Powers Act (Government Code, section 6500 et seq.). That act provides that a JPA is a public entity separate from the parties to the underlying joint powers agreement. To this point, the joint powers agreement for a CCA typically includes a provision stating that the debts, liabilities or obligations of the JPA shall not be debts, liabilities or obligations of the individual municipalities, unless the governing board of a municipality agrees in writing to assume such debts, liabilities or other obligations.

Opt-Out Risk

Opt-out risk refers to the risk that individual customers will decide to switch back to utility service.

Historically this risk has proved low, with actual opt-out levels averaging around 7% according to recent feasibility studies conducted on behalf of counties and cities exploring CCA formation. However, the data are not deep. The oldest CCA has been operating in California for only seven years.

The key thing to remember is that a CCA has the advantage of being the default electric service provider for all electricity consumers within its boundaries. Existing IOU customers are automatically switched to CCA service. This is provided for in AB 117. The act says that "if a public agency seeks to serve as a community choice aggregator, it shall offer the opportunity to purchase electricity to all residential customers within its jurisdiction . . . . [A]ll customers shall be informed of their right to opt out of the community choice aggregation program . . . . If no negative declaration is made by a customer, that customer shall be served through the community choice aggregation program."

Opt-out risk can also refer to the risk that counties or cities that initially voted to form a CCA will decide to withdraw from the CCA.

If a county or city leaves the CCA, then */ continued page 4*

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tariffs. Suniva is owned roughly 63% by Shunfeng International Clean Energy, a Chinese solar developer and cell-and-panel manufacturer, that opposes the tariff request.

The tariffs Suniva wants would apply to solar cells and modules imported from any country, with the exception of Mexico, Canada, Israel, Jordan and certain Caribbean countries as long as they are not among the top five exporters of solar cells and panels to the United States.

Thin-film products made from amorphous silicon, cadmium, telluride and copper indium gallium selenide would also not be affected.

SolarWorld said in late May that it would join in the request. The SolarWorld parent in Germany is also in bankruptcy.

Suniva laid off approximately 200 employees earlier in the year and has 35 remaining. It has factories in Georgia and Michigan.

The companies are asking for "safeguard" tariffs in a so-called section 201 proceeding. SolarWorld persuaded the US government to impose anti-dumping and countervailing duties in 2012 on solar cells imported from China (and later Taiwan). Those duties remain in place, but Suniva said they have been largely emasculated as Chinese manufacturers shifted manufacturing to other countries.

It is harder to make a section 201 case for safeguard tariffs against all imports than to make a case for anti-dumping or countervailing duties.

In order to prevail, Suniva must prove that solar cells and modules are being imported in such increased quantities as to cause serious injury to US manufacturers of the products. The increased imports must be a "substantial cause" of the serious injury, meaning no other cause can be more important.

In addition, the World Trade Organization appellate body has held that a country must explicitly find that the escalating imports are a result of "unforeseen developments" before it may impose restrictions.

The government has investigated 73 requests for safeguard tariffs under ***/ continued page 5***

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the CCA will no longer serve the load of those customers. This risk may prove to be low for two reasons.

First, the ability of a county or city to withdraw from a CCA is typically constrained by the terms of the joint powers agreement. In addition to a requirement to give advance notice of a decision to withdraw from the JPA, the agreement typically provides that a withdrawing participant will remain responsible for any financial obligations arising from the party's participation in the CCA program before the withdrawal date. Some joint powers agreements state explicitly that this continuing liability includes any losses from the resale of power contracted for by the JPA to serve the withdrawing party's load. Some agreements also allow the JPA to charge the withdrawing party a fee set at an amount that would offset costs to the remaining CCA ratepayers.

The second factor mitigating the risk of a municipal opt-out is that the CCA movement is underpinned by state and local climate change goals and renewable energy targets. California set an ambitious new goal in SB 32 in December 2016 of reducing greenhouse-gas emissions to 40% below 1990 levels by 2030.

Evidence suggests CCAs are helping meet these goals. A recent study by the Luskin Center for Innovation at UCLA found that for the same amount of electricity delivered, four out of five CCAs studied beat IOU emissions by an average of 43% due to higher use of renewable energy. The one outlier had an emissions level that was 1% higher than the local IOU due to heavy use of renewable energy certificates by the IOU.

CCAs are also often cited as being a key tool for achieving local renewable procurement targets. When San Francisco launched its CCA in 2016, public officials praised the program as an important step toward achieving the city's goal of 100% renewable energy use by 2020. Similarly, San Diego City's climate action plan sets a renewable procurement goal of 100% by 2020 and points to CCAs as a way to get there. The city of San Diego is currently exploring the idea of setting up a CCA.

Exit Fees

To remain competitive, a CCA must procure power at a rate that is lower than the retail rate charged by the local utility plus a surcharge called the power charge indifference amount or "PCIA."

The formula for calculating the PCIA is currently under review as part of a broader review of the regulatory and policy framework affecting retail choice and the future role of utilities by the CPUC and the California Energy Commission. (For the latest on these proceedings, see "The Changing California Electricity Market" in this issue starting on page 5).

The risk is that the PCIA could increase to a level that would drive customers away from CCAs.

The PCIA, more informally known as an "exit fee," is what utilities charge customers who leave utility service to take electric service from CCAs or other non-utility power marketers under the evolving California retail choice program. The objective of the PCIA is to ensure that the remaining utility ratepayers remain economically indifferent to whom California residents use as their electricity suppliers because the utilities would still cover the cost of power procurement investments made by utilities on behalf of customers who later switch to CCAs. These costs would have been recoverable by the utility through electricity rates, but they become stranded when the customers leave.

The amount of the exit charge is set annually by comparing the actual costs of the utility's portfolio of assets to the market value of those assets. The fact that they can change annually is a risk. The exit charge does not allow the utility to recover the entire cost of procurement, only the uneconomic portion, meaning the extent to which the power was procured at a price that is above the current market price. The idea is that if the utility procured the power at a price that is below current prices, then the utility should be able to mitigate losses by selling excess energy and capacity into the market. Because the PCIA represents the above-market portion of generation costs, when market prices fall, the PCIA increases.

There is general agreement that the current methodology for calculating the PCIA is flawed. (For a discussion of the main issues with the PCIA, see "Huge Potential New Demand for Power" in the October 2016 *Newswire*).

The CPUC has said that its task is to adjust the PCIA methodology in a way to both allows customers to continue to make the choices they want and ensures that all other customers are not left with an unfair allocation of costs. Fees set too high undermine retail choice, while fees set too low unfairly shift costs to unbundled customers of the utility.

Interestingly, AB 117 also gives CCAs the right to charge their own exit fees under certain circumstances. The law provides that fees may be imposed on customers who choose to opt out of CCA service after a 60-day grace period. The fee must be approved by the CPUC. This issue will be reviewed in the same CPUC and CEC proceedings relating to the PCIA.

The Changing California Electricity Market

by Jeremy Waen and David Howarth, with MRW & Associates in Oakland, California

The California regulatory agencies are scrambling to get ahead of a rapidly changing California electricity market as millions of Californians are being offered an expanding slate of alternatives to fully bundled electricity service from the local investor-owned utility or "IOU".

As many as 1.9 million customers are expected to use some form of customer choice by the end of 2017. More than 85% of the total utility load may depart to alternative suppliers by the middle of the next decade.

While competition in retail electricity supply is not new in California — retail choice was introduced in the late 1990s — that early foray into competition was hobbled by the California energy crisis in 2000 and by subsequent legislation capping the amount of load allowed to exit through direct access.

The driving factors behind the current exodus are the rapid expansion of community choice aggregators or "CCAs" and customers installing solar panels. (For background on CCAs, see "Another Potential Offtaker: Community Choice Aggregators" in the August 2016 *Newswire*, "Huge Potential New Demand for Power" in the October 2016 *NewsWire*, and "Financing Projects With Community Choice Aggregators" in this issue starting on page 1.)

The amount of customer load served by CCAs now exceeds the amount supplied by power marketers. With many more communities either forming new CCAs or joining existing CCAs, the amount of load departing utility service is expected to increase substantially in 2018.

Both the scale and the rate of load departures across the state are causing the California Public Utilities Commission and California Energy Commission to recognize that time is fleeting for policies to adapt to these changes. The regulators are particularly concerned about how the changes in industry structure are affecting their ability to ensure that California meets its aggressive greenhouse gas emission reduction goals.

The CPUC and CEC held a joint "en banc" meeting on these issues on May 19. The CPUC staff issued a */ continued page 6*

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section 201 since the section was enacted in 1974. Relief was granted in 35.6% of the cases.

The US International Trade Commission has until September 22 to decide whether US solar cell and panel manufacturers have suffered serious injury from increased imports. Briefs are due in the case by August 8. If it finds such injury, then the commission will hold a separate hearing to decide on the relief to recommend to the president. Any recommendation to the president must be submitted by November 13. The president then has 60 days to make a decision.

The commission has recommended relief in 54.8% of the 73 cases to date that it investigated. Presidents have then granted relief in 65% of those cases.

The last time the US imposed safeguard tariffs was a 30% tariff in 2002 to protect the US steel industry. The US justified the steel tariff by pointing to the Asian financial collapse in the late 1990s as the unforeseen development that led to higher steel exports to the United States.

Suniva argues the unforeseen development in this case was the move by Chinese solar manufacturers to move production to other countries to avoid US anti-dumping and countervailing duties, leading to a surge in imports from these other countries.

Any relief is supposed to be temporary and not remain in place for more than four years. However, the period can be extended for up to eight years.

The ITC can choose among several options, including tariffs, import quotas or orderly marketing agreements with other countries.

Any tariffs that will remain in place for more than a year must phase down at regular intervals.

Suniva is asking for tariffs declining over four years from 40¢ to 33¢ a watt on imported cells and a floor price declining from 78¢ to 68¢ a watt on modules. It also wants the $1 billion in anti-dumping and countervailing duties collected to date on Chinese solar cells to be distributed 50% to US solar cell and panel manufacturers and 10% to US polysilicon producers. ***/ continued page 7***

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white paper ahead of the meeting to tee up the discussion about how California can balance its priorities for greenhouse gas reductions, grid reliability, rate affordability, universal access and economic development in the rapidly evolving electricity market.

The white paper said the CPUC intends to initiate a formal rulemaking proceeding to explore the "future role(s), structure(s), fiscal and other functions of the three large California electric IOUs."

En Banc Highlights

Many prominent figures attended. The meeting lasted all day. For the CPUC, President Michael Picker and Commissioners Carla Peterman, Liane Randolph, and Martha Guzman Aceves attended. For the CEC, Chairman Robert Weisenmiller and Commissioners Karen Douglas and Andrew McAlister were present.

Several commissioners made opening statements. The day was then divided into separate panel discussions exploring four topics: customer preferences, the state of customer choice, IOU perspectives on the situation, and the future of retail electricity services within California.

The California regulators are scrambling to get ahead of the rapidly changing market.

Picker said the state has no coherent plan yet to deal with the rapid load departures from the IOUs. He said there are two fundamental questions to answer: how do we organize the electric system to achieve our goals, and who is going to finance it? He said the "decision-maker" role is shifting from the regulators to the electricity customers as they exercise retail choice. This shift creates tension between the pursuit of statewide goals and local priorities.

Weisenmiller said he wants to examine the consequences of moving away from a vertically integrated utility model and associated regulatory system. For example, he said the changing nature of the industry means California utilities are no longer signing bilateral contracts to buy capacity from independent generators, which has implications for how the state ensures reliability. He cautioned that "markets do not care about everyone" and the state must make sure this transition does not leave people behind. He said, "We are going into a future that, if we think about it and are clever, can work, but we need to get out in front of it."

Numerous speakers shared their perspectives on the potential consequences of a rapid shift in the electricity load from the IOUs to CCAs and other suppliers. In an unusual instance of stakeholder alignment, the CCAs, power marketers, solar developers, ratepayer advocates, and even the IOUs clamored for policy reform. While they all seem to agree that changes are needed, consensus remains elusive around what specifically needs reform and how best to do it.

A hot topic was how to handle the costs of future electricity supplies that the IOUs have already procured on behalf of ratepayers who are now leaving the utilities. These are called "legacy resource costs."

State law already calls for "ratepayer indifference," meaning the ratepayers who choose to remain with the local IOU should be neither better nor worse off as other ratepayers who choose to take their electricity from other suppliers.

Costs associated with IOU procurement have the potential to become stranded costs due to load departures. IOUs are already allowed to address this problem by collecting a non-bypassable charge known as the power charge indifference adjustment or "PCIA" from customers who move to other electricity suppliers. The PCIA is collected by the IOUs via a line-item charge on departing customers' bills.

The three big California IOUs say the present PCIA methodology is broken and that more costs are being stranded due to the increasing number of customers departing for other suppliers. They say these costs are unfairly being borne by remaining ratepayers on the utility systems. The utilities want the CPUC to use

a "portfolio allocation mechanism" that would replace the PCIA entirely and assign to the departed load the net costs and benefits of the IOU legacy resources rather than just the net stranded costs as is done currently.

The alternative service providers presented differing opinions. Geoff Syphers, CEO of Sonoma Clean Energy, a CCA, said the legacy resources largely overlap with CCA-led procurement because the IOUs failed to take into account CCA load departures in their procurement forecasts. As a result, much of these legacy resources are doubly procured on behalf of CCA customers. While Syphers agrees the PCIA needs reform, he does not agree that the utility proposal is the solution.

Syphers says that the IOUs should be required to mitigate legacy costs, which is not required by the utility proposal, and there must also be rate certainty for all parties and an end to double procurement.

The commissioners gave little insight into how they might resolve the legacy resource cost issue. Commissioner Peterman said the CPUC is treating the matter "with the utmost urgency."

Future Utility Role

Utilities are required by law to serve anyone who wants electricity. CEC Chairman Bob Weisenmiller asked panelists repeatedly, throughout the day, how California should address the utility role as providers of last resort.

The state has used directives to utilities about what type of electricity they supply as the primary tool to implement its goal of moving to greater reliance on renewable energy. The IOUs say the need to act as providers of last resort and to implement state goals in how they procure power sometimes pulls them in opposite directions.

In other states, utilities often serve the residual customer base with short-term, market-rate electricity purchases. Utilities in California have been pushed for state policy reasons to make long-term purchases to address state goals on greenhouse gas reduction, affordability, reliability and economic growth. The IOU panelists said balancing these roles becomes unsustainable in an increasingly competitive electricity market with declining utility bundled loads.

Another panelist, Sue Tierney, who served as a public utilities commissioner during utility deregulation in Massachusetts, said that while competition and retail choice exist in 14 other states, California is uniquely situated due to its climate-oriented policies and procurement mandates. Other states have effectively leveraged competitive markets to drive

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It wants 20% put into a fund that would be used by the US Department of Commerce to help reopen US solar cell and module factories that were shut down after anti-dumping and countervailing duties were imposed in early 2013. It wants the money collected under any new tariff to go into a separate fund to be used to help spur expansion of US solar manufacturing capacity. It also wants the US to negotiate directly with other countries to reduce the amount of product they are shipping to the United States.

Any tariffs at the level Suniva proposes would cripple further growth in US solar installations. Developers building utility-scale projects have had to make assumptions about future equipment costs when signing up to long-term power purchase agreements to supply electricity to utilities and corporate offtakers. The potential harm to project developers is immediate as the uncertainty created while the ITC and president consider the Suniva request makes it hard to bid on future contracts.

IHS Markit estimates the tariff Suniva wants would cause the US solar market to shrink 60% during 2018 to 2021.

Suniva says its two factories in 2016 were 50.6% of US manufacturing capacity for solar cells and 24% of capacity for combined cells and modules. Extrapolating from these numbers suggests 979 US manufacturing jobs are potentially at stake at US solar cell and module factories compared to some significant share that would be put at risk out of the 370,000 total jobs in the US solar sector.

Tariffs are imposed on the importer of record. Thus, where a foreign panel manufacturer sells its product in the United States through a US subsidiary, the US subsidiary must pay the tariff. The seller cannot reimburse the buyer for the tariff. Any such reimbursement must be paid to the US government as an additional import duty.

Section 201 allows an injured US manufacturer to ask for a tariff to be put in place on an emergency basis while its case runs the full course through the ITC as

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down electricity rates for customers while balancing the need for grid reliability, but no other state has had to figure out yet how best to leverage the competitive market to pursue greenhouse gas-reducing objectives.

According to panelists, states like Hawaii and New York are making progress in that direction, but are either too uniquely situated (in the case of Hawaii) or not far enough along (in the case of New York) to impart best practices onto California's efforts.

Several panelists spoke to the need to resolve the tension between state policy to encourage deployment of rooftop solar and other forms of distributed energy while also defaulting to utility-centric procurement.

Panelists with interests in solar technologies said the regulators should focus on rate stability and improved rate structures to support use of solar and battery storage to help with greenhouse gas reduction and grid reliability. While the IOUs have strong balance sheets and are well situated to leverage economies of scale, it remains hotly debated whether the IOUs can act quickly and innovatively enough to support distributed generation.

Other panelists argued for greater state efforts to push electrification of the transportation sector. One panelist, Nora Sheriff, on behalf of the California Large Energy Users Association, made a case for expanding the use of demand response to help achieve the state's goals. Another panelist drew a parallel between California's approach of using the IOUs to implement state goals and "Soviet-style central planning."

Road Ahead

The California electricity market is in transformation. As the CPUC staff said in the white paper, the drivers of change are "accelerating whether [regulators] want them to or not." The CPUC and CEC are attempting to adapt state regulatory policies, but the road ahead and timetable are uncertain. Market participants should prepare for a significant period of regulatory uncertainty and engage with the regulators on what they would like to see emerge from the policy review.

Participants in the day-long en banc meeting left with their heads spinning, filled with wonky thoughts after a wide range of issues was raised. The commissioners who presided over the meeting listened, but gave the audience little sense of how they might resolve the issues.

Only one thing remains certain: California is moving to widespread and competitive customer choice with potentially profound effects on the electricity market.

Hedges for Wind Projects: Evaluating the Options

by Rob Eberhardt and Christine Brozynski, in New York

With a dearth of traditional utility PPAs for US wind projects, project sponsors are evaluating alternative offtake arrangements.

At least three types of hedges have emerged as viable offtake structures: fixed-volume price swaps, virtual PPAs with corporate offtakers and proxy revenue swaps. It is critical for sponsors to understand the basic features of these offtake structures as they evaluate their options to finance their wind projects.

Fixed-Volume Price Swaps

A fixed volume price swap, often called a bank hedge, is perhaps the most tested alternative offtake structure.

Numerous projects over the last five years — mostly in Texas's ERCOT market — have used fixed-volume price swaps. The hedge provider is a bank or another strategic investor. Several large financial institutions with active ERCOT trading desks also make tax equity investments, and for these institutions it is common for fixed-volume price swap and tax equity commitments to be offered together.

At least in ERCOT, fixed-volume price swaps typically are a type of physical hedge, meaning the hedge provider purchases power as part of the transaction. The hedged transaction occurs at a trading hub agreed to by the parties. The project company purchases a fixed volume of power at the hub for the then-current hub price and immediately resells that power to the hedge provider for a pre-agreed fixed price per megawatt hour. Power produced by the project is not part of the transaction and is separately sold on a merchant basis at the grid node nearest the project. The intended result of these two distinct transactions for the project company is the sale of a fixed volume of power at a fixed price.

Basis risk is a central concern in fixed-volume price swaps and other alternative offtake structures. There is potential misalignment between actual realized revenue from merchant sales at the nodal price and the cost to purchase power at the hub at the hub price for resale to the hedge provider. This discrepancy (e.g., if the hub price is higher than the nodal price) is called basis risk.

The options for project companies looking to mitigate basis risk are relatively limited. Financial institutions have historically declined to provide financial hedges that avoid basis risk through settlement at a project node. Hedge providers are looking to settle transactions at liquid trading hubs.

One popular mechanism employed to delay the impact of (although not remove) basis risk over the term of the hedge is a "tracking account." The tracking account is like a working capital facility. For any settlement period for which the amount the project company must pay for power at the hub exceeds the merchant revenue realized by the project, the hedge provider makes a loan to the project company in that amount by letting the project company delay payment of an amount it owes the hedge provider. The tracking account records the cumulative balance of those loans as a negative amount with accrued interest until the balance reaches a pre-negotiated floor. After any settlement period for which the realized merchant revenue exceeds the purchase obligation at the hub, the project company partially repays the loans in the amount of the excess. At the end of the hedge term, the project company repays the tracking account balance in either a lump sum or installments.

The use of a tracking account provides liquidity and frees up cash for debt service or for distribution to equity. In lieu of a tracking account, a basis risk reserve or working capital facility can provide similar protections.

There also is the possibility for projects to use financial instruments like congestion revenue rights to mitigate basis risk. However, to our knowledge, congestion revenue rights or similar instruments have not been used to support project financing.

The project company's obligations to buy and resell power at the hub are hourly and typically match the volume of power expected to be produced by the project for the hour in a P99 scenario. Limiting the hub delivery requirement to the project's P99 production provides predictable revenues for the project company with acceptable volumetric risk and some cushion for price-driven basis risk. The project company may also deliver renewable energy credits as part of the transaction.

A force majeure or other curtailment event affecting the project's delivery of merchant power does */ continued page 10*

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"provisional relief" to address critical circumstances. An example of critical circumstances is a rush to import solar equipment ahead of a possible tariff. Suniva has not asked for such relief. Any tariffs would apply to solar cells and modules passing through US Customs after the tariffs are imposed, with the caveat that the president has authority to apply any provisional relief in a manner he "considers necessary."

The ITC notified the World Trade Organization in late May that the US is launching a safeguard investigation to determine whether it will impose tariffs.

SQN Capital told a Chinese trade association by letter in early May that the trade case would disappear if its members bought the factory equipment that SQN financed so that a $51 million debt by Suniva to it could be repaid, according to a report by Bloomberg. SQN Capital said later in May that it is no longer looking to negotiate such a sale.

PRODUCTION TAX CREDITS for wind, geothermal and closed-loop biomass projects will increase slightly in 2017 from 2016 levels, the Internal Revenue Service said in late May.

Credits for producing refined coal are increasing slightly in amount.

The credits for generating electricity from wind, geothermal steam or fluid or closed-loop biomass (plants grown to be used as fuel in power plants) are 2.4¢ a kilowatt hour in 2017. They will remain unchanged at 1.2¢ a kilowatt hour for generating electricity from open-loop biomass, landfill gas, incremental hydropower and ocean energy.

The credits are adjusted each year for inflation as measured by the GDP price deflator. They run for 10 years after a project is originally placed in service.

The credits phase out if contracted electricity prices from a particular resource reach a certain level. That level in 2017 is 12.6336¢ a KWh. The IRS said there will not be any phase out in 2017 because contracted wind electricity prices are 4.55¢ a KWh going into */ continued page 11*

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not excuse the delivery obligation at the hub unless expressly excused in the hedge. The force majeure provisions in the ISDA power annex — part of the documentation for the hedge — apply to the purchase and sale of power at the hub rather than a force majeure at the project site. Project insurance programs typically reflect this feature of fixed-volume price swaps.

During construction, the project company typically must post credit support in the form of cash or a letter of credit. The amount of required credit support is negotiated and typically steps down at commercial operation.

A hedge provider also typically will require liens on project assets and equity as credit support for the hedge. It also imposes a full set of covenants on the project company to limit the universe of competing creditors and to protect the collateral.

Three types of hedges have emerged as viable alternatives to PPAs in wind farms.

The hedge provider does not usually post credit support in the form of cash or a letter of credit as long as a parent guaranty from a creditworthy guarantor is in effect. Sometimes the creditworthiness of the guarantor is measured in tiers: while a high credit rating means the hedge provider does not need to post cash or a letter of credit, a lower credit rating requires the hedge provider to post margin in excess of a pre-negotiated threshold. As the credit rating steps down further, so does the corresponding threshold. At any time the guarantor is not creditworthy, the hedge provider must post margin in the full amount of the hedge provider's exposure.

Hedge providers with a lien should expect to execute a forbearance agreement with any tax equity investors and an intercreditor agreement with any lenders or other secured hedge providers.

Corporate PPAs

Corporate PPAs, also known as synthetic or virtual PPAs, are financial hedges provided by corporations. The corporate PPA is accepted as a financeable offtake structure.

Unlike physical hedges, no power sales typically occur under these hedges between the project and the hedge provider. The simplest form of corporate PPA is a basic contract for differences. The project company pays the floating price per MWh for a fixed percentage of power actually produced, and the hedge provider pays a pre-agreed fixed price per MWh for the same amount of power. The floating price is either a hub price or the nodal price. The project sells its physical output on a merchant basis into the market.

Basis risk exists only if the floating price paid by the project company is the hub price. Corporate PPAs do not usually provide a tracking account.

Price floors are a negotiated point in corporate PPAs. While the offtaker will prefer not to settle the hedge when energy prices are negative, tax equity investors may require that a negative price floor be set at the grossed-up negative value of the production tax credits.

Corporate PPAs typically contain annual minimum availability requirements. Customary excused hours may include force majeure and curtailment imposed by the transmission owner.

Corporations enter into these hedges for financial benefit and for environmental attributes, which are typically transferred as part of the transaction. Offtakers may also assert that their nearby corporate facilities run in part on renewable energy based on the added-generation test: the revenue stream from the corporate PPA directly enabled the construction and operation of the wind project.

For project companies, the hedge provides unit price protection for power actually produced.

Credit support requirements vary and usually take the form of a letter of credit, cash or a parent guaranty for the project company. The hedge provider often posts a parent guaranty and may be required to post margin at any time the guarantor is not

creditworthy. The credit of the offtaker will be a central concern, given the need for long-term contracts to support financings and the difficulty in taking long-term views on a corporation's credit.

Unlike fixed-volume price swaps or proxy revenue swaps, corporate PPAs typically can start settling immediately upon project commercial operations. The other two arrangements typically have fixed starting dates for settlement.

Proxy Revenue Swaps

The proxy revenue swap is a new product that debuted in 2016. Three 10-year proxy revenue swaps were executed in 2016 and supported third party debt and tax equity commitments.

The hedge provider in a proxy revenue swap is a weather risk investor. Fundamentally, the hedge provider is looking to make investments that are not correlated with other parts of the economy, but instead are based on natural phenomena like the wind resource regime at a project site.

As part of the financial settlement, the hedge provider pays the project company a pre-agreed fixed price per annum (rather than providing a fixed unit price per MWh generated or sold, as is the case in corporate PPAs and fixed volume hedges respectively). In other words, the project company receives a fixed annual payment.

The project company pays the hedge provider a fixed percentage of "proxy revenue," which is equal to the hub price multiplied by the "proxy generation" for that settlement period. "Proxy generation" is calculated under the hedge as the power that would have been produced by the project based on measured wind speeds and assuming pre-agreed fixed operational inefficiencies. The assumed operational inefficiencies include availability, performance and electrical losses.

By paying a fixed price per annum instead of per unit of output, the weather risk investor effectively hedges two variables for the project: the volume of power that the project will produce per year (removing any variation in production resulting from operational inefficiencies), and the hub price per unit.

From the project company's perspective, the proxy revenue swap evens out revenues that would otherwise vary significantly based on wind production.

The project company must contend with basis risk when entering into a proxy revenue swap.

The proxy revenue swap does not impose delivery obligations or minimum availability requirements. Availability is one of the fixed variables in the calculation of proxy generation.

Although the transaction does not entail a sale of power, the

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2017. It said it lacks data on contracted prices for electricity from the other energy sources.

Production tax credits for producing refined coal are $6.909 a ton in 2017. Refined coal is coal that has been treated with chemicals to make it less polluting than regular coal. The IRS said there will not be any phase out of refined coal credits in 2017. The refined coal credit phases out as the reference price for raw coal moves above 1.7 times the 2002 price of raw coal. The 2017 reference price is $51.09 a ton. A phase out would have started at $85.64 a ton.

The tax credit amounts are in IRS Notice 2017-33.

DOE WANTS A SHARE OF THE SALES PROCEEDS from a project that was paid for partly with US government money.

Abengoa set out to build an $850 facility for making cellulosic ethanol and an adjacent power plant in Hugoton, Kansas. The US Department of Energy entered into an "assistance agreement" in 2007 with the project and awarded it $95 million to be used toward construction. The department also made a $132.4 million loan guarantee in September 2011 of which $45 million was drawn and ultimately repaid.

Abengoa never finished construction of the project. Its project subsidiary, Abengoa Bioenergy Biomass of Kansas LLC, is in bankruptcy and filed a liquidation plan with the US bankruptcy court in Kansas in April. The project was sold last December to Synata Bio Inc. for $48.5 million. The government filed a claim as a creditor for a share of the sales proceeds. It says its money represented 27.4% of the $350.4 million that was spent on the project. Abengoa argues that the government was an equity investor rather than a creditor and says the assistance agreement lacks terms typical of a loan agreement, such as repayment terms, an outside maturity date, payment enforcement rights and an obligation to pay interest.

A hearing is scheduled in the case for July 12.

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Hedges

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project company may sell and deliver RECs to the hedge provider.

The credit support requirements for each party are similar to those in a fixed volume hedge.

Financing Energy Storage Projects: Assessing Risks

by Brian Greene and Deanne Barrow, in Washington

Technological and cost breakthroughs are expected to lead to rapid growth in the number of utility and behind-the-meter storage projects.

Industry insiders say the energy storage market in 2017 feels like the rise of the solar industry in the late 2000s. In 2016, energy storage developers in the US installed 336 megawatt hours of storage, double the amount from the previous year. By 2022, energy storage installations are expected to reach 7,300 megawatt hours and generate revenues of $3.3 billion.

States are stepping in to provide rebates and energy storage mandates. Deal flow is picking up, with lenders and investors eager to move in on this emerging trend.

In the last two years, at least two non-recourse project financings of standalone energy storage projects have closed in the US. For the energy storage market to reach its expectations, lenders and investors will have to get their heads around the unique risks posed by storage projects.

Two Types

Utility-scale storage projects provide services to the utility grid.

An important service is integrating energy from variable renewable sources. Energy storage helps in two ways.

First, it smoothes out fluctuating output from solar and wind that can otherwise wreak havoc on a grid by upsetting frequency balance. Both solar and wind are prone to rapid ramp up and ramp down, leading to grid instability. Batteries having short charge-and-discharge cycles on the order of seconds can respond to fluctuating renewable output more quickly and accurately than thermal power plants.

Second, energy storage can help integrate renewables by shifting supply to better align with demand. By doing so, curtailment of these sources is avoided. This service requires batteries with longer charge-and-discharge cycles on the order of hours.

Behind-the-meter systems provide services to the grid as well as to the host customer. These systems are installed on the customer side of a utility meter. The customer can be either commercial and industrial or residential. Both residential and commercial customers benefit from having a backup supply of power. If the customer is commercial or industrial, then it gets the added benefit of demand charge savings under its retail rates. Demand charges are what utilities charge customers for their maximum load during a certain interval. They can make up a significant portion of a customer's bill. By drawing on the battery instead of the grid during periods of peak electricity use, the customer can avoid expensive demand charges.

Behind-the-meter storage also helps with integration of distributed resources. The energy storage system can store excess energy produced by a solar system on the customer's roof, usually during the day when the customer is not home, and release the energy when demand increases, usually during the evening. Without energy storage, the excess energy gets fed back into the grid at a time when there is no matching demand, which can cause problems for the grid.

Creditworthy corporate offtakers like Whole Foods, Walmart and Amazon are increasingly interested in energy storage. The interest of these players in energy storage is an extension of the "corporate PPA" trend that took hold in 2016.

California is the dominant market leader for storage in the United States. Total deployments in 2016 increased 100% over the previous year largely due to a burst of activity in California in the fourth quarter of 2016, when more than 200 MWh came online. The deployments were driven by fast tracking of procurement to compensate for potential electricity shortages after a gas leak was discovered at the Aliso Canyon natural gas storage facility. Other markets such as Hawaii, Massachusetts, New York and Texas are waking up.

Incentives

Incentive programs are gaining momentum as more states pass laws and adopt regulations to drive this nascent industry. Project developers should have a firm grasp of any incentive programs to the extent the financing is dependent on them.

At the federal level, a 30% investment tax credit may be available for certain energy storage installed in conjunction with solar or wind projects. (For a more detailed discussion, see "Batteries and Tax Credits" in the October 2016 *NewsWire*.)

At the state level, the regulatory landscape varies widely.

In California, the self-generation incentive program (SGIP) has been a key contributor to the growth of the energy storage market by making the projects economically attractive. The program has been around since 2001. It offers rebates to certain distributed energy technologies, including wind, combined heat and power, fuel cells and energy storage. The SGIP is funded by a charge levied on all ratepayers and collected by the three California investor-owned utilities.

A revamped version of the program that greatly benefits energy storage became effective on May 1. Under the revamped program, the total amount of rebates being offered is $166 million per year, double the previous amount, and 75% has been allocated to the energy storage category. For commercial energy storage projects greater than 10 kilowatts in size, the rebate offered is 50¢ per watt-hour of energy produced (but only 36¢ for solar-plus-storage so as not to over-subsidize projects that qualify for a federal investment tax credit). The customer must bear at least 40% of total project costs.

California, Oregon and Massachusetts have each adopted an energy storage mandate that sets mandatory storage procurement targets for utilities.

In 2013, California established a collective mandate of 1,300 megawatts by 2020 for all utilities. Oregon followed in 2015 with a smaller-scale mandate of five megawatt-hours by 2020 per utility. In August 2016, Massachusetts passed a law authorizing its state energy commission to set a storage mandate. The Massachusetts Department of Energy Resources will decide the level of the mandate by July of this year. A state-commissioned report recommended 600 megawatts by 2025. If the recommendation is adopted, the Massachusetts target would be the most aggressive, representing 5% of peak load, while the California and Oregon targets represent 3% and 1% of peak load respectively.

In May, Maryland became the first US state to offer a tax credit for energy storage. The amount of the tax credit is 30% of the cost of a customer-sited installation, subject to a cap of $5,000 for residential installations and $75,000 for commercial installations. A total of $750,000 per year is available under the program. The Maryland tax credit is not limited to solar-plus-storage. The tax credit becomes available in 2018 and will run through 2022.

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A COMMUNITY SOLAR PROJECT owned by a utility received a favorable tax ruling.

A utility plans to build a pilot community solar array and to pay for it by offering subscriptions to its ratepayers. Anyone subscribing will continue to buy electricity from the utility as before, but will be credited on his or her monthly utility bills with an "incentive fee" that reimburses the subscriber for the fuel cost savings to the utility from moving to solar and for the value of the renewable energy credits to which the utility is entitled for generating solar electricity.

The utility will not put the plant into its rate base. Rather, it will charge all its ratepayers, including the pilot program subscribers, for the electricity from the plant as a purchased power expense. Utility rates are usually set at a level that is projected to earn the utility an agreed rate of return on its rate base, meaning the amount it has invested in plant and equipment. However, some costs, like the cost of fuel and electricity purchased from third parties, are passed through to ratepayers directly.

The utility needs fewer than 0.5% of its ratepayers to subscribe to cover the community solar project costs.

The IRS told the utility in a private letter ruling made public in May that the community solar array will not be "public utility property."

The ruling is important because it allows the utility to claim an investment tax credit and accelerated depreciation on the community solar facility without worrying whether its state regulators will force it to pass through the value of the tax benefits too quickly in the rates it charges its customers for electricity.

A regulated utility cannot claim investment tax credits and accelerated depreciation on new assets if its regulators make it pass through the benefits to customers more rapidly in rates than under a "normalization" schedule that spreads the benefits over time. The utilities asked Congress in the 1970s to be denied the two tax benefits if their regulators force the benefits to be passed through too quickly to ratepayers. They saw it as a way to ensure

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Energy Storage

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Revenues

Investors and lenders are eager to enter into the energy storage market.

In many ways, energy storage projects are no different than a typical project finance transaction. Project finance is an exercise in risk allocation. Financings will not close until all risks have been catalogued and covered. However, there are some unique features to energy storage with which investors and lenders will have to become familiar.

Energy storage projects provide a number of services and, for each service, receive a different revenue stream.

Distributed energy storage projects offer two main sources of revenue. Capacity payments from the local utility are one. Power purchase agreements providing capacity payments for distributed energy storage systems with terms of 10 years or more are becoming customary in California. Payments for demand charge management for on-site load are another. Demand charge management occurs when electricity is drawn from the during times when grid prices are highest. By drawing on the battery for power at those times, customers avoid expensive demand response charges. Although the customer's cost savings vary, developers can lock in a revenue stream by charging customers a fixed monthly fee based on projected cost savings.

Distributed energy storage systems that have been financed by borrowing on a non-recourse basis to date have been able to demonstrate a rate of return that is acceptable to lenders based on revenues from capacity payments from a utility and compensation for demand response management from creditworthy customers. What many industry players find exciting about distributed energy storage is the potential to stack even more revenue streams from ancillary services, such as spinning reserves and voltage support.

The primary benefit of distributed storage systems, so-called "value-stacking," also presents a risk if competing uses of the battery are not properly managed. Unlike traditional project financings where assets are limited in their application, an energy storage system must be given the flexibility to operate in a variety of service roles. Covenants in loan agreements, for example, need expressly to permit the various uses the battery is intended to serve or could serve in the future.

Unlike distributed energy storage, utility-scale projects do not have the intrinsic ability simultaneously to sell services behind the meter to a host customer and capacity or energy to a utility. Utility-scale projects have the potential to provide a number of ancillary services to support the grid, such as frequency regulation, spinning reserves and voltage support, but it is difficult to monetize these services at this time due to a lack of compensatory structures in wholesale electricity markets. As a result, while a utility-scale project could theoretically provide different services to separate offtakers, it is more likely to have a single offtaker or revenue stream.

A limited number of utility-scale energy storage projects have been financed to date on a project-finance basis. The number of utility-scale projects should increase as costs for energy storage technology decline and utility-scale projects find a way to generate multiple revenue streams.

In the case of behind-the-meter systems, the customer would typically pay for or provide the electricity required to charge the battery, but the developer must be able to show that the battery provides an economic benefit to the customer after taking this cost into account. If a distributed energy source such as rooftop solar is available at the site, then the battery can draw on the solar array for power. In that case, the customer has no expense except, perhaps, lost income if net metering is available.

If no such energy source is available, then the battery will have to charge from the grid. In that case, the cost of the power will be paid by the customer as part of its monthly utility bill. The developer should account for this cost when setting its monthly subscription fee. One option is to deduct a fixed amount for the projected

Lenders are working to understand the unique risks in energy storage projects.

charging costs from the subscription fee. The charging cost (up to the fixed amount) then becomes a "pass-through" charge. With this structure, the customer takes the downside risk if charging costs turn out to be greater than the fixed amount, but takes the upside potential if charging costs are lower than expected.

In the case of utility-scale systems, the storage project owner will need to purchase the energy to charge the battery through a PPA if the storage project is the electricity customer. Lenders and investors should conduct a bankability review of the PPA. The PPA is essentially the fuel supply arrangement for the project.

If the storage project is providing storage services to a utility, then the utility and the storage project may enter into a service contract that requires the utility to pay both a capacity payment and an energy charge to keep the battery on call to accept electricity for storage or discharge it back to the utility.

Service contracts between energy storage projects and utilities may allow the utility the option to require the storage project to be available to accept electricity 24 hours a day, seven days a week. This ensures that the battery can be used at any time to soak up excess power from the grid, such as during times of peak solar and wind output, and to discharge energy when needed to support the grid. Storage projects may also enter into service contracts with associated facilities developed by the same sponsor or an unrelated sponsor.

Risks

Regulatory regimes for energy storage are in a state of flux.

Both the Federal Energy Regulatory Commission and regional transmission organizations (RTOs) are grappling with how to update regulatory and policy frameworks to better integrate energy storage and remove barriers to market participation. Key regulatory issues currently under review include ways to remunerate energy storage in wholesale electricity markets and ways to facilitate interconnection.

Regulations affecting remuneration of energy storage services present a key risk because of the impact they can have on determining what is commercial. There is currently very little uniformity among RTO markets. The economics of charging and discharging during the day, versus at night, and the duration of the charging and discharging, can greatly affect economics.

On the subject of interconnection, there is some uncertainty over which FERC rules apply to large energy storage devices seeking to interconnect to the grid. A clarification that would place energy storage installations that / *continued page 16*

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they would be able to retain some incentive from the tax benefits to make new investments.

Potential loss of these tax benefits is an issue only for assets considered "public utility property." New generating equipment is public utility property only if the rates the utility can charge for the electricity output are regulated on a rate-of-return basis.

Even though the utility plans to sell the electricity in this case as part of an undifferentiated pool of all the electricity it supplies, the IRS said the cost for this particular electricity is passed through to ratepayers as a purchased power expense rather than at a regulated rate tied to a rate base.

The ruling is Private Letter Ruling 201718017.

ENERGY STORAGE systems will qualify for a tax credit in Maryland under a new law signed by the governor in May.

A tax credit can be claimed for 30% of the cost of new storage systems installed between 2018 and 2022. However, the credit is capped at $5,000 for a residential system and $75,000 for a commercial system. Maryland is the first state to offer a tax credit specifically for storage.

No more than $750,000 in total credits may be claimed statewide in a year. Taxpayers must apply to the Maryland Energy Administration for a certificate authorizing them to claim credits. Certificates will be awarded on a first-come-first-served basis. If the maximum credit is claimed on each storage unit, the cap will support a maximum of 150 residential units or 10 commercial units a year, or a smaller number of each in a mixture of the two.

The state credits may not be carried forward if not used fully in the year the storage unit is installed.

A 30% investment tax credit can be claimed on batteries at the federal level, but only on batteries that are considered part of the electric generating equipment at a solar facility. Batteries installed as part of other renewable energy facilities may also qualify, but in more limited circumstances. (For more details, ***/ continued page 17***

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exceed 20 megawatts within the ambit of FERC's large generator interconnection rules is currently under consideration as part of a pending rulemaking that was opened in December 2016. (For additional information, see "Developers are Watching Two FERC Proceedings" in this issue starting on page 26.) Small-scale energy storage is already expressly included in FERC's standard interconnection rules and agreements for small generating facilities.

However, small-scale energy storage installations face uncertainty for a different reason. When small-scale energy storage is combined with a distributed energy source like rooftop solar, it is not clear whether the addition of an energy storage component affects the status of the rooftop solar system as a "qualifying facility" under the Public Utility Regulatory Policies Act of 1978 (PURPA).

Qualifying facilities enjoy several benefits, including a right to interconnect, the option to sell energy and capacity to a utility at the utility's avoided cost, and relief from certain regulatory burdens. The PURPA rules are unclear whether a storage project that uses renewable electricity for charging would be considered to be a renewable resource and, therefore, be considered a qualifying facility. It is also unclear whether a combined rooftop solar and battery storage system would be considered a qualifying facility if the electricity used to charge the battery is not primarily from a renewable source.

Turning to environmental permitting, behind-the-meter storage systems do not generally raise separate material concerns because the footprints of such systems are typically small. Identifying permitting requirements for larger projects will require a review of local laws and regulations.

Utility-scale storage is usually financed as an add-on to a project that includes other assets. This can have implications for regulatory and environmental permitting requirements. If the battery and the other assets are owned by different project companies, then the situation could arise where regulatory and environmental permits pertaining to the battery are held in the name of the other project company. Shared use of the permits will need to be provided for in a shared facilities agreement, if the permits allow for such sharing.

According to GTM Research, lithium-ion batteries made up 98.4% of the US energy storage market in the last quarter of 2016. Lithium-ion battery prices have fallen 73% since 2010, due to improvements in technology and scaling by manufacturers. Battery prices as a whole have declined 40% since 2014.

The type of battery selected by the project will depend on the intended purpose because certain technologies are better suited for certain purposes. For example, batteries with long charge-and-discharge cycles work best for energy supply shifting and household solar PV, while batteries with short charge-and-discharge cycles are best for short-term regulation of the grid and frequency response.

US energy storage capacity is expected to reach 7,300 MWhs in 2022 compared to 336 MWhs today.

Because batteries are made up of chemicals, operating conditions can have a big impact on performance. The role of the asset manager is to optimize dispatch. The asset manager is a key player. Lenders will want to evaluate its credentials and track record. Given the nascent nature of the industry, many of these companies are startups.

Some companies that act as asset managers are both developers and dispatch managers. Examples are Advanced Microgrid Solutions, Stem and Green Charge Networks. Integration of the developer and asset manager roles can offer a competitive advantage. The companies can size the battery from the beginning by taking into account how they will optimize dispatch once the battery is operating.

A key operating parameter is the battery's depth of charge. This refers to the amount of total capacity that remains, usually expressed as a percentage. For example, a battery with a 90% DoD has 90% of its total capacity remaining. Different uses require different DoD. In general, the greater the DoD required

by a particular use, the faster the degradation of the battery and the more frequently the battery has to be replaced. It is good to look for a battery operator that knows the best operating parameters for the particular battery in question. Most battery developers offer O&M service for their batteries. Some developers may also be willing to provide a capacity guaranty.

Technical risk should be mitigated by a manufacturer's warranty. Tesla offers 10-year warranties for its batteries. Ten years is generally the market standard at this time.

Holdco Loans: Trends And Issues

by Jim Berger, in Los Angeles

Most renewable energy projects in the United States are financed with a combination of equity, tax equity and debt. Increasingly, the debt is holdco debt (also called back-levered debt), meaning the borrower is not the project company but rather an entity higher up in the corporate structure.

For some time, holdco debt was only term debt and the construction debt remained at the project company. However, the structures have evolved so that, in many transactions today, even construction debt is at the holdco level for simplicity of documentation and structuring.

Such debt is structurally subordinate to the tax equity financing, creating issues for lenders.

This article addresses trends and issues that have emerged recently in negotiating holdco loans.

Structures

Holdco loans can take more than one form.

When holdco loans were first starting to be used, there were usually different loan agreements at the project company level and the holdco level. A construction loan agreement and separate holdco loan agreement were sometimes signed at the same time. Funding under the holdco loan agreement was delayed until commercial operations, at which time the construction financing was paid off and the tax equity investor made its full tax equity investment. The holdco borrowing and the tax equity investment were used to repay the construction loan.

A variation on this early structure is sometimes still used. For

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see "Batteries and Tax Credits" in the October 2016 *NewsWire*.) An industry proposal to allow tax credits on standalone storage at the federal level is facing long odds in the current Congress. (See "Tax Credits Proposed for Energy Storage" in the August 2016 *NewsWire*.)

OFFSHORE WIND costs continue to fall.

The projected costs of two wind farms that won long-term power contracts for projects off the Maryland coast suggest installed costs of $5.5 to $6 million a megawatt.

The Maryland Public Service Commission awarded 20 years of offshore wind renewable energy credits, or "ORECs," at a levelized price of $131.93 a megawatt hour that the owners of the two projects can sell to Maryland utilities that will need the credits to comply with the state's renewable portfolio standard. The state RPS requires utilities to deliver at least 25% of the electricity they supply from renewable sources by 2020. Up to 2.5% of the electricity must come from offshore wind.

US Wind plans to build a 248-megawatt project at a cost of $1.375 billion using four-megawatt turbines. The company hopes to have completed the project by January 2020. Skipjack Offshore Energy, a Deepwater Wind affiliate, plans to build a 120-megawatt project at a cost of $720 million using eight-megawatt turbines. The Skipjack project has a target completion date of November 2022.

German utility Energie Baden-Württemberg AG — called EnBW — won a bid for a 900-megawatt offshore wind project in the North Sea in April without any subsidy, and Danish wind developer DONG Energy won two German offshore wind projects with zero-subsidy bids. The EnBW project does not have to be on line until 2025. The two DONG projects have until 2024. Both companies expect the cost of offshore wind turbines to have fallen enough by the time they must start construction to make the projects economic. By then, 13- to 15-megawatt turbines may be available. An

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Holdco Loans

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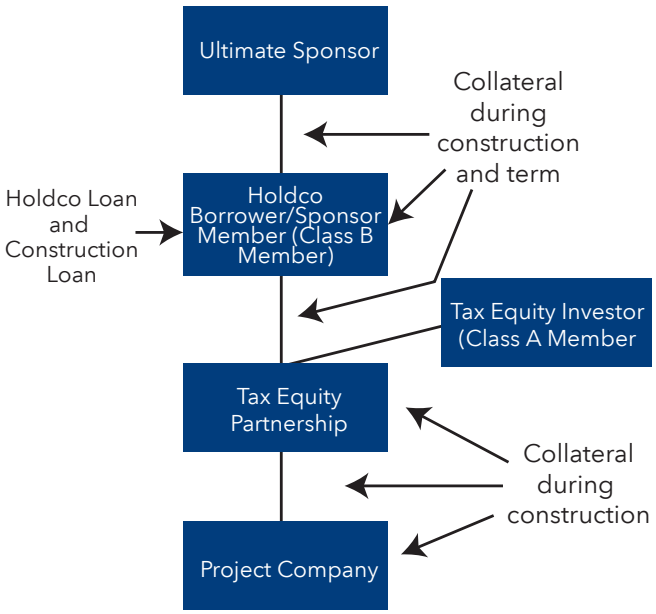
example, if there is no tax equity commitment in place at financial close either because the construction period is too long for tax equity to commit or the sponsor has simply not been able to obtain a tax equity commitment, the construction financing will be at the project company level. Once tax equity is found, the holdco borrower enters into a new holdco loan agreement or the existing loan agreement at the project company level is assumed by the holdco borrower. A number of issues arise when deciding how to alter or move the debt from the project company to the holdco borrower. They include fees, continuity of security and how the lenders' commitments are booked internally.

Another reason the early structure may still be used is to get around a tax problem created in situations where the sponsor has to guarantee repayment of the project debt. Under US tax law, when that sponsor enters into a partnership with a tax equity investor to own the project, the fact that the project debt is guaranteed will require an amount of depreciation on the project roughly equivalent to the debt to be allocated to the sponsor. This could also drag tax credits with it to the sponsor. It undermines the tax equity financing because there are fewer tax benefits to allocate to the tax equity investor. Moving the debt to the level of the sponsor partner after the project has been placed in service avoids the problem.

In order to streamline the documentation, most recent deals put both the construction and term debt at the holdco level. This reduces complexity because only one set of financing documents is required and there is no need to work through issues surrounding moving the debt from the project company level to the holdco level.

This structure still provides the lenders with typical construction loan-type collateral. During construction before the tax equity fully funds, the lenders have security in all assets of the project company, the entity that is or will become the tax equity partnership and holdco borrower and a pledge of the equity in the holdco borrower. Upon commercial operation (and repayment of the construction loan and conversion to the term loan), the collateral at the tax equity partnership and project company level is released so that the term lenders have a lien solely on the assets of the holdco borrower (meaning its interest in the tax equity partnership and all bank accounts) and the equity in the holdco borrower.

This structure is shown below.



Holdco loans emerged primarily because market terms for forbearance between project-level lenders and tax equity investors fell apart, forcing virtually all term debt to be junior to tax equity. There has been some movement in the market back toward leveraged tax equity transactions where the term debt is ahead of the tax equity in the capital stack. However, such transactions still remain rare.

Whether the debt is ahead of or behind the tax equity requires negotiation of inter-creditor issues. In cases where it is ahead of tax equity, the tax equity requires the lenders to agree to forbear from foreclosing on the project assets before the tax equity investor has had a chance to reach its target yield. The lenders can step into the sponsor role as managing member of the tax equity partnership in the meantime. In cases where the debt is behind the tax equity, then a consent will have to be negotiated governing terms for the lenders to be able to foreclose on the sponsor interest in the partnership. This is needed because the tax equity partnership agreement will restrict changes in control of the sponsor partner without tax equity consent. In some transactions, the equivalent of a consent is negotiated in the partnership agreement. Another issue is there are usually situations where the tax equity investor can sweep cash at the partnership level, leaving too little cash to pay debt service on the holdco debt.

Issues

Holdco loans raise issues that are not present with loans at the project company.

For example, if the project requires letters of credit such as the credit support required under a power purchase agreement and the LC is part of the holdco loan arrangements, then repayment of any loan resulting from a draw on the letter of credit should receive priority repayment. Sometimes the repayment will be classified as an operating and maintenance expense. The reason is that, despite technically being a financial obligation of the holdco borrower, it is in reality an operation and maintenance-type obligation of the project company and should be repaid senior to the payment of any amounts due to the tax equity investor.

Another unique feature of holdco loans is the insurance provisions. Lenders usually want to control whether and how a project is rebuilt after a casualty or whether insurance proceeds should be used instead to repay the debt. However, the tax equity may not see why a lender who is subordinate to it in the capital structure should have a say in such decisions.

The tension spills out in a number of ways. The holdco lenders will not want the tax equity investor to be named as a loss payee on the insurance policies to ensure any insurance proceeds are not paid directly to the tax equity investor. The lenders will want the project company or the tax equity partnership to be named as sole loss payee.

If the tax equity partnership agreement specifies when insurance proceeds will be used to rebuild the project, then the holdco lenders will want to be comfortable that the rebuilt project will still be able to service the debt and, if the project is not rebuilt, enough insurance proceeds will be distributed to the sponsor partner to pay off the outstanding holdco debt. The lenders will almost never find it acceptable for there to be a flat requirement to rebuild the project. Any discretion the sponsor partner has, as managing member of the partnership, whether to rebuild will need to be subject to the approval of the lenders.

Cash Sweeps

Because holdco loans are structurally subordinate to the tax equity, potential cash sweeps and cash diversions at the tax equity partnership level are of the utmost importance to the lenders.

The most common cash sweep is for unpaid indemnity claims. The market has generally moved toward a 50% or 75% cash sweep for unpaid indemnity claims. This */ continued page 20*

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additional savings for DONG is it will not have to build new transmission lines to bring the electricity to shore.

Meanwhile, citizens groups, called Bürger initiatives, won 93% of the 807 megawatts in contracts for new onshore wind farms that were put up for auction in Germany in May. The bids were 2 1/2 times oversubscribed. The average accepted bids were for the equivalent of US6.36¢ a KWh. The auctions are an effort by the German government to wean the renewable energy industry from subsidies. Bürger initiatives are groups of up to 10 private individuals.

A WOOD PELLET COMPANY can operate as a master limited partnership, the IRS said.

The IRS made the statement in a private letter ruling issued to a company that turns raw logs, wood chips and sawdust into wood pellets and then sells the pellets in bulk to retailers. The company also debarks logs that it chips and then the sells the wood chips and bark to one or more wholesale customers. Sometimes it simply earns a fee for chipping and debarking logs belonging to the customers.

MLPs, or master limited partnerships, are large partnerships whose units are publicly traded. No taxes are collected at the entity level. Rather, earnings are taxed directly to the partners. MLPs must receive at least 90% of their income each year from good sources. Good income includes rents from real property, interest, dividends and from "exploration, development, mining or production, processing, refining, transportation . . . or the marketing of any mineral or natural resource (including fertilizer, geothermal energy, and timber)." Companies organized as MLPs can raise equity at high multiples to earnings because no taxes are taken out of the earnings at the company level.

The IRS said the income the company expects to earn from its wood pellet and chipping businesses is good income. The ruling is Private Letter Ruling 201722023. The IRS made it public in early June. */ continued page 21*

Holdco Loans

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means that 50% to 75% of the cash that would otherwise be distributed to the sponsor partner would instead be swept to the tax equity investor to cover any unpaid indemnity claim. However, some tax equity investors still require a 100% cash sweep. The risk profile of a given project may also lead to a high cash sweep percentage.

A 100% cash sweep is never acceptable to the lenders because this could leave the sponsor partner with no funds to service the holdco debt. If the cash sweep percentage does not leave enough money to service the debt, then there must be another feature to protect the lenders, which can come in the form of a guarantee from the sponsor if the sponsor is creditworthy, another form of credit backstop, or a cash-backed letter of credit that can be drawn by the lenders.

Another cash sweep that has become more important since the November election is a cash sweep for failure to flip by the target flip date. This would only occur in a partnership flip transaction that is yield based rather than time based. If the flip does not occur by a target date, then most or all of the cash after that date may be swept to the tax equity investor. If the debt matures before the target date, then this cash sweep only concerns the lenders to the extent there is a chance the project will underperform and the debt maturity will be extended past the target flip date.

Transfer Restrictions

The lenders' most important collateral during the term loan is the interest the sponsor partner holds in the tax equity partnership. Consequently, the ability to foreclose on and subsequently transfer this collateral is extremely important because the sale of this collateral may be the only way for the lenders to recover their investment after a default.

Tax equity partnership agreements restrict changes in control of the sponsor partner without tax equity investor consent. There are extensive transfer provisions in every partnership agreement with which lenders must comply in a foreclosure or subsequent transfer after foreclosure.

Tax equity investors generally take one of two approaches with respect to lender transfer provisions. The first approach is to view lender transfers no differently than any other transfer of the sponsor interest in the tax equity partnership. Under this approach, lenders generally have to satisfy the same requirements that the sponsor would have to satisfy if it were to transfer its interest in the tax equity partnership. Some tax equity investors will make minor accommodations for the lenders.

The second approach is to write a separate set of transfer provisions specifically governing a lender foreclosure and subsequent transfer. Under this approach, the transfer restrictions are generally relaxed for a lender foreclosure and subsequent transfer compared to other transfers of the sponsor interest in the tax equity partnership.

There are still extensive negotiations around the details in either case. In situations where there are no special lender transfer provisions written into the tax equity documents, a smart sponsor usually insists that the tax equity investor consent in advance to a change in control after a default on the holdco debt. The main issues come down to the financial tests that must be satisfied by the entity the lenders use to foreclose and any subsequent transferee as well as what experience the subsequent transferee must have operating the types of projects involved.

Forbearance

Even with a holdco loan, there may still be forbearance issues between debt and tax equity if the lenders expect to retain project-level collateral until the project reaches commercial operation.

The tax equity investor must be a partner for tax purposes before the project is placed in service in order to share in any investment tax credit on the project. A utility-scale project is usually considered placed in service when it reaches substantial completion under the construction contract. Tax equity investors in solar projects, on which investment tax credits are claimed, usually stage their investments. They invest 20% before the project is placed in service and 80% after.

The lenders may still be holding a security interest in the project directly until the 80% investment is made.

Some tax counsel may not allow the lenders to hold a security interest in the project directly during this interim period because it looks like the sponsor to still treating the assets as if it owns them directly.

If the lenders still have a direct security interest in the project assets, a debt default could lead to the lenders taking the assets. This possibility leads to a tense negotiation over whether tax equity has the ability to cure the debt default and under what circumstances and for how long the lenders must forbear from exercising remedies.

One approach taken in some deals is for the lenders to be given the right to buy out the tax equity by repaying the tax equity the

Back-levered debt in renewable energy projects creates tension with tax equity investors.

amount of their investment. However, this may be viewed as an unwind that calls into question whether the tax equity investor is really a partner during the period its investment may be unwound in this fashion. In some transactions, the tax equity investor proceeds have been placed into an escrow account and can be used to repay the tax equity when it is bought out by the lenders. Any such escrow would have to belong to the sponsor and the interest earned on the account reported by the sponsor as income. Even then, the arrangement may be viewed as not a real investment by the tax equity investor until the escrow is released. Other steps can be taken to reduce this risk.

Tax Reform

Congress is expected to reduce the corporate income tax rate and make other changes in the US tax code, although when this will happen is unclear.

There are two potential effects on holdco loans.

One is the effect on the actual tax benefits claimed in renewable energy projects, like tax credits, depreciation and interest deductions.

The other effect is a change in the federal corporate income tax rate.

The timing of any tax reform complicates any analysis.

Most of the market believes that Congress is unlikely to alter the current timetable for phasing out production tax credits and investment tax credits for renewable energy projects. Production tax credits are already being phased out and the investment tax credit for solar is scheduled to start phasing out after 2019. (For more detail about the phase outs, see "Tax Credits Teed Up For Extension" at https://www.chadbourne.com/tax-credits-teed-up-extension-121615.)

If the tax credits were to be changed before the tax equity funds, then it could be grounds for the tax equity not to fund or lead to a lower tax equity investment. Either way, there would be a hole in the capital structure that would */ continued page 22*

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The IRS said the ruling would not apply to income earned from making retail sales of wood pellets or chips directly to end users.

The company is planning an initial public offering.

AN ARIZONA APPEALS COURT said property taxes do not have to be paid on most rooftop solar systems in the state.

The Arizona Department of Revenue insisted the systems are "renewable energy equipment" that is subject to annual property taxes on 20% of the depreciated cost.

State law defines "renewable energy equipment" as "electric generation facilities" that produce solar electricity "not intended for self-consumption." The court said most rooftop solar systems are not picked up by the property tax statute because they supply electricity to the occupants of the buildings or houses where the systems are mounted. It does not matter, the court said, whether a solar company owns the system and leases it to the homeowner or other building occupant. The solar rooftop companies use leases rather than power purchase agreements in Arizona.

The court rejected an argument that the state constitution requires property taxes to be collected on the systems. The Arizona constitution has an exemptions clause that says property not specifically exempted from taxes by the legislature is subject to tax. The court said just because the legislature can tax property does not mean it has chosen to do so.

The state constitution also has a uniformity clause that bars discrimination against similarly-situated taxpayers. The court said someone who uses a rooftop system to generate electricity for his own use is not similarly situated to a utility whose business is generating electricity for sale.

Arizona allows homeowners with extra electricity to send it to the grid through net metering, meaning the electricity meters runs backwards, effectively giving the homeowner credit at the retail rate for ***/ continued page 23***

Holdco Loans

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have to be filled. If the sponsor does not contribute additional equity, then there would be a default on any construction debt.

A reduction in the future value of production tax credits, which are claimed over 10 years, could reduce the amount of the term loan if production tax credits are taken into account in sizing the term loan. To the extent the tax equity investor does not have tax credits to help it reach its flip yield, then it will need to draw on more cash to do so. Many term lenders are not sizing debt based on potential tax changes.

A reduction in the corporate tax rate would have two effects on holdco lenders.

The first is an effect on the broader renewable energy financing market. If corporations in general are required to pay less in taxes, this could lead to a smaller tax equity market, which could lead to increased tax equity yields and fewer projects getting financed. However, a reduction in tax rates would probably not reduce the amount that the largest tax equity investors have available to invest.

The more immediate impact on holdco lenders is a reduction in the value of depreciation deductions that are a significant portion of the tax equity return. A dollar of depreciation is worth 40% more at a 35% tax rate than at a 25% tax rate. This affects both production tax credit and investment credit deals because both types of transactions rely on depreciation as a source of tax equity return.

The timing of a change in corporate tax rate is important. A change in the tax rate before or soon after a project is placed in service is more likely to reduce the amount of tax equity financing that can be raised. A change after a project has been operating for a while is more likely to accelerate the flip date and leave more cash to service back-levered debt. (For a more complete analysis, see "The Market Reacts to Possible US Tax Reforms" in the February 2017 *NewsWire*.)

A separate tax change issue that occasionally comes up during negotiations is a provision that increases the amount of cash distributed to tax equity if there is a change in tax law that slows future depreciation. This is not a common provision and is the result of a proposal by former Senator Max Baucus, who stepped down as chairman of the Senate tax-writing committee to take up the post of US ambassador to China in February 2014, to move to "pooled" depreciation. Under pooled depreciation, all equipment would be put into one of four asset pools. Each year, a company would deduct a fixed percentage times the aggregate unrecovered cost of assets in the pool. Any new capital spending on equipment during the year would be added to the pool. The change would have affected existing assets.

The Baucus bill would have slowed depreciation. Senator Ron Wyden (D-Oregon), who replaced Baucus as the senior Democrat on the tax-writing committee, introduced his own pooled depreciation bill in 2016 that would have accelerated depreciation of renewable energy projects. (For earlier coverage, see "US Tax Changes Start to Take Shape" in the December 2013 *NewsWire* and "Wyden Proposes Depreciation Revamp" in the June 2016 *NewsWire*.)

Other Items

The US government will move to assessing partnerships directly for any back taxes the partners are found to owe after a partnership audit starting in the 2018 tax year. The Internal Revenue Service is tired of chasing partners for these taxes.

Holdco lenders are interested in how the IRS implements the new system. In particular, partnerships can elect one of three or four alternative procedures under the new rules. If the tax equity partnership is responsible for paying taxes that the tax equity investor should have paid directly, it would reduce the amount of cash available for distribution to the sponsor partner and potentially leave too little cash to service the back-levered debt.

Many lenders require the partnership "push out" any tax liability to the partners directly by making an election under section 6226 of the US tax code. The election causes audit adjustments to be the responsibility of persons who were partners in the tax equity partnership during the tax year under audit.

Most Holdco loans have a tenor of around seven years, but tenors can range from five to 10 years.

Some holdco loans fully amortize. Others have a bullet payment due on the maturity date, which would typically require a refinancing. In all cases, these variables are determined by the financial model.

The pricing of holdco loans is mostly in the range of LIBOR plus 2% to 3% currently. The variations in pricing are typically based on the perception of risk, which includes variables such as sponsor experience, counterparty default risk and the result of negotiations with tax equity. Some start as low as LIBOR plus 1.75%, but this requires an exceptionally strong financial profile. In addition, the margin typically increases between 12.5 and 25 basis points every three or four years to encourage repayment as quickly as possible. ◎

Tax Change Risk in Tax Equity Deals

by Keith Martin, in Washington, and Amanda Rosenberg, in Los Angeles

A review of 16 renewable energy tax equity deals since tax change risk became a major concern for tax equity investors after President Trump was elected shows that there is a common set of issues, but the market is all over the map on how it addresses them.

In the meantime, the likelihood that Congress will be able to pass a tax reform bill this year is receding quickly. White House economic adviser, Gary Cohn, said on June 2 that the Trump administration plans to submit a detailed tax plan to Congress in early September after spending the summer working with Republican leaders in the House and Senate in an effort to come up with a common plan that can clear both houses.

The last major tax overhaul in 1986 took 13 months from when the House tax-writing committee started voting on a detailed plan and when the bill was signed by the president.

There may be some further evolution in how tax equity deal papers deal with tax change risk if it becomes clear that tax change risk is a 2018 or later problem.

Thirteen of the deals were partnership flip transactions. One has a fixed flip date. The others flip when the tax equity investor reaches a target yield.

Three of the deals are sale-leasebacks of utility-scale solar projects.

Funding Conditions

All of them make it a condition to each funding by the tax equity investor that there has not been a material adverse change in tax law before the funding. Most make it a condition that there has also not been a material adverse proposed change in tax law.

How early in the legislative process a proposal can be an excuse not to fund varies. All the deals pick up a proposal after it has been reported by either tax-writing committee in the House or Senate. Most pick it up at the point it is proposed by the chairman of either tax-writing committee. Some go earlier in the process and pick up proposals by the Trump administration. Some pick up a proposal in an executive order, a budget resolution or formal administration or leadership proposal. None treats a tweet or the one-page tax "plan" the administration released to great fanfare in late April as a tax reform proposal.

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the electricity going to the grid. The Arizona Corporation Commission, which regulates the power sector, bars rooftop systems from producing more than 125% of the annual electricity consumption at a location. The solar rooftop companies say they design systems to produce less than 100% to ensure compliance.

The case is *SolarCity Corporation v. Arizona Department of Revenue*. Sunrun joined SolarCity in challenging the tax. The two solar companies sought a declaratory order from the courts that property taxes do not apply. They lost in the state tax court, but won on appeal. The appeals court released its decision in mid-May.

SOLAR surpassed wind for the first time last year in terms of new capacity additions worldwide.

Solar was up 42% over wind, according to the "Global Market Outlook 2017" released in late May by SolarPower Europe.

The top four countries for solar in 2016 were China, which accounted for almost half of new capacity additions, the United States at 19.32%, Japan at 11.23% and India at 5.87%. New solar installations in the United States were up 97% in 2016 compared to 2015.

GTM Research says that the average EPC pricing for utility-scale fixed-tilt solar facilities in the US was $1.00 a watt at the start of the year and is projected to fall to 90¢ a watt by mid-year and to 80¢ by 2020. Tracker systems are expected to cost $1.08 on average by mid-year.

The average residential solar system was sold for $3 to $3.50 a watt in the United States in 2016. This compares to an average of $2 a watt in Europe.

Attila Toth, CEO of PowerScout, a platform for home improvements, argued in Greentech Media in April that the residential rooftop sector is due for a "radical makeover." He says only 4% of the purchase price for the average automobile goes to cover sales and marketing, while 17% — some people say as high as 25% — of the price of a rooftop solar installation is the cost of customer acquisition. Solar panels account for 10% to 25% of the system cost.

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Tax Equity

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Most make it a condition to use a proposal as an excuse not to fund that the proposal must be reasonably likely to be enacted. Others say a proposal cannot be used as an excuse not to fund if "it is reasonably clear it will not become law." Another variation is that a proposal must be "not unlikely to be enacted." There is no standard for determining whether this subjective element has been satisfied. Rather, the objective test of how far the proposal has moved in the legislative process acts as a check on what is considered a proposed change in tax law for purposes of the tax equity papers.

In many deals, a proposed or actual change in tax law is not an excuse to stop funding if it can be reflected in the pricing model.

Pricing and Repricing

In all the deals, the pricing model is re-run before each funding to reflect actual changes in tax law and, in many cases, proposed changes.

Focusing on initial pricing, in close to half the deals the tax equity investor is already assuming a reduced corporate tax rate in the range of 20% to 28%. In some deals, the rate is assumed to be 35% in 2017 and 20% in 2018 and later years. In half the deals, the tax equity investor prices based on current law.

Wind deals are more likely to assume reduced rates. Solar deals are more likely to be priced at current tax rates. A panel of tax equity investors at the SEIA finance and tax workshop in New York in early June said that they are prepared to go either way based on the desires of the sponsor and other factors.

In many deals, there is a one-time repricing and the tax equity investor may be required to invest more if the final tax rate is higher than was assumed for initial pricing. The investor can almost always sweep cash to return any amount it over invested if the final tax rate is lower than originally assumed for pricing. In some deals, the transaction is re-optimized and the sharing ratios are adjusted before any cash sweep.

This repricing usually occurs when the current Congress ends at the end of 2018 or, if earlier, when a corporate tax reform bill clears Congress. In some deals, the model may be re-run through the end of 2019 or 2020. One tax equity investor is seeking tax-change protection for six years. The investor also takes into account in its original pricing a mixture of adverse tax law changes in different proposals. It can mix and match, choosing a combination of the most adverse proposals.

The repricing usually takes into account not only a change in tax rates, but also cost recovery and tax credits. Interest deductions are also in play in the current tax reform debate. Alternatively, the repricing may use any changes that improve the tax equity investor's position as an offset against negative changes, but not as a basis for requiring the investor to make an additional investment.

Sometimes the original pricing remains unless the tax law changes are projected to delay the target flip date by more than three months or some other period.

In one deal that used current tax rates, the parties agreed to work in good faith to restructure the deal if tax rates are reduced by 10% or more post-funding. If sharing ratios cannot be adjusted enough for the tax equity investor to maintain its investment targets, then there may be a cash sweep to give the tax equity investor back the amount it overinvested. The sweep is usually a sweep of 100% of cash.

If a tax law change occurs after the final re-running of the model, then the flip date will be delayed or accelerated from what was anticipated. For example, a lower tax rate two or more years after closing is more likely to accelerate the flip date, especially if the tax equity investor has taken a depreciation bonus.

A cash sweep, adjustment to the cash sharing ratios or delayed cash flip can cause problems in a transaction where there is back-levered debt at the sponsor level. Some back-levered lenders have been requiring "cash diversion guarantees" from the sponsor's parent to cover any reductions in cash flow to the sponsor member as a result of tax law changes. In some back-levered deals, sponsors are reserving the right to make capital contributions to the tax equity

Sixteen tax equity deals since the election address the potential for tax reform in different ways.

partnership for immediate distribution to the tax equity investor as a way of eliminating or reducing deferral of the flip date. At least one set of deal papers signed before the election was amended to allow for such a contribution by the sponsor and distribution to the tax equity investor.

Mitigating Features

In almost all of the deals, the tax equity investor takes a depreciation bonus to accelerate deductions into 2017 before tax rates change as a way of mitigating tax-rate-change risk. The math may not work in deals with portfolios of projects. Claiming a bonus on all the projects may push the capital account of the tax equity investor into deficit in year one, potentially causing tax credits to shift to the sponsor along with a share of the year-one losses. In some cases, a bonus is claimed on fewer than all the projects, as a way of avoiding this problem, by putting one or more of the projects in separate partnerships below the tax equity partnership.

Electing bonus depreciation can lead to loss absorption issues for the tax equity investor. Each partner in a tax equity partnership has both a "capital account" and an "outside basis." These are two ways of tracking what the partner put into the partnership and what it is allowed to take out. When a partner's capital account hits zero, then any further losses that would be allocated to the partner shift to the other partner. Taking the depreciation bonus causes a capital account to reduce more quickly. One solution in many tax equity deals is for the tax equity investor to agree to a deficit restoration obligation, or DRO. A DRO is a promise by a partner to contribute more capital to the partnership at liquidation if the partner has a deficit capital account. A partner is allowed to take losses up to the amount of its DRO after its capital account hits zero. DROs in the current market can hit 40+%.

In wind deals, pay-go structures are sometimes being used as a way to mitigate tax change risk. This means the amount the tax equity investor invests is tied partly to the tax credits it is allocated. IRS rules allow no more than 25% of the total tax equity investment to be tied to tax credits or output. In at least one deal, the tax equity investor must make pay-go payments after the flip date if the flip date occurs before the 10-year period for production tax credits has run. This is a way of addressing the potential for tax law changes to leave the tax equity investor with a windfall. In other deals, use of a pay-go structure may be a way for the investor to defer part of its investment until the tax law is clearer.

In two deals, the sponsor must / *continued page 26*

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US WIND capacity stood at 84,143 megawatts at the end of March 2017, after developers installed almost 2,000 more megawatts in the first quarter.

The 2017 first-quarter additions were the fastest start to a year in any of the last five years and were almost four times the number in 2016.

The rate at which new wind projects came on line started slowly in 2016 and built to a crescendo in the fourth quarter. The figures were 520 megawatts in Q1, 310 megawatts in Q2, 895 megawatts in Q3 and 6,478 megawatts in Q4.

The American Wind Energy Association says that 9,025 megawatts of wind projects were under physical construction and another 11,952 megawatts were in advanced stages of development at the end of Q1 2017.

Texas has 54% of the new wind capacity under construction and 14% in advanced development.

More than half of US wind capacity is in just five states: Texas, Iowa, Oklahoma, California and Kansas.

RECENT US TAX REGULATIONS remain in limbo.

Donald Trump directed the US Treasury in late April to review "all significant tax regulations" issued in 2016 and early 2017 before Trump took office and flag any in an interim report that "impose an undue financial burden" on US taxpayers, "add undue complexity" to the tax laws or "exceed the statutory authority."

The interim report is due June 20.

The Treasury is then supposed to report by September 19 on the specific actions it is taking to cancel or fix the regulations.

Various interest groups have sent the Treasury lists of regulations they would like to see withdrawn. For example, the US Chamber of Commerce sent a list of 12 regulations of which the Chamber wants 11 withdrawn and one revised.

MINOR MEMOS. SSR, an independent investment research company, / *continued page 27*

Tax Equity

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indemnify the tax equity investor for tax law changes through the end of 2018. The indemnity is sized to refund to tax equity what would have been an overinvestment by it if the tax law changes had been taken into account when the initial pricing model was run.

In partnership flip transactions, there is a list of "fixed tax assumptions" that are used for tracking when the investor reaches its flip yield. It was almost always a fixed tax assumption in the past how depreciation is calculated in the base case model. In many of the latest deals, depreciation is no longer a fixed tax assumption or, if it is, it is a fixed tax assumption only as long as the depreciation rules are not changed.

Developers Are Watching Two FERC Proceedings

by Caileen Gamache and Jacob Yaniero, in Washington

Two initiatives that have the potential to affect project developers are currently stalled at the Federal Energy Regulatory Commission, but should start to move once recent Trump nominees are confirmed to fill vacancies.

The commission is in the process of updating its policies on interconnecting independent power plants to the transmission grid. The existing policies date to 2003.

FERC is also grappling with a debate that has spilled over to the federal courts about the extent to which states can adopt policies that favor certain types of generation over other types. The debate has the potential to affect renewable portfolio standards that favor renewable energy.

Multiple Vacancies

The commission needs at least three members to have a quorum required to do business. It has had just two of five commissioners since February.

Cheryl LaFleur is the acting chairwoman, and Colette Honorable is the other commissioner, but Honorable has announced she will not seek reappointment at the end of her current term, which ends in June.

President Trump nominated a Republican Senate staffer, Neil Chatterjee, who is an advisor to Senator Mitch McConnell (R-Kentucky), and Rob Powelson, a commissioner of the Pennsylvania Public Utilities Commission (and current chairman of the National Association of Regulatory Utility Commissioners) to join FERC. The Senate energy committee is expected to approve their nominations the first week in June. The process may still take several weeks before the nominations are put before the full Senate for a vote.

They might be joined by a third rumored Republican pick, Kevin McIntyre, an energy attorney currently in private practice.

Based on campaign promises, transition team statements and industry appeals, the re-constituted FERC is likely to prioritize energy infrastructure development, grid reliability, cyber security and wholesale market design.

Some groundwork on two initiatives of particular interest to project developers has already been laid.

Interconnection

FERC issued a notice of proposed rulemaking, or "NOPR," in December 2016 indicating that it plans to update its regulations governing interconnection of large generators, meaning greater than 20 megawatts, to the utility grid. The proceeding is in Docket No. RM17-8-000.

Large generators use a form agreement called a Large Generator Interconnection Agreement, or "LGIA," that FERC prescribed in 2003 based on negotiations between the Edison Electric Institute and representatives from the independent generators.

FERC proposed 14 separate reforms in its notice of proposed rulemaking. The reforms are designed to address "concerns with systemic inefficiencies and discriminatory practices" expressed by independent generators, changes in technology and the generation resource mix and the frustration expressed by utilities dealing with late-stage queue withdrawals.

FERC wants to give generators greater control over the timely construction of interconnection facilities by making it easier for generators to build interconnection facilities themselves: the so-called self-build option. FERC also wants utilities to coordinate with neighboring transmission systems (known as "affected systems") earlier in the interconnection process to avoid unanticipated delays and expenses for generators. Although not part of the proposed rule, FERC also requested comments on whether it should impose a cap on the amount of network upgrade costs that may be assigned to a generator. This should facilitate planning and mitigate serial re-studies.

FERC wants to improve transparency by increasing communication and information access. For example, it proposes to require owners of transmission lines to post congestion and curtailment information all in one place on their Open Access Same-Time Information System (OASIS) sites and to publish specific study processes and inputs to network models that are used for interconnection studies. Better up-front communication of information should hasten queue speeds and allow affected parties to predict the timeline for interconnection more accurately.

Another proposed reform is a requirement for utilities to offer provisional interconnection agreements to allow generators to operate on a limited basis before completion of the full interconnection study process. This could make a significant difference in project viability by allowing new power plants to start earning some revenue before the full interconnection process has played out. A few utilities already offer provisional interconnection and, when available, it is generally viewed as a way to mitigate certain development risks.

FERC is rewriting its large generator interconnection agreement.

FERC also wants to tackle interconnection issues specific to emerging technologies and, in particular, energy storage. It proposes to include energy storage as part of the "generating facility" that can interconnect through use of the form LGIA and to require utilities to reevaluate their modeling methods for interconnection studies as related to energy storage. Such reforms would align the LGIA with the interconnection agreements and procedures for small generators and may mitigate key risks in the financing of energy storage projects, as discussed in a separate article in this issue called "Financing Energy Storage Projects: Assessing Risks" starting on page 12. This proposal is somewhat more controversial than some of the others in the NOPR as many still question whether it is too restrictive to put energy storage in the "generation" box when storage is */ continued page 28*

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estimated in May that electrification of the entire 260 million US vehicle fleet would increase electricity demand by a third . . . . The North American Electric Reliability Corporation says in its "2017 Summer Reliability Estimate," released in late May, that US electricity reserve margins this summer range from a high of 31.91% in SERC-SE, the part of the grid covering all or portions of Alabama, Mississippi, Georgia and Florida, to a low of 17.45% in ERCOT, which serves Texas. ERCOT is projecting reserve margins above 18% in four of the next five years. ERCOT total generating capacity is 82,000 megawatts. The 2017 summer peak demand is expected to reach 73,000 megawatts.

— contributed by Keith Martin in Washington

FERC

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able to function in other capacities, such as transmission and load.

Many companies filed comments in response to the NOPR, but FERC is currently unable to act due to lack of a quorum. The newly-constituted commission will have no obligation to advance the proposal, but it will be difficult to ignore. The NOPR includes a preliminary finding "that certain interconnection practices may not be just and reasonable and may be unduly discriminatory or preferential," in violation of the Federal Power Act. At a minimum, the new commissioners may be pressured to explain any contrary conclusions.

State Incentives

FERC held a technical conference in early May to discuss the contentious interplay of state incentives for particular types of generators and federally-regulated competitive wholesale markets. The discussion generated some heat, mirroring escalating tensions in the industry more broadly.

In one corner sit states with the power under the US constitution to protect the health and welfare of their citizens. This power has been deployed broadly to reduce environmental pollutants, support important industries and ensure reliable energy supply. State regulators, in turn, must execute state laws enacted pursuant to this power.

In the other corner is FERC, an independent agency charged by federal law to ensure all rates for the wholesale sale of electricity are "just and reasonable" and "not unduly discriminatory or preferential." Independent generators typically align with FERC, viewing state subsidies as discriminatory and skewing market signals.

The Supreme Court stepped in to referee last year in *Hughes v. Talen Energy*. FERC won that round. The court threw out a Maryland program designed to secure in-state capacity by directing a utility to pay a generator the difference between an established "strike" price and the price it received through participation in the wholesale power market operated by PJM.

The narrow decision failed to provide the industry much guidance, and states continue to seek ways to work around the markets and advance their internal policies while avoiding this precedent. For example, New York established a program to encourage three nuclear power plants to remain operating by establishing "zero emission credits" that have led to nearly $1 billion in payments to the plants on top of the revenue they earn from electricity sales. This approach was also adopted by Illinois regulators, and both programs are being challenged in court. Other states are considering similar programs.

The notice of the technical conference said the "Commission staff seeks to understand the potential for sustainable wholesale market designs that both preserve the benefits of regional markets and respect state policies." It laid out a "spectrum" of solutions, ranging from administering wholesale markets in a manner that incorporates and satisfies state policy goals to designing wholesale markets to avoid conflicting with state policies. Several options along this spectrum were discussed at the conference, with no clear consensus.

State regulators, not surprisingly, were vocal about preserving states' rights to make policy decisions for the benefit of their citizens. For example, the chairperson of the Illinois Commerce Commission said, "FERC should adopt a policy that requires [regional transmission organization (RTO)] energy and capacity market designers and operators to account for state energy policies."

One obstacle to requiring RTOs to accommodate state policies is RTOs operate across state lines and individual state policies differ in terms of targeted resources, types of incentives, implementation and ultimate goals. It would be particularly challenging for a multi-state RTO such as PJM to operate in a manner that promotes competition to ensure adequate resources across the system at least cost, yet avoids conflict with all state laws within its 14-state footprint.

The chairwoman of the Massachusetts Department of Public Utilities described an effort among the commissions from several New England states to align on policies. She said members of the Integrating Markets and Public Policy (IMAPP) initiative are trying to determine whether a consensus can be reached on state policies among the New England states that might be advanced broadly by ISO New England (ISO-NE), their RTO. Each of the states involved has state renewable standards or emission reduction laws or both.

Representatives from the RTOs were skeptical about the possibility of preserving the benefits of competitive wholesale markets while accommodating state policies. A pre-conference statement by ISO-NE expressed concern about the entry of subsidized market participants undermining cost-effective price formation in the ISO-NE's forward capacity market: "[I]f current investors, after incurring the sunk costs of entry, face state-subsidized competition that depresses their capacity market

revenue, then future investors (in unsubsidized resources) may logically hesitate to develop new capacity, require greater risk premiums, or only offer to develop new capacity at such a high price as to recover their total costs and return on equity within a short, initial capacity price lock period. This risk could raise the net cost of new entry substantially over time, and inefficiently undermine the cost-effectiveness of competitive markets to the detriment of society overall."

ISO-NE has indicated on other occasions that the lack of financeable projects raises resource adequacy concerns within the region. The possibility of a carbon cap and trade system was raised as a compromise measure, but has its own attendant market risks to consider.

The independent market monitor for PJM was more direct: "The subsidy approach is inconsistent with the PJM market design and inconsistent with the market paradigm and constitutes a significant threat to both."

FERC cannot act in response to the conference until it has a quorum. As such, FERC lacks the ability to challenge state programs that it believes impermissibly affect the wholesale power market, which only the federal government can regulate. In the meantime, all eyes are on the litigation over the zero emissions credit program in New York. (For earlier coverage, see "State Mandates and Incentives" in the December 2016 *NewsWire*.) The case could have far-reaching consequences.

Inverted Leases

by Keith Martin, in Washington

Inverted leases are a structure used to raise tax equity for renewable energy projects. The structure is used mainly in the solar rooftop market.

About 10% to 20% of tax equity transactions in that market today involve an inverted lease.

The other two tax equity structures are partnership flips and sale-leasebacks. All wind and other projects that rely on production tax credits use partnership flips. This is required by statute. Sale-leasebacks are somewhat more common in utility-scale projects, but far less common today than in the past. (For a discussion of these other structures, see "Solar Tax Equity Structures" in the September 2015 *NewsWire* and "Partnership Flips" in the April 2017 *NewsWire*.)

The US government offers two tax benefits for renewable energy projects: a tax credit and depreciation. They amount to at least 56¢ per dollar of capital cost for the typical solar or wind project. Few developers can use them efficiently. Therefore, finding value for them is the core financing strategy for many US renewable energy companies.

Tax equity covers 20% to 85% of the cost of a project. The developer must fill in the rest of the capital stack with debt or equity.

Comparisons

Each of the tax equity structures raises a different amount of tax equity, allocates risk differently and imposes a deadline on when the tax equity investor must fund its investment.

Inverted leases raise the least amount of capital: roughly 20% to 42% of the capital stack. A partnership flip raises 35% to 50% of the typical solar project. A sale-leaseback raises in theory the full fair market value, but in practice, the developer is usually required to return 15% to 20% of the amount at inception as prepaid rent.

The developer may bear more tax risk with an inverted lease or sale-leaseback than a partnership flip. Developers in lease transactions are more likely to have to indemnify the tax equity investor for loss of tax benefits. Tax indemnities are usually more limited in partnership flips. In a flip, the tax equity investor simply sits on the deal with a large share of the economics until it reaches its target yield.

Sale-leasebacks buy the most time to raise tax equity. The tax equity investor must be in the deal before the project is put in service in both an inverted lease and partnership flip. A sale-leaseback gives the developer up to three months after the project goes into service to close on the tax equity financing.

Drilling down into the details of inverted leases: they are a simple concept. Think of a yo-yo. A solar rooftop company assigns customer agreements and leases rooftop solar systems in tranches to a tax equity investor who collects the customer revenue and pays most of it to the solar company as rent.

The two tax benefits on the solar equipment are bifurcated. The solar company passes through the investment tax credit to the tax equity investor as lessee. It keeps the depreciation and uses it to shelter the rents paid by the tax equity investor. That's why the structure raises the least amount of capital.

The diagram on the following page shows a basic inverted lease structure.

Some tax counsel prefer that the customer agreements be power purchase agreements rather than / *continued page 30*

Inverted Leases

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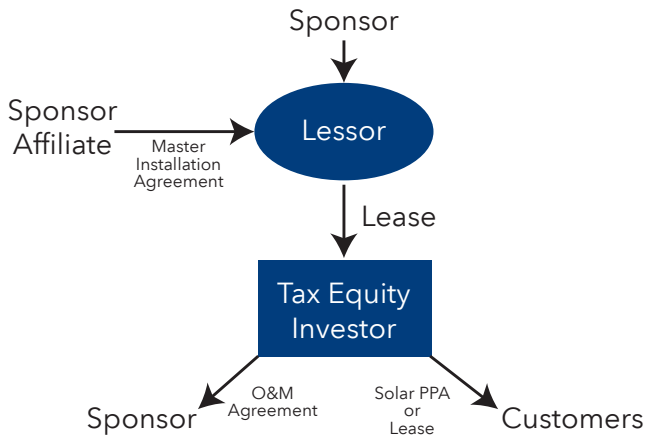


leases. A PPA leaves operating risk with the tax equity investor or inverted lessee. It is important to be able to show that the lessee is exposed to real business risk rather than merely collecting fixed rents from customers.

Most tax counsel also limit the degree to which customers can have prepaid for electricity for the same reason. Many borrow a limit in section 470 of the US tax code that limits the sum of defeasance arrangements, cash reserves, letters of credit, customer prepayments and rent prepayments under the inverted lease to between 20% and 50% of the lessor's tax basis in the projects leased to the tax equity investor. Where particular tax counsel draw the line varies.

The sponsor usually retains responsibility for operating or monitoring the assets and dealing with customers under an operations and maintenance agreement with the lessee. Many tax counsel prefer not to see the sponsor bear the operating costs for a fixed fee. It is better to use a cost-plus-fixed fee approach so that operating costs are passed through to the lessee. The O&M agreement should ideally have a short term — for example, five years — with the lessee then having an option to renew at one-year intervals. It should be the type of agreement that a third party would be willing to assume.

Attractions

Solar rooftop companies like inverted leases because they get the equipment back when the lease ends without having to pay for it.

The solar company can monetize the projected rents by borrowing "back-levered" debt. Such debt may be easier to put in place than a similar borrowing in a partnership flip structure.

Both solar companies and tax equity investors like the relatively short term of the financing.

The primary disadvantages are an inverted lease is a more complicated structure than the alternatives and does not raise as much capital, and fewer tax equity investors offer the structure.

The market was originally drawn to the structure in 2009 as a way for investors without tax capacity to continue doing deals during the Treasury cash grant era when the US Treasury was paying 30% of the tax basis in a project as an alternative to claiming tax credits. The recent drop off in use of the structure is due to a variety of factors.

Not all sponsors can use the structure. Government agencies, tax-exempt entities, Indian tribes and real estate investment trusts cannot elect to pass through the investment tax credit to a lessee.

Normally when a solar company claims an investment tax credit, it must reduce its tax basis in the equipment for calculating depreciation by half the investment credit. In an inverted lease, the tax equity investor reports half the investment credit as income ratably over five years. Some tax equity investors took the position, where the lessee is a partnership, that they can deduct the lessee income inclusion later as a capital loss by withdrawing from the partnership. The IRS put a halt to this practice in temporary regulations in July 2016. (For more detail, see "IRS Addresses an Inverted Lease Issue" in the August 2016 *NewsWire.)*

Inverted leases have terms of seven to 24 years, depending on the counsel acting for the tax equity investor. Some tax counsel like to see a "merchant tail," meaning the lease should run at least 20% longer than the customer agreements. In deals with long lease terms, the lessee usually has an option to cut the transaction short.

The tax equity investor must have upside potential and downside risk to be considered a true lessee. If there is no substance to its role as lessee, then it will not be able to claim the investment tax credit. Some of the big four accounting firms treat inverted lease transactions as loans rather than real leases.

Some tax counsel believe the tax equity investor is a real lessee based on market exposure if the lease runs longer than the customer agreements. Others focus on the amount of prepaid rent that is paid by the lessee and want to see at least 20% prepaid rent. However, too much prepaid rent can make the deal look like a loan.

In more conservative deals, the tax equity investor has a hell-or-high-water obligation to pay fixed rents to the solar company under the inverted lease. In some deals, part of the rent is contingent on output or lessee cash flow; contingent rent adds tax risk to the structure. The portion of the customer revenue that is retained by the lessee can vary substantially.

Solar companies have an interest in minimizing the share of customer revenue retained by the tax equity investor as lessee. They prefer to monetize future revenue at a back-levered debt rate rather than a higher tax equity yield. Most tax equity investors require at least a 2% pre-tax yield.

There are no IRS guidelines for inverted leases, unlike partnership flips and sale-leasebacks. However, the structure is common in historic tax credit deals, and the IRS acknowledged it in guidelines in early 2014 to unfreeze the historic tax credit market after a US appeals court struck down an aggressive form of the structure in a decision called *Historic Boardwalk*. The guidelines are in Revenue Procedure 2014-12. (For more discussion, see "Tax Equity Market Weighs New IRS Guidelines" in the February 2014 *NewsWire*.)

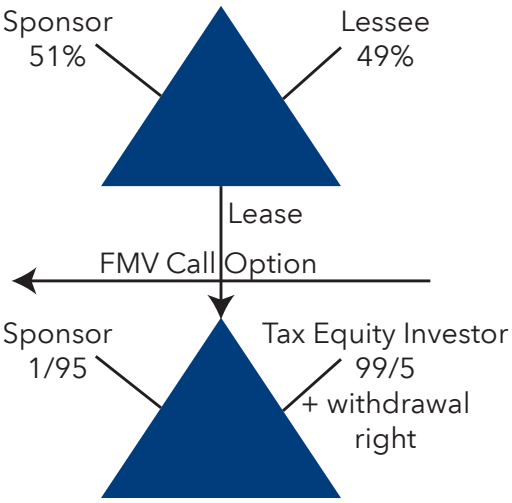
Overlapping Ownership

The central challenge in inverted leases is how the 20% to 42% of the capital stack raised by the structure moves from the tax equity investor to the solar company. In the conservative form of inverted lease, it moves from the lessee to lessor as prepaid rent.

In the overlapping ownership structure, the tax equity investor makes a capital contribution to a lessee partnership, and the lessee makes a capital contribution of the amount to the lessor in exchange for a 49% interest in the lessor. The capital contribution may be distributed by the lessor partnership to the solar company tax free. The investor is able to claim not only the investment credit, but also 49% of the depreciation on the solar assets.

The overlapping ownership structure is shown in the next column.

The overlapping ownership structure raises more tax equity because there are more tax benefits for the tax equity investor. Both the lessor and lessee are partnerships. The solar company owns not only 51% of the lessor, but it also owns a 1% interest in the lessee and acts as managing member. The solar company has an option to buy the tax equity investor interest after the recapture period has run on the investment tax credits. The tax equity investor has an option to withdraw from the partnership



if the solar company does not exercise the option to buy out the investor.

In other variations on the basic structure, the sponsor may sometimes own 100% of the lessor and take a small interest in the lessee (1% to 5%) as managing member to allow the tax equity investor to avoid consolidating the lessee for book purposes.

In some deals, a sponsor affiliate enters into a master installation agreement with the lessor to install solar systems as customer agreements are signed. More commonly, the sponsor contributes the equipment to the lessor which then leases it to the tax equity investor.

Tax Treatment

Focusing on the tax treatment to each of the parties, the lessor must report the rent it receives as income, but has the depreciation as shelter. The lessee may prepay part of the rent. That part is treated as a "section 467 loan" and is reported by the lessor as income over time.

The lessee must report the revenue from customers as income. It deducts the rent paid to the lessor and claims an investment tax credit on the solar equipment. Any prepaid rent is deducted over the same period the lessor reports it as income. The lessee reports half the investment credit as income over five years.

The tax equity investor is locked in for five years. The "unvested" investment credit must be repaid to the US government if the lease terminates or the investor transfers its leasehold interest within five years after the equipment is put in service. A transfer of the equipment by the lessor does not trigger recapture, unless the transfer is to someone like a government or tax-exempt entity that cannot elect to / *continued page 30*

Inverted Leases

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pass through investment credits or the transferee takes the equipment freed from the inverted lease.

Termination of the inverted lease accelerates the remaining lessee income inclusion in theory, but in practice, the lessee does not have to report more income than half the investment tax credits it is allowed to keep. It would already have done that in a solar inverted lease.

There is no recapture of the investment tax credits if the lessee purchases the equipment from the lessor.

The Internal Revenue Service and Treasury inspector general have probed into the inverted lease structure on audit, but not taken issue with it. Nevertheless, the structured is perceived as carrying more tax risk than other tax equity structures.

Many tax equity investors are limiting the percentage markup they are willing to see in fair market value above cost, although this is most common in utility-scale projects. Tax basis risk is borne in most deals by the sponsor. Tax loss insurance is being used in some solar tax equity transactions to avoid diversions of cash flow to cover tax indemnities, but it is expensive.

In general, tax risks about which the sponsor has special insight are borne by the sponsor. An example is facts that go to when a project was placed in service. Tax risks into which both the sponsor and tax equity investor have equal insight are borne by the tax equity investor. An example is whether the inverted lease structure works.

Risks into which neither party has special insight are usually a matter for negotiation. The biggest such risk is tax change risk. The risk is being put on sponsors, but the market is still feeling its way on how to address it. (For more discussion, see "Tax Change Risk in Tax Equity Deals" in this issue starting on page 23.)

Tax Reform

Progress on tax reform has stalled while Congress waits for the Trump administration to reveal what it wants. The tax "plan" released by Trump in late April had only 30 words on corporate tax reform. No one expects a completed tax bill on the president's desk before year end at the earliest. Lower tax rates are expected to be phased in starting in 2018 because of cost.

There are six changes potentially in play that could affect the economics of inverted lease transactions. House Republican leaders have lined up behind a plan that would reduce the corporate tax rate to 20%, allow the full cost of new equipment to be deducted immediately, deny interest deductions, exempt export earnings from income taxes, and deny any cost recovery on imported goods and services. Congress could also change the existing phase-out schedule for the solar investment tax credit, although this is not expected.

Trump wants to reduce the corporate tax rate to 15%, and he has talked about imposing a "reciprocal tax" on imports, but without offering any details about how it would work.

Some tax equity investors are already pricing deals using a 20% to 28% corporate tax rate. There is a one-time price reset at the end of 2018 or sooner after a tax overhaul bill clears Congress. A materially adverse proposed change in tax law not reflected in the pricing model is grounds to stop funding additional tranches. The parties debate at what stage in the legislative process it is appropriate to cut off further funding.

Tax equity investors generally have an incentive to accelerate tax equity deals into 2017 when deductions can be taken against a 35% tax rate. However, this is less true of inverted lease transactions where the depreciation remains with the solar company and the lessee must report half the investment credit as income.

The lack of depreciation benefits makes tax reform less of an issue in inverted leases. Without depreciation benefits, the investor's return is likely to increase from a lower tax rate unless the investment tax credit is overhauled by Congress.

Property taxes are an ever-present issue in transactions involving solar equipment in California. Any change in ownership of solar equipment after initial installation will trigger a property tax reassessment. Putting a tax equity partnership in place is not considered a change in ownership, but later exercise of a sponsor call option or investor put is.

Inverted leases are roughly 10% to 20% of the solar rooftop tax equity market.

WIFIA Gears Up

by Jake Falk, in Washington

Forty-three entities have expressed interest in borrowing from the US government under a new WIFIA loan program administered by the US Environmental Protection Agency. WIFIA stands for the Water Infrastructure Finance and Innovation Act.

EPA has not released the names of the prospective borrowers or the projects for which they submitted letters of interest, but it said the requests add up to $6 billion of WIFIA loans, which is four times the approximately $1.5 billion of loans that EPA estimates it currently has the budget authority to make.

The Trump administration appears to be prepared to implement WIFIA, which was authorized by Congress in 2014 during the Obama administration.

The fiscal year 2018 budget that the Trump administration sent Congress in late May would continue to fund the WIFIA program at the same level it was initially funded for 2017.

Trump's pick to head the EPA, Scott Pruitt, sent the message that WIFIA is important in a speech in early March that he delivered to the US Conference of Mayors. Pruitt said in this speech that investment in water infrastructure will be an important part of the President's infrastructure plans.

How WIFIA Works

WIFIA will provide loans or loan guarantees for eligible water projects.

Loans can carry low interest rates at the US Treasury borrowing rates for similar maturities. There is no spread above the Treasury rate.

They can have flexible repayment terms, including provisions that allow for a 35-year maximum final maturity date from substantial completion of the project and up to five years of payment deferral after substantial completion.

There are certain statutory limitations. For example, WIFIA can only fund up to 49% of eligible project costs. This reflects a policy that the federal government's role in these projects should be to fill market gaps, or to provide credit support to projects that will leverage federal loans to attract additional debt and equity from the private sector.

Eligible projects include drinking water, wastewater, desalination, drought mitigation, aquifer recharge, water recycling, and projects for enhanced energy efficiency at drinking water and wastewater facilities.

Eligible borrowers include government entities at the state, local or federal level, tribal governments, and state infrastructure financing authorities. Private entities are also eligible borrowers.

For a private borrower, the federal government would expect a demonstration of public support. A public-private partnership would be eligible, as would a wholly private project that could demonstrate appropriate public support. The public support gives the federal government the confidence that it needs that the project fits within the broader public goals in the region or area.

EPA will review the expressions of interest and invite selected projects to submit full loan applications. The amount of time to reach a formal loan will depend on how quickly EPA can complete the detailed financial and engineering review for a particular project and agree on loan terms with the applicant. Applicants will be required to pay an application fee when they submit their applications. The application fee will be applied toward a credit processing fee paid by the borrower after financial close. The credit processing fee reimburses EPA for actual engineering, financial and legal costs, which EPA expects to range from $350,000 to $700,000 in the typical project.

Although the WIFIA program was originally passed by Congress in 2014, Congress did not appropriate any money for WIFIA to start making loans until the end of last year when it provided $20 million of budget authority.

EPA announced on May 17 that WIFIA received an additional $8 million of budget authority in an appropriations bill signed by President Trump on May 5. Together with the earlier appropriation from December 2016, EPA estimates that it now has the budget authority to make up to $1.5 billion in loans.

US Water Infrastructure

There have been some recent high-profile problems that have drawn the attention of lawmakers and the public to the need for investment in water infrastructure.

President Obama declared a state of emergency last January in response to a water crisis related to contaminated drinking water in Flint, Michigan.

California imposed the state's first-ever mandatory water restrictions two years ago as a result of four years of the worst drought in the state's history.

More recently in California, a damaged spillway at the Oroville dam threatened severe flooding, leading to the evacuation of an estimated 200,000 residents. Officials are moving quickly to get

WIFIA

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the spillway fixed before next winter's rainy season.

Even without these high-profile problems, the case for investing in US water infrastructure has been building for many years. The US has fallen behind both on maintaining existing water infrastructure and building new facilities to accommodate population growth. Investment gaps are quantified in different ways, but there appears to be a consensus that the needs in the US water sector are substantial.

The Value of Water Campaign, which is supported by a diverse group of leaders in the water industry, released a report in March, called the "Economic Benefits of Investing in Water Infrastructure," that said many underground pipes that were installed early in the first half of the 20th century are coming due for replacement because they are reaching the end of their 75- to 100-year useful lives.

In addition to infrastructure aging, if the infrastructure was being built today it might be built in different ways, given advances in technology. More modern infrastructure could also target considerations such as sustainability and resiliency and take advantage of real-time information about system performance.

The federal government's contribution to funding US water infrastructure has been falling for decades. It was 63% of total capital spending on water infrastructure in 1977. It was just 9% in 2014. Federal spending was $76 per person in 1977 and just $11 in 2014. Both per capita figures are in 2014 dollars.

State and local government spending increased during the same period.

TIFIA Lessons

Congress designed the WIFIA program based on the US Department of Transportation's existing "TIFIA" program, which makes loans and loan guarantees for road, mass transit and other surface transportation projects.

The TIFIA program was first passed by Congress in 1998 and has been reauthorized multiple times since then. Congress expanded TIFIA substantially in 2012, as the program's popularity increased, giving TIFIA enough budget authority to make more than $17 billion in additional loans.

In 1998 TIFIA was, in many ways, starting from scratch. WIFIA should be able to start making loans relatively quickly by building on the experience with TIFIA.

Experience suggests annual budget authority for WIFIA may lag the pipeline of projects that are ready to borrow from the program. As the TIFIA program attracted more borrowers, its budget authority was not always quickly adjusted. This resulted in a backlog of projects competing for a limited amount of TIFIA loan capacity.

Congress seems to have become more attuned to this issue over the years with respect to TIFIA, and may be flexible in adapting the appropriations process to help meet demand for WIFIA loans.

TIFIA has invested over the years in crafting transaction documents, including template terms sheets, template loan agreements, application forms and letter of interest forms. These documents should be relatively easy to adapt to WIFIA.

An immediate focus for the WIFIA program will be the criteria that are in place to evaluate projects.

The notice of funding availability that EPA issued in January 2017 to solicit letters of interest for WIFIA's current budget authority included a list of the statutory selection criteria that are to be used to select projects. These criteria include things such as the national or regional significance of the project and whether WIFIA funding will accelerate delivery of the project.

The EPA notice also included a list of EPA priorities. They include such things as adaptation to extreme weather and climate change, enhanced infrastructure resiliency, enhanced energy efficiency, green infrastructure and the need to repair, rehabilitate and replace infrastructure.

Changes to the statutory selection criteria would require action by Congress. However, the Trump administration and the EPA could revise the EPA priority list in a future notice of funding availability.

EPA is expected to work through the 43 letters of interest this summer, at which point it should be able to start inviting prospective borrowers to provide information for a financial and engineering review and to start negotiation of loan terms. ◎

Environmental Update

The US Environmental Protection Agency has begun a systematic process of withdrawing or modifying various Obama-era environmental regulations.

EPA under President Trump characterizes these actions as refocusing EPA on its "core statutory duties" and deferring to states on environmental regulation.

Thus far, Trump signed a series of executive orders driving agencies toward deregulation, including one that requires the repeal of two existing rules for every one new rule and requires agencies to meet a zero net regulatory expense target. Another order requires federal agencies to create task forces to review existing regulations in an effort to reduce regulatory burdens.

Another order directed EPA to review and possibly withdraw the "Clean Power Plan" that sets greenhouse gas limits for existing power plants as well as a rule on methane emissions from new oil and gas wells.

EPA has begun weighing whether to withdraw or modify numerous other regulations in response to industry petitions, including its air quality standards for ozone, the Clean Water Act effluent regulation for power plants, and rules limiting refrigerants that contribute to global warming.

While the deregulatory push is underway, there are obstacles to speedy implementation.

One obstacle is finding enough staff to tackle such a determined agenda. President Trump had named only two people to top jobs at EPA as the NewsWire went to press: Scott Pruitt as EPA administrator and Susan Parker Bodine as new head of the office of enforcement and compliance assurance. Bodine is currently chief counsel for the Senate Committee on Environment and Public Works.

Budget cuts may also slow things. The administration is proposing to cut the EPA budget by 31% and reduce agency staff by 25% for fiscal year 2018, which begins on October 1.

The agency faces numerous statutory, regulatory and court-imposed deadlines that take up staff time. Reexamination of existing regulations, including through notice and comment rulemaking, can be as time consuming as issuing a new regulation.

Sue and Settle

The new administrator, Scott Pruitt, has directed EPA staff to curtail "regulation through litigation" where environmental groups use "sue and settle" tactics with a goal of having courts issue consent decrees that set deadlines for rulemaking by the EPA or other government agencies.

In the typical scenario, an environmental group sues a government agency for missing a statutorily required rulemaking deadline, and the government and the plaintiffs then negotiate a settlement under which the court approves a new deadline.

Pruitt views such tactics as an abuse of the process. "The days of ruling by consent order, the days of ruling by litigation in the judicial system are over," he said. "There is a time and place to settle, there is a time and place to engage in a consent decree, but the consent decree should not be used to engage in rulemaking because that subverts the process that Congress has set up."

It is unclear to what degree the new administration considers itself bound by past consent decrees about which rules must be addressed and by when since the consent decrees are settlements with a different agency head.

Republican leaders in Congress are trying for a legislative fix.

One pending bill would restrict lawsuits against federal agencies that miss statutory deadlines to issue new rules. Another bill would bar the government from agreeing to pay plaintiffs' costs when settling claims under environmental statutes. Such statutes allow courts to award costs to the successful party. However, neither bill appears to have much traction yet.

Meanwhile, attorneys general in some Republican-controlled states are considering lawsuits to force repeals of various environmental regulations. It remains to be seen whether the Trump administration will embrace "sue and settle" in cases where plaintiffs seek deregulatory outcomes.

Paris

The Rhodium Group recently estimated that, under Trump, US emissions will probably fall 15% to 19% below 2005 levels by 2025, rather than the 26% to 28% that the US pledged previously.

Since the Trump administration has already signaled an end to the Clean Power Plan, which was to serve as the initial means by which the US would have taken significant first steps toward meeting its pledge in the Paris agreement to reduce its emissions by 2025, there seems little practical effect on the US market of the announcement by President Trump on June 1 that the US is withdrawing from the accord, unless withdrawal galvanizes US states to take further action to curb carbon emissions.

Environmental Update

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The most important political effect may be that the US is unlikely to fulfill its monetary pledges to help developing countries meet their obligations. The US agreed to pay up to $3 billion by 2020 to help poorer countries meet climate goals and adjust to a warming planet, particularly island countries that are expected to be flooded by rising seas. The United States delivered $1 billion under the Obama administration, but President Trump has indicated that is now at an end.

The danger is that failure by the US to meet its commitments could serve as a catalyst for other countries to retreat from theirs.

China and India

The number one and number three greenhouse gas emitter nations, China and India, are expected to exceed targets they set for themselves in the 2015 Paris Climate Agreement, according to United Nations monitors.

Chinese emissions of carbon dioxide may peak more than 10 years sooner than expected. China pledged in the Paris agreement that its emissions would peak around 2030 and that it would source about 20% of its electricity from carbon-free renewables by then. China's faster progress is largely due to reducing coal use for three years in a row, as China moves to bring severe air pollution under control, and a decision to drop plans to build more than 100 new coal-fired power plants.

India had pledged to reduce its carbon intensity per unit of economic activity in line with historical levels, reversing spiraling trends as its economy industrializes. India is now expected to generate 40% of electricity from non-fossil fuel sources eight years ahead of schedule by 2022.

China and the United States are the world's two biggest emitters, accounting for approximately two fifths of greenhouse gas emissions.

Greater Sage Grouse

A federal judge in Oregon in April revoked approval for a wind project given by the Bureau of Land Management. The judge said the bureau failed to properly consider the effects on the greater sage grouse.

An environmental group appealed the approval in 2015. The case went to a US appeals court that sent it back to a lower federal court in May last year after deciding the agency incorrectly concluded that the sage grouse does not spend the winter at the proposed site by relying on data solely from other sites.

The project is the 104-megawatt Echanis project. The developer is proposing to put between 40 and 69 wind turbines on 10,000 acres of private land serviced by transmission lines crossing land owned by the federal government.

The case is *Oregon Natural Desert Association v. Ryan Zinke.*

— contributed by Andrew E. Skroback in Washington

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