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PROJECT FINANCE
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Corporate PPAs

Utilities are working to squash net metering, but missing the larger picture. Seventy-five percent of the 1,800 megawatts of new power purchase agreements signed by wind companies in the United States in Q4 2015 were directly with large corporate offtakers. Have we reached a tipping point where most contracts in the future will be with corporate buyers? What does it mean for the financing of projects? The following is an edited transcript of a discussion about these and related questions at the Chadbourne 27th annual global energy and finance conference in early June.

The panelists are Quayle Hodek, chairman of Renewable Choice Energy, Paul Kaleta, executive vice president and general counsel of First Solar, James Pagano, CEO of Terra-Gen Power, Mitchell Randall, president of Recurrent Energy, and Michael Storch, executive vice president and chief corporate development officer of Enel Green Power North America. The moderators are Rob Eberhardt with Chadbourne in New York and Caileen Kateri ("Kat") Gamache with Chadbourne in Washington.

MR. EBERHARDT: Quayle Hodek, give us a sense for how significant a market there is for corporate PPAs.

MR. HODEK: In 2013, there were roughly 500 megawatts of power contracts signed by large corporations directly with developers. The contract terms might run 12, 15 or even 20 years.

In 2014, the market grew to about 1,100 megawatts and then, last year, we had 3,200 megawatts. In the wind market, more than 50% of all new PPAs signed last year were corporate PPAs. It looks like 2016 will be even bigger with something like */ continued page 2*

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A FOUR-YEAR LOOKBACK rule is causing pain for some US renewable energy developers.

Production tax credits can be claimed for 10 years at full rates on the electricity output from wind, geothermal, biomass, landfill gas, incremental hydroelectric and ocean energy projects that are under construction by December 2016. There must also be continuous work on the project after construction starts.

The IRS said in early May that it will not make a developer prove continuous work on any project that is completed within four years. However, the four years start at the end of the year construction started. Thus, for example, if a wind developer dug several */ continued page 3*

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4,000 megawatts of contracts expected to be signed this year.

My company, Renewable Choice Energy, has been advising corporate purchasers for 15 years on their renewable energy options. They have a lot of options. They can do onsite solar. They can do renewable energy credits. They can do carbon offsets. They look at a lot of things and, while PPAs are just one of those, they are by far the most interesting option today for companies trying to hit long-term sustainability goals.

Of the Fortune 500, you have more than 220 companies that have made specific carbon reduction, renewable energy or sustainability targets, and the question is how best to reach those targets. Several industry groups and non-profits have been formed to bring these large corporate buyers together. These are high-level gatherings. This is a CFO-level decision when a company is looking at committing to a $150 million long-term contract. The Rocky Mountain Institute is projecting 60,000 megawatts of new wind and solar projects will have to be built between now and 2025 to serve the corporate market.

MR. EBERHARDT: We have four representatives from project developers. Jim Pagano, what has been your experience to date with corporate offtakers?

Challenges

MR. PAGANO: We have been in discussions with several corporate offtakers, but we have not gotten one over the line yet.

We see a couple of trends over the last 18 months. Corporations were interested initially in the sustainability objective and the additionality that implies. We have operating projects that are uncontracted. They do not want megawatt hours from those projects. They want new megawatts so they can advertise the additional renewable energy that is being built as a consequence of the contract they are signing.

Companies with this focus were hurt as gas and, therefore, wholesale power prices fell throughout 2015. They are now a little more focused on their ability to hedge basis risk, or the value relative to the wholesale market price. They have become more sophisticated.

The private financing side of the house has become more concerned about some of the positions. We see a trend toward greater risk on the developer. Arguably that is where it belongs because corporate offtakers lack the expertise to evaluate basis risk in the same manner that a utility would.

MR. EBERHARDT: Mitch Randall, has your experience been the same?

MR. RANDALL: We have found utilities willing to buy long-term power. We have about 1,000 megawatts under construction, and it is all contracted with investor-owned utilities, municipal utilities and community choice aggregators. We are starting to talk to potential corporate offtakers in ERCOT, PJM and CAISO. We have not gotten anything over the line yet. Negotiations started fast and then bogged down as offtakers identified some of the risks. They are trying to wrap their heads around the basis risk. We did some behind-the-meter deals a few years ago.

MR. EBERHARDT: Mike Storch, what about Enel?

MR. STORCH: We are constructing a 200-megawatt project with a corporate offtaker as we speak. That was the first corporate PPA we signed in the US. We have several in other countries. We are seeing more opportunities for global plays with large multinationals like General Motors.

The process is painful. It is very long and drawn out. It is price driven. The terms are very different than in a utility deal and you have to be sensitive to making sure you end up with a financeable transaction when all is said and done. The credit issues are different. As we all know, a AAA credit today can be a bankruptcy in a relatively short period of time. The tax equity market does not have a real understanding of those kinds of issues.

I believe corporate PPAs will account for the lion's share of contracts for the next 18 months to two years. Utilities are holding back to see what happens to the Clean Power Plan. They are focused on use of rate-based assets to meet clean power goals for now and are signing fewer PPAs with independent generators during this grey period.

Roughly 4,000 MWs of corporate PPAs are expected to be signed in 2016.

Location

MS. GAMACHE: Mike Storch, how important is the location of your project to a corporate offtaker?

MR. STORCH: Corporate offtakers are more focused on the location of a project relative to their needs. They want it at least to be in the same RTO. Many PPAs are actually contracts for differences or hedges. The offtaker pays a fixed price in exchange for a floating price for the electricity for which it has contracted. The offtaker buys the actual power it uses from its local utility. Offtakers are sensitive to basis risk, or where you inject your power compared to where the contract price is set for purposes of payments under the contract for differences. Those can be horrific challenges.

MR. HODEK: Many offtakers are multinational corporations. They have a lot of load globally. They look for the best opportunities in all the countries in which they operate. They might start off by thinking, "Here is one of our data centers, here is one of our big manufacturing facilities, here are our corporate headquarters. Can we do something nearby that makes sense?" That is usually the first look.

What happens after that is a search for opportunities to bundle widely distributed load together to do a utility-scale deal of 100 to 200 megawatts. Some physical transactions get done with a large enough load base in a certain area. Or it may be possible to do a virtual transaction by bundling together load in disparate areas. Salesforce.com is a great example of this. It does not even own its data centers. Everything is co-located data center load and yet it is able to contract for a large-scale wind PPA in a different region than where most of the load is with a virtual transaction.

The virtual PPA structures have opened a market for companies to do deals in geographically distant regions.

MR. STORCH: One of our first corporate PPAs was with a large company with a household name, with manufacturing facilities all over the world, several in the US, and it was committed to doing something within the communities where its facilities are located in terms of whatever jobs and economic benefit would come from the additionality associated with the facility.

In the end, it did a deal tied to a power plant in ERCOT, where it had no facilities whatsoever, because the electricity price was so much lower than the prices in other parts of the country.

MS. GAMACHE: Is retail choice a big obstacle or are virtual PPAs or hedge able to overcome those issues?

MR. HODEK: The largest deals have been in places with organized electricity markets. Offtakers want / continued page 4

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turbine foundations on the site for a wind farm in 2013, then the four years would run out at the end of 2017.

Before May, a developer had two years to finish without proving continuous work. The two years ran from the current construction-start deadline: for example, from the end of 2016.

More importantly, there are two ways to start construction. One is by beginning physical work of a significant nature at the site or at a factory on equipment for the project. The other is by "incurring" at least 5% of the total project cost.

If the developer ends up having to prove continuous work to qualify for tax credits because a project takes more than four years to build, then it makes a difference how construction started. It should be possible to prove continuous work if construction started under the 5% test because the developer must prove "continuous efforts" on the project. This can include steady work on development-type tasks.

If construction started under the physical work test, then "continuous construction" must be proven. This may be impossible to do for a wind farm that normally takes only six to eight months to build once work begins in earnest on the site.

When the IRS announced a retrospective four-year window in early May, it also said that developers who started work in anticipation of earlier construction-start deadlines by doing physical work would not be able to upgrade to the 5% test based on incurred costs through the end of 2016.

This is causing pain for developers who did modest work ahead of earlier deadlines.

The development rights to their projects have become difficult to sell. The projects also have become difficult to finance in the tax equity market. Michael Storch, executive vice president and chief corporate development officer of Enel Green Power North America, asked at the Global Windpower 2016 convention in late May, "Are we going to end up with a double standard where we could not raise tax equity earlier because [of concerns about whether / continued page 5

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multiple ways to liquidate the power into the market if they are not taking physical delivery. In such arrangements, retail choice is not so important.

California has some unique challenges and barriers to doing deals, but there have been large-scale deals done. The biggest barrier is lack of experience among corporate offtakers. For the vast majority of the companies entering into corporate PPAs, this is the first deal. We have had 28 large corporate deals announced so far; fewer than half of those are with Fortune 500 companies. They are almost all first-time deals, except for Google, Amazon, Microsoft and Facebook, who have done more than one.

It is a heavy lift. You mentioned how long it takes for companies to figure out what they are doing. We work with most of our clients for more than two years to get them to the point where they are ready to transact.

MR. RANDALL: It is a completely different negotiation when you have a utility that is compliance-driven versus a corporation that has a lofty goal. The corporate negotiation is price-driven. The company can defer the deal until the price meets its objectives. The process drags out. There is not the same motivation on the part of a corporate purchaser to get across the finish line.

Stranded Costs

MR. EBERHARDT: Paul Kaleta, First Solar had some interesting experiences in Nevada with NV Energy and Switch.

MR. KALETA: There is a lot of activity. We have participated in a number of deals. We have two public deals in process. One is in Nevada and looks to be a win for both the utility, NV Energy, and the customer, Switch. Switch is a big data-server farm. It is privately owned. It was looking to leave the NV Energy system. NV Energy is a good customer of ours.

Nevada has a law that was put in place after the western energy crisis in the early 2000s that allows NV Energy customers with a certain amount of load to leave the system, but they have to reimburse the utility for its stranded costs.

Switch went to the regulatory commission, and the battle over stranded costs started. The staff said one thing. The utility said another thing. Switch said a third thing. And then the commission effectively said we think, under the circumstances, we are not going to let you leave the system.

NV Energy has a green tariff that was put in place years ago when it was entering into a lot of higher-priced contracts to buy renewable energy. The utility had customers, both residential and businesses, coming to it saying, "We want green power." And NV Energy responded with the green tariff. Prices have now come down very dramatically.

In this situation, what happened is we ended up in a three-way deal with NV Energy and Switch that relies on the NV Energy green tariff. We have two PPAs with NV Energy for 170 or so megawatts. NV Energy, in effect, delivers the power to Switch and charges Switch under the tariff. We are essentially doing a utility deal from our perspective. This avoids many of the risks that we have been discussing on this panel.

Sleeve Deals

MR. HODEK: There are many ways for us in the audience and all of our companies to serve this growing corporate load. There are regulated states where you have to work through the utility, and you have to help it set up a green tariff. These are called sleeve deals.

There is a group called the RE100 made up of 50 global companies that have promised to get 100% of their electricity from renewable energy. Roughly another 60 companies have signed on to the World Wildlife Fund's Buyers' Principles. These are companies that want to save on electricity by buying renewable energy.

Sustainability is an important driver, but for a company to transact, it must see a good deal for its shareholders. There are many ways to transact. It can be through physical delivery of power. It can be a virtual PPA using a contract-for-differences structure. It can be through a utility with a green tariff. It can be separating out the renewable energy credit stream. These companies have massive demand, and they want to be supporting brand new projects. They want to be able to claim additionality.

MR. RANDALL: There are several utilities with the green tariffs, but none seems to have gotten traction yet. A corporate buyers conference in Seattle this year identified improving green tariffs as one of the top three initiatives. Green tariffs could solve problems for utilities on stranded assets because they are a way to keep the commercial and industrial customers. They can put the basis risk on the right party and solve financeability issues for the developer. They avoid forcing a very complicated negotiation on a team at a C&I customer that has never done this kind of thing before.

MR. KALETA: I agree. Utilities are our principal customers. I think we will see more and more utilities get more creative by necessity. They have to do it because they are seeing big customers with big, steady load looking to leave.

In Nevada, MGM, which is one of NV Energy's largest customers, announced publicly that it is looking to leave the system, and it said it will just pay the stranded cost and leave. Other casinos appear to be teed up to do the same thing.

The casinos see a marketing benefit, but costs are also coming down dramatically for both wind and solar so that pricing has become very attractive on its own. We have a deal in California with Apple, which was announced publicly some time ago. It is a single project with 150 megawatts going to Apple under a 24-year PPA and 130 megawatts going to PG&E under a 15-year PPA. Apple is a sophisticated customer that has done other deals. One of its first deals was in Nevada with NV Energy. I was general counsel of NV Energy at the time.

Green tariffs offer a good opportunity, but it can take time to get such tariffs approved by state regulators.

Off Ramp

MR. STORCH: We worked pretty hard on sleeve deals that are basically back-to-back PPAs where the customer is buying directly from the utility and we are supplying through the utility. Those PPAs are a nightmare from my experience, and financeability issues become real challenges due to credit issues and the like.

You want an off ramp in the contract. You are willing to pay a certain amount of money if you cannot finance the project, if you cannot get a critical permit, if your interconnect does not come through or it comes through at a ridiculous cost. It is rare to have a project construction ready at the point where you are seeking a PPA.

Our experience is that corporations do not want to provide any off ramp. They say, "We are telling our customers that we will be 100% green with our energy and there is no alternative. If we contract with you, we want to know that the project will be built."

And the conversation continues. "Look, if you can't build it, then in addition to liquidated damages, we want RECs for three years equivalent to what you would have produced so that we have time to contract with somebody else." It is a very different standard than we are used to in the utility market. It is a chicken-and-egg kind of problem. You have to decide how far advanced a project has to be before you are ready to contract and then how much risk are you willing to take to get the contract based on where you stand.

MR. PAGANO: We are seeing the same issues with investor-owned utilities. To bid into utility RFPs, / continued page 6

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there was] enough physical work, and we cannot raise tax equity today because what the investors thought was too little now looks to them like too much."

One group of developers asked the Treasury and Internal Revenue Service to address the problem by letting developers choose to live under the former two-year window for completing projects that runs from the end of 2016, regardless of when construction started. This option would be available for any developer whose project was under construction before 2017. It would mean a project on which construction started in 2016 or any earlier year would have until the end of 2018 to be completed to qualify for full tax credits. If the project takes longer, then the developer would have to prove continuous work.

Anyone choosing this two-year window would be allowed to prove continuous work based on the 5% test if at least 5% of the project cost is incurred by the end of 2016, even if physical work started in an earlier year. This would make it easier to prove continuous work if required to do so.

The American Wind Energy Association proposed a series of alternatives. AWEA wants the IRS to address when earlier physical work can be abandoned and, thus, free the project to establish a new construction-start date.

It also wants a four-year window from the end of 2016 for all projects that started construction any time before 2017. And it says a project should not be barred from upgrading to the 5% test. If work started under both the physical work test and the 5% test, then the developer should be able to choose which it prefers. At the very least, it says, inability to upgrade should be applied prospectively after the IRS changed the rules on May 5 this year.

Developers faced earlier deadlines at the end of 2011, 2013 and 2014 to start construction to qualify for Treasury cash grants or tax credits.

The IRS has issued five notices — two in 2013 and one each in 2014, 2015 and 2016 — explaining how the / continued page 7

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you have to have a more developed project than you needed perhaps three or four years ago or even two years ago. The corporates want it tomorrow, but it takes a long time to negotiate a contract. You will be working with them for a year, and things will change dramatically during that period.

As a general rule, the more developed your project is and the quicker you can represent that you can get it online, the more interested corporations are in talking to you, which puts a lot more risk on the developer in terms of the expenditures it must make on the front end.

MR. STORCH: I couldn't agree with you more. We are trying to explain to our home office in Rome why we need to pour so much money into a project before we have a PPA. Far more development capital is required on the front end. The good news is the corporates are finally getting to the point where they are ready to sign contracts. Folks like Renewable Choice Energy and Altenex have educated them about the accounting challenges and other issues.

Corporate PPAs shift basis risk to the sponsor and have shorter tenors than utility PPAs.

It is difficult to bring a whole new business model to these companies that is not their core business. It is a little like what happened years ago when we were peddling inside-the-fence deals. A new business model sprang up because companies did not pay much attention to the utility side of their businesses. They would say, "I can earn a 20% return on a new pulp and paper machine, but I am going to earn 7% to 8% on putting in a new boiler? No thank you."

So I am saying we finally got over those hurdles. Now if we can just get Renewable Choice Energy to do this for nothing, it will be almost perfect. Right? They actually expect to get paid. I don't understand that. [Laughter]

Financeability

MS. GAMACHE: To pick back up on the financeability issue, we heard the bankers say yesterday that they have a hard time pricing the risks in corporate PPAs, and Ray Wood said, "Get used to it." From a developer's standpoint, how are you helping the bankers get used to corporate PPAs?

MR. PAGANO: I don't think it is the job of the developer to help them get used to it. The market reacts to opportunities. We have seen a pattern through the history of the industry where the bankers will take risks tomorrow that they would not take yesterday. This is another example of that.

The banks will build in cash traps for credit trips and things of that nature. The term loan B market is a great example of something that did not exist when this industry was in its middle stages. You can get a lot of things done today that you could not get done 10 or 15 years ago.

The market will evolve. It will come up with structures to box this risk. The developer may help some, but it will be done largely on the financing side. The banks will come up with creative solutions for an opportunity that they want to pursue. That is what we have seen in the past.

MR. HODEK: Among the things that have to happen for a large corporate to get into a deal are it has to hire the right counsel, it has to understand the dynamics of the PPA market, and it has to understand how the contracts are structured because getting them financed is a key part of their consideration. They want to know where the project is, what type of resource it is, what term they can get and what the economics look like.

They want to feel confident the project can be financed and will actually get built. They realize that they have to conform to the standards of how PPAs are done. One of the requests that by and large all corporates have is to have a hub-delivered or hub-settled product, much like if they are doing a hedge. They do not want to take delivery at the bus bar, and that is a fair request, but it obviously makes financing the project more challenging. You have to have the right sponsors involved to make that work.

There is an opportunity here for our whole industry. There are potentially another 60,000 megawatts of demand from corporate customers, but we will have to work hard on educating all the financing parties and help the corporates understand what is financeable and what is not. They want to get deals done, too.

MR. PAGANO: The key is the 60,000 megawatts. This is a real opportunity. It is not a fad. It will be around for the foreseeable future. The banks are going to have to get used to it and figure out how to finance it because there is a lot of opportunity in front of them. Between the corporates bending a little and the financing parties getting creative, I think people will learn how to take advantage of the opportunity.

Corporate Credit

MR. STORCH: We have one thing you will almost never see in a utility PPA, which is the offtaker posting a letter of credit to secure its obligation to purchase. Look at California posting a year of revenues in a typical PPA to secure the obligations under the PPA. With corporates, we have found a willingness to post security if their credit falls below a certain level, even though the credit remains investment grade but falls to something like BBB+. Then we require a letter of credit to secure the obligation for a reasonable period of time.

They are not puking all over that. Corporate credit is one of the bigger challenges in these contracts. We all know the drill with what makes a deal financeable. For a company like Enel, we can underwrite the PPA by just indemnifying everybody that the counterparty under the PPA will meet its obligations, but we still have to get comfortable with that credit ourselves, and we would much rather that credit risk be covered under the contractual arrangements directly with the counterparty.

MR. KALETA: The same credit issues are coming up in other contexts, like with the rise of aggregators, particularly in California. Dealing with General Motors or somebody like that is going to be easier than dealing with an aggregator. It is the same set of issues that we see across the board.

MS. GAMACHE: Jim Pagano said this is not a passing fad. Does everybody else on the panel agree with that? Speak also to whether expiration of renewable energy tax credits will have any effect on the future of corporate PPAs.

MR. PAGANO: I think what is embedded in your question is how much of this is economic and how much of it is for the marketing side of the organization. It is moving more to an economic decision. In the case of wind, production tax credits are a critical factor in being able to offer a product that is cost competitive.

The corporates have become more focused on whether projects are under construction in time to / *continued page 8*

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construction-start rules work for tax credits.

The agency has reserved on construction-start issues for solar projects, which have until the end of 2019 to start construction and qualify for a full 30% investment tax credit. Solar projects, unlike other projects, face an outside deadline of December 2023 to be put in service to qualify for a larger tax credit than the permanent 10% investment tax credit. The IRS must still decide what continuous work requirement, if any, to impose on solar in view of this outside deadline to finish.

The solar notice is expected this fall.

It could serve as a vehicle for relief on the retrospective four-year window for other renewable energy projects. However, if the solar notice slips to late in the year, then it would not leave enough time for developers who want to move to the 5% test to do so. The Treasury is aware of this problem. It is possible there could be a separate, shorter notice solely addressed to the lookback issue.

TREASURY and the IRS continue taking flak from Senator Orrin Hatch (R-Utah), chairman of the Senate tax-writing committee, about the Treasury cash grant program and tax basis issues for solar projects.

Hatch sent follow-up letters to the US Treasury secretary, the IRS commissioner and the Treasury inspector general for general tax administration on June 9 after the Treasury responded on May 11 to earlier letters he sent in March.

In the latest letters, Hatch asked the Treasury secretary, among things, to do the following.

The Treasury said the section 1603 review team "evaluates a project's claimed basis by comparing the basis against certain market-based benchmarks," Hatch said. He wants "the benchmarks used since this review method was established" and "what system characteristics the team considers in evaluating an applicant's claimed basis against these benchmark prices."

Treasury said in its May 11 response that of 104,733 cash grants paid to / *continued page 9*

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qualify for tax credits. However, having said that, I think we can offer a competitive price even without tax credits. The price does not float like the retail electricity rate over the contract term. Obviously the willingness of the developer to commit to a competitive price depends on his or her view of the forward curve for gas or the general energy markets. My sense is that if you have a reasonable forward curve and you have safe-harbored wind turbines, you can see these projects making good economic sense over the next three to four years before the tax credits go away.

The equipment manufacturers see costs coming down and energy capture increasing so that they can offset the loss of production tax credits on the wind side. We think there is room for optimism even after the tax credits expire.

The pressure will remain within these organizations to make sure that PPAs are cost effective. This may force developers to move projects to better wind regimes. California has decent wind resources, but not the wind resources of ERCOT or SPP. Proximity may become less important, and folks may look for production that is cost effective even though they may start with the objective of proximity to their load.

MR. RANDALL: I agree. It is not a passing fad. The contracts are economic. There has not been as much penetration of the market by solar as there has been by wind, and I think that is price driven. As the price of solar continues to come down, solar will get more traction.

MR. STORCH: I am a big believer in what has been happening from a technological standpoint. Look at where wind and solar have gone in terms of price performance and what it costs for a typical megawatt hour of output today versus 10 years ago. The cost reductions are staggering.

Despite the fact that wind is more mature than solar in terms of movement down the cost curve, more movement is still to come. We are seeing 120-meter towers today, and they are more likely than not going to become the norm where air restrictions do not limit their use. Construction techniques will make it more economic to maintain and build towers at that height and to install nacelles of three-and-a-half and four megawatts.

We still have 50-kilowatt units running in California, but these will disappear as the tax credits run out.

I think the turbine vendors will move costs to the point where wind is competitive without tax credits relative to thermal alternatives. It will always be an issue of price. The industry will be able to meet the expectations of its customers, and corporates are going to account for a bigger and bigger part of the market.

The biggest competitor is going to be the utilities themselves. One utility executive years ago said a PPA to me is like kissing your sister. It is just not how I want to spend my day. They do not make money on PPAs and if they do a sleeve deal, it is just not the same as a rate-based asset delivering power to a customer.

Globalization

MR. HODEK: Last year, more than half of all the wind PPAs signed were with corporates and that trend will continue. When you sit down with a corporate executive and he or she looks at the list of major corporations that have already done renewable energy deals, the executive asks, “What am I missing? How do I do this? How is it possible? In what markets is it possible?”

The tax credits may cause the market to shift more to solar over time since the solar tax credits have a longer runway than wind credits. Corporations will weigh which of wind and solar is the better deal.

The United States is a great market today for these companies to transact for a lot of reasons, but as the cost curves change, companies will be looking more and more at global markets. All of these companies have massive global load.

MR. KALETA: The economics work. Demand is driven by low costs. The tax credits were tremendous accelerants to get the industry started both in wind and solar, but right now, we are seeing so much demand being driven just purely on price. The driver is not a state RPS. It is not a feed-in tariff. It is the electricity price that these projects are able to offer.

We now focus on utility-scale solar. You are going to see new products and approaches that address electricity market needs. The power industry is going to become fairly creative.

MR. STORCH: My company just won a huge award in Mexico for 1,200 megawatts, and we are doing solar there for electricity prices in the low $30-a-MWh range. There are no tax credits.

The cost of doing business in the United States continues to be somewhat of a challenge. Labor is more expensive. But the Mexican example points to what is possible.

Another Potential Offtaker: Community Choice Aggregators

by Deanne Barrow, in Washington

Community choice aggregation is a growing trend in US energy procurement that could increase demand for renewable energy.

Under this model, a municipality or a group of municipalities forms a new entity known as a community choice aggregator or "CCA" that procures electricity in bulk to cover the combined load of interested residents and businesses within the municipalities' political boundaries. Much of the electricity comes from independent power producers that provide renewable energy to the CCA under a long-term power purchase agreement. The local utility, which no longer provides the electricity, remains responsible for transmission and distribution of the power, as well as for billing, collections and other customer services.

Most CCAs offer customers the option of buying electricity that has a higher renewable energy content than what is available from utilities. Customers are typically given two or three energy mix options to choose from, ranging from 30% renewable energy up to 100% renewable energy. The sources of renewable energy vary from program to program, but typically include solar, wind, biomass, geothermal and small hydropower, with a strong preference for locally generated energy.

The goal of a CCA is to negotiate lower rates than individual households or businesses purchasing electricity can obtain on their own from utilities or other retail suppliers within the service territory.

The nation's largest CCA, the Northeast Ohio Public Energy Council or "NOPEC," has reportedly saved its 500,000 customers a total of $218 million since its inception in 2000. In 2012, Chicago launched a CCA program that provided average customer rate savings of 25% to 30% over the utility benchmark, but the program was discontinued in 2015 when potential savings were eliminated after the utility dropped its rates. Local officials say the program may be brought back if market conditions change.

Growth of CCAs

CCAs are legislatively enabled in California, Illinois, Massachusetts, New Jersey, New York, Ohio and Rhode Island. CCA laws were passed in these states as part of electricity / continued page 10

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date, 29,249 were for less than the amounts requested. That is 28%.

Hatch wants Treasury to tell him what actions Treasury is taking to authenticate claims in the annual performance reports that grant recipients are required to file for the first five years after a project is put in service. Grant recipients must report if the projects have been sold and how well they are still performing.

Treasury said that 177 grant recipients had not submitted annual reports for 981 projects by the end of March this year. Hatch wants a list of the grant recipients, projects, grant amounts and status of collection proceedings. Treasury sends a reminder by email 30 days before the report is due. Failure to file an annual report leads to recapture of the cash grant paid on the project.

The Senator asked the following of the IRS.

He wants to know the IRS "process for reviewing claims regarding fair market value" by taxpayers claiming investment tax credits and "whether the agency is considering changes to how it evaluates FMV."

He wants "a list of all instances when the IRS sought to recapture an energy credit of $10 million or more claimed for an energy property since 2010," including taxpayer and project names, the amount it attempted to recapture and how much it ended up recapturing.

He also want to know whether the IRS plans to "determine whether taxpayers [who were paid reduced grants] are also overstating the costs [of] solar properties for which an energy credit was claimed."

Finally, he asked the Treasury inspector general to determine whether companies that had their grants reduced have been claiming investment tax credits on the basis that was disallowed and, in each case, whether the IRS has taken any action.

HOUSE REPUBLICANS released a tax plan in late June that they hope to put through the next Congress if Republicans remain in control.

The Republicans enjoy / continued page 11

CCAs

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restructuring in the late 1990s and early 2000s. Now, state and local climate change policies are causing more counties, cities and towns to take advantage of the structure.

CCAs have seen the most traction in California. The state went from having one CCA serving 6,000 customers in 2010 to four CCAs serving more than 400,000 customers today. The two most populous counties in the state, Los Angeles and San Diego, are actively considering proposals to start aggregation programs for their residents. In June, PG&E said the potential loss of retail electric customers to CCA programs, which compete with the incumbent utility for business, contributed to its decision to shut down the Diablo Canyon nuclear power plant, which it plans to phase out by 2025.

San Francisco is the latest municipality in California to launch a CCA program. On May 1, CleanPowerSF, as the program is known, rolled out initial service to 7,800 residential and commercial customers, with plans to add another 48,000 residential customers by the end of 2016 and 300,000 more accounts by 2022. Regulatory and political setbacks delayed plans to launch in 2014, but now the program enjoys strong backing from both the San Francisco Public Utilities Commission and the city's mayor. Both have identified the CCA program as an important step toward achieving the city's ambitious goal of 100% renewable energy use by 2020.

Most of the electricity will initially come from wind. In February 2016, CleanPowerSF signed a power purchase agreement with Iberdrola Renewables for 25 megawatts from the Shiloh I wind project.

May 1 was also the start date for the first New York CCA program, which won regulatory approval from the state Public Service Commission in February 2016. The program is run by Sustainable Westchester, Inc., a local non-profit consortium of 20 towns in Westchester County. It started off with a customer base of 113,600 residents and small businesses and is offering a 100% renewable energy option at a rate that is about 5% cheaper than the 2015 utility rate for energy with a 23% renewable content. Two thirds of the participating towns voted to enroll their residents in the 100% renewable energy option by default. As in the case of San Francisco, the Westchester program is considered a key strategy for achieving local and state clean energy objectives, among them, New York's goal of 50% renewable energy consumption by 2030.

In April 2016, Sustainable Westchester, Inc. negotiated an energy supply contract with ConEdison Solutions, the deregulated arm of the distribution utility Consolidated Edison Company. Under the contract, ConEd will sell electricity to 90,000 homes and businesses at a fixed rate over a term of two years. ConEd can purchase renewable energy certificates as validation that the electricity it is supplying is from renewable sources. (By contrast, the San Francisco CCA does not allow the use of RECs separate from the electricity.) However, the contract allows Sustainable Westchester, Inc. to replace some of ConEd-sourced energy with new, local generation. If this happens, then ConEd can increase rates to make up for any electricity it ends up selling at a loss as a result of the displacement.

Community choice aggregators are another potential customer for electricity from renewable energy projects.

Opt Out

Where CCAs exist, they are the default energy provider for electricity customers in the applicable service area, meaning once a CCA begins to provide service, residents and businesses are automatically switched over from the utility to the CCA.

Customers then have the ability to "opt out" and go back to utility service at any time, although some CCAs are allowed to charge an exit fee for doing so after a grace period, typically 60 days after the start of service. As an exception to the opt-out model, in deregulated markets like New York, Massachusetts and Illinois, consumers who are receiving service from a competitive supplier rather than the local utility are not automatically enrolled in the CCA. They must specifically request enrollment after the contract with their current supplier has ended.

Opt out is a key feature behind the success of CCAs. The lowest participation rate for opt-out programs that offer renewable energy is around 75%, whereas the highest participation rate for opt-in programs (those that require affirmative consent for participation) is around 25%. Moreover, the national average opt-out rate is only 3% to 5%. The success of the program depends on the ability of the CCA to charge rates that remain competitive with the local utility.

Financeable PPA?

A PPA entered into with a CCA can provide the basis for securing project financing for a new project.

In September 2015, Recurrent Energy was able to finance the 100-megawatt Mustang solar project in California on the basis of long-term PPAs signed with Sonoma Clean Power and Marin Clean Energy.

The key issue is that CCAs generally do not have a credit rating from nationally recognized rating agencies, such as Moody's, Standard & Poor's or Fitch. In order for a PPA to be financeable, lenders typically require the offtaker to have an investment grade credit rating. The absence of a credit rating in the case of CCAs makes financings based on PPAs with CCAs challenging.

In at least one recent deal, in order to overcome the absence of a credit rating for the CCAs, the lenders analyzed the metrics used by rating agencies in rating utilities and included cash sweeps that were triggered if the CCA did not meet similar metrics. However, such provisions are not easy to implement since the borrower may not have access to information that is needed to determine whether the CCA is in compliance with such metrics. As financings involving CCAs become more common, provisions of this type are likely to evolve.

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a large majority in the House. They are in greater danger of losing control of the Senate, particularly if Donald Trump loses the presidential election by a large margin. Even if Trump wins and Republicans retain control of both houses of Congress, his plan and the House plan are far apart. The two will have to find common ground.

The House plan is in a 35-page blueprint. Kevin Brady (R-Texas), the House tax committee chairman, said House Republicans are still working on the details.

Economists are calling it a cash flow tax with a cross-border adjustment or a destination-based cash flow tax.

The US corporate income tax rate would be reduced from 35% to 20%.

There would be three tax brackets for individuals: 12%, 25% and 33%. However, individuals would be taxed at half these rates on dividends and capital gains recognized on dispositions of corporate shares.

The US has essentially two tax systems for corporations: a regular corporate income tax and an alternative minimum tax at a lower rate on a broader base of income. Corporations must calculate both and pay essentially whichever amount is greater. The tax plan would eliminate the alternative minimum tax.

It would allow capital spending on tangible and intangible assets, but not for land, to be deducted immediately. This is called 100% expensing. It is the opposite of what the last House tax committee chairman, Dave Camp (R-Michigan), proposed just two years ago. Then, Republicans were advocating lengthening depreciation periods to help pay for slashing the corporate income tax rate.

The House plan would not allow net interest expense to be deducted. Interest expense could be used to offset current-year interest income, and any remaining interest would have to be carried forward and used to offset future interest income. This would give companies an incentive to buy new assets with cash rather than borrow to do so. */ continued page 13*

Community Solar Financing Issues

Community solar is a form of independent power project whose output is sold at retail rates. The financing community is just starting to get its arms around the risks. What are the risks? Can this type of project finally get traction with tax equity investors and lenders? A panel of three community solar developers, a lender and a tax equity investor talked about these and other questions at the Chadbourne annual global energy and finance conference in early June. The following is an edited transcript.

The panelists are David Amster-Olszewski, CEO of SunShare, Mark Boyer, chief capital officer of Clean Energy Collective, John Eber, managing director and head of energy investments at J.P.Morgan, Sanjiv Mahan, president of WGL Energy, and Vinod Mukani, head of infrastructure and energy financing for the Americas for Deutsche Bank. The moderator is Marissa Alcala with Chadbourne in Washington.

MS. ALCALA: There are a number of myths about community solar. The first myth that I want to dispel is that community solar is a new asset class. Mark Boyer, is it a new asset class or is it simply that some potential equity participants, lenders and tax equity investors are taking time to come up the learning curve?

MR. BOYER: We have been doing it since 2010 and have been able to finance all of our projects, which is 100+ projects around the country in multiple states.

It is taking a long time for the financiers to come up the learning curve. It has not been a matter of walking into a bank and saying, "I have a community solar project," and then having the bank evaluate it the same way it evaluates a commercial and industrial solar project or a project with a long-term power purchase agreement with a utility.

Our early deals had take-or-pay power purchase agreements with electric cooperatives that supplied the electricity, in turn, to the community. We financed our projects based on these PPAs.

Then we layered in community solar where the coops helped us find the subscribers, but always still with a take-or-pay PPA with the coop as a backstop. That is about half our business right now.

The places where it looks like a different asset class are in states like Minnesota, where David Amster-Olszewski is doing a ton of work, or Massachusetts or Colorado, where you have different regulatory regimes for community solar. It is taking the financial community a long time to come up the learning curve.

Community solar is clearly getting traction. We are seeing a lot more people interested in it and trying to get comfortable with the risks around the offtake arrangements, because that is where it all lands at the end of the day.

MS. ALCALA: So community solar is a diverse asset class. David Amster-Olszewski, how long have you been doing community solar projects?

MR. AMSTER-OLSZEWSKI: We have been developing projects for about five years.

MS. ALCALA: So community solar does not seem new to you either.

MR. AMSTER-OLSZEWSKI: I guess to the market perhaps it is a new asset class, but the concept of it is not new at all. In fact, if you look at our executive team and our board, we stacked the team with a lot of telecom experience. Think of community solar as more of a wireless cell phone plan and it does not look like such a new asset class. You have a remote asset from which customers receive a service. There is no equipment bolted to the roofs of their houses. You do not have to roll a truck if a customer defaults. You just switch off a meter.

Our cost of customer acquisition is down to $300 a customer, so if you compare that to the rooftop residential companies' costs of $2,000 to $6,000 to acquire a customer, it is a massive difference.

MS. ALCALA: Community solar is looking better by the minute.

MR. AMSTER-OLSZEWSKI: There are more useful parallels perhaps between community solar than to the power industry. You could also look at community solar as taking the best from among the three existing types of solar projects. It has multiple customers and, therefore, risk diversification like the rooftop sector, only it is easier to deal with customer defaults by simply switching the service to another customer on a waiting list. You have control over the asset like you would if it were a utility-scale project. You have the benefit of a lower cost to construct due to scale and the ability to put the solar arrays where they will maximize output.

So it depends how you look at it, but I do not think it is that new of a concept. You are just putting together different pieces in a new way.

MS. ALCALA: Another myth about community solar is that the projects cater primarily to individuals as customers. Sanjiv Mahan, Washington Gas is doing community solar projects that are focused mainly on commercial subscribers, right?

MR. MAHAN: That is correct. We are approaching community solar in a very slow and progressive manner. We have watched what others have done over the past few years, tried to learn from their experiences and focused on what seems the best fit for us.

We have been focused on the C&I aspects of the business. We wanted in Minnesota to learn first how the market works, so we started with 40- and 50-kilowatt systems. An organization like ours does not usually play in such small systems, but we wanted to learn the local landscape. We worked with local developers and local communities. From there, we moved to larger projects with Xcel, and now we are moving to build up a subscriber base.

Lender Perspective

MS. ALCALA: Deutsche Bank has done financings of community solar projects. Vinod Mukani, is it easier to finance projects with a mix of residential and commercial subscribers?

MR. MUKANI: I find this discussion very interesting. David Amster-Olszewski said it right. These projects are the best of both worlds. If you arrange the different types of solar projects along a spectrum, utility-scale solar is well understood. Everybody knows what the issues are and how to finance it.

C&I has a different risk profile. The portfolio and the credits matter. With residential solar, you need to factor in consumer default history.

Community solar picks up the best parts of all and sits right smack in the middle with utility-scale solar and residential solar. The issues related to utility-scale solar are well understood. Now add some residential solar features. You know what FICO mix you need to have. You know what the diversification benefits are. We have a view on how the residential customers behave. We have the default history data from other asset classes. We can underwrite and price that combined risk. Based on that, we can deal with the subscription aspect of community solar. We can put all the pieces together.

Frankly, it is a risk mitigant that the system is not installed on the roof of the customer's house. It is a benefit that the subscription can move from one customer to another customer. In that sense, it is an improvement on residential rooftop solar from a risk standpoint. The involvement of the municipality and the state also gives you some comfort.

The biggest challenge has been aggregation to get to a meaningful size. Trying to do a 10-megawatt community solar asset is tough because the legal fees are just as high as for a 100-megawatt project. But if you are able to get the size right, then financing becomes a lot more available.

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The intention is to equalize the tax treatment of different types of financing. The blueprint says the tax committee "will work to develop special rules with respect to interest expense for financial services companies, such as banks, insurance, and leasing, that will take into account the role of interest income and interest expense in their business models."

Kenny Marchant (R-Texas), a senior Republican on the House tax committee, said he thinks the blueprint needs a 10-year transition period between the current tax system and one that operates without interest expense deductions and with 100% business expensing.

The plan has not been scored, so it is not clear how much it would add to the federal budget deficit. House Republicans believe that the economic growth stimulated will help increase tax collections enough to pay for it. They are also working from a tax baseline that assumes $400 billion lower tax collections over the next 10 years if Congress makes no changes in tax law. The baseline assumes that all the tax extenders last December, including for renewable energy, will be made permanent. Thus, any decision not to extend these items further will be scored as a revenue increase.

The blueprint says the plan "generally will eliminate special-interest deductions and credits." The only exception is the tax credit for research and development will be made permanent.

The plan would create a powerful incentive to bring manufacturing home.

It would move to a territorial system of taxing US companies. US companies would no longer be taxed on worldwide income. Dividends from offshore subsidiaries would no longer be taxed. "Subpart F" rules that allow the US to look through offshore subsidiaries and tax any passive income that has been shifted offshore will be "streamlined and simplified." The "bulk" of them would be eliminated.

All US and foreign corporations would be taxed at the 20% US corporate income tax rate on income from sales of goods

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So from a Deutsche Bank standpoint, we took a view that this is not an entirely new asset class. It is an asset class that takes the best parts of the different solar market segments. We were able to offer an aggregation facility for a client to help it fund a portfolio. The portfolio is more than $100 million in size. Now you are able to come up with a financing structure that is efficient. There is a master tax equity facility involved that provides additional capital, but pushes lenders to a back-leveraged position.

As the size becomes relevant, as more states adopt community solar programs, as the portfolios grow in scale, I think financing is there to be had.

MS. ALCALA: We could probably put you on a roadshow for why community solar is great and should be financed by everybody.

MR. AMSTER-OLSZEWSKI: I want to record that. Come with me as we meet with financiers.

MR. MUKANI: I don't think I am saying anything fantastic. If you look behind the curtain and try to parse the risk, it is sum of parts. If you are in Massachusetts, you need to appreciate how the SRECs work. If you already understand how the SRECS work — they are part of the cash flow stream — then you can underwrite that.

You have to form a view on the consumer risk. Then you can underwrite that. You have a view on the risks associated with getting an asset in the ground, the permitting, the interconnection and all that stuff. You can underwrite that. If you add all of this together, there is nothing extraordinary about the financing.

Tax Equity View

MS. ALCALA: John Eber, J.P.Morgan has been a dominant player in the tax equity market. You have not found a community solar project or set of projects in which you are interested in investing. Why?

MR. EBER: Yes. I am beginning to wonder why Keith Martin has put me up here today.

MS. ALCALA: Because we love diverse perspectives.

MR. EBER: That feels like a bit of a set up. [Laughter]

MS. ALCALA: You are going to tell us the problems that we need to overcome, and then we are all going to work together on solutions.

MR. EBER: We are actually in our 10th year of doing solar tax equity investments. We started with CSP or solar thermal projects. We have done C&I deals, residential rooftop deals, and large-scale utility photovoltaic projects. I think only two community solar deals have made it to my desk. There are a bunch of internal filters before I get to see things, so people on my team have probably seen more of them than I have.

The challenge with the ones that we have seen is scale. We are a scale investor, and most of the other tax equity investors with whom we partner are also looking for scale. It feels to me like it is still in the development stages in the sense that there are a lot of smaller deals. I am talking the true community solar deals, the ones that do not look like traditional solar transactions with long-term power purchase agreements.

It is a great concept. It is a fascinating theory. There are all sorts of advantages as just described. We just have not seen opportunities at the scale we need to invest.

MS. ALCALA: One of the scalability issues is the differences among programs across states. We had a discussion at our conference last year about community solar at a time when there were community solar programs in nine or 10 states. Now there are programs in 14 states and Mark Boyer, I believe your company has been doing projects in states without community solar legislation.

Every state has different rules. How should sponsors overcome that as they push for the scale that tax equity investors or lenders require to finance projects?

MR. BOYER: We have actually done community solar in Wisconsin. We have three projects here in Wisconsin, and there is no state legislation. We did them with help from the Dairyland Power Cooperative.

If you are building one-megawatt community solar arrays and trying to aggregate those across 13 states, it is a nightmare from an underwriting perspective. What we have done in that situation is to go to local or regional banks to borrow. We financed almost all of our construction debt and even our long-term debt from regional banks instead of the larger banks, because the bite size works for them. The transaction costs are lower when dealing with smaller banks. They don't have as many lawyers.

Tax equity can be very difficult to arrange. We have been able to do tax equity. We did it with US Bank, but in a very specific region.

We have been able to raise other tax equity across different states, but with high-net-worth individuals. That is hard to scale. It will not take us to financing large transactions, but it is a good place to start, and we are trying to build on it.

Now what we do is exactly what John Eber said. We will take 20 to 40 projects in Massachusetts, pull them together, do a single financing facility and run all the deals in that state through it.

We are taking one step at a time. The regional banks love this type of project. It has been a good fit. We have even gotten a couple of them to do tax equity, which took some time, but we got them there.

Scale

MS. ALCALA: David Amster-Olszewski, what is the largest project volume you have in a single state?

MR. AMSTER-OLSZEWSKI: We are building 100 megawatts of projects in Minnesota over the next two years. In Colorado, the portfolios are smaller, but we are starting to increase the scale of the program there, as well.

I think we are starting to get to the point where we can talk with the larger institutions to attract tax equity. One of the issues we had this year was we were in between: we were too large for the smaller tax equity players, and we were still too small for the mainstream tax equity market. My hope is that we will get to the scale that the larger investors are looking for in 2017.

In the meantime, we have been working for five years on building the software, building the systems, building the sales force, and pushing down the customer acquisition cost. Now we are looking at acquisition opportunities to bring more projects into our portfolio.

Four years ago, there were not any developers of two- to six-megawatt projects that were not connected to a host site that was using the energy. There was no market for community solar. In the last four years, that has changed a lot.

Now you have a bunch of developers that are developing these sites, but have no idea how to subscribe high-revenue customers, how to manage those customers, and how to bring these projects across the finish line. I think that is the other opportunity that we have. It is jumping into acquiring projects and adding them to our portfolio and then bringing them to the large institutions.

MS. ALCALA: That is a little like the C&I market. That market is full of smaller companies that may not know how to get projects across the finish line. It is struggling to reach scale.

MR. AMSTER-OLSZEWSKI: That is exactly right. There is another piece at which you hinted before, and that is the regulatory environment. How these programs work varies from state to state. After working with utilities on community solar as a product for the last five years, we have / *continued page 16*

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and services to US customers, regardless of where the goods are produced. This could raise the cost of imports. US companies would not be able to deduct the cost of imported production materials. Brady said he has not settled on whether to deny the entire deduction or only a fraction.

Income from goods manufactured in the US but sold abroad would not be taxed at all. Thus, a US company considering moving abroad and selling into the US market would face the prospect to having to pay taxes both in its new foreign home and on its income from sales to US customers.

The blueprint said the US is in a disadvantageous position because other countries with value-added taxes refund taxes on exports and tax imports. All sales income ends up being taxed somewhere. However, in the case of the US, the system breaks down. The border adjustment replicates to some extent the treatment as if the US were part of a global VAT regime.

The cross-border adjustments might not pass muster under World Trade Organization rules. The WTO prohibits cross-border adjustments of income and other "direct" taxes that encourage domestic manufacturing. House Republicans argue that their plan is closer to a consumption or cash flow tax and should be tested under the same rules for a VAT or other indirect tax that is allowed to have border tax adjustments.

Earnings that US multinationals have parked in offshore subsidiaries when the new system takes effect would be subject to a one-time tax at an 8.75% rate when held as cash or cash equivalents and at a 3.5% rate otherwise (with the ability to spread out taxes at the 3.5% rate over an eight-year period).

Net operating losses of US companies could be carried forward indefinitely and would be increased by an interest factor that compensates for inflation "and a real return on capital to maintain the value of the amounts that are carried forward." No carrybacks would be permitted. / *continued page 17*

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gotten a very good idea how different utilities view community solar, how to work with them, how to work through their processes, how to make sure you are first in the interconnection queues, how to make sure that you write the programs and systems so that you are able to bill your project and make the subscriber bill credits work with different utilities.

For example, I was just in a meeting two days ago in Minnesota where more than 1,000 megawatts of community solar projects have been proposed. We are working with the utilities on rules for approval of the switch gear in their interconnection process. We have to order switch gear and install the systems, and we would like the utilities to confirm the switch gear will work with their interconnection.

But guess what? Nobody has done that for community solar, so we have to write the process. Those are the things where companies like ours and Clean Energy Collective are leading the way. We can really leverage that knowledge of how to write the rules as this business expands.

Fully Subscribed?

MS. ALCALA: Let's talk more about subscribers. How important is it to have a project fully subscribed in order to finance it. Can the tax equity investors and lenders get comfortable with the idea that a company with a track record will be able to execute on subscription agreements during a construction period? Or must a developer have 85%, 90%, 95% of the subscribers lined up before the projects can draw on a construction loan?

MR. BOYER: John Eber, I think you were set up. [Laughter]

MR. AMSTER-OLSZEWSKI: But I would love to hear your answer.

MR. MAHAN: Let me help John with his answer. We got comfortable with it because when we went into Minnesota, we had a good idea whom we would target as subscribers. We had already had conversations with our larger potential subscribers.

We started putting in the applications with utilities before all the subscribers were identified and in place, but we were comfortable that we had the right partnerships and the ability on the ground to build the subscriber list.

Yes, it was a leap of faith compared to what a large company like ours has done traditionally. With C&I, you have a 20-year PPA. You have the customer agreements in place before you build.

We are a third-party retailer in five states. We sell both natural gas and electricity in five states that are contiguous on the east coast. We can bundle wind energy that we have purchased in the market with brown energy and offer it to customers, and you do not need long-term agreements. We are simply taking that experience and applying it to community solar. It is the same business.

We think we do not need to have all the subscribers identified in advance. We know that we will have success in marketing the power because of our track record of offering other renewable energy solutions like it to our customers.

MR. EBER: Focusing on the underwriting process from an institutional standpoint, the tax equity in a highly optimized structure for a solar deal is only about 40% of the value of the equipment. So essentially you need significantly less than the total output value to pay out the tax equity.

You don't necessarily need to have 100% of the project contracted for tax equity to be able to view a deal as financeable. The challenge comes when you try to raise the rest of the capital if that capital is behind the tax equity in priority of payment.

Maybe one way is you find another investor who is more comfortable with the risks and who wants to be more of a strategic player than just a financier, and who is willing to bridge some of the risks for a different kind of return, something higher,

> The biggest challenge for community solar is aggregation to get to a meaningful portfolio size.

but delayed. It is all about how you put the capital stack together.

MR. MUKANI: It is important to have a view that the project will be fully subscribed.

We are interested in the track record of the entity that is lining up subscriptions. What is the cost to acquire and replace customers? Does the project have to be fully subscribed at the start of construction? No. Does it need to be close to that? I think the answer is yes, because a loan is essentially a monetization of future cash flow. When we make a loan, we are taking a view that the developer or aggregator is not only able to get the subscriptions done while it is building the portfolio, but also that it will be able to substitute down the line when there are defaults or if a customer wants to get out of a particular contract.

When construction starts, there is a certain level of subscription that one looks for, and the ramp up is what you are judging as a lender. Maybe there is a structure that allows for higher loan to value as more subscriptions come in. The underwriting process is a function of the subscriptions that you have already obtained plus the track record of having been able to do that before.

Going back to the discussion about how you get to scale, I appreciate that it may not be a concern for smaller banks or for Washington Gas, but there may be other ways to get to scale, for example, by mixing in some C&I projects with community solar. Maybe your portfolio is 60% community solar and 40% C&I. That is a way to get to scale that could be interesting to the banks.

Now to the point that each jurisdiction will have its own issues and how do you solve for that. How do you create a template that works across the portfolio? It can be managed. We have seen it done.

MS. ALCALA: Maybe when you mix community solar with C&I and in different states, it helps if the portfolio is limited to two, three or four states, and the customer agreements and site leases use as nearly as possible standard forms.

MR. MUKANI: That is spot on. Striking the right balance so that there is a template that allows you to combine particular states where similar documents can be used becomes an important part of how to assemble a financeable portfolio. Maybe that is how the industry should think about ramping up to get to scale.

Residential v. Commercial Mix

MS. ALCALA: Let's hear from the developers on the panel how they view commercial versus residential subscribers.

MR. BOYER: We have about 50-50 across our entire portfolio. However, when you go into a particular / *continued page 18*

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Meanwhile, in the Senate, the tax committee chairman, Orrin Hatch (R-Utah), continues working on a different approach to corporate tax reform. Hatch wants "corporate integration," meaning to impose a single tax on corporate earnings at either the corporate or the shareholder level. His self-imposed deadline to release the details keeps getting pushed back. It is not clear how much interest in corporate integration there is in the business community.

ENERGY STORAGE facilities would qualify for tax credits under bills introduced in the House and Senate.

The measures are unlikely to be enacted this year, but lay down a marker for next year, depending on the outcome of the US presidential and Congressional elections in November.

Eight Senators, led by Martin Heinrich (D-New Mexico) and Dean Heller (R-Nevada), introduced a bill in mid-July to allow a 30% investment tax credit for any "equipment which receives, stores, and delivers energy using batteries, compressed air, pumped hydropower, hydrogen storage (including hydrolysis), thermal energy storage, regenerative fuel cells, flywheels, capacitors, superconducting magnets, or other technologies identified by" the IRS "and which has a capacity of not less than 5 kilowatt hours."

The tax credit would phase out on the same schedule as the investment credit for solar projects. Thus, the 30% credit would apply to storage facilities that start construction by 2019, drop to 26% for facilities that start construction in 2020 and 22% in 2021. The facilities would have to be in service by December 2023. There would be a permanent 10% credit for storage facilities that miss these deadlines.

The bill would also allow a 30%, 26% or 22% residential credit for batteries with a storage capacity of at least three kilowatt hours "installed on or in connection with a dwelling unit located in the United States and used as a residence by the taxpayer." The battery would have to be put in service by 2019, 2020 or / *continued page 19*

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state, it depends on the utility, how its program works and what the goals are of that program.

For example, when we do a deal with an electric cooperative, it is extremely important to that coop to see at least 50% residential customers. The coop is member owned. Those are the members. That is who they are interested in doing this for.

If you look at a state like Massachusetts, it is a very different sort of regulated deal. The utility would prefer you never build the project, but you get it done anyway. We are still about 50-50 in residential and commercial customers in Massachusetts. We like that mix because we prefer to keep as many residential customers in the deal as we can.

We think it mitigates our risk. There is a much larger potential base of residential customers and, with the software programs, we can shut someone off in literally 20 seconds if he or she fails to pay, and stick someone else in. You can build a nice backstop for your financiers where you have a waiting list of people who want to subscribe.

If I have a single large commercial subscriber, even if it is an AAA or AA credit, if it drops out, that is a much larger blow to manage. So our goal across all of our projects is to try to keep at least 50% residential customers in the mix.

MS. ALCALA: David Amster-Olszewski, what is your preferred mix of customers?

MR. AMSTER-OLSZEWSKI: I think we are a little more aggressive. We are probably closer to 70% residential customers, but it depends on the state where we are operating and rules and regulations in each state. Clean Energy Collective focuses on electric cooperatives. We focus more on the large regulated utilities. Our base of commercial customers is almost all AA credit with a couple AAA customers.

It is interesting and, Mark, you mentioned this, but a lot of financiers say they prefer the AA-rated customers and would like more of those when we first get into discussions, until you get to the conversation about subscription guarantees in your customer management agreement over the 20- or 25-year life of that contract.

All of a sudden, the rate of residential customers moving out of the service territory is 0.3% a year, and we could still go after them legally to continue paying under binding subscription agreements, but we never do. So the financier asks why we will only guarantee an 80% subscription rate. Well, you wanted commercial in the portfolio and, if one commercial customers drops out, then you will lose 20% of the portfolio.

And, by the way, it does not take me one week to find a new residential customer or just pull from the backlog we always have. So you end up having a bigger chunk of lost revenue in your portfolio if that commercial customer drops out. At the end of the day, residential is really a lot more flexible. There is a lot more demand, and it is a lot faster to get residential customers signed up, and there are more customers behind them in the queue.

The other piece of this is we have never turned on a system that was not fully subscribed. A significant pain point for us has been that we cannot keep up with the demand for our product.

For example, people were on a waiting list for one of our projects in Colorado for a year and half. We want to start accelerating our development, construction and financing schedules so that we can keep up with customer demand.

One of our concerns is what happens over time as the market becomes more saturated. Do you have more competition for those customers and, therefore, do residential customers start dropping out because they are moving to the competition and start breaking their contracts? Legally we can go after them, just like the rooftop solar companies can, but it is not worth the trouble.

Finally, another factor in favor of residential customers is if you are monetizing cash flows at the residential retail rate, you are earning a 35% higher revenue stream. If you add that to a cost basis for the equipment of $2.50 a watt, that is quite a significant profit. That is what is drawing in the competitors.

MS. ALCALA: Sanjiv Mahan, you are focused on commercial customers. After what you heard David say, why?

MR. MAHAN: It is a natural extension of how we have done traditional solar. We have been doing this for the last eight years or so. We have always been focused on C&I. We have a 168-year old gas utility standing behind us. We own assets, including solar and fuel cells, that we use to provide services to commercial and industrial customers across the country. We are now in 19 states and the District of Columbia with that business. It is a natural progression to move to community solar, but focus on commercial customers. We are comfortable with how we have already been doing this business. We think it works.

I agree with David and Mark that we are going to have to make this more a commodity business. When you have 180,000 customers and are in mass markets, you can afford to have some leave in 30 days because they got a better deal from someone else. The only way it works is if you have the mass subscription base.

We think the way to grow community solar is to get away from long-term 20-year PPAs for every single residential customer, because that is a standard offering in an era where customization is what sells. The current customers who sign these contracts are all being very much social minded. They really want to do this for the betterment of the environment, but they also really want this product, which is an absolute truth. They want this product. The best way to grow is to eliminate one of the hurdles, which is the long-term contracts. Turn it into a commodity offering. Then I think you will get mass adoption. The qualifications of an individual are the standard credit qualifications that any third-party retailer would look at.

Then I bring it into my mainstream business. I have to handle all the billing and the other pieces that go with administration and marketing, but we have an engine that already does this, so why not take advantage of it?

MS. ALCALA: Vinod Mukani and John Eber, until we get to the ultimate model that Sanjiv just described, is there a mix of residential and commercial customers that you prefer from a lender or tax equity perspective?

MR. EBER: There are pros and cons to each. We have done a lot of residential solar. We are comfortable with it. I won't say the risks are easy, but we know how to underwrite them. So to the extent the subscriber base is substantially residential, we are familiar with it. That is the good news.

The bad news is it really takes even more scale to build up to a large enough portfolio to be attractive in our market on the residential side than it does if you are working in the C&I space.

However, the C&I space is more difficult to underwrite because not only are the credit risks varied and challenging, although many of them are customers of our bank so we are familiar with them, but also the customer agreements are all different because it seems to be part and parcel of dealing in the C&I space that the companies want to customize their contracts. The customer agreements are more heavily negotiated. Lack of standardization is a challenge.

That said, we can work with either.

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2021 to qualify for tax credits at these levels. The residential credit would disappear after that.

Meanwhile, five House members, led by Mike Honda (D-California) and Tom Reed (R-New York), introduced a more complicated proposal in the House.

Their bill would allow a 30% investment tax credit for "qualified energy storage property." The term has a broader and more involved definition than in the Senate bill. Onsite energy storage would not qualify unless it has a storage capacity of at least five kilowatt hours and then the tax credit would be limited to $1 million. It is not clear whether that is the limit for all such storage property put in service by a single taxpayer in a year or per storage property.

There would be a $2 billion total limit on all tax credits for storage.

Taxpayers would have to apply to the US Department of Energy and the IRS jointly for an allocation, and the storage facility would have to be under construction within two years after the allocation or the tax credit would be lost. However, compressed air storage facilities and pumped-storage projects would have three years to obtain permits and would have to start construction within five years after credits are awarded.

No more credits would be allocated after 2026.

A 30% residential credit could be claimed though 2026 on storage equipment with a storage capacity of at least five kilowatt hours that is installed in or on a dwelling unit in the US "owned and used by the taxpayer as the taxpayer's principal residence" and used to "provide supplemental energy to reduce peak energy requirements" or "designed and used primarily to receive and store, firm, or shape variable renewable or off-peak energy and to deliver such energy primarily for onsite consumption."

Of the bill sponsors, only Dean Heller (R-Nevada) and Tom Reed (R-New York) are on the Senate and House tax committees and, therefore, in a position to advance the proposals.

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Loan Agreements: Political Risk Default Trigger Needed?

by Peter Weiland, in London

The recent coup attempt in Turkey is causing lenders to think about including in loan agreements a political risk clause that allows the lenders to call an event of default in case of political unrest.

The Loan Market Association suggests wording in its developing markets template loan agreement, but there is no universally accepted version of this. Many variations are possible, but two fundamental variants can be identified.

One is an unqualified political risk clause.

The other is a political risk clause that is qualified by materiality, for example, by being subject to the risk event having a "material adverse effect" on the borrower.

The unqualified clause has the advantage that the mere occurrence of a political risk event triggers an event of default, entitling the lender to stop funding the borrower, placing the facility on demand or demanding immediate repayment of all disbursed loans. Risk events that are typically covered include war, hostilities, invasion, armed conflict, revolution, and insurrection or insurgency. So an attempted coup d'etat by force of arms will trigger the clause, even if the coup is put down swiftly.

By contrast, the qualified clause requires the effect of the risk event on the borrower to be assessed. The lender must wait and assess the consequence or, depending on the wording of the qualification, the reasonably likely consequences of the risk event, before it becomes entitled to take any action, although certain rights may be triggered earlier, especially the right to request enhanced reporting or information from the borrower. It will depend on the wording of the qualifier how long the lender must wait and what assessment is required to trigger the event of default.

Borrowers usually resist inclusion of political risk events of default, since political events are not within a borrower's control.

Lenders are tempted to concede the point either by agreeing to a qualified clause or by dropping the requirement altogether. Unless the decision is made on the basis of a principled risk assessment of the relevant jurisdiction, lenders tend to convince themselves with the following argument: "If there were to be political unrest, first, we will have other problems altogether and, second, we would be protected by our material adverse change clause anyway." Let's analyze these considerations in turn.

Other Problems

It may be true that incidents of political unrest cause wider problems that will affect the lender's activities in the relevant country. However, it is not obvious that such impacts will be immediate, even though they may be foreseeable.

Broadly, the possible ramifications of political unrest fall into three categories.

The first is contractual breach. The political unrest means the borrower cannot perform its obligations under the loan agreement or other finance documents, like the security agreements, cease to be enforceable or otherwise lose value. This can take many forms: for example, the borrower's business may be interrupted, and currency regulations may be imposed so that payments cannot be made.

The coup attempt in Turkey is leading to a renewed focus on political risk default triggers.

Another potential ramification is illegality. After the political unrest has played out, the lender is no longer permitted to do business in the country of the borrower or with the borrower. For example, there is a regime change and sanctions are imposed by the lender's home government.

Another possible ramification is strategic withdrawal. The affected country is no longer a place where the lender is comfortable conducting business. A strategic commercial decision is made in the bank to withdraw from that market. This could be the case, for example, if the result of political unrest is that the reliability or impartiality of the civil administration or judicial services in a country is eroded.

The "other problems" claim holds up only for the first two categories: contractual breach and illegality. Strategic withdrawal is not a reason for terminating a loan agreement. Thus, lenders would have to seek a buyer for their engagement to exit the investment and, following the political unrest, this may be difficult.

Also, contractual breaches or changes in the law leading to unlawfulness may not manifest themselves immediately. For example payment default may not become apparent until a payment milestone is reached and the borrower fails to pay. In other words, the lender will have to wait until breaches actually occur or become inevitable before being able to take action.

So, the political risk clause has real value, because it allows the lender to take swift action, effectively placing the facility on demand, as soon as an event of political unrest has occurred. This increases the options available to the lender and adds protection, in case the fallout from the political unrest is such that the lender wishes to withdraw from the engagement for reasons not otherwise captured in the facility documentation.

MAC Protection

The limitations of the material adverse change or "MAC" clause are well known, and a full discussion of why lenders tend to be reluctant to invoke it is beyond the scope of this article. Suffice to say that the main limitation of the MAC clause is that it requires the bank to make a decision about whether the political risk event has a material adverse effect on the borrower as stipulated by the specific wording of the MAC clause itself.

Unless a breach of another representation or covenant occurs in the meantime, whether a material advance change has occurred may not become clear until the political risk event has moved into a more advanced stage, at which point matters may be worse for the borrower or the lender. Thus, the MAC clause cannot give the same comfort as a political risk clause.

Further, when negotiating any qualifications to the political risk clause, it should be borne in mind that a qualification by reference to material adverse effect can result in the political risk clause collapsing into the MAC clause, so that its value is eroded.

The bottom line is there is value to a lender in an unqualified political risk clause. / continued page 22

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A MUNICIPAL UTILITY can own part of a power plant through a partnership with a private developer and issue tax-exempt bonds to buy its interest in the partnership, the IRS said.

The bond proceeds will not be considered put partly to "private business use."

The IRS made the statement in a private letter ruling that it made public in late July. The ruling is Private Letter Ruling 201630011.

IRS regulations make clear that a municipality can issue tax-exempt debt to finance its share of a power plant in which it owns an undivided interest as a tenant in common. A power plant is owned this way if the parties elect out of partnership treatment for the entity that owns the project and each takes its share of the electricity in kind.

The new ruling addresses a case where the entity remains a partnership. The IRS said that works, too.

Anyone issuing tax-exempt bonds must be careful not to allow more than 10% "private business use" of the assets or the tax exemption on the bonds will be lost. The reason the ruling was issued is the municipality must have felt it was not clear whether a power plant owned in partnership with a private party is put partly to private business use. The IRS also has rules for permissible terms in any contract that a private party has to manage the project to ensure that the arrangement does not slip into private business use.

The ruling involves a municipal authority that runs the electric, water and wastewater systems for a city. It issued bonds to acquire an interest in a power plant that was otherwise privately owned by a partnership.

Each partner, including the municipality, has a capital account — or claim on the project assets if the partnership were to unravel — equal to the fair market value of its interest in the project. The partnership allocates income and loss to the partners in a fixed ratio / continued page 23

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It offers protection that goes beyond the standard repertory of covenants and events of default. A MAC provision is not a substitute. The decision not to insist on a political risk clause should be made on the basis of an assessment of the degree of political risk to which the relevant country is exposed and the lender's appetite for that risk.

New Trends: View From The Investment Bankers

Five investment bankers had a wide-ranging discussion at the Chadbourne global energy and finance conference in early June about new trends in the market. The following is an edited transcript. The five are Jonathan Cody, managing partner and head of investment banking at Whitehall & Company, Jonathan Fouts, managing director at Morgan Stanley, Andrew Redinger, managing director and group head, utility, power & renewable energy, at KeyBanc Capital Markets, Roberto Simon, managing director and head, project and energy finance, Americas, at Société Générale, and Raymond Wood, managing director and head of global power & renewables, at Bank of America Merrill Lynch. The moderator is Eli Katz with Chadbourne in New York.

MR. KATZ: We had a number of yield cos rise rapidly and then come crashing down to earth, and now there seems to be nothing to take their place. What do you make of this trend, and what do you see going forward in terms of who comes in and takes the place of yield cos? Andy Redinger, let's start with you.

MR. REDINGER: Maybe they have gone below what we would consider their fair value, but that is because they became overheated. Some have come crashing down. I think we know who those are. I do not think there is anything that takes the place of yield cos, except more yield cos.

I have been saying this for quite some time: I think it is an education problem. I would put this asset class up against any other vehicle that provides investors with a yield and a little bit of growth. We forget that when the first yield co, NRG Yield, went public, we all said it was wildly successful. That yield co went public at a 5% yield, and in its S-1, it said it hoped to grow the dividend at 3% a year. It think it tried to say 5%, but the SEC said, "You can't say that."

That was a wildly successful yield co that started this marketplace, and we need to remember that. There are a lot of investors that like that model. The existing yield cos are obviously fighting a lot of headwinds at the moment, but I suspect the yield cos that have already gone public will recover. Calmer heads will prevail. I think there are more yield cos on the horizon.

MR. KATZ: Jon Fouts, any comment on that?

MR. FOUTS: I agree. Over the long term, there is certainly a place for yield cos. We have to remember that if you look at yield cos versus the master limited partnership market, the MLP market over the past 20 years has certainly had its ups and downs, and I think we can make a pretty compelling argument that the yield co model, compared to the MLP model, is just as good, if not better.

That said, short term, there is clearly a dislocation in the market. It will take a while to get through that. We need more market cap and more flow to have yield cos work over the longer term.

They are not a panacea. Last year, I think people thought yield cos, to a large extent, were a panacea, and they are not. It will take a while, but long term, we are bullish on yield cos.

Public v. Private Equity

MR. KATZ: All of the capital markets are in some way connected. As you look across the market, you still see a quiet period in terms of raising equity capital. The IPO market seems very quiet. How is that affecting the renewables sector in general, especially with respect to new technologies? Ray Wood, do you want to comment on that?

MR. WOOD: I don't think we have seen a drop off in overall capital deployment, but it is hard to predict how long the education process will take before people return to buying stocks. I share the optimism about the longer term.

That said, there is just a wall of money in the private markets coming in to buy projects that are at the notice-to-proceed stage. There is no problem with liquidity once a project is fully developed, or reasonably fully developed, and there is increasing appetite in the private market for a certain amount of development risk with proven sponsors.

There are ongoing cost reductions and efficiencies and technological innovation in materials. PPAs continue to show up from utilities as well as from corporations, and hedges are still available.

The capital is there. It is an odd time in the public markets. There is no IPO activity. We recently sold a controlling stake in a battery deployment company in California. We ended up not selling it to a pre-IPO growth investor or a yield co. We sold it to a large European strategic. There continue to be buyers in this sector.

MR. FOUTS: But on the private side.

MR. WOOD: On the private side.

MR. REDINGER: We are not seeing any new equity on the public side. Just to add to the litany of data points, independent power producers generally are trading in the public markets at $400 to $500 a kilowatt. Meanwhile, conventional assets are getting sold in private deals at $700 to $800 a kilowatt. There is clearly a dislocation between the public markets and the private markets, and that is what is driving a lot of this private investment.

MR. FOUTS: One piece of tangible evidence to support the optimism you hear here today is the astounding recovery of the high-yield debt market since mid-February. There is a correlation. The public equity markets should start recovering fairly soon, subject to the uncertainty imposed on all the markets by the US presidential election.

MR. SIMON: There has been a re-pricing of risk by the market, so even on the private side, especially for development risk, we are seeing valuations come down. We are marketing a small solar company now and getting interest from strategics. What is interesting is it is European strategics that are rationalizing price on the basis of other growth opportunities within their diversification efforts.

MR. KATZ: Going back to the point about a gap in pricing between the public and private markets, which market do you think has it right and which one corrects and how?

MR. CODY: I think the private markets are closer to reality than the public markets, and a couple of data points lead me to that conclusion. Look at how the markets are valuing conventional power assets currently. When you work from the valuations back to the income statements, it is clear the public markets are assuming natural gas prices will be way below $2 an mcf. But that is not where most equity research analysts have gas going. So you start to ask the question, "Well, wait a minute. If your valuations are using a sub-$2 gas price, but / *continued page 24*

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that is the same as their ownership percentages. The ownership percentages are the share of capacity belonging to each partner divided by total capacity.

MINNESOTA cannot bar Minnesota utilities from signing new long-term-power contracts to buy electricity from fossil-fuel power plants in other states, a US appeals court said in June.

The case was being watched closely by opponents of renewable portfolio standards who hope it will give them grounds to argue that state RPS statutes are unconstitutional.

Minnesota enacted a "Next Generation Energy Act" in 2007 that bars construction of new power plants of 50 megawatts or more in the state that contribute to carbon dioxide emissions unless an offset project is undertaken at the same time to reduce emissions by the same amount. The statute also bars electricity from being imported into Minnesota from such power plants in other states.

North Dakota and various electric cooperatives sued to block enforcement. The Minnesota statute complicates life for electric cooperatives that cross state lines. For example, the Dairyland Power Cooperative in Wisconsin provides electricity from a coal-fired power plant in Wisconsin that Minnesota views as a new power plant. About 16% of the electricity goes to members of the cooperative in Minnesota. The Basin Electric Cooperative in North Dakota supplies power to 135 rural electric system members in nine states, including 12 members in Minnesota. The members share the costs. Basin Electric buys a lot of electricity through requests for proposals.

A federal district court held in April 2014 that the Minnesota statute violates the US constitution because it requires coops in other states effectively to seek approval from Minnesota before undertaking a transaction in another state.

A US appeals court agreed.

The appeals court said the law violates the "dormant" commerce / *continued page 25*

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the forward price curve is suggesting something higher, there is a clear disconnect."

I don't think the public investors, whether they are retail investors or institutional investors, spend as much time as the private guys do trying to understand the dynamics of some of the fundamentals driving prices. So I am inclined to believe that the private guys are closer to reality than the public guys in terms of valuation.

There is a wall of private money eager to buy projects that are at the notice-to-proceed stage.

MR. REDINGER: I agree with that in concept, but when I see where assets are trading today, I have to second guess myself. We are in the market ourselves with a few contracted solar assets. They are already operating. I am seeing the private guys bid these assets at a 30-year levered pre-tax IRR of 9%. The bidders are assuming a negative IRR for the first 15 years and I ask myself, "Geez, is that what I would do?" So I agree with you, but then I see where these assets are trading, I question whether we are correct.

MR. CODY: We continue to see people migrate from being limited partners to co-investors to direct investors. Do they get it right versus the public guys? It is a tough question to answer because you are comparing apples and oranges. You have a lot of legacy assets at the public companies. There are some that are worth close to zero, and there are some that are in line with private valuations. Most of the private-side investors with whom we work are looking at single opportunities or defined portfolios.

MR. KATZ: Let me go back to the pricing of assets. Part of the reason people pay these valuations is because you bankers are willing to lever up their assets. So for the prices to begin to moderate, somebody has to step off the gas. Will it be you guys? How does the music stop? Or do the valuations just keep going higher?

MR. WOOD: I don't think Wall Street is propping up valuations. There may have been a time when there was reckless lending. I would say that time has passed based on the stricter supervision from the Comptroller of the Currency and the Federal Reserve and on what it takes for me to get something approved.

A lot of the buyers of this type of asset are not leveraging. People are buying renewable assets at returns that are unlevered and after tax equity, and they are buying conventional assets at levered equity returns because you do not have the complication with conventional assets of an inter-creditor or forbearance agreement.

Wall Street is not propping up valuations. We are seeing returns come down as well on utility cash acquisitions. It is not as if buyers are bidding much lower returns when buying a toll road or solar project than buying an equity interest in a regulated utility.

I think returns are coming out around a seven handle after tax equity returns, depending on your assumptions. Yes, leverage is being used, but I don't think we are in a period of aggressive overleverage. We may see some people lose money on some of the new builds, but it will be the equity losing the money, not the debt.

SunEdison

MR. KATZ: Let me shift to another big trend that has dominated the renewable energy sector this year, and that is SunEdison. If you had been hired as an investment banker to SunEdison three years ago, what would you have told the company to do?

MR. FOUTS: We all need to be careful here, but I would say it is not a problem with the quality of the assets. All those assets are good assets. I think it was just too much growth, too fast.

MR. CODY: We were hired by a couple groups to sift through some of the SunEdison assets, and I would respectfully disagree that all the assets were good assets. It is easy to be a Monday morning quarterback, but it looked like there was a pretty significant lack of discipline in evaluating projects and a real confusion between actual IRR and current yield.

MR. WOOD: I would go beyond that. I think there was a rush to assemble the earnings engine for the incentive distribution rights machine, for the general partner interest.

They built wind development capability, solar development capability, and pushed to develop behind-the-meter residential and commercial rooftop capabilities with Vivint. That was all good, but the velocity of deals coupled with pretty aggressive leverage and use of a captive yield co as the source of value creation led the equity market to close on them.

The yield co model with an 85% or 90% payout requires constant access to capital. Whatever form of yield co that emerges in the future has to have either a sugar daddy or a better liquidity facility. You cannot make a big acquisition contingent on an equity raise six months from now. Maybe it is not that you cannot do that as much as everyone was doing it at the same time and, when the music stopped, there was no capital to raise and prices fell. This is a classic case of relying on capital markets to take you out of reasonable positions. The capital markets open and shut. It is dangerous to assume they will always remain open.

This then reverberated through the development side of the business. Maybe milestones started being missed. This is a portfolio that fundamentally had value, but when you miss a milestone and you lose an interconnection agreement or lose a PPA, that value goes away pretty quickly.

MR. KATZ: There has been a lack of understanding about how many assets are in play. Who do you think the likely winners of those assets will be and at what prices do you think they will trade?

MR. REDINGER: There are probably a lot fewer assets available in the US than people think. My impression is the market thinks there will be a huge wave of SunEdison assets hitting the market in the US through the section 363 bankruptcy process. There will be some. There appear to be more assets overseas, but it is hard to get your arms around what is there.

MR. KATZ: What is your sense of who has the lowest cost of capital to bid for these assets and at what discount rates the assets will ultimately trade?

MR. FOUTS: Since the yield cos are off the table, we are seeing a ton of interest from pension funds and particularly from ones in Canada.

The cost of capital will be in the high single digits to low double digits for levered returns to equity, and there is a lot of capital at these prices. The biggest issue is these types of investors want to write big checks and some of the packages coming out of SunEdison are smaller, so it makes it tougher for such investors to put capital to work there.

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clause in the US constitution, which limits the ability of states to enact laws that impede interstate commerce. The statute seeks "to reduce emissions that occur outside Minnesota by prohibiting transactions that originate outside Minnesota. And their practical effect is to control activities taking place wholly outside Minnesota," the court said.

Last year, another US appeals court considered whether the RPS statute in Colorado violates the dormant commerce clause.

Colorado requires Colorado utilities to supply at least 20% of their electricity from renewable sources. The percentage is scheduled to increase to 30% in 2020. The Energy and Environment Law Institute argued that the Colorado RPS statute harms a coal company in another state that is a member of the law institute because coal-fired power plants in other states will lose business in Colorado, leading to less demand for coal.

The court in the Colorado case said the problem with this argument is that it would require courts to strike down all state laws that regulate health or safety by requiring manufacturers who want to do business in the state to alter their designs or labels. It said it can see how a state statute that discriminates against out-of-state rivals goes too far. An example is a state law requiring all milk sold in New York to be purchased from New York dairy farmers. However, requiring Colorado utilities to supply a certain percentage of electricity from renewable sources confers no special advantage on Colorado power producers.

The Minnesota court called the Colorado decision a "somewhat contrary position" to its decision to strike down the Minnesota statute.

The Colorado decision, it said, suggested that "non-price standards for products sold in-state" may withstand commerce clause scrutiny under a balancing test, but they do not warrant "near automatic condemnation" on account of their extraterritorial reach. It said did not have to reach the issue of balancing interests, since Minnesota did not argue that near

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We have also seen some interest from investors in emerging markets, like India, and from some Middle Eastern sovereign wealth funds. This is capital with a cost in the single digits.

MR. SIMON: We are also seeing European strategics looking to diversify into renewables. We are also starting to see some Chinese utilities look at this sector in the Americas: not necessarily in the US, but in the broader region.

MR. WOOD: SunEdison's big assets are TERP and TERP Global. SunEdison has control positions in them. The question for the creditors and bankruptcy court is whether to liquidate those positions and sell a control position in the public yield cos to a new sponsor in an effort to revitalize the yield cos, given the optimism here. Neither TERP nor TERP Global is in bankruptcy. Such a sale would be the best referendum on where the market is today with respect to yield cos and renewable portfolios.

US Politics

MR. KATZ: Let me shift to energy policy more broadly, because obviously that dictates the market to some extent. It has often been said the US has no energy policy, and maybe never will. There seem to be a lot of tailwinds now for a market that is moving to a more distributed model and a market that is moving toward clean energy. What would it take to accelerate that trend? Do you think all the pieces are in place?

MR. SIMON: I don't think the US will ever have a coherent energy policy in the same way that some of the European countries have them. The reason is that we have 50 state governments in the US that determine energy policy to a certain degree.

Unless we do away with our federal system, it is very difficult, other than through tax incentives and so on, for the US to push a coherent energy policy as we define it. So the trend will be continued use of tax policy to provide incentives. I don't see tailwinds frankly. As long as natural gas and oil prices stay relatively low, the effort to use tax policy to force a shift will continue to face headwinds.

MR. REDINGER: I agree with that. I think the distributed market got out of the gates quickly. We are seeing a little bit of a slowdown. Keith Martin mentioned that 10 states are expected this year to revisit their net metering policies. It is not that the policies are being changed to make it harder for rooftop solar to thrive — some of them are being changed to the positive — but the fact that they can be changed so quickly is a little unsettling to a long-term lender. Who knows which way the political winds will blow five years from now. They could change again.

The bank market in the distributed world has not developed as quickly as we thought it would develop, which is concerning. When you look at the alternative financing options and the take outs in the distributed market that we thought would be there, the ABS market is there, it is just not at a price that people who invested in the space thought it would be. There are a lot of short-term maturities coming up in the distributed space. It will be interesting to see where those go.

MR. KATZ: Roberto Simon, you touched on the US presidential election. As we get closer to it, does the market react in any way? Is there any trade based on the uncertainty and will there be any obvious play the day after depending on who wins?

MR. SIMON: With my personal money, when we get to late June, I plan to sell everything I have in equities, because people are going to panic no matter who gets elected. And then after the election, everyone will realize that the president is important, but does not really run the country, because we have three branches of government. I will buy my equities back. I have no idea, honestly.

MR. WOOD: Buy puts.

MR. FOUTS: One dynamic that we are watching pretty carefully is it is hard to overstate the amount of scrutiny that the banks have gotten from the regulators on things like tax equity, lending requirements and risk capital. If Trump gets elected and he starts rolling back some of the regulations on banks, does that open up the tax equity market more for us? Does it ease lending requirements? I don't know how to quantify that, but it is one dynamic that I would watch pretty carefully.

MR. SIMON: We are regulated by two entities: the European Central Bank and the Federal Reserve. In the last 12 months, life has changed dramatically. We have constant visits from both entities. My view is this will not change after the election. They have hired bazillions of new people. It is not going to change for a long time because we now have technocrats running the process. It is very difficult to unravel a bureaucracy once it is in place.

Tightening Bank Regulation

MR. KATZ: Basel IV is somewhere in the pipeline. What would that do, when do you think that's coming, and how does it affect banks in the power sector?

MR. SIMON: The Basel committees regulate the amount of capital that the bank is required to have to support its lending.

European banks, unlike US banks, are regulated by risk-weighted assets. That is how European regulators try to have us manage our risk.

The regulators have decided that having two models — a European and a US model — is too complicated, and they are trying to simplify the process. There is a possibility they will put in place a minimum capital requirement that assumes a higher loss in the event of default. What that will do is it will change the amount of risk-weighted assets that banks have to put toward a loan. It will basically cut into the return on equity for every loan that an institution makes.

There is really only one way to compensate for that, and that is to increase pricing. So if Basel IV goes into effect and those changes are made for European institutions, what we expect to happen is for tenors to be shortened considerably and for pricing to go up.

Right now, US banks occasionally will lend short term. They get in and out very quickly. The Canadians are just behind them, and then you have the Europeans and the rest of the world lending long term.

I think the Europeans will dial back close to where the Canadians and Americans are. We will be short-term lenders. Pricing will be higher. We will be looking for riskier assets to justify the higher interest rates. It will be more difficult for developers who are accustomed to long-term European bank money to find that money. It could have a dramatic effect on the project finance market.

MR. WOOD: I agree with that. If we have to use a higher-loss-given-default methodology because we are being bundled in with other industries or because the Fed is forcing us to do that, then that will be disproportionately painful to the asset-intensive finance sectors like power and other energy infrastructure.

We saw the regulatory impact and the oil and gas problem last year, with the rapid decline in prices, or let's call it price volatility to use a nicer term, and what happened was a lot of these asset-based loans had to be called, and there was no extension because the Fed said no.

There was then a wave of bankruptcies. We can talk about whether that was better or worse for the system three or four years from now when we know. But there is no question the regulatory impact is being felt.

MR. CODY: Last year, Bob Diamond from Barclays wrote a really interesting article after someone asked him about his vision of the future for commercial banks. His perspective was that the regulators are angling to have the banks */ continued page 28*

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automatic condemnation was an inappropriate standard.

The Minnesota case is *State of North Dakota v. Heydinger.*

The Energy and Environmental Law Institute asked the US Supreme Court to hear arguments in the Colorado case, *Energy and Environmental Law Institute v. Epel* et al., but the Supreme Court declined last December to do so.

INVERTED LEASES will produce less benefit for some tax equity investors.

Inverted leases are a form of transaction used to raise tax equity to finance portfolios of rooftop solar installations in the United States. The US offers two tax benefits as an inducement to invest in new solar equipment: an investment tax credit worth 30¢ per dollar of capital cost and accelerated depreciation worth 26¢ per dollar of capital cost.

In an inverted lease, the solar company that owns the equipment leases it to a tax equity investor and elects to let the tax equity investor claim the investment tax credits on the equipment while the solar company retains the depreciation. For more information about the structure, see "Solar Tax Equity Structures" at http://www.chadbourne.com/Solar_Tax_Equity_Structures_projectfinance.

If the solar company kept both tax benefits, then it would only be able to depreciate 85% of the cost of the solar equipment rather than the full cost. US tax law requires the depreciable basis be reduced by half the investment tax credit.

However, in cases where the tax credits are passed through to a lessee, rather than make the lessor reduce its depreciable basis, the lessee must instead report half the amount of the tax credits as income ratably over five years. This lessee income inclusion is required by section 50(d) of the US tax code.

Some tax equity investors have taken the position, where the lessee is a partnership, that they can deduct an amount equal to the lessee income inclusion later as a */ continued page 29*

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be utility providers of capital and that any business that is outside an approved risk spectrum will eventually be routed out of the system.

Corporate PPAs

MR. KATZ: Maybe the public markets priced some of this in. Let me pick up on the theme about pricing differently to corporates and utilities. One of our panels is about the large wave of corporate PPAs coming. Will the bank markets price these differently because you have essentially long-term debt from corporates. How do you think about that? Will there be different pricing?

MR. SIMON: With all due respect to all the project finance bankers, we are probably the worst at pricing risk.

Mr. KATZ: Worse than lawyers?

MR. SIMON: Probably. Because you guys take a step back. We look at the last deal. If you look at the LNG space, there have been projects that have been financed on the back of long-term tolling agreements with corporates. In theory, there should be no reason why you cannot finance a project with a corporate PPA. However, when people dig deeper, they realize there is a lot more volatility in the earnings of a corporate than there is in the earnings and cash flow of a regulated utility, and the odds are reasonably high that over a 20-year period, or even a 10-year period, they end up having grossly mispriced the risk.

I won't name the company, but there is a concrete example. An LNG facility was financed a year ago for a BBB company that is a toller. That company today is rated a single B. The project has a really different risk profile than the day you financed it, and the change happened in a very short period of time.

MR. CODY: I agree with Roberto. When you have a core asset that is part of an obligation to serve, which is what we have with most of our assets in the US power space, that is a different type of arrangement than a long-term obligation with a corporate.

MR. WOOD: Get used to it, guys. Utilities are not going to be signing up given the move of technology and given where price points are now. Gas is merchant and needs intermediate term hedges, depending on where it is in the merit order and where people view forward commodity prices.

There is no question that for LNG, getting leverage two years ago against 20- and 30-year offtake contracts was easier because oil prices were high and the arbitrage was in the money.

Fast forward to the fourth quarter last year, there was an LNG export terminal that was fully permitted and trying to get built. The developer managed to raise the money, but it was time to grit teeth. It is not that the fundamental analysis of the contract has changed. It was what happens if the contract goes away: the what if.

IPP shares are trading in the public markets at $400 to $500 a KW, while conventional assets are selling in private deals at $700 to $800 a KW.

The dislocation in the public markets means this was bank debt designed to be a bridge to a capital markets permanent takeout. When you have volatility in the underlying commodity market and you have volatility in the takeout market, it is going to freeze up the bank market.

MR. SIMON: Let's forget Basel IV for a moment. Developers have become accustomed to getting 14- and 15-year money from European and Japanese banks. I think if you see one or two mistakes by lenders and then all lenders will start thinking, "Well, maybe I should be 10 years with a sweep."

There will be an effect on both pricing and structure that developers will have to take into account, because it will affect their returns when it occurs.

Link to Oil Prices

MR. KATZ: Let me turn to commodity pricing because it is hard to have a discussion with bankers without you guys referring to commodity pricing. It is fairly obvious to most people how the price of natural gas affects the value of assets in the power sector. What about the price of oil? Oil goes down, the equity markets seem to go down, asset trading gets more volatile, and oil now goes up. What does oil have to do with asset pricing in our markets, if anything?

MR. SIMON: Nothing.

MR. KATZ: Does everyone agree with that?

MR. CODY: No.

MR. FOUTS: Only on the down side in that when oil goes down, all the solar stocks went down. When oil went back up, there was no rebound. It is a one-way risk and, to me, this is further evidence that the public markets are not the best at valuing or understanding some of these dynamics.

We have seen this most vividly in the solar space where people are struggling for a valuation methodology. Is it retained value? Is it cash flow? It is all over the place. As it relates to the public stocks, I just don't think people understand the dynamic or the correlation.

MR. WOOD: I don't think it is just public stocks. Private equity fund managers out to raise fund three or fund four of an energy and power fund are also feeling the headwind. Just having the word energy in the name makes it more difficult when oil prices are falling. It sounds pretty unsophisticated, but people allocate money. If they are all of a sudden feeling over-allocated to energy, power is not necessarily going to get a separate allocation. We have those discussions internally. "No, no, no, this is not really energy risk. There is no commodity price exposure. It is investing against long-term contracts. It is project finance." But it falls on deaf ears. Power is part of energy.

The reaction is not just in the public markets. There is a private market reaction as well.

MR. CODY: There is no better proof than the institutional term loan market.

MR. WOOD: Absolutely.

MR. KATZ: Let me turn to the high-yield bond market. We have seen some ability by independent power projects to access that market, but it seems like the examples of such access have been few and far between. Do you expect more activity in that space and, if not, is the problem on the issuer side or the buyer side?

MR. WOOD: I think it is the issuers. The high-yield debt market is a place where seasoned issuers with ready financials can go. A lot of the attempted offerings in the B loan market have been by players without all of those accoutrements. The high-yield market is open. It is very hot right now. We have seen a number of issuers in the power space tap it. You will see more. But you will continue to see the term loan B market used for more asset portfolio financings than single projects. Some of the accoutrements you need to issue high-yield debt / continued page 30

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capital loss by withdrawing from the partnership.

Each partner has an "outside basis" in its partnership interest. Partnerships do not pay income taxes. Rather, any income at the partnership level is reported by the partners directly. As a partner has to report a share of partnership income, its outside basis in its partnership interest increases. If a partner disposes of its partnership interest, it has a gain or loss equal to the amount it receives for the interest less its outside basis.

The IRS issued temporary regulations in late July to prevent tax equity investors from recouping taxes they paid on such inverted lease income by later claiming the lessee income inclusion as a loss. It said the income is not a "partnership item" that increases the partner's outside basis. Rather it starts with the partner directly.

The new regulations apply to solar equipment put in service on or after September 20, 2016. The IRS left open the door to challenge losses already claimed by tax equity investors by saying no inference is intended about what US tax law required until now.

The new regulations also address the consequences of terminating the inverted lease. Any termination of the lease within five years after the solar equipment is put in service will lead to recapture of the unvested investment tax credits. The investment tax credits vest ratably over five years. The termination also accelerates the remaining lessee income inclusion in theory, but in practice, the lessee does not have to report more income than half the investment tax credits it is allowed to keep. It would already have done that in a solar inverted lease.

The tax equity investor should also make sure that the solar company does not transfer the equipment during the first five years, when the investment tax credits remain exposed to recapture, to a tax-exempt or government entity.

There is no recapture of the investment tax credits if the lessee purchases the equipment from the lessor. There is also no recapture if the lessor sells the equipment / continued page 31

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are not always there on a timely basis for the B loan participants.

MR. FOUTS: Obviously things got really dicey in the fourth quarter last year and first quarter this year when people were slow to write commitments.

The difference in writing commitments today versus in 2008 is there are very few situations where banks have a big backlog. As a result, people are willing to be a little bit more out on the risk curve, and we are starting to see CLOs come back in the market, so there is liquidity. There is just not enough product out there to give these guys the yield they want. The demand is there. I think people are once again writing commitments.

Lightning Round

MR. KATZ: Since we have only a couple of minutes left, I am going to make a statement and ask you to tell me whether you agree or disagree and maybe add one or two sentences in defense.

There will be little to no market for new-build gas plants without PPAs.

MR. SIMON: Disagree. I think as long as there is demand for the electricity, you will see plants being built without PPAs in certain markets. It is just a question of which markets will accommodate new builds.

MR. REDINGER: Disagree. We will be in the market shortly with one, and we expect it to go very well.

MR. WOOD: Disagree. I think projects get financed based on market fundamentals, not PPAs.

MR. CODY: Disagree. What's a PPA? I haven't seen one in years. [Laughter]

MR. FOUTS: The same.

MR. KATZ: Unanimous. Here is another one: we will see at least one more large-scale bankruptcy in the renewable sector before the end of the year.

MR. SIMON: Disagree.

MR. REDINGER: Besides?

MR. KATZ: Besides SunEdison and Abengoa.

MR. REDINGER: Disagree.

MR. WOOD: I have no idea.

MR. CODY: I second Ray.

MR. FOUTS: Totally disagree.

MR. KATZ: Okay. A number of lenders that funded these new quasi-merchant plants are going to get hung when they cannot roll over their debt.

MR. SIMON: Agree. I do not think lenders fully understand the risk they are taking.

MR. REDINGER: We hope so.

MR. WOOD: You should talk to Andy later if you are one of those players.

MR. CODY: I disagree. I think that a lot of the metrics that have been put into place are around asset recovery. It depends on how you define "hung."

MR. FOUTS: I think it will be asset-specific. There will be banks that lose money.

MR. KATZ: Last one: most of the deals done in the bank market today should be rated BB, but the ratings are trending down.

MR. SIMON: Agree. I think most of the stuff at which we are looking is BB or BB+. BB+ is probably trending down to BB.

MR. REDINGER: Agree it is BB. Disagree that it is trending lower.

MR. WOOD: It is pretty solidly in the BB range. If it is trending lower, then it is going to a weaker BB, but I don't see it piercing that.

MR. CODY: I don't see BB.

MR. FOUTS: Maybe trending, but that is the stuff we like to look at.

Most deals done in the bank market today are rated BB.

IRS Updates Tax Treatment Of Interconnection Payments

by Keith Martin, in Washington

The Internal Revenue Service reaffirmed in June that utilities do not have to report most payments from independent generators to reimburse for the cost of grid improvements as taxable income.

The IRS action is important because the agency had been taking a narrow view of when such payments can be received tax free by utilities. As a consequence, some utilities had begun collecting "tax gross ups" that run in some cases into the millions of dollars on top of the cost reimbursements.

IRS policy since 1988 has been not to tax utilities in most cases when independent generators connect to the grid and reimburse the utility for the cost of substation improvements and network upgrades to accommodate the additional power on the grid.

The independent generator must be careful to transfer its electricity to someone else before the electricity reaches the grid so that the generator is not considered a customer of the utility or grid for transmission. Utilities must report payments from customers as income.

The IRS published a "safe harbor," or list of conditions, that must be met by utilities to avoid reporting cost reimbursements from independent generators as income in 1988, and then updated it in 1990 and 2001.

One of the conditions is that the cost reimbursement must be required by a long-term power purchase agreement or interconnection agreement with the utility receiving the payment.

The IRS dropped this requirement in Notice 2016-36 in June.

It no longer matters what agreement requires the cost reimbursement. The issue had come to a head recently because grid congestion is leading generators to enter into transmission upgrade agreements with neighboring utilities whose congested grids are forcing generators to curtail, or cut back, the electricity from their projects. Some wind farms on the PJM grid have been forced recently to curtail electricity output by as much as 97% due to congestion on parts of the neighboring MISO grid. The owners of the wind farms reimbursed the utilities on the MISO grid for the cost of improvements to relieve */ continued page 32*

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as long as the sale is not to a tax-exempt, government or other entity that cannot pass through tax credits to lessees and the new owner takes the equipment subject to the lease.

GAS-FIRED POWER PLANTS that buy gas at the field and then pay a pipeline to transport it may get a break on transportation charges, at least by pipelines that are owned by partnerships.

United, Delta, Southwest, US Airways and several refineries sued the Federal Energy Regulatory Commission challenging a decision by FERC to let SFPP, L.P., a partnership that owns gas pipelines that carry refined petroleum products in the western United States, charge rates for transportation that include an income tax allowance even though, as a partnership, the company is not subject to income taxes. Any taxes on its income would be paid by the partners directly.

A US appeals court directed FERC to take another look at the matter. The case is *United Airlines v. FERC*. The court released its decision on July 1.

The airlines argued that the pipeline is getting an unnecessary additional recovery because the rate-of-return approach that FERC uses to set rates already calculates what pipeline investors need to earn on a pre-tax basis to make the investment.

Most oil and gas pipelines are owned by partnerships. Thom Hirsch, a regulatory lawyer with Chadbourne in Washington, said FERC could start a rulemaking or policy statement proceeding and ask all industry participants for comments, or it could choose to deal with the issue on a case-by-case basis. He said he expects FERC to issue an order this fall indicating how it plans to proceed. Pipeline customers are expected to use the court's opinion to argue for lower maximum cost-of-service rates for the pipelines.

TAX EQUITY INVESTORS did not qualify for most of the tax credits they claimed on 24 landfill gas projects, the US Tax Court said.

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the congestion. The IRS notice makes clear that these cost reimbursements do not have to be reported by the MISO utilities as income.

The IRS also made it easy for utilities that reported payments as income to get the money back. The utilities will be able to reduce the taxes they owe on their current-year tax returns rather than having to file amended returns for past tax years.

Some independent generators may be entitled to refunds of tax gross ups they paid utilities in the past.

The IRS also broadened the policy of not taxing utilities on cost reimbursements to cover interconnection and network upgrade payments from standalone energy storage facilities that connect to the grid.

Background

Independent power plants must be connected to the grid in order to deliver electricity to market. It is market practice for the owner of the power plant to pay the cost not only of any radial lines and substations needed to connect to the grid, but also the cost of any upgrades to the grid itself to accommodate the extra power.

The utility insists on owning those parts of the intertie that come in contact with the grid.

The independent generator usually either constructs the intertie and conveys title to the utility or reimburses the utility for the cost.

Ordinarily, when one company pays money or transfers property to another, the recipient must report the value as taxable income.

Interties paid for by generators have historically never been reported by utilities as taxable income. However, in 1986, Congress changed the law to say that property supplied to a utility by a "customer or potential customer" must be reported.

At the urging of the independent power industry, the IRS issued a notice in 1988 to make clear that interties paid for by "qualifying facility" projects — independent power plants from which utilities are required by federal law to buy electricity — do not have to be reported by utilities as income. That was Notice 88-129. In 2001, the IRS extended the same policy, in Notice 2001-82, to cost reimbursements from other independent power projects that do not qualify as qualifying facilities. There was also a notice in between in 1990 when negotiations between independent power companies and the three investor-owned utilities in California over getting back tax gross ups that had been collected by the California utilities after 1986 became stalled.

The latest notice replaces all the earlier notices.

Five Tests

Stating June 20, 2016, utilities do not have to report payments from owners of independent power plants and energy storage facilities as income that satisfy five tests.

Utilities can apply the new rules retroactively to past payments.

First, the generator or storage facility must not be expected to buy more than a small amount of electricity from the utility over the first 10 years after the project is first connected to the grid.

No more than 5% of the total power flows in both directions over the intertie can be electricity flowing to the project from the grid. Power moving over the intertie to affiliates of the generator is taken into account. The utility must project power flows in both directions over the first 10 years. The projection must be supported by an independent engineer's report or other "appropriate documentation." However, power flows in the first utility tax year that the intertie is in service can be ignored.

Second, if electricity from the project will be wheeled over the grid to a distant customer, then someone other than the generator must take ownership of the electricity before it reaches the grid. Thus, either the customer for the electricity should take delivery of the electricity or else title should be transferred to a

Some independent generators may be entitled to refunds of tax gross ups they paid utilities in the last few years.

power marketing affiliate on the project side of the grid.

Make sure that any affiliate taking title to the electricity is a different entity for tax purposes. For example, if the affiliate and the project company that owns the power plant are both single-member limited liability companies with a common parent, then they may be considered the same entity for tax purposes.

The key is that the generator should not be a customer of the utility receiving the interconnection payment. It is a customer if it has to pay for transmission.

Third, the utility must not put the intertie or other improvements paid for by the generator into rate base.

Fourth, the intertie must be used for "transmitting electricity." Some distributed solar facilities connect to distribution lines rather than transmission lines. The IRS said it intends the policy of not taxing utilities on cost reimbursements will apply equally to them. The suggestion the intertie must be used for transmission left the new notice less clear on this point than was intended.

Finally, the generator must recover the cost reimbursements for tax purposes on a straight-line basis over 20 years.

Income

It is possible that the utility might have to report income in the future, although the likelihood is small.

The IRS identified two situations.

The IRS wanted a check in the event the intertie is in fact used "for the purpose of selling power to the generator" despite the earlier expectation that the amount of power flowing back to the generator over the intertie would be minimal.

If electricity sold to the generator is more than 5% of total power flows in both directions over the intertie in any three of five consecutive years, then the utility must report a fraction of the fair market value of the intertie at the end of the three years as income. This need to monitor power flows is not limited to the first 10 years. The fraction is supposed to represent the percentage of actual and anticipated future use of the intertie to sell power to the generator, not just during the three years when power flowing back to the generator triggered a tax. The fair market value for this purpose is the depreciated replacement cost, meaning the utility calculates what a new intertie would cost and then reduces the value for the fact the intertie has been in use for a number of years.

The other situation where the utility might have to report income is where the generator has a power contract to sell electricity to the utility and the utility keeps the / continued page 34

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Two trusts formed to own the projects had very poor records.

The US government allowed 10 years of production tax credits to be claimed under section 29 — and later section 45K — of the US tax code for producing "gas from biomass." Landfill gas qualified. The gas had to be sold to a third party. The facility for collecting the gas had to be in service by December 1997 or by June 30, 1998 if installed under a binding contract in place by the end of 1997.

Resource Technology Corp. developed the projects. It went bankrupt in 1999 and transferred the gas rights to affiliates who provided debtor-in-possession financing. The Tax Court did not try to sort out who owned the gas rights during 2005, 2006 and 2007, the tax years at issue in an IRS audit of the tax credits.

The landfills were divided into "venting/flaring" landfills that either vented the landfill gas into the atmosphere or flared it after collection, and non-venting landfills.

A Chicago law firm found the tax equity investors and deducted its fees from the amounts paid by the investors "for tax credits." Resource Technology Corp. acted as the trustee of the trusts in which the investors invested.

There were serious questions about whether the gas collection facilities were in service in time to qualify for tax credits. The trusts argued that all it had to do by the deadline was put in one or more vertical wells but not the entire collection system. The Tax Court rejected this. An integrated facility is not in service until all parts of it are working. The IRS said it was not enough for a collection system to be connected to a flare; the system had to be connected to a diesel generator, gas cleaning facility or equipment capable of storing gas until it can be delivered to a customer to be considered ready for its intended use.

The government ended up stipulating that six of the collection facilities were in service in time.

The investors argued that they should be allowed to claim tax / continued page 35

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intertie after the power contract terminates.

In that case, the utility must report the fair market value of the intertie, less any amount it pays the generator for it.

However, the IRS said it will not require the generator to report income after a power contract terminates unless circumstances "indicate an intention by the parties to characterize the contribution of the intertie as a transaction that in substance constitutes a [contribution in aid of construction]" to the utility and, even then, if the utility pays anything to the generator for the intertie "under a procedure or method established or used by the relevant utility commission," then that payment will ordinarily be presumed to be the full value so that there is no income for the utility to report.

An example in the notice makes clear that if the utility does not need the intertie, then the value should ordinarily be nil.

Other

The IRS will no longer issue private letter rulings about whether payments are covered by the new notice. Congress has forced a 19% reduction in manpower on the IRS in the last six years. The IRS issued the notice in the hope that this would cut down on the time it has to spend answering questions in this area.

Some payments by generators to cover the cost of network upgrades to the grid are treated as loans to utilities and are not income to the utilities for that reason. A borrower does not report borrowed money as income. This is true in cases where the utility is required by the interconnection agreement with the independent generator to return the network upgrade payments to the generator within 20 years with interest.

The interconnection agreement must require that the refunds be made in cash.

It must require that the interest be calculated at the Federal Energy Regulatory Commission rate in Order No. 2003-B. The order refers to FERC regulations that explain interest should be paid at the average prime rate for each quarter, calculated to the nearest one hundredth of one percent, as reported in the *Federal Reserve Bulletin* or the "Selected Interest Rates" (Statistical Release G 13) published by the Federal Reserve Board. The 20-year period within which the utility must be required to reimburse the generator for the full amount of the network upgrade payments runs from the commercial operation date of the generator's power plant. The model interconnection agreement that FERC adopted in March 2004 has a form of letter that independent generators are supposed to send utilities announcing when their power plants have been put into commercial operation.

The IRS guidelines for interconnection payments treated as loans are in Revenue Procedure 2005-35.

Merchant Gas Projects: How Many More?

Merchant gas-fired power projects in ERCOT, PJM and ISO-New England helped carry the North American project finance market in 2015. Many banks are feeling flush with merchant gas risk in PJM. Panda Energy Partners is suing ERCOT over losses on three merchant gas projects in Texas in which the company invested $2.2 billion. How much more appetite is there for such projects? Two developers, two bankers and one equity investor discussed these and related questions at the Chadbourne annual global energy and finance conference in early June. The following is an edited transcript.

The panelists are Ravina Advani, managing director at BNP Paribas, Jay Frisbie, managing director at Tenaska Capital Management, Herb Magid, managing partner and co-head of Ares EIF, Michael Pantelogianis, co-head of power & infrastructure finance for North America at Investec USA Holdings Corp., and Scott Taylor, chief financial officer of Moxie Energy. The moderator is Rohit Chaudhry with Chadbourne in Washington.

MR. CHAUDHRY: The PJM capacity auction results came out on May 24, and they left a number of people very unhappy. Ravina Advani, what were the results and why were people unhappy with them?

MS. ADVANI: The results were abysmal. Looking at the RTO alone, capacity payments went from $164.77 to $100. That was a huge shock to pretty much everybody in the industry. There were a lot of consultants who were predicting 20% to 40% higher in their expectations of where the RTO would clear. So, absolutely abysmal, particularly when from a debt-sizing perspective, those capacity payments represent anywhere from 35% to 50% of the underlying gross margin. It was very unfortunate.

MR. CHAUDHRY: Considering those results, I want to get a sense from each of the panelists whether you think there will be any new plants built in PJM. However, before I do that, I want to get some basic facts and statistics out on the PJM market and how it looks after this auction. Scott Taylor, how many megawatts of capacity cleared in this PJM auction, and how did it compare to prior years?

MR. TAYLOR: This year, 167,000 megawatts cleared, which is maybe 500 megawatts more than cleared last year. What helped to drive down the price is PJM reduced its peak demand forecast by something like 4,500 megawatts just prior to the auction in February when PJM releases its parameters and, on top of that, 185,000 megawatts were offered versus 180,000 last year.

MR. CHAUDHRY: So there was an increase in supply. I think there have been around 5,000 megawatts of new builds.

MR. TAYLOR: Yes. More than 5,000 megawatts of new gas plants bid.

MR. CHAUDHRY: Coupled with a decrease in demand on the PJM market. So in light of these two factors, I want to go around the panel and ask whether you fear an overbuild scenario in PJM.

Overbuilt Market?

MR. TAYLOR: It is hard say. The $100-per-megawatt day was terrible. I am not aware of any consultant who forecast that.

There are a couple of offsetting factors that suggest we are not yet in an overbuild situation. I know that was a topic when we were trying to market the Freedom project, and I am sure it will remain a topic for anyone taking a project to the bank market today.

One of the tricky things to decipher is PJM has two types of products. One is for capacity performance and involves more risk and a higher price, and one is a base product. This year, 26,000 megawatts of capacity cleared as a base product that will not be able to clear as base in the next auction, so it will have to convert to capacity performance.

A driver of the build out of gas plants has been the coal retirement projections. Coal retirements will increase in number. Nuclear plants are also being retired, which I do not think was expected several years ago. PJM has been a coal and nuclear market. The two retirements together mean a lot of capacity will fall out of the market and will need to be replaced by something. That something is obviously gas. Put everything together and it is hard to say the market has been overbuilt.

MR. CHAUDHRY: So let me pin you down a little more, Scott. I agree that it is hard to say. Moxie has done three projects, but your company has been quiet for the last few months, maybe even for the last year. Are you looking to come back into the market?

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credits on gas that was vented or flared. They argued that the purpose of the tax credit changed over time from production and sale of landfill gas to merely avoiding unsafe build ups of landfill gas underground. The Tax Court said there was no evidence of this.

The IRS argued that it was not enough to produce and sell raw gas, but the gas also had to be cleaned up for use as fuel. The court rejected this view. It said the credit amount was self-adjusting since it was tied to the energy content in mmBtus of gas sold.

In the end, the Tax Court denied tax credits on gas from the facilities that were not in service in time or whose gas was flared or vented. It allowed credits on gas that was used to generate electricity that was sold to utilities, and allowed one of the trusts to back into the amount of gas produced from logs showing the amount of electricity sold "increased by the amount of parasitic load" by the generators.

The case is *Green Gas Statutory Trust, et al. v. Commissioner*. The Tax Court decision was released in mid-July.

A PURCHASE MONEY NOTE given to buy an interest in a partnership that owned geothermal projects was not a real debt, the US Tax Court said in late July.

Lausanne Energy, Inc. bought a Dutch corporation in 1984 that was an original investor in a partnership that owned geothermal projects in California that were developed by Caithness and that had long-term contracts to sell electricity to Southern California Edison. Lausanne invested another $1.08 million in the partnership in 1986.

By 1991, Lausanne was running up liability for US branch profits taxes on its income from the Caithness partnership that it wanted to avoid. The US collects two taxes on foreign corporations that own interests in US partnerships. First, the foreign corporation is considered engaged in the United States in the same business as the partnership and must pay US income taxes on its income

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MR. TAYLOR: I have been catching up on my sleep, trying to kick back and relax. There are only five people in our company. It has been a pretty hectic few years. Having said that, we are trying to catch our breath and see how our three deals perform and then figure out what makes sense to do next. There are other solid gas plants in front of us, so I don't think it would be a smart move just to try to catch up with those deals that are getting ready to come to the market for financing.

MR. CHAUDHRY: Let me ask the others. Herb Magid, are we in an overbuild situation?

MR. MAGID: I do not think we are in an overbuild, but you went from it being an easy analysis to some need for new development to replace coal and nuclear plants being shut down. Some projects that might not have inherent benefits, like gas location or maybe a favorable underlying contract, are probably being pushed off. The ones that will be done are the better projects.

More merchant gas-fired power plants will be financed this year in PJM and New England, despite some deal fatigue.

PJM is a market where you have to channel your inner Bernie Sanders. It is kind of a rigged system for the utilities and the incumbents. New entrants have a hard time. I would imagine the capacity payments will move up and down over time, so good projects will continue to be done. It is unlikely to get into an overbuild and as banks get taken out by refinancing in the public debt markets, they will look for other good projects. I think it is a sustainable market.

MR. CHAUDHRY: Jay Frisbie?

MR. FRISBIE: A couple thoughts. First, auction results are notoriously hard to predict. The auction is a black box. When we try to do an analysis around where prices might land, we have a pretty wide range. We had the bottom of our range where it actually came out. It was certainly possible to do.

Second, it is important to keep in perspective that this was one auction and one auction result. These are long-lived assets. They are going to continue to go through these auction processes, and the results move up and down. You have to be able to stomach that as an investor. It also means that you have to have a keen focus on your operational capabilities because there are going to be leaner years when the capacity prices are not as strong and you will be relying more heavily on your merchant generation for revenue.

As for whether there is an overbuild, it depends. There has been a lot of new build out in Pennsylvania and Ohio where the prices were strong for a long period of time. In the last two auctions, Commonwealth Edison has broken out quite significantly suggesting there may be an opportunity for some new build there.

PJM is a pretty broad ISO. You have to analyze where we are in an overbuild situation by looking at specific locations within the PJM grid.

MR. CHAUDHRY: You mentioned ComEd and Ravina mentioned the RTO price at $100 a megawatt, but ComEd was significantly higher than that. What was the ComEd price?

MR. FRISBIE: It was over $200, but I don't remember the exact price.

MR. CHAUDHRY: It was $203.

MR. FRISBIE: It was even higher than that at the previous auction. If you have generation in that region, you were not disappointed with the results.

MR. CHAUDHRY: Tenaska recently closed on the financing for the Westmoreland project in PJM. Are you pursuing new opportunities in PJM or, like Scott, are you just recuperating?

MR. FRISBIE: We are always looking at opportunities, and not just within PJM. It has been in the press that we have some projects in ERCOT. We are looking at ISO-New England, but it is an asset-specific case-by-case situation.

The Westmoreland project was the first time we have built a project like this. It was quasi-merchant. Historically, Tenaska has always been about long-term contracted generation, whether it was gas-fired 10 or 15 years ago, or some of the utility-scale solar that we have purchased or built in the last five years. It is a step outside our comfort zone, but with the long track record and long history, it is a calculated risk and it seems the right thing to do. We will continue to look for opportunities like that. ERCOT is challenging, and PJM is going to be challenging.

Bank Reaction

MR. CHAUDHRY: Mike Pantelogianis, how does the bank view the results of the capacity price auction? How did you react to it?

MR. PANTELOGIANIS: A higher capacity environment is always viewed more positively. We expected a downturn. We looked at the results from last year. There were a lot of omissions in terms of new build. When we compared what got bid versus where the financing calendar was, we did not expect as healthy pricing for the general region as last year.

I agree with Jay Frisbie. The analysis has to be more focused on specific locations.

When you look at PJM, it is hard to generalize on an overbuild. We looked very closely at expected retirements. We are trying to get comfortable that capacity additions are definitely at or below the level of retirements. We have made seven or eight investments in PJM projects in the last three years. We try to do that analysis and make sure that supply and demand and retirements and additions reflect a healthy balance.

MR. CHAUDHRY: Ravina Advani, you started with the comment that the prices are abysmal. This panel seems to have a very balanced, relaxed view about what will happen as a result of that. What is your take?

MS. ADVANI: On an overbuild situation, I think it does really depend. As a lender, we have really aggressive budgets to meet. I am hopeful that we are not in an overbuild. We see a handful of transactions still coming to the market, despite the recent auction results. In addition to some that my fellow panelists are pursuing, there is the Quantum transaction, an Invenergy transaction and a CPV transaction, so there seems to be a pretty robust pipeline for the rest of the year. I am hopeful.

Spark Spreads

MR. CHAUDHRY: Scott Taylor, the other part of the story besides capacity payments is spark spreads. How have they reacted to the movements in capacity prices.

MR. TAYLOR: Spark spreads are still strong. It is that fact as well as the expected retirement of coal and nuclear plants that is driving the continued development of new plants.

I agree with the comment that the capacity auction price is a one-year event. Last year, it was $164. That is a big drop in one year, but these are 30-year assets, and you are not developing these projects based on a one-year result. */ continued page 38*

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from the partnership. Second, the US, like other countries, collects a second tax at the border when the earnings are repatriated. In this case, the second tax is called a branch profits tax. It is collected in theory when the foreign owner brings its earnings home, but can be levied in practice without waiting for the earnings to be repatriated.

KPMG suggested a way that Lausanne might avoid the second-level tax and that would make better use of US operating losses that Lausanne was unable to use. It suggested selling the partnership interest to a US company, Heimdal Investment Company, Inc., that was affiliated with the original owner of the partnership interest for a note with a term not to exceed seven years with 12% interest and additional "interest" that was essentially a share of excess cash flow distributed by the partnership above the amount needed to pay debt service on the note. The US collects withholding taxes at the border on interest payments, but KPMG suggested the withholding tax would not have to be paid if the interest qualified as "portfolio interest." It also suggested a way to avoid a separate tax that the US insists US buyers withhold when buying a direct or indirect interest in any US real property from a foreign seller. Geothermal projects are considered partly real property.

The parties eventually followed through on the plan, but did not implement it exactly as KPMG suggested. Heimdal paid $5 million for the partnership interest by giving a note with a maturity date in 10 years and 12% stated interest. The note required cash distributed by the partnership be used to pay or prepay interest already accrued or expected to accrue during the year. All cash above that was to be split 50-50 between Heimdal and Lausanne. If Heimdal had to contribute any capital to the partnership, then the parties would "consider in good faith" whether the 50-50 sharing of excess cash flow "should be modified to reflect the */ continued page 39*

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A bigger driver is spark spreads. Spark spreads this year are down compared to last year for a bunch of reasons not worth getting into, but the spark spread forecast is still solid and, as long as it remains solid, you will see continued development in PJM.

MR. CHAUDHRY: I want to ask both lenders what impact all of this is having on your existing financings. What did you project for instance in capacity prices in your base case models in the deals that have closed? What is the impact on financings that are still ahead this year?

MS. ADVANI: It really depends asset to asset. We have probably a dozen assets that are located in PJM. It really depends on the capacity forecast that we used in sizing the original debt. In a lot of cases, we assumed an overbuild situation and, in others, we assumed a base case forecast. By and large, most of the projections, particularly for the 2019 to 2020 delivery period, were in excess of where we currently cleared. We have one asset where we assumed $180 a megawatt in the 2019 to 2020 delivery years, so that is one project where there could be a default on interest or principal.

On the flip side, these transactions have been structured pretty well with a dynamic target debt balance to deal with this very instance, so the result may be we end up with a higher dollar-per-KW metric at maturity. It was expected in most of these deals to be in the $350 to $375 range. It may end up higher in most of the deals if the capacity prices do not turn around.

MR. CHAUDHRY: On the first panel this morning, the bold statement was made that some banks will end up taking losses. Do you agree?

MR. PANTELOGIANIS: Wow. I certainly have a lot of respect for my colleagues on that panel and their views.

MR. CHAUDHRY: You don't need to. [Laughter]

MR. PANTELOGIANIS: But — the but was coming — I have the benefit of having lived through the first round of merchant expansion, which was just before the merchant meltdown and the Enron bankruptcy. We did deals differently then. The hedging markets were not as developed as they are today. Our financings today include a lot of stability in terms of spark spreads and put and call options that are entered into by our clients to hedge price risk. The transactions that are done today are much better in terms of credit quality from those that were done 10 and 15 years ago.

We look at it bottoms up. We do not want to rely too heavily on capacity payments. We look at our portfolio. We start with the spark spreads and try to understand what the heat-rate call option or the put provides for in the context of a stable spark spread.

What we have noticed in the last three years is that the hedge counterparties are charging more for certainty and delivering lower spark spreads.

Projects that have a high cost of capital and that might have gotten done in a stronger market have a bigger nut to crack as capacity payments fall. Our clients have a lot of equity in these deals. They are not making these investments without getting comfortable with the downside. Like Ravina said, we are in a volatile merchant market. Our clients are prepared for that. We are a lot more sophisticated in our understanding of merchant risks today than we were 10 or 15 years ago.

Capacity Prices

MR. CHAUDHRY: Do you expect capacity prices to rebound, stay the same or continue moving down, and why?

MR. PANTELOGIANIS: They will be different.

MR. CHAUDHRY: I need something more than that. Scott Taylor, you go first.

MR. TAYLOR: I have been wrong every year, so . . . . [Laughter]. If I was going to guess an over-under for next year, I would put them at $140.

MR. CHAUDHRY: What is the driver for that? Coal and nuclear plant retirements? Something else?

MR. TAYLOR: One of the unknowns is that you have 26,000 megawatts of base capacity that can't be "base capacity"; it has to take on the capacity payment risk. It has to convert, so the question is how much of that will actually take on that risk or just go away. You also have the retirement story, and then there is the question how many of these new projects will actually get financed.

To go off on a tangent for a second and talk about the lenders, I do not think there is any big risk under which the lenders will risk taking a haircut, at least on the deals that I have seen. The lenders have done a very good job of structuring to cover themselves on the downside.

MR. CHAUDHRY: It looks like you are trying to finance a new project, Scott. [Laughter]

MR. TAYLOR: No, I am not. [Laughter]

MR. CHAUDHRY: Let's hear from Herb Magid and Jay Frisbie on where they think the capacity price will be after next year's auction and why?

MR. MAGID: Scott is probably in the right range. There are four or five things that move around. We shop consultants because you try to see what all the experts are saying. The consultants fall into two camps. One camp says the capacity price increase over time, and the other camp believes it will remain flat at $100 and it is the spark spread and the total cost of energy that matters. Both groups are persuasive. A big wild card is whether the states or cities where the nuclear plants are located will make a special effort to keep them open.

Investor returns on merchant gas projects are in the low teens to low 20s.

I second Scott's opinion that there is no way the banks will lose money given how the deals have been structured. It is just the equity at this point that is exposed to losses.

MR. FRISBIE: There is logic as to why we should expect to see the prices increase in the next auction, but I go back to my comment about the process being a black box.

As Herb said, there are many other factors that affect the auction price. The bidding behaviors by each individual bidder can be so diverse and have a profound impact on what happens with the auction results. They may change from auction to auction. We have pretty detailed and long discussions when each auction approaches as to what price we will bid.

The fact that the auction is moving to 100% capacity performance will put a lot of pressure on bidders, particularly demand response, and that should take supply out of the market. But who knows? These bidders could come up with creative ways to get comfortable and feel good about bidding into such a capacity performance market. It is always hard to predict.

The Adults

MR. CHAUDHRY: Let's look at this from a different angle. There are three key stakeholders in all the projects. There is the equity. There are lenders. There are the commodity hedge providers. All have exposure to these projects. Among / continued page 40

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economic effect of such capital contribution."

After the 10-year maturity date, the note was extended another three times for a total of seven more years. During one of these extensions, the stated interest was reduced to 6%, but Heimdal continued to pay 12% as if the rate remained unchanged. Sixteen years after the note was originally issued, Heimdal "prepaid" the $5 million principal amount.

The US Tax Court said that the note was not a real debt and disallowed Heimdal's interest deductions and losses claimed by it as a partner.

It based this on the following conclusions.

There was no real sale of a partnership interest, it said. Everything was done by memos exchanged by tax advisers focused on producing the best tax result. No real negotiation of a sale took place.

Repayment of the debt was contingent on the success of the underlying business. The reason the note had to be extended another seven years is Heimdal did not have enough cash from the partnership to repay the note on time.

Heimdal was a special-purpose entity set up to own the interest. The note barred it from doing anything else. Lausanne retained substantial control over the partnership interest.

The parties behaved like they did not believe the note was a real debt. Heimdal violated the terms by failing to pay interest in 2003 and 2004. No default was called. The interest rate was reduced to 6% in 2006, but Heimdal continued to pay 12% interest.

The case is *American Metallurgical Coal Co. v. Commissioner* and *Heimdal Investment Company, Inc. v. Commissioner*. The court released its decision on July 25.

OREGON cannot tax part of the income earned from sales of electricity and gas that pass through the state on the way to customers in California. / continued page 41

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these three, who is truly going to regulate the market to make sure there is no overbuild? Just one word answers. Of the three, who do you think would be the true constraint that controls this market? Banks? Equity? Hedge providers?

MR. PANTELOGIANIS: I think it is probably a combination of banks and hedge providers. Developers are always going to develop, but if the capital is not there to get the projects done, or the hedges are not there, then it will be difficult to move forward.

MR. MAGID: I would say it's hedge, then equity, then debt.

MR. FRISBIE: None of them.

MR. CHAUDHRY: None of them? So it is going to be a chaotic situation?

MR. FRISBIE: Everyone thinks his project is the best and has a rationale. If you are looking for a safety net, it is not there.

MR. CHAUDHRY: Ravina?

MS. ADVANI: I'm going to go to the other end of the spectrum and say, "All of the above."

MR. TAYLOR: I would have expected hedge providers because they have to take a true view on spark spreads. Hopefully it is actually the developers, but Jay is probably right. Hedge providers, but it should be the developers.

Equity Returns

MR. CHAUDHRY: Let's focus on the equity part of this equation. What return to equity can investors expect in these PJM projects?

MR. TAYLOR: I think it depends on the type of investor. You have some investors who are relying on after-tax consequences. Bonus depreciation plays into it. You have some investors that are pension funds who have no ability to use tax benefits.

Generalizing, it is fair to say that people are looking for returns from the low to high teens when developing a project. You build hoping for a return at the upper end of the range, but are prepared to accept something at the lower end. You manage your downside risks as best you can.

MR. CHAUDHRY: What is interesting to me is that these returns are dramatically higher than what people have said the leveraged returns are on renewable energy deals. The returns mentioned there are in the high single digits. When you compare the two, merchant gas still sounds like a good bet.

MR. FRISBIE: That's true. It reflects the fact that these assets lack the long-term contracts that renewables have, and they do not have the aura of social good, so there are many investors who want to invest in contracted renewables and those investors see themselves holding those contracted renewables for a long time so, even if it earns a single digit return, the multiples could be three or four times over a long period of time. It is harder to have a long-term hold in the merchant gas market. Returns are in the low teens to low 20s.

MR. CHAUDHRY: Scott Taylor, are valuations for these projects on the way down or holding tight, notwithstanding the capacity auction results?

MR. TAYLOR: There is one project that is in the process of being sold. From what I understand, it is getting attractive bids. That reflects the strong spark spreads in PJM and the fact that newer assets have a competitive advantage when they are located in the right area. Maybe some more projects will be sold this year so that we can give you a better answer next year.

Bank Metrics

MR. CHAUDHRY: Let's move to the bank side of things. When this market started, it basically started with term loan B lenders providing the debt. Then at some stage, banks became flush with cash and started lending to these projects and the term loan B market was not doing so well. The last few deals were done when the bank market has been somewhat constrained. Projects have just about made it over the finish line, lining up the entire book. How constrained is the bank market now for PJM debt? Do you think a bank market can fill the entire debt piece?

MR. PANTELOGIANIS: I still think good deals get done. We just came off closing a transaction from Macquarie called Lordstown and that question was asked.

MR. CHAUDHRY: There was no issue with Lordstown. We were sponsor's counsel in Lordstown. [Laughter]

MR. PANTELOGIANIS: Exactly. And we were able to oversubscribe the transaction and get to a good sell-down position. I anticipate the financing calendar will offer us a lot of opportunities to pick and choose what we want to play in.

Is there a little deal fatigue? I think so. I think it's probably related to some of the institutions that approach the sector in a careful way. A lot of these institutions remember Enron and I think that still sits in the back of people's minds, and so they are just trying to be portfolio managers and actively look at their exposures and say, "Is this enough? What could throw it off?" The question is out there. There is noise in the market, but it has chadbourne

not kept deals from getting done.

MR. CHAUDHRY: Jay Frisbie, you guys were also able to get there this year on another deal.

MR. FRISBIE: Yes, we were able to do Westmoreland, and it was well received in the market. But we did hear noise that there are some lenders who are up to their exposure limits in PJM. It was not surprising. That is where all the activity has been. It is a risk thing for them.

MR. CHAUDHRY: Ravina Advani, how many active banks are lending to the PJM market? How does that change after the capacity auction? I know some French banks have retreated somewhat.

MS. ADVANI: There is still a healthy number of banks that are active in PJM and just generally active in the quasi-merchant space. The number is between 10 and 15.

We are seeing banks be more selective in terms of the opportunities they pursue from a sponsor perspective, from a remuneration perspective and based on the underlying credit profile of the asset.

There have been a couple refinancings of projects. The Newark transaction is one, and that obviously helped banks recycle some of their capital. LS Power refinanced its Seneca pumped storage project in Pennsylvania. This has freed up some bank exposures.

The capacity in the bank market depends on the underlying size of the transaction. Once you start pushing $700 or $800 million, assuming the capital costs are higher than that, you really need to consider back-filling the balance and alternate markets. The term loan B market is much more robust. We have seen a number of re-pricings come to market. We have seen a number of dividend recaps come to market. The term loan B market remains a viable outlet for some of these financing.

MR. CHAUDHRY: So you expect there to be more hybrid deals, with a bank loan tranche and an institutional debt tranche with someone like Prudential providing the institutional debt tranche?

MS. ADVANI: Yes. I think we will start to see more Opco-Holdco structures and a lot more hybrid transactions.

MR. CHAUDHRY: What kind of complexity does that add to the deal?

MS. ADVANI: There are obvious inter-creditor issues in such structures, but nothing that is insurmountable.

MR. CHAUDHRY: How do you see some of the metrics for how the debt is structured and the bank market changing in light of lower auction prices and concern about spark spreads? Where do you see leverage going? / *continued page 42*

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Companies are taxed in Oregon only on income that is earned in Oregon. Revenue from sales of "tangible personal property" is treated as earned in the place of delivery. Thus, if the customer is in Oregon, the sales income is earned in Oregon. Other sales are sourced to where most of the income-producing activity occurs.

BC Hydro, through a trading subsidiary called Powerex, sells electricity generated in Canada to wholesale customers in the United States. Some of the electricity is delivered to a delivery point on the Oregon utility grid, but most of that electricity is then wheeled over the grid to customers outside Oregon.

The state Supreme Court held in the case in March 2015 that electricity is *not* tangible personal property. Therefore, whether sales income can be taxed depends on where the electricity is considered delivered. It sent the case back to the Oregon Tax Court, where it had originated, to consider where the electricity is delivered. The Tax Court said that even though the electricity changed hands between two transmission systems in Oregon on the way to California, that is not delivery in Oregon but merely transfer of the electricity from one common carrier or shipper to another to continue the journey.

The case is *Powerex Corporation v. Department of Revenue*. The Oregon Tax Court released its decision on August 1.

Powerex also delivers natural gas to a hub in Oregon. The ultimate users of this gas are outside Oregon. The company conceded that gas is tangible personal property, but argued that the state should adopt an ultimate destination rule by treating the sale as occurring where the gas is ultimately used. Both the Tax Court and the state Supreme Court agreed.

OKLAHOMA cannot collect property taxes on natural gas temporarily stored in the state by interstate pipelines while awaiting shipment to customers in other / *continued page 43*

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MS. ADVANI: I see leverage potentially coming down on these transactions. When lenders look at these transactions, they are looking at a capacity forecast. Most of these deals have been levered between 50% and 60%. If anything changes, it will be leverage.

In terms of pricing and structure, I don't see much movement, at least in the near term. And in terms of remuneration, it depends on the sponsor and the transaction. We have seen arranging fees range from $360,000 to $1 million. Up-front fees have remained pretty stable north of 2%.

MR. CHAUDHRY: Mike Pantelogianis, anything to add to that?

MR. PANTELOGIANIS: I agree. People are going to be creative for larger deals in the current market.

I think there could be an incremental uptick to the required equity because the hedges are costing a lot more money either up front or on heat-rate call option premiums. In order to provide for that incremental cost, there could be a slight uptick. Having said that, equity is typically between 40% and 50% of the capital structure, but I still think that equity probably goes as high as 50%, but not more than that.

Hedges

MR. CHAUDHRY: We do not have a hedge provider on the panel, so maybe I will ask some of the developers. How constrained is the hedge market? How many hedge providers are there? How easy is it to get a hedge? And are banks getting overexposed to certain hedge providers?

MR. FRISBIE: When we went through Westmoreland, we had a fairly competitive process. I would not say there was a large number, but certainly enough to make the process competitive. It is potentially a big constraint. The number of hedge providers ebbs and flows. There will not be as much capacity in PJM as the developers would like. Other markets could also eventually prove difficult.

MR. TAYLOR: Don't take any contingency fee deals based on closing. The reason I say that is good sponsors will get their deals done, but one of the tough parts about this business is the lenders create structures that work for them and they might involve a certain hedge price and that also drives into the equity structure. One of the challenges is that you do not know what the final deal is with the hedge until you get to the day of closing.

For some reason, the numbers you get from hedge providers never increase on the day of closing. I don't know why that is, but it just seems to work that way. If you have a tight deal where you are counting on X, you had better have a lot of confidence in your hedge provider that it will be able to deliver X.

The hedge market still seems to be strong. Prices may have increased, but there may come a day where the hedge number that makes everyone happy cannot be delivered at closing and there will not be enough room between the equity and debt to make up the difference.

MR. CHAUDHRY: Last question, as we are running out of time. Other than PJM, where do the other opportunities lie?

MR. FRISBIE: In places like ISO-New England and New York Zone J. That is a little different type of market, but those essentially cleared markets are the most attractive to us at this point in time.

MR. CHAUDHRY: Herb Magid, your take?

MR. MAGID: I agree with that, but I think there is an interesting opportunity for at least equity investors on smaller deals and it was mentioned on the prior panel. A lot of corporate customers and manufacturers are returning to the US. We are seeing large steam users who are looking to invest in their facilities. They might have old oil-fired or coal boilers. There may be an opportunity to sign long-term contracts with such offtakers.

These are smaller deals, not billion dollar projects, but I think you will start to see some of those in the market, more of the old inside-the-fence kind of projects.

Uncertainty and Surplus Allowances Dog California Cap-and-Trade Program

by Brandon Charles, Laura Norin, and William Monsen, with MRW & Associates, LLC in Oakland, California

Prices for greenhouse gas emission allowances under the California cap-and-trade program are likely to remain low for the foreseeable future.

Legal and regulatory uncertainties cast a shadow over the future of the program. There are also too many allowances on the market in relation to demand.

Of the allowances that the state tried to auction in May, just

11% of the 2016 vintage allowances and fewer than 1% of the 2019 vintage allowances found buyers. In contrast, in the auctions before 2016, all available allowances for the current-year vintage were sold, and 70% of available allowances with future-year vintages were sold. The latest auction settled precisely at the auction floor price — called the "reserve price" — and auction proceeds totaled about $10 million, a decrease of hundreds of millions of dollars from prior auctions.

The steep drop in auction trading volume in May should not be taken as an extreme loss of confidence in the cap-and-trade program. Rather, some of the lost trading volume has shifted from the state auction to the secondary market, where allowances are trading at prices below the reserve price. Other volume can be made up without penalty in subsequent auctions or market purchases before the end of the 2015-2017 compliance period.

The drop in allowances prices is a more meaningful indicator of market conditions. Even if legal uncertainties are cleared up and the future direction of the program is clarified, auction and secondary market prices are likely to remain near the auction reserve price until allowance surpluses are permanently removed from the market, which will probably not be before January 2018 at the earliest.

How the Program Works

The California Air Resources Board (CARB) officially launched the cap-and-trade program in 2012, with mandatory compliance obligations beginning in 2013. The program establishes an annual cap on California greenhouse gas emissions so as to reduce emissions to 1990 levels by 2020, and below this amount in subsequent years. Entities covered by the program include electric utilities with retail loads, large industrial energy users, and, as of 2015, natural gas suppliers. Covered entities must submit an allowance to CARB for each equivalent metric ton of CO_2 that they emit. The number of allowances available each year is equal to the number of metric tons of emissions that is allowed under that year's cap.

Certain covered entities receive free allowances from the state to cover a share of their emissions. For the electric utility sector, the amount of these free allowances was set to exceed the number of allowances the utilities are expected to need, in recognition that utility customers have been paying for greenhouse gas emission reductions, such as through the procurement of renewable resources and energy efficiency, since before the start of the cap-and-trade program. / continued page 44

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states, a state appeals court said in late June.

Missouri Gas Energy is a local gas distribution company in Missouri. It buys gas out of state and has it transported by interstate gas pipelines. One of the pipelines, Southern Star Central Gas Pipeline, has a storage facility in Grant County, Oklahoma where it stores gas belonging to transportation customers. The gas does not originate in Oklahoma.

Southern Star allocates the gas among the customers each year and lets the Grant County assessor know the allocations. The county collects a personal property tax on the gas.

Missouri Gas Energy challenged whether the tax can be collected on its gas. The court said no because the gas cannot be taxed under the "Freeport exemption" in the state constitution.

Gas qualifies for an exemption if it is "consigned to a consignee in this State from outside this State to be forwarded to a point outside this State." Property generally cannot sit in Oklahoma for more than 90 days, but this is extended to nine months in the case of "goods, wares and merchandise . . . held for assembly, storage, manufacturing, processing or fabricating purposes."

The issue was whether gas is "goods, wares and merchandise." A lower court said it is not, but the state legislature then changed the law to make clear that it is while the case was awaiting appeal. The state argued that the legislature could not change the law retroactively, but the court disagreed. It said the legislature was merely clarifying what the law had said all along.

Missouri Gas Energy also argued that the gas does not have enough connection to Oklahoma — what tax lawyers call a "taxable situs" — for the county to be able to collect a property tax. The court disagreed. It said the county could have taxed the gas if the Freeport exemption had not applied.

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Entities receiving extra free allowances or that can reduce their emissions below their allowance allocations can sell their surplus. Covered entities who do not receive allowances from the state or whose emissions exceed the allowances they are issued must buy allowances in the market. Entities without compliance obligations may also participate in the program by voluntarily reducing their own emissions or by trading allowances as a liquidity provider.

California cap-and-trade allowances may be traded through two markets or bilaterally.

The first market is the allowance auction held by CARB each calendar quarter. In these auctions, allowances issued by CARB and by the Quebec government, which is working jointly with California to reduce emissions, along with allowances consigned to the auction for sale by covered entities, are sold at the auction settlement price, which has typically been slightly higher than the auction reserve price.

The second market for California allowances is the Intercontinental Exchange (ICE) trading market. This secondary trading market settles daily. Until recently, allowance prices in the secondary market have usually been higher than CARB auction settlement prices.

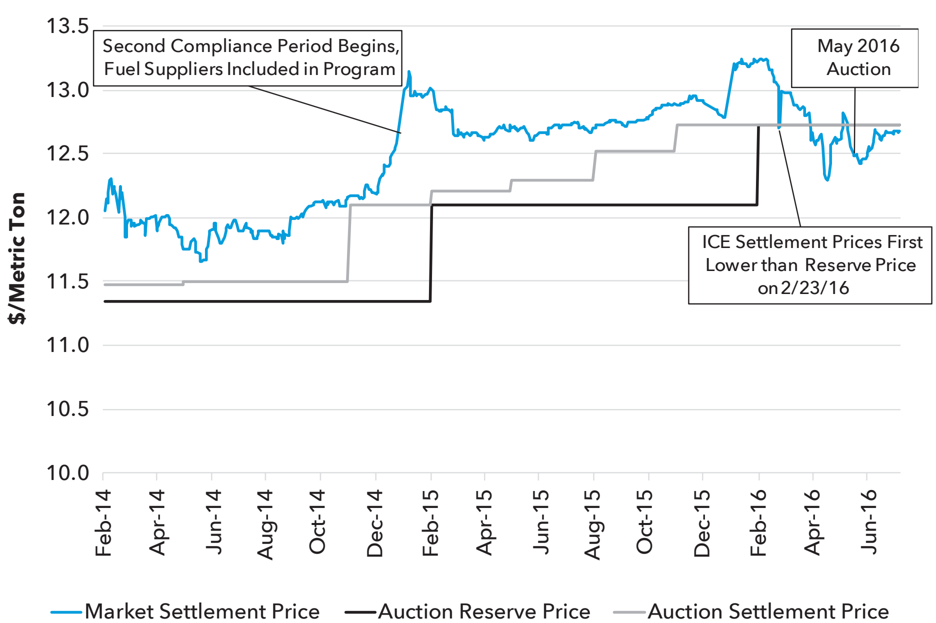
CARB has held quarterly auctions of allowances since November 2012. Each auction after 2012 has been of allowances for both the current-year vintage, meaning allowances that can be used to meet compliance obligations in the year they are auctioned, and for a vintage three years ahead.

Allowances that an entity does not need to cover its compliance obligation for a particular year may be banked for use in a future year, with no expiration date. Allowances with a future-year vintage may also be used to meet a current-year obligation as long as the allowance vintage is within the same three-year compliance period as the obligation. Also, at least 30% of the current-year obligation must be met with allowances from the current-year vintage or an earlier vintage.

Table A: ICE California GHG Allowance Volume and Settlements for December Delivery (With CARB Settlement Price for Comparison)

Current-Year Vintage (2016 Data through July 6)	Average Daily ICE Volume	Max Daily ICE Volume	ICE Settlement Price	CARB Current Vintage Settlement Price
2014	118,000	2,007,000	$12.02	$11.65
2015	257,000	4,300,000	$12.77	$12.44
2016	374,000	8,750,000	$12.80	$12.73

Figure 1: ICE California GHG Allowance Settlements and Volume for December Delivery, Current-Year Vintage, Compared With CARB Auction Allowance Settlement and Reserve Prices



Shift in 2016 Market

Current-vintage allowances sold out in each of the first 13 CARB auctions from November 2012 through November 2015, but the situation changed this year: in the first 2016 auction (in February), 18% of current-vintage allowances remained unsold, and in the second auction (in May), nearly 90% remained unsold. Sales of future-vintage allowances also dropped sharply in the 2016 auctions.

Meanwhile, average daily trading volumes on the secondary market for the December delivery product have more than doubled since 2014 and have increased by more than 45% between 2015 and 2016. (The December delivery products are allowances that would be physically delivered to the buyer in December. ICE allows trading for products with different delivery months as well, but the December contracts are the most consistently traded.)

Prices on the secondary market have usually been higher than CARB auction settlement prices. However, the price differential has narrowed substantially this year and has reversed in recent months. As shown in Figure 1, ICE allowance prices temporarily dipped below the auction reserve price in late February 2016, dropped below the reserve price again in late March, and have generally remained below the reserve price since then. This does not indicate that sellers are taking a loss; it is more likely that they are selling allowances that they had procured for even lower prices in previous years when the reserve price was lower.

With the first drop in ICE prices below the auction reserve price, trading volumes on the secondary market spiked as shown in Figure 2. However, since that time, ICE volumes have not returned to anywhere near the February peak and, since March, have generally been below the 12-month rolling average.

Why?

The dynamics in the current market appear to be driven by two factors: general uncertainty about the program and the future value of allowances, and a likely surplus of emission allowances on the market.

The primary uncertainty over the future of the cap-and-trade program stems from a lawsuit currently before a US appeals court in California that challenges the validity of the program. If the court invalidates the program, then compliance obligations could disappear and allowances could lose all their value. An April court order requesting supplemental briefs was interpreted by some analysts as a negative indicator for the program, potentially adding to the concern about possible program invalidation and contributing to the drop in allowance prices.

Trading prices may also be influenced by factors outside of California. Notably, the US Energy Information Administration linked a drop in prices of allowances in / *continued page 46*

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The case is *Missouri Gas Energy v. Grant County Board of Equalization*.

TENNESSEE can subject interstate pipelines to high property tax rates as utilities, a Tennessee court said in late July.

The Colonial Pipeline Company challenged the constitutionality of how it is taxed for property tax purposes in Tennessee. It transports gasoline, home heating oil, and jet and diesel fuel from Texas to Linden, New Jersey near New York City. It has delivery points in Chattanooga, Knoxville and Nashville. It does not own the products it transports. It charges solely for transportation at rates that are regulated by the Federal Energy Regulatory Commission. It can use eminent domain to take land.

Tennessee collects property taxes on industrial and commercial equipment at 30% of value. Industrial and commercial real property is assessed at 40% of value. Utility property is assessed at 55% of value.

Colonial argued that its pipelines should be classified as commercial and industrial equipment and assessed at 30% of value.

The state legislature classified pipelines as utility property by statute in 1973 and added that they are real property in 2004.

Colonial argued that this is unconstitutional, because it is an impermissible state interference with interstate commerce and a denial of equal protection under the law. The state acknowledged that some local pipelines that are locally assessed by county assessors may be treated as commercial equipment and assessed at a 30% rate. Interstate pipelines are assessed at the state level. Colonial also argued that it is not a utility because it has no monopoly to provide services.

The court said the state legislature was entitled to classify pipelines as utility property as long as it had a reasonable basis for doing so. It had such a basis. The court said there is no discrimination / *continued page 47*

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the Regional Greenhouse Gas Initiative (RGGI) market, in which eight states in the mid-Atlantic and New England participate, to a decision by the US Supreme Court in February 2016 to suspend enforcement of the Clean Power Plan, the federal plan for reducing carbon emissions from US power plants. Shortly after this Supreme Court decision, secondary market prices in California fell below the CARB auction reserve price for the first time.

There are additional uncertainties about the value of allowances in the post-2020 period. Primary among these factors is the lack of program regulations for this period, including regulations determining how allowance reserve prices will be set and how many allowances will be available for sale.

There is also uncertainty about how plans to expand the reach of California Independent System Operator to cover sections of the power grid in other western states will affect demand for allowances.

Another factor contributing to a collapse in prices is a surplus of allowances on the market. Data from CARB indicate that more than 30 million allowances of 2013 and 2014 vintage remain available for meeting current and future compliance obligations. This surplus can be traced at least in part to lower-than-expected load growth and higher-than-expected renewable energy generation in the electric utility sector, which appears to have resulted in a lower need for allowances than was anticipated when CARB allocated free allowances to the sector.

As shown in Figure 3, electricity sales in 2013 through 2015 did not increase as expected, but remained relatively flat and are now expected to grow much more slowly than was expected when the cap-and-trade program was under development in 2012.

Furthermore, utility procurement of renewable energy has increased much faster than expected as a percentage of annual electricity sales and, based on current utility contracts, is expected to far exceed the required 33% renewable portfolio standard by 2020, as shown in Table B below. This over-procurement stems from lower-than-expected sales and from improvements in the utilities' renewable power contracting practices that have reduced contract failure rates, leaving the utilities with a larger amount of renewable energy deliveries than they had planned.

Lower sales and a higher share of renewable power each reduce the amount of fossil-fueled electricity that the utilities need to meet their loads. This, in turn, should reduce the need to run less efficient fossil-fueled power plants

Figure 2: ICE California GHG Allowance Trading Volume for December Delivery Current-Year Vintage

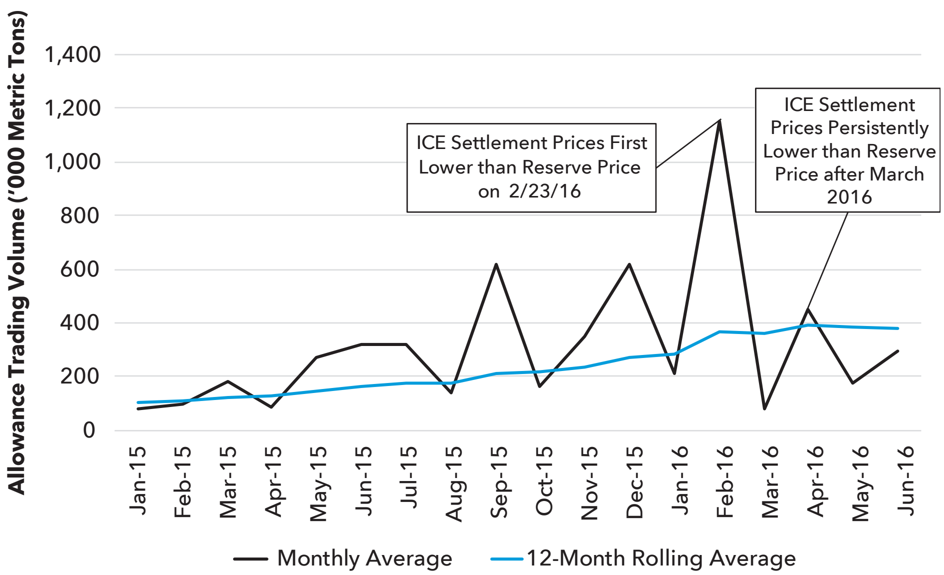

Table B: California Investor-Owned Utility RPS Procurement

	2014 Required RPS Procurement	Actual 2014 RPS Procurement	2020 Required RPS Procurement	RPS Procurement Under Contract for 2020
PG&E	21.7%	28.0%	33.0%	37.0%
SCE	21.7%	23.2%	33.0%	36.9%
SDG&E	21.7%	31.6%	33.0%	43.1%

that have higher heat rates and higher emission rates, which are generally used when demand is highest. Running these less efficient plants less of the time further reduces utility-sector greenhouse gas emissions.

Even considering the need for additional natural gas generation in recent years due to the retirement of the SONGS nuclear power plant in southern California and the depressed availability of hydroelectric generation (due to drought conditions), the overall need for greenhouse gas emitting fossil-fueled power in California appears to be lower than was expected when the cap-and-trade program was being developed. This is probably a key factor behind the allowance surplus.

Outlook

The combination of program uncertainty and allowance surpluses pushed secondary market allowance prices below the CARB auction reserve price, shifting some activity from the CARB auction to the secondary market and probably prompting some entities to hedge their bets and reduce their allowance purchases in case allowance prices continue to fall or allowance obligations are eliminated.

The cap-and-trade program was designed to address such a situation through an auction price stabilizing mechanism. Under this mechanism, allowances that are designated for auction by CARB or Quebec, but are not sold, are withheld from future auctions until settlement prices in two consecutive auctions fall above the auction reserve price. This mechanism will reduce the allowance surplus at least for the remaining two 2016 auctions, which should help to stabilize prices in both the auctions and the secondary markets.

However, once the clearing price in the CARB auction rises above the reserve price for two auctions, then the allowances that were removed from earlier auctions will re-enter the auction.

When this happens, the CARB auctions will face a new allowance surplus that will again put downward pressure on prices. These re-auctioned allowances cannot exceed 25% of allowances previously designated by regulators for that auction, so the impact of this mechanism may be spread over several auctions.

The effect of removing surplus allowances from the remaining 2016 auctions is likely to be muted since covered entities may use banked allowances from 2013-2015 to meet up to 100% of their 2016 compliance obligations, and may also use 2017 vintage allowances to meet up to 70% of their / *continued page 48*

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against interstate pipelines, and if Colonial is being taxed differently than some of its competitors who are assessed locally, this is a problem with execution of the laws by the state rather than a sign that the statutes violate the constitution.

The case is *Colonial Pipeline Co. v. Wilson*. The Tennessee chancery court released its decision on July 29.

A CONTINGENT PURCHASE price in an installment sale makes calculation of the seller's gain complicated.

The IRS addressed how to calculate gain in such situations in four private letter rulings that it made public in late June. The rulings are Private Letter Rulings 201626009 through 201626012.

All the rulings were issued to shareholders in an S corporation who sold their shares to a C corporation so that the S corporation became a subsidiary of the C corporation. The consideration was a mix of cash and shares in the C corporation.

The purchase price was paid in four annual installments. However, the installments were adjusted based on change in the value of the C corporation shares in the five trading days before each installment payment.

The US tax code lets anyone selling property for payments over time report his gain over the period the sales price is received. This approach is automatic. However, a taxpayer who prefers to report his full gain up front can elect on his tax return to do so. Paying taxes over time will require payment of an interest charge on the deferred tax liability.

The gain is normally considered earned over time in the same ratio the sales price is received.

However, this is not easy to calculate when the sales price is contingent on future events.

In that case, if there is a maximum sales price, then the seller uses it to spread out the gain. / *continued page 49*

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2016 compliance obligations. These provisions will allow entities to wait and see how the market evolves before making most of their remaining purchases for this year's compliance obligation and to make additional purchases this year only if prices are near the reserve price.

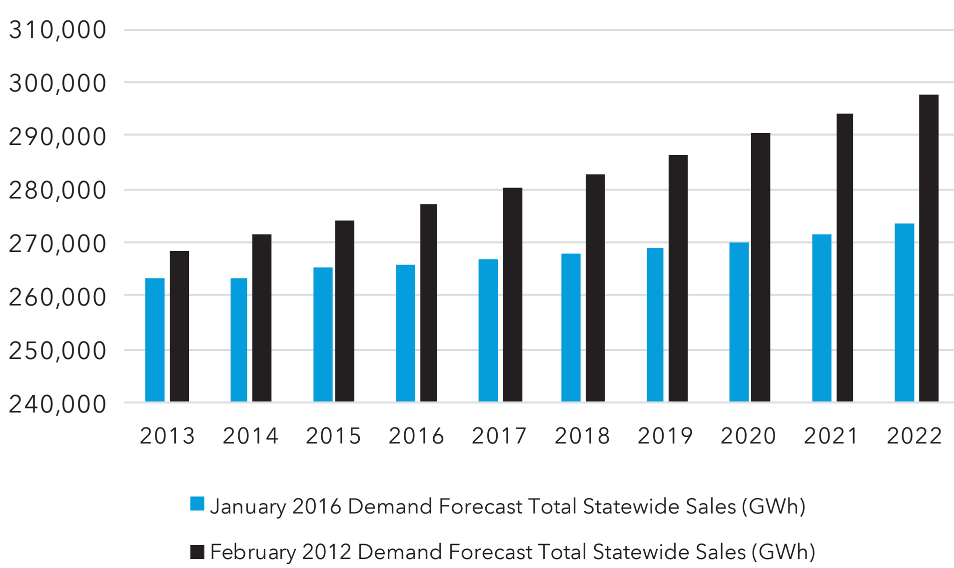
Since 2017 is the last year of the second compliance period, the situation will be different next year in that all allowances for the 2015-2017 compliance period must be met by allowances of vintage 2017 or previous vintages. As a result, there could be short-term price increases during the final opportunities to meet the 2015-2017 compliance obligations, particularly if entities defer large allowance purchases until 2017 and also if traders withhold allowances from the market in anticipation of higher prices in the future. Even if this were to occur, these price increases would probably be followed by a drop in price at the start of the 2018-2020 compliance period (when allowance purchases could again largely be deferred until 2020), and prices can overall be expected to remain near the reserve price unless something fundamental changes in the market to eliminate the surplus allowances.

CARB is considering such a change. In response to stakeholder concerns that a persistent surplus exists and may grow in the future, CARB has proposed amendments to the current regulations that would permanently remove any unsold auction allowances from the auctions after 24 months. CARB has proposed that this change take effect by January 2018, and that it cover allowances that were unsold in auctions before this date. If adopted as proposed, all unsold allowances from the 2013-2015 period would be removed from the auctions as of January 2018. Unsold allowances from 2016 and subsequent years would remain in the auctions until auction prices exceed the reserve price for two auctions or 24 months elapse.

It is reasonable to expect allowance prices generally to remain near the reserve level until CARB's proposal for permanently retiring unsold allowances is implemented or another solution is found. As with CARB's proposal for permanent allowance retirement, other solutions, such as setting the post-2020 allowance levels so as to remove the surplus, are likely to be designed so as to keep enough allowances in the market to avoid a price spike. As a result, barring unforeseen circumstances and with the possible exception of short-term spikes, the market recovery is likely to be gradual.

Price levels will also be influenced by developments in the legal proceedings concerning the California cap-and-trade program and possibly also the Clean Power Plan. California's post-2020 cap-and-trade regulations and implementation of the cap-and-trade program within the context of a regional power market as the California ISO expands will primarily influence longer-term pricing. However, given that allowances may be banked for long-term use, developments in these areas may also inform pricing in the near-term to some extent.

Figure 3: California Energy Commission Forecasted/Actual Statewide Electricity Sales (GWh)



Tax Equity Trends

Three tax equity investors and the lawyer who handles energy issues on the elite tax policy staff at the US Department of the Treasury talked at the annual ACORE/Euromoney Wall Street Renewable Energy Finance Forum in New York in late June about new trends and current issues in the tax equity market. The following is an edited transcript.

The panelists are Adam Altenhofen, vice president for renewable energy at US Bank, John Eber, managing director and head of energy investments at J.P.Morgan, Hannah Hawkins, attorney-advisor in the office of tax policy at the US Department of the Treasury, and Jonathan Stark, managing director for origination at GE Energy Financial Services. The moderator is Keith Martin with Chadbourne in Washington.

MR. MARTIN. John Eber, it seems like everybody took his or her foot off the accelerator after Congress extended tax credits in December. The tax equity market was pretty slow in the first part of the year. Do you see it getting back to a normal pace? Is it there now? What do you see for the rest of the year?

MR. EBER: We see the market looking a lot like it was last year, which was one of the largest years ever for tax equity. There was $13 billion raised last year, and this year is off to the same pace as last year. I am not in the business of predicting, but I think the market will be similar, if not a little bit larger than last year.

MR. MARTIN: Adam Altenhofen, US Bank is a big part of the market. Do you agree?

MR. ALTENHOFEN: Yes. I share the view that it got off to a little slower start. A lot of people, including US Bank, were expecting there to be a major drop off at the end of 2016 as tax credits expired, so we did a lot of investing last year for 2016 projects. We had to do a little recalibration at the start of 2016 after Congress extended the tax credits. We have been focusing lately on bringing additional investors into the market to try to help grow that $13 billion number.

MR. MARTIN: You did $2 billion of the $13 billion last year. What do you expect this year?

MR. ALTENHOFEN: We will probably commit about $1.6 billion this year. We closed a bit more last year in anticipation of a cliff.

MR. MARTIN: Jon Stark, are we back to normal now? It is late June.

MR. STARK: I think it is normal for there to be a slowdown after an extension, in particular a four-year extension. While the beginning of the year has been slow on new */ continued page 50*

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If there is no maximum price, but there is a fixed period for the installment payments, then the seller subtracts his basis from the installment payments ratably over the fixed period, but no loss is allowed in that case until the end. Thus, for example, if the basis ratably allocated to year two exceeds the installment payment that year, then the year-two loss is rolled into year three and used to offset the installment payment in year three.

Alternatively, the taxpayer can ask the IRS for permission to recover the basis on a different schedule. The alternative approach must be reasonable. The seller must get an IRS private letter ruling. It must apply for the ruling before the due date, including extensions, of the tax return on which first installment will be reported. The IRS will only approve an alternative method if the seller can show it will allow recovery of the basis at least twice as fast.

In this case, the IRS allowed the sellers to match the pattern that the sales proceeds were expected at inception to be received.

— contributed by Keith Martin in Washington

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PPAs, we hear from developers that they are being shortlisted, and new PPAs are imminent. We expect more wind transactions to hit the market later in the year as new PPAs are executed.

We are seeing a lot of solar right now. A number of solar projects that developers were hoping to close by year end were delayed and are in the market now.

MR. EBER: That was probably the biggest development last year. Solar surpassed wind for the first time in deal volume. A big chunk of that was in the residential sector and right behind it was utility-scale solar. As long as those two sectors remain popular, there will be continued growth in the demand for tax equity.

MR. MARTIN: What was the breakdown last year between solar and wind?

MR. EBER: We estimated about $6.8 billion in solar and $6.4 billion in wind. We can see the entire wind market. The solar market is a little harder to quantify because there are many smaller transactions that are not as readily identifiable as there are in the larger-scale deals.

MR. MARTIN: The solar rooftop stocks have been battered since the SunEdison share price collapsed on July 22 last year. Has this had any effect on how people like you view the solar rooftop market?

MR. STARK: The pressure is healthy. It is good for these companies to try to manage the pace of their growth and to keep the capital markets, and especially the public markets, happy so that they can continue to raise equity as they go forward. So if that is what the markets are demanding, it is healthy.

MR. MARTIN: SolarCity says it needs $1.8 to $2 billion in tax equity this year. Are you as likely to step up this year as you were two years ago?

MR. ALTENHOFEN: I echo what Jon Stark just said. It is healthy. Residential companies are focused on being cash-flow positive at a system level, and some of the publicly-traded companies are getting close to that level. That is a positive for the sustainability of the residential market. We are as likely to invest in the residential market as before. Our view of that market has not changed.

New Trends

MR. MARTIN: Jon Stark, what other new trends are you seeing this year in the market?

MR. STARK: We see two. Tax equity, particularly in wind, is accounting for a larger percentage of the capital stack. Five years ago, 60% was probably on the high end; now we are seeing deals come in at around 75% tax equity.

MR. MARTIN: Is that because there are more production tax credits, more output, from more efficient wind turbines?

MR. STARK: Yes. The wind turbines are much more efficient. Five years ago, you saw capacity factors in the low 40s. Now they are in low 50s with the same or lower capital costs on a per-megawatt basis.

MR. MARTIN: Is it also true in solar that tax equity is accounting for a larger share of the capital?

MR. STARK: There is more variability in solar tax equity structures than there is in wind. In wind, the target flip is always around 10 years. With solar, there is more variation in the flip date and therefore, more variation in the tax equity size.

MR. MARTIN: If tax equity accounts for 75% of the capital for a typical wind farm today, then what is the range for solar?

MR. STARK: Solar is between 40% and 60%, depending on structure and underlying economics. We have found some sponsors prefer a short-dated flip and they want to maintain a high percentage of the cash, leading to a lower advance rate. A number of sponsors like a longer-dated flip. The reason they want the longer-dated flip is it is more efficient in terms of monetizing the tax benefits, and it can increase the amount of back leverage. At GE, we have the flexibility to offer both shorter- and longer-dated flips to optimize the structure for the sponsor.

MR. MARTIN: Adam Altenhofen, any other new trends?

MR. ALTENHOFEN: Community solar is the big one. We are getting a lot of questions about financing community solar.

MR. MARTIN: You flip on a date certain, while many other tax equity investors flip when they reach a target yield.

MR. ALTENHOFEN: That's right. Ours is still a time-based flip.

MR. MARTIN: John Eber, new trends?

MR. EBER: Falling prices for wind electricity mean there is a lot less cash in projects with newer PPAs. This creates structuring challenges. Tax benefits are getting suspended and are not used fully, and deficit restoration obligations are getting larger than what they used to be.

Construction-Start Issues

MR. MARTIN: The IRS issued guidance in early May about what it takes to start construction of a wind farm or other renewable energy project. The developer must do two things. He or she must start construction by a deadline and then work continuously on the project.

What the IRS said in early May took many people by surprise. It said that it will not make developers prove continuous work on any project that is completed within four years. The four years run from the end of the year construction started. Until now, the IRS has said it will not require proof for any project that is completed within two years, but the two years ran from the latest construction-start deadline.

This new approach is causing a lot of pain. Many developers rushed to start construction in 2011, 2013, 2014, and so on ahead of earlier construction-start deadlines that keep getting pushed back by Congress. This has now come back to haunt them.

John Eber, Mike Storch from Enel said at the Global Windpower 2016 convention in May that he worries people like you will now ask him whether he turned a shovel of dirt on his site sometime in the distant past, and he will be out of luck because four years have run since then. Is that a reasonable fear?

MR. EBER: That is probably one of the bigger uncertainties in the new guidance. The issue is how we are going to prove a negative that the project was not under construction at some earlier date.

It is a concern. I am not sure how it will be addressed. So far, we have had nothing but theoretical inquiries about such cases. We have not been shown a real situation yet where we can try to analyze the facts and make a determination.

MR. MARTIN: Jon Stark, the rubber meets the road with smaller developers who did not have the wherewithal to incur more than 5% of the project cost. They may have ordered a transformer or they may have had a road or several turbine foundations dug on the site several years ago. Are you starting to see this issue come up with developers who are trying to sell development rights to projects?

MR. STARK: I think we are going to see an interesting dynamic over the next four years as sponsors and the financing community work through the most flexible way to qualify projects. Do you begin physical work for projects that might not be completed for four more years? Or do you incur at least 5% of the total project cost by taking delivery of equipment?

MR. MARTIN: Haven't people already had to address those issues in past runs at these deadlines?

MR. STARK: It is different with a four-year run versus a two-year run. The 5% test may give developers more flexibility to identify projects at which stockpiled equipment will be deployed.

MR. MARTIN: Fair enough. Hannah Hawkins, have you had complaints about how the four-year clock works? Is there any possibility the government will revisit it?

MS. HAWKINS: Complaints and feedback, and this is feedback we expected to hear. So far, to John Eber's point, it sounds theoretical, but of course, over time, there may turn out to be real substance behind the complaints.

We have no plan to revisit this aspect of the guidance, but one can never say "never." Since 2013, there have been many clarifications.

MR. MARTIN: So it is possible this may be revisited. Why did the government decide to apply the clock retroactively? To reset the stage, there used to be a two-year clock, but it ran from the construction-start deadline. Now you have four years, but they run from an earlier date. Why do it that way?

MS. HAWKINS: The goal was to put a time limit around the beginning construction standard, and we thought it made sense to look back to the start of the beginning construction universe.

Obviously there are issues. We were aware before we put the guidance out, and we are aware now, that there are issues associated with the way we did this. I hope that we put enough flexibility and enough time into these rules so these issues are manageable.

MR. MARTIN: We see the issue coming up with geothermal, biomass and wind developers who started projects in 2011, 2012 or 2013 and who are now out of luck. The rights to these projects cannot be sold, and the projects cannot / continued page 52

Tax equity accounts for 75% of the capital for the typical wind farm and 40% to 60% for solar.

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be financed because of uncertainty about whether they will qualify for tax credits.

The guidance that came out in early May dealt with everything but solar. You reserved on solar issues. When do you see construction-start guidance coming out for solar?

MS. HAWKINS: We are working on it. We hope to have it out in the next few months.

MR. MARTIN: The next few months?

MS. HAWKINS: That is probably optimistic. How about fall to winter?

MR. MARTIN: That is very good news because I think a lot of people thought it might not be before 2017.

MS. HAWKINS: It is the next thing on our plate.

MR. MARTIN: Have you seen a draft yet from the IRS?

MS. HAWKINS: I would rather not say.

MR. MARTIN: What additional issues need to be addressed for solar that were not already addressed in the wind guidance?

MS. HAWKINS: We are still working through that. I think there could be several issues. For example, with respect to solar, what is a unit of property is not always clear, especially when you are talking about distributed generation. Whether and how the rules for aggregating or disaggregating a single project should apply to solar is something we have to think about. We need to think about how a developer can start physical work on a solar rooftop project that normally takes an afternoon to install. We just need to think about how the physical work rules apply in this context.

MR. MARTIN: Will there be a four-year clock for solar?

MS. HAWKINS: I don't know.

Less Cash

MR. MARTIN: We will come back to you. Let me go in the meantime to the rest of the panel. PPA prices have been falling, and we are now seeing wind PPAs with prices below $20 a megawatt hour. John Eber, you touched briefly on this earlier. How will low prices affect tax equity deals?

MR. EBER: Low prices are having a big impact on wind deals, especially for projects in the central part of the country. There is less cash to distribute after paying operating expenses. Depending on how aggressive you are in terms of factoring in inflation and projecting O&M and other costs, if you have a flat PPA price over a 20-year PPA term, you can find yourself running very low on cash as you get into the out years. When we run downside scenarios to test how well some of these structures might hold up in, say, a P90 or a P95 scenario, we see some of these deals getting extremely tight on cash as they get out into the later years, even though we might be getting 100% of the cash. There is just not that much cash to look to.

MR. MARTIN: So it puts pressure on your ability to get to a 2% pre-tax yield, which is what most people want?

MR. EBER: You can get to the 2% pre-tax yield, but you may not feel comfortable with when the flip will occur in your downside scenario.

MR. MARTIN: Are there any other issues from low wind PPA prices? Jon Stark, you look like you are about to say something.

MR. STARK: The only thing to add is low PPA prices make it harder to work out of a DRO. There may not be enough income to allocate to the tax equity investor.

MR. MARTIN: A DRO is a promise by the tax equity investor. Each partner has a capital account. The capital account is a way of measuring what the partner put in and what he is allowed to take out. Tax equity investors have too little capital account to absorb the full tax benefits. One way to be able to absorb more is for the tax equity investor to agree to contribute more money to the partnership when it liquidates to cover any deficit in his capital account. The promise to contribute more is called a DRO.

MR. EBER: Taxable income helps increase your capital account, but there is a lot less taxable income in some of these deals.

MR. MARTIN: How large are these promises to put capital back in? 20% of the tax equity investor's original investment? 30%? 3%?

MR. STARK: It depends on the amount of cash and the structure of the deal. In solar deals, DROs are higher than wind because solar tax equity accounts for a smaller portion of the capital structure. The real issue is whether the investor will be allocated enough income over time to reverse the DRO.

MR. MARTIN: Next question. John Eber, how much sponsor equity do you require and do you let a sponsor borrow from a subordinated lender and count that as equity?

MR. EBER: We are only going to put up the amount of tax equity necessary to monetize the tax benefits. In a solar deal, it might only be about 40%. In a wind deal, it might be currently around 50%.

The sponsor needs to put up all the rest, and we recognize that it is a lot of capital to raise and that it may come from different sources. Some sponsors will partner with investment funds, whether they have their own yield co or are looking to an unaffiliated infrastructure fund to raise true equity, or they may use back leverage to raise part of the capital in the form of subordinated debt.

We don't set a hard number on the amount of sponsor equity required. The key to us is the sponsor has enough at risk to ensure its interests are aligned with ours to see that the project performs well.

MR. MARTIN: So did I hear that you do not require any minimum amount of sponsor equity? Can the sponsor have only its development spending in the deal and the rest come from a subordinated lender?

MR. EBER: Every partner we have has a different approach as to how it wants to fund its business, and the vast majority of those approaches have worked fine. The only thing about which we are sensitive is we want our partner to remain invested for the full period until we reach our yield.

Corporate PPAs

MR. MARTIN: Let's shift to corporate PPAs. In the fourth quarter last year, 75% of new PPAs signed by wind companies were with corporations. I was surprised to learn at the Global Windpower 2016 convention that wind company CFOs are not too keen on corporate PPAs because they shift something called basis risk to the sponsor. They also tend to have shorter terms, and the creditworthiness of the offtakers is not as secure as with utilities.

John Eber, have you done deals with corporate PPAs?

MR. EBER: We have done quite a few.

MR. MARTIN: What special issues do they raise?

MR. EBER: We are working on a host of others currently because they are so prevalent today in wind. The challenges are many. One is the term. They have a shorter term than a utility PPA, but the term runs longer than the point at which we expect to reach our target yield.

The credit issues are always there. A regulated utility is nice to have on the other side versus even a well-rated corporate, because the creditworthiness of a corporate could change rapidly.

Having said that, most of these offtakers are clients of our bank and so we know them well, and we are happy to do business with them.

MR. MARTIN: Is the cost of tax equity higher with a corporate PPA?

MR. EBER: I don't think so. Generally not. Most projects with corporate PPAs are financed as part of a portfolio in which you might have three or four different PPAs, so you get some risk diversification in terms of offtakers.

However, you might find more tax equity investors who would pursue a regulated utility deal than investors who would do a corporate PPA, so having a corporate PPA might thin out the market a bit.

Community Solar

MR. MARTIN: Let's move to community solar, another trend. In a community solar project, a utility-scale solar facility is built, and the electricity moves to the local utility. But subscribers — apartment dwellers, businesses — subscribe for a share of the electricity, and they are given bill credits by the utility. It is like a utility-scale project, but at retail rates for the developer.

Adam Altenhofen, I think US Bank has actually closed on tax equity for some community solar projects. Is that correct and, if so, how many?

MR. ALTENHOFEN: We closed two community solar transactions so far in Colorado and Massachusetts and are working on three others. We like these types of projects.

We are an investor in the residential rooftop market, commercial and industrial projects and in the utility-scale market, and community solar marries the three together pretty well. So we like it from a risk diversification standpoint. You get a lot of different subscribers that are easily replaceable if one falls out, which is an advantage versus traditional C&I, where if the offtaker defaults and the system is on its rooftop, it is hard to replace the offtaker.

MR. MARTIN: With community solar, you do not have to pull the panels off the roof.

MR. ALTENHOFEN: Correct.

MR. MARTIN: What special issues does community solar raise for a tax equity investor?

MR. ALTENHOFEN: The subscriptions tend to be a rolling nature in terms of how subscribers are found. You may get into the deal at notice to proceed with construction, and the sponsor does not have any subscriptions yet, so you have to create parameters around the types of subscriptions you will accept. You have to have a form subscription agreement. That can create challenges from an underwriting perspective. You don't know who your offtakers will be. You have to make sure the subscriber mix satisfies whatever requirements there are in the particular state.

MR. MARTIN: The subscribers can disappear overnight or with a short notice period. How do you protect yourself?

MR. ALTENHOFEN: You have to build an adequate buffer over the minimum requirements, so in Minnesota, for instance, there must be at least five subscribers by law */ continued page 54*

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to remain qualified as a community solar garden. Requiring some level of the fund to be residential and requiring the sponsor to have a backlog of subscribers can mitigate that short-term vacancy risk.

MR. MARTIN: What mix of commercial and residential do you require?

MR. ALTENHOFEN: No specific mix. We like to see some residential subscribers to mitigate the risk of dropping below the five-subscriber minimum, but we have no specific mix.

In Massachusetts, we have done 100% residential. In Colorado, where residential does not really make a lot of sense, our transaction was mostly C&I and municipalities.

Rooftop Solar

MR. MARTIN: Let's talk about C&I solar. For the last several years, everyone has said C&I solar has a lot of potential, but the scale of C&I solar companies is small. Somebody needs to do a rollup. How do you view a portfolio of C&I solar projects versus residential? Which is more attractive to you as a tax equity investor?

MR. STARK: Although we are not in the residential market, residential is easier to execute on than a portfolio of C&I transactions.

MR. MARTIN: Why?

MR. STARK: Standardization is the key. It is a cumbersome process to diligence and close a C&I deal with different offtakers and PPAs.

MR. EBER: Residential solar is a lot easier to underwrite, easier to execute, and frankly the residential sponsors can deliver the volume they promise. We are a scale investor. We are looking for large-scale deals. It is difficult in the C&I space to get somebody who can deliver that kind of volume to you within a reasonable period of time.

MR. STARK: We have succeeded in C&I where there is a single offtaker with multiple sites. For example, we closed a deal last year with a strong sponsor who had 60 sites with the same offtaker.

MR. EBER: That's a rare deal. There are not many like that.

MR. MARTIN: Sounds like Walmart.

Many people are talking about combining PACE financing with tax equity. Municipalities borrow and make loans to individuals or businesses who want to put solar on their roofs. A group of such systems would be packaged together and financed in the tax equity market. Have you seen any such deals done? [Pause] I guess no answer means no.

Next question: one of the reasons people are pushing in this direction is to try to make the cash flow stream more certain. How attractive is it to a tax equity investor to have a more certain cash flow stream or, put differently, less credit risk that the scheduled customer payments will be made?

MR. ALTENHOFEN: Any time you can make something more certain, it will be attractive, and whether PACE accomplishes that is a bit unknown to me.

MR. MARTIN: So one person answered that if you can make the payment stream from the customers more certain, it may be worth the effort. Any dissenting views? [Pause] Okay.

Next question: geothermal and biomass projects are notably difficult to finance in the tax equity market. Do you provide tax equity to these types of projects?

MR. STARK: Sure. We made a cash equity investment recently in an existing portfolio of geothermal projects. We are not opposed to providing tax equity to geothermal or biomass. What we find is the hit rate on such deals is very low, and we have not had many such projects coming into the shop these days.

MR. MARTIN: What is the principal issue that leaves you with a low hit rate?

MR. STARK: The problem is not usually on our side. The developer ends up unable to finish development of the project.

MR. EBER: There are very few biomass deals that come to market. We have done a number of geothermal deals on existing properties, and we will continue to do them if we can find deals of the right size. We have not seen anything in biomass in quite some time. The fuel costs add another risk.

Basis Issues

MR. MARTIN: Let me switch topics. There's been notable tension with the government over the tax bases being used in projects with investment tax credits. One case involving a wind farm went to trial before the federal claims court in May. A decision is expected as early as this summer. A solar rooftop case is headed to trial in the first quarter of next year.

What benchmarks are you using to decide whether the bases used to calculate investment tax credits are appropriate?

MR. EBER: I would like to hear the government's response on this one.

MR. MARTIN: I don't think Hannah wants to wade into this.

MR. EBER: That's the challenge right now with ITC. We do not really have clear guidance from the IRS about how to determine the basis.

MR. MARTIN: So what do you do?

MR. EBER: Hopefully we will get some case law from these two cases on which we can rely. Right now, people are using various methodologies to calculate fair market value.

We saw some benchmarks under the Treasury cash grant program, but the program swung from being generous to conservative. So that has left a lot of us who make a living in this business a bit confused.

MR. MARTIN: Where do you think the basis is currently for rooftop solar? How many dollars per watt? What range? [Pause] This is a notably reticent panel. They were very talkative in the back room.

Next question: how common is tax credit insurance and what is your view of it?

MR. EBER: We are doing a couple deals with it now and it has a place in the market. I suspect it will become more common going forward. It is helpful because it goes right back to your prior question about the right basis to use for calculating the investment tax credit. All of us are getting indemnities from our sponsors to protect us should the government conclude that we used too high a tax basis. The insurance just helps diversify how much of that indemnity exposure we might be building with any one client by substituting an insurance company into the mix.

MR. MARTIN: Any idea what tax credit insurance costs?

MR. ALTENHOFEN: Yes. We have used it as well for the same reason as J.P.Morgan to diversify credit risk. The typical premium is about 4% of the policy amount.

MR. MARTIN: Let me go back to Hannah Hawkins. The government asked for comments on investment credits. The regulations on what qualifies for an investment credit go back to 1982. You received 25 to 30 comment letters. The IRS is now sifting through these.

A lot of people wanted the government to make clear that batteries and other storage devices qualify. Do you see any possibility that batteries will not qualify?

MS. HAWKINS: Right now we are in the process of sifting through 30+ comment letters that, by the way, have been very helpful to us, and we are also having meetings with people who sent in comments to do a deeper dive into the different storage technologies: how they function with respect to the energy property, with respect to the grid, and the ownership structures.

I think the broad view is that there are many situations in which storage technologies should qualify, but it is a matter of identifying those situations and being able to describe them.

There is also the problem, of course, that the existing regulations have a dual-use rule that requires that at least 75% of the energy that a battery uses has to be from the renewable energy resource, and it is a cliff. If you do not meet that, then you are ineligible. So we have to decide to the extent storage qualifies, whether there should be a dual-use rule and, if so, how it should work.

MR. MARTIN: I read a lot of the comment letters, and wrote three of them, and it seems like this is a very complicated area to get one's arms around. Do you think the government is likely to come out with new regulations before 2017?

MS. HAWKINS: Before 2017, probably not. I think we are hoping to get the proposed regulations out next spring and then maybe finalize them a year later.

MR. EBER: We are going to be seeing a lot more batteries in the residential space. Hawaii already is moving in the direction of hooking up new residential systems only when they come with batteries.

MR. MARTIN: So there is some urgency to have clear rules.

Hannah, there is an effort on Capitol Hill to extend the orphan tax credits: investment credits for fuel cells, CHP projects, geothermal heat pumps. Are you aware of any other tax issues in play either on the Hill, at Treasury or the IRS involving renewable energy?

MS. HAWKINS: On the Hill it is hard to say, but I don't know of anything other than the orphan tax credits that has any legs.

As for the IRS and Treasury, we already talked about the investment tax credit regulations. We are very close to releasing regulations related to section 50(d) income for inverted lease transactions. [*Editor's note: These regulations were released in July and are discussed on page 27.*] It is a discreet issue. In an inverted lease, the lessee has no basis in the investment credit property to reduce by one half the investment credit, so the lessee has to report half the investment credit as income instead. Questions have arisen about how that income inclusion works, particularly when the lessee is a partnership.

Something else that has been brought to our attention recently, and on which we are starting think about whether we want to spend time, is solar installations on federal land. Office of Management and Budget regulations apparently require the government to be given ownership at the end of the power contract. This is making people nervous about whether that blows tax ownership or prevents the power contract from being treated for tax purposes as a service */ continued page 56*

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contract under section 7701 of the US tax code.

MR. MARTIN: This is the issue on military bases, for example. The military can throw you off the site, and it will not let you keep your asset on the site after the power contract ends. The issue is whether that affects tax ownership.

Audience, this is your chance to ask questions.

Solar REITs

MR. REICHER: Dan Reicher from Stanford. In 2014, Treasury and the IRS issued a proposal to allow real estate investment trusts to own some types of solar. The government received a number of comments from trade associations, companies and others. The president actually announced the move to expand the potential use of REITs at a solar event at Walmart, but we have not heard anything since about what is happening. Do you expect the REIT proposal to be issued in final form and, if so, when?

MS. HAWKINS: We are actively working on that, and hopefully you will see something soon. I can't really say much beyond that. Sorry.

MR. MARTIN: Do you think the rules will be out this year?

MS. HAWKINS: Hopefully.

MR. MARTIN: There is an unwritten policy at Treasury of not issuing big rulemakings after Labor Day in a presidential election year. Do you think we will see any guidance after Labor Day in these areas we have been discussing?

MS. HAWKINS: It depends on the type of guidance. Regulations are harder to get out, particularly in an election year. But subregulatory guidance, which are your notices, revenue procedures and things like that, are a little easier to move through the system and so there is a better chance of that type of guidance continuing to come out throughout the year.

MR. MARTIN: Let me ask all of you my last question. Hannah, you can pass on this if you wish. We ran an article in the Project Finance Newswire earlier this year called "How to Lose a Banker in 10 Minutes." There must be an equivalent for tax equity. I am going to phrase the question this way: where do sponsors, particularly small sponsors, go wrong? What do they not realize when they come to talk to you? John Eber, let me start with you.

MR. EBER: They come too early. They come in before the project is fully baked or even substantially put together. The conversation is premature. They do not have the fundamental characteristics that you need to get a project financed.

MR. MARTIN: Adam Altenhofen?

MR. ALTENHOFEN: I agree with that. Adding to it, it is not only failing to have the project fully baked from a standpoint of having a viable plan to fill out the capital stack, but also not having the diligence ready to go, not understanding the breadth of diligence that a tax equity investor requires. You get into the deal, and the sponsor does not appreciate fully the scope of the asks.

MR. MARTIN: Is it a mistake for people to come in and give you a head's up they will want to talk to you when the project is closer to completion?

MR. ALTENHOFEN: There is a time where you say, "Why don't you come back when you have your PPA, your site lease, your debt financing or sponsor equity."

MR. MARTIN: Jonathan Stark?

MR. STARK: We are pleased to discuss general structural terms with developers before there is a signed PPA, but some smaller developers want a formal proposal or very detailed discussion on terms and conditions.

MR. MARTIN: We have come to the end of the hour. Four things stood out for me. The first is Hannah Hawkins' statement that we will probably see construction-start guidance for solar by the end of the year. The second is that community solar is financeable. In fact, some tax equity has been done already in community solar. The third point is that projects with corporate PPAs can be financed in the tax equity market. Tax equity investors may analyze them as if they are merchant projects with a hedge. The last point is the tax equity market has been slow this year, but it is picking up speed and should equal what we did last year: $13 billion. Thank you, panel.

Low electricity prices mean there is less cash to distribute to partners.

Guarantees for Investments in Emerging Markets

by Shalini Soopramanien, in Washington

Emerging markets offer new and exciting investment opportunities, but risks accompany the potential rewards.

Guarantees from multilateral development banks, or "MDBs," are an invaluable risk mitigation instrument that not only helps to cover perceived government-related risks, but also facilitates access to private sources of finance.

MDBs offer two types of guarantee products: credit guarantees and risk guarantees.

Credit guarantees cover all or part of a financial obligation (usually a loan or bond) and are triggered irrespective of the cause of the default — whether political or commercial — while risk guarantees also cover all or part of a financial obligation, but are called only when the government or government-owned entity fails to meet specific obligations under project agreements to which it is a party.

This article compares and contrasts guarantees offered at the following four major MDBs or MDB groups: the World Bank Group, the Inter-American Development Bank, the Asian Development Bank, and the African Development Bank Group. It is a complement to an article in the April 2016 NewsWire that focused on the World Bank's enhanced guarantee program for private projects.

Guarantees Explained

Guarantees are a specialized form of insurance that helps a borrower leverage external resources beyond the lending capacity of MDBs. The borrower can be a national or sub-national government, state-owned enterprise or private investor.

Most MDBs prefer to offer partial coverage guarantees that do not cover the entire amount borrowed. The rationale is that a "wall-to-wall" guarantee would generate moral hazard risks, as the guaranteed investor would have little incentive to conduct its own due diligence on the viability of the proposed project and would not be subject to market scrutiny. Partial coverage guarantees on bond issues also avoid the potential pitfall of contaminating the MDB's market for its own bonds.

There are many benefits to using MDB guarantees over traditional loan financing operations. First, MDB guarantees are intended to be flexible, both in terms of the risk covered and the tenor of the guarantee. Guarantees can target specific classes of risks (for example, expropriation, political violence, currency inconvertibility, etc.), according to the terms of the underlying guaranteed financial obligation. MDBs have high bond ratings (AAA) that enable them to provide substantial credit enhancement to sovereign and sub-sovereign obligors.

Second, multilateral guarantees help to diversify funding options and catalyze private financial flows to emerging market countries by mitigating government performance risks that private lenders are reluctant to assume. This helps to create a more stable financing structure in emerging markets. The close association of MDBs with governments and preferred creditor status can open the investor base more broadly and mobilize resources well beyond the guaranteed amount. This is the so-called 'halo' or 'crowding-in' effect.

Third, MDBs determine country allocations according to their strategic objectives in their respective portfolios, the absorption capacity of each sector and region, and other internal policies. As discussed in more detail below, some MDBs analyzed in this article recognize commitments on guarantees as counting only toward 25% of the country's lending envelope.

Last but not least, MDB involvement in MDB-supported projects provides a strong incentive to host governments and their state-owned entities to honor their contractual obligations. A government or state-owned utility's failure to honor commitments under an MDB-supported project could trigger reimbursement obligations under an indemnity agreement from the host government and potentially jeopardize existing and future development financing to the country.

Practical Obstacles

Despite these advantages, guarantees have been significantly underutilized to date compared to other forms of development financing. The MDBs considered in this article approved a total of US$40.17 billion in non-trade project guarantees between 2004 and 2015, which represents 4.4% of the total development financing over that same period.

There are several possible reasons for this apparent underutilization. MDBs face a number of major impediments to using guarantees more extensively, most notably linked to their risk capital allocation, costs, and lack of visibility.

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Table 1: Comparison of World Bank and MIGA Guarantee Instruments

	IDA and IBRD	MIGA
Objective	Mobilizing private finance and mitigating government-related risks for strategic projects to support economic growth and improved public services.	Promoting economic growth and development by facilitating private investment in its member countries.
Products and Risks Covered	• Project-based guarantees and policy-based guarantees.	• Risks covered are non-commercial, including contractual, regulatory, currency, and political risks. • MIGA offers political risk insurance for non-commercial risks (currency inconvertibility, expropriation cover, war and civil disturbance, and breach-of-contract cover). • MIGA offers credit enhancement solutions (failure to honor sovereign financial obligations and failure to honor financial obligations for state-owned enterprises).
Eligible Clients	• Private (domestic or international) investors, covering debt and equity. • Sovereign, sub-sovereign, and state-owned enterprises.	• For its political risk insurance products: international private investors from MIGA member countries only, covering equity, quasi-equity, and debt. • For its credit enhancement products: sovereign, sub-sovereign, and state-owned enterprises.
Geographic Distribution	Principal beneficiaries are European and central Asian (ECA) countries (especially the Balkan countries) and sub-Saharan Africa.	Significant focus on Latin American countries in 2000s, shift towards ECA countries, and to a lesser extent sub-Saharan African countries.
Sectoral Distribution	Mostly in the energy sector.	Emphasis on the infrastructure and finance sectors and, to a lesser extent, the agribusiness, manufacturing, services and extractive sectors.
Required Documentation	Indemnity agreement, guarantee agreement, project agreements, and guarantee support agreements.	• Host country approval required from the outset. • Supporting documentation (feasibility study, financial model, loan documentation, financial statements, permits, lease agreements, any other agreements as required by MIGA).
Pricing and Tenor	• Concessional and not risk reflective. • For IBRD, 0.5% to 1%, with a maximum 35-year tenor. • For IDA, 0.75% with a maximum 40-year tenor.	• Premiums calculated on both country and project risk (i.e., not risk reflective). • Fees average 1% of the insured amount per year. Up to 15 years (possibly 20 if justified by the nature of the project).
Recovery Method	• Recovery from the government through indemnity agreement.	• No indemnity agreement required. • Arbitral award required for political risk insurance, but not for coverage for failure to honor financial obligations. • MIGA will subrogate investor's claim and seek reimbursement from host country through subrogation.

Starting with risk capital allocation, MDBs book guarantees on the same basis as loans for the purpose of risk capital allocation. Booking guarantees 1:1 with loans discourages the use of guarantees because guarantees are treated as a loan exposure for 100% of the amount, despite the fact that guarantees are unfunded until called. The rationale is that MDBs prefer to err on the side of caution to safeguard their AAA-rated balance sheets and shareholder capital. In practice, there have been fewer guarantees called per dollar of exposure than defaults on loans. For example, there have been no calls on the World Bank's partial risk guarantees for private or public projects since they were first issued in 1994.

Costs are another factor. An implication of the 1:1 treatment is that loans and guarantees are priced at the same level because MDB pricing is based in large part on the use of equity capital and cost of funding. MDBs rely on equity capital as money paid in to support their operations. The equity-to-loan ratio of most MDBs is in the 25% to 35% range, significantly higher than commercial institutions for which the ratio is nearer 10%. In practice, guarantees tend to have higher transactional costs than loans because of the need for a financier in addition to the MDB. All other things being equal, borrowers in these circumstances will be inclined to borrow through a single financier, rather than incur equivalent or higher costs in contingent loan instruments.

The last hurdle is lack of information and awareness of guarantees as a means of catalyzing private sources of finance. MDBs are essentially lending institutions and historically have prioritized their lending programs over their guarantee products. As a result, borrowers tend not to benefit from the full ambit of financing options that are at their disposal.

Major MDB Guarantee Operations

With these advantages and disadvantages in mind, it is important to understand the distinctions among the various development guarantees offered at the major MDBs or MDB groups selected for this article.

The World Bank Group, headquartered in Washington, includes the International Bank for Reconstruction and Development (IBRD), the International Development Agency (IDA), the Multilateral Investment Guarantee Agency (MIGA), the International Finance Corporation (IFC), and the International Centre for the Settlement of Investment Disputes (ICSID).

IBRD issues loans to governments of middle-income and creditworthy low-income countries on commercially attractive but non-concessional terms and provides both project- and policy-based guarantees. IDA issues concessional loans and grants to governments of the world's 79 poorest countries and provides project- and policy-based guarantees.

Project-based guarantees are issued for the benefit of specific investment projects in countries seeking to attract private investment whereas policy-based guarantees support a World Bank Group member country's policy and institutional actions through general balance-of-payments support.

MIGA provides political risk insurance or guarantees to public and private entities in order to promote foreign direct investment into developing countries against certain non-commercial risks to cross-border investments.

The IFC, the private-sector arm of the World Bank Group, issues long-term loans, equity, structured and securitized products, and advisory and risk mitigation services to private enterprises in developing and transition countries. Whereas IBRD can guarantee government obligations and seek reimbursement from the government if that guarantee is called under an indemnity agreement, the IFC is not allowed to make sovereign loans or accept sovereign guarantees as a basis for its financing. The IFC can provide guarantees against project risk and seek reimbursement from the project or the private parties if this guarantee is called, but cannot structure a guarantee with recourse against the host government.

The guarantee instruments offered by the World Bank Group can naturally converge in practice. For example, the 450-MW Azura-Edo power project in Nigeria benefited from IFC loans, MIGA political risk insurance, and World Bank partial risk guarantees or political risk guarantees to help mitigate risks. Last month, *EMEAFinance* magazine awarded the 2015 African public-private partnership prize to the Azura-Edo power project for its multi-sourced financing.

IBRD and IDA

The IBRD Articles of Agreement had envisaged IBRD to be a guarantee institution at the end of World War II; however, this proved to be impractical when the New York financial community became vocal about its suspicion that World Bank guarantees could "contaminate" the market for the Bank's bonds. As a result, the World Bank Group shifted its focus to loans rather than guarantees. It was during the debt crisis of the 1980s that the World Bank decided to revisit the issue of guarantees as an alternative means of attracting more foreign direct investment into emerging markets.

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By 2014, the World Bank adopted a new strategy that seeks to leverage private capital and expertise through expanded use of its risk mitigating instruments. It launched a comprehensive modernization of its guarantee policy and instrument. In brief, the reform marks a shift from defined structures (political risk guarantees and partial credit guarantees) to more flexible structures (project-based guarantees and policy-based guarantees).

The new policy also makes no distinction between countries under the non-concessional window (IBRD) and countries under the concessional window (IDA). Previously, IDA-only countries were offered political risk guarantees, but under the new policy, IDA-only countries have access to all types of guarantees (except for countries under certain fiscal or debt distress). To date, the World Bank guarantee program has seen 63 guarantee operations, with guarantee commitments valued at US$5.1 billion, spanning 45 countries. These guarantee commitments were able to mobilize a whopping US$21.7 billion in private capital.

The new World Bank project-based guarantee covers two types of risk: loan guarantees and payment guarantees. Loan guarantees cover loan-related debt service default for public or private projects whereas payment guarantees cover default of government payment obligations unrelated to loans for private projects only. The new policy-based guarantees support a World Bank member country's program to promote growth and reduce poverty where that country already has an adequate macroeconomic policy framework in place.

As for pricing, IBRD and IDA guarantees carry the same commitment fees and commitment charges as apply to IBRD loans and IDA credits, respectively, and, in terms of the Bank's financial exposure on the guarantee, they are booked on the same 1:1 basis that applies to loans. Pricing includes up-front fees that may be paid by the implementing entity or the private project in the case of project-based guarantees, or directly by the government in the case of policy-based guarantees. Once the guarantee fees are fixed, they remain unchanged for the life of the guarantee. In addition, commitments on IBRD and IDA guarantees count only as 25% of the country's allocation envelope.

MIGA

Since its inception in 1988, MIGA has issued more than US$33 billion worth of guarantee commitments in more than 750 projects across the world. In 2015 alone, MIGA issued a total of US$2.8 billion in guarantees for 40 projects in MIGA's member countries.

MIGA was established to encourage the flow of foreign investment to developing countries by providing political risk insurance, which is conceptually similar to a political risk guarantee, to cover an investor's equity or debt exposure, or both, in a qualifying investment. Over time, MIGA's activities became more focused on equity investments than debt obligations.

The holder of a contract can insure a government's commitments through a MIGA political risk insurance policy covering one or more of the following non-commercial risks: currency inconvertibility, political violence and expropriation risks, breach of contract (arbitration award defaults and denials of justice) and the failure to honor financial obligations.

Table 2: Comparison of Various AfDB Guarantee Instruments

	PRG		PCG		
	AfDB	**ADF**	**AfDB**		**ADF**
Sector	Public		Public	Private	Public
Pricing	Pricing is 1:1 with AfDB/ADF loans				
Leverage Effect	75% of an equivalent loan's risk capital allocation	25% guarantee amount deducted from performance-based allocation	75% of an equivalent loan's risk capital allocation		25% guarantee amount deducted from performance-based allocation
Maturity	Up to 25 years	Up to 40 years	Up to 25 years	Up to 15 years	Up to 40 years
Guarantee Fee	0.6%	0.75%	0.6%	Lending margin	0.75%
Front-End Fee	0% to 1% of Bank's maximum possible exposure		0%	0% to 1%	0%
Commitment Fee			0%	0.5% to 1%	0.5%

MIGA provides coverage for up to 15 years and, in some cases, 20 years if justified by the nature of the project.

For equity investments, MIGA can guarantee up to 90% of the investment. For loans and loan guarantees, MIGA generally offers coverage of up to 95% of the principal (or higher depending on the project).

MIGA coverage is made available to investors only if the financial payment obligation is unconditional and not subject to any defenses for non-payment from the sovereign, sub-sovereign or state-owned entity.

Just as the World Bank did, MIGA fine-tuned its insurance products in response to market demands. MIGA's coverage for failure to honor financial obligations is the latest, non-traditional MIGA insurance product that is Basel II compliant and designed primarily to provide capital relief to commercial lenders lending to public-sector entities in a MIGA member country. Such coverage protects the guarantee holder against losses resulting from a failure of a sovereign, sub-sovereign government or qualified state-owned enterprise with satisfactory credit ratings to make a payment when due under an unconditional financial obligation or guarantee related to an eligible investment and not subject to any defenses.

In contrast to MIGA's breach-of-contract coverage, the coverage for failure to honor financial obligations does not require the investor to obtain an arbitral award in order to file a claim for compensation with MIGA. Rather, a mere certificate is sufficient to file a claim for compensation. Among other benefits of the coverage is the timeliness of the claims determination period and the certainty of the date of payment of the claim.

With regard to pricing, MIGA prices its guarantee premiums on the basis of country, sector and transaction risks. Fees amount to approximately 1% of the insured amount per year, but can vary significantly.

Fees apply to the three different phases of the underwriting process. First, the definitive application fee amounts to US$5,000 for cover of less than US$25 million and US$10,000 for larger amounts. Second, a processing fee may be incurred where the project is complex and requires additional due diligence steps (for example, arranging a site visit). Last but not least, a syndication fee applies when MIGA secures a project's total insurance requirements through reinsurance.

IFC

The IFC adopted an official policy on guarantee instruments in 1988, six years after issuing its first guarantee in 1982.

The IFC only issues flexible partial credit guarantees that cover non-compliance with a financial obligation (loans or bonds) up to a predetermined amount, irrespective of the cause of default. The guarantee holder is not required to obtain a sovereign counter-guarantee in order to be eligible for coverage.

In practice, IFC guarantees range from 25% to 50% of the amount of a bond issue rather than a full "wall-to-wall" guarantee.

The partial coverage guarantee avoids moral hazard risks and encourages the market to make its own appraisal of the issuer and mobilize additional funds in local markets and in local currencies, without relying exclusively on the international capital markets.

With respect to pricing, guarantee fees are consistent with IFC's loan pricing policies. As of end of FY2015, US$3.168 billion in guarantees were outstanding (US$3.679 billion as of end of FY2014).

IADB

The Inter-American Development Bank was established in 1959 and is headquartered in Washington. It has 26 member countries located in Latin America and the Caribbean.

The IADB launched its policy on guarantees consisting of political risk guarantee and partial credit guarantees to both sovereign and non-sovereign borrowers. Sovereign borrowers are obligated to provide a sovereign counter-guarantee whereas non-sovereign borrowers are not required to do so.

The IADB's guarantee program was originally geared toward the private sector and that continues to be the case today. No guarantees with sovereign counter-guarantees were approved by the IADB in 2013 or 2014. By contrast, non-trade related guarantees are used minimally. In 2015, only two non-trade related guarantees without sovereign counter-guarantees were approved for US$112 million (four for US$33 million in 2013 and five for US$146 million in 2014).

IADB political risk guarantees offer political risk coverage for debt instruments for breach of contract, currency convertibility, and transferability, among other risks.

IADB partial credit guarantees can extend up to 50% of project costs with a cap of US$150 million. By contrast, IADB partial credit guarantees cannot exceed 25% of total project costs with a cap of US$200 million. As for smaller economies with limited capital market access, the IADB can guarantee up to 40% of projects or US$200 million, whichever is less.

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ADB

The Asian Development Bank is headquartered in Manila and is owned and financed by 67 member countries. The ADB's financing instruments include loans, guarantees, and other risk mitigation instruments.

The ADB only issues guarantees to public and private entities out of its non-concessional Ordinary Capital Resources window, but it has discretion to direct guarantees to its lower-income concessional Asian Development Fund window.

The ADB offers political risk guarantee and partial credit guarantee instruments. While the political risk guarantee instrument is similar in scope to MIGA political risk insurance, the partial credit guarantee covers sovereign payment risks through its guarantee covering failure of a sovereign to honor financial obligations. ADB partial credit guarantees are predominantly applied in the financial services, capital markets and infrastructure (for example, power, transportation, water supply, waste treatment, telecommunications) sectors.

Unlike the World Bank Group and African Development Bank guarantees, ADB guarantees can cover up to 100% of principal and interest in special cases; however, this is not done in practice due to moral hazard risks.

The volume of guarantees approved by the ADB jumped from US$20 million in 2014 to US$341 million in 2015. However, the dollar exposure on guarantees was down in 2015 compared to 2014. As of December 31, 2015, US$809 million in non-trade related partial credit guarantees and US$73 million in political risk guarantees were outstanding compared to US$903 million in non-trade related partial credit guarantees and US$114 million political risk guarantees as of December 31, 2014.

As for pricing, the ADB uses a similar price structure as the African Development Bank for guarantees. ADB political risk guarantees require a front-end fee, a guarantee fee, and a standby fee. By contrast, ADB partial credit guarantees require a front-end fee, a guarantee fee, and a commitment fee. Policy-based pricing applies for guarantees that benefit from a sovereign counter-indemnity.

AfDB

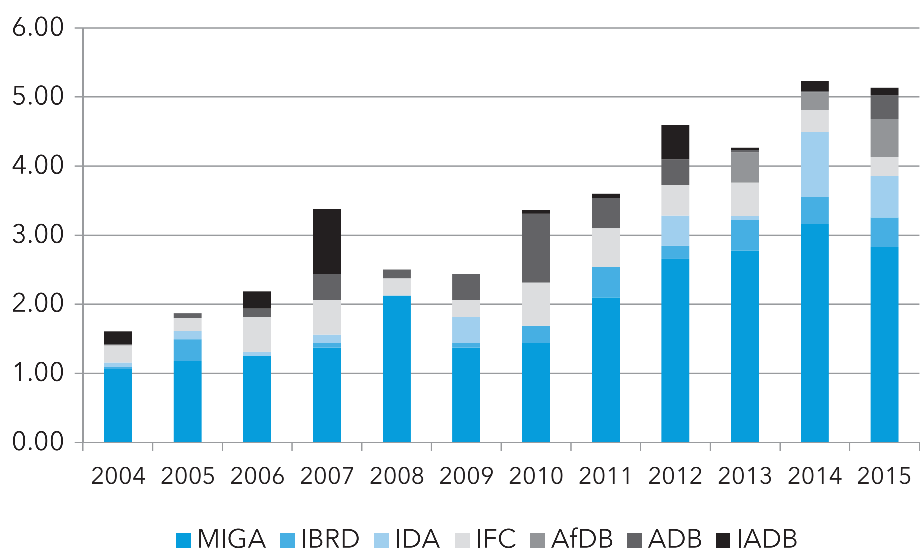
The African Development Bank Group is headquartered in Abidjan, Côte d'Ivoire. The AfDB Group's regional member countries benefit from funding from the following three windows: the AfDB, the African Development Fund (ADF), and the Nigeria Trust Fund (NTF).

The AfDB window is used for non-concessional loans to creditworthy members while the ADF window is used for long-term low-interest loans and grants to the least developed members. The NTF window is used for financing at below-market rates for the poorer regional members.

As with other MDBs, the AfDB Group's financial products have evolved over time, mostly in response to market demands. In addition to loans, the AfDB also issues guarantees and other risk management products. A formal guarantee policy was launched in 2004, and a political risk guarantee was subsequently issued in 2012.

The AfDB Group issues two categories of guarantees: political risk guarantees and partial credit guarantees.

Table 3: Total Volume of Non-Trade Guarantee Commitments, Selected MDBs (US$ billions)



Note: Data from 2004 through 2013 are sourced from Humphrey and Prizzon. Data from 2014 and 2015 are drawn from MDBs' official annual reports and financial statements.

The AfDB guarantees share many similarities with World Bank guarantees, including the requirement of an indemnity agreement between the regional member country and the AfDB. Moreover, ADF political risk guarantees count only as 25% of the country's performance-based allocation, which is the equivalent of the World Bank's country allocation envelope described earlier. By contrast, AfDB political risk guarantees count toward only 75% of book value for purposes of capital risk allocation.

Table 2 shows the principal differences among the AfDB's public and private political risk guarantees and partial credit guarantees.

The AfDB has issued very few guarantees over the past few years. In 2014, the AfDB approved only five guarantees with an approved value of US$250.7 million in total. In 2015, the total number of approved guarantees increased to seven, with a cumulative value of approximately US$965.7 million. Although the AfDB's guarantee usage has been minimal, the Bank's ADF political risk guarantee was used in the Lake Turkana wind power project in Kenya, Africa's biggest wind power project, which went on to win the 2015 African deal-of-the-year award.

Trends, Recap and Recommendation

Table 3 shows the volume of non-trade guarantee commitments by the MDBs or MDB groups that are the focus of this article. The data spans the period 2004 through 2015 during which US$40.17 billion in non-trade guarantees were issued across the MDBs or MDB groups. It represents a mere 4.4% of total development lending by the MDBs over the same period.

As can be seen from the data, MIGA has issued the most guarantees compared to other MDBs, which is hardly surprising, given that MIGA's mandate is tied to the issuance of guarantees. It is also apparent from the data that the global financial crisis in 2008 saw a downturn in guarantee issuances, in light of the lack of available credit in the international markets at the time.

Going forward, MDBs need to take steps to address this apparent underutilization of guarantees. As previously mentioned, guarantees face three major practical impediments: risk capital allocation, costs, and lack of visibility.

First, in terms of risk capital allocation, there are proposals to establish set-aside funds for guarantees so that their usage is marked against the set-aside fund and not their country allocations. There are also recommendations that MDBs should consider reducing the equity capital allocation for political risk guarantees because they are less likely to be called compared to partial credit guarantees.

Second, regarding costs, guarantees are currently booked 1:1 with loans despite the fact that guarantees are unfunded at the outset. The pricing for guarantees should be reduced, and loan charges should be increased, in order to stimulate greater use of guarantees, especially in the public sector, in light of their importance in achieving important developmental objectives.

Last but not least, MDBs, potential guarantee users and beneficiaries, and the wider project finance legal and financial community should promote greater awareness of guarantees and organize training programs on the technical aspects of these guarantee instruments.

This article reviewed various guarantee instruments offered across four major MDBs, giving details of the different options that eligible clients may take into consideration or MDB groups when applying for a guarantee. As discussed, the various MDBs have been compelled to fine-tune their guarantee instruments, and broader risk mitigation products, in order to adapt to modern trends and create new opportunities to mobilize additional funds in more effective ways.

To date, guarantee usage has been minimal in contrast to other forms of MDB development financing. More robust institutional and operational incentives should be adopted by MDBs in order to promote guarantee usage as an effective means of achieving important developmental objectives in emerging markets.

The Rooftop Solar Business Model in Transition

Where is the rooftop solar business model headed with business possibly shifting to direct sales, analysts pressing for positive cash flow and at least 10 states expected this year to revisit their net metering rules? A group of panelists addressed these and other questions at the Chadbourne 27th annual global energy and finance conference in early June. The following is an edited transcript.

The panelists are David Field, CEO of OneRoof Energy, Mina Kim, general counsel of Sunrun, Nicholas Mack, general counsel of Spruce Finance, Robert Scheuermann, president of SoCore Energy, and Jorge Vargas, head of the Americas for the AMP Solar Group. The moderator is Todd Alexander with Chadbourne in New York. */ continued page 64*

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MR. ALEXANDER: Mina Kim, is the solar rooftop market moving in the direction of direct sales where customers buy rooftop systems rather than sign long-term power purchase agreements for electricity or long-term leases to rent the rooftop equipment?

MS. KIM: No. We are not seeing any change, frankly, away from third-party ownership of rooftop systems. About 15% of our business is direct sales. That percentage may move up a bit, but not a ton. Any shift toward direct sales is driven more by our distribution channels at any particular moment in time than by consumer demand. We do not see a long-term trend toward direct sales.

The recent extension in the investment tax credit should mean there will remain an incentive for third-party ownership over the longer term. Residential tax credits for direct sale transactions will go to zero after 2021, but third-party-owned systems will continue to benefit from a 10% tax credit.

Rooftop solar companies are under pressure from Wall Street to move to a model that generates positive cash flow.

MR. ALEXANDER: Nick Mack, do you agree?

MR. MACK: I have a slightly different view than Mina. We are seeing more of a balancing. For example, in the California market, which is the largest residential solar market in the country, third-party-owned systems were about 70% of the market over the last few years, and I think we will see for the end of 2015, 2016 and probably 2017 a move toward more of an even split between third-party-owned and direct sales with financing or straight cash.

I think that third-party ownership still offers a lot of value to a large segment of consumers, especially those who do not want the up-front cash outlay or who are somewhat intimidated by the concept of ownership and want someone else to monitor and care for the equipment.

At the same time, as homeowners become better educated about solar and as the price of an installed solar system comes down — it has basically dropped from around $40,000 to $20,000 for the average-sized system over the past several years — a lot more homeowners will be interested in ownership.

This will be particularly true during the next few years when direct purchasers of systems will still qualify for a 30% tax credit. We are seeing this trend in our deal pipeline.

MR. ALEXANDER: David Field, one selling point that bigger rooftop companies offer is the ability to put the whole package together. A solar PPA or lease is a form of long-term financing. As the cost of a rooftop system drops to $20,000, are homeowners more likely to take on the financing themselves?

MR. FIELD: I am more in Mina's camp. Homeowners buy what homeowners are offered, so it is a function of who is knocking on their door, calling on the phone or sitting down with them in their kitchens.

We continue to see the same consistent split of about 80% third-party ownership and 20% direct sales, notwithstanding the proliferation of companies eager to make loans to finance direct purchases.

Direct sales are driven by the thousands of solar installers that sell and install solar in the United States. They can make a lot more money if they sell for cash. There are a lot of these installers who say, "I am not going to sell Sunrun's PPA or our PPA or anything else, because the rooftop solar companies do not pay me as much as a cash transaction pays." Therefore, they sell only a Mosaic loan product or cash or other financial products.

At the end of the day, it is a function of who is in front of the homeowner. What we are seeing is that as more non-traditional solar distribution platforms come to the market, like retail energy providers, they find it easier to sell a PPA, basically sell an electricity rate, because that is what they do. They sell competitive electricity in the northeast and elsewhere as a rate.

I think that consumers want a choice. You will always have consumers who say, "I want to own something and want it simple, and I am fine taking care of the maintenance and everything else. It is part of my house." And then there are many others, I think the vast majority, that say, "This is a service. I am just buying electricity, so sell it to me like you would electricity."

MR. ALEXANDER: Jorge Vargas, on which side are you?

MR. VARGAS: I agree with David that consumers want a choice. I was doing research on solar back in 2009 when I was at a homebuilder called Lennar, and we were running focus groups to ask whether they wanted granite counter tops or solar on their roofs. At that time, people wanted granite counter tops, not solar. I suspect that has changed. Financing is becoming commoditized. When I was at Morgan Stanley, we thought that solar loans to make direct purchases would emerge as a new product, and we are seeing that right now. The industry is evolving.

Monetizing Cash Flow

MR. ALEXANDER: Mina Kim, the solar rooftop companies had been looking to the ABS market and securitizations as a way to monetize the cash flow from rooftop systems. Seven solar securitizations have been done to date, but that market appears to be in a temporary stall. Spreads have widened in the broader ABS market to a three-year high. How is inability to place paper in that market affecting your strategy, if at all?

MS. KIM: We did a securitization in July 2015 on what we thought were very attractive terms. We had an A tranche and a B tranche. The A priced at something like 240 over and the junior piece priced at something like 340. It was a very attractive financing for us.

I know there has been a lot of speculation about what the market has been doing recently and, frankly, the bankers in the room are better placed to talk about what is going on there in terms of the trends. The important point is that the underlying assets remain high-quality assets. Since inception for us on our fleet, we have collected 99% of billings. We are replacing an existing household debt load. Our customers are basically paying us the utility bill, but at a discount to what they were already paying. There is no new debt created for the homeowner.

In the long term, putting aside the market noise, there is no reason our service won't continue to find a strong market. We are offering an easily recognizable benefit to consumers.

MR. ALEXANDER: Jorge Vargas, how large a portfolio does a rooftop company need to have before it can start thinking about a securitization?

MR. VARGAS: We were in the market with a C&I portfolio of $100 million and that was considered small, so I think you need to be at least at that level.

MR. ALEXANDER: How many different installations do you need?

MR. VARGAS: I can't remember all the numbers, but ours was about 2,500 residential systems and about 250 C&I installations. It was small. There were some concentration issues. The securitization ended up not going forward.

MR. ALEXANDER: David Field, does the securitization market have appeal to you?

MR. FIELD: It has served the industry well so far. It is still at an early stage. We think there are good opportunities in the bank market, and they are a lot less time consuming and complicated to realize.

Other financial tools are becoming available. Everyone is trying to put in place more warehouse facilities to amass assets long term.

At the same time, we have an investment climate that does not value the players in this industry from a pure asset aggregation perspective. That is why we have seen a number of companies try to raise equity against assets recently.

So I think, A, securitization is a valuable tool, B, we are seeing other tools becoming available because, C, there are different ways of valuating these platforms, and that issue is still in flux.

MR. ALEXANDER: So why do you think we have seen the recent slowdown?

MR. FIELD: There is a tremendous amount of pressure right now for profitability in the residential rooftop sector. Nobody is immune to it. It has caused everybody to look differently at how we are monetizing or liquidating assets in order to fund ongoing working capital needs, as opposed to the traditional method of raising equity and being cash flow positive.

C&I Strains

MR. ALEXANDER: Let's move to commercial and industrial solar. The press has been focused lately on strains in the residential rooftop sector, probably because it is of more immediate interest to newspaper readers, but the C&I sector is under the same pressures. How has the increased scrutiny brought on the industry by the SunEdison travails affected your business?

MR. SCHEUERMANN: We are part of a larger company, and so our financials stay blended within Edison International, but there is tremendous pressure to grow earnings and not to be a residual cash flow valuation in the larger scheme of things.

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We see a trend moving in the opposite direction from what you are seeing in residential solar, where more and more of our customers are really looking for PPA solutions. SoCore has historically done a lot of EPC work. It is a good cash flow business. The construction progress payments over the two or three months that it takes to build a project are commensurate with the cash outflows. The earnings look good. However, more and more of our customers are saying they would rather sign a long-term PPA to buy electricity than have to spend money upfront on installing solar equipment.

Or we have new customers who say, "This is a great value proposition. I can save X% on my power bill. You will own the system. You will take care of it." This is easy to get approved.

The trend has been toward PPAs, which makes us think about our financing structures and how much of the value in the company we want to be a residual play.

When you are building an operating company, you have to cover the cost of overhead. Luckily we are part of a much larger organization. Where others are constantly seeking external capital to fund their operations and are under more pressure and scrutiny after SunEdison collapsed, it is not as much a challenge for us.

MR. ALEXANDER: How large a discount do you have to offer a C&I customer from its current electricity rate to get it to talk to you?

MR. SCHEUERMANN: I am guessing we have a few competitors here, so it will be a range between 0% and 100%. [Laughter] Look, if you cannot save your customer at least 10% out of the gate, then you are probably not going to get any traction.

In some markets, like New Jersey with the way the SREC pricing has gone lately, there are huge savings for customers. In other markets, if you can get 10% to 20% savings out of the gate and the escalator in the contract price for electricity is lower than the projected tariff increases, then the customer could have substantial savings over time, as well.

MR. ALEXANDER: Jorge Vargas, you are also chasing C&I. Do you have anything to add about originating business, and what type of pressure do you feel in this market segment?

MR. VARGAS: You have to show up with a good value proposition. Our C&I effort is with community solar. It is a little different because we are building a utility-scale solar array. One of the things we struggle with is the long lead time between when we sell the C&I customer power and when the electricity starts to flow. It can be 12 to 18 months before the electricity starts to flow. We have a warehouse debt facility, but you have to show subscriptions before you can draw on it. We are looking in the meantime for other sources of revenue to be cash positive.

AMP has been cash-flow positive for the last few years, but last month we acquired a small EPC contractor to diversify our revenues and to be able to have some cash flow intermittently through long development cycles for solar. We are definitely feeling the same pressure to show positive cash flow as the residential rooftop companies.

MR. ALEXANDER: Where does the financing come from?

MR. VARGAS: At AMP, we are doing an equity warehouse. We use it to acquire projects and that way we don't have to deal with construction financing. It is like a credit card that we use to acquire projects. Then we layer on the tax equity.

Commoditization

MR. ALEXANDER: Let's talk big picture about the industry. One thing I find very interesting about residential solar is the companies have fantastic websites. You think you are buying solar, but it is almost as easy as buying a book on Amazon. You put in your address, and you find out what the cost is. When you see a whole industry moving to this point, then it becomes a question of who is the lowest cost provider. The customer is buying a commodity. This argues for large scale.

On the one hand, you could view residential solar as competing against retail rates. On the other hand, you could view it as a competition against everyone else who is providing residential solar because customers can get on the internet and solicit and compare offers.

Does this suggest the residential rooftop market is headed toward having just a few champions? People will know them like they know Amazon is the place to buy a book?

MS. KIM: I think fundamentally we feel that we are competing against retail rates. That is fundamentally the customer proposition and the customer value. I think the differentiators are in quality of installation and customer service. We believe that we put the customer at the center.

We don't know that the utilities do that or are good at delivering the kind of customer service that we think the rooftop industry is moving toward.

We continue to believe that the best value for the customer is in the third-party-owned product, and we do not see that changing over time. It is hard to say what that means for some of the smaller players.

MR. ALEXANDER: Nick Mack, can I count on you to disagree?

MR. MACK: I am not going to disagree entirely. I agree that fundamentally the value proposition is in offsetting the retail utility price.

What is interesting is you are starting to see a little bit of a step back from vertical integration. See what has happened with SolarCity and its MyPower loan product that was supposed to finance direct sales. Granted, that product had some challenges just in the way it was structured, but it is also an indication that it is difficult to run an origination and installation business and a financing business and a long-term asset management business all under one roof.

Sunrun is one of the few examples remaining in the industry of a company that is doing it all, and it seems to be doing well. This is a capital-intensive business. It is challenging to do it all in a vertically-integrated company. That is where companies like Spruce have a great opportunity because we focus on one segment of the overall residential market, which is providing financing, and we work with partners who want to focus on other segments.

There are companies that are very good at origination. That is all they want to do. There are companies that are very good at installation. That is all they want to do. Having such companies work together gives consumers more choice.

It is interesting to look at how consumers make their buying decisions. Some definitely want a brand name, and Sunrun and SolarCity have both spent a lot of time building brands. They have broad name recognition. They spend a lot on marketing. It drives up their costs, but it also increases their deal pipelines.

There are a lot of consumers who view home improvement as a much more personal interaction where they want to deal with somebody local. They get recommendations from their friends. Some of those recommendations are going to be for the big vertically integrated companies. Others are going to be for smaller contractors who have worked in the neighborhood for many years and who may offer financing through another source.

MR. ALEXANDER: David Field, are people shopping among websites or is it really a matter, as you said earlier, of who comes knocking on the door?

MR. FIELD: You are going to see a much more competitive market. Understand that residential solar is still a cottage industry. The first solar lease was written in 2008 by SolarCity. That was just eight years ago. Today, real professional sales and marketing companies are coming into the space, guys that sell 15,000, 20,000 customers a month for competitive energy on the east coast.

These guys know how to market energy. They have existing books of business between 200,000 to a million customers. These guys know how to convert potential customers into buyers. They are migrating to the space because they can make 10 to 15 times more money per customer.

What that should tell us all is this is electricity. It is not rocket science. It is a commodity, and the lowest cost wins. Right now in most markets, if a solar installer sets up an appointment to sit in your home and pitch you solar, it will walk out of your home 40% of the time with a contract signed.

That tells you that homeowners do not go out for bids. They do not know who you are. They do not even know what brand equipment you are using. It is an impulse buy. Most Californians will tell you that they have had their doors knocked on at least eight times, and they do not open the door anymore. More than 50% of solar in the United States is sold door-to-door like the Fuller Brush salesman.

That model is not scalable, and it is not low cost. If you really believe that it is going to become competitive energy, because it is electricity, then customer acquisition techniques will change, and you are going to see a different type of vertical integration. It will not be the classic form that we have seen in the past. You will see vertical integration around the sales and the customer-capture side, and you are going to see more platform-oriented companies.

When I say platform-oriented companies, if a major energy retailer sells something to a homeowner who wants to get into solar, it will not set up a solar division. That is way too complicated. It will never figure out tax equity structures or asset management or you name it.

It will come to one of us and say, "Can we partner with you? We know nothing about solar, but we know that we can make a ton more money doing it. So tell us how to do it."

If you look at the largest solar dealers in the United States today, the largest guys, they simply cannot exist on the margins they are earning today.

They are constantly running out of cash and their margins are razor thin, and prices are continuing to come down. The prices that Sunrun or Spruce or we are willing to pay them go down, which is why they migrate to cash and loans. If that is how a good part of the market is selling solar today, then it tells you that the business model is ripe for change.

We are at an inflection point where I / *continued page 68*

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believe you are going to see a lot of new players come into the space. You will see more of the Amazon-type of approach. You will see more brands because brands increase conversion ratios for homeowners and that lowers your cost of customer acquisition.

Revamping C&I

MR. ALEXANDER: Rob Scheuermann, the C&I companies have had a problem because their projects are small but each deal is separately negotiated, so the deals are expensive to do. What do you see as the trend there?

MR. SCHEUERMANN: I think there will be a much bigger transformation in the C&I business than just vertical integration or consolidation. The changes will be driven by the need to get to a lower-cost product.

The market will not be limited to long-term owners like SoCore. That is a thin slice of what the customer base wants. The customers are looking for comprehensive solutions. They want energy as a service.

We are part of a broader push within Edison to roll out integrated solutions to Fortune 500 companies. Solar will be only a part of these solutions. The solutions will also include battery storage, micro-grids, energy efficiency and energy procurement.

We see a long-term trend toward a broader platform of services, at least for commercial and industrial. You will still see some smaller solar players, but it is very difficult to make money to support the cost of the machine. If you are just rolling out 30 to 50 megawatts of projects a year, it is very hard to create enough value to cover the overhead.

The C&I solar business has not grown the way residential has. It is a crowded space as well. It is very tough to install 150 to 200 megawatts a year of C&I.

MR. ALEXANDER: Jorge Vargas, what is the future for C&I? It seems to suffer from high transaction costs relative to the size of the deals. It is difficult to standardize.

MR. VARGAS: I think the issue is financing. There are a lot of potential customers for C&I, but there are a lot of unrated credits. There are a lot of small strip malls and others that, when you take the projects to tax equity, they say, "No way."

To me, the key to C&I is unlocking the financing so that you can offer a meaningful discount to customers. Finding a solution to that is the biggest current challenge.

MR. SCHEUERMANN: It has been a constant struggle to get financiers comfortable. Eighty to 90% of the customers are not investment-grade corporates. They are real estate developers who have really solid office buildings on which they are looking for solar, but they are not going to put a corporate credit behind it, and their tenants stay for an average of five years.

Opening up that part of the market is key. A lot of times, it is a couple megawatts here and a couple megawatts there, and you tuck them into an investment-grade portfolio, and your banks say, "Okay, we can live with that."

I think the real solution is if some financiers come to the table with a whole platform. They say, "Give me your five or 10 or 20 megawatts. We will combine them with another 200 megawatts that we have from other sources." Build the diversity that way.

Net Metering

MR. ALEXANDER: Let me change topics to net metering. You see a lot of the utilities complaining that the rooftop solar companies are picking off their best customers with the highest FICO scores and then using the grid basically as a battery for the excess power generated by the solar systems during off-peak hours, but not paying full fare for this use of the grid. We saw the utilities in Nevada succeed in rolling back net metering. Where do you see the net metering debate headed, and what effect will any changes have on the C&I and residential solar companies?

MR. FIELD: It is no secret that there is a lot of pressure on net metering across the country. The pressure will continue. At the same time, I think that you will see states like California come out with more balanced approaches and serve as a bellwether for most states. Not all states. There will always be outliers like Nevada.

By and large on the residential side, we still see growth at rates of 50% to 100% year over year, which is pretty phenomenal. This has become a populist issue, which is why it was such a no-brainer for the California Public Utilities Commission to do what it did. You end up with a lot of homeowners that are vested in the space and believe in energy independence. Utilities are usually not well liked by their customers.

MR. VARGAS: How do you fend off the utility argument, though? There is a logic to it.

MR. FIELD: No, no, what I am saying is this. The system has to change because there is a logic to the utility argument that you cannot ignore. But as net metering changes, it will change in a balanced way. It will change through appropriate rate design at the same time that costs for delivering solar continue to come down.

You will see progressively over the next three to five years real change throughout the system, but it will not come at the expense of one or the other is all I am trying to say.

MR. ALEXANDER: Will solar customers have to pay fixed monthly charges to help support the grid? How will we reach a new equilibrium now that the amount of residential solar is growing to a scale where it is having an effect on the overall system?

MS. KIM: There is no one in the world who is more tired of talking about Nevada than I am. But I am going to do it again. Nevada is an outlier. There are 42 states today that have net metering. I think 95% of them have been supportive of net metering. There may be a shift. I think California is a model for the future. It is one that supports our industry, and we think it is a great outcome.

More than 50% of rooftop solar is still sold door to door.

MR. ALEXANDER: What in particular do you like about California versus Nevada or the other states that have revisited their rules in this area?

MS. KIM: It is a matter of appropriate rate design. There is time of use. There is a non-bypassable charge. The rate regime still supports savings in residential solar. We think it is a model that works for us.

California has been a leader. Nevada was an outlier. A lot of attention was focused on the lack of grandfathering in Nevada for homeowners who had already installed solar. Even Arizona, which has not been terribly friendly to rooftop solar, has been very clear that any changes will not affect existing solar customers.

MR. ALEXANDER: Nick Mack, what do you see as the impact if net metering rules are changed, and what are the overall opportunities for growth in this industry?

MR. MACK: I agree with my fellow panelists that net metering reform the way that California has done it is good for the industry, and I think it is also good for the utilities. A connection charge and some sort of base-level customer bill charge to support the grid make sense.

Net metering in its initial conception was kind of a blunt instrument, and it is being refined in ways that ultimately may not support solar in a few states. This will be a temporary glitch. This industry has gone through plenty of those and figured out ways to overcome them.

I will be curious to see how distributed storage plays into this. Over time as the solar equipment, including batteries, becomes cheaper, you will see more customers adding storage, allowing them to drop off the grid altogether, making net metering less important.

MS. KIM: That is a really important point. We have already started seeing this in Hawaii. We have launched a solar-plus-storage solution in Hawaii in response to what has happened there on the regulatory side.

Batteries

MR. ALEXANDER: Battery storage is always a hot topic when people talk about renewables. You just touched on it in Hawaii. Is battery storage ready for prime time and, if the answer is not currently, how long will it be before there is widespread deployment?

MS. KIM: We launched a product in Hawaii. It works there. As for the pace of adoption in other places, that will be driven by cost. The cost of storage is expected to come down by 40% by 2020.

MR. VARGAS: AES has been incredibly successful in California deploying big batteries. In Mexico and Puerto Rico, for example, some solar projects have had to have batteries to be considered for utility RFPs. You are already seeing it.

MR. FIELD: There is already a business case for batteries in the residential sector in two places. One is in Hawaii, and the other is on the east coast for backup generation for homeowners who do not want to lose power after the next storm.

Costs are coming down. As costs continue to come down, there will be more and more business cases for it.

Environmental Update

The US Environmental Protection Agency filled in details in late June about how it will reward generators in states that move early to reduce carbon emissions ahead of deadlines in the Clean Power Plan.

The rewards are under a part of the Clean Power Plan called the "clean energy incentive program."

The Clean Power Plan assigns each state individual carbon reduction targets and requires each to submit an implementation plan demonstrating how it will achieve them. States that fail to submit plans will have a federal plan imposed on them.

The plan is currently stalled after the US Supreme Court imposed a stay on implementation in February to give it time to hear arguments about whether the plan goes beyond what the Obama administration has legal authority to do. The court is not expected to render a decision until late 2017. A number of states and Indian tribes have said they plan to continue working on their own implementation plans anyway. EPA continues to provide support.

Owners of qualifying projects in states that cut emissions ahead of deadlines in the plan will receive emission allowances or emission rate credits in 2020 and 2021 for the electricity they save or the renewable power they produce. These allowances or credits can be sold in the market for cash.

EPA originally proposed that only solar and wind projects were eligible for allowances or credits. It proposed in late June to expand eligibility to geothermal and hydropower projects.

The date that projects become eligible to receive allowances or credits has also changed. Eligibility had been tied to the date on which a state submitted its final implementation plan, with final plans due on or before September 6, 2018. With that deadline no longer applicable in light of the US Supreme Court stay, EPA is now proposing that qualifying energy projects in all communities should become eligible for matching allowances or credits if they begin commercial operation on or after January 1, 2020. EPA also proposes that energy efficiency projects in low-income communities become eligible for double the matching allowances or credits if they begin operation on or after September 6, 2018. With the length of the stay uncertain, these dates remain subject to change.

A project will be considered a low-income project if it is in or benefits a low-income community. A project will be considered in commercial operation when energy is being sold for renewable energy projects or when the community is saving electricity for energy efficiency projects.

Opponents of the Clean Power Plan are arguing in court that the Supreme Court stay prohibits EPA from working on any element of the plan, including the incentive program. The attorneys general of Texas and West Virginia and Republicans in the US House of Representatives are calling on EPA to cease action on the incentive program on grounds that that its continuing work on filling in details of the program amount to a "shadow regulatory structure" that undermines the stay.

EPA is accepting comment on the latest proposals until August 29, 2016.

Clean Water Act

The US Supreme Court ruled on May 31 that property owners who are told by the government that their lands include waters subject to the Clean Water Act may challenge that finding in court immediately, rather than having to complete the process of obtaining a permit or subjecting themselves to the threat of an enforcement action for failing to obtain a permit.

The Clean Water Act requires a permit before discharging fill material or other pollutants into "jurisdictional" waters, meaning certain streams, wetlands and other water bodies. As a practical matter, most construction and related disturbances in jurisdictional waters are regulated and require a permit. The first step in determining whether a permit may be required is a jurisdictional determination by the US Army Corps of Engineers.

There are two types of jurisdictional determinations: "preliminary" and "approved." A preliminary jurisdictional determination advises a property owner that regulated waters may be present, while an approved jurisdictional determination definitively states that such waters are present or absent. An approved jurisdictional determination requires detailed fact finding and is the US Army Corps of Engineers' final decision. In contrast, preliminary jurisdictional determinations are not definitive declarations of jurisdiction, but instead operate as determinations on the scope of jurisdictional waters that the property owner has agreed not to contest. One of the purposes of a preliminary jurisdictional determination is to avoid a potentially lengthy and expensive regulatory process.

The Supreme Court held that an "approved" jurisdictional determination is a final agency action that can be appealed to a court.

Renewable energy projects may receive carbon allowances or credits under the Clean Power Plan that can be sold for cash.

The Court's ruling is narrow and limited to approved jurisdictional determinations, but it may help projects that are challenging preliminary jurisdictional determinations that affect jurisdictional waters. Until now, in instances of contested impacts, property owners faced a choice of moving to an approved jurisdictional determination in the hope that the outcome will be different or delaying project plans for months or years in order to secure the required permit. Before this decision, courts had held that approved jurisdiction determinations were not final agency action and, thus, not subject to judicial review until completion of the permitting process or commencement of enforcement proceedings. Now, in such instances, the property owner may go directly to court without waiting for the permitting process to be completed. The decision has no impact on preliminary jurisdictional determinations.

Lesser Prairie Chicken

The US Fish and Wildlife Service removed the lesser prairie chicken from its list of threatened species in mid-July after declining to appeal a Texas federal district court decision that vacated the listing.

It said it would re-examine the bird's status to determine whether a threatened listing is still warranted.

Fish and Wildlife said in a written statement, that "[r]esponding to this court ruling by removing the bird from the Federal List does not mean we are walking away from efforts to conserve the lesser prairie chicken. Far from it. We are undertaking a new status review to determine whether listing is again warranted, and we will continue to work with our state partners and others on efforts to protect vital habitat and ensure this flagship of the prairies survives well into the future."

The court said, when delisting the bird, that the government had failed to take into account the success that the species has had in re-establishing itself. "The LPC population has been increasing, the severe drought conditions have abated, oil and gas development has slowed significantly due to the decrease in oil prices, and wind development has not and seemingly will not pose a substantial threat to the species." The court said that ongoing multistate conservation efforts have also contributed to the success, and the Fish and Wildlife Service should have factored them into its analysis when it listed the bird.

These conclusions are hotly disputed by environmental groups, who criticized the Service for failing immediately to propose new protections for the bird. It remains to be seen which way Fish and Wildlife will go.

Climate Change

The US presidential candidates are offering voters a stark choice on the issue of climate change.

Republican presidential nominee Donald J. Trump has called climate change a "hoax" created by the Chinese. Trump also has said he will renegotiate the multi-lateral COP-21 accord that 174 countries reached in Paris last fall to work together to limit carbon emissions. By selecting Indiana Governor Mike Pence as the party's nominee for vice president, Trump doubled down with a vocal critic of any government efforts to address climate change.

Pence helped lead Republican efforts against comprehensive climate change legislation in 2009 and backed legislation barring the US Environmental Protection Agency from regulating greenhouse gas emissions when he was in the US House of Representatives. As Governor of Indiana, he vowed not to implement the Clean Power Plan to control emissions from power plants. He said, "I believe the Clean Power Plan as proposed is a vast overreach of federal power that exceeds the EPA's proper legal authority." Pence has called the idea that human activity is a primary driver */ continued page 72*

Environmental Update

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of climate change a "myth" and says he does not believe science has established a connection.

In contrast, Democratic presidential nominee Hillary Clinton said in her acceptance speech at the Democratic convention that climate change is one of the most important issues facing the US government. She has a long record of supporting legislative and regulatory action to address the issue.

Clinton's campaign has said she would probably focus on smaller legislative actions and employ executive powers in light of Republican opposition to more dramatic action like a carbon tax. This would reportedly include more investment in clean energy, energy efficiency and research and development, measures that could get traction in Congress because of the money that would flow directly to states and create jobs.

Clinton's choice for vice president, Senator and former Virginia Governor Tim Kaine, supports the Clean Power Plan and has a record of pressing coastal communities and military bases to prepare for rising sea levels. At the same time, Kaine has a more moderate record with the fossil fuel industry than Clinton, including past support for offshore oil drilling and legislation to put construction of LNG export terminals on a fast track.

Carbon Emissions

The US Department of Energy reported in July that the US transportation sector surpassed the energy sector in terms of the amount of carbon emitted for the first time in more than 30 years. According to DOE, the transportation sector now emits 25% to 30% of total US carbon emissions. The number of vehicles worldwide is expected to double in the next 20 years.

– contributed by Andrew Skroback and Richard Waddington in Washington

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