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PROJECT FINANCE
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PURPA and Solar

by Robert Shapiro, in Washington

Solar developers are again using a 1978 federal law that requires utilities to sign long-term power purchase agreements to secure utility PPAs after years of disuse, but the recent track record of developers trying to use this statute is mixed.

The law, called the Public Utility Regulatory Policies Act or PURPA, requires utilities to buy electricity from renewable energy projects of up to 80 megawatts in size at the "avoided cost" the utility would otherwise spend to purchase or generate the electricity itself.

PURPA is expected to overtake state renewable portfolio standards as the biggest driver for utility-scale PPAs in 2017 due to falling solar electricity prices.

Solar electricity can now be delivered at less than utility avoided costs in such states as North Carolina, Georgia, Utah and Oregon.

Any developer planning to use PURPA should analyze first how likely it is to end up battling with the utility before the state public utility commission and, if so, with what likelihood of success.

Potentially Useful Tool

For more than 10 years, renewable energy developers have relied on renewable portfolio standards, or RPS, created under state laws as the primary way to get a utility to enter into a long-term PPA that can support project financing. Twenty-nine states and the District of Columbia have RPS standards.

However, as most of the state utilities in RPS states have signed */ continued page 2*

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A TAX EQUITY TRANSACTION was set aside on audit.

The Internal Revenue Service said two tax equity investors "invested only in tax benefits, and had no meaningful expectation of risks or rewards" from the underlying business. The business was producing refined coal.

The IRS made the statement in a technical advice memorandum that it sent to the tax equity investors on February 10.

The case had been pending in the IRS national office during much of 2016 and went all the way up to the IRS chief counsel for resolution.

Refined coal is coal that someone has altered to make less polluting. Nitrogen oxide emissions must be reduced by at least 20% and mercury or sulfur dioxide emissions must be reduced by at least */ continued page 3*

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contracts to fulfill their RPS requirements for the near term, renewable power developers have turned to a long-existing, but infrequently used, federal utility law in an effort to find a long-term market for their electricity output: PURPA.

PURPA was the landmark federal law passed in 1978 to encourage the development of small renewable energy and cogeneration facilities, known as qualifying facilities, or QFs. PURPA directed the Federal Energy Regulatory Commission to issue rules requiring each utility to offer to purchase the output from QFs, and to purchase the output at its avoided cost.

The avoided cost is set at the time that the QF establishes a legally enforceable obligation by the utility to buy electricity from a project.

A unique feature of PURPA is that it is up to the individual state public utility commissions, rather than FERC, to implement the FERC rules under PURPA.

In the 1980s, almost all renewable energy was developed as a result of long-term contracts that utilities entered into under PURPA, with most projects developed in states with commissions that established or approved the highest avoided costs for their utilities. Starting in the late 1980s, with avoided costs falling due to the drop in natural gas prices following gas deregulation and growing surpluses of generating capacity in many regions, QF contracts dwindled.

New projects began to be developed by independent power producers that did not meet the PURPA standards for QF status. Aided by the Energy Policy Act of 1992, which created an exemption from regulation for wholesale-only generators (called exempt wholesale generators or EWGs) independent power projects that were not QFs began to negotiate and sign long-term PPAs with utilities to supply electricity from conventional power plants. This was a period when growing power demands ate into the utility's excess capacity.

At the start of the millennium, several states tired of waiting for the federal government to create a federal renewable energy standard, and they began to implement their own renewable portfolio standards. Avoided cost pricing at the time was too low to accommodate the financing needs of renewable power. An RPS requires the state's regulated utilities to supply a specified percentage of its electricity load from renewable energy. Over time, many states followed suit, with many increasing the percentage of renewable purchase obligations under their RPS programs on a periodic basis.

In states without a state RPS law, absent PURPA, a utility has no obligation to sign a long-term contract for the output from independent renewable projects.

In the last couple of years, particularly as wind and solar projects have become less expensive to build, developers in states without RPS standards, and in states whose utilities already have enough renewable energy to meet near-term RPS requirements, began to press utilities to buy their output under PURPA rules.

A few states also have separate solar mandates within their RPS programs that require a certain percentage of the renewable electricity the utility is required to deliver must come from solar. Some of these programs require solar projects to be QFs under PURPA to qualify, and require the state's utilities to purchase the solar output at its avoided cost, using the PURPA standards for their cost determinations.

Track Record

In North Carolina, policies under PURPA have led to tariffs that permitted more than 1,000 megawatts of small solar projects up to five megawatts to enter into long-term contracts at fixed tariff rates and for larger solar projects to obtain contracts with somewhat shorter terms and at negotiated avoided cost rates. Because of the success of these projects, solar developers have continued to propose solar

Solar developers are having mixed results using PURPA to land utility PPAs.

projects in the state, leading Duke Energy recently to file an application with the North Carolina utility commission to limit eligibility for fixed-tariff solar pricing to projects that are one megawatt or less in size — down from five megawatts — and to reduce the term of the long-term contracts and to require large QFs to use a competitive bidding process in place of negotiated avoided cost rates. Duke also proposed that PPAs provide for an adjustment every two years in the QF tariff energy rates. A number of developers have filed a complaint against Duke at the state commission, objecting to Duke's new negotiating position to limit contract terms to five years for QFs larger than five megawatts.

In addition, North Carolina utilities and many other utilities across the country with PURPA obligations have their own plans to build solar projects and include their facilities in rate base so that they can recover the cost plus a return through their retail utility rates, without the same price limitations, term limitations or financing constraints that would apply to QF projects and without offering to purchase the output from them. Two recent examples include MidAmerican in Iowa and Xcel Energy utility affiliates in the north central states, that have big plans to add hundreds of megawatts of utility-owned wind generation in rate base.

PURPA gives FERC the ability to grant waivers from the mandatory purchase obligation to utilities that operate in workably competitive markets, including regional transmission organizations like the PJM system in the mid-Atlantic and rust belt states, the New York independent system operator or NYISO, the New England independent system operation or ISO-NE, the California independent system operator, or CAISO, and the Midcontinent independent system operator, or MISO. FERC has said it will waive the purchase obligation in such markets for projects that are above 20 megawatts in size. Most of the utilities that operate in these markets have sought and obtained waivers from FERC from the mandatory purchase obligation from PURPA for such projects.

Because nearly all the southeastern states and several states in the upper northwest have not formed sufficiently competitive regional markets, FERC has not granted waivers for utilities in these areas. These areas also have historically been the most resistant to signing QF contracts.

The states have considerable latitude in how they implement PURPA within their borders. They determine on their own or merely approve a regulated utility's determination of its avoided cost. They can determine eligibility for and the duration of any long-term contracts.

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40% compared to the emissions from burning raw coal. The US government allows a tax credit of $6.71 a ton for producing refined coal. The facility at which the refined coal is produced must have been in service by December 2011. Tax credits can be claimed for 10 years on the output sold to third parties.

The case under audit involved two refined coal facilities that a developer installed on a site belonging to a utility. The developer arranged to buy raw coal from the utility and then sell the utility the refined coal at a discount to the raw coal. The developer also paid the utility for use of the site.

The developer brought in two tax equity investors as partners to own the refined coal facilities. Each partner paid the developer its ownership share times the cost to install the two facilities. One of the investors also paid the developer an ongoing "finder's fee" that was a fixed number of cents per dollar of refined coal tax credits allocated to the investor.

However, most of what the tax equity investors paid to buy into the deal were ongoing royalty payments tied to the amount of tax credits they were allocated. The partnership paid these royalty payments to an entity the developer formed with some other investors. The royalties were for use of the chemical formulas for treating the raw coal to turn it into refined coal. The IRS said the royalties were the bulk of the payments to the developer. The tax equity investors made capital contributions to the partnership to fund them.

The entity receiving the royalty payments did not own the chemical formulas. Rather it had a license to use them from someone else. It entered into a sublicense with the partnership allowing the partnership to use them. The IRS said the royalties the refined coal partnership paid under the sublicense greatly exceeded the royalties that had to be paid under the main license.

The developer operated the projects for the partnership.

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Absent support from the state commission, a solar developer would have to appeal an adverse state commission decision to a state court of appeals or ask FERC for relief from how the state commission is implementing PURPA. If a QF petitions FERC to enforce PURPA against a state commission, and FERC does not initiate an enforcement action within 90 days, then the QF is permitted to "stand in the shoes" of FERC and file a complaint against the state commission in federal court. In the history of the statute, FERC has only sought enforcement against a state commission on PURPA implementation once, and ultimately dropped that challenge. In reviewing a petition from a QF that it believes is meritorious, FERC's typical practice has been to declare that it will not initiate an enforcement action, but then go on to explain why it believes that the state's implementation of PURPA is inconsistent with the federal rules.

PURPA also applies to unregulated utilities like municipal utilities and electric cooperatives. However, since these entities are not subject to state commission regulation, a QF that has a dispute over a long-term contract cannot go to the state commission for resolution of the issues. Rather, the QF would have to file a PURPA complaint in the proper state court or go to FERC to seek an enforcement action against the unregulated utility.

Some state commissions defer to FERC for interpretation of the PURPA rules, and some do not.

The states most notable for declining to accept FERC's PURPA interpretations are Texas and Idaho. Their utility commissions rejected FERC's view that certain QFs entered into legally enforceable PPAs, and the highest appellate courts in both states affirmed those state commission determinations.

The West

In the last couple years, utilities in Idaho, Utah, Wyoming and Montana began signing up long-term PPAs with small and large wind and solar projects of up to the 80 megawatts in size at avoided cost rates. (A project larger than 80 megawatts does not qualify as a QF and, therefore, cannot use PURPA as a means to obtain a utility PPA.)

However, the utilities in these states are now taking steps at their state commissions to try to put an end to, or severely limit, their purchase obligations under PURPA. Most of the utilities in these states are seeking, and in some cases obtaining, state commission approval to reduce to size cap for availability of standard rates and to obtain shorter contract durations.

For example, the Montana commission recently agreed to a request by Northwestern Energy for an "emergency" limit of standard avoided cost rates to solar projects under one megawatt in size, from a previous three-megawatt limit, and the Idaho commission recently agreed to limit fixed avoided rates and term length to two years for QF projects.

While the Utah and Wyoming commissions rejected attempts by the regulated utilities to reduce the contract length to two years or revise avoided cost methodology, Wyoming did not actually resolve the dispute over contract length and avoided costs, preferring to encourage parties to resolve the issues in an informal manner. This informal approach had not led to any resolution for over a year.

In the meantime, utilities in the four states have been continually reducing their avoided cost rates, making contracts less attractive to potential solar developers.

The Southeast

Most states in the southeastern United States do not have renewable portfolio standards. These include Florida, Georgia, Alabama, Mississippi, Louisiana, Arkansas and Tennessee.

In those states, the only legal basis to compel purchases has been the federal statute, PURPA. But the law has rarely led to utility scale solar purchases by utilities.

QF contracts in some of these states are being signed with solar projects under voluntary solicitations for limited amounts of solar capacity that are initiated by the utilities themselves. The pricing is based on a PURPA avoided cost methodology approved by the state commission, and the projects are required to be certified as QFs under PURPA. For example, Georgia Power has conducted several voluntary solar programs to acquire solar power in the last couple years, and the PPAs have been for long duration and at avoided costs determined under a methodology long approved by the Georgia commission for QF pricing.

These programs have involved quickly announced and implemented solicitations with a specified cap on total solar megawatts. The total amount of solar generation acquired in these programs has not been substantial.

Despite being the sunshine state, Florida has a meager amount of solar capacity. None of the utilities has an incentive to offer prices to QFs that will permit the financing of independent solar power, and the utilities have demonstrated a remarkable ability over the years to construct their own generation to add to rate base even in the context of competitive solicitations. Florida Power and Light has already built several solar plants recently to put in rate base, and it has several more under construction in its service area. Absent any prodding from the Florida Public Service Commission, there is unlikely to be a significant upswing in independent solar power production under long term agreements.

FERC Reengages

At the prodding of Congress, FERC held a technical conference on its PURPA rules in the summer 2016, inviting speakers and written commenters to reexamine the scope of its rules on the utility mandatory purchase obligation and the determination of avoided costs.

In particular, FERC sought and received comments about five issues. They are whether to retain a mandatory purchase obligation for utilities in competitive organized markets for projects up to 20 megawatts, whether to limit curtailment of QF power, whether to wade into assessments of current avoided cost methodologies by the state commissions, what the standard should be for a legally enforceable obligation that triggers a utility's avoided cost purchase obligation, and whether to reconsider a rule that permits developers to divide up what would otherwise be a project larger than 80 megawatts into smaller projects to qualify as separate QFs in cases where the generating equipment is more than one mile apart.

Berkshire Hathaway, on behalf of its subsidiaries PacifiCorp and NVE Energy, argued that the recently created energy imbalance market, or EIM, in the western United States, in which the utilities participate, is a sufficiently competitive market to warrant waiver of the mandatory purchase obligation. The EIM market provides economic energy interchange among the utilities in CAISO and interconnected utilities outside California. Other commenters strongly disagreed.

On the whole, the investor-owned utilities did not take a strong position on the existing FERC rules, perhaps due to their experience with existing RPS requirements and the fact that the state commissions have considerable discretion in addressing PURPA implementation issues. In September, following the technical conference, FERC asked for additional comments on these subjects.

At this writing, FERC has only two seated commissioners out of the five commissioner positions, and it takes three to make a quorum. Until another commissioner is confirmed by the US Senate, FERC is unable to adopt any new rules in this area should it decide to do so. Even with a quorum, it would take a few months for the new commissioners to get / continued page 6

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All of the contracts had terms that expired when the federal tax credits expired.

One of the investors had a "put" to sell its partnership interest back to the developer if a period of months passed without tax credits.

The facilities failed to produce as much refined coal as expected. They were idle for roughly two years out of the first five years. Both investors exited in year 5. One exercised the put and the other negotiated an exit.

The IRS said "monetization of tax benefits is not necessarily prohibited," but this was nothing more than a sale of tax benefits. It did not reach the question whether the investors were real partners or invoke something called the "economic substance doctrine" to say the transaction lacked real substance. Instead, it said while there was a real activity of producing refined coal, the investors were not really engaged in making refined coal. They would have received no benefit if the price of refined coal had gone up. There was no meaningful variation in the financial return from the underlying business. The investors were "merely observers in an activity engaged in by others."

The IRS said it was reserving on the issue whether there was a "sale" of refined coal to the utility since the utility was being paid, in effect, to take the product. Refined coal tax credits can only be claimed on refined coal that the producer of the refined coal sells to a third party.

The refined coal market was largely frozen while the technical advice memorandum or TAM was being worked on by the IRS.

The TAM suggested the same developer has 12 other facilities that may be audited next.

It is not the IRS position that no transactions work in this area. The amount the investors invested seemed to be largely a function of the tax credits they received and to be paid on a pay-go basis. In some other areas, like tax equity transactions in the wind market, the IRS has guidelines requiring at least 75% of the tax equity investment to be fixed in amount. The IRS had an informal policy in synfuel / continued page 7

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up to speed on these and many other pending FERC matters. There is no legal requirement for FERC to revisit its rules.

It should be noted that there are other potential sources of long-term PPAs outside of a state or federal mandate. Corporations and municipalities have been signing PPAs with renewable energy projects, originally in order to reduce their carbon footprints, but increasingly due to the fact that renewable power prices have become competitive with market prices in general.

PURPA and its implementation paved the way for competitive wholesale markets that are now thriving in the United States. There are still opportunities for solar projects to use PURPA to get long-term PPAs at financeable prices outside state RPS processes, but there are headwinds in many states at the level of the state utility commissions. ◎

Emerging Storage Business Models

It is important in any new market like electricity storage to get the business model right, as that is what helps such markets get traction. For example, development of a third-party ownership model was key to the rapid growth of the solar rooftop business in the United States. There is a lot of curiosity about the business models with which energy storage companies are experimenting. Three panelists talked about them at the Infocast Storage Week in Oakland in late February.

The panelists are Katherine Ryzhaya, chief commercial officer of Advanced Microgrid Solutions at the time of the panel discussion, Karen Butterfield, chief commercial officer of Stem, and Craig Horne, vice president for energy storage at RES Americas and a board member of the Energy Storage Association. The moderator is Keith Martin with Chadbourne in Washington.

MR. MARTIN: Karen Butterfield, Stem has a pilot project in Hawaii that involves 29 batteries put in places like Whole Foods, Albertson's, a florist and an auto body shop. Many of the customers have solar panels on their roofs. This network of 29 batteries will experiment with making at least one megawatt of capacity available to the Hawaiian Electric Company in 15-minute intervals when the utility needs additional capacity on short notice to balance the grid. How do the economics work?

Aggregated Storage Models

MS. BUTTERFIELD: The program started a couple of years ago when an energy accelerator kicked in about a million dollars to get the project going and, as you said, it is a pilot project. We offer commercial customers a subscription service. The customer signs up for three years of storage services. This is not unlike a power purchase agreement or an energy savings performance contract. HECO gets control of the capacity. We have handed over to API . . .

MR. MARTIN: What is API?

MS. BUTTERFIELD: It is a software portal where a dispatch team can check how much capacity is available from this aggregated network of batteries. There are times when that capacity on those 29 batteries is at 30% of potential capacity, and there are times when it is at 90%. HECO has the opportunity to control what is there.

MR. MARTIN: Does Stem own the batteries?

MS. BUTTERFIELD: We do. We own them through a project finance structure. The owner is a partnership between Stem and another party.

MR. MARTIN: The customer pays the partnership a percentage of its savings on electricity. How does the battery allow the customer to save?

MS. BUTTERFIELD: We install a powerful software platform on the customer premises to manage energy use and costs, with intelligent storage in the background to automate savings. The software predicts when a customer's onsite load will peak, and discharges to obviate the peak, thereby mitigating utility demand charges that can be 70% of a customer's monthly bill.

MR. MARTIN: What percentage of the savings does the customer pay?

MS. BUTTERFIELD: Sometimes the customer saves twice as much as it pays and sometimes three or four times what it pays. It depends on the load shape of the customer's battery. Unless the customer will save at least twice the subscription fee, then you probably cannot engage the customer because the proposition is not of high enough value.

MR. MARTIN: You said Stem owns the batteries through a project finance structure. Lenders will not usually lend against a revenue stream that is uncertain. The lender will determine how much if any, of the revenue is certain and lend only against that. How are you able to borrow in this case?

MS. BUTTERFIELD: We guarantee the lender that it will be made whole. The customers are also creditworthy. They include Safeway and other Fortune 500 companies. The florist you mentioned is the largest maker of leis on the island. We charge customers a fixed subscription fee for our storage subscription service as part of every contract.

MR. MARTIN: What do you receive from the utility?

MS. BUTTERFIELD: In this case, we receive grid service payments. In some other cases, we receive capacity payments.

MR. MARTIN: So this is a three-year experiment. You are two years into it. You have two revenue streams: you receive a share of the energy savings from the customers, and you receive something from the utility. What percentage of the cost of the storage device is covered by the two revenue streams?

MS. BUTTERFIELD: Keep in mind that we installed the batteries a couple years ago. Batteries were much more expensive then. So maybe the revenue streams cover two thirds of the cost, and the rest is paid by an energy accelerator. To be very clear, we do not pursue a shared savings model. We offer customers a subscription service where they pay us a fixed subscription charge.

MR. MARTIN: What have you learned from the experiment so far?

MS. BUTTERFIELD: First, customers see it as a no-brainer. The uptake rate has been amazing, especially among customers who were already early adopters of rooftop solar systems. Second, we found we were providing other value to customers, such as the florist you mentioned. Its solar system inverter was not working properly. We alerted it to the problem. It was amazed that we were on top of such things, but we spotted it through our close monitoring of battery-related data.

On the utility side, we learned two things. One is that instead of just discharging electricity when the utility needs additional capacity — instead of acting solely as a type of spinning reserve — we can also offer to take surplus power from the utility during periods when the utility has a lot of back-feeding of solar from its other customers.

The other thing we learned from aggregating battery storage is we have become a lot better at predicting what will happen to the batteries. We started off hedging how much capacity we can offer. For example, we would say to the utility that it can have 600 kilowatts today or, perhaps, 700 kilowatts at this moment. With machine learning and predictive analytics, we have been able to hedge less and provide more capacity to the utility.

MR. MARTIN: You have another aggregated storage system in the Southern California Edison service */ continued page 8*

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transactions — which qualified for a forerunner of the refined coal credit — that at least 50% of the investment amount had to be fixed.

NUCLEAR DISPOSAL FEES that a nuclear plant owner paid to the US Department of Energy to dispose of spent fuel rods cannot be carried back 10 years for federal income tax purposes, a federal district court said.

The court, in south Florida, released its decision in late March. The case is *NextEra Energy, Inc. v. United States*.

A 1983 law requires nuclear power plant owners to pay the Department of Energy annual fees tied to the amount of nuclear electricity they produce. The government then takes responsibility for disposing of the spent fuel rods.

The fees are deductible for income tax purposes.

If a company has more deductions in a year than it can use, normally the extra deductions — called a net operating loss — can be carried back up to two years to recover any income taxes paid in the past and, if still not used fully, can be carried forward for up to 20 years.

However, any "specified liability loss" can be carried back up to 10 years in the past.

A "specified liability loss" is defined in section 172(f) of the US tax code as including amounts paid under a federal or state law requiring the "decommissioning of a nuclear power plant (or any unit thereof)."

The plant owner argued that the fees were "decommissioning" costs, if not of the entire plant, then at least of a "unit."

The court disagreed.

It said the common dictionary understanding of decommissioning is to take a ship, airplane or nuclear reactor out of service. It said these items are commissioned and then later decommissioned. It said no one talks about "commissioning" a fuel rod. The court also said it believes the word "unit" in the statute refers to something like a reactor — nuclear power plants have multiple reactors — rather than a fuel rod.

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Energy Storage

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territory. You won a contract from Edison in 2014 to provide 85 megawatts of storage capacity. As of last November, you had turned on something like one megawatt or four megawatt hours of storage capacity. Does the business model in California work the same way as your pilot project in Hawaii?

MS. BUTTERFIELD: It is almost exactly the same. In November, we turned on our first small tranche. We turned on another tranche in December or January. We are at four or five megawatts now. We took our own batteries and synchronized them with other storage devices that Edison already has in place. We passed the test. Some of the early data scientists that were trying to develop the predictive analytics and algorithms were jumping up and down and high fiving as the test results came in. It was the first aggregated battery dispatch for California and maybe in the world.

The way we look at storage is we build it based upon the economics and then you add other value streams. The value stream that we just added in southern California is what we call demand response assist. You take the capacity that Southern California Edison is paying us to provide, and take the demand charge management that the customer is paying for in its subscription, and you layer on another program, which is a form of demand response. Eventually we hope to layer on two or three more as time goes on.

MR. MARTIN: So you will retain ownership of the 85 megawatts of storage devices and finance them in the project finance market?

MS. BUTTERFIELD: We are using project finance nonrecourse financing. We have two financiers. We bring them in in stages as tranches of storage devices are put into service.

MR. MARTIN: Your revenue streams are unpredictable. How do the lenders decide on an advance rate?

MS. BUTTERFIELD: The revenue streams are pretty predictable because Southern California Edison has a capacity contract with Stem to pay us for capacity as long as we deliver it. We end up arguing with the financiers that the revenue stream on the customer side is also predictable because we charge our customers a fixed monthly subscription fee and based on how our systems have performed to date.

MR. MARTIN: Is the utility also paying an energy charge for the electricity it uses?

MS. BUTTERFIELD: Yes. In this case, Southern California Edison pays an energy charge.

MR. MARTIN: A bank will lend against the capacity charge. Will it lend against anything else?

MS. BUTTERFIELD: Our financiers are lending against the capacity payments from the utility and the customer payments. These are creditworthy offtakers.

MR. MARTIN: Katherine Ryzhaya, Advanced Microgrid Solutions also has a contract from Southern California Edison to provide 40 megawatts in aggregated storage capacity. All of the storage is behind the meter, meaning it is on customer properties. Will your storage system operate the same way that Karen Butterfield described?

MS. RYZHAYA: Yes. We actually have two contracts with Edison that sum to 90 megawatts of storage capacity.

MR. MARTIN: How much is already operating?

MS. RYZHAYA: Probably about five megawatts. Probably about the same amount as Stem.

MR. MARTIN: How did you finance your five megawatts?

MS. RYZHAYA: Our development partner, Macquarie, owns the project and provides the capital to build the system.

MR. MARTIN: Are your contracts with the customers and the utility the same as Karen described?

MS. RYZHAYA: Our contracts with Southern California Edison are 10+ years in duration, which to a financing entity looks and feels like utility power contracts that they know and love. The contracts are also heavily capacity-based versus energy, which shows firmness of revenues coming from the utility, which again is attractive for financing. Our customer contracts are

Aggregated behind-the-meter storage systems are starting to attract financing.

also 10 years in duration.

MR. MARTIN: How are the capacity and energy payments determined?

MS. RYZHAYA: The capacity payments were set in our original bid in response to the utility solicitation. The energy payments are bilaterally negotiated and are performance based.

MR. MARTIN: Can you give us some order of magnitude?

MS. RYZHAYA: I would say it is in line with what any new peaker infrastructure would cost.

MR. MARTIN: Is the amount of the payments public information?

MS. RYZHAYA: It is confidential.

Massachusetts

MR. MARTIN: Massachusetts is toying with imposing a storage mandate or something like 600 megawatts in service by 2025. The mandate amounts to about 5% of peak load. To put it into context, the mandate in California is about 2% of peak load.

Do you expect Stem and AMS to use the same business models in Massachusetts that you described in Hawaii and California?

MS. RYZHAYA: The AMS business model is almost entirely centered around the utility. We do not offer the utility incremental capacity when the system is not in use by the customer. We dedicate the initial capacity to the utility and if the customer would like to receive demand charge savings in addition to coincident benefits during utility dispatch, we will upsize the system.

MR. MARTIN: How does that work? These are behind-the-meter systems that you are planning in Massachusetts, but the utility has first claim on the storage capacity.

MS. RYZHAYA: Correct.

MR. MARTIN: This is where the software is very important if the customer also wants to use the battery. What does the customer have to say to you to be able to use it?

MS. RYZHAYA: In California, each battery must meet a four-hour performance requirement under our contract with Southern California Edison. Therefore, we will install four hours of storage capacity at the site, and those four hours are exclusively dedicated to the utility. There are coincident benefits to the customer when the utility dispatches the system. The benefits are quite robust. But, suppose Edison does not dispatch until 2 p.m. and the customer's peak is at 8 a.m., then we will have to add additional kilowatt hours to the system to make sure that if and when Edison actually calls on the system, the capacity it requires is there.

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A LEASE-LEASEBACK transaction did not subject the tax equity investor to taxes in New Jersey.

Altria, a tobacco company, agreed to lease 483 buses from New Jersey Transit in September 2002 for a term of 37 years, and then sublease them back to NJ Transit for 12.25 years with an option for the transit agency to buy the remaining leasehold interest after the subleases ended for a fixed price that was expected to exceed the fair market value at time of exercise. If the transit agency failed to exercise the purchase option, then it had to find someone else interested in using the buses or continue to operate them. The buses had useful lives of 25 years.

Altria prepaid $318 million to lease the buses from NJ Transit. It borrowed 80% of the purchase price on a non-recourse basis from a bank. NJ Transit deposited most of the $318 million in a defeasance account from which it made the rental payments under the sublease. The rents went directly to the bank to pay off the loan.

Altria booked a $0 residual value on its books.

NJ Transit treated the transaction as a "capital lease" on its books, suggesting it retained ownership of the buses and the arrangement was just a financing.

The IRS disallowed the depreciation that Altria claimed on the buses. Altria had reported the transaction as a sale-leaseback. It said it should be viewed as having bought the buses because the lease to it of 37 years ran well beyond the useful lives of the buses. The IRS said that what Altria did in reality was make a loan and try to buy tax deductions.

The IRS alerted the New Jersey tax department to its action.

The loss of tax deductions at the federal level had the effect of increasing Altria's taxes in New Jersey, since the starting point for the state tax calculation is federal taxable income. The state then figures out how much of that income was earned in New Jersey. It does this by applying a three-factor formula: the share of property, payroll and sales that Altria */ continued page 11*

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MR. MARTIN: Karen Butterfield, will Stem use the same model in Massachusetts that it uses in Hawaii and California?

MS. BUTTERFIELD: Not exactly the same. There is latent value in the system, so our job is to extract all of that value from the system. Sizing the system is critical and choosing either a two-hour, four-hour or six-hour battery is critical to how we run our algorithms and what capacity we have available for the utility.

For example, we come in at 85 megawatts for four hours. It is our job to make sure that is available or we will be penalized. We are using software to maximize the value we can extract from the battery.

MR. MARTIN: Craig Horne, RES is focused mainly on utility-scale storage. How do you see Massachusetts? What sort of market will it be for you?

MR. HORNE: We have a distributed segment to our business that, like Stem and AMS, is looking at behind-the-meter storage.

We see Massachusetts as a great opportunity. It will open the door for the northeastern US. In terms of front-of-the-meter, the capacity value that storage can provide, much like in California, is to avoid having to build new peakers by getting more use out of the existing fleet.

Other Business Models

MR. MARTIN: I believe there are only three states with storage targets. We talked about California and Massachusetts. The other one is Oregon, which has a target that is about 1% of peak load. Are there any others?

MR. HORNE: No.

MS. RYZHAYA: I think a bill is moving through the Minnesota legislature.

MR. HORNE: Arizona requires 10% of new capacity procurements to be reserved to make storage cost effective.

MR. MARTIN: Will the business models be different in these other states? Karen Butterfield, you are nodding yes.

MS. BUTTERFIELD: They have to be, right? We have 50 states, and the bane of our existence is trying to find business models that fit each one of these regulatory constructs. Storage is the hot topic currently among state regulators. They are trying to determine whether it should be in front of the meter and rate-based by the utilities, or it should be behind the meter and treated as a distributed energy resource, or whether it should be a combination of them, and under what circumstances ratepayers are helped or harmed by these different structures. Some states will adopt structures that favor in front of the meter, and some will favor behind the meter, and some will be in between.

Storage owners hope eventually to benefit from as many as nine revenue streams.

MR. MARTIN: In the behind-the-meter storage, it sounds like you are installing the battery for the customer without requiring any up-front payment. You receive a revenue stream from the customer over time that is a percentage of savings. You receive payments from the utility in the best case that are predictable capacity payments and you may also receive separate energy payments. The fact that Macquarie has gone into this market suggests that not only is the revenue covering the cost of the batteries, but also there is already a healthy return possible from these projects.

Do you think what I just said about the return is true in most cases or is the industry still in the experimental phase trying to figure out how it can get the economics to work?

MS. RYZHAYA: No. I do not think it is true in all cases and states, and the truth is you need that long-term utility capacity payment in order to get players like Macquarie into this market. That is the beauty of the contracts that we were able to secure early on. The challenge is to secure additional such contracts going forward. If you look at 2016, it was a great year for new projects, but most of them were pilot sized and, going forward, likewise or behind-the-meter.

Potential Opportunity

MR. MARTIN: GTM Research says that the annual revenue in virtual power plants, which is what storage is, worldwide could grow from $1.5 billion in 2016 to $5.3 billion in 2023, with the US taking about $3.7 of the $5.3 billion. Do these figures sound right?

MS. BUTTERFIELD: Bloomberg New Energy Finance has a similar number. Many of you will remember the early age of solar in 2005 and 2006. Our first project at Nellis Air Force base was a 14-megawatt project that cost more than $6 a watt to install. By the time we reached the third tranche, the installed cost had come down to $1 a megawatt.

In 2005 and 2006, everyone asked us the same questions. How do the economics work? How can the project be financed with an unpredictable revenue stream? We had to barter our first and second children to get the deal done. Some of the same things are happening now. It is great if you can get an incentive payment from the state or the utility regulator. It is great if the utility will make capacity payments. It is great if you can get an investment tax credit, which you can only get today if you pair storage with solar. It is the combination of all those things and the incredibly fast-dropping cost of lithium-ion batteries that are driving growth in this market.

MR. MARTIN: In which states is the industry getting capacity payments currently?

MS. RYZHAYA: Probably in around 25 states there are capacity payments or demand-response program payments of some kind. But those payments are roughly $60 per kilowatt year, a number that does not always inspire a customer to cut its demand. In other words, demand response-based capacity is not as reliable, as firm or as fast as battery storage.

The storage industry wants to be paid for the storage attributes. Direct capacity payments for storage are available in very few places today.

MR. MARTIN: Craig Horne, RES is putting a lot of effort into utility-scale storage, not just in the United States, but also in other countries. Does the projected growth of $1.5 billion today to $5.3 billion worldwide in eight years sound like what you are counting on to justify the effort?

MR. HORNE: I think the opportunity is larger given the way costs are declining across the board, not only for the battery, but also for installation and related items. The rapid decline in costs speaks to the ability of the market to accelerate.

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has in New Jersey as a percentage of the company's total property, payroll and sales. New Jersey gave double weighting to the sales factor in the tax years at issue.

Altria filed an amended return to remove the buses and sublease rents from the property and sales calculations, since the IRS said it did not own the buses for tax purposes.

New Jersey rejected the refund claim.

The state tax court said in late February that Altria is correct since the buses remained owned for tax purposes by NJ Transit. The case is *General Foods Credit Investors #3 Corporation v. Director, Division of Taxation*.

OKLAHOMA is moving to repeal a tax credit for generating electricity from wind for projects put in service after July 1, 2017.

The credit is 0.5¢ on the electricity generated by a new project in the first 10 years after the project is put in service. It had been scheduled to expire at the end of 2020.

The credit can continue to be claimed on solar and geothermal projects completed by the original deadline.

The Oklahoma house voted 74-24 on March 9 to move up the deadline for wind farms. The Senate appropriations committee voted 34-6 to do the same on March 29. The bill goes next to the full Senate. The governor, Mary Fallin (R), called for the rollback in her budget message.

Fallin also asked the state legislature to impose a tax of 0.5¢ a KWh on wind electricity generated in the state. Mark Tygret, staff director of the House Fiscal Division, said legislation to implement the tax has not been submitted yet. If such a tax were imposed, Oklahoma would be the third state to do so. Wyoming taxes wind electricity at 0.1¢ a KWh. South Dakota imposes taxes of 0.065¢ a KWh on wind farms that commenced operating between July 1, 2007 and March 31, 2015 and 0.045¢ a KWh for wind farms that went into operation more recently. / continued page 13

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MR. MARTIN: How many people attended the Energy Storage Association convention last year?

MR. HORNE: Around 1,600. We are expecting around 2,000 this year.

MR. MARTIN: The frequency regulation market in PJM has not been in play for very long, but it seemed to fill up almost immediately. How much potential is there really with utilities for standalone storage?

MR. HORNE: If you look at the benefits curve in PJM, the more fast response you get, the less storage you need. When you get to something like 40% fast response, storage becomes, on a megawatt-to-megawatt basis, equivalent to the slower-responding resources.

As storage becomes less expensive to install, it becomes a way to diversify your portfolio. It is an alternative to installing another gas peaker. Storage offers shorter settlement times of five- to 10-minute intervals. This makes the choice to have storage as part of the portfolio even more compelling.

MR. MARTIN: Didn't you just say that the more storage you have, the less need there is for additional storage?

MR. HORNE: That is the kind of fast-responding benefit at current installed costs, but as storage becomes more cost effective, there will be more room for it within the existing market context.

MR. MARTIN: Let me ask the question this way. I moderated a panel discussion among CEOs at the Wall Street REFF conference two years ago. The panelists were renewable energy company CEOs. They were all turning their noses up at committing time and money to standalone storage to provide ancillary services to utilities after seeing the market in PJM for such services reach capacity quickly in a single auction. Are they wrong? Are they missing the opportunity?

MR. HORNE: I think they are focusing on what storage has been rather than what storage will become. The benefits from storage can be both on the uptake and discharge and can be controlled precisely. Those are benefits whether you are designing a high-powered, short-duration storage system or optimizing for longer duration.

The longer duration systems are becoming more and more competitive within the existing market frameworks. As more such systems are deployed, storage will become a special category. It will be considered just another option along with everything else. It will not rely on shallow markets. It can be deployed within six months at a scale of tens of megawatts. It can solve problems on the grid on a real-time basis. It will be very hard for traditional thermal resources to compete.

Installed Cost

MR. MARTIN: Karen Butterfield, what do you think is the installed cost per megawatt of battery capacity today? Start with utility scale and then move to distributed applications?

MS. BUTTERFIELD: I am not able to speculate on that. Our model does not go down that road. It focuses on the customer's load and available incentives to put together a value equation for the customer.

MR. MARTIN: But you have to pay the cost of the battery.

MS. BUTTERFIELD: We do. We made a really big mistake in solar. Solar rooftop companies talked in terms of dollars per watt. What does that mean? We are about to make the same mistake in storage. We are financing storage based on an economic starting point, and then value streams are added on top of it. I think we do ourselves a disservice if we start saying, "Storage costs 10¢ a kilowatt hour" or "It's a million dollars a megawatt." What we are really trying to do is find economically viable propositions for the customers.

MR. MARTIN: But there are two sides to the coin. Someone has to pay the cost. You are asking financiers to advance money to do so. Why is it a disservice to try to pin down what is on one side of the coin?

MR. HORNE: Storage is multidimensional. You can look at the cost in two ways: dollars per kilowatt installed or per kilowatt hour installed. It is important when looking at dollars per kilowatt also to look at the duration of the power charge.

The key thing when looking at either metric is to understand that it is just setting a foundation on which various value streams can be built. Unfortunately, the truest metric, the levelized cost of storage, which is the total value you are bringing to the customer, is complicated to calculate and is highly situational.

When looking at capital expenditures, it is important not to lose focus. At the end of the day, the key is how many megawatt hours of AC electricity the storage device can dispatch and for what duration. To give you an example, one company might have a 10-megawatt AC four-hour project. Another company might have 60 megawatt hours of nameplate storage capacity behind it because of the way the technology behaves over time, and another might have 50 megawatt hours, but the cost of that 50 might actually exceed the cost of 60. This makes it hard to compare based on a single metric.

MR. MARTIN: Katherine Ryzhaya, did you want to add to that?

MS. RYZHAYA: I am going to give a number.

We are a three-year-old company. We do not have as much experience as Stem and RES at doing these projects, but we have significant capacity. Our current operating assumption is $560 per kilowatt hour, and the breakdown between that is roughly $400 for hardware, for batteries essentially, and another $150 for installation.

And this is an important point: when people talk about the cost of lithium ion, the cost of batteries is falling, but the installation costs are not falling and often they are a significant part of the overall cost.

MR. MARTIN: That is a very interesting ratio. Is the 400 DC or AC?

MS. RYZHAYA: AC.

MR. MARTIN: Craig Horne, any other data points?

MR. HORNE: Yes. For utility-scale storage, there are obviously economies of scale, both on the purchasing side for the hardware and then installation. The value streams are different, as well, so I caution against trying to do a straight comparison to the numbers that Katherine just offered. A front-of-the-meter utility-scale storage system would be 20% less expensive for batteries going in currently.

This is on a four-hour system, so you normalize the cost of the interconnect and the other front-end items. For a four-hour system, you can be on a $1 per kilowatt basis installed at the level of the feeder.

MR. MARTIN: Name and affiliation?

MR. ELLIS: Erik Ellis, APS. This information is not secret. It might be for some suppliers, but you can go get Tesla's costs from its website. Tesla is transparent about them. The Tesla power pack comes in 200-KW building blocks. The cost is around $350 a KWh for a four-hour system. That includes the inverter. You still have to pay installation costs on top of that, but anyone can visit the website and get that information.

MR. HORNE: We found that there is a pretty big difference in cost between a power conditioning system that is basically just doing straight AC-to-DC conversion versus one that is also providing Black Star-grade performance capability. That alone can account for 25% to 30% variation in costs, depending on the manufacturer.

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ARIZONA said an electric cooperative had to pay use taxes on natural gas and coal purchased from out-of-state suppliers to fuel its power plant.

The coop owns a 605-megawatt gas- and coal-fired power plant in Cochise County called the Apache Generating Station. The electricity generated is sold to coop members and in the general electricity market.

Most states collect sales taxes on "tangible personal property" purchased in state, and they collect use taxes on tangible personal property purchased outside the state and brought into the state for use there. Without use taxes, there would be an incentive to buy everything across state lines.

The coop used to pay use taxes on the fuel, but thought better of it and applied for a refund of use taxes it paid from 2003 through 2010. The state tax department declined to refund the money. The coop sued. It lost in the state tax court. A state appeals court said at the end of March that it agrees use taxes should be paid.

The coop made two arguments, both of which the appeals court rejected.

Purchases for resale are not subject to sales or use taxes in Arizona or in most other states. The coop said it was buying the fuel to resell it in effect to its electricity purchasers. The court said the fuel is not resold but rather is consumed by the coop when generating electricity.

Most states also have sales and use tax exemptions for articles used in "manufacturing." Generating electricity is usually considered manufacturing. However, the Arizona version of this exemption requires the article "directly enter[] into and become[] an ingredient or component part of" the manufactured item. The court said the fuel is not incorporated into the electricity. It is consumed by the coop.

The case is *Arizona Electric Power Cooperative, Inc. v. Arizona Department of Revenue*.

CURTAILMENTS are a growing problem for solar projects in California.

Wind farms in west Texas are also affected.

An internal memo by the California

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Customer Arrangements

MR. MARTIN: Let me now move in another direction. The solar rooftop industry started to get real traction when it came up with a third-party ownership model. Solar rooftop companies offer to put solar on people's roofs for free. The customers pay for the electricity they use or to lease the systems over 20 years.

We have also seen companies like Mosaic and PACE loan programs get traction by making loans to homeowners who want to buy solar systems for their roofs. In the case of PACE programs, the homeowner repays the loan over time through special property tax assessments. I read that both Stem and AMS have been raising funding to enable them to offer financing to customers who want to buy batteries. Starting with you, Katherine Ryzhaya, how will the financing you are making available to customers work?

MS. RYZHAYA: It is similar to the solar rooftop model, except where the customer sees value really is in the demand component.

MR. MARTIN: So you enter into a contract with the customer. Are you actually selling the battery to the customer or are you retaining ownership and merely providing a service to the customer?

MS. RYZHAYA: We use both models. Some customers have very cheap capital — municipalities, for example — and they like to own infrastructure on their own sites. In that case, we sell the system and remain involved as an asset manager and contract operator. In other cases, we may own the system and merely provide services.

MR. MARTIN: In the third-party ownership case, is the contract with the customer for 20 years?

MS. RYZHAYA: We have contracts that range from seven to almost 20 years.

MR. MARTIN: Does the customer have to buy out the back end of the contract if he or she wants to get out?

MS. RYZHAYA: If that is how the contract is structured, yes.

MR. MARTIN: Karen Butterfield, same models?

MS. BUTTERFIELD: Largely. Our customer agreements run five to 10 years in length. Our customers pay a subscription fee. They pay hell or high water. And contracts have a termination clause.

MR. MARTIN: Are you offering these arrangements to people who have a solar system on the roof? For example, if someone has a contract with SolarCity or Sunrun to supply electricity, do you act as a separate storage company?

MS. BUTTERFIELD: We do not support the residential market, but if a commercial or industrial customer has solar, we do a system site analysis to determine whether we can save the customer enough on its bill for demand charges to make storage worthwhile. Often you can do so with solar. We look at whether the savings on demand charges more than offset the cost of the battery. In cases where a company is installing rooftop solar and wants a battery at the same time, we may own the battery and claim the investment tax credit. We go in together with the solar rooftop company and make a joint installation.

MR. MARTIN: You are teaming up with the solar rooftop companies. You are not in competition.

MS. RYZHAYA: It is the same with us. We are not in the residential market. We are in the largest C&I space, so our average installations are 500 kilowatts to multiple megawatts in size. We are working on our first solar-plus storage project now. It will be online by the summer with a partner, but we are the lead.

MR. MARTIN: SolarCity says it is getting 10 times annual growth in battery installations in the residential sector. What growth rates are you seeing in the C&I sector?

MS. BUTTERFIELD: I think Stem grew around five or six times last year. When you start with a small number, a 10-times growth is not as large a number as it sounds. I think we will to continue to see three-times growth in our industry at a minimum as new states open to storage.

A third to half of the cost of a utility-scale battery can be covered by debt.

Utility-Scale Models

MR. MARTIN: Craig Horne, let's move to utility-scale storage. You said RES works in both, but it is the one company on this panel that has a large stake already in utility-scale storage. I read that you have 47.6 megawatts in operation, 77.5 megawatts under construction, and another 200 megawatts in development, and your facilities range in size from two to about 20 megawatts. You own some batteries. Some you have sold to utilities. How do the economics work in cases where RES retains ownership?

MR. HORNE: I have updated numbers. We now have about 90 megawatts in operation and a little more than 55 megawatts under construction. We have two 55-megawatt projects in the United Kingdom that are enhanced frequency response.

We have a pretty flexible business model. We retain ownership of some of the operating projects, and we finance them on a nonrecourse basis: for example, senior nonrecourse debt from Prudential Capital.

MR. MARTIN: What is the revenue stream against which Prudential is lending?

MR. HORNE: The underlying arrangement is actually a hedge. The projects are both just a notch under 20 megawatts. The Jake project is in Joliet, Illinois, and the Elwood project is in west Chicago. The projects have a hedge contract for part of their revenue stream, and the debt is a borrowing against the fixed payments on the hedge.

MR. MARTIN: It is a hedge of what?

MR. HORNE: I can't go into the details. The business model is still pretty new. The customer is a utility.

MR. MARTIN: So the utility is the one using it as a hedge. It makes a fixed payment in exchange for floating payments of some sort.

MR. HORNE: Yes, that's it.

MR. MARTIN: The UK and Canada are two other countries in which RES is doing storage projects. Do the business models differ from what you are doing in the United States?

MR. HORNE: We have a project in Canada that has been in operation for about two years. It is a 4-MW project that provides frequency regulation services in Ontario. It is the largest battery project to date in that province. We won the right to build it through a tender. It is our second project providing such services in Ontario.

We have an operating project in the UK called Hired Hill. It is a 300-KW two-hour project. It is tied to a 5-MW solar photovoltaic plant in the Western Power Distribution network. The solar plant and battery are a demonstration project / continued page 16

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Independent System Operator CEO to the CAISO board in early February said heavy rainfall this winter in California and significant additional solar installations are expected to lead to curtailments — or cutbacks — of up to 6,000 to 8,000 megawatts of capacity this spring. The extra rainfall is contributing to bumper amounts of hydroelectricity.

Excess electricity leads to periods when merchant generators must effectively pay the grid to take their electricity. There have been three periods of negative pricing in California since 2012: April to June 2015, March to April 2016 and January and February 2017. California on-peak prices fell as low as minus $37.73 a MWh on February 23 this year.

California curtailments in January and February this year affected about 4% of electricity from solar projects. New solar projects in California are increasingly displacing other solar projects. In February, 80% of California curtailments were solar. In February, 13% of all five-minute interval marginal energy prices were $0 or below. The figure for early March was 17%.

Curtailment issues are playing out in new power purchase agreement negotiations. Bob Shapiro, a power contracts expert in the Chadbourne Washington office, said curtailment risk is usually handled by excusing payments by offtakers during curtailment periods where curtailment is due to system operating problems, but requiring payment for curtailment for economic reasons. Recently in regions like California and west Texas with higher curtailment risk, there has been a trend toward excusing payments by offtakers for periods of negative market prices up to a capped level or for a specified number of hours that can be curtailed for any reason without compensation. (For a more detailed discussion, see "Renewables Face Daytime Curtailments in California" in the November 2014 *Project Finance NewsWire*.)

THE SOLAR STOCK INDEX fell 37.3% in 2016.

The PHOTON photovoltaic stock index PPVX tracks 30 stocks listed on / continued page 17

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that is providing nine different services.

MR. MARTIN: So nine revenue streams.

MR. HORNE: Yes. Ramping, time shifting, some capacity, things like that.

MR. MARTIN: They are all forms of ancillary and capacity services to the utility?

MR. HORNE: There are some energy payments, as well.

We worked with National Grid to define a nice droop curve for storage that provides certainty of service, but that also lets us minimize the duration we have to build behind it. In places like PJM in the US, you need 20 to 25 minutes of duration behind every megawatt if you are participating in the frequency regulation market. In Germany, it is an hour and 20 minutes.

Three US states have set storage targets of 1% to 5% of peak load.

If you look at the droop curve that we worked on with National Grid, it is actually a band and the band gets narrower as the frequency diverges from its ideal point. The band allows you then to adjust your state of charge without dropping out of the market.

We have a 20-megawatt bilateral contract with National Grid to test some of these advanced droop curves. National Grid plans to add 200 megawatts of storage in each of the next five years. It awards three-year contracts.

Warranties and Debt Coverage

MR. MARTIN: Most of you are using lithium-ion batteries. For how long are the warranties you are getting from manufacturers?

MS. BUTTERFIELD: The warranties are 10 years. We supply data to the provider and it determines the worth to longevity. We have been doing batteries for almost six years. We have a lot of real-time data. Several battery manufacturers have asked us for the data because it is one of the few ways to track six years of operating history.

MR. MARTIN: Craig Horne, are you also being given 10-year warranties in the utility-scale market?

MR. HORNE: Yes, but those are considered extended warranties. You have to pay extra for them. The free part is two to three years depending on the manufacturer.

MR. MARTIN: Name and affiliation?

MR. LEWIS: Craig Lewis with the Clean Coalition. When you think about the capital structure for financing any tech project, you generally want to include as much debt as possible because it is the cheapest capital. A lender will usually require a debt service coverage ratio of something like 1.4x, and that is where the cash flow on which it is based is really stable and predictable. This might be a silly question for Craig Horne, but if you look at the ISO markets today, what percentage of the cost of the battery can be covered by debt, assuming you need a predictable cash flow stream and a 1.4x coverage ratio?

MR. MARTIN: We are down to the last 30 seconds, so let's just have a percentage if you have one.

MR. HORNE: You can cover at least half, if not more.

MR. MARTIN: That is true today or what you hope to see in the future?

MR. HORNE: That is for bids going in today.

MR. MARTIN: Karen Butterfield, do you have a percentage?

MS. BUTTERFIELD: Since he did that without the benefit of a calculator, I will take a similar flyer: 31.2%. [Laughter.]

MS. RYZHAYA: I think I am closer to Karen. ◎

Partnership Flips

by Keith Martin, in Washington

Partnership flips are used to raise tax equity in the US renewable energy market. They are not the only structure for doing so, but they are the most common, and they are the only way to raise tax equity for wind farms and other projects on which production tax credits will be claimed.

This article describes how the structure works and current issues that are taking up time in partnership flip transactions.

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

Before tax equity started to adjust pricing this year in anticipation of an overhaul of the US tax code, tax equity accounted for 50% to 60% of the capital stack for a typical wind farm and 40% to 50% for a typical solar project. The percentages are down in 2017 as investors assume lower tax rates for purposes of sizing their investments. Many deal documents provide for a one-time price reset after a tax overhaul bill clears Congress with either an additional investment by the tax equity investor or a capital contribution by the sponsor or cash sweep to return part of the investment that was already made, depending on where the final tax rate settles in relation to the rate used for pricing at original funding.

The developer must fill in the rest of the capital stack with debt or equity.

Simple Concept

Partnership flips are a simple concept. Tax benefits can usually only be claimed by the owner of a project. Partnerships offer flexibility in how economic returns can be shared by the partners. A developer finds an investor who can use the tax benefits. The two of them own the project as partners through a partnership.

In the typical partnership flip transaction, the partnership allocates 99% of income, loss and tax credits to the tax equity investor until it reaches a target yield. Cash is shared in a different ratio. After the yield is reached, the investor's share of everything drops to 5% and the developer has an option to buy the investor's remaining interest.

The typical structure is shown in Figure 1. / *continued page 18*

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public markets in different countries. At least 50% of sales of listed companies had to come the previous year from PV products or services. The stocks are weighted by market capitalization and are a cross section of both developers and equipment vendors. The 30 companies tracked include Canadian Solar, Sunrun, First Solar, Jinko, Scatec Solar, SunPower, Trina and three US yield cos: TerraForm Global, TerraForm Power and 8point3 Energy Partners.

The index has gained 242% since the start of 2003. PHOTON started tracking solar stocks in August 2001.

MINOR MEMOS. Developers are expected to sell more wind and solar projects at the end of construction to utilities in lieu of long-term power contracts: 14% of all such projects in 2017, according to *Bloomberg New Energy Finance,* compared to 7% during the period 2009 through 2015. The projects end up being put in utility rate bases. Utilities used to be unable to claim investment tax credits on solar projects in order to prevent utilities from dominating the sector. Congress dropped the restriction in October 2008 . . . . Renewable generating capacity grew 8% worldwide in 2016, according to the International Renewable Energy Agency. Of that growth, 58% was in Asia. Solar capacity additions were 71,000 megawatts compared to 51,000 megawatts of wind . . . . The Lawrence Berkeley National Laboratory reported in March that wholesale prices for wind and solar electricity have fallen to record lows in the US. New power purchase agreements are being signed at $15 to $25 a MWh in the Midwest for wind, and solar PPAs are going for $35 to $50 a MWh in the Southwest . . . . Some US states have imposed or are considering temporary limits on building new large solar projects on farmland. The states with such limits already in place or under consideration include Connecticut, Maryland and parts of North Carolina and Washington. Massachusetts is putting incentives in places to steer solar to rooftops and brownfield sites.

— contributed by Keith Martin in Washington

Partnership Flips

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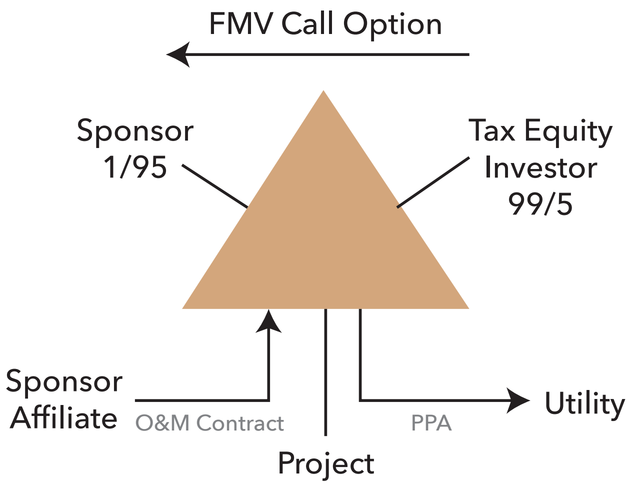
Figure 1: Basic Partnership Flip



Developers like partnership flips because they get back 95% of the project without having to pay anything for it.

In some deals, the investor takes as little as 2.5% of the cash after the flip, but this is uncommon.

The sponsor call option is usually for fair market value, although the IRS allows a fixed price that is a good faith estimate at inception of what the value will be when the option is exercised. Some developers require the investor to pay enough to avoid a book loss on sale. Sometimes the option can be exercised before the flip, but not before five years have run after the project is placed in service. Any option before the flip must pay the investor enough at a minimum to get the investor to its target yield.

The developer retains day-to-day control over the project. A list of major decisions requires consent from the tax equity investor. In some deals, the list is shorter after the flip.

The Internal Revenue Service published guidelines in 2007 for partnership flip transactions. The guidelines are in Revenue Procedure 2007-65. Some revisions were made two years later in Announcement 2009-69. Most transactions remain within the guidelines.

The individual guidelines that are most likely to come into play are that the tax equity investor must retain at least a 4.95% residual interest after the flip, the flip cannot occur more quickly than five years after the project goes into service, any option to buy the investor's interest must be for fair market value or a fixed price that is a good faith estimate at inception of what the fair market value will be at time of exercise, the investor must make at least 20% of its total investment before the project is put in service, and the investor cannot have a "put" to require the sponsor to purchase its interest.

The guidelines bar guarantees of production tax credits by anyone, including third parties, and the developer, turbine supplier and electricity offtaker cannot guarantee the output for the investor.

Most investors want to see at least a 2% pre-tax or cash-on-cash yield. The market treats tax credits as equivalent to cash for this purpose.

The IRS said in an internal memo released in June 2015 that the flip guidelines do not apply to solar projects or other projects on which investment tax credits are claimed. The memo said to apply general partnership principles to test whether the investor is really a partner. It is CCA 201524024.

The investor must not walk so close to the line as to be considered a lender or a bare purchaser of tax benefits. A lender advances money for a promise to repay the advance plus a return by a fixed maturity date.

Variations

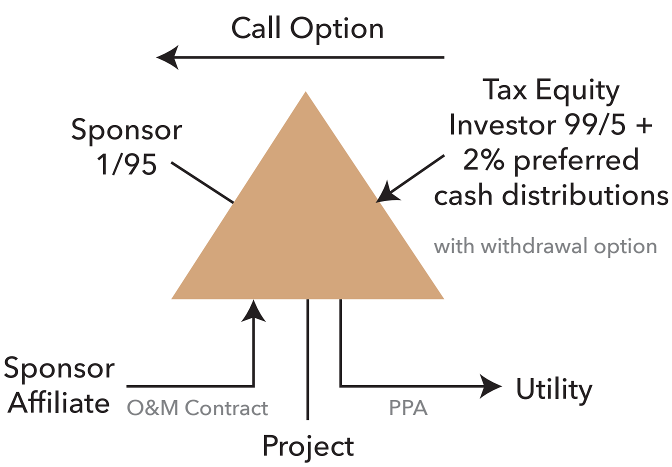
There are several variations in forms of partnership flip transactions.

At least one major investor uses a fixed or time-based flip structure. The investor flips to a 5% interest on a fixed date, usually after five years. The developer has a call option. The tax equity investor has a withdrawal right six months to a year later if the call is not exercised.

The investor in a fixed-flip transaction receives preferred cash distributions each year equal to 2% of its original investment and some percentage of remaining cash. Developers like this structure because it lets them retain as much cash as possible. Developers would rather borrow against future cash flow at a lower debt rate than a tax equity yield.

The percentage of capital raised through tax equity is down slightly in 2017 as investors anticipate lower tax rates.

Figure 2: Fixed Flip



An area of tension in fixed-flip transactions is how quickly the partnership must pay the market value of the investor's interest after it withdraws from the partnership. Most deal documents give the partnership two years. The withdrawal amount is paid out of partnership cash flow. If the full price is not paid within two years, then the investor can take the project.

Another source of tension is the developer ends up with a negative capital account because it keeps most of the cash. The consequences of this are discussed in more detail below.

Another common variation on the standard flip is a pay-go structure used in wind and geothermal deals with production tax credits. The investor makes 75% of its investment at inception or as a fixed amount over time, and the other 25% is tied to production tax credits the investor is allocated each year. The IRS flip guidelines limit the amount of investment that can be tied to output or tax credits to 25%. Investors were originally not keen on pay-go structures because they preferred to earn a return on the full investment from inception. However, they have gained in popularity as a way to mitigate operating risk and the risk that the tax law will change.

Most uses of the pay-go structure lately have been as a way for sponsors to get additional value for remaining production tax credits after the investor has already reached the flip yield. The pay-go payments are made in the post-flip period from the flip date through the end of the 10-year period for claiming production tax credits.

Absorption Problem

Almost all partnership flip transactions have an "absorption" problem. Each partner has a "capital account" and an "outside basis." These are two ways of tracking what a partner put into the partnership and is allowed to take out.

Once the investor's capital account hits zero, then its remaining share of tax losses shifts to the developer.

Once its outside basis hits zero, then any further losses it is allocated end up being suspended. They can be used only against future income the investor is allocated by the partnership. Any cash it is distributed is considered an "excess cash distribution" and must be reported as capital gain.

There are two ways to deal with an inadequate capital account. One is for the investor to agree to a "deficit restoration obligation" or "DRO." This is a promise to contribute more money to the partnership when the partnership liquidates to cover any negative capital account. On that basis, the IRS will let the investor absorb more losses. However, the investor may still have too little outside basis to absorb them immediately. Suspended losses should not count toward the flip yield until used.

The IRS said in October 2016 that it is studying whether DROs are real. The agency released a list of four factors that it said may be a sign that a DRO is not real. The practical effect of the four factors is to impose a net worth test on the tax equity investor to make sure it can satisfy the DRO. The list of factors is in proposed regulations that will not take effect until republication in final form, but some tax equity investors are moving to comply without waiting. (For more details, see "Tax Equity and DROs" in the October 2016 *Project Finance NewsWire*.)

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DROs sometimes reach 40+% of the tax equity investment. Falling electricity prices are forcing them to these levels. Investors who agree to DROs usually want to be allocated income as quickly as possible after the flip to reverse the deficit and to be distributed cash to cover the taxes on the additional income.

Such post-flip measures could turn the original 99% allocations to the tax equity investor into "tax-shifting allocations" if they are reversed within five years. The IRS does not allow tax-shifting allocations.

An investor always places a dollar limit on the DRO to which it has agreed.

Some investors wait to see how a year went and then increase the DRO after the year ends. Partnership allocations for a year can be adjusted retroactively up to the due date for the tax return for the year (not including extensions.) In most deals, once the deficit starts to contract, the cap on the DRO goes down as well.

In fixed-flip deals where the developer ends up with a negative capital account, the investor may require the developer to agree to a DRO. This makes the promise that the developer will be able to keep most of the cash somewhat illusory, since the developer may have to recontribute cash to the partnership. Special measures to reverse the developer deficit are rare.

High DROs may drive the market to look at another way to deal with absorption problems. Adding project-level debt turns part of the depreciation into "nonrecourse deductions" that can be taken by partners even after they run out of capital account. The debt also increases the investor's outside basis.

However, partners taking nonrecourse deductions must be allocated an equivalent amount of income later as the debt is repaid, thus turning the nonrecourse deductions truly into a mere timing benefit. These later allocations are called "minimum gain chargebacks." The partnership earns revenue from selling electricity. The partners must report the income. However, the cash goes to the lender to pay debt service, leaving the partners with "phantom" income: income but no cash distributions to cover taxes on the income. The minimum gain chargebacks are of this phantom income. Chargebacks are not additional income, but rather an override on how some of the income the partnership is already allocating to partners must be allocated.

If not already clear, it is important to model what will happen inside the partnership. The business deal may be to allocate income, losses and tax credits 99% to the tax equity investor, but that is usually not what will actually happen. (See "Calculating How Much Tax Equity Can Be Raised" in the June 2008 *Project Finance NewsWire* for help with how to model the deal.)

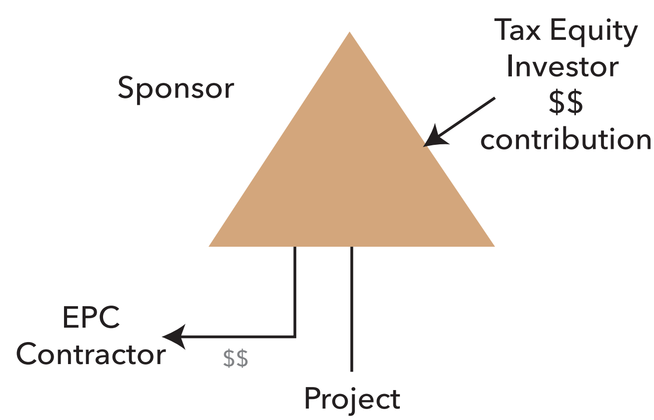
The amount of tax equity raised through a flip transaction is the present value of the discounted net benefits stream to the tax equity investor. The investor receives three benefits: tax credits, cash, and tax savings from losses. It suffers one detriment: taxes have to be paid on the income it is allocated. It discounts these amounts using its target yield to a present-value number.

Purchase v. Contribution Model

There are two ways to put a partnership flip transaction in place.

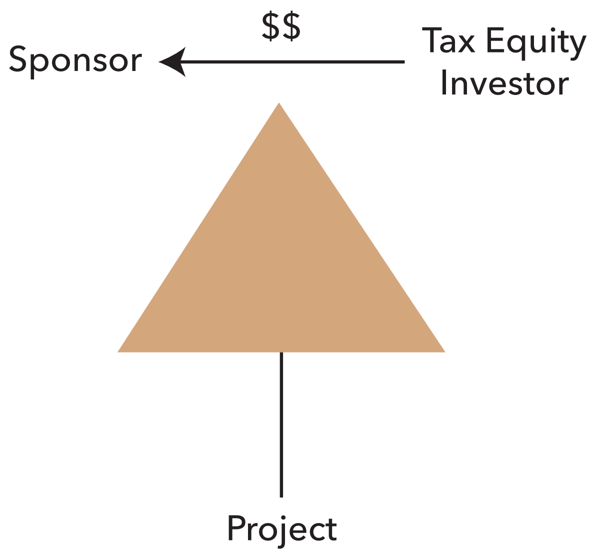
Under the "contribution model," the tax equity investor acquires an interest in the project company or a holding company in exchange for a capital contribution.

Figure 3: Contribution Model



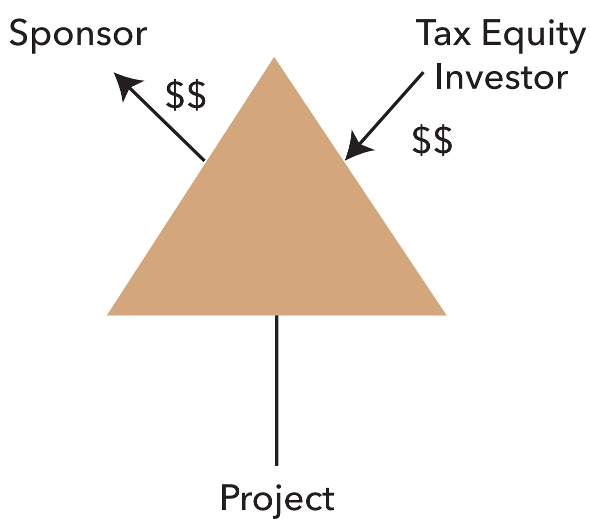
Under the "purchase model," the tax equity investor pays the developer directly for an interest.

Figure 4: Purchase Model



In the contribution model, the contribution by the investor may be distributed to the developer.

Figure 5: Contribution Model with Distribution Out



The choice of model turns in the first instance on where the money will be used. It makes sense to use the contribution model if the money will be used by the partnership to pay a construction contractor to build the project.

The contribution model is also used by developers who want to avoid having to pay taxes on the tax equity investment. The IRS may view the distribution of the tax equity contribution to the developer as a taxable "disguised sale" of the project to the partnership. Developers try to fit the distribution in a "pre-formation expenditure" safe harbor that lets the developer treat the distribution as reimbursement of its capital spending on the project over the last two years.

A project cannot be worth more than 120% of the tax basis the developer has in the project when the partnership is formed with the tax equity investor to make full use of the safe harbor. If there is a debt on the project when the entity used by the tax equity investor funds, then it will complicate the calculations to determine whether the safe harbor applies. (For a discussion about how the safe harbor works, see "Tax Triggered When Partnership Formed?" in the October 2016 *Project Finance NewsWire*.) Any developer planning to use the safe harbor should make sure the partnership agreement says that the distribution of the tax equity contribution to the developer is reimbursement of pre-formation expenditures within the meaning of section 1.707-4(d) of the US income tax regulations.

The purchase model is used when the tax equity investment will end up going to the developer. The developer is usually treated for income tax purposes under the purchase model as selling a share of the project assets to the investor. It will have to pay income taxes on its gain from the sale of that share of the project.

The purchase model leads to a "step up" in basis used to calculate depreciation and the investment tax credit on the share of the project purchased by the investor. There is no step up under the contribution model, unless the tax equity contribution is distributed to the developer in a disguised sale of the project to the partnership.

Two Biggest Risks

Tax basis remains the biggest risk in the solar market. The US Treasury started challenging solar companies on the bases they claim in 2009. There is IRS audit activity. Two closely-watched cases are working their way through the US courts. The US Court of Federal Claims decided one in favor of the tax equity investors in October 2016. The case involved a wind farm financed in a sale-leaseback transaction. The government is appealing the decision. (For more detail, see "Treasury Loses Key Case" in the December 2016 *Project Finance NewsWire*.) The other case involves the bases claimed in the solar rooftop market and goes to trial on May 1, 2017.

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Some tax equity investors are starting to limit the basis step up they will allow through payment of developer fees to 15% to 20% above project cost.

The possibility of corporate tax reform is emerging as the other big issue this year in deals. House Republicans have proposed a bill that would reduce the corporate tax rate to 20%, allow the full cost of new equipment to be deducted immediately, deny interest deductions on debt, and deny any cost recovery for imported equipment and services. Income from exports would go untaxed.

The House plan is stalled while the market waits for the Trump administration to come out with its own proposal or fall into line behind the House plan. Most Washington lobbyists do not expect a tax bill to be on the president's desk before December 1 at the earliest. In the meantime, many tax equity investors are pricing or sizing their investments using a reduced tax rate, and there is a one-time resizing of the investment at the end of the current Congress or sooner after a tax overhaul bill is enacted. In partnership flip transactions with multiple fundings — for example in the solar rooftop market — the parties debate how far a proposed adverse tax law change needs to have advanced in Congress before the tax equity investor can use it as a reason to stop further funding.

A tax rate reduction would mean less tax equity will be raised on future projects. Developers will have to make up the gap in the capital stack through more debt or with equity. A lower tax rate could also ultimately reduce the supply of tax equity, although how much is unclear. Tax equity yields are a function of demand and supply.

In a yield-cased flip, the lower tax rate could delay or accelerate the flip, depending on when it takes effect. The tax equity investor bears the risk of tax law change in a fixed-flip structure. At least one fixed-flip investor is asking developers for an indemnity to make up any loss in value of tax losses.

Tax equity investors have had little interest in the past in taking the 50% depreciation bonus on offer from the US government because they wanted to spread their scarce tax capacity over more deals. However, with the tax rate now expected to fall, many are moving to take as large deductions this year as possible. The rate reductions are expected to be phased in over time.

Back-Levered Tensions

There are a number of recurring issues in flip deals.

Many developers, particularly in the solar market, use back leverage to borrow against their shares of partnership cash flow. A back-levered loan is a loan to the developer against its share of cash flow from the partnership.

This creates tension between the back-levered lender and the tax equity investor, particularly over any cash sweeps at the partnership level that could divert cash needed to pay debt service on the back-levered debt. Cash sweeps may come up in two contexts. One is where an indemnity has to be paid by the developer. The other is some tax equity investors have a cash sweep to get back on track, in a deal that is falling behind, to reach the target yield on the date originally projected.

Many investors are agreeing to limit the percentage of cash that can be swept to mitigate the risk to the lender. Some agree not to sweep an amount of cash equal to scheduled principal and interest payments on the debt.

Change-in-control issues also come up. The lender wants a right to foreclose on the developer's partnership interest after a debt default. The tax equity investor wants an experienced renewable energy operator as its partner and may impose net worth and experience requirements on any subsequent transferee of the interest. It would be a good idea for sponsors to get agreement from the tax equity investor on the terms of a consent by the tax equity investor to such a foreclosure and subsequent sale of the sponsor interest when the flip partnership closes, if the back-levered debt will be added later, to avoid costly and time-consuming negotiations later.

The investor in a deal with investment tax credits must be a partner before the project is put in service in order to share in the investment credits. This has led to investors contributing 20% of the expected investment before the project is completed and the other 80% later. Some investors want a right to unwind the transaction if the conditions for the 80% contribution are not met by a deadline. Any unwind right should lapse once the project is in service.

Tax loss insurance is being used in some deals, especially to avoid cash sweeps. The premiums run anywhere from 2% to 5% of the potential payout. The investor should buy the insurance rather than have the sponsor do so.

Other Recurring Issues

Investment tax credits must be shared by partners in the same ratio they share in "profits" in the year a project is put in service. The tax credits will be recaptured if a partnership has more than a one-third reduction in its share of profits during the first five years after the project is put in service.

Some investors reduce their share of losses to 67% after year one until the first year there are profits, when the percentage goes back to 99%. This puts less pressure on the investor capital account. The standard partnership agreement says that once a partner runs out of capital account (plus any DRO), then its remaining share of losses will be diverted automatically to the other partners. Many tax counsel believe such a loss shift will drag production tax credits in years when losses shift to the sponsor; the tax credits are shared in the same ratio that losses end up being allocated in such years. Some counsel worry that unvested investment tax credits may also be recaptured in years that losses shift if the tax equity investor ends up with more than a one-third reduction in its share of losses in such a year. This position is not shared by most tax counsel.

Many deal documents provide for a one-time price reset after a tax overhaul bill clears Congress.

Many investors insist on holding the 99% income share for at least one full year — and sometimes for two years — of meaningful income lest the IRS say the first-year 99% allocation used to send 99% of the investment tax credit to the investor was illusory because it changed by the time there were profits.

Partnerships that generate and sell electricity must use the "inventory method of accounting." This means they can only allocate net income or net loss. They cannot disaggregate the elements that go into the calculation of net income and loss and allocate them differently. Income and loss from rooftop solar equipment that is leased to customers can be disaggregated and allocated differently.

Taxpayers cannot claim losses on sales to related parties. This means that a partnership cannot claim net losses in years when electricity is sold to a partner. In some partnerships owning merchant power projects, the developer must put a floor under the electricity price to finance the project. Any contract between the partnership and the developer should be a swap rather than a power purchase agreement, at least during the first few years before the partnership turns tax positive.

Some developers approach inappropriate parties as tax equity investors. Passive loss and at-risk rules make it hard for individuals, S corporations and closely-held C corporations to use tax benefits on renewable energy projects. A closely-held C corporation is one where five or fewer individuals own more than half the stock. Stock held by family members is combined. An investor who is subject to the passive loss rules can use tax credits and depreciation to shelter income from other passive investments, but what is considered passive income is limited. Interest received on debt instruments and dividends received on stock are not considered passive income for this purpose.

Bank tax equity investors should be careful to invest in the project company directly or one tier up. An investment higher up could run afoul of the Volcker rule that bars proprietary trading by banks. (For a discussion, see "The Volcker Rule" in the February 2014 *Project Finance NewsWire*.)

National banks cannot hold equity positions in real estate. The Office of the Comptroller of the Currency, which regulates such banks, has issued three interpretative letters analyzing partnership flip transactions. Two of the three letters said that bank participation in particular partnership flip transactions were not equity investments, but rather loans for bank regulatory purposes. The called into question the advice given in the first letter after the OCC concluded that the bank to whom the first letter was addressed had not accurately described the transaction. (For more discussion, see "The Volcker Rule" in the February 2014 P*roject Finance NewsWire*.) State chartered banks are regulated by the Federal Reserve Board rather than the OCC.

New partnership audit rules will complicate partnership tax audits starting in 2018. The IRS issued 277 pages of proposed regulations in January 2017 to implement */ continued page 24*

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them, but the regulations are temporarily frozen under a Trump directive freezing all regulations until the new Trump team has time to review them. The IRS will be able to collect back taxes directly from the partnership.

Some partnership agreements signed recently direct the managing member to elect to "opt out" of audits at the partnership level, meaning that any audits of 2018 or later tax years would be of the partners directly. Developers dislike this option because they will remain on the hook for tax indemnities, but lose the ability to handle the IRS audits that may lead to an indemnity.

Some recent partnership agreements choose a "push-out" election instead, meaning that any taxes imposed at the partnership level will be pushed out to persons who were partners in the year under audit. It is important in such cases to make clear that the back taxes will be pushed out to partners in a ratio that reflects how they agreed to share the tax risks giving rise to the back tax liability.

Some recent partnership agreements leave any liability for back taxes by default at the partnership level, meaning that the economic burden to pay these taxes will fall on persons who are partners years in the future when the partnership is audited. This may be after the flip.

Once the IRS rules in this area are finalized, there will be a push to amend many partnership agreements to make a more informed decision about the best approach. (For more detail and what options partnerships have available to them, see "US Partnerships Get a Makeover" in the November 2015 *Project Finance NewsWire*.) ◎

Batteries and Rooftop Solar

Battery installations to supplement rooftop solar systems "behind the meter" are a growing market in the United States. They accounted for 20% of the annual US energy storage market in 2016 and are expected to reach 52% by 2022. Such batteries were not considered economic as recently as a couple years ago. What has changed? Where is the growth? Two energy storage leaders who are on the Global Cleantech 100 list for 2017, and a provider of behind-the-meter ice battery storage that has customers in more than 40 US utility service territories, discussed these and other questions at the Infocast Storage Week conference in Oakland, California in late February.

The panelists are Jon Fortune, senior director of product strategy and market development at Sunverge Energy, Mike Hopkins, CEO of Ice Energy, and Ryan Wartena, co-founder of Growing Energy Labs. The moderator is Shellka Arora with Chadbourne in New York.

MS. ARORA: How big is the residential-solar-plus-storage market in the United States, and how does that market compare to other countries, including Germany and Japan?

MR. FORTUNE: Residential energy storage is the fastest growing energy market segment in the United States. Greentech Media suggests the market will be 200 megawatts a year by 2019 and around 600 megawatts by 2021.

Demand for storage hinges on rate structures. A lot of places outside the United States do not have time-of-use rate structures for residential customers that are an inducement to add storage. Germany, for instance, uses battery storage predominately as a back-up solution. Each market is different.

MR. WARTENA: It is hard to talk about the numbers at this stage because the landscape is changing rapidly. We are starting to see governments in Japan, the Czech Republic and the United Kingdom allow energy storage to qualify for the same subsidies that apply to the solar systems when storage is added to solar.

Australia and New Zealand have hundreds of thousands of small solar systems that run $6,000 to $10,000 in cost on homes, but only hundreds of battery systems. There have not been that many hardware sets. Most were initially built for Germany. Now we are starting to see LG Chem, Tesla and others move into the market down under. While the equipment remains in relatively short supply, everything is converging at the same time.

I think 2017 will be a big year for residential solar and storage. We will see people who have existing solar systems adding batteries and people with lead-acid backup replacing those with lithium-ion.

MS. ARORA: Mike Hopkins, what do you say about the numbers?

MR. HOPKINS: The residential load, after commercial, has always been the largest part of load for pretty much every utility. The problems that the utilities have managing their grids are overwhelmingly residential load problems and not commercial. That is probably because residential load is not as well-managed as commercial load.

This means that the residential load is by far the biggest opportunity for solar, but when solar penetrates residential loads, it creates a new problem for the grids, one of which is the duck-curve problem.

We have reached the point in markets, like Hawaii, with high residential solar penetration where everything has come to a head and something has to give: either there will be a moratorium on new solar installations or there has to be a breakthrough of storage.

Technologies

MS. ARORA: Is everyone in the residential market using lithium-ion batteries? Are flow batteries limited to industrial applications?

MR. WARTENA: We should see both lithium-ion and lead-acid batteries in the residential market. Flow batteries in the residential segment are a bit of a stretch. Safety is a big concern.

MR. FORTUNE: Let's emphasize the last point. Customer safety at homes is a critical issue, especially where storage systems are being aggregated by utilities. The fire hazard is on everyone's mind. Safety is critical.

MR. HOPKINS: I think one has to be creative when thinking about storage for residential use. It is naïve and unrealistic to think that we are going to have a single storage solution for an entire home and that the solution in every case is some kind of chemical battery. I am sure we will get there eventually, but we are not there today. We have chemical batteries, but they are very expensive. It makes no sense today to size them for the whole home given their cost.

We need to think today about taking advantage of different ways of storing energy, including thermal, and think on a portfolio basis. You see that in the commercial and industrial market where the most economic storage solutions are actually portfolios. There is more than one form of energy storage for the same building. The different forms of storage do different functions optimally. Flow batteries do not really compete with lithium-ion, and lithium-ion does not compete with thermal. They do storage in a different way for a different purpose. If you take that portfolio approach, then you get a much more realistic near-term solution that is cost effective and reliable.

MS. ARORA: Does a portfolio approach make sense for residential applications?

MR. HOPKINS: Generally speaking, no. Nevertheless, the portfolio approach is a great business for companies wanting to serve residential load, and I have seen it work in places. For example, in Hawaii, solar companies are interested in diversifying into multiple services for the home. A portfolio approach for the home — making the home not independent but an optimal load — is a good business in Hawaii.

MR. WARTENA: There are two sides to the residential solar equation. One is the residential load problem, and the other is the customer. The customer is usually focused on the experience and not the economics. You cannot go to a customer with just solar and storage. We are seeing a path forward where the customer first wants the ability to monitor its energy consumption, then take some easy efficiency measures, then maybe connect the hot water heater, and then do solar and storage and put in a charger for an electric vehicle, in that order. Both the energy efficiency companies and the solar companies are diversifying. They are doing hot water heaters and electric vehicle chargers and developing ways to wrap all this together for the customer.

MR. FORTUNE: The dominant delivery channel for residential customers varies from market to market.

In California, the dominant customer outreach comes from solar and other service companies, but in markets like Australia, you have retail utilities that are concerned not merely about supplying electricity, but also about broadening their reach into other services. There may be debate about how customers perceive monopoly service providers like the utilities. The bottom line is that homeowners really do not want to spend a lot of time thinking about this stuff. They want to save money on their electricity bills, and they want convenience. Capital investment is a huge problem for homeowners. The markets are evolving to attract homeowners to varying solutions. It will be interesting to see how the various types of service providers — regulated utilities, solar rooftop companies, roofers and energy efficiency specialists — vying to win over these / continued page 26

Batteries

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customers with efficiency measures will fare in the competition.

MS. ARORA: How do customers distinguish Tesla's Powerwall from Sunverge's solutions to Geli's solutions?

MR. FORTUNE: Let me start with this. I promise you I will not say Sunverge is the solution you want to select.

MR. WARTENA: You just did. [Laughter.]

MR. FORTUNE: Homeowners tend to fall into three buckets. The first is homeowners who want the fastest economic return. The second is homeowners with limited budgets looking for capital efficiency. The third is homeowners wanting to eliminate their electricity bills.

While there are a lot of ways to acquire customers, it is all about clean and concise marketing and financing packages. You need a clear offer to the customer, with an easy-to-follow description of savings and reliability, because homeowners could not care less about the mechanics and the math involved. The complications associated with programming batteries to optimize time-of-use rates and aggregation opportunities will happen behind the scenes.

MR. WARTENA: Half the value of residential solar plus storage over the first 10 years is in energy savings to homeowners, and the other half is in the relationship the homeowner has with its utility: in deferral, in demand response and in aggregation of systems. Nailing the utility half is key to getting into the residential market.

MR. HOPKINS: Marketing is a function of solar penetration. In Hawaii, where there is very high solar penetration, there is an extreme awareness of the need for energy storage that would not be true of residential customers elsewhere. Hawaiians are painfully aware because they are now under a self-supply regime instead of net metering, and they have lost 40% of the value in what they are generating. It is a different market than on the mainland, but I think it is the market of the future.

Economics

MS. ARORA: Is residential storage currently economic anywhere besides Hawaii, and is my assumption correct that it is already economic in Hawaii?

MR. HOPKINS: I can speak about Hawaii. Some types of storage are already economic in Hawaii. At $200 dollars a kilowatt hour, it is economic for a homeowner to add storage to a solar rooftop system, but we are talking thermal storage rather than lithium-ion batteries, as the latter do not pencil out in cost right now, plus the homeowner must view storage as a long-term investment rather than something that produces a quick payback.

MR. WARTENA: On that topic, anyone who has not seen a NOVA special on PBS called Search for the Superbattery should watch it. It is super cool. [Laughter.]

MR. FORTUNE: My view is the economics work currently in Hawaii. We have less than 10-year paybacks in Hawaii. You cannot fail to have good paybacks with electricity costing 45¢ a KWh.

The future, as we are seeing it evolve in California, is time-of-use rates and big price spreads between rates at different times of the day. In places where the price spread is 15¢ to 20¢ a KWh between peak and off peak rates, storage has a big effect on a customer's utility bill.

The challenge in California is we have different winter and summer rates, and if your peak periods are any wider than four or five hours, then you start to accrue more cost because you are going to consume more energy during peak periods. The point is there are ideal cases for how time-of-use rates fit with energy storage, and such a wide band may not work.

There are also places where it is advantageous to have a larger storage system. For example, with one of the time-of-use rates in the Southern California Edison territory coupled with the new self-generation incentives, having a 20-KWh battery provides a better return on your investment than having a 12-KWh battery.

We are seeing positive return on investment within the

Residential battery storage is the fastest growing US energy market.

warranted period of the product in a lot of markets: certainly in Australia, New York, California, Hawaii and Arizona.

This is a big year for storage, specifically in California where the new residential incentives are a game changer. In the past, incentives were available, but those incentives got sucked up by the commercial and industrial market, and now we have incentives carved out for energy storage projects smaller than 10 kilowatts. We are going to see higher storage adoption in California than we seen in other places.

In Hawaii, storage is a requirement if you want to go bigger than offsetting 20% of your energy with a small PV system.

Higher adoption rates for storage in California and Hawaii will increase customer and brand awareness, which Tesla proved is critically important to market viability. I think utilities are also becoming more aware and interested in residential storage.

MS. ARORA: Weren't time-of-use rates optional until recently for residential customers in California?

MR. FORTUNE: Yes. I think customers across all states will see wider adoption of time-of use rates as technologies enable people to not to have think about them.

MR. HOPKINS: Rates and rebates are beginning to reflect the real world, and that is good for energy storage and solar. In the real world, energy does not have a flat value or a flat cost but, historically that is how ratemaking has been done with residential customers. As the market moves toward time-of-use rates, which is still not truly real world, they are more reflective of real world.

The self-generation incentive program in California — called SGIP — is a good program in terms of correctly capturing approximately the value that utility customers provide the rest of the grid when they invest in technologies that are good for the rest of the grid.

When you have both time-of-use rates and SGIP together, then you have utility customers being properly rewarded for good behavior or properly penalized for bad behavior.

I do not view them as subsidies or incentives. You are merely giving the right economic signals.

MR. WARTENA: Let us take rate structures to the limit. What is the limit? The limit would be exposing residential customers to real-time market prices. We are seeing that in Kentucky, Australia and New Zealand.

Utilities are figuring out how to get into distributed energy, and they are redefining the relationships with the customers.

MR. FORTUNE: Coming back to time-of-use rates, Hawaii lowered the value of solar during daytime periods in exchange for shifting the peak price. The off-peak price is higher than the daytime price because Hawaii has so much renewable capacity.

A static price structure that has high price periods from 2 pm to 8 pm is not a given under all circumstances in the future. There are places that are creating day-ahead dynamic hourly price signals for residential customers. San Diego Gas & Electric is enabling integration projects by providing locational price signals for electric vehicle charging. They are combining demand and distribution costs within a single energy price.

Net Metering

MS. ARORA: Does net metering discourage installation of batteries?

MR. HOPKINS: Net metering has been an important part of incentivizing adoption of solar, but it is a short-term phenomenon because, as solar adoption grows, you will lose net metering because the utility will not be able physically to handle the solar over generation. The utility will do what Hawaii has done. It will go from net metering, which is subsidization, to self-supply, which is recognition that once you have over generation, net metering does not have a positive value at all. It has a negative value.

MR. FORTUNE: Customers in Hawaii have time-of-use rates, but they do not have hourly residential customer profiles that one can download and determine the right system size. Smart meters are important. They provide hourly profiles for each homeowner. This is important to determining the economic value proposition with time-of-use rates. It is challenging, without smart meters, in Hawaii to determine the economic value proposition of installing a battery.

MS. ARORA: What are your thoughts about the approaches that different utilities are taking? Some are worried about grid defection while others, like Hawaii, which has the self-supply program, and Green Mountain Power, which is offering Tesla batteries for either leasing or owning, are trying to capture new opportunities?

MR. HOPKINS: Within the United States, there is a complete spectrum from attempts to prevent home solar installations, at least owned by the homeowner, all the way to strong encouragement and everything in between. Even where there are efforts to slow down solar, the declining cost and popularity of solar mean it spreads everywhere. Even in states that are not ideal in terms of sunlight, it is just going to happen, and all we are talking about is the rate at which it happens. Another reality is that, as solar gains greater market penetration, the */ continued page 28*

Batteries

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continuation of net metering becomes unrealistic. Net metering is just a form of storage, and there will have to be local storage solutions.

MS. ARORA: Jon Fortune, can you speak about different business models?

MR. FORTUNE: In any given market, there is not going to be a single business model. The challenge today is that without utility ownership or involvement, market mechanisms have not matured enough to all small-scale resources to capture the full value streams. That will change over time. The different business models — from a partial-ownership structure to customers buying systems outright to solar providers providing financing with no ownership by customers — are designed mainly to get customers to sign. The models will co-exist but evolve over time as we get smarter about which business models work in which markets with which customers.

MS. ARORA: How are batteries being added to existing systems? How does it affect the economics for the solar companies?

MR. FORTUNE: The federal investment tax credit is important. Putting batteries in existing solar systems is economically challenging. We are seeing that solar companies are very interested in having storage as an asset, longer term, and having it be a separate asset from the solar system. It is easier from a bankability standpoint to treat the devices as separate and allow the storage device to charge from the solar and dispatch.

MR. HOPKINS: Utility procurements have changed. All of our contracts with utilities until two years ago were product purchases. Now all of our business is power purchase agreements, which is a good thing. There is a lot of appetite for investors to invest in projects with 10- to 20-year power purchase agreements with utility credit. Such contracts support the scale in which utilities are interested today. ◎

Argentina Plans to Auction More PPAs

by Rachel Rosenfeld, Monica Borda and Shalini Soopramanien, in Washington

Argentina is expected to auction another round of power purchase agreements for renewable energy projects as early as July or August.

Several thousand megawatts of projects that were awarded PPAs in late 2016 are just starting to seek financing, creating something of a potential backlog. A trust arrangement, called FODER, and a World Bank guarantee that stands behind key government payment obligations and potential "put" payments by the trust are expected to be a key element in the financings.

Opportunity Knocks

Argentina is Latin America's third-largest power market, with around three quarters of generating capacity owned by private companies. Its electricity demand continues to grow: forecasts suggest 6% annual increases in electricity load. Argentina's government wants to increase the share of renewable energy to 20% of the energy mix by 2025.

Argentina is in need of additional generating capacity and new transmission lines. Low investment during the last few decades in the power sector has led to blackouts and consumption restrictions. Argentina's grid is operating at near capacity and without a reserve margin. Energy consumption has grown while generation has remained flat.

Argentina's power market is dominated by fossil fuels, which account for approximately 80% of its total energy mix. Argentina has had to import gas from neighboring countries.

In terms of geography, Argentina is well-positioned as one of the windiest and sunniest places in the world, with a large area of semi-desert in its north and a windy area in the south. The abundance of windy regions, high insolation and dry weather conditions are ideal for renewable energy.

The new government that took office in December 2015 has enacted a series of market-friendly reforms aimed at increasing renewable energy, promoting foreign investment and reintegrating Argentina into the global capital markets. Market reforms include eliminating foreign exchange and capital controls, unifying the exchange rate, negotiating and executing a successful agreement with holdout creditors, modernizing the import regime, reducing inflation and reforming the national statistic system. In April 2016, the government sold US$16.5 billion of dollar-denominated bonds to international investors in a single day, which marked a record for an emerging market.

Current Challenges

Despite the promising statistics, economic and institutional challenges remain.

On the economic front, the Argentine economy grew rapidly in an inclusive manner after the 2002 crisis, with an average GDP growth of 3.5% from 2010 to 2015. This rapid growth derived from export gains, internal consumption and private investment. However, economic activity contracted by 2.3% during 2016. The GDP is expected to resume growing. The latest World Bank forecast is for 2.7% annual growth in 2017.

Inflation remains in the double digits. Argentina's annual inflation rate is currently at about 20%, down from an estimated rate of about 40% in 2016. The central bank is targeting a 5% inflation rate three years from now.

Argentina is expected to auction more PPAs as early as late summer.

The government implemented measures to ensure that tariffs for generation, transmission and distribution accurately reflect costs. To offset the impact of such measures on low-income energy users, the government recently introduced a new, reduced "social tariff" that entitles certain users to subsidies on the basis of income and assets owned.

There is too little transmission capacity for projects already awarded. Argentina will need to add 5,000 kilometers (3,100 miles) of transmission lines in the next three years in order to bridge the transmission infrastructure gap.

Government Policies

The government has put in place a string of policies to help renewable energy, including tax relief and financing incentives for private investment, RenovAR, an auction program to award power purchase agreements to renewable energy projects, and FODER, a government trust fund set up to provide payment guarantees to support all tendered PPAs and project financings. (For earlier coverage, see "Argentina Launches Innovative Renewables Program" in the June 2016 NewsWire.)

The government issued a new Decree 9 in January 2017 naming 2017 as the year for energy diversification through the use of renewable energy for electricity generation. Decree 9 lists the motivations: reduction of greenhouse gas emissions, creation of local jobs in construction, development, and operation and management services and a move toward greater self-sufficiency in energy supply.

The government is still studying ways to set prices, trading rules and guidelines for bilateral contracts between consumers and generators.

In the meantime, by law, all electricity consumers with loads of 300 megawatts or more can buy power directly from clean generators to meet an 8% renewables target set by Law 27,191 in December 2017. Because wind and solar power can be purchased more cheaply in the wholesale market than from national grid operator CAMMESA, consumers and generators are already preparing for a private PPA market that is expected to reach 1,000 megawatts a year.

Q3 Auction

Argentina is planning at least four energy auctions this year that are expected to attract as much as US$7 billion in investments for both conventional and renewable power plants. The country will hold two auctions for new thermal capacity, one for renewable energy and one for new transmission lines. The government is considering a possible fifth auction for thermal projects.

As much as 6,500 megawatts of new capacity will be added to the grid over the next three years. That includes 3,600 megawatts of fossil-fuel projects and 2,800 / continued page 30

Argentina

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megawatts of renewable energy projects other than hydropower.

The renewable energy auction is expected in July or August.

Companies that won contracts to deliver electricity in earlier auctions are still seeking financing to build projects. About 3,000 megawatts of renewable power projects were auctioned in 2016. The 2017 auction has been pushed back as the winning bidders in the 2016 auction are still looking for financing. There is a concern that if Argentina holds the next auction too soon, before new projects already auctioned are structured, they might generate a bottleneck on the financing side.

Argentina has set up a system to monitor the status of the projects and government officials will meet with project developers and sponsors to help smooth out any problems they face with national and provincial government red tape.

The lack of transmission capacity may dampen enthusiasm for the auction this summer, as most of the country's transmission capacity was filled by projects from the first two auctions last year. There are limited transmission nodes in areas with good wind and sunlight.

The two auctions under the RenovAR program in 2016 were viewed as successful. Projects already awarded should bring the national renewable mix to 6% of total generating capacity. The winning projects signed 20-year PPA agreements with CAMMESA within 60 days after the contract awards. The projects must be in operation in 2018.

Round 1 initially offered 600 megawatts of wind, 300 megawatts of solar, 65 megawatts of biomass, 15 megawatts of biogas and 20 megawatts of small hydropower capacity, but the solar figure was increased to 400 megawatts after 123 bids were submitted for more than 6,300 megawatts. The winning bids included 12 wind projects with a combined capacity of 708 megawatts, four solar projects with a combined capacity of 400 megawatts, and one biogas project of 1.2 megawatts.

Argentina launched round 1.5 on heels of the announcement in October 2016 of the winning bidders in the first-round auction. Round 1.5 offered contracts for 600 megawatts of projects, divided into 400 megawatts of wind and 200 megawatts of solar. Only projects that failed to secure a PPA in the round 1.0 tender or that did not qualify for the process initially were able to take part in the additional round. Round 1.5 received bids for 2,500 megawatts. A total of 30 projects were selected in November 2016 under this additional tender, including 10 wind projects, representing 765.4 megawatts of capacity and 20 solar projects, representing 516.2 megawatts. The total capacity awarded was more than double the 600 megawatts the government had requested.

The winners of rounds 1 and 1.5 are expected to need US$4 billion in long-term debt and US$2 billion in equity.

Average prices for PPAs came in at US$59.70 a MWh for solar and US$59.40 a MWh for wind in round 1, and US$54.90 a MWh for solar and US$53.3 a MWh for wind in round 1.5.

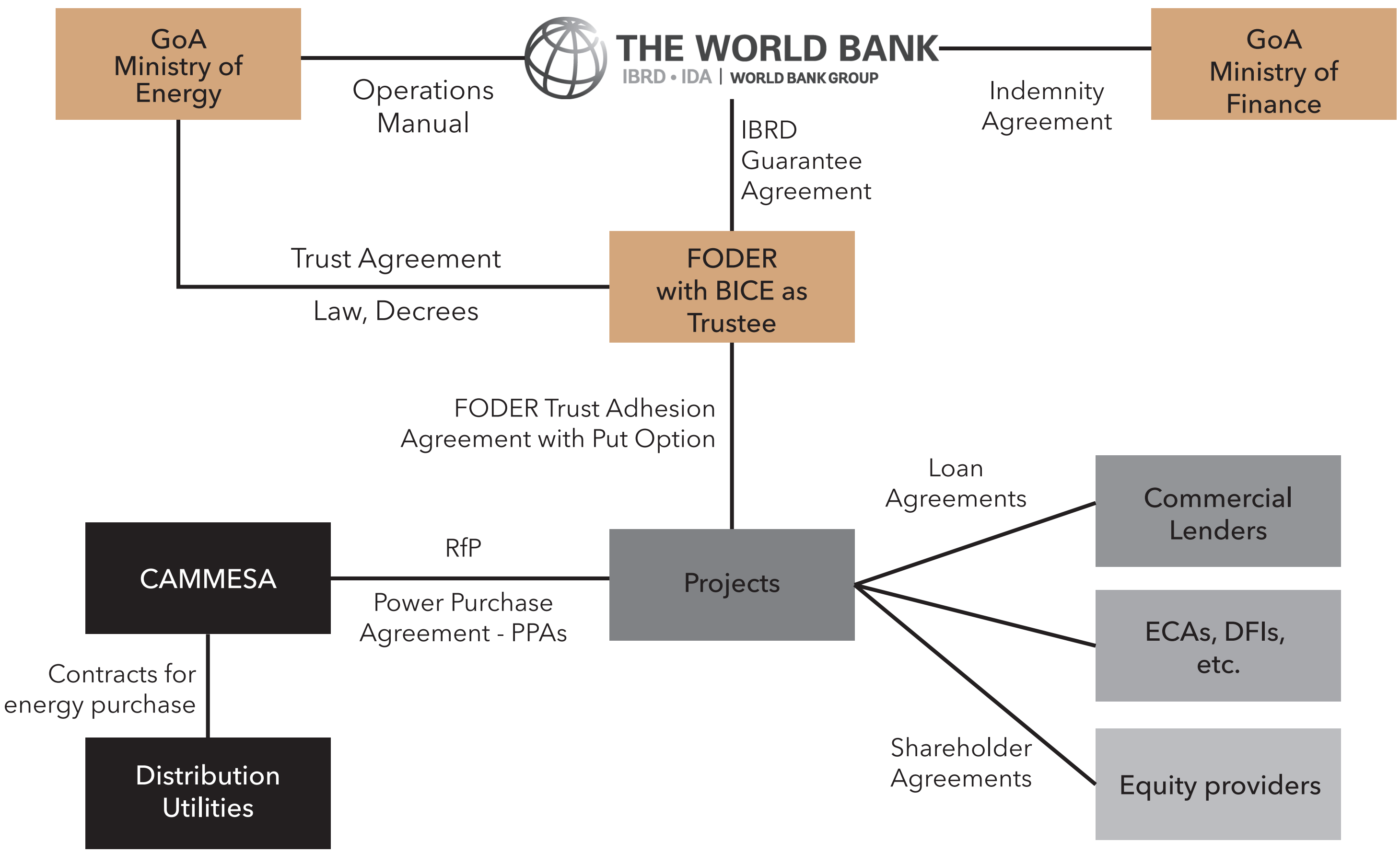
The lowest price was US$ 46 a MWh for the Pampa wind project, a bid by Sinohydro, a Chinese state-owned hydropower engineering and construction company. The renewable energy tenders may be as much as US$10 to $20 a MwH below the prices necessary to compensate for Argentine risk, according to recent market surveys. These prices reflect the competitive participation of Chinese capital (including entities such as Envision in wind and Power China in solar) and Chinese technology in the winning bids.

World Bank Guarantee

World Bank guarantees contribute to the success of the RenovAR program.

The World Bank approved US$480 million in guarantees in early March 2017 to backstop critical aspects of payment guarantees by the government to projects under PPAs awarded in the round 1 and 1.5 auctions in 2016. The World Bank estimates that its guarantee package will help leverage approximately US$3.2 billion in renewable energy financing under rounds 1 and 1.5, which is 6.7 times the amount of the guarantee itself, with a further US$2.5 billion from commercial sources.

The World Bank's International Bank for Reconstruction and Development (IBRD) not only issues loans to governments of middle-income and creditworthy low-income countries on commercially attractive, non-concessional terms, but also provides project-based guarantees. These guarantees are issued for the benefit of specific projects in World Bank member countries seeking to attract private investment. Private investors (domestic or international), as well as sovereign, sub-sovereign and state-owned enterprises, are eligible to apply for a project-based guarantee from IBRD. IBRD considers a number of factors when determining whether a given project (public or private) is eligible for guarantee support, including, but not limited to, the project's development impact, its ability to attract private loans or equity investment, and the project's technical and financial viability and



Source: World Bank Group

sustainability in the short, medium and long terms. (For additional information, see "Guarantees for Investments in Emerging Markets" in the August 2016 *Project Finance NewsWire*.)

The success of rounds 1 and 1.5 was due, to some extent, to the "halo" effect of the IBRD guarantee. According to the World Bank, 15 of the 29 awarded sub-projects in RenovAR round 1 with an aggregate installed capacity of 590 megawatts and a value of US$295 million requested the IBRD guarantee. For RenovAR round 1.5, 12 of the 30 awarded sub-projects with an aggregate installed capacity of 443 megawatts and for a total value of approximately US$184.3 million requested the IBRD guarantee. These projects include 10 solar photovoltaic (306 MWs), 12 wind projects (721 MWs), four small hydroelectric projects (4 MWs) and one biogas (1 MW).

The IBRD will backstop certain "put option" payments that the FODER trust might have to make. A project can be put to the trust after any of five events of default: extended default by the offtaker under the PPA, inconvertibility of the Argentine peso, transfer restrictions, material adverse changes to FODER's operations without the sub-project's prior consent, and non-compliance with an arbitral award or judgment.

FODER's "put option" payments are a type of termination coverage available to investors that entitles them to sell their projects to the FODER trust if certain macroeconomic or sector-specific risks materialize. The five events of default are an example.

Innovative Structures For African Projects

by Shalini Soopramanien, in Washington

Africa will have to turn to innovative financing structures to reach a goal of financing the large number of power and other infrastructure projects needed to meet existing demand and satisfy the growing population.

This article discusses three such structures.

The energy deficit in Africa is both immense and well documented. Today, 620 million people in Africa do not have access to electricity, which represents nearly two thirds of the total population of the continent. According to the latest Africa Progress Panel report on electrification in Africa, the number of Africans without access to power is projected to increase by 45 million in 2030 if current trends remain unchanged. A detailed breakdown of the statistics paints an equally alarming picture: the average African (excluding South Africa) uses just 160 kilowatt hours of electricity per year whereas the average American consumes over 13,000 kilowatt hours per year.

Despite these enormous energy challenges, Africa boasts vast, untapped potential in power generation, in particular in its renewable energy potential. Africa has a staggering 10,000,000 megawatts of potential solar energy, 350 of hydroelectric power, 110,000 of wind power and 15,000 of geothermal energy. This vast energy potential, coupled with the continent's rapid population growth as well as recent cost reductions in renewable power generation technologies, represents a promising investment opportunity.

A recent report by McKinsey & Company suggests that, in order to realize its full energy potential, Africa as a whole will require about US$490 billion of capital for new generation and another US$345 billion for transmission and distribution.

Innovative financing solutions involving both public and private sectors are key to unlocking Africa's untapped energy potential and generating the investments required to secure the success of viable and sustainable energy projects.

Obstacles to Investment

Risks accompany rewards, and Africa is no exception. There are multiple risks — financial, credit-related and political — that investors face whenever investing in energy projects on the continent.

In order to mitigate these risks, independent power producers typically request a sovereign guarantee from the host government to cover potential termination payments and offtake obligations under a power purchase agreement. However, a sovereign guarantee is only as good as the government issuing it. In accounting terms, a sovereign guarantee is a contingent liability on a sovereign's balance sheet. Problems arise whenever a sovereign reneges on a sovereign guarantee or refuses to honor the contingent liabilities on its balance sheet.

A case in point is Tanzania's state-owned utility, Tanzania Electricity Supply Company (TANESCO), which has been in arrears in its payments to SonGas Limited, an independent power company that runs a gas-powered plant in Dar es Salaam and contributes nearly 20% of Tanzania's grid power. SonGas's investment is backed-up by a sovereign guarantee from Tanzania, but when, in December 2016, SonGas threatened to suspend its operations due to long-standing arrears by TANESCO, the sovereign guarantee was of no avail and arrears continued to grow.

At the other end of the spectrum is Kenya, which refrains from granting sovereign guarantees in energy projects and has instead resorted to issuing "strong letters of government support." One such letter of support was recently issued by the Government of Kenya to support the development of the US$144 million Kinangop wind farm in Nyandarua county in central Kenya, which has since been placed in receivership and is currently the subject of an International Chamber of Commerce arbitration. The outcome of this arbitration will help shed light on the value of letters of support, both practical and juridical and the protections they afford, if any, to their beneficiaries.

Development finance institutions (DFIs), including the World Bank Group and the African Development Bank (AfDB), provide important sources of funding through a combination of grants, equity investments, debt finance (oftentimes on concessional terms for low-income countries), guarantees and credit enhancement products on a project-by-project basis. Insurance products are also provided by certain DFIs, such as the Overseas Private Investment Corporation and the Multilateral Investment Guarantee Agency, export credit agencies and private insurers.

For its part, the World Bank recently announced that it would be investing US$57 billion to accelerate growth and development in sub-Saharan African countries over the next three years. By contrast, the AfDB launched the "New Deal on Energy for Africa," which represents a commitment of US$12 billion on energy over the next five years with a goal of leveraging US$50 to US$60 billion from the private sector and other financial partners.

Investors would do well to study the DFI's terms and conditions for funding carefully to determine whether they meet a particular DFI's eligibility requirements and strategic sector areas. Investors must also bear in mind that DFIs offer a limited range of products, which might not always respond to their particular needs.

More recently, in late March, French development agency, Agence Française de Développement (AFD), launched the "African Renewable Energy Scale-Up" facility at the Africa CEO forum in Geneva. This €24 million facility will help fund early-stage development of innovative on-grid and off-grid renewable energy projects, in particular solar energy projects, as well as other technologies like biomass, wind and mini-hydro.

In light of the uncertainty of sovereign guarantees and the limited product offerings of DFIs, investors will need to turn to more innovative financing solutions that better address their needs and mitigate the risks of their investments.

There are three recent financing solutions in particular that deserve to be highlighted and are explored further below. They are public-private partnerships (PPPs), green bonds and the put-and-call option agreement.

Public-Private Partnerships

Traditionally, infrastructure projects in Africa are financed through the public sector, using tax revenues or public borrowing. Of late, however, African governments have become increasingly attuned to the advantages of using private sector capital for public services. With private sector investment in Africa's public infrastructure growing, PPPs have emerged as the favored vehicle for infrastructure projects, particularly in the power and transport sectors.

The development of PPPs in Africa is still in its nascent stage, and there are countries that have yet to develop the necessary legal and regulatory framework for PPPs or that lack the technical skills to manage PPP projects.

Nonetheless, there are a number of initiatives that have been rolled out with the aim of supporting the deployment of PPP projects across Africa.

South Africa's "Renewable Energy Independent Power Producer Programme" is one example of a successful partnership between the private sector and the government to promote renewable energy projects under a clear procurement structure with firm bidding deadlines.

Another is the World Bank Group's "Scaling Solar" initiative, which provides a holistic, one-stop shop for investors and developers seeking to de-risk investment opportunities in emerging markets, by using the whole suite of World Bank Group products on a PPP basis. (For more information on Scaling Solar, see "Off the Grid in Africa" in the February 2017 *Project Finance NewsWire*).

Africa50 is an infrastructure fund established by the African Development Bank in 2012 and headquartered in Casablanca that is designed to accelerate infrastructure development and PPPs in Africa, particularly in the energy, transport, information and communication technology and water sectors. Africa50 mobilizes funds from African governments, DFIs and institutional investors, including pension and sovereign wealth funds. Its stated objective is to shorten the time period from project conception to financial close, bringing it down from an average of seven years to under three years. In December 2016, Africa50 signed a joint development agreement with Scatec Solar and Norfund to mobilize resources for the development phase of an 80-megawatt solar photovoltaic project in Nigeria. The electricity will be sold to state-owned offtaker, NBET, under a 20-year PPA.

Africa GreenCo is one of the latest innovative solutions geared towards de-risking projects in Africa. Africa GreenCo seeks to mitigate two main risks: lack of creditworthy offtakers and lack of a viable power market in which to sell the electricity.

Africa GreenCo is currently in the feasibility stage. It will involve setting up a PPP in the form of / continued page 34

Three innovative financing structures are being used in Africa.

Africa

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a single, creditworthy counterparty who will sit between buyers and sellers of electricity from independent power projects in sub-Saharan Africa. According to Africa GreenCo's recently published feasibility report, Africa GreenCo will serve as an "independently managed, creditworthy (investment grade), intermediary offtaker and power trader" that would complement existing structures. Africa GreenCo proposes to operate as a member of the African regional power pools. In the event that a utility defaults on its electricity purchase obligation, Africa GreenCo would have the option to sell the power to other utilities or via the regional power pools.

This innovative structure brings many benefits, including creating a more favorable, certain investment environment for investors and, quite interestingly, allowing "open access" to DFI credit support for private investors. Africa GreenCo aims to replicate the success of PTC India Limited. PTC was similarly established as a credit risk mitigating intermediary offtaker for private power project developers and served as the catalyst to develop the Indian subcontinent's regional power sector trading market.

Green Bonds

Green bonds are another alternative innovative method of raising funds domestically and internationally for projects that support environmentally-friendly and climate-focused projects.

The proceeds from green bonds are earmarked for environmentally-friendly projects. Moody's, which launched a service aiming to standardize green bond issuances last year, predicted that green bond issuances in 2017 will reach a record US$206 billion, following an increase of 120% to US$93.4 billion in 2016.

In November 2016, the Morocco Agency for Solar Energy (Masen), a public-private venture established by Moroccan Law No. 57-09, issued Morocco's first sovereign-guaranteed green bond to help finance three separate solar photovoltaic plants comprising the "NOOR PV 1" program. The proceeds of the 1.15 billion dirham (US$118 million) green bond will be used to fund two of the plants — the 80-megawatt NOOR Laâyoune and 20-megawatt NOOR Boujdour projects — and part of the cost of the third — the 70-megawatt NOOR Ouarzazate IV power plant. Additional funding in an amount of €60 million will be provided by German bank Kreditanstalt für Wiederaufbau (KfW) to cover the cost of the NOOR Ouarzazte IV project.

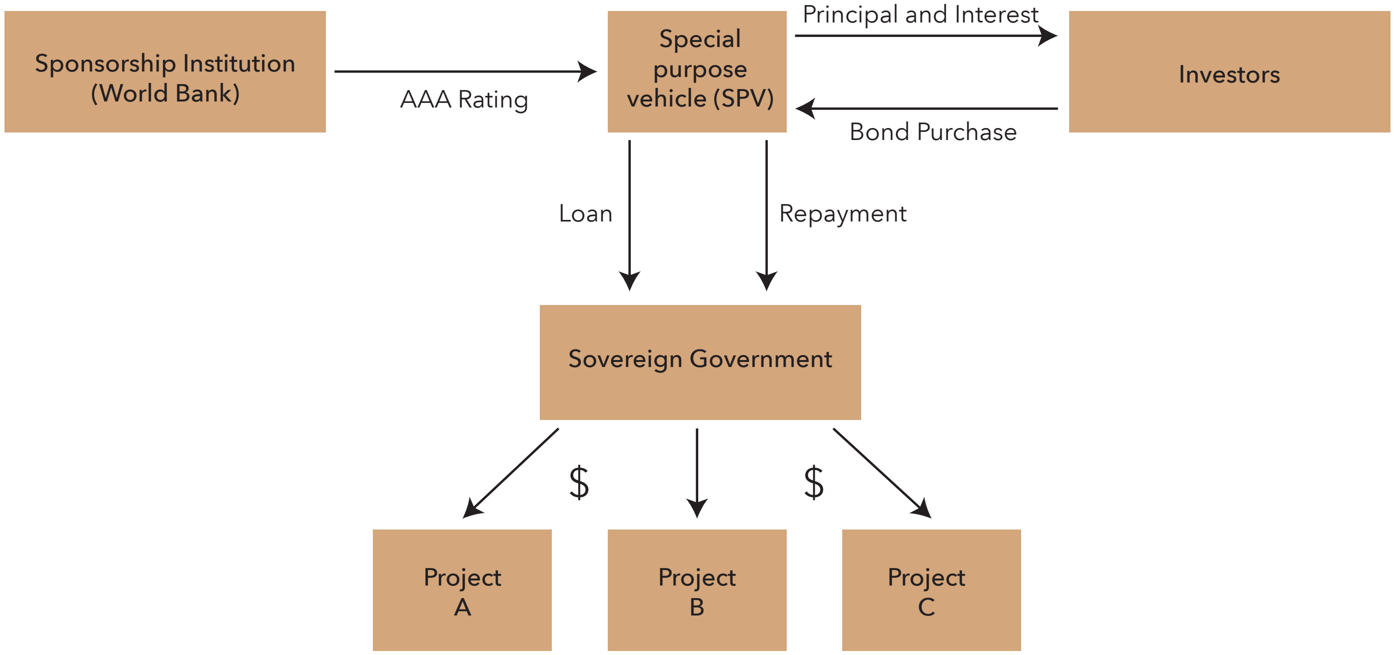
Last year, Masen signed a 20-year power purchase agreement with a consortium led by leading Saudi-based electricity company ACWA Power for the development and long-term operation of the three projects under a BOOT (build, own, operate and transfer) scheme. Masen will use the green bond proceeds to fund its obligations under the PPA.

In West Africa, Nigeria is gearing up to float a proposed N20 billion (US$64 million) sovereign green bond under the first tranche before the end of the first quarter of this year, the proceeds of which would fund a range of climate-related initiatives, including energy, transit and afforestation programs.

The challenge for African countries will be to attract enough funding through green bond issuances to meet project needs. The key will be to aggregate projects in order to create a more attractive value proposition to local and international investors.

DFIs, such as the World Bank, also issue green bonds. An innovative feature of these green bond issuances is that a host government can leverage a sponsor institution's credit rating to issue a debt that is to be repaid through a loan to the host government. For example, the World Bank could issue a green bond to help finance an infrastructure project in an emerging market, Country X. Country X would then repay the World Bank on the bond. Country X would benefit from the higher credit rating derived from the World Bank's financial standing, which in turn would result in cheaper capital than if Country X were to issue the bonds on its own. This model has been applied in World Bank's

Put-and-call options can sometimes replace traditional sovereign guarantees.



Source: Milken Institute

green bond issuances. The diagram on this page shows how to leverage a sponsor insitution's credit rating through a green bond issuance.

Put-and-Call Option Agreement

Yet another alternative innovative financial solution is the put-and-call option agreement (PCOA), which was first used in the 450-megawatt open-cycle gas-fired Azura-Edo project in Edo State, Nigeria, that reached financial close in 2015.

The PCOA establishes a direct contractual obligation between the host government and the project company. It in effect replaces a traditional sovereign guarantee or letter of support with a contingent real estate transaction. The PCOA provides both a "put" option in favor of the project company and a "call" option in favor of the Nigerian Finance Ministry, that are subject to certain conditions, which typically include the termination of the PPA after certain specified "trigger" events.

The "put" option, if exercised by the project company, requires the host government to purchase the plant or the assets of the project company by a date certain for a pre-agreed purchase price. Conversely, the "call" option is a discretionary right of the host government to require the project company and shareholders to sell the plant or the assets of the project company on a date certain for a defined purchase price, which may vary according to the circumstances (such as a seller default under the PPA) that triggered the government's exercise of the call option.

The PCOA was key to the financing of the Azura-Edo project that is due to come online in 2018. In Azura, the federal government of Nigeria decided to adopt a PCOA structure rather than the traditional letter of support. The PCOA granted the government the option of purchasing the plant (or the project company's shares) in the event of an early termination under the PPA after certain trigger events. This call option gave the government added comfort, in the event of an early termination under the PPA, by assuring the government that it would be able to recoup the physical assets of the project if certain conditions were met. The PCOA structure in Azura is now being considered in other projects across sub-Saharan Africa and beyond. ◎

Emerging Themes in Bankruptcies

by Howard S. Beltzer and Eric Daucher, in New York

More than 200 US oil and gas exploration and production companies carrying more than $100 billion in debt have filed for bankruptcy since late 2015.

Most are trying to restructure their debts and reemerge from bankruptcy.

Common themes have emerged in the strategies these companies are using to do so.

Price Collapse

Beginning in mid-2014, prices of crude oil and other commodities experienced sharp declines from the historically high prices of preceding years. As low crude prices persisted throughout 2015, a significant portion of the US oil and gas oil exploration and production industry became distressed.

By late 2015, a large number of Ef&P companies had filed for chapter 11 protection (and, in some instances, chapter 7 liquidation).

The trend accelerated into 2016 as scheduled borrowing base redeterminations drove production companies into bankruptcy. The financial distress of production companies caused immediate spillover distress for oilfield services companies, which have sought bankruptcy protection at a comparable rate, albeit with less aggregate debt. Nor have mid-stream companies been spared from the wave of bankruptcies.

Given the sheer number of E&P bankruptcy filings, and the prevalence of "repeat players" among investors, lenders and restructuring advisors, it is unsurprising that common themes have emerged in the strategies these companies are using to exit bankruptcy.

This article addresses those themes so that company managers, equity investors, and lenders involved in the sector can better prepare.

Theme 1

Most chapter 11 restructurings rely on either a debt-for-equity exchange where old lenders become new equity holders and old equity holders' rights are substantially diluted or even extinguished, or on a sale of the company's assets usually free and clear of all liens, claims and other encumbrances.

Outside the E&P field, asset sales have become increasingly popular because they allow the restructured business to move forward quickly while leaving creditors, the shell company and the bankruptcy court to work out how the sale proceeds should be divided.

As an added bonus, asset sales can often be accomplished through a relatively straightforward motion in courts that usually takes just weeks to be approved, rather than a more complicated plan of reorganization that usually takes many months, if not years to work through the court.

Debt-for-equity swaps tend to be a slower option than asset sales for exiting bankruptcy. By their nature, they require heavy negotiation among the company and the various tiers and types of creditors, and they need to be approved through a plan of reorganization.

Despite the growing popularity of asset sales, E&P sector bankruptcies have strongly favored debt-to-equity conversions for various reasons.

First, for most of the last two years, continuously falling crude oil prices made it difficult to lock in sale prices. While rapidly falling prices can also hinder proposed debt-to-equity conversions, they pose less of a problem where junior creditors and equity holders are in a loss position.

Second, E&P companies face a number of regulatory and permitting issues, described in the sidebar on page 38, that can hinder asset sales in some instances.

Third, and perhaps most significantly, the sheer volume of E&P bankruptcy cases has led to the development of unusually clear bargaining parameters around debt-for-equity swaps. With the help of these clearer negotiating boundaries, parties have been increasingly able to avoid value-destroying litigation and to short circuit otherwise lengthy reorganization plan negotiations around the terms of proposed debt-for-equity exchanges.

While asset sales are still employed in E&P bankruptcies, they have mostly been limited to smaller companies, with notable exceptions, such as Quicksilver Resources, which adopted an asset-sale approach after determining that it could not obtain enough creditor support to confirm a debt-for-equity exchange plan.

Theme 2

A major advantage to the asset-sale approach is that squabbling creditors can be left to resolve later how a fixed pie of sale proceeds should be divided.

In a debt-for-equity swap, this issue has to be resolved up front. As a result, parties to debt-for-equity swaps focus on how to keep the deal from being disrupted by junior creditors and equity holders. That task is made more difficult by the fact that junior creditors and equity holders whose investments stand to be extinguished have every incentive to make long-shot valuation arguments to put themselves in the money, or to threaten litigation alleging lien imperfections or pre-bankruptcy misconduct by the company or senior lenders.

After a few high-profile examples of value-destroying litigation in the E&P sector, most parties (outside of a few particularly disgruntled equity holders) have tentatively settled on a solution: distributions of reorganized equity for junior classes of creditors or even old shareholders that exceed what would be implied by a strict "waterfall" distribution of value.

For example, in the Magnum Hunter bankruptcy, three tiers of debt were converted into equity in the company: a first lien debtor-in-possession bankruptcy loan, a second lien term loan and unsecured notes. While the first lien facility was converted at a rate that implied a 100% recovery, the second lien facility was converted at a rate projected, at the time of creditor voting, to result in a 78% to 89% recovery. Despite the fact that secured creditors were not being made whole, unsecured noteholders who would normally recover little or nothing were allowed to convert their notes at a rate expected to yield a 35% to 41% recovery.

Three themes are emerging in recent bankruptcies.

Taking this approach a step further, a number of E&P restructurings have been built around debt-for-equity swaps that grant specified stakeholders — often unsecured creditors and occasionally old shareholders — the opportunity to participate in rights offerings or to receive warrants for a specified portion of the reorganized company's equity.

While this approach is potentially dilutive to senior creditors, it can have the dual benefits of buying peace with junior stakeholders and simultaneously bolstering the reorganized company's liquidity. High-profile examples of this approach include Energy & Exploration Partners, Inc. (rights offering for secured creditors, warrants for unsecured noteholders), Sabine Oil & Gas Corp. (warrants for second lien noteholders), and Bonanza Creek, Inc. (rights offering for unsecured noteholders, warrants for old equity holders).

Theme 3

A company voluntarily filing for chapter 11 has three options. First, it can file for bankruptcy without first obtaining creditor support for a proposed restructuring. These "free fall" bankruptcies tend to be the longest, most contentious and most expensive. Unfortunately, they are often unavoidable, particularly when a company has multiple tiers of debt and an uncertain valuation, which together virtually guarantee strong clashes of creditor and equity holder interests.

Second, a company can agree with key creditors, pre-bankruptcy, to a restructuring support agreement that sets out the general terms of a proposed reorganization and binds the parties to support any deal that meets the specified criteria. These "pre-arranged" bankruptcies still require the company to obtain court approval for the restructuring support agreement once the bankruptcy case has been filed, and then to move through the other plan disclosure and confirmation requirements. However, by "locking up" key stakeholders ahead of a bankruptcy filing, a company can greatly accelerate negotiations with other creditors and ultimate approval of the restructuring.

Finally, a company can fully solicit creditor votes in favor of a proposed restructuring plan pre-bankruptcy. In these prepackaged bankruptcies, the debtor will file a plan of reorganization on the first day of the case, and ask to schedule a hearing to approve the plan as quickly as possible. If all goes smoothly, a company going through a prepackaged bankruptcy can emerge from chapter 11 in two months or even less. Obviously, this puts the onus on the company, and key / continued page 38

PROJECTS WITH GOVERNMENT CONTRACTS

The power to restructure a company through bankruptcy is sweeping, but there are potentially two important limitations when regulators and other government entities are involved.

First, a restructuring, whether through an asset sale or a plan of reorganization, in most cases cannot interfere with or limit existing state or federal regulatory regimes.

This has broad implications for restructurings in the heavily regulated energy sector. For example, if Federal Energy Regulatory Commission approval of a transaction is required outside of bankruptcy, then FERC approval may still be required in bankruptcy. While government entities are prohibited from discriminating against bankrupt companies or denying regulatory approval or permitting as a result of a bankruptcy filing, regulators may be able to deny, limit or condition approval of restructurings where they find fault with the merits of the underlying proposed transaction.

Second, asset sales that contemplate the assignment of government contracts to a new operator are often impossible without the consent of the government entity. To facilitate reorganizations, bankruptcy law generally invalidates "anti-assignment" provisions in contracts. However, the relevant law may bar the assignment. Many government entities, including the federal government, have moved to protect themselves by enacting laws or adopting regulations that broadly prohibit the assignment of government contracts without the consent of the government entity that is party to the contract. Government-issued permits often face similar restrictions on assignments or transfers. As a result, it may be impossible to complete an asset sale of regulated or permit-dependent energy businesses without the affirmative consent of the relevant regulatory authorities.

Company managers, investors and lenders should bear these restrictions in mind when negotiating potential restructurings in the energy sector.

Bankruptcies

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stakeholders, to be fully engaged well before a bankruptcy filing becomes necessary.

Over the last 10 years, major restructurings have been moving in the direction of prepackaged and prearranged bankruptcies.

E&P companies are following the trend even more strongly than the broader market. This is again enabled, in part, by the now well-developed E&P restructuring playbook. It makes little sense for a company or its creditors to spend more time in the expensive and necessarily uncertain chapter 11 process than is strictly necessary, particularly where the broad contours of a potential value-maximizing restructuring can quickly be determined.

Notably, these themes increasingly come together in a single bankruptcy case. For example, on January 4, Bonanza Creek, Inc. and its affiliates filed for chapter 11 protection and proposed to emerge from bankruptcy as rapidly as possible through a prepackaged plan of reorganization (theme 3). The prepackaged plan proposed a straightforward debt-to-equity swap (theme 1) pursuant to which $867 million of bond debt would be converted into 95.5% of the reorganized company's equity, with the remaining 4.5% going to old equity holders. Finally, the plan incorporated tools for existing stakeholders to bolster the reorganized company's capital position (theme 2) via a $200 million rights offering to unsecured creditors and three-year warrants offered to old equity for up to 7.5% of the reorganized equity based on a total equity value of $1.45 billion.

For now, crude prices have recovered to some degree, and the E&P industry appears to be beyond the peak of its distress. Nevertheless, the industry can expect to see elevated levels of bankruptcy filings for some time as the aftershocks of the price collapse play out. Stakeholders should be aware of the three themes described in this article as those bankruptcies unfold. ◎

The Art of the Deal Revisited: Part II

by John Schuster, with JLS Capital Strategies in Washington

Experience is the hardest teacher because it gives its tests first and its lessons afterwards. After the big test in late March on how to pass complicated health care reform, the lesson is clear: business promotion and poker playing techniques many associate with deal making are not useful in the legislative process. Instead, let us add legislation to the realms where project finance style negotiations would be more effective.

Project finance deals have much in common with the legislative process. Both require careful listening to all parties at the table and a thorough understanding of details necessary to put deals together — more like working together to solve a common problem than trying to score a win against the other. Deals cannot be forced on the other party. Rather, both sides have to feel satisfied with the outcome and the process, or there is no deal.

President Trump's inability to persuade the Republican Congress to "repeal and replace" Obamacare took most observers by surprise. The press was replete with stories describing the hit the president's reputation as a negotiator has taken. These negotiating failures should not have been surprising to readers who use negotiation principles used in project finance. (For a description of these principles, see "Art of the Deal: An Alternative View" in the February 2017 Project Finance NewsWire and "Learning from Venus" in the April 2016 *Project Finance NewsWire*.)

The negotiation challenges in Trump's real estate world are different from the needs of Washington politics and negotiating challenges in most business settings. To be effective, the art of the deal must give way to a more rigorous and scientific approach. Charm and bluster are not tough but are actually soft, and the lack of rigor makes those who follow the Art of the Deal prone to bad outcomes.

Problem Solving, Not Winning

The Art of the Deal is full of catch phrases that describe an approach that may work well in deals that have a short-term character such as real estate and bond trading, where parties get in, make a deal, and move on.

In those realms — using the buzz words in the Art of the Deal — one can "think big" and make a lot of demands, toss out a "lot of options," "use leverage" and "get the word out" to sell the deal, "fight back" as necessary, and look for a chance to "deliver the goods," remembering to "have fun" and to maintain balance and perspective. The deal is the thing, but this deal world is the exception rather than the rule.

Project finance, international diplomacy, the legislative process, business mergers, and most other forms of negotiation involve interested parties who were there before negotiations started, are at the table, and with whom you will have to continue working for years after the deal is done. You, your counterparty and others not at the table have interests that merit consideration, problems that must be addressed, and alternatives that can be explored.

In project finance, we have all seen parties trying to bully their way into scoring the big win, bringing leverage to bear from all sides to achieve their ends. But this rarely works. Parties refuse to accept dictated terms, and even if one can pressure parties to agree, deals favoring only one side tend to fall apart, are renegotiated, or yield poor outcomes because the "loser" cannot perform over the long term. Most negotiations are like project finance deals —- there are few places where long-term interests and problems of all parties can be ignored.

Style and Substance

Proponents of Art of the Deal techniques perceive the negotiation approach of listening carefully to what each party needs and then working together to solve problems, which has a basis in Harvard Negotiation Project techniques, as overly intellectual and ponderous or even soft or weak. The Art of the Deal is for the practical, hard-headed deal doers who get things done.

The truth is entirely the opposite. Most successful negotiations require careful consideration and discussion of the facts, interests, problems, solutions and alternatives, and require discipline, resolve and effort, as do listening carefully for openings, and making sure that one's own interests are heard. There are no short cuts. While distilling complicated policy options to Twitter length may be an art, there is no substitute for thorough command of the substance.

Lack of preparation can lead to wrong turns that waste time or even create new issues. Before Inauguration Day, the president-elect eschewed long-time convention on China by discussing with the Taiwanese president the close ties that exist between Taiwan and the United States. The telephone call was applauded by some as tough, but by */ continued page 40*

Art of the Deal

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February, the administration had walked back these remarks by reaffirming support a one China policy. Lingering tensions now limit our options for dealing with China.

Experience is the hardest teacher because it gives its tests first and lessons afterwards.

The same can be said of the immigration executive orders. Again bold moves, but the lack of preparation led to a situation where the first order had to be withdrawn and a second one has become bogged down for now in the courts. Meanwhile, sectors relying on tourism are reporting a significant drop off in visits from parts of the world not covered by the travel ban because of adverse impressions given by a ham-fisted rollout.

On health care, Harvard negotiation techniques could have helped. The relevant negotiations were within the House Republican caucus where the divisions were complex. What other interests in the House Freedom Caucus other than standing in opposition merit discussion? What were the interests of Republican governors in 16 states who rely on expanded Medicaid coverage under the Affordable Care Act? What were the interests of Trump supporters who are concerned about rising premiums? Promising to address these disparate concerns later in health care phases two and three was a poor substitute for listening to parties, discerning their problems, and identifying potential solutions now – working together to solve common problems — even if procedural barriers in the Senate prevented voting on all three parts as a single bill.

Many in Congress and the administration had incorrect ideas about the provisions and issues of the Affordable Care Act. When inaccuracies came to light, parties realized the "repeal and replace" bill was not doing what parties thought and the bill lost support in the electorate.

Once things began to fall apart, the lack of preparation manifested itself by the administration making ultimatums and again backing away. To use a piece of useful jargon, parties had not researched and did not know what their Best Alternative To a Negotiated Arrangement — BATNA — was. They were not prepared with enough information and alternatives to solve problems. With a proper BATNA, the president would not have been left having to resort to threats or ultimatums. Members of the House Freedom Caucus reported their surprise upon coming to the White House to horse trade that the president and senior aides appeared unable or unwilling to engage on substance. Perhaps the administration thought style and tactics would produce a good outcome, but in legislation, as in project finance, they rarely do.

Looking ahead to tax policy and the budget, preparation will be even more important. These are complicated issues. Even a large project finance deal is simple compared to the disparate interests that will have to be understood and addressed. These challenges are infinitely better suited to a tough and rigorous approach that methodically addresses interests, problems and alternatives, compared to the soft and imprecise path recommended by the Art of the Deal. ◎

Environmental Update

US environmental rules that encourage renewable energy are in flux as the Trump administration tries to reverse a decade of US leadership on climate change.

In 2007, the US Supreme Court decided a case brought by Massachusetts and 11 other states to force the Environmental Protection Agency to establish guidelines on emissions of carbon dioxide, methane, nitrous oxide and hydrofluorocarbons. The states pointed to language in the Clean Air Act obligating EPA to set emissions standards for "any air pollutant" "which may reasonably be anticipated to endanger public health or welfare." In the context of motor vehicle emissions, the states asked why the agency had refused to consider whether greenhouse gases fell into that category.

Through *Massachusetts v. EPA*, the court overturned EPA's 2003 determinations that the agency lacked authority under the Clean Air Act to regulate greenhouse gases and that, if it had the authority, it would decline to exercise it. As a result, EPA began the formal process of examining the science documenting the risks posed by greenhouse gases, ultimately recognizing that those emissions had contributed to a public-safety crisis. Grounded in this science and the established statutory obligation, EPA's 2009 "endangerment finding," as it is known, survived multiple court challenges to form the basis for new standards on auto emissions and, later in 2015, for Obama's Clean Power Plan.

Two months into the Trump administration, the Clean Power Plan is now endangered and the scientific finding is under political assault.

Executive Order

President Trump traveled to EPA headquarters on March 28 to sign an executive order to set in motion the reversal of most of the Obama regulatory initiatives addressing climate change.

The order directs EPA to suspend, revise or rescind the Clean Power Plan limiting carbon emissions for existing power plants. It revokes several Obama executive orders and memoranda, including one that tried to remove regulations that deter private industry from responding to climate change by innovative means and another that requires the military to assess the threats posed by climate-induced turmoil abroad, including potential flows of refugees fleeing famine or war.

The order requires EPA and other agencies to identify rules that may hinder energy production. Within 180 days after the order, the head of each federal agency must submit a final report with "specific recommendations that, to the extent permitted by law, could alleviate or eliminate aspects of agency actions that burden domestic energy production." Each agency "shall, as soon as practicable, suspend, revise, or rescind, or publish for notice and comment proposed rules suspending, revising, or rescinding, those actions, as appropriate and consistent with law."

The order also directs federal agencies to stop considering how their actions will affect climate change when reviewing federal actions under the National Environmental Policy Act.

Significantly, however, the order did not instruct the EPA to rescind the agency's 2009 endangerment finding that carbon dioxide is a pollutant.

Clean Power Plan

The Clean Power Plan, which would regulate greenhouse gas emissions from existing fossil fuel-powered power plants, has been tied up in the courts for over a year, after more than 26 states and others who believe the plan is unconstitutional sued to block implementation. The EPA head, Scott Pruitt, led the effort to overturn the plan in court while attorney general of Oklahoma. In 2016, the Supreme Court stayed implementation while the case was being argued before a lower court.

The Clean Power Plan requires a 32% reduction in carbon dioxide emissions from most existing coal- and gas-fired power plants by 2030. Each state had been assigned individual carbon reductions and would be required to submit an implementation plan demonstrating how it will achieve such reductions. The federal government would impose a federal plan in states that fail to submit their own plans or submit plans that fall short of what the Clean Power Plan requires.

As a response to the endangerment finding, the Obama EPA projected that the plan's pollution reductions — which extend to more pollutants than just greenhouse gases — would prevent 3,600 premature deaths and 90,000 fewer asthma attacks in children in the United States between now and 2030.

Implementation has been on hold since the Supreme Court stay to let the litigation play out. A US appeals court heard oral arguments on the merits in September 2016. A decision is expected this year, with an appeal likely to follow to the Supreme Court.

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Environmental Update

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The Trump administration asked the appeals court on March 28 to dispense with writing a decision on grounds that the court would be wasting time to decide a case about a plan the government expects to dismantle.

Ending the Clean Power Plan by agency action will not be easy. The plan was published in final form, so the Trump administration cannot simply reverse it by fiat. The government must go through the standard rulemaking process to undo it. Advocates of the plan are urging the appeals court in the meantime to issue an opinion.

It will take at least a year — probably longer — for EPA to scrap or otherwise revise the Clean Power Plan. The federal Administrative Procedures Act requires EPA to issue a notice of any proposed change, allow for public comment, and build an administrative record that presents a reasoned analysis supporting the changes.

Like any new environmental regulation, litigation inevitably follows.

The fact that the endangerment finding about greenhouse gases remains in place means the agency remains obligated to take action to reduce greenhouse gases under the Clean Air Act. Thus, even if EPA were successful in withdrawing the Clean Power Plan, the agency will face demands to take other action on greenhouse gases. Attorneys general from 18 states have intervened in the appeals court case in support of the plan. The Trump administration is being advised to preserve some minimal level of climate regulation to give it a better hand in court.

If the court were to strike down the plan on grounds that it exceeds the agency's authority, then the administration would not have to go through the rule-making process to undo it.

Most observers believe that repealing the Clean Power Plan will have little effect on the US solar and wind industries because prices have come down enough to allow renewables to compete with fossil fuels. Many utility executives are moving forward with plans to diversify their generating portfolios and reduce carbon emissions anyway in anticipation that the country will eventually have to move in that direction, even if US policy is unclear in the near term. Utilities grow by adding to rate base. One way to do so is by investing in pollution control or in new power plants that use cleaner fuels. Doing nothing is not a recipe for growth.

Many states have continued working on their implementation plans, and EPA had been continuing to provide support while the Clean Power Plan has been on hold in the courts.

However, at the end of March, EPA canceled proposed guidance to states for implementing the plan and model emissions trading rules, as well as rewards to states that take early steps to curb greenhouse gas emissions before the rule was to take effect.

Coal Power Plants

EPA also told a US appeals court on March 28 that it will no longer defend carbon emissions limits for new and modified power plants in light of President Trump's executive order directing EPA to review and probably drop the limits. It urged the court to drop the case. The limits were issued under the Clean Air Act. They require that any new or modified coal-fired power plant be equipped with carbon capture technology.

The administration's request came three weeks before the court was scheduled to hear oral arguments. The court canceled arguments as it evaluates the agency's request.

Endangerment Finding

The conservative Competitive Enterprise Institute petitioned EPA in March to withdraw the 2009 endangerment finding. The finding led the agency to conclude that it had to regulate greenhouse gas emissions.

The petition says "evidence has continued to mount that directly contradicts" the idea that greenhouse gases pose a threat to public health and welfare. It says the evidence shows a pause in global warming since 1998, what warming there has been falls within the Earth's historical temperature fluctuations, and the atmosphere is less sensitive to carbon dioxide buildup than previously predicted in warming models.

The established body of scientific evidence supporting climate change means any such effort to overturn the endangerment finding is vulnerable to a court challenge if pursued. Accordingly, new EPA head Scott Pruitt has wanted to avoid this head-on fight. He lobbied Trump to cut language from the March 28 executive order that would have called for a review.

EPA must respond to the petition within a reasonable time frame, but there is no specific deadline. The agency could deny the request or start a new rulemaking to revise or rescind the finding.

Paris

President Trump is expected to decide whether to keep the US in the 2015 Paris global climate pact by late May 2017, just before he travels to the Group of Seven, or G-7, summit in Italy on May 26.

The Paris Agreement was reached after more than two decades of United Nations negotiations and is the first agreement to include climate actions by both developed and developing nations. The goal of the Paris pact is to keep the planet from warming more than 3.6 degrees Fahrenheit, the point at which many scientists suggest the earth will be locked into a future of severe droughts, rising sea levels and food shortages.

A US decision whether withdraw from the Paris climate pact is expected in late May.

Trump has the authority to reverse course since the United States pledged itself to the terms of the Paris climate accord using Obama's executive authority to negotiate international agreements rather than entering into a treaty. A treaty would have been hard to get the US Senate to ratify. Trump promised to "cancel" US participation during the presidential campaign.

The decision on whether to formally withdraw would announce the United States' formal abdication of its leadership role on climate change, but it is likely irrelevant in practice as far as the US is concerned. The Trump Administration has already begun the process of gutting the key means by which the United States had planned to meet its obligations under the accord to reduce the nation's climate footprint.

While many nations — including China — have promised to move forward even if the United States withdraws, withdrawal by the United States, the second largest emitter of greenhouse gases, puts the broader climate accord in jeopardy as other nations may follow suit.

Formal withdrawal may be academic in any event since the administration has made clear it has no plans to follow through on any commitments the US made in the Paris accord to reduce emissions. The US was supposed to reduce greenhouse gas emissions by 26% from 2005 levels by 2025. The Clean Power Plan was supposed to be the down payment on the US commitment. If successfully implemented, the plan would have put the United States half way toward this goal.

Naughty Words

According to news reports, a supervisor in the US Department of Energy international climate office instructed staff not to use the phrases "climate change," "emissions reduction," or "Paris Agreement" in any memos or other written communications. Staff were reportedly told that the words would cause a "visceral reaction" with Energy Secretary Rick Perry, his immediate staff, and the cadre of White House advisers at the top of the department. However, the Department of Energy says there has been no such directive.

The "climate office" regularly communicates with other countries in its role of trying to advance clean energy technology internationally. State Department staff and staff in other DOE offices have not been given a list of banned words, but have been avoiding climate-charged terms in memos and briefings in favor of words like "jobs" and "infrastructure."

EPA Cuts

The Trump administration is proposing to reduce the EPA budget by 31% and to cut staff by / continued page 42

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20%. A leaked 64-page internal EPA memo, dated March 21, provides details of the proposed budget cuts and spending priorities.

Of note to the power sector, the budget suggests a modest increase by $188,000 for National Environmental Policy Act implementation to expedite project reviews.

The White House will release its formal budget in May. Presidential budgets are viewed by Congress merely as suggestions. Congress has ultimate control over how much is spent.

The Trump budget cuts and Congressional inaction may deal a deathblow to the Science Advisory Board, an independent panel of outside scientists that advises EPA on scientific issues. The board would see its $646,000 budget cut by 84% "to reflect an anticipated lower number of peer reviews."

The board has been under attack in Congress. In March, the House passed "The EPA Science Advisory Board Reform Act of 2017," which would impose new qualifications for board members, such as disqualifying scientists who have EPA grants or contracts as having a conflict of interest. It would also require that at least 10% of the board be made of state or local or tribal government officials. The bill now heads to the Senate. ◎

— contributed by Andrew Skroback in Washington

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