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PROJECT FINANCE
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Negotiating A Corporate PPA

As it becomes harder to find utilities willing to enter into long-term contracts to buy electricity, renewable energy developers have been signing power purchase agreements to sell electricity directly to large corporations. Several thousand megawatts of corporate PPAs are expected to be signed in 2016 in the US market. Some of the contracts are for physical delivery of electricity. Others are virtual PPAs that are swaps of fixed-for-floating payments around the electricity from a project.

Two corporate buyers of electricity and two renewable energy developers talked at an Infocast conference in late September in Washington about the main issues that must be addressed before such a contract can be signed. The room was standing-room only. The buyers are Anthony Davis, project manager for renewable energy, global environmental compliance sustainability group, General Motors, and Renée Morin, living progress-stakeholder relations, Hewlett Packard Enterprise. The sellers are Ted Romaine, director of origination for Invenergy, and Jacob Susman, vice president and head of origination for EDF Renewable Energy. The moderator is Keith Martin with Chadbourne in Washington.

MR. MARTIN: We will do two things this afternoon. First, there are a number of general questions listed on the program and, in case you have come to hear those answered, we will answer them first. Second, we want to show you what happens when the two sides sit down to negotiate a corporate PPA. We have two buyers and two sellers. We want to talk through what issues need to be resolved to give you a feel for how they might settle.

Starting with the general questions, Jake Susman, are there enough renewable energy projects to meet corporate demand in 2016?

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TAX EQUITY TRANSACTIONS in which the investor agrees to a deficit restoration obligation may need a fresh look.

The Internal Revenue Service said in early October that it has concerns about "whether and to what extent it is appropriate to recognize DROs."

A deficit restoration obligation, or DRO, is a promise by a partner to contribute more capital to the partnership at liquidation if the partner has a deficit capital account. Each partner has both a "capital account" and an "outside basis." These are two ways of tracking what the partner put into the partnership and what it is allowed to take out. When a partner's capital account hits zero, then any further losses that would be allocated to the partner shift to the other partner.

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MR. SUSMAN: In a word, no. Development pipelines have thinned. Many developers, especially in wind, are in the process of rebuilding them. If you look under the hood of a lot of projects today, they are still somewhat early stage.

MR. MARTIN: Developers thought 2016 would be the end of the market before Congress voted late last year to extend renewable energy tax credits. Ted Romaine, what do you think about 2017 and beyond? Will there be enough projects to serve the demand?

MR. ROMAINE: I think there will be. I think Jake is right. We are rebuilding pipelines. We heard from some panelists this morning that it is really a buyer's market. Looking forward to 2017 and 2018, more projects will be nearing completion.

You have the production tax credit for wind starting to phase out next year. That will affect what people do in the short term. There will be greater interest in wind farms that qualify for full tax credits. There is a little longer runway for solar. Developers like EDF and Invenergy will work very hard to bring up our pipelines and make sure we have enough capacity to satisfy the market.

MR. MARTIN: So Jake Susman, Ted Romaine said it is still a buyer's market this year, even though development pipelines have thinned. How can that be?

MR. SUSMAN: It is a question of timing. We had a lot of end-of-year demand last year when people thought we could be nearing the end of tax credits for wind and solar. Wind got only a four-year extension, but there is favorable IRS guidance around that extension.

That basically caused people to pause to think about how they want to do their procurement over the next couple years. We are feeling the demand ramp back up in real time, but it will take some time for demand to ramp back up to match supply. Call it 12 months. I think you will then start to see people realize their pipelines are a little thin.

MR. MARTIN: Here is another general question for our two sellers. There were predictions as recently as June that the corporate PPA market would reach 4,000 megawatts this year. From where you sit, does that seem right?

MR. SUSMAN: I think we are going to fall a little short of that. I think there was a real push at the end of last year to get those projects done with the tax-credit cliff hanging over our heads. I don't know exactly where the figure will end up this year.

MR. MARTIN: Let's move to the buyers. Renée Morin, how are buyers like you finding the right opportunities for your companies?

MS. MORIN: Speaking for Hewlett Packard Enterprise, we have one deal that has already been concluded and is in Texas. For that deal, we enlisted the services of a third-party consultant, Schneider Electric, who helped us through that process. It was a steep learning curve. It was the first time for us. We also had to enlist the help of a lot of others within Hewlett Packard besides our sustainability group. We got our local real estate people, procurement department and data center team involved. We need the outside help to make sure we could get it done.

MR. MARTIN: It sounds like a long process.

MS. MORIN: Yes, but we hope the second time around will be quicker.

MR. MARTIN: Anthony Davis, how does General Motors find sellers?

MR. DAVIS: The second time around is never quicker and I say that from GM's experience. [Laughter.]

MS. MORIN: Maybe less painful?

MR. DAVIS: It does get less painful.

MR. MARTIN: How long is it just as a point of reference?

MR. DAVIS: We are on our third time around at General Motors. We hope to be able to announce our third PPA before the Business Renewables Center gathering in November, which will be at General Motors headquarters at Detroit. That is a shameless plug. [Laughter.]

So, yes, it takes a while because there are a lot of people who have to get involved.

MR. MARTIN: Six months? Eight months?

MR. DAVIS: Six to eight months has been the norm for

Fewer corporate PPAs will be signed this year than originally expected.

the last two. It takes that long because we are not renewable energy companies. We are car companies and enterprise data companies. We are everything else except for renewable energy.

It takes time to get people on a call or to respond to emails so that we can respond as a company to an issue. Then it takes more time for the developer to respond. It is a rambling sort of back and forth. It would not take so long if you could lock everyone in a room and say, "Don't think about your normal day job for a week."

There is definitely an appetite for these PPAs among corporations. We signed onto a 100% renewable energy goal. We just have to get to a point where we are more efficient at execution.

MR. MARTIN: How do you find the sellers? Do they come to you?

MR. DAVIS: We also have a third party, Altenex, that helps us identify available projects and developers and come up with a set of criteria. We also have a lot of good relationships from the different conferences that we attend from Solar Power International to forums like this. We have made a lot of good contacts.

Term Sheet

MR. MARTIN: Let's move next to where the rubber meets the road. We plan to drill down and see whether we can get to a deal between these two groups. We have two buyers and two sellers. Just to frame the discussion, we are talking about a 100-megawatt project for what could be a contract for physical delivery of electricity or a virtual PPA.

The points we will hit are pretty much the different sections in a term sheet.

Let me start with the buyers. Renée Morin, do you care whether the power project is wind or solar?

MS. MORIN: That is generally not one of our criteria.

MR. MARTIN: You have signed one contract to date. That project was wind?

MS. MORIN: It was wind. Anthony Davis, do you care?

MR. DAVIS: Not necessarily, but I think we would lean more toward wind because of the better economics that you get from wind technology versus solar. While we are open to all technologies, the prices for wind electricity are usually lower than for solar.

MR. MARTIN: Do you care about the credit-worthiness and the experience of the seller?

MS. MORIN: Our procurement department does.

MR. DAVIS: Yes. Very much so.

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Almost no tax equity investor has a large enough capital account to absorb the full depreciation on a project. One way to deal with this is for the tax equity investor to agree to contribute more capital when the partnership liquidates to cover any deficit in its capital account.

Many tax equity investors today are agreeing to deficit restoration obligations of up to 40+% of the original investment in order to absorb more of the depreciation on a project.

The IRS said in early October that it is concerned about whether promises to restore deficits are real since the obligation is not triggered unless a partnership liquidates. "[S]ome partnerships are intended to have perpetual life and other partnerships can effectively cease operations but not actually liquidate; therefore, a partner's DRO may never be satisfied," the IRS said.

The agency released a list of four factors that it said may be a sign that the DRO is not real. The list is in proposed regulations that will not take effect until they are republished in final form. In the meantime, the IRS is looking for comments. Comments are due by January 3.

Many partners may structure DROs as if the proposed regulations are already in effect.

Factors that suggest that a DRO is not real are the partner giving the DRO is "not subject to commercially reasonable provisions for enforcement and collection of the obligation," the partner is "not required to provide (either at the time the obligation is made or periodically) commercially reasonable documentation regarding the partner's financial condition to the partnership," or the DRO ends or can be terminated before the partnership liquidates or while the partner still has a negative capital account.

The practical effect is to impose a net worth test on the tax equity investor to make sure it can satisfy the DRO.

PROJECT DEVELOPERS are more likely to have to pay taxes on any appreciation in project value when forming a partnership */ continued page 5*

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MR. MARTIN: What does somebody have to bring you in terms of credit-worthiness and track record?

MR. DAVIS: The developer must be able to post a letter of credit or a credit-worthy parent guarantee to cover damages if the project fails to move forward after we sign the contract. Developers ask us to post a letter of credit as well. There were questions around GM's credit-worthiness when the company was coming out of bankruptcy.

MS. MORIN: Concerns about credit-worthiness and the need for security to ensure performance are a two-way street.

MR. MARTIN: Anthony Davis, how large a letter of credit do you require of the developer, and how long does it have to remain in place?

MR. DAVIS: I would say large enough that we need to get a lot of people to sign off on it before the PPA can be signed. I can't give any numbers because I am not sure whether GM would consider the number confidential.

MR. MARTIN: Is there a relationship between the size of the letter of credit and the value of the project or the value of the power contract?

MR. DAVIS: Yes.

MR. MARTIN: What is it?

MR. DAVIS: I don't know the exact relationship. It seems linear so far based on the two to three that we have done. The larger the project, the larger the letter of credit that is required. Our treasury group crunches the numbers to determine what security we need, and we also get input from our consultants at Altenex.

MR. MARTIN: Do you release the letter of credit or other security once the project is operating?

MR. DAVIS: Yes. We require the letter of credit to be posted 10 days after we sign the PPA.

MR. MARTIN: Sellers, does that work for you?

MR. SUSMAN: Your credit is looking a lot better recently, Anthony.

MR. MARTIN: We have learned that corporations can disappear almost overnight. Think of Enron or SunEdison.

MR. DAVIS: GM is not going anywhere.

MR. MARTIN: It almost went somewhere. Sellers, you need to finance the project based on this power contract. What sort of security do you need and for how long?

MR. SUSMAN: We focus on things like percentage of the overall investment in the project on a dollars-per-kilowatt basis or maybe a total-number-of-years-of-revenue type of measurement to establish a minimum amount of security we need posted to ensure the buyer will pay for the electricity we are delivering.

MR. MARTIN: Should the amount of security be tied to the amount of debt you have to repay or the amount required to enable the tax equity investor to reach its target yield?

MR. SUSMAN: Think about it. We are going to invest hundreds of millions of dollars to build the project on the assumption that HP or GM will be around to pay for the output for 20 years. If something goes sideways, we need some time to be able to establish a plan B. So you want to make sure that you have enough credit to cover the gap until plan B can be implemented.

MR. MARTIN: Does it have to be an LC or will you accept a parent guaranty?

MR. ROMAINE: There is a range of options for the security: an LC, a funded reserve account or security deposit, a parent guaranty.

Settlement Point

MR. MARTIN: Buyers or sellers, where is the delivery point for the electricity or, if we are doing a virtual PPA, the settlement point where the market price is set for the electricity?

MR. DAVIS: We have been told over and over again never to settle a deal at the bus bar, so I will never settle a deal at the bus bar, only at the hub. I still do not know how to explain why in less than two minutes.

There is a lot more risk to signing a deal to take or price electricity at the bus bar than at the hub. By settling at the hub, the basis risk is on the developer. That seems appropriate because the developer understands that part of the business better than the buyer does. It should be better able than HP or GM to manage and mitigate the risk.

MR. MARTIN: Ted Romaine, what risk is he pushing off on you, and are you willing to accept it?

MR. DAVIS: Just say yes. [Laughter.]

MR. ROMAINE: Always, always. We have announced four deals with corporate customers. We have done both bus bar and hub. We have been successful at getting all four deals financed. The risk that we take with the hub-settled deals is the congestion and price difference between the bus bar and the hub.

I understand from GM's perspective why it is interested in a hub settlement, especially if GM plans at some point to trade around the position. It makes sense to price at the hub because there is a more liquid market there.

At the same time, I encourage buyers to look at it on a project-by-project basis. I think buyers could be better off staying at the bus bar depending on the project. I do not think there is necessarily a right or wrong way to look at it. I would not make it as absolute as everything has to be at the hub.

MS. MORIN: We have considered both in our evaluations.

MR. SUSMAN: I appreciate the buyers' arguments, but I think it is a little less black and white than they lay out. I think there is a lot more value to be garnered by doing one of these deals at the bus bar and, of the six that we have done, some have been bus bar, some have been hub, and it all comes down to a question of the sophistication of the buyer to some degree and its ability to analyze and price the risk of being in one location versus another. I usually tell customers you will get better value if you trade with me at the bus bar.

MR. MARTIN: Why is the electricity price different at the bus bar than at the hub?

MR. ROMAINE: I can only go so far into this, but the grid operator in an organized market will run a security-constrained economic dispatch model that will determine pricing at all of the nodes in the market, and that will take into account the physical constraints of moving electricity between pricing nodes. When the computer crunches the numbers and generates a price at each point, the difference in price between two points is basically the "basis."

MR. MARTIN: Why isn't the price at the bus bar the same price as at the nearest pricing node on the grid?

MR. SUSMAN: There are lots of different wires, or "pipes," that are set up to move power around the system. Some are really fat, and some are really skinny. Sometimes new power plants get built. Sometimes power plants get retired. Sometimes people use a lot of electricity in certain places. In other places, people use little electricity.

This all happens at different times of the year and different times of the day. You have to look at a model and decide how your new project will be able to fit the output through the nearest pipe when there are 12 other projects, and some additional ones planned, competing for the same piece of pipe. People assess the risk. They may say it is safer at point A on this side of the pipe than point B on that side of the pipe.

MR. MARTIN: So sellers, you have told Anthony and Renée that they will get a better deal if they buy at the bus bar. I don't know if you persuaded them.

MR. SUSMAN: If you are a particularly savvy buyer of energy, you will see that I have to finance my project and raise money from tax equity, and the financiers will / continued page 6

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or joint venture with a money partner under new IRS regulations issued in early October.

The developer may be considered to have made a "disguised sale" of the project to the new partnership.

This result may be triggered when forming a tax equity partnership for a renewable energy project.

Often when a new partnership is formed, the developer contributes the project and a money partner contributes cash. The money partner may be a tax equity or strategic investor. The cash is then distributed to the developer.

Under US tax rules, the developer is usually treated as having sold the partnership part of the project if cash contributed by the money partner is distributed to the developer within two years. The part sold is the distributed cash as a percentage of the fair market value of the project.

However, a pre-formation expenditure "safe harbor" lets the developer receive the cash tax free as long as the cash merely reimburses the developer for capital spending on the project during past two years. The amount of cash the developer can receive tax free is limited to 20% of the fair market value of the project at time of contribution. However, there is no cap on reimbursement if the project is worth no more than 120% of the "tax basis" that the developer has in the project at time of contribution.

The IRS said in new regulations in early October that whether there is a cap on reimbursement, and how much, will have to be determined on a "property-by-property basis."

The regulations do not explain how to break down a wind, solar, geothermal or other power project into separate properties. The IRS said in 2013 that a coal-fired power plant consists of 27 separate pieces of property. Examples of them are boilers, turbines, scrubbers, cooling water systems, condensers and continuous emissions monitoring systems. (For more details, see page 19 of the June 2013 *NewsWire*.)

The IRS also said in early October that it is studying whether the safe harbor is appropriate or should be eliminated. It / continued page 7

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take a very conservative approach to basis risk. It will cost me an extra X percent for tax equity.

If you have an appetite to share some of that risk or even take it all on yourself, then you reduce my cost of capital and you make it possible for me to give you a lower price for electricity.

MR. DAVIS: Doesn't that expose me to more price fluctuation at that local bus bar location versus a more smoothed-out price prediction at the hub, where the greater liquidity makes the pricing a little more stable? My CFO and treasurer want to be in a better position to predict our future cash flows.

MR. SUSMAN: 100%. Let me key in on the word "value." If safety is the only thing you care about, then the hub is probably the better place for you. If you are fairly sophisticated and savvy and you also see an opportunity to create some value by wearing a little bit of risk, then you might want to share some of that risk with me to get to the higher value.

MR. MARTIN: So sellers, let's say we have not made the sale here. Our buyers are going to set the price at the pricing node on the grid. The relevance of this, correct me if I am wrong, is our buyers are actually going to pay a fixed price for the electricity, and you will give back the settlement price at the grid node. I am thinking this is a virtual PPA.

MR. SUSMAN: Correct.

MR. MARTIN: What happens if the grid node price is below zero?

MR. SUSMAN: That will be a negotiated term in the contract. For some folks in the audience who may be unfamiliar, if we do not get paid for our generation at a certain hour and decide, as a consequence, not to generate that hour, then we also lose the production tax credit which has a pre-tax value that is actually higher than its face value of $23 a megawatt hour. So this is often a hotly negotiated topic.

MR. MARTIN: So you want to keep operating.

MR. ROMAINE: It depends on the technology. Wind and solar are different beasts because one has production tax credits that depend on electricity sales and the other has an investment tax credit that does not. Economically speaking, it makes sense for a wind farm to operate all the way down to the negative value of the grossed-up PTC. Solar is not like that.

MR. MARTIN: How do you settle in that case? You have to pay Anthony or Renée the market price for the electricity in exchange for the fixed contract price. The market price is negative. Do they owe you the negative amount?

MR. ROMAINE: Yes.

MS. MORIN: That can happen.

MR. ROMAINE: That's pretty much the crux of the PPA. It is a swap of the fixed contract price for the floating market price.

Term

MR. MARTIN: Renée Morin, how long a term of contract would you be willing to sign?

MS. MORIN: Our current one is 12 years, which has opened the door for our internal folks to feel a bit more comfortable about a longer term. That is not typically how they contract for other goods and services. They feel uncomfortable about anything over three to five years, so 12 is a hurdle, but they understand this is a different market. We may even be able to go longer on our next deal.

MR. MARTIN: Anthony Davis, how long will you go?

MR. DAVIS: We have only signed PPAs that are five years long. I am just kidding. I wanted to see if people would go, "What?" [Laughter.]

MR. MARTIN: We are getting some uncomfortable laughs out here in the audience.

MR. DAVIS: So . . . .

MR. SUSMAN: You are uninvited to dinner. [Laughter.]

MR. DAVIS: Fifteen years is good. The main consideration for us is the car model years and how long the plant will remain in the area producing a particular model. That is typically a 12- to 15-year period.

When sellers first proposed 20 to 25 years, GM was like, "No way. Get it down." So we got it down to 15. Last year we signed a 14-year contract, and now we are working on a 12-year deal. It is coming down, but I think we are in our comfort zone where our finance folks feel comfortable with the market projections and our treasury feels good with the term of the LC that will be required.

MR. SUSMAN: This is another one of those safety-versus-value questions. Folks who are doing their first deal tend to want the shorter tenor, and they tend to want to transact at the hub. But as they get a little more used to it, they start to realize that the value in these contracts is in going out more years. The longer tenor implies more risk, but we think there is more value to be had for the buyer.

MR. MARTIN: The longer tenor is an insurance policy against rising electricity prices. Somebody from Bloomberg New Energy Finance said at a recent conference that he thinks many corporates are not signing up for PPAs currently because they believe electricity prices will fall in the long run. Anthony Davis, you are nodding yes.

MR. DAVIS: Yes. At least from my point of view, I see prices falling. Falling natural gas and oil prices continue to depress the market. I am also of the view that as we put more renewable energy on the grid, the basis for pricing in regional markets will shift to renewable energy rather than natural gas, coal or oil.

Once we move completely out of coal, coal will no longer be a metric in any market. It will really be natural gas, and natural gas is cheap and abundant right now, so why would the electricity price go up? I understand there are a lot of counter-arguments to that as well.

There are other countries besides the US that will continue to rely on natural gas and coal. India is one of them that relies heavily on coal, and local coal prices are still rising.

Contract Price

MR. MARTIN: Ted Romaine, we are going to offer the buyers a fixed price. How do you arrive at the fixed price?

MR. SUSMAN: What would you like?

MR. ROMAINE: Always start with the customer.

MR. DAVIS: Free would be great, but . . . .

MR. ROMAINE: We finance everything on a project finance basis, so we will need to raise the money to build the project and we are not shy about saying we like to earn a little bit of money along the way as a reward for our trouble. We run an internal model to determine the price. It is a discounted cash flow model that I am sure almost everybody in the industry uses, with slight variations on capital stack, from one seller to the next.

That is one piece of the equation. Then there is understanding the market, the customer, and the terms and conditions. We never separate price from terms and conditions.

MR. MARTIN: Renée Morin, Ted Romaine has come in and offered you a fixed price. Jake then comes knocking at the door. Do you tell him, "You have to beat X price to be in play?"

MS. MORIN: No, no, no. We cannot disclose certain attributes of the deal like that. We work with our developers individually because each deal and project is different. The finances are not necessarily apples-to-apples. I think the terms and conditions are also important.

MR. MARTIN: Name one big term and condition that is as important as price.

MR. DAVIS: Price. [Laughter.] That is really what it comes down to. Other than the term, which we have kind of hammered out, price is going to be important. We have to feel happy with the initial PPA price and the escalator.

MR. MARTIN: If there is an escalator. / continued page 8

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asked for comments by January 3.

Things become complicated if there is already project debt when the partnership or joint venture is formed. In that case, the cash that the developer is considered to have been distributed may include part of the debt.

The developer could also be considered to have been distributed cash solely on account of the project debt, thus triggering a disguised sale, even if no cash is distributed.

Taking these situations one at a time, formation of the partnership will not be treated as a disguised sale of part of the project if there is project debt, but no cash is distributed and the debt is a "qualified liability." Most debt should be a qualified liability.

Turning to the other case where there is project debt and cash is distributed, the developer is treated as having been distributed not only the cash, but also relieved of a share of the debt. The sum of the two can only reimburse the developer for capital spending on the project during the past two years and cannot exceed any cap on reimbursements.

Of how much project debt was the developer relieved? The answer is the amount of project debt that US tax rules treat as shifting to the money partner.

The disguised sale rules require a special calculation. In most cases, the money partner will be treated as having assumed its profits percentage: the share of income it will be allocated times the principal amount of the debt. However, the developer can claim less debt was shifted under an alternative formula. The alternative formula is to divide the actual cash the developer was distributed by the equity value the developer has in the project. The equity value is the fair market value of the project minus the project debt.

Any use of the pre-formation expenditure safe harbor must be reported to the IRS. Any claim that project debt is a "qualified liability" must also be reported.

The new rules apply to property transfers on or after October 5, 2016. Thus, a new tax equity partnership formed on or / continued page 9

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MR. DAVIS: Yes. If there is one, the price has to remain below the projected market price. We have external analysts that are running low-, base-, and high-cost projections and we also just look at it bare bones, take inflation into account from an internal GM perspective with a very conservative market price escalation, to see what the net present value of the contract will be.

The PPA price and the escalation are the two biggest things for us.

MR. MARTIN: Ted Romaine, how hard can this be? He is looking at a retail price and you are offering wholesale.

MR. ROMAINE: Yes, we should be able to charge a lot more. [Laughter.]

MR. MARTIN: Anthony Davis, is it true that you are comparing a retail price to a wholesale price on offer from our sellers?

MR. DAVIS: No. We are looking at the hub market price. For example, one of our two existing PPAs settles at an ERCOT hub. That is our benchmark for testing where we are being offered a good deal rather than the retail electricity price paid by one of our facilities.

Additionality

MR. MARTIN: Renée Morin, do you care whether the power plant from which our sellers are proposing to sell electricity is already in operation?

MS. MORIN: We want additionality as one of our criteria from the sustainability perspective. We have not been offered one that is already in operation to my knowledge. We typically contract for the output before COD.

MR. MARTIN: Anthony Davis, you are nodding yes. You agree?

MR. DAVIS: Yes. Additionality is important to us as well. We recognize that there are a lot of projects already, but as part of our sustainability goals and wanting to put more renewables onto the grid, we like to see new projects and we like to feel like we have had an impact.

MR. MARTIN: How long are you willing to wait for this power to start flowing?

MR. DAVIS: Forever. [Laughter.]

MR. MARTIN: Can the project be one year out? Two years out?

MS. MORIN: You can work it out so we have the bridge RECs. Once the deal has been signed, maybe we are 18 months away from the commercial operation date, depending on how far along you guys happen to be. We are flexible as long as we receive bridge RECs.

MR. DAVIS: We are comfortable with a developer who is trying to complete his facility within the next two years. That works for us for the most part. We only look for the RECs that come from this project, so we are willing to wait and we are patient.

MR. MARTIN: Renée Morin, bridge RECs sounds like testimony from the Chris Christie George Washington bridge trial. [Laughter.] What are they?

MS. MORIN: I don't know who coined the term, but once the PPA is signed, it will have an expected operation date of 12, 18 or 24 months. We need the ability to receive RECs . . .

MR. MARTIN: . . . after the guaranteed commercial operation date?

MS. MORIN: They need to be green E-certified equivalent RECs.

MR. MARTIN: Jake Susman, where will you get those RECs?

MS. MORIN: Not everybody will do this.

MR. SUSMAN: Before I answer your question, Keith, I think the bridge REC concept is something that is good for the planet, and let me see whether I can make that linkage. There are enough companies now that have made sustainability statements about what they are going to do and by what date. They find themselves signing up to contracts for projects that may not, in fact, start operating until 2018 or even beyond.

But they have made those statements, and their shareholders are still holding them to account. Environmental organizations may also be holding them to account, so in order to honor their commitments, they procure a certain amount of RECs, either in the market or from some other project.

MR. MARTIN: Is your obligation to deliver bridge RECs in lieu of delay damages if the project is delayed?

MR. SUSMAN: It is possible to see both.

Guaranteed Operation Date

MR. MARTIN: Anthony Davis, do you have a guaranteed commercial operation date in the contract, and how do you define "commercial operation"?

MR. DAVIS: Yes. Commercial operation is when everything is pretty much brought on line. There might be a few terms in there that allow for maybe temporary . . .

MS. MORIN: . . . testing.

MR. DAVIS: Yes, some temporary testing or some equipment that might not be final, but typically commercial operation means the project is running full bore. We have not signed any contracts that define commercial operation as something less than 100% of capacity. For us, it has been everything or the project is not at COD yet.

MR. MARTIN: Ted Romaine, you are shaking your head no.

MR. ROMAINE: I do not think it needs to be at full capacity operation. We have signed contracts where we are able to declare COD if we are almost at full capacity. You still have to meet certain technical requirements of turbines installed, commissioned, gen-ties done, capable of generating and putting electricity on the grid.

We do not want to be declared in default where we are close to full capacity.

MR. SUSMAN: There is some fine-tuning that goes on during development all the way to the bitter end of construction. You could find yourself in a situation where you and the customer are better off if the project is a little smaller or maybe even a little bit bigger. So hitting it exactly 100% on the nose is not necessarily the best outcome.

MR. DAVIS: Usually we are signing deals that are for a percentage of the output from a large wind farm. For example, we may contract for 30 megawatts from a 200-megawatt wind farm. In that case, I am going to expect all 30 of those megawatts. That seems only fair to me.

MR. MARTIN: What happens if the project is delayed? It is not in commercial operation by the guaranteed date.

MR. DAVIS: Then there are delay damages. The amount is negotiated.

MR. MARTIN: If the contract is for 100 megawatts, how would the delay damages per day be determined?

MR. DAVIS: They are typically an amount per megawatt. I don't know the typical equation. The developer provides it, so maybe our sellers have any insight from the developer side.

MR. MARTIN: Ted Romaine, do you have a number for us?

MR. ROMAINE: It is a negotiated amount.

MR. MARTIN: Is there a cap on the total delay damages?

MR. DAVIS: Yes, and that is another thing that is negotiated. It is usually a dollar amount per megawatt of capacity. Delay damages might run for a certain number of months, after which we would have a right to terminate the contract.

From a buyer's perspective, we need delay damages to ensure the expected energy savings are received. We put the savings into our earnings forecast models. The CFO will be very unhappy if we don't hit our targets.

MR. MARTIN: Jake Susman, does it sound like a deal is possible here?

MR. SUSMAN: I think we are very close to a deal, guys. I am pleased with the direction of the negotiation.

On Anthony's last point, there are two kinds of natural governors on how far the contract can go with / continued page 10

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after October 5 will be affected.

Sometimes a partnership borrows more money to fund a cash distribution to the developer. The cash distribution must be taken into account in determining whether there was a disguised sale of part of the project by the developer to the partnership. However, the developer is not treated as receiving the full cash. Its cash distribution for this purpose is only the cash that exceeds the developer's share of the new debt used to fund the distribution.

MEXICO awarded long-term power contracts to 23 companies in its second power auction, according to Chadbourne partner Raquel Bierzwinsky.

The results were announced in late September. The auction awarded contracts to buy electricity, capacity and clean energy certificates — called CELs — from roughly 3,945 megawatts of projects. Of that amount, 2,891 megawatts will come from greenfield projects. The numbers break down to 1,824 megawatts of solar, roughly 1,129 megawatts of wind, 68 megawatts of hydro, 25 megawatts of geothermal and 899 megawatts of gas-fired combined cycle power plants, according to Javier Félix with Chadbourne in Mexico City.

The weighted average price for energy and CELs offered in the second auction was $33.47 a megawatt hour, or 30% less than the $47.70 a megawatt hour average price in the first auction at the end of March.

INBOUND US ACQUISITIONS are generating more heat.

A bipartisan group of US House members asked the Government Accountability Office, the audit arm of Congress, in September to look into how an interagency committee that reviews foreign acquisitions of US companies for national security implications is working.

The 16 House members say they are concerned about the increasing number of acquisitions by state-owned / continued page 11 *continued from page 9*

any kind of damages, delay or otherwise. First, there may be a seller letter of credit in place. Second, the buyer usually has a right to terminate before the numbers get too big.

MR. MARTIN: So the point about the seller letter of credit is the buyer will draw on the LC up to the face amount.

MR. SUSMAN: That's the idea.

MR. MARTIN: Buyers, are you offering our sellers a delay in the guaranteed commercial operation date and start of delay damages if a force majeure event happens, and for how long?

MR. DAVIS: Yes. There is a force majeure out. Both what constitutes force majeure and the permissible delay are negotiated. I think we have been fairly lenient and understanding of what is considered force majeure.

MR. MARTIN: Sellers, are all the customary events considered force majeure for this purpose, or have you found buyers being stingy?

MR. ROMAINE: We do not find buyers pushing back on the force majeure definition. It has been pretty easy to reach consensus on that. We will require day-for-day extension on delay damages.

MR. SUSMAN: As wind and solar development has matured, sellers are less likely to take crazy technology risks or build in crazy places. The possibility of force majeure outcomes has narrowed pretty dramatically as the industry has matured.

Guaranteed Availability

MR. MARTIN: Ted Romaine, in order to win this contract, do you offer a guarantee that the project will be available at some capacity?

MR. ROMAINE: Absolutely. We are an owner-operator. We are really good at that.

MR. MARTIN: What is your guarantee level?

MR. ROMAINE: It is another point to be negotiated in each contract, but typically we will start out at a percentage in the early part of the contract and step that up after, say after one year. We like to have the first year to work out any kinks.

MR. SUSMAN: Here is another instance where the maturity of the industry helps and the science is so good now. Our predictive capabilities are so good. I think our customers can rely on us to produce, and we can be held accountable.

There needs to be some smoothing as you could have a bad wind year or a month or two when a couple of turbines are having issues. You want the ability in that case to smooth the availability over a longer period of time.

MR. MARTIN: So your guarantee period is one year, two years, longer? You get credit if you produce over the availability number to offset shortfalls later?

MR. SUSMAN: We want at least two years to smooth it out.

MR. MARTIN: I think Anthony Davis is saying no.

MR. DAVIS: I am just basing that view on the contracts I have seen. I know there is an availability guarantee. We see them today at a 80% to 90% level. But there are clauses to cover situations where a turbine needs to be taken down for maintenance and similar events that are also in the contract.

Every year there is a guarantee that says the seller will provide some percentage of the electricity it promised for that year.

MR. MARTIN: Will the seller's availability guarantee have to run for the full term of the contract?

MR. DAVIS: Yes.

Buyers want "additionality," meaning they want a new project that will start operating within the next 18 months.

Audience Questions

MR. MARTIN: We are down to our last five minutes. Audience, this is your chance to participate.

MR. BARCLAY: Buz Barclay from Rimon PC. Are there practical problems that arise with the project lenders when each buyer is taking only a fraction of the output?

MS. MORIN: I think it comes up. This is a negotiation, and we are both trying to get to an endpoint together, so there is give and take.

MR. ROMAINE: It is a high-wire act for us. We have done club deals. The onus is on us to make sure that we negotiate terms and conditions that are financeable for the lenders.

MR. SUSMAN: Three of the six corporate PPAs that we have signed have been multi-party projects. That is why I always encourage customers to be the anchor tenant. Be the first to sign up because you will get to dictate the lion's share of the contract terms. That will also facilitate an easier financing.

MR. HAUG: David Haug from Arctas Capital. I am curious whether GE and HP are buying the full output of the plant or a pro rata 30 out of 200 megawatts or are they buying P50 or P90 or some other negotiated amount?

MR. DAVIS: We are buying a notional amount. If it is a 200-megawatt project, and we are signing up for 30 megawatts, we are hoping to get whatever is produced from that 30 megawatts of capacity. The availability guarantee says the seller will deliver at least 80% or 90% of that each year.

MR. ILLERS: Brett Illers with Yahoo. This is for the sellers. As utilities come back into the market for long-term PPAs because they have to meet rising RPS targets, how will that affect my ability to negotiate a corporate PPA?

MR. ROMAINE: Great question. Someone put up a slide this morning showing utility PPAs and corporate PPAs. The piece that was missing is what the utilities are doing on acquiring projects. That is a very active space right now for utilities as they look for assets to put in rate base. There is a robust utility market today if one looks at this larger picture.

MS. MCCAIN: Shelley McCain with Shell Energy North America. This question is for the buyers, and it is twofold. When you quantify savings, against what baseline are the savings measured? Brown power, retail, wholesale? My second question is when you make concessions in your terms and conditions, all the ones we just went through, what are the general concessions that you are willing to make?

MR. DAVIS: We measure savings against the wholesale hub price. We look at the net present value of the savings.

We are getting to a point where the PPA that GM likes is becoming set in stone because all our legal, technical, accounting and finance folks have weighed in. We give / continued page 12

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companies in China and Russia.

CFIUS — short for the Committee on Foreign Investment in the United States — is an inter-agency committee of 16 federal agencies, headed by the Treasury Department, that reviews potential foreign investments in US companies for national security concerns. Submission of proposed deals is voluntary. However, the committee has authority to set aside transactions after the fact that were not submitted for review.

The committee makes recommendations. The President has ultimate authority to block a transaction. Presidential action to block a transaction is rare. Most transactions that raise problems are voluntarily withdrawn. Many are later resubmitted on revised terms. In some cases, transactions are approved after the acquirer agrees to mitigation measures.

The 16 House members cited two recent Chinese deals as reason for their concerns. One is the acquisition of Swiss agrichemical giant Syngenta by China National Chemical Corp. CFIUS cleared the transaction in August. Syngenta supplies 10% of seeds to US soybean farmers and a fifth of world pesticides. The House members also cited the interest of Dalian Wanda Group in buying one of the big six US film studios. The Dalian Wanda Group already owns 75% of AMC Theaters.

At least three Chinese deals were abandoned earlier this year due to fears the acquisitions would not be approved.

The House members asked the Government Accountability Office to consider whether the FBI (Federal Bureau of Investigations) and other agencies should be added to CFIUS, whether tougher screening should be given to acquisitions by state-owned companies from designated countries like China and Russia, and whether there should be mandatory reporting of such acquisitions to CFIUS. They also want to know whether CFIUS should investigate, as part of its review of national security implications, any state subsidies the buyer receives in its home country as part of / continued page 13

Corporate PPAs

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our terms to the developer and see what we need to fine tune.

MR. STEVENS: Bill Stevens with NJR Clean Energy Ventures. We are a long-term owner and operator. Question for the buyers: do you prefer a lower starting price with an escalator or a levelized price without any escalator?

MS. MORIN: An escalator is harder for us to put in front of our finance people.

MR. MURCHIE: Colin Murchie with Sol Systems, a developer and asset owner. For the buyers, you have gone through a long negotiation, six months, and you put up an LC. There were a lot of late nights. You are on the hook for a multi-million dollar contract. Let's say the RECs are gone for the first few years of the project, and certain claims have gone with them.

Are there some claims that you would still feel comfortable making? Would you say this project would not exist but for us, or would you make a narrative claim where you detail the RECs went here, the energy went there, here is everyone's role?

MS. MORIN: The RECs were gone, meaning . . . ?

MR. MURCHIE: Already sold to someone else.

MS. MORIN: I don't think we would have gotten into the deal.

MR. DAVIS: We do not do the deal unless the RECs are a part of it.

MS. MORIN: We are not doing pure financial plays at this point. I know some companies do.

MR. HESSE: Balduin Hesse, Frontier Renewables. Question for the sellers: on the hub deals, when you go to finance the project, do you make an assumption around historical basis differential or do you buy a hedge? I am guessing you will get walloped for that risk to a certain extent when you go to finance the project. How do you fix it or do you just make an assumption around a certain differential?

MR. SUSMAN: In our case, that is what is nice about having a department of professional analysts. We have an internal view that we just take, and we decide how we want to price risk. ◎

Huge Potential New Demand For Power

by Deanne Barrow, in Washington

Community choice aggregators (CCAs) could displace as much as 20% to 40% of electricity load in California. They are a new kind of offtaker of renewable power.

The utilities are bracing for the loss of so many customers and charging exit fees for customers that leave the utilities for CCAs to cover their stranded costs. There is controversy surrounding the calculation of the exit fees. CCAs must take the exit fees into account when figuring out how much they can charge customers for electricity and still have an economic proposition.

This article explains how exit fees are calculated, what issues have been raised about the current methodology and proposals for reform.

What is a CCA?

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

In California, CCAs are subject to the same renewable procurement targets as investor-owned utilities under the state renewable portfolio standard program. At least 50% of retail electricity sales must come from qualifying renewable sources by 2030. However, in reality, CCAs strive for even higher levels of renewables by offering customers the option to purchase electricity that has a 100% renewable energy content. The default power mix offered by IOUs is currently around 29% renewable.

The focus on renewable energy makes CCAs a significant new class of offtakers, and the power purchase agreements they sign can provide the basis for financing new projects. (For a further discussion of the financeability of PPAs with CCA offtakers, see page 9 of the August 2016 *Project Finance NewsWire*.)

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CCAs in California

Although community choice aggregation is legislatively enabled in seven US States, California has seen the most traction. Table 1 provides an overview of operational and emerging CCA programs within the state.

There are now five operational CCA programs in California, and at least 15 more are in various stages of planning, all together covering 23 counties.

Of the planned programs, Los Angeles County and San Diego City are ones to watch. If all eligible cities participate in LA County's program, at full enrollment it will account for approximately 40% of Southern California Edison's total load. (SCE itself accounts for about 27% of aggregate state load.) San Diego City accounts for roughly 44% of San Diego Gas and Electric's total load. Pacific Gas & Electric has already begun to reduce its annual procurement targets to account for existing CCAs within its service territory as well as large planned programs like the one in Alameda County. PG&E's latest procurement plan forecasts an incremental loss of 15,444 gigawatt hours in 2017 due to CCAs, the equivalent of 21% of its 2016 load.

Exit Fees

As scores of communities in California explore the idea of forming CCAs, IOUs are facing the prospect of substantial stranded costs and the need to recoup these costs by charging departing customers large exit fees.

Exit fees are designed to cover costs of power procurement investments made by utilities on behalf of customers who later switch to CCAs or other alternative electricity suppliers. These costs would have been recoverable through electricity rates but become stranded when the customers leave. Exit fees are also referred to as non-bypassable charges because they cannot be bypassed by switching service providers.

The policy underlying exit fees has its roots in legislation passed in 2002 as part of electricity restructuring. When the electricity markets were restructured, the California Public Utilities Code was amended to provide that each retail end-use customer should bear a fair share of electricity purchase costs and obligations incurred by utilities on behalf of those customers and that there should be no shifting of costs from exiting customers to remaining customers. This policy was affirmed in S.B. 350 enacted in September 2015, which provides that bundled retail customers of an electrical corporation shall not experience any cost increase as a consequence of implementing a community choice aggregator program.

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a national strategic plan to gain access to the US market.

PARTNERS sometimes use guarantees to try to shift the ratio in which debt at the project or partnership level is put in the "outside bases" of partners.

The IRS is taking aim at such efforts.

The greater the share of such debt assigned to a partner, the greater capacity the partner has to be allocated losses and distributed cash without having to pay taxes on the cash distributions.

Each partner has both a "capital account" and an "outside basis." These are two ways of measuring what each partner put into the partnership and is allowed to take out. When a partner's outside basis hits zero, then any further losses the partner is allocated end up suspended; they can only be used to shelter future income the partner is allocated by the partnership. The partner must also report any further cash it is distributed as capital gain.

A partner's outside basis starts as the sum of three items: any cash the partner contributed to the partnership, its tax basis in any property contributed, plus a share of any debt at the project or partnership level.

Most debt in the project finance market is nonrecourse debt. This must be shared by partners according to complicated rules, but most of it ends up being shared in the same ratio as the partners are allocated partnership income. If the ratio for allocating income will flip after a target yield is reached, the partners can choose either set of percentages. Alternatively, they can use the ratio in which the partners are expected to share in depreciation on the part of the project cost paid for with the debt.

Recourse debt is put entirely in the outside basis of the partner who is ultimately liable to repay the debt. Thus, a partner might guarantee repayment of the debt as a way of putting it entirely in the partner's outside basis.

Another example of recourse debt is where

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Table 1: CCA Programs in California

Name of CCA Program	Start Date	Service Area	Incumbent IOU	Forecasted Demand at Full Roll-Out (GWh/year)*
Operational				
CleanPowerSF	May 2016	City and County of San Francisco	PG&E	3500-4000
Lancaster Choice Energy	May 2015	City of Lancaster	SCE	536
Marin Clean Energy	May 2010	Marin and Napa Counties, and the Cities of Benicia, El Cerrito, Lafayette, Richmond, San Pablo and Walnut Creek	PG&E	2,897
Peninsula Clean Energy	October 2016	San Mateo County	PG&E	3,672
Sonoma Clean Power	May 2014	Sonoma and Mendocino Counties	PG&E	2,341 (plus Mendocino County)
Implementation Plan Submitted to the California Public Utilities Commission				
Apple Valley Choice Energy	April 2017	Apple Valley Town	SCE	294
Silicon Valley Clean Energy	Spring 2017	Santa Clara County	PG&E	3,753
Feasibility Study Complete				
East Bay Community Energy	2017	Alameda County	PG&E	7,000
Los Angeles Community Choice Energy	2017	Los Angeles County	SCE	26,290
Monterey Bay Community Power	September 2017	Monterey, San Benito and Santa Cruz Counties	PG&E	3,701
Redwood Coast Energy Authority	Spring 2017	Humboldt County	PG&E	858
TBD	TBD	Yolo County and City of Davis	PG&E	560
TBD	TBD	Riverside County	SCE	1,539
TBD	TBD	Placer County	PG&E	1,329
Feasibility Study Underway				
Central Coast Community Choice Energy	TBD	San Luis Obispo, Santa Barbara and Ventura Counties	PG&E/ SCE	N/A
Inland Choice Energy	TBD	San Bernardino County and cities in Riverside County	SCE	N/A
San Jose Clean Energy	TBD	City of San Jose	PG&E	N/A
TBD	TBD	Butte County	PG&E	N/A
TBD	TBD	Contra Costa County	PG&E	N/A
TBD	TBD	City of San Diego	SDG&E	N/A

**Source: Implementation Plan or Feasibility Study*

PCIA

In 2006, the California Public Utilities Commission established a special kind of exit fee known as the power charge indifference adjustment, or "PCIA," that applies to CCA customers and customers of other non-utility energy providers under the California "direct access" program. A different non-bypassable charge applies to customers of municipal utilities. The objective of the PCIA is to ensure that the remaining utility ratepayers remain economically indifferent, meaning no better or worse off as a result of customers switching from IOUs to CCAs.

The prevailing PCIA rate charged by PG&E is between 2.072¢ and 2.363¢ per kilowatt hour for residential customers, who make up the bulk of CCA customers. (The range is due to different vintage years.) For a typical residential customer using 500 kWh of electricity per month, PCIA charges will amount to about $11 a month. Because CCAs only offer generation services, the difference between their generation rates and the utilities' generation rates is the only basis upon which they can compete with utilities. The PCIA, which is assessed on a customer's bill as a generation charge, therefore directly cuts into a CCA's competitive margin. To remain competitive, the CCA must procure power at a rate that is lower than the retail rate charged by the local utility plus the PCIA.

Figure 1 shows how the PCIA is calculated.

The PCIA is determined on an annual basis by comparing the actual costs of the utility's portfolio of assets to the market value of those assets. Utilities cannot recover the entire cost of procurement, only the uneconomic portion, the idea being that they should mitigate losses by selling excess energy and capacity into the market.

The market price benchmark is a proxy for the market value of electricity. It is made up of a brown adder, green adder and capacity adder. These adders are estimates of the market value of fossil-fuel energy, RPS-compliant energy and resource adequacy (grid stability) obligations respectively.

If the total portfolio cost exceeds market cost, then the difference represents the uneconomic costs. If the costs of a portfolio are below market costs, then the difference is negative and effectively represents a credit due to the CCA customers. Negative amounts are "banked" or carried forward by the utility and used to offset the next year where there is a positive difference.

A customer is responsible only for net costs of commitments that were made before the customer departed utility service. The year the customer departed utility service is known as the customer's vintage year. The rule is that / *continued page 16*

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a partner or an affiliate is both a partner and a lender. The partner is considered ultimately exposed to the loss if the debt is not repaid, thus making the debt recourse to the partner.

The IRS issued temporary regulations in early October that attack "bottom-dollar guarantees." A bottom-dollar guarantee is a guarantee that is illusory because someone else has promised to reimburse the partner or the real burden is split among other parties by using tiered or upstream entities, legal subordination or similar tools.

The IRS will ignore such guarantees put in place on or after October 5, 2016. A guarantee that a partner is obligated to provide under a binding contract signed earlier will not be affected.

Bottom-dollar payment obligations must be disclosed on IRS Form 8275.

The IRS said it may end up recognizing a guarantee for a "vertical slice" of debt at the project or partnership level, even if the rest of the guarantee is considered illusory because someone else will reimburse the partner, in cases where the reimbursement falls short of covering the full debt.

It is not a problem to have the *partnership* agree to reimburse the partner if the partner has to pay the guaranteed debt. This will not make the guarantee illusory. It assumes other partners will not have to contribute to fund the reimbursement.

The IRS also released a list of seven factors in October that suggest a partner guarantee to pay debt at the project or partnership level is not real. The factors are merely proposed. The IRS will use them starting after the proposed regulations are republished in final form.

The factors include that there are no commercially reasonable contractual restrictions to "protect the likelihood of payment," including, for example, restrictions to prevent the guarantor from shedding assets for less than full value or making cash distributions to equity owners, the guarantor is not required to produce commercially reasonable evidence / *continued page 17*

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the customer is responsible for resources committed by the utility prior to June 30 of the customer's vintage year. Power contracts are considered committed when the contract is executed and physical resources are considered committed when construction begins.

Issues

There are three main issues with the PCIA.

First, the PCIA has a potentially unlimited duration. This follows from a 2004 CPUC decision allowing utilities to recover stranded costs associated with renewable contracts over the entire term of the contract. By contrast, the recovery period for fossil-fuel contracts is limited to 10 years.

Figure 1: PCIA Calculation Methodology*

PCIA ($) = **Costs of Total Portfolio** – **Market Value of Total Portfolio**[1]

- **Costs of Total Portfolio** = costs of pre-2002 resources + costs of post-2002 **Vintaged Resources**
  - **Vintaged Resources** = PPAs and IOU-owned generation resources committed (executed or construction started) before June 30 of the Vintage Year
  - **Vintage Year** = year CCA service was initiated in the customer's service area if before June 30 or the following year if service was initiated after June 30

- **Market Value of Total Portfolio** = **Market Price Benchmark** (**MPB**) x generation output (MWh) of total portfolio x IOU-specific line loss factor
  - **MPB** ($/MWh) = [(1-RPS%) x Brown Adder] + [RPS% x Green Adder] + Capacity Adder
    - **RPS%** = fraction of RPS-compliant resources included in Vintaged Resources
  - **Brown Adder** = weighted average of peak and off-peak forward energy prices for October 1 to 31 for the Calculation Year (as reported by Platt's Megawatt Daily), weighting based on the most recent publicly available bundled load profile data for the IOU
    - **Calculation Year** = year which the PCIA is intended to cover
  - **Green Adder** = [68% x average forecasted cost of RPS-compliant power contracts and IOU-owned resources (for all three IOUs) beginning deliveries of power in the Calculation Year and the previous year, net of capacity] + [32% x simple average of price premiums of voluntary renewable energy programs in the Western Electricity Coordinating Council based on surveys conducted by the National Renewable Energy Laboratory for the US Department of Energy]
  - **Capacity Adder** = [total Net Qualifying Capacity specified by CAISO for each generation resource in the Vintaged Resources] x [going forward cost (sum of insurance, ad valorem and fixed O&M) of a combustion turbine as determined by the California Energy Commission] / forecasted MWh supplied by Vintaged Resources]

- **PCIA ($)** is then divided among the different classes of customers, allocations being determined based on the class's contribution to the system's top 100 hours of usage.
- For each customer class, the **PCIA ($)** share is then divided by forecasted usage of the customer class to arrive at PCIA rate ($/kWh) appearing on the customer's bill.

**Based on CPUC Decision 11-12-018 and Resolution E-4475*

[1]A separate charge called the competition transition charge (CTC) covers the above-market costs of certain pre-restructuring assets. The CTC is collected from all ratepayers and is subtracted from the PCIA ($) to avoid double counting since the costs of those assets are also included in the Costs of Total Portfolio.

This means that liability for PCIA fees ends only after the last renewable energy contract in a utility's portfolio expires. PG&E has indicated that customers who switched to CCA service in 2012 and later could continue to see PCIA charges until 2043 due to three renewable contracts signed in 2010 that expire in 2043. Whether customers end up in fact paying a PCIA charge depends on whether the contract prices are above-market in any given year.

The CPUC's 2004 decision was supposed to encourage utilities to contract for renewables on a long-term basis, thereby supporting renewable energy development. The renewables industry has since matured and CCAs have argued to the CPUC that the recovery period for all resources should be limited to 10 years.

The second issue is that the rate is volatile. As part of its 2016 energy resource recovery account application to establish 2017 rates, PG&E is proposing to increase the PCIA by 24% to 2.937¢ per kilowatt hour for customers with a 2012 vintage year. In 2016, the PCIA rate for residential customers rose by as much as 95% compared to the previous year's rates, depending on vintage year.

PG&E has said the increases are due to reasons outside its control, such as lower market prices for both natural gas and renewables. As discussed earlier, the PCIA represents the above-market portion of generation costs, so when market prices fall, the PCIA increases.

To counteract volatility, CCAs are proposing that the market price benchmark for fossil-fuel energy be based on a five-year forward price instead of the current one-year spot price. Utilities, on the other hand, are pushing for changes to the renewable energy and capacity components of the market price benchmark, though not for reasons of volatility. They argue that the market prices yielded by the current methodology are too high, resulting in an underestimation of uneconomic costs. As shown in Figure 1, the market price benchmark for renewable assets is determined in part based on the average cost of RPS-compliant resources coming on line in the current year and the previous year. According to utilities, many contracts starting deliveries in real time were signed many years earlier when prevailing prices for renewable power were significantly higher than what they are now. They are calling for the present formula to be replaced with market indices for California RECs, such as those published by Platts.

The third issue is a lack of transparency around PCIA inputs. Without visibility into the pricing, volumes and terms of the utility contracts that underlie the annual / *continued page 18*

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of its financial condition "either at the time the payment obligation is made or periodically," the partner can terminate the guarantee before the debt is repaid, or the debt terms are no better with the guarantee than without.

INDIAN TRIBES lost a round with the IRS.

The agency revoked a private letter ruling suggesting that an Indian tribe can transfer the investment tax credit on a solar project the tribe owns by entering into an inverted lease with a tax equity investor. The now-revoked ruling suggested the tribe could also transfer the investment tax credit by entering into a sale-leaseback transaction.

The revocation had been expected. It does not affect any transaction the taxpayer to whom the ruling was issued already closed based on the ruling.

The IRS made public in late September a letter it sent the taxpayer last summer. The letter is Private Letter Ruling 201640010. The revoked ruling was Private Letter Ruling 201310001.

The original ruling was surprising when it was made public in early 2013. An investment tax credit cannot be claimed on equipment "used by" a tax-exempt or government entity. The original ruling said that even though the tribe owned the project, the project would not be "used by" the tribe. The reasoning was narrowly technical. The tribe is not a tax-exempt entity because, as a sovereign nation, it has no need of a tax exemption to escape federal income taxes and it is not the sort of government entity that tax code has in mind. Investment credits are lost only when equipment is used by a federal, state or local government entity, the original ruling said.

By mid-2014, it was clear the IRS planned to withdraw the ruling.

Tribes need to look at other relationships to a solar or other renewable energy project besides ownership or else own a minority interest in an otherwise privately-owned corporation that owns the project. / *continued page 19*

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calculation, CCAs are finding it hard to predict values and plan around potential changes to the rates.

As shown in Figure 1, the market price benchmark for renewable energy is based on the average cost of renewable resources in all three IOU portfolios that are starting deliveries in the year in question and the next year. This information is submitted by the IOUs in October each year and used by the CPUC to establish market price benchmark values for rates that take effect on January 1 of the following year.

The information is confidential under CPUC rules. CCAs can gain access through the use of arms-length "reviewing representatives," who sign non-disclosure agreements with the IOUs limiting what they can reveal to the CCAs. CCAs are finding it hard to find consultants who qualify and are willing to act as reviewers, leaving them to resort to other methods, such as data requests and discovery, meet and confer sessions and motions to compel. The IOUs want to maintain tight confidentiality requirements because they say this information gives away their dispatch strategies, contract terms and load requirements to CCAs that are competing with them for market share. The CCAs have pointed out that they do not sell power to utilities and so cannot use price and contract information to utilities' or bundled customers' disadvantage. In addition to advocating for more relaxed data access rules, CCAs have also asked that IOUs provide 10-year forward forecasts of total portfolio costs and portfolio mix as these factors also influence the annual adjustment.

Reform

In its 2012 decision establishing the current PCIA methodology, the CPUC explicitly left open the possibility for reform. The commission said it would be willing to modify the calculation methodology and process based on changed circumstances in order to ensure that community choice aggregators can compete on a fair and equal basis with IOUs. Indications are that the CPUC will be receptive to proposals to reform the methodology.

In March 2016, the CPUC's energy division held a workshop bringing together IOUs, CCAs, representatives of direct access consumers and other stakeholders to discuss PCIA reform. Proposals ranged from what can be considered granular revisions to the methodology to more fundamental, structural changes to the utility model.

One of the more fundamental proposals is to replace the annually adjusted PCIA with an up-front, fixed valuation for each vintage year. The valuation would be negotiated and agreed in a formal settlement between each CCA and the relevant IOU, and be subject to approval by the CPUC. CCAs want the flexibility to pay the fixed fee on a lump-sum basis and recover the cost from their ratepayers or amortize the payment over a period so as to cap annual increases at a fixed level.

Los Angeles County is proposing more structural changes in light of the large departure of load that would be caused by its anticipated CCA program. It argues that the appropriate way to allocate procurement costs is to transfer power contracts from the IOUs to CCAs, replace IOUs with CCAs as providers of last resort and grant CCAs reciprocal powers to charge exit fees to departing customers to recoup uneconomic generation costs. (Los Angeles County is different from the City of Los Angeles, which has its own municipal utility.) The CPUC may not have jurisdiction to require transfer of contracts, however, so this proposal may require legislative action that is not considered likely. Furthermore, the question of which contracts will be subject to assignment and whether counterparties will agree to assignment are issues that would need to be worked out.

Following the workshop, the energy division issued a report summarizing the discussions, but declined to adopt any of the proposals. Instead, it has invited stakeholders to petition the CPUC for the changes they would like made. ◎

New Product: Solar Revenue Puts

by Richard Matsui, Jason Kaminsky and Jared Blanton, with kWh Analytics in San Francisco

The solar market needs a revenue put like what is now used to finance merchant gas-fired power plants, except it would cover output rather than price risk.

Such a put would lead to higher advance rates for solar project debt and possibly also tax equity.

The insurance market is the natural venue in which to place this product.

Challenge

While the multi-year extension of the federal investment tax

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credit has reduced market risk, solar companies nevertheless continue facing challenges in financing projects and securing cost-effective project debt.

The deterioration of the yield co model and the liquidation of industry giant SunEdison point to a need for a "back-to-basics" approach to securing capital. With these recent crises fresh in investors' memories, corporate debt is increasingly difficult to raise. Firms are now focused on raising capital against the cash flows of their existing assets, highlighted recently by the $305 million sale of future cash flows SolarCity completed for a 230-megawatt portfolio of residential, commercial and industrial PV projects.

New financial instruments, such as energy hedges, that facilitate increased capital flows would be highly welcomed in this industry context. But new financial instruments require a new depth of understanding about solar risks.

At its most basic level, cash flows in the electricity generation business are a function of two factors: the price of electricity multiplied by the quantity of electricity. This basic equation applies across all electricity sectors. With gas-fired generators, the quantity of electricity produced is controlled by the plant operator. The unknown part of the equation — the risky part — is volatile prices for electricity sold on the wholesale markets.

For solar, the problem is reversed. With zero marginal cost to produce a unit of energy, there is no price risk with a photovoltaic system. Well-structured PPAs ensure that the electricity delivered will be sold at an agreed-upon price to an offtaker with a strong balance sheet such as utilities, big-box retailers, or residential customers with high credit scores. The unknown variable in the equation is the amount of energy produced. In other words, uncertainty in solar production is the real risk.

Uncertainty chiefly comes from two sources: weather and system quality. Cloud cover and other weather patterns are major contributors to inter-annual weather variability, in addition to inclement weather events such as snow and hurricanes. In addition to weather risk, the quality of the photovoltaic system itself is variable due to the choices between hundreds of module manufacturers, dozens of inverter brands, thousands of different contractors, and varying O&M programs. All of these variables create millions of permutations that add uncertainty to the expected energy output of a project.

This volatility, without widely available data to quantify it, is the reason lenders assign conservative coverage ratios for solar projects. Independent engineers provide lenders with projected energy output, but

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REITS remain hard to use for solar projects.

Final regulations the IRS issued in late August on what types of assets may be owned by real estate investment trusts were disappointing to solar advocates.

REITs are corporations or trusts that do not have to pay income taxes on their earnings to the extent the earnings are distributed each year to shareholders.

The renewable energy industry is interested in REITs potentially as a source of cheaper capital. Congress created REITs in 1960 as a way for small investors to invest in large-scale real estate projects. Small investors pool their investments in the REIT and are treated essentially as if they had invested in the real estate projects directly without a corporate-level tax being taken out along the way. The challenge for renewable energy is that a REIT must hold at least 75% real property or interests in real property. Examples of such assets are land, site leases, buildings and mortgages secured by real property.

Solar advocates hoped the IRS would treat solar panels as real property by viewing the panels as structural improvements to buildings, as inherently permanent structures on land or as real property for REIT purposes simply as policy move to encourage renewable energy. The IRS declined to go farther than it went in May 2014 in proposed regulations. (For earlier coverage, see page 9 of the June 2014 *NewsWire*.)

Machinery does not ordinarily qualify as real property. An example in the regulations makes clear that the IRS views solar panels as machinery.

Solar equipment can qualify as real property as a "structural component" of a building if it performs a utility-like function for the building, such as providing electricity. However, the IRS said the electricity must be part of what the building occupants get for their rent for the use of space, the REIT must own or have the same legal interest in both the solar equipment and the building, and the solar equipment must be expected to remain

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Solar Hedges

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these are only opinions — estimates that are not guaranteed.

Volatility in cash flows is not a new problem. Other asset classes have faced similar financing challenges and have overcome them through independent, industry-wide databases of historical performance. There is an opportunity to combine data with strong balance sheets to create new financial products that transfer risk away from the solar projects and into the hands of well-capitalized specialists like insurance companies; it is not dissimilar to what happened with revenue puts for combined-cycle gas-fired power projects.

Natural Gas Hedges

An instructive example can be found in the experience of gas-fired generators. These generators smoothed out the volatility in the delta between electricity revenue and the cost of inputs through hedges called revenue puts.

An essential primer on the revenue put was covered in the article on page 38 of the November 2015 *Project Finance NewsWire* by Chadbourne attorneys Robert Eberhardt and Monika Szymanski. As described by the authors, a revenue put operates as insurance against volatile wholesale power prices for power project owners. A revenue put establishes a floor — a minimum revenue amount — for a merchant gas-fired generator. If the revenue from electricity delivered does not meet that floor in a given period of time (typically a year), then the hedge provider pays the difference.

The revenue put became prevalent in the immediate aftermath of electricity market deregulation in the late 1990s when merchant-based projects were being proposed and the price of natural gas subsequently increased. Revenue puts have become an essential component of most project finance deals involving combined-cycle gas-fired power assets.

Applying a similar hedge to solar, wrapping not the price of electricity but rather the expected power production of a project, would substantially lower the cost of capital by allowing lenders to increase project leverage.

Because this concept is not new, a project developer today can go to any number of financial institutions and negotiate a production hedge. But because that hedge provider does not possess a strong understanding of solar production risk, it will require prohibitively expensive premiums, if it agrees to take on the risk at all. What is needed in combination with a balance-sheet provider is quality industry-wide performance data that allows for actuarial analysis and deep understanding of the risk.

Increasing Leverage

The liquidity challenges facing the solar industry create fresh urgency for equity investors to raise greater amounts of cheaper debt. The uncertain outlook for corporate credit has forced developers to be more creative in securing project finance.

The challenge is to change the status quo of conservative underwriting to allow for more debt to be safely placed within a project finance transaction. For developers, leveraging project deals frees up equity that can be more optimally deployed toward other business objectives. The more leverage they can stack on project deals, the better.

Coverage ratios in today's market are typically in the 1.3x to 1.4x range, providing debt for roughly 75% of the projected cash flow of a project. These coverage ratios fall in this range because that is what lenders are comfortable providing given their understanding of the risk presented by solar projects or portfolios of projects. At their core, coverage ratios address perceived volatility in cash flows.

Solar assets today have lower advance rates than aircraft leases, student and auto loans, mortgages, and even credit cards.

Part of the perceived risk is the long-term nature of solar assets. The most comparable of these asset classes might be mortgages: it is a long-term cash flow secured by an asset. Mortgage-backed securities, incidentally, have advance rates of 99%, largely because there is an independent third party with a vast depository of historical performance data on US mortgages

The solar market would benefit from a revenue put to cover output rather than price risk.

that allows for data-driven predictive risk modeling.

The prevailing approach to underwriting loans in solar forces developers to commit pricey sponsor equity to fill the remaining project capital requirements. A floor on energy production, backed by a strong balance sheet provided by the global insurance market, would transfer production risk away from the project finance transaction and result in lower coverage ratios and increased project leverage.

The global insurance market has been used before to secure capital in the solar market. Lenders have reduced exposure to investment tax credit recapture with an insurance product specifically tailored to this market. Recapture insurance unlocked new value in solar project finance by enabling securitizations. Similarly, a production floor would increase leverage and lower equity contributions, reducing the overall cost of capital for solar projects.

The solar industry has seen that strong balance sheets can lead to better terms on debt. Transactions have been completed where diverse corporate balance sheets can wrap solar production risk to achieve a lower cost of capital. The challenge today is how to price the risk effectively for a disinterested third party in a way that creates value for both project sponsor and lender. Traditionally in the insurance market, historical data and actuarial analysis provide the means to correctly price risk.

Insurance Market

A credible production guarantee that captures the drivers of volatility — including weather, equipment performance, O&M practices, etc. — is an effective means of risk transfer that makes the cash-flow profile of solar projects much more predictable.

As has been demonstrated by recapture insurance, having specialty insurers in solar project finance can add value to these structured transactions. For solar, attracting this kind of balance sheet, likely in the form of the global reinsurance market, requires a missing ingredient: data. In order for a provider to feel confident that it understands the risk being transferred to its balance sheet, it needs an actuarial analysis informed by historical, industry-wide production data.

The benefits of such a financial transaction are clear for both asset owners and project lenders.

For lenders, the reduction in volatility takes away the need for conservatism in loan structuring. Having a credible third-party backstop would enable lenders to reduce their risk and extend more capital in each deal.

For asset owners, the benefit of / continued page 22

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permanently in place.

The IRS and US Treasury are still thinking about whether it makes a difference if some of the electricity is supplied to the local utility, for example, through net metering. The IRS said in August that it will not object in the meantime as long as no more electricity is sent to the local utility in a tax year through net metering than is purchased from the utility that year for the building.

The regulations have two solar examples. One concludes that a solar system mounted on the ground next to a building whose electricity it supplies is a structural component of the building. The system is sized solely to serve the building and there is nothing to suggest the system will not remain in place indefinitely.

The other example concludes that the land, underground gathering lines, concrete base and metal racks that hold the solar panels in place at a utility-scale project qualify as real property, but the solar panels do not.

Some renewable energy companies have been worried that any expansion of what is considered real property for REIT purposes could undermine other positions the industry has taken. The industry treats solar projects as equipment in order to claim investment tax credits and five-year accelerated depreciation on the projects. These tax benefits can be claimed only on equipment and not also on real property. The US renewable energy sector has attracted a large amount of foreign investment, including by prominent European utilities. These investors are not subject to US capital gains taxes when they exit US projects unless the projects are considered real property.

The IRS said the regulations draw lines between real property and equipment solely for REIT purposes.

MUNICIPALITIES have greater flexibility to negotiate terms with private companies to operate and maintain municipal facilities after

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Solar Hedges

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increased leverage means a lower proportion of project capital from sponsor equity and subsequently a lower cost of capital. For the solar industry more broadly, simplified underwriting analysis would attract more investors into the space, potentially reducing the cost of capital even further as more lenders enter the market.

We have observed that as other asset-based markets have matured, they have been able to secure more debt because the variability of those assets was accurately quantified by robust data analysis. Solar is still seen as highly uncertain, thus the high cost of capital today. Simplifying the investment thesis by allocating risk to entities that understand it best is a necessary step in solar's progression toward a more established asset class. ◎

Jordan Turbocharges Distributed Solar

by Marc Norman, in Dubai

Conditions in Jordan are perfect for rapid growth in commercial and industrial solar.

The country recently abolished a limit on the nameplate capacity of renewable energy plants connected to the grid that can benefit from net metering.

Net metering permits a consumer of electricity generated by a renewable energy plant to feed any excess generation to the national grid in return for credits on future utility bills.

While the country's initial net metering directive issued in September 2012 prohibited the connection of any renewable energy plant above five megawatts, the directive issued last month provides that plant capacity will be subject to the approval of the sole transmission company or the relevant distribution company, on a case-by-case basis, based on an assessment of the grid at the relevant location.

In the short-to-medium term, this means that new projects are likely to remain limited in grid-constrained areas such as the south of the country, but the removal of the nameplate capacity cap will create significant opportunities elsewhere.

Subject to approval by the transmission or relevant distribution company, there is no cap on the amount of electricity that the renewable energy plant may feed into the grid. However, the distribution and transmission companies are only required to pay an annual amount of up to 10% of the electricity consumed by the electricity consumer, at a kWh rate of 120 Jordanian fils (roughly US$0.17) for solar, 95 Jordanian fils (US$0.13) for hybrid resources and 85 Jordanian fils (US$0.12) for other renewable energy sources.

The government commits to pay a 15% tariff uplift if the renewable energy plant is of Jordanian origin. There is no official guidance on the meaning of Jordanian origin; however, in practice, very few renewable energy developers have benefited from these types of incentives.

As an extension to net metering, Jordan also permits electricity wheeling. In exchange for a capped fee, this allows electricity generated by a renewable energy system at an electricity consumer's site to be transported, via the grid, to another site owned or leased by the same consumer (i.e., the same legal entity) and be either consumed or net metered at the alternative site.

The combination of the nameplate capacity cap removal, the relatively attractive electricity tariff paid by the transmission and distribution companies and the ability to wheel electricity is likely to give rise to larger-scale and more numerous projects than have been witnessed to date in the increasingly active commercial and industrial market segment.

Perfect Storm

Electricity that is produced at or near the point where it is used is referred to as distributed generation. Over the past few years, Jordan has witnessed a rapid expansion of renewable energy distributed generation, and solar photovoltaic distributed generation in particular.

The combination of high solar yields, plummeting solar photovoltaic plant costs and high electricity prices has created a perfect storm for solar photovoltaic distributed generation.

The German development agency, *Deutsche Gesellschaft für Internationale Zusammenarbeit*, says that in many of Jordan's regions the solar yield -— the electricity output achieved by a solar photovoltaic panel under full solar radiation — stands at around 1,800 kilowatt hours per kilowatt peak. This is far more, for example, than the 900 to 950 kilowatt hours per kilowatt peak recorded by research institute Fraunhofer ISE for solar output in Germany, the leading international solar distributed generation market.

The levelized cost of electricity of solar photovoltaics fell by 58% between 2010 and 2015, driven in large part by dramatic reductions in solar photovoltaic panel prices, according to the International Renewable Energy Agency. IRENA estimates that by 2025, the global weighted average levelized cost of electricity of solar photovoltaics could fall by as much as another 59%, most likely driven by efficiencies in balance of system costs, like inverters, racking and mounting systems, and civil works, technology innovations, operations and maintenance costs and quality project management.

Commercial and industrial solar is poised for rapid growth in Jordan.

Jordan has little oil and gas. Thus, the country has had historically to import almost all of its energy needs — 97% in 2014, according to the latest published annual report of the sole transmission company, the National Electric Power Company.

These energy imports have often been unreliable. Since 2011, the country has had to run its conventional gas-fired power generation plants on oil at high cost due to gas pipeline sabotage between Egypt and Jordan.

Electricity generation and distribution costs in Jordan are cripplingly high: around 157 Jordanian fils (US$0.22) per kWh in 2014, according to NEPCO. Because many small electricity consumers benefit from subsidized electricity rates, the rates charged to commercial and industrial consumers are particularly high. For instance, one kWh of electricity supplied by NEPCO or any distribution company currently costs a bank 285 Jordanian fils (US$0.40), and a high-consuming telecommunications company 300 Jordanian fils (US$0.42).

To put things into perspective, in May 2015, the Jordanian government announced the bid tariffs of its second round tender to procure four 50-megawatt solar photovoltaic projects, and the winning tariffs were 43.441 Jordanian fils (US$0.0613), 45.9784 Jordanian fils (US$0.0649), 48.949 / continued page 24

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new guidelines the IRS issued in late August.

Municipalities that issue tax-exempt bonds to finance schools, roads, hospitals and other public facilities must be careful not to allow more than 10% "private business use" of the facilities or the bondholders could end up having to pay taxes on the interest they receive on the bonds.

Hiring a private company to operate and maintain a public facility can be private business use, depending on the terms of the management contract.

This is potentially an issue for any facility owned by a municipality. However, it is not an issue for facilities that are financed with "private activity bonds." Such facilities are already considered to have too much private business use, so the content of a management contract with a private party is irrelevant.

The new guidelines are in Revenue Procedure 2016-44.

A management contract with a private party will not be considered "private business use" of a public facility if the contract is purely for incidental services, like janitorial services, office equipment repair, billing, payroll or similar tasks.

It is also not private business use for a private party to manage utility-type property if the private party is merely reimbursed for its direct expenses plus reasonable administrative overhead.

In all other cases, the management contract must comply with the following guidelines to avoid being labelled a form of private business use.

The compensation paid to the private party must be reasonable in amount. Thus, the municipality should not pay more than other parties are charging for the same services. The amount does not have to be the lowest bid.

The contract cannot tie the contractor's compensation to profits or losses. Thus, the contractor cannot share in profits. It cannot be paid less or have its compensation deferred if there are losses. However, a penalty for failure to keep expenses below / continued page 25

Jordan

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Jordanian fils ($0.0691) and 54.3 Jordanian fils (US$0.0767).

While a number of market participants questioned the sustainability of the round two tariffs, it remains startling that the lowest bidder's tariff is 72% less than NEPCO's generation and distribution cost.

More importantly, it is incredible that a solar photovoltaic developer is able to provide electricity to NEPCO at a rate that is 85% lower than what NEPCO would charge a high-consuming telecommunications company.

In Jordan, like in many other emerging markets, the pendulum has swung far beyond grid parity, and the business case for commercial and industrial electricity consumers to adopt distributed solar, and renewable energy more widely, has become extremely compelling.

With the publication of the new net metering directive, Jordan creates even better conditions for the continued development of distributed solar and other renewable energy projects. The race for developers to secure deals with the most bankable and highest paying electricity consumers is well and truly on. ◎

How To Grow: Raising Capital

Many small developers lack capital to take their projects through construction. They end up seeding projects for larger developers. The goal is to move the projects as far up the development curve as possible before having to sell. How do some companies get past this stage? What lessons have they taken away from dealing with strategic partners, private equity funds and banks? What is the secret to raising capital to support growth?

A group of CEOs and company founders talked in late September about how they got their own companies off the ground. More than 1,700 people registered to listen. The group was Ryan Creamer, CEO of sPower, Jeffrey Eckel, CEO of Hannon Armstrong Sustainable Infrastructure, Declan Flanagan, CEO of Lincoln Clean Energy, Sandy Reisky, founder and chairman of Apex Clean Energy, and Mikhail Segal, founder and chairman of LS Power. The moderator is Keith Martin with Chadbourne in Washington.

MR. MARTIN: Ryan Creamer, when was sPower started?

MR. CREAMER: We started in 2012.

MR. MARTIN: Describe the company's focus.

MR. CREAMER: We develop renewable energy projects. We have a current portfolio of about 1,200 megawatts of solar and about 140 megawatts of wind, but we look at all types of power. The "s" stands for sustainable.

MR. MARTIN: If I am not mistaken, in the space of just four years, you have already moved to a place where you build and own your own projects.

MR. CREAMER: Correct. We started as a small family office that serviced the back end of 104 nuclear power plants in the United States and operated all 20 reactors in the United Kingdom. Five years ago, I was called the naysayer of solar. I watched the technology get better and the cost come down. It got exciting. We jumped in.

In 2014, we had the opportunity to merge with a solar development platform, called Silverado Power, that Fir Tree Partners, a private equity fund, had acquired, and over the last 30 months we have placed in service almost 700 megawatts of solar assets and 60 megawatts of wind, and we have another 600 megawatts of projects moving into construction. We are building between six and seven megawatts a day.

MR. MARTIN: So the merger with Silverado provided the spark. What were your first two years like?

MR. CREAMER: During the first two years, we built about 40 megawatts of smaller, commercial- and industrial-scale solar projects. When Fir Tree Partners started provided funding, it let us move to another level. Fir Tree has a number of different funds within it: a hedge fund trading desk, a real estate fund, and a private equity arm, and through it and with its backing, we were able to raise almost $1 billion of equity.

MR. MARTIN: So for roughly the last two years, you have had no trouble finding capital. You can get all the way through construction. But how did you fund the business during the first two years?

MR. CREAMER: I would not say the last two-and-a-half years have been easy. I'll be honest. I didn't think I would ever say that a billion dollars is not enough, but to build what we have today, we have had to raise almost $1 billion of tax equity and almost $1 billion of back-levered debt. We have a continuing need for more capital.

When we first got started, I was probably a bit naive in thinking all it would take would be to throw a little money from our family office to get traction. It was funded out of our own pockets. The initial thought was to see how far we could get with $4 or $5 million.

By the end of the first two years, we were into it a lot more than that. We learned we had to make a commitment to the industry and not to one or two projects.

MR. MARTIN: So in your case, your own money carried you to a point where you got backing from a private equity fund.

Let's move to Jeff Eckel, who is currently CEO of Hannon Armstrong Sustainable Infrastructure, which provides financing for other renewable energy developers, but before that, he ran two development companies, Wärtsilä Power Development and EnergyWorks. Tell us about them and how they were funded.

Bootstrap First

MR. ECKEL: I feel like a history lesson because Wärtsilä Power Development was 25 years ago. I started as CFO for North America, and we delivered engines to the electric utility in the Dominican Republic, CDE, but the utility pulled its letter of credit securing payment for the engines just before the ship arrived. As CFO, I said, "This is a catastrophe. Turn the ship around." The Finns — Wärtsilä was a Finnish company — delivered the engines anyway. CDE of course didn't pay for the engines, so I said, "I think we are in the development business."

I went down there and turned it into a $15 million power plant. What I figured out was we were also starting in the operations and maintenance business. There was a pretty good margin in the O&M business, so I proposed to our parent company in Helsinki, "You weren't counting on this O&M margin. We got the problem fixed. Let me run this development business. The only thing I ask is that you never touch my million dollars a year in O&M margin."

They were fine with that approach, and we went on to develop 750 megawatts.

MR. MARTIN: These were barge-mounted diesel generators, right?

MR. ECKEL: Land- and barge-mounted.

MR. MARTIN: Did you have to raise outside capital or did all the money come from the Finnish parent?

MR. ECKEL: We took no money from the Finish parent to cover development spending. We funded development with the million dollars a year and most of our developer fees and then financed construction on a project-finance basis through a combination of debt and equity. The equity was usually about 25% of the total capital cost, and it came from a variety of / continued page 26

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specified targets is okay. The dollar amount of penalty should be set in advance in the contract. It can be a range of dollar amounts and expense targets.

The contract cannot have a term longer than 80% of the expected economic life of the facility or 30 years, whichever is shorter.

The municipality must retain a "significant degree of control" over use of the facility. It must approve annual budgets and capital expenditures, dispositions of any parts of the facility, and the rates charged for the electricity, steam or other output.

The municipality must bear the risk of loss to the facility from a casualty or other event outside the control of the contractor.

The contractor cannot have a role in the project company — for example, director positions that give it more than 20% of the vote or a board role for the contractor's CEO or board chairman — that might undermine the ability of the municipality to enforce the management contract.

MINOR MEMOS. Utilities are starting to fight back as renewable power companies enter into power contracts directly with large industrial customers. The Minnesota Public Utilities Commission approved a 5% reduction in the electricity price that Minnesota Power charges 11 industrial customers in September. The customers account for 60% of the utility's total load. The utility had asked the commission at the same time for a 10% rate increase for its residential customers to balance revenue, but the commission asked to see other options . . . . The Lawrence Berkeley National Laboratory reported in August that the median price for utility-scale solar projects completed in the United States in 2015 was $2.10 a watt on a dc basis ($2.70 a watt ac) based on a sample of 64 projects, or 77% of all US utility-scale solar projects completed in 2015. The lowest-priced projects cost $1.20 a watt with the lowest 20% / continued page 27

Growth

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investors who put capital into Latin American projects. We used a portion of our developer fees to fund about 10% of the equity.

Bechtel recruited me to start EnergyWorks, which was a very different business model. While the goal at Wärtsilä was to find a use for Wärtsilä generators, EnergyWorks was a startup business focused on India, Indonesia and Brazil, and we were supposed to execute on a distributed and renewable generation strategy so that Bechtel could see how smaller projects could get done. We did not have as our goal generating construction projects for Bechtel. That was in 1995. Unfortunately, we were just a little ahead of our time.

The company was owned by Bechtel and PacifiCorp as joint venture partners. They funded the venture. We were not short on capital.

I took away two lessons from the experience. One is that strategic investors change strategies a lot more often than I think is appreciated. After three years, Bechtel and PacifiCorp decided the company was a stupid idea. The other lesson is joint ventures are riskier to the management team than a single strategic investor, because the company is only as stable as its weakest partner. I have looked askance at joint ventures since then.

Hannon Armstrong, where I am now, has also dabbled in the development business. We formed a geothermal development company, EnergySource. If you want to make a lot of money, geothermal is not the place. Although we were very successful with the Hudson Ranch I project, we doubled down on Hudson Ranch II, and it was not quite as successful.

Hannon Armstrong did fine with EnergySource, but as a public company, we no longer invest in development assets or developers. We are a public vehicle that needs current yield.

MR. MARTIN: Where did the capital come from to develop the geothermal projects?

MR. ECKEL: From Hannon Armstrong. I have a view that if you need money from private equity, you are in trouble. If you cannot find a way to bootstrap your way into the development business and have to turn to private equity for funding, then you are put in the position of having to pay the private equity fund return ahead of any return you might earn, and the inevitable delays in development make it very challenging for the developer management team to make any money.

Now, that said, you have on this panel, a group of people who are just awesome developers and who have done fantastic jobs with their companies. I am not nearly as good as those gentlemen. But in my experience, if you need private equity, you are in trouble.

MR. MARTIN: So if private equity is out as a source, what is the right source?

MR. ECKEL: If I were getting into the renewable energy business today, I would focus first on solar, not wind, because wind is so capital intensive, and I would bootstrap my way into the first project, bootstrap my way into the second and generate some operating cash flow. I know it is difficult to do this in solar, but these other fellows have shown it can be done. Their growth trajectories have been just astonishing. I would probably take it more slowly because I do not have the same appetite for risk.

MR. MARTIN: Bootstrap means use your own resources?

MR. ECKEL: Yes.

Private Equity

MR. MARTIN: You have just teed up Declan Flanagan. Declan, you have done a great job of growing Lincoln Clean Energy, and you have followed a more rapid growth strategy than perhaps Jeff was describing. When was Lincoln Clean Energy founded?

MR. FLANAGAN: Toward the end of 2009.

MR. MARTIN: So the company has been in business for seven years. What types of projects are you developing?

MR. FLANAGAN: The current focus is mostly wind, some solar. We have some activity in natural gas, but that will take a number of years to bring to fruition.

MR. MARTIN: Are you at a stage now where you are building and retaining ownership of your own projects?

MR. FLANAGAN: Yes.

MR. MARTIN: Did you go through discrete steps to get to that stage or did you start there?

MR. FLANAGAN: I started in 2009 using my own capital and some founding partners' capital and focused initially on solar for all the reasons that Jeff articulated. The goal was to develop smaller projects that we can get into operation without institutional capital and take it from there.

In hindsight, we were a little too early into some markets, particularly the mid-Atlantic states and southeast that are really booming now, but they were infertile ground in 2010. We had some success in New Jersey where we still own assets, and we had some success in California where we developed a couple projects that we later sold.

Three years into the company in 2012, we started to get a lot more traction with wind projects. We have developed more than

1,000 megawatts of wind since then, all of which we have sold. At the end of last year, we decided that we needed to raise more capital to build on our success with large wind farms. We specialize in 200- to 300-megawatt wind projects. So in December last year, we sold the company to a private equity fund, I Squared Capital, and with the momentum we have built up with our platform, we now build and own our own projects with a focus mainly on wind, but also some solar.

MR. MARTIN: What was the intermediate step along the way? You used your own resources initially, got some traction, and now you are owned by a private equity fund. Was there an intermediate step?

MR. FLANAGAN: We brought in some capital from a Texas-based venture growth equity fund, Austin Ventures, who are great partners and investors. They came in at the project level. We had a co-investment from Danson Construction in 2011 to 2012 through a joint venture that focused on a couple solar projects.

That was the intermediate capital between the founder capital and where we are now. I think it is really important in any development business that you have quite a bit of founder capital to build momentum. During that intermediate period, we didn't actually launch any processes to raise capital. We were in a comfortable position of just responding to incoming approaches, from people who were looking to partner. Early-stage development capital, particularly in small increments, is difficult to raise.

Don't be in too great of a hurry.

MR. MARTIN: Let me make sure I understand the intermediate step. You had one or two partners. Did they take interests solely in particular projects or at the company level?

MR. FLANAGAN: In both instances there was an element of holdco capital.

MR. MARTIN: What was the nature of the relationship then with each partner? Did you give up 30% of the company? Did you give warrants? What was the deal?

MR. FLANAGAN: There are many ways to structure such arrangements. You probably have many different arrangements just on this panel. When issuing equity to build up a development platform, it is more common and easier to achieve alignment of interests if there is some sort of preferred return to the external money.

MR. MARTIN: Let's go to Sandy Reisky next. Sandy, I think your earliest venture was wind. You amassed a portfolio of sites for wind farms. The sites proved as valuable as beachfront property. You ended up selling them to BP Alternative */ continued page 28*

IN OTHER NEWS

at or below $1.60 a watt. The lab looked at the "installed price," which is the price at which each project was sold, including in a tax equity transaction. Fixed-tilt installations commanded a premium of $0.02 to $0.08 a watt. Prices varied by region of the country, with the most expensive projects in California and New England and the least expensive in the Southwest and Southeast. Projects over 100 megawatts were the least likely to show a price reduction because of the longer time required to construct and the administrative and regulatory challenges of dealing with sites as large as 10 square miles and 2.5 million solar modules. The data is in a report called "Utility-Scale Solar 2015" . . . . Prices for solar panels have slid approximately 20% in recent months to below 40¢ a watt in the US market . . . . Swedish company Vattenfall won a bid in September to supply electricity from two offshore wind farms near shore in the Danish North Sea for US$67.33 a megawatt hour, 20% lower than the previous record.

— contributed by Keith Martin in Washington

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Energy. Then I think you took a look at solar, but now you are back focused on wind and it seems like every third big wind farm coming to market for financing lately is an Apex project. Are you at the stage currently where you are building and owning your own projects?

Happy Investors

MR. REISKY: I would say we are building for the market. We might retain an interest in the projects, but we have really focused on bringing a portfolio of projects to market to be sold to a strategic partner or an infrastructure group or fund.

MR. MARTIN: You build and retain projects until you have a large enough portfolio to sell?

MR. REISKY: The original company I started in 2000 was Greenlight Energy. We completed a 150-megawatt wind farm in Kansas. We developed it and built it together with PPM Energy, and we were at the point of bringing a 300-megawatt wind farm to market together with Babcock & Brown when BP acquired Greenlight.

From a founder's perspective, the value that BP saw in our company could be recovered quickly because there was a large project ready to go into construction. BP could justify the purchase of the whole company with that late-stage asset and the pipeline of development projects.

MR. MARTIN: Describe the discreet stages you went through to get to where you are today.

MR. REISKY: The story is similar to some others on this panel. After the transaction with BP, there was a non-compete agreement for a number of years, but we had capital and we had a lot of happy investors. All the capital we raised for Greenlight was from friends and family and local family offices.

The theme was we are investing in clean energy resources. We launched a new company, Axio Power, to pursue development of utility-scale solar facilities. We acquired three companies and rolled them up into one. We had assets in California and Canada, in the northeast and in Hawaii.

The Canadian assets were well positioned to benefit from the Ontario feed-in tariff program. We were awarded a number of contracts. The lesson was that a geographically diverse portfolio with critical mass where you are covering a lot of markets gave us a good hit rate. We sold the company to SunEdison.

MR. MARTIN: You have been paid the full purchase price?

MR. REISKY: Good question. Yes. We then had another shot on goal that connected with investors, and were able to continue raising capital for our current company, Apex Clean Energy. Apex launched in 2009. The SunEdison transaction for Axio was in 2011.

All of this has given us a lot of momentum. The Apex founding story is that we had some of our own capital and, over the years, we brought in capital from our investor group. I agree with what Declan said that it is best to use founding capital to get to a point where the company has critical mass.

About 18 months ago, we worked with Prudential Capital Group, and that was our first institutional capital. They were great to work with, and it was a good transaction for Apex that gave us resources to invest in more projects and bring them to market.

The inflection point for Apex that truly got us launched was completion of the 300-megawatt Canadian Hills project in Oklahoma. The revenue from that sale really fueled our growth. We have about 220 people now. We originate, develop, finance and build our own projects. We are also operating about 1,000 megawatts of assets from a state-of-the-art remote operations center.

MR. MARTIN: Although the breakpoint was the revenue from the Canadian Hills project, it sounds like the real key was you had a lot of happy investors from your first venture, Greenlight Energy, and the success with Greenlight meant they were willing to continue investing in your follow-on ventures.

MR. REISKY: That's absolutely correct. What we were telling investors is this is a resource play and people may look at it as project development, but it is really about investing in energy resources that have tremendous option value.

MR. MARTIN: Option value meaning what?

MR. REISKY: The option to produce energy and sell it for a fixed price over a 20-year term delivered to a specific spot on the grid. An option like this can have significant value in an environment where energy prices are higher than the cost to produce the energy.

Delay Outside Capital

MR. MARTIN: Let's turn to Mike Segal, who is one of the big names in the independent power industry and who built LS Power into a major independent power company. How did LS Power get started and in what year?

MR. SEGAL: I feel a bit like a dinosaur next to these guys, because we started in 1990. We were a very small shop at that time focused on projects with high barriers to entry. The reason to like those deals is there is limited competition for them, and they usually offer the best rewards.

When we started, we tried to advance the first group of our development projects as far as possible using our personal resources. We managed to push them up the development curve to a point where they were significantly de-risked. At that point, we took a small amount of outside funding to support further development of this group of projects. By waiting as long as possible, the dilution was very small and we retained full control.

During the 1990s, we developed approximately $3 billion in enterprise value of projects.

MR. MARTIN: Where did the outside capital come from initially?

MR. SEGAL: The outside capital, which was very small, came from one institution and a family office and their participation was limited to the first group of projects.

MR. MARTIN: Was it equity or debt?

MR. SEGAL: It was a limited partner interest.

We completed about $3 billion of deals in the 1990s and sold them, so that by early 2001 we ended up with a very enviable cash position. That gave us the resources to continue developing our own deals. We never needed any more development capital because we had a pretty strong balance sheet.

MR. MARTIN: Before taking the story further, you had a small amount of institutional capital, it sounds like at the project level, from a limited partner. Surely you had to raise other outside capital to complete the $3 billion in projects?

MR. SEGAL: The initial capital was to support completion of the development efforts on the first few projects and came at a portfolio level. The remaining capital was mostly debt, our own equity and, occasionally, sale of the limited partnership interests in specific deals at construction financing.

MR. MARTIN: So now we are in 2001 and you have raised a lot of cash from selling a portfolio of natural gas-fired power plants at the top of the market before Enron collapsed.

MR. SEGAL: Since 2001, we have completed another $6 billion in development projects. They include transmission lines and substations, some renewables and several large fossil-fuel fired plants. All the funding came from a combination of debt and our own equity.

After 2001, we broadened our platform from the initial focus of building and owning gas-fired power plants. We set up a hedge fund. We formed several private equity funds and took in outside investment in them. Both are focused on the energy sector. The hedge fund trades securities, passive positions in companies in the utility and energy sectors, and the private equity business buys existing operating projects that are undermanaged and then we try to improve their performance and resell the projects at a higher price. We raised about $6.5 billion across the three private equity funds. In 2006, we purchased Duke Energy's North American portfolio of gas-fired projects. We got a gas portfolio from Mirant, from NextEra, and there were others.

The private equity funds buy existing projects. We never use capital from the private equity funds to fund development of our own projects.

Other Wisdom

MR. MARTIN: These are some very different approaches among the five panelists.

Now let me ask each you what lessons you learned about raising capital along the way. We are looking for practical advice. Ryan Creamer?

MR. CREAMER: I was a little naïve. I had just come off financing more than $2 billion of nuclear installations. I looked at solar and thought, "It is like my erector set as far as difficulty to build." But it was not easy to do the financing.

One of the toughest tasks was arranging tax equity. There is only a small number of players investing tax equity. They are serious companies. Getting invited to that club and being able to get their help financing your projects was a challenge. Then later adding debt and trying to tie it together with tax equity was even more challenging.

One of the things we found was you have to have some skin in the game. They want to know that you are in the energy business and that you have a good track record. I had a track record servicing nuclear power plants, but I began to feel like I was pretty inexperienced to go build solar facilities. The financial community wanted to see industry-specific experience with solar.

So we ended up building a couple facilities on balance sheet to get there. We recycled some early capital.

MR. MARTIN: Was the lesson to prove you can walk before you try to run?

MR. CREAMER: You have to walk before you run, but you also have to ensure you are always capitalized appropriately. As Jeff Eckel said, these projects always take longer than expected.

We all hear the term "shovel ready." You really have to make sure your projects are to the nth degree ready for due diligence as you go in for financing. Make sure you are */ continued page 30*

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appropriately capitalized so that you can weather any delays. Be mindful of deadlines in the power purchase agreement.

When we combined with Fir Tree, we looked at the Silverado portfolio and concluded there might be 100 megawatts that we can bring to fruition. Months later, after a lot of hard work, a lot of sweat and tears, and after throwing a lot of capital at projects, we saved almost 370 megawatts out of Silverado's 500-megawatt development portfolio. We got the projects to a point where they were execution-ready and buildable.

MR. MARTIN: There seem to be two lessons in what you just said. Developers need more money than they think. Make sure everything is neatly tied together before taking a project to market.

MR. CREAMER: Absolutely. There is no tax equity investor or bank that wants to spend the time training you to do your job. Maybe another lesson from our own experience is that half of our portfolio has come from greenfield development and the other half has come from working with other developers to help push their projects across the finish line. The lesson is to understand your core capabilities and where you add the greatest value in the development cycle.

MR. MARTIN: Interestingly, you said as a former nuclear power expert that one of the hardest things about moving to solar energy was the complexity of tax equity.

MR. CREAMER: Yes. It was a lot more difficult than I thought. I thought nuclear was about as tough a game as there is trying to explain to people and get comfortable with risk. But renewable energy financing is at another level. It is a good thing we are building renewable energy facilities because the amount of paperwork these projects take to get financed is destroying whole forests.

MR. MARTIN: Jeff Eckel, you offered some practical advice earlier, but do you have other advice for CEOs of small project developers that want to grow?

MR. ECKEL: Many capital providers think most problems can be solved by money. I do not believe that is the case. It comes down to the management team. It takes experience, wisdom, lessons learned and just plain street smarts actually to develop a project.

The next point is you have to be in a position to say no. Either be willing to fund it yourself or bootstrap with others or work your way into a related business that generates a revenue stream and puts you in a position where you do not have to ask financiers for cold, hard cash. That will give you a lot of leverage.

MR. MARTIN: Mike Segal said he pushed his first project to a point where it was largely de-risked before going out to raise capital. That way he kept more of the project.

MR. ECKEL: LS Power has been just genius at this for decades.

Speaking today as a capital provider, you only want to give money to people who don't need it. That is a sad fact, but it is the way it works. A developer has to bet the farm a few times to get the value he deserves.

MR. MARTIN: Let me test one other proposition. It sounds like you believe business plans change, so you basically are putting your money behind particular people. They need to be resilient and determined enough to be able to work through the inevitable obstacles that are thrown in the way of developers.

MR. ECKEL: Yes. Ryan Creamer talked about the need for industry-specific experience. Bechtel had a great phrase: it wanted to be the first party into a construction project the third time around. You are going to have a few broken plays before a capital provider will be confident you know the six ways you could lose money. Until you stub your toe a few times, you don't know what you don't know. Experienced people are extraordinarily valuable.

MR. MARTIN: No mistakes, no experience. No experience, no wisdom. Declan Flanagan, what practical advice would you give people trying to move up the

Make sure everything is neatly tied together before taking a project to market.

development chain?

MR. FLANAGAN: You do not want to get into a situation where you are in too much of a hurry or too much of a corner that you must do a deal. You will end up having to work through the consequences for a long time.

It is one thing to take a sub-optimal deal for a single project — it is bounded — versus growth capital or holdco capital. Things always take longer than expected. Always make sure you give yourself adequate time.

Another lesson when it comes to growth capital and bringing in partners that is obvious, but that too few people heed, is really get to know them upfront and diligence them. Look into their backgrounds. Spend time with them. Get to know how they think before you are sitting around a board table making decisions.

Again, back to the first point: do not allow yourself to get into a situation where you are in an undue hurry.

MR. MARTIN: Sandy Reisky, what practical advice do you have for CEOs of smaller companies?

MR. REISKY: There has been a lot of really good advice already. I am afraid I might repeat some of it. Start raising capital well before you need it, because you do not want to be in a position where you are desperate for the capital. Allow yourself time and have alternatives, and say no if it is not the right capital.

When I first got in the business, I thought people would see that this is the future. This is green energy. It is clean. It does not use water. Frankly, people also wanted to hear the story about the value proposition, and it seemed the more you talked about the renewable aspect of it, you were not doing yourself any favors, particularly back then.

Really know what your value proposition is and how you are going to manage risk. Be able to express the value proposition simply and to explain the risks your business will face and how you are going to address them.

Be able to explain what the real sizzle is in your business model. You have a business that requires $10 million in risk capital for early-stage development, but a project can deliver multiples on that. What you are really capturing when you sell a project is the net present value of 20 years of earnings above your cost of capital.

If the market moves and there is a carbon tax or natural gas prices go higher, all the projects across the portfolio get more valuable as wind gets deeper in the money, and we all know that there are technology trends that will make wind and solar continue moving down the cost curve, and the rest of the energy market probably will not follow as rapidly. That is a fundamental part of our value proposition.

The emphasis on assembling the right group of people that I have heard already today is absolutely spot on.

We brought in a lot of veterans from a lot of other great companies to join the Apex team. They really brought the expertise, especially on the operations side. Part of our business model that not many others are pursuing is we are ready to sell projects that are completely de-risked and in operation to strategics and financial counterparties. We have a terrific operations center with 25 people that is run 24/7 and is staffed by industry veterans.

Moving away from holdco capital and explaining how to drive a company to the point where it has to focus on how to finance projects through construction, Apex did what I think a lot of the people on this call did. It is like climbing up a ladder. We were capitalized in anticipation of the next few rungs, and once you climb those, then you get to the next stage in the capital cycle.

MR. MARTIN: Mike Segal, many people envy the progression of your company. Explain to someone who has just come to the United States and wants to start up a similar company how to follow in your footsteps.

MR. SEGAL: You are being too kind. I always believed that capital is available for the right idea sponsored by the right, competent and credible team. So if you have that right combination of a good idea, good project, and a team that has credibility, competence, and ability to add value at each stage of the project, plus personal integrity, you should not have a lot of difficulty finding the initial capital to get the business going.

There are two other lessons. Projects that enjoy competitive advantage in raising capital are the ones with some unique, innovative commercial structures or with the first-mover advantage. On the other hand, if your deal is a kind of plain vanilla, low-barrier-to-entry type, you may get funded, especially under current conditions when so much liquidity is sloshing through the system around the world, but you better watch out for the exit because the music can stop and you can end up stranded.

So the quality of the deal that you are presenting to potential investors combined with your competence and credibility determine the outcome. I have seen it many, many times over my entire professional life. We see many developers come through our doors and present deals, ideas, projects, and if there is not the right match of personal capabilities and characteristics with the right project, as an investor, I pass.

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MR. MARTIN: That is lesson number one. There was one other, you said.

MR. SEGAL: Lesson number two is one that I think everyone on this panel can endorse. The longer you can hold on without diluting yourself, the better your chances of building a successful, sustainable business. Dilution and the loss of control will ultimately adversely affect your ability to grow your business.

Audience Questions

MR. MARTIN: Thank you panel for the hard-earned wisdom. Let me turn now to some audience questions. I will throw them out to the panel. Let's see how quickly we can answer them. Maybe one person answer a question, and then we will move on to the next one.

First question: How can you attract private equity capital that targets 14+% returns in a sector like solar, where project yields are around 8% to 10% unlevered?

MR. CREAMER: It is tough. The market is maturing. There was a time and place for 14+% returns. Some of the early money that we raised in 2014 was opportunistic. We took some hairy projects and had to clean them up and were able to get better returns. The greater maturity of the market means that returns are falling.

MR. MARTIN: Another audience member asked a related question. In early development, when risks are higher, but manageable, what type of internal rates of return are necessary to attract investors? Equity returns of greater than 16% are hard today.

MR. SEGAL: As a private equity investor myself, I would not be investing in a development-stage project for a 16% rate of return. The development process risks would not justify, at least in my mind, the rewards associated with a return in the mid-teens.

MR. MARTIN: What do you think is appropriate?

MR. SEGAL: It depends on the stage of the development process.

MR. REISKY: From Apex's standpoint, we always want to fund the early-stage development capital ourselves because that is exactly the risk-reward delta that we are trying to capture. We would rather not invite in partners at that stage.

MR. SEGAL: That is a very wise idea.

MR. MARTIN: I suspect a lot of people are asking the next question, and it is a long one. For solar projects in the 10- to 40-megawatt range, the high effective leverage ratios from bank debt and tax equity can lead to a situation where a developer has already contributed the owner's equity requirements by the time the financing is required. The developer has built up equity through a combination of land acquisition costs, interconnection deposits, environmental permits, etc. However, there are often multi-million dollar letters of credit required for development security under power purchase agreements. Small developers do not have the balance sheet to secure the LCs nor do they have a few million dollars in cash to backstop them. What are some of the avenues available to small developers for these LC requirements?

MR. CREAMER: If anybody has a secret, I would love to know it. It is something we have struggled with for a long time. We did not get our first credit line for development LCs until after we had almost $1.5 billion on our balance sheet.

MR. MARTIN: So no good answer. Can anyone do better?

MR. ECKEL: Work outside the US, in Latin America or another place where your capital and your ability to develop is more highly valued than in the US.

MR. MARTIN: Here is the next question. Many counterparties want corporate guarantees. What advice do you have for CEOs about them?

MR. ECKEL: What is this concept of guarantee that you speak of, Keith? I'm unfamiliar with it.

MR. MARTIN: When you go to financing —

MR. ECKEL: I'm teasing. No corporate guarantee. No corporate guarantee.

MR. MARTIN: How do you get away without it?

MR. ECKEL: We don't develop

> One of the hardest things about moving from nuclear energy to solar was the complexity of tax equity.

anymore, but my advice is don't guarantee anything. You have given your time and most certainly some money. That should be enough.

MR. MARTIN: Anyone else?

MR. CREAMER: Grandma always said, "Don't ever do a personal guarantee," so you live by that. As for corporate guarantees, there will be things for which you have to indemnify your partners. In a non-recourse project financing, such guarantees should be minimal.

MR. MARTIN: The next question is how important is it to keep the burn rate low? Some people say it is best to act from the start like a large company.

MR. CREAMER: We started with seven people in 2012. Keeping the burn rate extremely low until we could get momentum was important. Today, we have only 80 people, and that is everything across the board from development to the back end of operating facilities and the control room. Controlling the burn rate is critical, especially as the industry matures and margins compress. The dollars saved go directly to the bottom line.

MR. MARTIN: What are some of the approaches you have seen for early-stage capital? Some that Chadbourne has seen are selling projects to fund development of other projects, development-stage loans, funding from a strategic investor in exchange for a right of first offer to buy projects when they are ready for construction. What else?

MR. REISKY: We managed to complete a loan from a turbine company in the early days of Apex.

MR. MARTIN: Any other ideas?

MR. CREAMER: We have done joint development agreements where we work with a partner to put early money into the project. There are various ways to structure such arrangements. We have had useful relationships blossom from them. The simpler the construct, the better.

MR. MARTIN: We are at the end of the hour, so this will have to be the last question, but it is a question that many people probably have. I will read the whole thing. We have been funding the development of our anaerobic digestion/power project through a combination of our own funds and a multi-million dollar state grant. We need to raise multi-millions more to complete the project through construction and commissioning. We have been approached by several "developers" offering to arrange the remaining capital stack, and also by investment bankers, accounting firms, and attorneys. Whom should we hire and when?

I guess an alternative question is whether he should hire anyone at all.

MR. ECKEL: We will look at everything, but I think for the particular developer, it is a matter of recognizing where your core strengths are and then finding the right partner. That will also determine when you want to bring on the partner. ◎

Batteries and Tax Credits

by Keith Martin, in Washington

The Internal Revenue Service has issued three private letter rulings confirming that a 30% investment tax credit can be claimed on batteries that are installed as part of renewable energy projects.

The batteries must be positioned and operated in a way that they are considered part of the electric generating equipment.

Two of the rulings involved 32- and 36-megawatt batteries installed at merchant wind farms. One addressed batteries installed with rooftop solar systems. The US Department of the Treasury paid a cash grant on another battery installed at a large contracted wind farm.

The IRS has also declined to rule in some cases that pushed boundaries beyond the cases on which it has ruled.

The IRS is in the process of revisiting in what circumstances batteries qualify for investment tax credits. Tax credits can only be claimed on generating equipment. The issue is when is a battery considered part of the generating equipment. The IRS is sifting through 25 to 30 letters received in response to a request for comments. The issues are complicated and will probably take into 2017 to resolve.

IRS Rulings

In the first private ruling, a 32-megawatt lithium-ion battery installed at original construction of a merchant wind farm qualified for a tax credit as part of the generating equipment.

The battery is on the low side of the step-up transformer. Only 3% of the electricity stored each year on average was expected to come from the grid. The main function of the battery is to act like a knob on a motor to regulate the ramp rate at which wind electricity is fed into the grid. However, the plan was to use the battery also to provide frequency regulation */ continued page 34*

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services to the grid. Revenue from regulation services was expected to account for roughly 20% of total revenue of the wind farm.

The second private ruling dealt with a 36-megawatt advanced lead-acid battery installed at an existing merchant wind farm.

The wind company said about 15% of electricity on average used to charge the battery would come from the grid. The battery is on the low side of the step-up transformer. It is being used to provide various ancillary services to the grid. These services include spinning reserves, non-spinning reserves, voltage support, ramp control and black start. Revenue from ancillary services amounts to about 15% of total revenue of the project.

The third private ruling was issued to a solar rooftop company.

The company installs batteries on the same side of the inverter as the solar rooftop systems. The batteries have four possible uses: to store excess solar electricity from the rooftop solar system, store grid electricity at off-peak rates for use during peak hours, reduce demand charges and earn revenue by providing regulation services to the grid. The solar company said it was unable to represent that the batteries would be used mainly to store excess electricity from the rooftop systems. As a consequence, the IRS said the batteries qualify for investment tax credits, but it imposed a "75% cliff."

A "75% cliff" means that at least 75% of the electricity stored in the year the battery is put in service must come from the grid to be able to claim any investment tax credit. The actual tax credit is the percentage of solar electricity stored that year.

For example, if 80% of the electricity stored in the first 12 months after the battery is installed is solar electricity from the rooftop system, then a 24% investment tax credit — 80% of 30% — can be claimed on the battery. If the percentage drops in any of the next four years, then there is partial or full recapture of the unvested tax credits.

Investment tax credits vest ratably over five years. Thus, for example, if solar electricity accounts for only 75% of electricity stored in year two, then 5% (the 80% first-year use minus the 75% second-year use) of the unvested tax credit must be repaid to the US Treasury. The unvested credit in year two is 80% of the original 24% tax credit.

If the percentage drops below 75% in any of years two through five, then the entire unvested tax credit that year is recaptured.

The IRS told the two wind companies that there would not be a 75% cliff in their cases. After the solar rooftop ruling, the IRS warned that it might rethink whether a 75% cliff should also apply in the wind cases, but it never revised the wind rulings.

One problem with a 75% cliff is it is unadministrable. It does not work to make whether and how large a tax credit can be claimed in the tax year in which a solar system is placed in service depend on measurements that must be done over the 12 months after the battery is installed. The measurements could run well past the deadline for filing the tax return on which the tax credit is supposed to be claimed.

The IRS declined to rule that a 45-megawatt battery qualified that was physically distant from a solar project whose electricity it would store. A utility bought the electricity at the substation for the solar project and proposed to send it back to the solar company for storage in the battery. The electricity would have stepped up to transmission voltage in the meantime and then stepped down when it reached the battery. The battery would have been owned by the same project company that owned the solar project. The solar company proposed to collect a premium from the utility for the electricity for delivering a more firmed and shaped product.

Private letter rulings are not binding on the government, except for the taxpayers who received them.

Suggestions

Here are the main lessons to take away. An investment tax credit can be claimed currently on a battery, but in order for the battery to qualify, it must be considered part of a solar, wind, geothermal or other power plant that qualifies for tax credits. It should be on the low side of the step-up transformer or the same side of the inverter as a solar rooftop system. It should be owned by the same legal entity that owns the project. It should be used mainly to store electricity from the renewable power plant or solar rooftop system. In the case of a utility-scale power plant, it should be like a knob on a motor that regulates the ramp rate at which electricity from the power plant is fed into the grid.

There may be some cosmetic benefit if the battery is also treated for regulatory purposes as a generator rather than a transmission asset. However, the regulatory treatment does not determine ultimately whether the battery qualifies.

An investment tax credit cannot be claimed on a battery that is added to a power plant on which production tax credits will be claimed on the electricity output. Claiming tax credits on the electricity output while at the same time claiming a tax credit on part of the project cost would double up impermissibly on tax benefits.

Even though one of the three private rulings says otherwise, the IRS is unsure whether an investment tax credit can be claimed on improvements to existing facilities.

We think the law is clear: an investment tax credit can be claimed on later improvements assuming they are completed when the investment tax credit is available. After discussions with the IRS branch in Washington that handles these issues, the branch reported back that it agrees. However, when a solar company asked the branch to put the position in writing in a private letter ruling, the branch said the ruling request was too abstract. The IRS only rules on actual cases. The IRS position also seemed a little less clear after the ruling request was assigned to a new attorney in the branch who was not part of the discussions that preceded the ruling request.

There are two tax credits for solar projects: an investment tax credit under section 48 of the US tax code for solar equipment put to business use and a residential solar credit under section 25D of the US tax code for solar equipment purchased by a taxpayer for personal use in his or her residence. No rulings have been issued about batteries and the residential solar credit under section 25D. Eligibility is probably the same as for the investment tax credit. The battery must be used to store solar electricity.

Congress set deadlines in December 2015 for different types of renewable energy facilities to be under construction to qualify for investment tax credits. A battery that is an addition to an existing project must be under construction by the same deadlines.

It is rare to see a wind farm in 2016 on which an investment tax credit will be claimed. If given a choice between a tax credit tied to electricity output and one tied to project cost, wind companies choose the tax credit on electricity output. Turbine prices have been falling and efficiencies have been increasing. The only exception where an investment tax credit might be claimed is an offshore wind farm that has a very high capital cost.

Solar projects qualify only for investment tax credits. Unlike wind farms, they do not have a choice of claiming PTCs. Solar projects must be under construction by December 2019 to qualify for a 30% investment credit. Projects that start construction in 2020 qualify for a 26% credit. Projects that start construction in 2021 qualify for a 22% credit. After that, the credit falls to its permanent level of 10%. Any solar project on which greater than a 10% investment credit will be claimed must be in service by December 2023.

A battery added later to an existing solar project must also meet these deadlines.

There are two ways to start construction. One is by doing physical work of a significant nature at the project site or by starting work on the battery at the factory. There must be a binding contract in place with the battery vendor for the battery, or with another contractor for other work, before the work starts.

The other way to start construction is to "incur" at least 5% of the total cost before the construction-start deadline. Costs are not incurred merely by spending money. As a general rule, costs count only as equipment is delivered. Delivery can be at the factory. However, it may be possible to pay before the deadline and take delivery within 3 1/2 months after payment. (For more details, see page 14 of the February 2016 *NewsWire* and page 24 of the June 2016 *NewsWire*.)

New Guidance?

The existing IRS regulations on what qualifies for investment tax credits date to 1982. The IRS is in the process of updating them.

Many comments were received about when energy storage facilities should qualify for investment tax credits. The issues are complicated and are unlikely to be resolved before 2017 at the earliest.

The Solar Energy Industries Association is urging the IRS to dispense with the 75% cliff and allow a full investment credit if the primary use of the battery is to store solar energy or the battery lets the taxpayer use solar energy when local utility service is not available. It also wants the IRS to allow different ownership of the battery and solar power plant.

At least one solar company proposed a functional use test. A battery would be considered part of the electric generating equipment — and, thus, qualify for an investment credit — if it performs a "generator function," meaning it is on the solar side of the inverter and is used to store excess solar electricity or to regulate the ramp rate.

The IRS received 25 to 30 comment letters. It met over the summer with some groups that submitted comments. Two IRS attorneys have been assigned to work on the new regulations.

Meanwhile, the IRS said in a new notice in June that amounts that owners of standalone energy storage facilities pay utilities to connect to the grid do not have to be reported by the utilities as income. This will make interconnecting */ continued page 36*

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standalone storage projects less expensive. Utilities would otherwise have asked standalone storage owners to pay not only the cost of switchyard improvements and network upgrades to accommodate the storage project on the grid, but also a tax gross up that could have added significantly to the interconnection cost. The notice is Notice 2016-36. (For more detail, see page 31 of the August 2016 *NewsWire*.)

The storage facility cannot be a customer of the utility for transmission services or for more than a minor amount of backup power.

Separately, a bill that would allow a 30% investment tax credit to be claimed on all types of energy storage — whether or not they are part of renewable energy facilities — is gradually picking up support in Congress. Tax credits would be available on the same schedule as the investment tax credit for solar. (For more information, see page 17 of the August 2016 *NewsWire*.) The bill is unlikely to be enacted in 2016. Its prospects in the next Congress in 2017 or 2018 depend on the outcome of the presidential and Congressional elections in November. ◎

Britain Targets Enablers of Aggressive Tax Plays

by Paul White, in London

Britain is proposing stiff penalties for tax advisers who help with aggressive tax schemes.

The proposals go far beyond penalizing promoters, tax lawyers and accountants for working on transactions that the government has warned go too far.

Anyone found to have worked on a transaction that the UK tax authorities successfully challenge later could be "named and shamed" and forced to pay a penalty equal to 100% of the tax assessment.

Tax avoidance continues to be a hot topic in the UK media and one that politicians are more than happy to address. The rich and famous who avoid tax are bad people, right? Successive governments have introduced new tax regimes, then changed them, and changed them again, all aimed at preventing the avoidance of tax. Until now the primary aim of the changes has been to increase compliance by building on the self-reporting duties imposed on firms that market avoidance schemes and their clients.

In August, the UK tax authority, HM Revenue & Customs — called HMRC — launched a two-month open consultation on "strengthening tax avoidance sanctions and deterrents." Consultations on anti-tax avoidance and the ensuing strengthening of the UK tax code in relation to compliance have been regular events over the last few years, so the latest is not in itself surprising.

What is surprising is the potential reach of the proposals and the stinging financial sanctions on parties who have not actively participated in the avoidance of tax, including accountants, lawyers and other professional service providers involved in the execution of schemes, even though they played no role in the avoidance and received only a standard fee for their services.

Before reviewing the latest proposals, it is worth considering why HMRC is looking to make these changes now and why it is targeting more or less passive participants.

Background

Historically, HMRC's ability to challenge avoidance was hampered by two factors. First, the inevitable time lag, often a matter of years, between the tax-avoiding transaction and the point at which HMRC would have an opportunity to identify the avoidance in the taxpayer's tax returns. Second, HMRC lacked the analytical personnel and the technical means to reverse engineer convoluted schemes developed by highly paid teams of professionals.

Both those problems were addressed a little over 10 years ago by the introduction of the "DOTAS" regime. The acronym stands for disclosure of tax avoidance schemes. The regime applies to "notifiable arrangements" and "notifiable proposals" that are designed to effect a UK tax advantage as a main expected benefit and that fall within any one of the legislative categories or "hallmarks."

The reporting obligation falls on the scheme "promoters" who market the scheme, but may extend to the professional advisers who devise the scheme or provide the tax structuring advice and even, in some cases, to the scheme users.

The main purpose of regime is to provide HMRC with early notice of new tax schemes and details of how they operate. This enables HMRC to challenge the effectiveness of the schemes before there is wide-scale use and also to legislate to the close loopholes exploited by the disclosed schemes.

HMRC considers the DOTAS regime to have been a great success, and the Treasury confirmed that 42 amendments to the tax code were made between 2010 and 2014 as the result of HMRC's analysis of disclosed schemes. But, perhaps inevitably, fewer schemes are being disclosed each year: 84 in the 2012-13 tax year, but just 40 the following year. While this may be a testament to the regime's success, the view persists that avoidance continues on a major scale, so HMRC has been looking for new ways to deter the scheme promoters.

In 2014, the Cameron government introduced a new "POTAS" regime, targeting promoters of tax avoidance schemes, with the intention of curbing the activities of high-risk tax scheme promoters. Under POTAS, a serial promoter of tax avoidance schemes may be served a "conduct notice" by HMRC requiring the promoter to act or cease to act in a particular way. For example, a notice may require a promoter to comply with its disclosure obligations or to desist from activities that might tend to prevent others from complying with DOTAS.

If a recalcitrant promoter fails to comply with a conduct notice, HMRC may apply to the first-tier tax tribunal for approval to issue a monitoring notice. If a monitoring notice is issued, and is not appealed or the promoter's appeal rights are exhausted, HMRC will publish the name of the promoter and other related information, and the promoter is bound to notify its existing and new clients that it is subject to a monitoring notice.

Key to the structure and effectiveness of POTAS is the assumption that taxpayers will be wary of using tax mitigation products that are being marketed or structured by firms or individual advisers who are already the subject of HMRC's targeted compliance procedures and sanctions. And, therefore, a promoter who is at risk of being the subject of a published monitoring notice can be expected to modify its activity to comply with the tax code and, in particular, with DOTAS.

Despite the two compliance regimes already mentioned and a variety of other anti-avoidance initiatives since the 2008 financial crash, the idea persists in the UK media and, it appears, in HMRC that a significant number of taxpayers are avoiding tax.

In recent years, the media, and especially the tabloid press, have suffered a barrage of criticism from the rich and famous for phone tapping and other invasion of privacy issues, and that has resulted in Parliamentary investigations and criminal prosecutions. Over the same period, tax cases brought by HMRC have revealed the extent to which celebrities from the entertainment and sports worlds have invested in tax avoidance schemes, particularly those related to movie finance and offshore holdings. Not surprisingly, the newspapers have taken every opportunity to highlight the alleged hypocrisy of celebrities who avoid paying their "fair shares" of tax.

Latest Proposals

Britons often like to talk about what is fair or unfair. It is a topic almost as interesting as the weather. And they make frequent use of idioms about fairness, most of which are related to sports and especially cricket, while cricketers themselves are expected to play not only in accordance with the arcane written rules of the game, but also "the spirit of the game." At this point you might be wondering what any of this has to do with taxation; surely no one has suggested that tax should be paid not only according to the published code, but also "the spirit of the code." Actually, that is almost exactly what is happening.

While one should not be surprised when the tabloids vilify celebrities for not paying their "fair shares" of tax, it is disappointing that the tax authority adopts the same language when announcing new initiatives.

The tone of the latest proposals is set in the very first paragraph of the discussion paper. According to HMRC, a minority of taxpayers "attempt to pay less than their fair shares by using tax avoidance schemes" that have been "developed, marketed and facilitated by a persistent minority of promoters, advisers and other intermediaries." The discussion paper even alludes to those who operate outside "the spirit of tax law" in order to identify those to whom the proposals are intended to apply.

Another, perhaps more valid, fairness issue in relation to defeated avoidance schemes is that while the taxpayers will eventually have to pay their "fair shares" of tax, together with late-payment interest and penalties, the firms that market the schemes do not suffer financially for the schemes' failure.

The proposals represent a step change in HMRC's approach in that they target all participators, not only the promoters, and they introduce both financial and non-financial, "name and shame," penalties for enablers of tax avoidance schemes that have been defeated by HMRC.

Some of the proposals are vague while others would seem to face significant practical difficulties in operation, but presumably HMRC is aware of those issues and is not concerned by them. Although the proposed rules will only apply to tax schemes that are challenged and defeated by HMRC, */ continued page 38*

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they will inevitably affect the activities of advisers when transactions are being structured and undertaken.

The object of the proposals is clearly to deter lawyers, accountants, company formation agents, trust companies, financial intermediaries, banks, etc. from participating in business arrangements that might be challenged by HMRC as tax avoidance schemes.

HMRC has cleverly turned the time lag between execution and challenge to its advantage. A "defeated scheme" will likely be one about which there is a final determination of a tribunal or court that the arrangements do not achieve their purported tax advantage, or, in the absence of such a decision, there is an agreement between the taxpayer and HMRC that the arrangements do not work. So, at the time of execution, there is no way of knowing whether a transaction may eventually become a "defeated scheme."

It is foreseeable that some advisers may decline to act on transactions that may be defeated under challenge. Or, they may seek indemnities from their clients, so in the event of a successful challenge by HMRC, the client would be liable not only for its own tax, but also the penalties applied to other participants.

The proposals target the "enablers" as everyone in the "whole supply chain" for tax avoidance arrangements and schemes. The discussion paper notes that these participants bear limited risk or downside when the avoidance arrangements are defeated by HMRC. There is little acknowledgement that most enablers do not benefit from the upside either, but simply receive standard fees for their services.

HMRC says that sanctions would not apply to an enabler who was unaware that the services it provided were connected to wider tax avoidance arrangements, but this is just one of the areas where the practical details of operation seem not to have been fully considered.

According to the discussion document, "the purposes of a penalty for those who enable tax avoidance is to influence behavior and discourage the design, marketing and facilitation of avoidance generally." Although conceptually similar to POTAS, this time the sanctions are proposed to include significant financial penalties.

The consultation document briefly considers a variety of sanctions, including the Australian model of fixed-sum penalties and penalties based on one or both of the amount of tax avoided and the financial benefit enjoyed by the relevant enabler.

Britain is moving to impose major penalties on advisers who help with aggressive tax planning.

The approach favored by HMRC is a combination of fixed sums or, if higher, as much as 100% of the tax avoided plus the non-financial sanction of publishing the names and offenses of sanctioned enablers. Although, HMRC acknowledges that the size of the penalty needs to be proportionate to the services provided by the enabler and the financial reward it received, discussion of the quantum misses the point of the latest initiative.

The proposals are aimed at making professional service providers think twice before becoming involved, however tangentially, in arrangements that may prove in time to be a "defeated scheme." Even if the economic cost of the penalty is borne by another party, the "naming and shaming" sanction is unavoidable. If challenged by HMRC, the adviser may seek to avoid sanctions by pleading ignorance of the scheme's effect, but that is almost like admitting that, "provided we are paid, we do not care what we are involved in," which could be even more damaging to the adviser's market reputation than admitting involvement in a defeated scheme. Some commentators fear that in their current form the proposals will affect the willingness of advisers to participate in any tax advantaged transactions, besides bringing additional costs and time delays to structured deals.

With Brexit looming, the new Prime Minister and her Chancellor have been loudly proclaiming that Britain remains "open for business," so perhaps HMRC's proposals will either be dropped or significantly curtailed before they become law. We may not have long to wait for an answer. The Chancellor will make his first autumn statement on November 23, a sort of mid-tax year mini-budget, in which he is expected to outline the government's vision of the UK's fiscal future outside of the EU and hopefully will not reference "the spirit of tax law." ◎

Community Solar and Securities Regulations

by Rachel Crouch, in Washington, and Amanda Rosenberg, in Los Angeles

As the community or shared solar model becomes more popular, people are asking whether the customer agreements under which customers subscribe to a share of the electricity or buy into a community solar array could be considered securities.

If the customer agreement is considered a security, then developers would normally be required to register offerings of the contracts with state and federal regulators and would be subject to enhanced disclosure and anti-fraud requirements.

The time and expense of complying with these requirements would probably make development of community solar projects uneconomic, so the favorable resolution of this question is an important first step for developers.

The potential for confusion, and even litigation and fines, has led to requests for clarification from state and private entities seeking to avoid securities risk. For instance, the risk was perceived by the California Public Utilities Commission to be great enough to require a securities law opinion for developers to participate in the enhanced community renewables component of the "green tariff shared renewables program" in California. In a relatively early case, a developer — CommunitySun — requested and received a no-action letter from the US Securities and Exchange Commission in connection with its development of a "SolarCondos" project in Colorado.

This article describes the framework for evaluating securities issues in community solar projects and suggests appropriate actions for developers and financiers seeking to understand and mitigate the securities risk.

Federal Securities Laws

Whether a community solar customer agreement is subject to regulation as a "security" depends on how the arrangement is structured, how it is marketed by the developer and the customer's motive for entering into the contract.

The US Supreme Court has laid out a four-factor test — known as the Howey test — for determining whether a contract should be considered an investment contract and, thus, a security. A contract falls in this category if there is (1) an investment of money (2) in a common enterprise (3) based solely on the efforts of a promoter or a third party (4) for which there is an expectation of profits.

Courts generally consider whether the contract requires an investment of money to be a simple question with an obvious answer.

There are two main structures used in community solar projects. The first is an "ownership model" that involves participants in a community solar program buying an ownership share of the community solar array. They may pay in full at inception or over time. The electricity from the project is delivered to the local utility. The utility gives the customers bill credits that can be used to offset their monthly electricity bills. It is usually clear that the customers have invested money.

The second community solar arrangement is a "subscription model" that looks more like a typical power purchase agreement between a project owner and a residential or commercial offtaker. In the subscription model, each customer buys a percentage of the electricity output from a solar array. The price is usually a fixed amount per kilowatt hour. The power is sold to the utility by the project owner, and the customers receive credits on their monthly utility bills for their shares of the electricity. In such arrangements, customers pay periodically as electricity is generated rather than making an upfront payment. With no upfront cash outlay, no ownership interest in the project itself and payments tied to monthly power generation by the project, the subscription model looks more like a service contract than a security. However, at least one early state securities analysis (by the Colorado Division of Securities) implies that subscription payments could be considered an investment of money. Because this element of the four-factor test has not been as extensively developed in litigation as the other three factors, it is helpful for developers, financiers and their lawyers to consider the three other prongs as well.

Turning to the second of the four factors, the "common enterprise" test has not been conclusively defined by the US Supreme Court. Courts generally look at whether the success of investors and the promoter are linked. On a

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common-sense level, a common enterprise is a business that a group of people is undertaking together. If one views community solar customers as investors rather than mere customers, then the common enterprise prong is probably met.

It may help to avoid having a securities regulator conclude that a common enterprise was formed for the customer agreements to be clear that the benefits to any particular customer do not depend on the participation of other customers, and the customers' money is not being pooled together for the making of an investment. If the state regulatory regime allows for it, then developers using an ownership model might do better to sell individual solar panels rather than a share or undivided interest in the whole project.

Given the awkwardness of arguing that a "community" or "shared" arrangement is not a "common enterprise" developers would do well to focus on the other elements of the four-factor test to ensure their contracts are not securities.

Some subscription agreements in community solar projects may be "securities."

The third factor is whether the benefits to participants come through the efforts of a third party — namely, the developer. The participants generally are passive and not involved in business decisions. Although the developer has no control over when the sun will shine, the benefits to the participants, in both the subscription and ownership models, depend to a material extent on the developer's entrepreneurial and managerial efforts.

However, in so-called "condominium" arrangements, this factor may be absent. In its no-action letter request, CommunitySun explained that under its model, each condo owner has an individual net metering agreement with the local utility, and the condo owners govern a condo association that is free to hire and fire employees and enter into contracts for operation and maintenance services. This level of control by customers over the operation of the system in condominium arrangements makes it less likely that the efforts of a third party will be seen as central.

The fourth factor is whether the customer entering into the arrangement had an expectation of profits. Whether a customer agreement is a security often comes down to this question. The analysis may turn on the motive of the participant: did she enter into the shared solar arrangement to earn a profit or was the primary motivation to reduce her carbon footprint or monthly electricity bill? It is hard to see how a customer motivated by the latter has a profit motive. Nonetheless, it is important to examine both how the arrangement was marketed to customers and any evidence of customer motivations for entering into the agreement.

Developers should keep this in mind when marketing their projects to customers. Emphasize the environmental benefits and potential savings on utility bills. Do not suggest that customers will earn a profit.

There could be a profit motive if customers can sell their subscriptions to others, potentially at a gain, or make money if the customer's share of energy generated exceeds what the participant uses. In some community solar arrangements, the excess or unused bill credits get rolled forward to be used on future bills and then are converted ultimately to cash. However, the customer's subscription or ownership share is usually limited to a fraction of the customer's expected energy usage. This makes it unlikely the customer will have unused bill credits to convert to cash.

If it looks from the four-factor test like community solar arrangement is a security, then the parties should examine whether an exemption to federal securities registration requirements is available. However, even if an exemption from registration applies, the marketing of customer agreements will require enhanced disclosure and compliance with anti-fraud requirements.

State Securities Laws

A separate securities analysis must be done to determine whether a community solar arrangement is subject to state securities registration and disclosure requirements.

Many states have adopted the federal four-factor Howey test for state purposes. However, other states use broader approaches, so an arrangement that is not be a security under federal law may still be considered a security under state law.

A minority of states adhere to a broader "risk capital" test that was first developed by the California Supreme Court. The California test looks at whether funds are being raised for a business venture or enterprise, the transaction is offered indiscriminately to the public at large, participants are substantially powerless to affect the success of the enterprise and participants' money is substantially at risk because it is inadequately secured. Sixteen other states have adopted some form of this test.

Other states take a different approach. For example, in Minnesota, courts sometimes have relied on the federal four-factor test, but supplement it by adding "the placing of capital or laying out of money in a way intended to secure income or profit from its employment is an investment as that word is commonly used and understood."

The Path Forward

The bottom line is that the ownership and subscription community solar models should be evaluated differently. The subscription model appears to be gaining currency in the market, and as discussed earlier, it may present fewer securities risks than the ownership model.

It is also important to consider securities issues on a state level, keeping in mind that even if an arrangement does not pose a problem under federal law, it may still be considered a security under state law.

The degree to which developers and financiers have been comfortable with the securities risk has varied in community solar transactions. Because community solar financings are relatively new, a standard for what lenders and equity investors will require is still emerging. The community solar models may also evolve further. In novel contexts, the parties may decide they need official guidance, like no-action letters. State and federal securities opinions have been requested and delivered in some deals. The California Public Utilities Commission required securities law opinions from developers in that state, although the requirement is being challenged by some stakeholders and may be subject to modification. In other cases, proper diligence has been enough to get the parties comfortable. Developers should expect that lenders and equity investors will want to see written evidence of how the projects were marketed to customers. Similarly, when acquiring the development rights to projects or operating projects, the buyer should investigate how the customer agreements were marketed. ◎

Net Metering: Opportunities on the Road to Reform

by Megan Strand, in Washington, and Ana Vucetic, in New York

Although the year began with the end of retail net metering in Hawaii and Nevada, there have been positive developments for net metering in other key solar states.

By the first half of 2016, Massachusetts, New Hampshire and Pennsylvania had for the most part extended existing retail net metering and, in the case of Massachusetts and New Hampshire, raised statewide net metering caps. New York has focused at the same time on reaching consensus about the level of compensation for net metered customers as part of the state's broad review of its renewable energy policies.

Hawaii

Hawaii was the first US state to pivot away from retail net metering. In October 2015, the Hawaii Public Utilities Commission closed the net energy metering program to new participants. Customers of the Hawaiian Electric Companies applying to net meter after the decision were left with two alternatives.

The first — a "grid-supply option" — resembles traditional net metering. It credits a customer's utility bill for excess energy exported to the grid. The credit is set for a two-year period and equals the 12-month average on-peak avoided cost for the relevant island grid and varies based on utility service territory: from approximately 15¢ a kWh on the island of Oahu to 28¢ a kWh on the island of Lanai. Any credit in excess of a customer's monthly utility bill is not carried forward to the next month. The commission capped participation in this new grid-supply option at 35 megawatts across the state, including a sub-cap of 25 megawatts for net metered systems on Oahu and a sub-cap of five megawatts for systems located in each of the Maui Electric Company and Hawaii Electric Light / continued page 42

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Company service territories.

The second approach — a "self-supply option" — is designed for customers who consume all of their own electricity on site and is intended mainly for systems that incorporate energy storage. There is no cap on the number of self-supplied systems.

The commission also directed the Hawaiian Electric Companies to develop a third option in the form of a new time-of-use tariff. The utilities are supposed to initiate a two-year pilot program to test the interim time-of-use rates, broken down into three distinct time and rate periods that will be open to voluntary enrollment for residential customers. The tariff is supposed to be filed by the end of October.

Data from the last 11 months indicates that customers across the state have expressed an overwhelming preference for the grid-supply option. By the first week of September, installed and approved grid-supply systems totaled almost 23 megawatts out of the 25-megawatt cap for such systems on Oahu, while each of Maui Electric Company and Hawaii Electric Light Company had hit its respective five-megawatt cap. By contrast, fewer than two dozen self-supply systems had been installed or approved during the same time period.

Nevada

Several months after the net metering decision in Hawaii, the Public Utilities Commission in Nevada made waves when it approved a successor tariff that restructured net metering in the state by increasing monthly service charges, reducing rates from retail to avoided cost and creating a separate rate class for residential and small commercial systems and a time-of-use pricing mechanism. The commission reaffirmed the tariff in mid-February 2016, including a controversial provision applying the new rates to existing net metering customers of NV Energy and its two subsidiaries, Nevada Power Company and Sierra Pacific Power Company.

The lack of "grandfathering" for existing customers was successfully challenged in state court and separately addressed before the commission. In mid-September, a state district court determined that the commission's decision to affect existing net metered customers' rate design was a denial of fairness and due process because of inadequate notice, since the notice provided by the commission as to the scope of the hearings leading up to the decision did not accurately reflect the subject matter.

Shortly thereafter, the Public Utilities Commission issued an order adopting a compromise worked out among the commission staff, SolarCity, the Nevada Bureau of Consumer Protection and NV Energy that would grandfather existing customers. The commission also approved a proposal by NV Energy to establish a separate net metering rate class for grandfathered private generation customers through a tariff rider labeled "NMR-G."

The new rider applies to all customers who had installed a system or had an active net metering application as of December 31, 2015 or withdrew or let a reservation expire between December 23, 2015 and December 31, 2015. Net metered customers who have already interconnected will automatically receive service under the new tariff, while other eligible customers may opt in by the end of February 2017. The new tariff takes effect on December 1, 2016 for a 20-year period.

Massachusetts

Massachusetts has opted to manage net metering through statewide caps, including on certain categories of net metered projects. In April, Massachusetts raised statewide net metering caps from 4% to 7% for projects with private offtakers and from 5% to 8% for projects with public sector offtakers. This affects mainly the commercial and industrial subsector rather than residential projects, as the caps generally do not apply to systems at or below 25 kilowatts.

Final implementing regulations went into effect on July 29 and preserve close to retail rates for new systems at or under 25 kilowatts and those with public offtakers, but provide that other new private systems are credited for only 60% of excess generation.

The new rate regime is triggered when the total number of net metered systems statewide hits 1,600 megawatts (dc), which happened by the end of June. This threshold is separate from the statewide cap discussed below. The new regime applies to net metered systems that apply for a cap allocation after September 26, 2016. Thus, to remain under the old regime, a project must have applied for a cap allocation by the September 26 notification date, be told that its application is complete and receive the cap allocation by January 8, 2017.

Around 400 megawatts (ac) remain available under the overall statewide net metering cap, subject to certain sub-limits.

The statewide cap is broken down both by utility service territory and category of offtaker: for example, projects with a public entity offtaker under the "public cap" versus projects with a private sector offtaker under the "private cap." Within the

National Grid service territory, only nine kilowatts of net metering capacity remain available under the private cap, and there are approximately 17.8 megawatts of projects on the waitlist. By contrast, around 44.5 megawatts of capacity are available under the National Grid public cap. Thus, opportunities remain for developers looking to enter into agreements with public entity offtakers.

New Hampshire

New Hampshire has seen recent movement favorable to net metering, but more changes are on the way.

The state doubled the statewide cap on total capacity of owned or operated systems eligible for net metering from 50 megawatts to 100 megawatts in May. The law allocates 40 of the 50 megawatts of additional capacity to small projects at or below 100 kilowatts, while the remaining 10 megawatts were allocated to larger projects up to one megawatt.

The new law also requires the Public Utilities Commission to develop new net metering tariffs. The commission opened docket DE 16-576 shortly after the new law was enacted to develop alternative tariffs. Initial filings are due in late October and a final order is due by March 2, 2017.

New Hampshire had roughly 29 megawatts of installed solar capacity at the end of 2015, approximately two thirds of which is residential. While this places it in the bottom half of US states in terms of total amount of solar installed, ranking 30th, recent data indicates solar in New Hampshire is on an upward trajectory that is in line with the state's renewable portfolio standard of 24.8% renewable energy by 2025. Comparing New Hampshire to a state of similar population size such as Hawaii (with a total of 117 megawatts of installed solar as of 2015), installations across New Hampshire last year increased by 400% versus a 10% increase in Hawaii.

However, there is limited room under the revised caps for new large projects.

New Hampshire's largest utility, Eversource, for example, was allocated approximately 7.8 of the 10 megawatts of new capacity reserved for large projects, and around three fourths of the 40 megawatts of new capacity reserved for small projects. Under Eversource's small project sub-cap, about 21 megawatts of capacity remain available, while Eversource's large project sub-cap is oversubscribed by one megawatt. The commission directed utilities in March to implement new net metering application procedures aimed at ensuring only projects at an advanced stage of development are allocated capacity under the statewide net metering cap in an effort to allocate space under the cap to projects that are actually moving forward.

New York

New York remains a state to watch for developers looking to enter the distributed solar market and for other state commissions searching for a common ground approach to net metering reform.

New York is moving away from the binary discussion of retail versus wholesale net metering rates and focusing instead of the value of net metered solar as interpreted by all parties involved.

Net metering in New York is being addressed as part of Governor Cuomo's "Reforming the Energy Vision," or "REV," strategy. The New York Public Service Commission established a clean energy standard last August as part of the REV strategy. The overall goal of REV is to reach 50% renewable energy by 2030. To place New York developments in context, the California renewable portfolio standard also requires 50% renewable energy by 2030 while the Hawaii standard requires 100% renewable energy by 2045. New York has set interim targets of 26.32% renewable energy by 2017 and 30.54% by 2021.

New York is well on the way. It is currently at about 25%. It must double renewable energy generation in the next 13 years.

However, the rate for net metered electricity remains uncertain. The New York Department of Public Service suspended net metering caps in New York and instructed utilities to continue to accept interconnection applications from prospective net metering customers while REV proceedings are ongoing.

The major New York utilities and three large solar developers submitted a compromise proposal in April. The proposal expands on a white paper issued by commission staff that would have calculated the net metering electricity rate using a formula known as LMP + D. The coalition adds a value "E" to this equation.

"LMP" in the equation is the locational marginal price, which includes the wholesale electricity price of energy plus transmission congestion charges and transmission line losses. "D" is the additional value provided by the net metered system, to be calculated using a handbook developed by each utility. The "additional value" is the value of the solar system to the distribution system (rather than just the wholesale system). An example is local load relief. "E" is the value of external benefits associated with the net metered system, including renewable energy certificates and emissions reductions. The proposed compromise also contemplates that customers */ continued page 44*

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who install systems that are eligible for net metering before the interim program begins will be grandfathered at their previous rates.

Several collaborative meetings discussing an interim net metering policy were held in August aimed at issuing a report for consideration by the commission by the end of the year.

Pennsylvania

The future of net metered projects in Pennsylvania remains uncertain.

The Public Utility Commission voted in February to retain net metering at the full retail rate. Controversy arose over a new requirement approved concurrently by the commission to limit the sizing of any new net metered system to 200% of a customer's historic annual electric consumption. This figure is higher than the 110% figure initially proposed by the commission, and was an attempt by the commission to strike a balance between allowing load growth, limiting oversizing of systems and ensuring least-cost service to customers over time.

In June, the five-member Pennsylvania Independent Regulatory Review Commission, which is tasked with overseeing Public Utility Commission decisions, rejected the new rules, citing a lack of clear statutory authority for the 200% size limit.

Soon after, the Public Utility Commission dropped the 200% size limit. Its revised rules were again rejected by the review commission in July.

Notwithstanding the two review commission disapproval orders, the PUC approach may still go into effect. The Pennsylvania legislature failed to block implementation. It had 14 days to do so. The rules now move to the Pennsylvania attorney general for review, although the scope of this review is limited to form and legality. ◎

South Africa Readies for Bids for LNG-to-Power Projects

by Lido Fontana, in Johannesburg

The South African Department of Energy released a preliminary information memorandum in early October that explains how the department plans to procure LNG-to-power projects.

Pre-qualification appears to be a fairly straightforward pass-fail process.

An initial request for proposals will be released with the proposed project agreements for comment. This is expected in April 2017. The final request for proposals will follow after the government takes into account any comments.

The focus is expected to be on two sites: Coega Industrial Development Zone, which is adjacent to the deepwater port of Ngqura in the Eastern Cape Province, and the Port of Richards Bay in KwaZulu-Natal Province. Both sites have been identified by the government as having sufficient existing infrastructure, such as port, transmission lines and gas pipelines, to support the first phase of the procurement program. However, site development risk will be assumed by the bidders, who are not precluded from proposing their own sites.

The expectation is that 1,000 megawatts will be allocated to Coega and 2,000 megawatts to Richards Bay, with separate procurement processes for projects at each site.

Bidders will be responsible for verifying the suitability of the transmission line route and site selection, as well as obtaining the necessary land rights for the transmission line.

At this time, it is envisaged that the plants will operate effectively as mid-merit. The request for proposals will set a minimum annual dispatch level expressed as an annual average plant capacity factor and a maximum monthly dispatch factor, and these will be reflected in the power purchase agreements.

Fully Integrated

Bidders will be required to develop, finance, construct and operate gas-fired power plants at designated ports, with an associated gas supply chain from a floating supply regasification unit, or FSRU, or equivalent LNG regasification and storage technology.

This will entail a large amount of equipment in addition to the power plant. Bidders will be responsible for building port infrastructure, including fixed maritime structures, and for dredging of the berthing pocket for the FSRU. The marine structures must have a design working life of at least 40 years. They must also deliver gas pipelines to connect the FSRU with the new power plant, a gas distribution hub for a third party to distribute gas by pipeline, and a distribution hub for handling LNG that may then be distributed, by a third party, by either road or rail.

The power plant must be able to accept gas from local suppliers.

There must be alternative fuel storage facilities, including the option for alternative back-up fuel supplies, to mitigate the impact of unplanned interruptions to the LNG supply chain.

Bidders must ensure that the projects are "future proofed" to allow for indigenous gas and third-party gas offtake. There will therefore be a requirement to use larger sized industry-standard FSRU and to oversize capacity of the LNG receiving, storage and re-gasification elements beyond capacity requirements of the new power generation facility. The facility must also have a capacity of approximately 175,000 square meters and corresponding throughput capacity for the regasification facility and pipeline. Throughput capacity is the number of flow units per unit of time. The government wants third-party access to the extra capacity of the gas infrastructure.

Bidders should highlight their experience in use of combined-cycle gas turbines, open-cycle gas turbines, and gas-engine technologies to balance renewables.

In order to pre-qualify, a bidder must name the equity participant on whom it will rely to fulfil each of the capability qualification criteria in the request for qualifications. Bidders will need to show experience as a power plant developer, LNG supplier and terminal operator.

Each bidder will be required to propose mitigation actions to prevent the risk of any single cargo arriving late or arriving without the required LNG quantity and quality, including being responsible for putting in place back-up fuel arrangements .

Bidders will have to be ready to name its equipment suppliers and EPC contractor.

PPA

The government will award a power purchase agreement for each project with a term of 20 years from the scheduled commercial operation date.

The national utility, Eskom, will be the anchor offtaker. An implementation agreement guaranteeing Eskom's payment obligations will be provided by the Department of Energy.

The proposed tariff structure will be Rand (ZAR) based and compensate for fixed costs (including capital, development, financing, insurance costs and fixed elements of operations and maintenance) via a capacity payment. The capacity payment will be payable regardless of dispatch as long as the successful bidder delivers on its obligations. There will also be reimbursement for variable costs (including fuel, variable operations and maintenance, consumables and chemicals) via an energy charge.

The Department of Energy, in consultation with the national energy regulator, NERSA, will provide a mechanism for gas regulation that reduces electricity price volatility in the short–to-medium term and further reduces foreign currency exposure while ensuring bankability of the project.

The price competition among bidders will include the pricing of the fuel costs.

It is currently anticipated that evaluation of the electricity pricing will be done by selecting a widely-recognized and neutral indexation forecasting service for the forecast of the different potential LNG pricing indexations, thus allowing the government to compare the various LNG price structures on a like-for-like basis.

Timetable

The request for qualifications is expected to require local participation equity requirements. Bidders will have to set aside equity interests for state-owned corporations and broad-based black entities meeting certain criteria.

South African equity participation will be at least 35%. There may be a requirement to grow this shareholding over time.

The government is in the process of compiling a list of socio-economic objectives for bids, as it did with its renewable energy program.

A key equity participant may only work with one bidder for each project. The equity participant will also be required to sustain its role and level of equity participation in the successful bidder for a set period of time after the PPA for a project is signed.

Meanwhile, a bidder may participate and pre-qualify under one or both requests for qualifications and bid for both projects. There is nothing to prevent a single company from winning both projects.

The formal procurement process will play out in two stages: a request for qualifications, which will / continued page 46

South Africa

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assess on a pass-fail basis the ability to carry out project, and a request for proposals, initially in draft put out for comment and then a final revised RFP.

The RFP will include the proposed suite of project agreements. The Department of Energy will be looking for comments on them from potential bidders. The comment stage may take some time, after which a second and final version of the RFP will be issued and used to solicit final bids.

The project documents will not be subject to negotiation after the final RFP is issued.

The expected timetable is follows. The RFQ is expected in November. Potential bidders are expected to have to submit their qualifications by February 2017. The government is expected to release the list of pre-qualified bidders in April 2017. The Department of Energy will then engage with these potential bidders over the terms of the RFP for a month, and then the final RFP will be released around August 2017. Bids will be due sometime after that. ◎

Practical Advice About Optimizing Generating Portfolios

by Jeff Bodington, with Bodington & Company in San Francisco

Optimizing a portfolio of generating assets by weeding out some assets in the portfolio or adding others is about enhancing synergy.

It can make sense to sell assets that have become poor fits.

It can make sense to buy assets that spread fixed costs, improve operational flexibility and lower risks in addition to growing earnings.

This article discusses the sell-side motivations and the accounting, tax, financing and regulatory issues that are unique to portfolio-driven sales. It also addresses the buy-side motivations and key portfolio-related issues for buyers. There are some lessons learned, too: sellers usually wait too long and buyers are at risk of over-estimating the values of their turn-around capabilities and synergies.

Portfolio-related considerations are an additional reason why an owner may decide to buy or sell specific generating assets. The portfolio-level considerations most often involve lack of synergy. B&Co has advised sellers who lack project-specific expertise and cost-sharing synergy because an asset is one of a kind that requires unique operations, maintenance, parts, compliance, staff and knowledge. The seller may own the asset because it came as part of a purchased portfolio that contains assets that are a poor fit. The seller may want to sell a project in an isolated location or a difficult state regulatory environment. Selling off what have become orphans is part of focusing ownership and expertise.

Portfolio optimization is also a tool of corporate finance. Selling off minority ownership positions is part of consolidating ownership, improving control and simplifying financial reporting. Owners also sell marginal- and low-or-no-synergy projects to fund new development and improvements to projects with more potential.

Sell Side

The orphan assets are sometimes obvious. More often, an asset-by-asset evaluation needs to consider a broad range of factors.

Projects to consider first are those that are geographically isolated from the rest of the portfolio. Unless owning that project is a foundation for strategic growth in a new region, that project may be costly to manage. Maintenance, operations, accounting and regulatory compliance costs involve material diseconomies of scale. A project may both be costly to own and worth more to a regional owner who can amortize fixed costs over a number of local projects. In one case, a far-away owner felt that managing the project had become difficult and that replacing on-site leadership in a drive for scale economies would be dangerously disruptive.

A detailed analysis of how well a project fits requires an examination of synergies with the rest of the portfolio in operations, maintenance, critical spare parts, power sales administration, regulatory compliance, roving operating staff, major maintenance crew rotations, forced outage response, managerial control and expectations of future financial performance. Forced outage response can be the deciding factor. Delays in repairs at one facility caused the capacity factor to fall below a PPA threshold and triggered substantial power price reductions. In another case, although there had not yet been an outage and there were no contractual penalties, the fear of failing to supply power to certain customers, and the resulting harm to the owner's local reputation, led that owner to sell to a larger owner with a deep quick-response capability.

Once one or more assets are identified for sale, getting the deal done can be worthwhile but difficult. The reasons for sale may not be unique to the seller; thus the market may be thin. More often, the challenges can include getting the owners of a jointly-owned project to agree on a reservation price and terms, unwinding an interest rate swap, and getting upstream lenders and bondholders to release collateral interests. In some cases, obtaining a necessary regulatory approval adds a condition precedent with a long lead time to close. For regulated utilities that are optimizing their portfolios of generating assets, obtaining desired rate treatment can add risk and six to more than 12 months to a closing schedule.

Book and tax accounting issues can be key considerations to sellers.

Selling a project can be a tool for managing earnings. Public companies need to consider the magnitude and timing of a gain or loss on sale within the context of consolidated earnings. Planning to close and book a sale during a specific quarter is common as the seller keeps an eye on other projected changes in earnings that quarter. Although privately-held companies may not be as concerned as public companies about reporting net book income, covenants in bond indentures and other financing agreements may be tied to book results, and these could also have a bearing on timing.

Income tax issues are important. It may be useful to match taxable gains or losses on the sale of a project to losses or gains due to other activities at a portfolio level. Material changes, such as expiration of a key supporting contract or financial distress for other reasons in advance of a sale, can lead to prickly accounting and tax analyses and decisions. Appraising and reporting an impairment loss, and writing down an asset for tax purposes, may smooth reporting of book losses and accelerate some cash income tax savings.

Although lenders may consent to a sale and leave a financing in place, that may not be assured. If debt needs to be paid off and potentially refinanced, consider the cost of breaking a swap and the process of releasing collateral.

Estimate the cost of breaking a swap by discounting the difference between the fixed rate and the forward curve for the underlying floating rate using the forward LIBOR curve. The resulting present value is what has to be invested at the forward LIBOR curve to meet future obligations under the swap that the project will no longer satisfy. This present value, plus fees, is the cost of breaking the swap. This cost can be substantial if the forward swap spread is high; that situation is common due to today's low forward LIBOR rates. The cost also increases as the number of years remaining on the swap increases. A wrinkle in the math occurs when a lender is willing to remain on terms that include a partial pay down or a sweep to prepay. In that case, part of a swap is broken or funds need to be reserved to meet the swap obligation as it materializes. Either way, sellers should plan on that cost and the associated reduction in net proceeds.

Moving upstream in the capital structure, a trend toward corporate-level debt instead of, or in addition to, project-level debt began more than 10 years ago. Much corporate-level debt is now secured by project assets. Corporate-level lenders and bondholders may have a right to consent to a sale of some of their collateral and may demand payment or other security. Sellers should assume there will be a cost to win consent.

Winning approval from bondholders can be a special challenge. In one case, although there was substantial institutional investor ownership of the bonds, many of the non-callable bonds were owned by "widows and orphans" in brokerage account street names. The seller had to run a tender offer, buy a threshold number of the bonds, and then fund a trust to defease those bonds that could not be purchased. The sale of the asset and the tender offer had a simultaneous closing. While the transaction was ultimately successful, closing had to be delayed due to difficulty in finding and buying enough bonds.

For some assets, two other options must be considered. Some assets are just not economic for any potential owner. The growing number of idle biomass-fired power projects in California is an example. Coal-fired and several regulated-utility-owned nuclear units are another example. The exit strategies to date have been case-specific. Although many have assumed for years that residual value would net to zero, B&Co experience so far is that decommissioning and site restoration costs exceed the sales value of salvaged equipment, metals and real property. Electric, fuel and permit infrastructure may have value, but adapting those assets to a new project is likely to require replacements, upgrades, permit revisions and transmission system impact studies. A few idled projects on valuable ocean- and river-front property have been decommissioned, but many sit dark at a cost of liability insurance and nominal property taxes.

In contrast, other projects may be economic under different ownership but have liabilities that are difficult to discharge. Cogeneration projects with uneconomic steam sales agreements are an example. Hydroelectric projects */ continued page 48*

Portfolios

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with water supply obligations are another. Owners of several such projects have run liability auctions and sold the projects to the bidders who needed to be paid the least amount to assume the net liabilities. The buyers, for example, have been lumber mills and water users who could monetize non-power values that the current owner could not. For those sellers, the cost of the liability auction was lower than the costs and risks associated with potential litigation, bankruptcy and decommissioning.

Obtaining approvals from regulatory authorities to transfer certain permits and entitlements is a part of closing nearly all transactions. A benefit of selling ownership of a special-purpose entity, rather than assets, is that the special-purpose entity reduces the number of, and process for obtaining, the necessary approvals. Several aspects of that process are unique to portfolio optimization transactions. In one case, the FERC license for a hydroelectric project that covered several projects had to be divided into two licenses. The costs and risks associated with intervenors and new license terms needed to be considered. In another, jurisdiction over a natural gas pipeline had shifted to the Pipeline and Hazardous Materials Safety Administration. An approval that had not been required for the project within the portfolio was required, under a disputed interpretation of the regulations, to complete a sale of that project out of the portfolio.

Buy Side

Buy-side portfolio optimization transactions require additional work. That work is often the source of additional value and competitive advantage.

Economies of scale are material in many aspects of power generation. Power marketing, fuel procurement, daily operations, periodic major maintenance, regulatory compliance and finance involve substantial fixed costs that can be amortized over more megawatts and decreasing marginal costs that can lead to lower average costs and higher average margins. A buyer purchasing another facility near one or more that are already owned will realize such economies.

More interesting are acquisitions with unique synergies. Adding to a portfolio of facilities that can sell power to the same party and then amending PPAs to allow electricity to be delivered from any source can lower the risk of PPA penalties for under delivery and enhance maintenance scheduling. One owner of hydroelectric projects purchased a nearby project so that it could unwind an agreement that required sharing water flows, thereby allowing the owner to run the most efficient unit at maximum output during periods of high flow. Several owners of biomass-fired projects have acquired the critical mass of projects to enable them to establish regional fuel procurement organizations. Those organizations work to increase supply, to improve fuel delivery logistics, and to improve the quality of the fuel actually delivered. For owners of natural gas-fired combustion turbine projects, the cost of a leased engine to use in emergencies or during major maintenance can be substantial. Owning a fleet of combustion turbines that then justifies owning a spare engine leads to cost savings and operational flexibilities.

Buyers and sellers make different calculations when optimizing portfolios of generating assets.

Another aspect of buy-side portfolio M&A involves minority ownership interests. Many projects were developed when the Public Utility Regulatory Policies Act limited ownership of independent power projects by utility subsidiaries to less than 50%. Although that limitation was removed in 2003, some PPAs require ownership to continue under the FERC rules in effect "as of the effective date" of the PPA. B&Co has advised non-utility parties who wanted to consolidate ownership by purchasing the interests they did not already own from a utility subsidiary. Often, those purchases were made under a purchase option in the partnership agreement. The details of right of first refusal, right of first offer, appraisal requirements and the definition of an acceptable replacement owner can be advantageous, disadvantageous and a contributor to litigation.

Another consideration for buyers is a filing required under section 203 of the Federal Power Act whenever a "jurisdictional" asset changes hands. While B&Co defers to Chadbourne for a legal interpretation of when section 203 applies, it requires many transfers of public utility assets to receive prior approval from FERC. Importantly, public utility assets in this case include PPAs and transmission agreements with independent power producers. Even the sales of ownership interests in entities that are parties to those agreements may fall under section 203. Among the many issues considered by FERC is whether the transaction will result in concentration that leads to market power in wholesale electric power markets. That is an important consideration for buy-side portfolio optimization M&A.

A purchase and sale agreement may require a seller to make a section 203 filing, and FERC approval may be a condition precedent to close. Indeed, the need to file has stopped several owners from acquiring power projects in particular regional markets. Buyers need to consider the possibility that FERC approval will be required to close and allow time to prepare, file and obtain FERC approval in a closing schedule.

Another consideration for buyers who are adding to their portfolios is the facility-level staff that comes with an acquisition. Integrating that staff into an existing portfolio requires harmonizing job descriptions, job titles, pay scales and benefit programs. B&Co's experience is that buyers appreciate that power generation facilities do not come with instructions, and the existing staff has essential knowledge about a facility's idiosyncrasies during start up, operating procedures and maintenance issues. The local relationships of existing staff may be essential for water supply management at hydroelectric projects and fuel supply to biomass- and waste-fired power projects. Although buyers usually plan to re-hire all of the staff upon closing, individual interviews and decisions are part of due diligence and the closing process. In the few cases in which an employee was not re-hired, the employee was already a questionable fit and the sale crystallized a departure that would have occurred anyway.

Buyers must consider various accounting and income tax issues. Key among those for all acquisitions is a step up in basis under section 338(h)(10) of the US tax code for buyers buying a corporation or section 754 for buyers buying an interest in a partnership or limited liability company. Often left to the last minute, allocating the purchase price to various asset classes for reporting on Treasury Form 8594 can have material effects on depreciation deductions and valuations for other purposes, including property taxes and special financing and grant programs. Unique to portfolio optimization buyers is evaluating and deciding where a new asset fits in what can be a web of consolidating entities. Interposing corporations and LLCs can block, alter and redistribute both book and taxable income upstream from an acquisition.

Standing Back

Generalizations are perilous. Subject to that strong qualification, here are several lessons learned.

On the sell side, sellers usually wait too long to optimize a portfolio and sell a project that is a poor fit. At best, a non-core project remains a distraction to management. At worst, there is the experience of one owner who recognized that a project was a non-core asset. That owner trimmed the maintenance budget for the project to favor core assets. Lower maintenance led to the catastrophic failure of a key component, and that failure tipped dominos that ultimately caused default under the PPA and a near total loss of asset value.

On the buy side, acquisitions are a textbook example of bidder's ruin. B&Co's experience is that the successful bidder in an auction of a power project is rarely the buyer with the lowest cost of capital. While cost of capital is important, the successful bidder usually has the most aggressive forecast of underlying cash flow. Portfolio optimization buyers are in danger of overestimating synergies that seem to promise increased revenue and lower costs.

Yield cos built portfolios over the last two years and have been in the news. Many seem to be asset manager "lite" with a primary interest in low-risk projects with predictable cash flow. Some are now sellers after their share prices collapsed.

In spite of the challenges, optimization transactions can yield attractive returns to both sellers and buyers.

Sellers reduce their costs, reduce their needs for external financing and improve the rate of return on their remaining portfolios. Uniquely positioned buyers can earn attractive returns.

Most portfolio optimization transactions are not driven by a search for the lowest cost of capital. The lowest cost is about 8% unlevered after taxes for a good-quality project, plus or minus about 1% depending on the deal. Buyers in optimization transactions are fundamentally able to do something that the seller does not think it can do; thus pricing is determined by a difference in forecasts of cash flows and assessments of specific risks. ◎

Environmental Update

The global climate deal reached in Paris last year is on the verge of entering into force.

By early October, the number of signatories to the pact exceeded the threshold necessary to take effect, with 74 nations accounting for nearly 60% of total global greenhouse gas emissions formally joining the Paris agreement.

Early in September, President Barack Obama and President Xi Jinping joined the Unites States and China to the Paris agreement, signing up the world's two biggest carbon emitters. In early October, India became the 62nd nation to ratify the agreement. In early October, EU member nations and others joined, sealing the deal in advance of the next climate conference (COP22) scheduled to begin on November 7 in Marrakech, Morocco. There are now 197 nations as parties to the convention.

The Paris agreement requires each nation to set national targets for reducing or reining in its greenhouse gas emissions. Those targets are not legally binding, but countries must report on their progress and update their targets every five years.

The goal is to keep the global temperature increase "well below" 2 degrees Celsius and to pursue efforts to limit it to 1.5 degrees Celsius. Another goal is to cause greenhouse gas emissions to peak as soon as possible and achieve a balance between sources and sinks of greenhouse gases in the second half of the century. By 2020, $100 billion a year is to be dedicated to climate finance for developing countries with commitments of additional financing in the future. Once the deal comes into force, countries that have ratified it have to wait for a minimum of three years before they exit.

The United States and China together produce just shy of 39% of the world's man-made carbon dioxide emissions, with India responsible for about 5%.

The US has pledged to cut its emissions by at least 26% over the next 15 years, compared to 2005 levels. US Senate ratification is not required because the agreement is not considered a formal treaty. However, the Clean Power Plan the Obama administration is trying to implement, in the face of US court challenges, is a fundamental means by which the United States could reach its obligations under the Paris climate deal.

China announced a 2030 deadline for China's emissions to stop rising and agreed in principle to a faster phasedown of super-polluting hydrofluorocarbons. India has committed to ensuring that at least 40% of its electricity will be generated from non-fossil sources by 2030.

Clean Power Plan

The main force of the Obama administration's climate change policy went before a full panel of a US appeals court in Washington last month. The Clean Power Plan imposes the first national limits on carbon pollution from power plants, the largest source of greenhouse gas emissions in the nation.

The US Environmental Protection Agency finalized the Clean Power Plan and published emission guidelines for states to follow in developing plans limiting carbon emissions from existing plants in August 2015. The EPA left to the states to decide how best to meet the emissions goals in the first instance, but EPA will impose a plan on states that fail to submit their own plans or that submit inadequate plans.

The US Supreme Court blocked implementation pending a decision by the appeals court or further action in the Supreme Court in a 5-4 decision last February.

The case, now known as West Virginia v. U.S. Environmental Protection Agency, consolidates 157 petitioners in 39 lawsuits, including 27 states, numerous companies, trade associations and environmental groups. The 10-judge panel heard more than seven hours of argument in late September.

The Clean Power Plan was issued under section 111(d) of the Clean Air Act, a little-used provision that has never been employed as broadly before. The debate is whether requiring utilities to meet certain emissions standards under the Clean Power Plan falls within the agency's Clean Air Act authority to determine the best system of emission reduction when setting emissions limits under section 111(d) of the Clean Air Act, or whether the agency has the authority to regulate power plant emissions at all.

The coalition of states challenging the plan argues that the case is about an illegal expansion of EPA power and will require standards that will cause some coal plants to close because of their comparatively carbon high emissions. The EPA estimates the annual costs of the plan are $7.3 billion to $8.8 billion in 2030, but some industry estimates put the annual cost much higher.

Supporters of the plan argue there is a delegation of authority to EPA to address new problems as they arise under the Clean Air Act, and that this includes climate change.

Indiana Bats

A federal appeals court agreed in August with opponents of an Ohio wind farm that the US Fish and Wildlife Service issued a permit to developer without fully considering ways to reduce deaths of endangered Indiana bats.

Buckeye Wind estimated that its 100-turbine wind farm would injure or kill 5.2 bats per year with certain controls in place, with no more than 26 Indiana bats killed in a five-year period. The company applied for an "incidental-take" permit. The US Fish and Wildlife Service said, when it approved the permit in 2013, that the proposal to lower turbine speeds during certain months met statutory standards, with the estimated take of 5.2 bats per year affecting neither the Midwest recovery unit of bats nor a local unit of a single maternity colony.

In March 2015, a lower court found no violation of the Administrative Procedures Act, the National Environmental Policy Act or the Endangered Species Act. It credited the finding by the USFWS that the minimization and mitigation measures "fully offset" the impact of the taking of Indiana bats, making it unnecessary for the agency to determine whether the plan was the maximum protection that can be "practically implemented."

In a somewhat mixed August opinion, the appeals court partially reversed the lower court. It found that issuance of the permit was "arbitrary and capricious" and in violation of National Environmental Policy Act procedures because the federal agency did not analyze a sufficient number of alternatives to reduce the number of Indiana bats taken.

The court said that, while the National Environmental Policy Act does not require the agency to consider an "infinite array" of alternatives, it does require the agency to analyze a mid-range alternative that would take fewer bats while still enabling the wind farm to go forward.

It said the agency knew Buckeye Wind claimed that the maximum alternative it considered — which would have turned off the turbines at night from April to October — was not economically viable.

The court ruled that the agency should have considered whether an increased cut-in speed would still allow the project to go forward while protecting more Indiana bats.

The endangered Indiana bat has been central to a long-running battle against the proposed 100-turbine wind farm in Champaign County, Ohio. Although the species does not hibernate in the area, it migrates through the area during the spring and fall.

The case is *Union Neighbors United, Inc. v. Sally Jewell*.

Greater Sage Grouse

The Bureau of Land Management issued seven memoranda to its field offices in early September with guidance on how to implement new protections for the greater sage grouse.

The seven instructional memoranda follow amendments made to land management plans in 2015 that allowed federal regulators to avoid listing the greater sage grouse as a threatened species under the Endangered Species Act. The land use plans apply to federal lands managed by BLM and the US Forest Service.

The guidance is in response to state and stakeholder desires to see clear and consistent application of the agency's management activities across the western greater sage grouse states while providing flexibility to respond to local situations and concerns.

The land use plans have been challenged in court in variety of lawsuits. Industry critics argue that the new guidance includes arbitrary prioritization of leases and permits and say the memoranda, mostly about methodology, fail to ease their concerns that the BLM might insist on impractical restrictions.

Hydro

Large hydroelectric power suppliers are lobbying the New York Public Service Commission to be included in the state's new clean energy plan.

Hydro-Quebec and Brookfield Renewable Partners argue their hydroelectric plants should get the same subsidies for carbon-free electricity as those being given to wind, solar and nuclear power generators.

In August, the commission voted on a plan to get half of the state's power from renewable-sourced */ continued page 52*

Environmental Update

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electricity by 2030 in order to cut greenhouse gas emissions by 40% from 1990 levels. As part of the program, the state will provide credits to subsidize nuclear facilities as well as solar, wind, biomass and small hydro plants. Parties had until August 31 to file challenges to the plan, which is backed by New York Governor Andrew Cuomo.

Run-of-the-river hydroelectric facilities that have a capacity of five megawatts or less would qualify under the clean energy standard adopted by the commission, but petitions for rehearing on the issue of including larger plants are pending.

States have struggled with how and whether to account for large hydropower operations as part of their renewable energy goals. For example, California is under a mandate to get 50% of its electricity from solar power and wind farms, but it does not include large hydro plants as part of its target.

– contributed by Andrew Skroback in Washington

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