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America's Leading Renewables Market in Flux

Community choice aggregators in as many as 23 California counties, power marketers and customer-sited generation like rooftop solar could take as much as 85% of electricity load from utilities by the 2020s. The California Public Utilities Commission is in the process of changing two key constructs that are central to the economics of solar: net metering and time-of-use pricing. Storage is starting to gain a foothold and could displace gas peakers. Four key market participants had a lively discussion at the 28th annual Chadbourne global energy and finance conference near San Francisco in June about how these and other changes are transforming California.

The panelists are The Honorable Liane Randolph, a member of the California Public Utilities Commission, Jan Smutny-Jones, CEO of the Independent Energy Producers Association in California, Ed Fenster, executive chairman of solar rooftop company Sunrun, and Susan Kennedy, CEO of energy storage company Advanced Microgrid Solutions and former chief of staff to California Governor Arnold Schwarzenegger. The moderator is Todd Alexander with Norton Rose Fulbright in New York.

CCAs

MR. ALEXANDER: Jan Smutny-Jones, what are community choice aggregators?

MR. SMUTNY-JONES: It is fitting that this panel follows the Latin American one. California has a lot in common with our neighbors south of the border, except you / *continued page 2*

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NORTH CAROLINA opened the door to more solar energy while imposing an 18-month moratorium on new construction permits for wind farms.

Both actions are in a bill the governor signed in late July.

The solar provisions cut both ways.

North Carolina is second in the nation in terms of solar generating capacity with a little over 3,000 megawatts.

Solar developers have been able to enter into standard-offer contracts with North Carolina utilities to sell them electricity from small solar projects of up to five megawatts in size. The sales are at the utility's "avoided cost" the utility would have to pay to generate the same electricity itself. The bill reduces the project size to qualify for / *continued page 3*

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cannot get political risk insurance for doing business here. [Laughter] In 2002, after the California energy crisis, the state put a freeze on allowing electricity customers to choose their suppliers. We came up instead with the concept that communities can choose to leave the utility and form their own procurement entities.

It is important to understand that a CCA is not the same thing as a publicly owned utility. It is only doing procurement. This lay dormant for about a decade and then around 2010 to 2012, Marin County, which is north of San Francisco, formed a CCA. I think there are five now: Marin, Sonoma, San Francisco, the peninsula, and Lancaster, which is down in the high desert.

They are basically joint powers agencies that are not tied directly to a local government, so this presents a credit challenge. Are they creditworthy? They have been growing over the last couple years, and there is speculation that anywhere between 40% and 80% of the electricity customers will end up in CCAs.

One last important point: it is not really choice. If your local government decides to form a CCA, you become a customer of the CCA. You can opt out, meaning you can go back to your local utility.

MR. ALEXANDER: Susan Kennedy, you were on the California Public Utilities Commission around the time these rules were first being implemented. Was it intended that 20% to 80% of customers would procure their energy through community choice aggregators? Why were CCAs put in place? What do you think the impact will be?

MS. KENNEDY: Interesting. The market today is one in which commodity prices are going down, rates are going up, and there is an oversupply. These are the same conditions that preceded the energy crisis in 2000. But back then, as Jan suggested, you could depart the bundled service and be a direct-access customer.

Now that that gate has been shut and frozen, a CCA is the path of choice for communities that want to get out of bundled service. The concept lay dormant for a number of years because the economics were not compelling enough to use it, but we are starting to see the same conditions again where people are looking for alternatives to bundled service. A CCA is the place to go because direct access is not available.

MR. FENSTER: This is really just a longer-term trend that we see in our business and that drives our business: customers want choice. Rooftop solar is one manifestation of that. CCAs are another manifestation of that.

There is a hot debate about how this should work, but if a community leaves the local utility to form a CCA, there is a distribution charge or what is called a power charge indifference adjustment.

You are seeing a lot of CCAs supporting renewables. People want a higher renewables percentage than the local utility is currently offering. Marin has over twice the renewables procurement that PG&E has.

MS. KENNEDY: That's right. While the original motivation for CCAs was just wanting to get out of bundled service from the local utility in an effort to lower costs, the availability and falling prices for renewable energy have really fueled the growth of CCAs. The CCAs want cleaner energy.

MR. ALEXANDER: Jan Smutny-Jones, CCAs want more renewable energy. If I am a solar developer with a 100-megawatt solar project, can I sign a 100-megawatt power purchase agreement with a CCA and use that as a basis for financing my project? How do I prove to the banks I want to lend me money that the CCA is creditworthy?

MR. SMUTNY-JONES: There are several issues buried in that question. CCAs were originally not seen as a suitable foundation for building new large-scale power plants. The thought was new generators may sell some of their output to the CCAs, but not the entire output.

> California is struggling with how to do resource planning for a power system that is being atomized into smaller and smaller pieces.

Some of the CCAs have started recently to enter into long-term contracts. It is unclear whether this type of buying will become the norm or represents a few one-off situations.

I have been doing this for a very long time and my understanding of the wall of money that we have heard the investment bankers say is searching for projects has always wanted creditworthy counterparties. CCAs do not have credit ratings. Perhaps Marin is different. It has been in existence for a little longer than the others. It is a wealthy community. Maybe relying on it to pay is a low risk. However, creditworthiness is very much a live issue for how this phenomenon gets any momentum.

MR. FENSTER: It would be malpractice for anyone trying to start a power company today not to realize we are in a state of deep change in the electric industry. We have the rise of electric cars, which might add to load. There is an energy efficiency movement, which might reduce load. More people are opting for choice. More people want rooftop solar. Projecting exactly what load will look like five or 10 years out is as hard as it has ever been, and so you need to adopt an athletic position and be well capitalized to be able to move with the changing market.

Regulatory Challenges

MR. ALEXANDER: Perfect transition to the next question. Liane Randolph, how do the utility regulators plan in such a market? The state has a goal of getting to 50% renewable energy by 2030, and there is talk of pushing the target to 100%. How does the state plan in a market where it is not clear who will buy electricity from whom and who is obligated to do what?

MS. RANDOLPH: Ed said there needs to be an athletic approach. The PUC is exactly the opposite of that. [Laughter] We are a little slow, unwieldy and cumbersome, but we are trying to reframe our approach to long-term procurement in an integrated resource planning process that we are in the middle of launching. We are trying to be a little more resource-neutral from the supply and demand respect and trying to optimize a portfolio. The CCAs are saying they plan to procure as many renewables as possible, which is great, but we also need to look at the full landscape of reliability and costs.

The PUC has over the years really driven development of this great renewables market. We had the ability to tell the investor-owned utilities, "Thou shalt go do this, thou shalt go do that."

As load departs and goes more toward CCAs and customer choice, it creates a regulatory challenge to make sure that all of those entities are procuring the right mix of resources going forward.

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such contracts in the future to just one megawatt, and the size limit for contracts with individual utilities will drop to 100 kilowatts once the utility has signed 100 megawatts of standard-offer contracts after November 15, 2016.

Past standard-offer contracts had terms of 15 years. Future contracts will have terms of "up to" 10 years.

Developers with larger projects can negotiate directly with utilities, but any such power purchase agreements signed cannot fix the electricity price for more than five years.

In better news, the bill orders North Carolina utilities to issue requests for proposals to buy "energy and capacity from renewable energy facilities in the aggregate amount of 2,660 megawatts." The procurements are supposed to be spread over a 45-month period. Only projects of up to 80 megawatts can bid.

Utilities are allowed to build up to 30% of the 2,660 megawatts themselves. The rest must come from buying projects from developers or signing power purchase agreements with terms that are initially expected to run 20 years. The bill directs the North Carolina Public Utilities Commission to explore additional procurements after the initial 45-month period.

Independent generators will also have a third option. The bill directs each North Carolina utility that had more than 150,000 retail customers as of January 1 this year to set up a program where military bases, the University of North Carolina and other nonresidential customers with electricity loads of at least one megawatt in a single location or an aggregate of at least five megawatts at multiple locations can arrange directly with an independent generator to buy electricity, but then run the purchases through the utility.

The contracts would have standard content and run between two and 20 years. The utility must offer a range of contract terms; the customer can choose the length it prefers. The customer can also negotiate with the supplier over price.

A customer would not be able to contract for more than 125% of its peak

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MS. KENNEDY: I think it is the customers who are becoming more athletic. They are the ones who are driving much of the change. They are the cause of much of the difficulty for any load-serving entity to figure out how best to supply its load among gas, wind, solar and storage. The customer is now capable of responding to any price signal in a dramatic fashion. You have every load-serving entity, whether it is a CCA, bundled service or a direct access provider, trying to chase a moving target.

MS. RANDOLPH: You hit the nail on the head. Are we sending the right price signals to get what we need? Are customers being incented to do the right things for the grid and for reliability?

MR. SMUTNY-JONES: This raises a serious problem. The legislature, in its wisdom, decided that we need to do an integrated resource plan, which is fine if you have three entities that are doing integrated resource planning. We have done this in the past, not successfully, but we did it. Now, if you divide PG&E up into eight different pieces with different CCAs, what is integrated about that? How is that going to work? You will be shocked to hear that the CCA is telling the PUC, "You are not the boss of me."

It is an interesting question how to optimize the system while atomizing it into smaller and smaller pieces.

MR. ALEXANDER: Liane Randolph, I imagine the investor-owned utilities are not very happy. They have large stranded costs. They were obligated to enter into long-term contracts to buy renewable energy when it was still expensive, and now everyone wants to move to CCAs to buy renewables at the cheaper prices on offer today. How do you deal with that?

MS. RANDOLPH: Yes. That is the big issue before the commission.

MS. KENNEDY: The customers are following the price signals given to them through tax credits to encourage installation of rooftop solar systems, net metering, and feed-in tariffs. They are putting a bunch of solar on their roofs. The regulators are trying to catch up to what is happening in the market.

You have bundled utilities trying to push the time-of-use rates to later in the day in order to recover the system costs of trying to manage the electrons flowing back and forth on the grid. You have customers who put solar on their roofs saying, "Whoa, don't make me pay for somebody else's problem when I did exactly what policymakers asked me to do, which is go to clean energy by putting solar on my roof." This is a case where you have the regulatory bodies and utilities woefully behind on ability to catch up to where the market is.

MR. ALEXANDER: Ed Fenster, explain what California is doing with time-of-use pricing to try to balance the problem the utilities face with stranded costs with the interests of customers who put solar on their roofs.

MR. FENSTER: Let's talk separately about price signals and rate design. There is how we as a solar company deploying storage react, and there is a consumer education component. Time-of-use pricing is a good policy. We support it. What is it?

There are a few ways to set rate structures. There is a flat volumetric rate where every kilowatt hour you price costs a certain amount. You can do that by time of day where you say, "Between these hours, it is more expensive than between those hours." Maybe the prices also vary by whether it is summer or winter.

You can assess a demand charge which is based on the 15 minutes of your highest consumption during the month. Then there could be a fixed charge or a minimum charge.

In the residential sector, simplicity is really important. Demand charges do not work for homeowners because if I am using the microwave and someone upstairs is blow drying her hair, I don't know my electricity usage during that period. There is just no way to manage it.

It also should not matter because any customer turning on a couple appliances does not create system-wide grid cost. It is not like you have homeowners with aluminum factories in their basements. What matters is the aggregate system load, not the individual customer usage.

If it is the case that power is more expensive between four and seven in the evening, or whenever the hours are, then it is appropriate that a price signal is sent and we as a company can say, "Then we will start installing storage, and the batteries will shift the mid-day power so that it can be used later in the day." Maybe you install more west facing solar as a different example. We are actually nimble in responding to that.

One thing we learned, as net metering transitioned to time of use in California, is that it is a major effort to reeducate the customer base to adapt. There are tens of millions of people to whom you are effectively launching a new product. You have to think of the marketing costs necessary to explain the shift.

So we think these sorts of changes are appropriate, but they should be slow and well telegraphed because otherwise the marketing expense that we and our peers face ends up really high.

The alignment to socialized cost is important. We will see, particularly with the rise in storage, that the value of distributed resources on the grid is really high. The argument on the utility side about storage has been, "You are shifting costs to everyone else." Then the solar companies have said, "Yes, but every time we install a solar system on the grid, we are deferring investment in your transmission and distribution infrastructure. Less transmission needs to get built. The distribution system lasts longer."

In California, a lot of power plants are on the coast. I don't know how many of you are from California, but if you have looked outside, you can probably tell the coast would be a bad place to site solar systems because of all the fog. Our solar projects are on the other side of the state. If you then think about how you get to 80% renewables, our transmission grid is not really set up to accommodate that. Because the rooftop solar installations move renewable generation to the customer site, we are saving a lot of money as a state. Then when you layer in storage, which is beginning to happen, the numbers get even more exciting.

It should be obvious to everybody that storage is worth more on the customer side of the transmission grid than on the generation side of the grid because, if your pipe in between the two is full, it does not matter how much storage you have on the generation side.

For every 20 customers to whose system we add storage, that is one megawatt hour of storage. It is a 40-foot shipping container if you want to try to visualize it. Where are you going to put that in urban and suburban environments? We will need to see a lot of storage deployed. A lot of it will have to be distributed on customer sites because there is not a lot of other real estate in these places to do it.

So those are the components that I think make the value of solar and solar plus storage effective from a socialized perspective.

MR. SMUTNY-JONES: Now for something completely different. [Laughter]

There are some customers where what has just been described actually applies and may make sense. I am not disputing that. But the vast majority of people in my state, the 39 million people here, are not interested in this. They want the lights to go on. They want electricity to be affordable. They want it to be clean.

The group I represent also includes utility-scale solar generators. We heard a panel talk yesterday about how solar is being bid into utility auctions at less than 3¢ a kilowatt hour. That is not what is happening at the distribution / continued page 6

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load. Each covered utility must offer the program for five years or through 2022, whichever is later.

North Carolina utilities would not be required to enter into more than 600 megawatts of such contracts. Of that amount, at least 100 megawatts must be reserved for any major military base in the utility's service territory and at least 250 megawatts across all utilities must be reserved for the University of North Carolina. The military bases and the university have until the end of 2020 or three years after approval of the program, which is later, to subscribe for their full allocations. If not used by then, then the allocations can be used by other customers.

The utility would give the customer a bill credit to use against its bundled service from the utility for the contracted electricity. The bill credit cannot exceed the avoided cost the utility would have to spend to generate the electricity itself.

The bill opens the state to rooftop solar companies that want to offer solar leases. Such companies may only lease rooftop solar systems to customers; they may not sign power agreements with customers to sell them electricity.

This will make it challenging for the rooftop companies to do business with schools, hospitals and other government or tax-exempt entities, since solar equipment leased to such entities does not qualify for a federal investment tax credit or accelerated depreciation. Any "lease" to such an entity will have to be structured so that it qualifies as a "service contract" for federal income tax purposes to avoid losing the federal tax benefits.

The total solar leases signed in a utility service territory cannot amount to more than 1% of the utility's peak load on average over the previous five years. Customers can reserve space under the cap, but cannot transfer the reservation to someone else.

Any solar rooftop company proposing to engage in the leasing business must get approval from the North Carolina Public Utilities Commission. / continued page 7

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level. My first job was with Western Solar Utilization Network in 1980. If you told anybody back then we would have a problem with the duck curve, that we would have too much electricity in the middle of the day, that would have been unbelievable, yet that is where we are today.

In 2008, we had 300 megawatts of utility-scale solar in this state, and it was all solar thermal. Today we have almost 10,000 megawatts of utility-scale solar and another 5,000 megawatts on roofs. Things have changed significantly.

How this gets managed is a pretty big deal. There is a relationship between storage and net metering. One of the arguments is that if you are benefiting from net metering, you kind of already are using the grid to store your electricity. The utilities are giving you back power at night when you need it. It is supposed just to be a swap of kilowatt hours. If you are now talking about doing something else with respect to batteries, it opens up interesting legal and financial questions.

Utilities had to sign long-term contracts to buy renewable energy when it was expensive. Now customers are moving to community choice aggregators at the cheaper prices on offer today.

MS. RANDOLPH: Jan raises a great point because we at the PUC have to worry about the customers that are not focusing so much on their energy usage. They are not looking at rooftop solar. They are not looking at rooftop storage. They do not read their bill inserts, and do not go to the website and read the detail. They just want to know that they will have reasonable and consistent electricity rates.

The education lift of trying to get people to respond to price signals is huge. Most people don't think about electricity usage and price signals. All they see is the amount of their monthly bill. They don't understand why the number is changing.

In my household, we switched to time-of-use rates because I thought we had better walk the walk. I still can't get my 16-year-old not to turn on the convection oven the minute he walks in the door to do his California Pizza Kitchen frozen pizza, and then he eats the entire thing! [Laughter] I am dutifully waiting to turn on the dishwasher until 9 o'clock, but he still has that convection oven on at 4 o'clock. [Laughter] It is difficult.

MR. SMUTNY-JONES: The integrated resource plan will take care of it. [Laughter]

MR. FENSTER: At least it is only a convection oven. This is why storage is so important. One reason why there is some regulatory work to do is because a lot of our solar-plus-storage systems are like having a thoroughbred locked up in the barn. Our Hawaii installations involve just self-consumption. We never export to the grid, and we slowly draw power from the battery over night.

The much more societally efficient thing would be for HECO to call us in the evening, when solar is coming down and the gas stuff is coming up, and we would just blast the battery out. Then you could help with those transitions, but what we do not have yet is a rate or framework to do that.

The regulators, utilities and the distributed companies will be working together over the coming years to figure that out and to help solve these problems. As we get to higher concentrations of renewables, we are going to need the storage. Think about how helpful it would be for the solar eclipse expected in August to be coordinated in that way.

We have to get storage deployed, and then we have to figure out how to coordinate better, because there is a lot of societal value to be had.

It is fascinating in our business how our marginal cost is encroaching on the utility-scale cost. The marginal cost of increasing a customer's rooftop solar system from six to 10 kilowatts is now in the single digits per kilowatt hour. Ultimately we want to get as much renewables as possible: not just electric, but also for transportation and heating. If we install a larger solar system, we can switch a customer's heat from gas to electric and do it at a lower cost on the margin and then also start to strip away the greenhouse gas emissions from gas and oil use. There are things like that that I think are important to think about as well.

Whither Storage?

MR. ALEXANDER: Susan Kennedy, where do you think storage makes the most sense today? Where is it getting traction? What policies are needed to make the best use of the energy storage that is available?

MS. KENNEDY: The secret to energy storage is that nobody wants batteries. Everyone wants what the battery makes possible. It is a load control technology, and so the question is really who needs load control? Who is willing to pay for it? Where do the economics work paying for it?

It is challenging to make storage work on the residential side because of the economics of such distributed scale. The scale is a little better with large commercial and industrial customers. When you get into battery storage behind the customer's meter, the critical issue is where is the return on that investment and who will make such an investment.

There is an artificial delineation today. The distribution system stops at the customer's meter. Everything behind the customer's meter is retail, and it is the customer's problem.

The only way to get to a position of being able to use storage for load control and for system planning and distribution-level benefits in order to address some of the issues that Commissioner Randolph talked about is when the utilities have visibility into, and some control over, the consumption on a large scale behind the customer's meter. The economics have to be able to translate behind-the-meter energy storage at a large-scale level into distribution-level benefits at the utility scale. If not, the economics of deploying storage will never pencil out.

The simple answer is that the battery is a piece of the grid infrastructure. If Congress wanted to make a significant, huge investment in infrastructure, it would make the investment tax credit available for stand-alone storage and let storage be deployed where load control makes sense and let the utilities use it for customer load control in a transactional way in order to balance the grid.

MR. FENSTER: I have a little different perspective. One hundred percent of our new systems being sold today in Hawaii have storage. We probably have the leading market share as a result in Hawaii today. Fifteen percent of / continued page 8

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Utilities may also offer solar leases.

One thing that has made the solar rooftop business work is net metering, where a customer with solar on his or her roof can sell any extra electricity generated during the day to the local utility. The electric meter runs backwards, so that the effect is for the customer to sell at the local retail rate.

The bill requires each North Carolina public utility to file a revised net metering rate for use with customers who own or lease solar systems. The new rates are to be established after "an investigation of the costs and benefits of customer-sited generation" and must be at a level that ensures the customer pays its "full fixed cost of service."

Owners of rooftop systems that are already connected to the grid before any new net metering rates are approved can still do net metering through 2026 at the rates in effect when their systems were connected to the grid.

The bill would also open North Carolina on a limited basis to community solar.

In a community solar project, an independent developer builds a utility-scale solar array and sells subscriptions to local residents, businesses, schools and other potential customers. Community solar projects were originally conceived as a way for customers who cannot put solar panels on their roofs to benefit still from solar. The electricity from the array goes to the local utility. The subscribers receive bill credits from the utility for their shares of the electricity from the community array.

The bill requires each utility to file a plan for a 20-megawatt pilot community solar program in its service territory. An array cannot be more than five megawatts in size. Each subscriber must subscribe for at least 200 watts of output. There must be at least five subscribers per array. No one subscriber can subscribe to more than 40% of the output.

The subscriber must be in the same county as the array, but the regulatory commission can approve exceptions where arrays are up to 75 miles from the subscribers. / continued page 9

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Americans already have some form of back-up generation. Usually it is a gas back-up generator.

Homeowners are actually willing to pay for back-up storage and are willing to split the use of the battery with us. This is slightly more true on the east coast where the perception is the electric grid is less reliable than on the west coast. I am optimistic that customers across the country will eventually find the value proposition of having back-up power is significant enough that it will defray the cost. I am very optimistic about the long-term deployment of residential storage.

MS. KENNEDY: How much of the deployment is contingent on the investment tax credit and subsidies?

MR. FENSTER: We are first and foremost a solar company, and we do storage with solar so it qualifies for the investment credit. We suspect there is a market that is not necessarily tied to solar, but I agree with you it would make more sense if the investment credit were not written the way it currently is.

MS. KENNEDY: The point I am trying to make is that the utilities are struggling to figure out how to create reliability in a system where you have such mass deployment of solar. In such a market, attaching storage to solar is the responsible thing to do. It is the economic thing to do. However, unless it is part of the utility solution for control, for balancing supply and demand, then the cost for managing that is going to be borne by the grid or by all the ratepayers in that area.

MR. FENSTER: We are working on solving exactly that issue. We announced a partnership in January with National Grid to propose and build all the market mechanisms that would allow us to work with utilities on everything from capacity for the batteries to even frequency regulation and other forms of services. Texas is probably the only market you could do it right out of the gate because it is not regulated by the Federal Energy Regulatory Commission. It is a totally open market.

We are building our business plans around working with utilities so that if they need power during the evening solar ramp down or for any other reason, they can call us and we can guarantee to deliver it. We hope in five to 10 years that regulators will bid out in a competitive process new utility transmission and distribution facilities. We might even participate in that and see if we can do it, distributed, at a lower cost.

Tying Everything Together

MS. RANDOLPH: The California Independent System Operator had a stage I emergency last month or the month before, which is the lowest level of reliability. It basically misforecast the demand for that day. There was cloud cover. It was hot.

MS. KENNEDY: Cloud cover knocked some of the solar off line.

MS. RANDOLPH: Also some out-of-state resources were unavailable. There was no actual problem because the ISO was able to call on demand-response resources to reduce the load.

MS. KENNEDY: One of our clients is a large industrial that signed up for one of the reliability programs called "base interruptible program." It faced a $125,000 fine because it was not able to respond quickly enough to that stage I emergency alert. There is a huge mismatch in the economic signals we are sending and the ability to count on demand response.

MR. FENSTER: California has a demand-response program. We bid into it with our storage assets this year and will participate in it next year. It is not a perfect fit for storage, but it is still ahead of what other states are doing for behind-the-meter solar-plus-storage technology.

MS. RANDOLPH: Part of the problem is defining the products and the dispatchability correctly.

MR. SMUTNY-JONES: There is also a need for a more robust grid. Many years ago, I was chair of the ISO and if there are 1,000 megawatts of demand response, the guys who sit on the floor expect only half that to show up. In this case, I think 60% of demand response showed up. If you are a drowning man, getting 60% to the surface will not cut it.

As much as 85% of the electricity load is expected to move to CCAs and other suppliers by the mid-2020s.

[Laughter] We need some additional tools in the toolbox.

What was interesting is this was the first stage I emergency we have had in 10 years. As was indicated, it was cloud cover. It was a hot day. There were other factors. The odds of all that happening at once are remote. You design your electric system around those kinds of events. We have mentioned that we are going to have a solar eclipse on August 21, so please be riveted to the TV set to see how we handle it. [Laughter] It will be the Y2K of this generation. The ISO has hired a bunch of Mayan priests to help carry us through. [Laughter]

The point is that this is getting more and more complicated, and the good news is that you are seeing very creative alternatives to how to fix this, but in many respects it also creates an additional level of complexity in terms of trying to tie everything together.

MS. RANDOLPH: The eclipse is kind of an educational opportunity, right? We do not think the lights are going to go off, but it is a chance to get the attention of the people who don't look at their electricity bills, the people who don't look at the PUC website, the people who don't think about their time-of-use rates. They start to hear a discussion about how the sun will go away for a little while. We have all these gas-fired assets that will ramp up. Maybe you folks who are concerned about greenhouse gas emissions need to think about turning your devices off for a couple of hours in the middle of the day. If you have a solar system with a backup battery, you will be fine for those couple of hours. It is an opportunity to have that conversation.

MS. KENNEDY: The economics become front and center during system planning. Utilities and the grid operators have to plan for peak usage during the entire 12-month period, so we have all these resources on spinning reserve that need to be available, not for the expected eclipse on August 21, but for the day when the heat is high and the cloud cover comes over. It is incredibly expensive redundancy we have to build into the system to do things the old way. Currently 30% to 40% of our daily load in the ISO control areas is solar and other renewables.

In an efficient market, you would have negative pricing in the middle of the day. But we are not seeing it. What we are seeing is increasing proposed real-time pricing in the middle of the day because of all those redundancies. That is a distorted market.

We started this panel by saying entities will respond to price signals. Send the price signals for what you want people to do, what you want entities to do.

The economics do not support storage today, so regulators have to figure out how to send the right / continued page 10

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The subscribers will receive bill credits at the utility's avoided cost.

Finally, the bill imposes a moratorium through 2018 on issuance of new permits to build wind farms or expand existing ones while the state assesses what effect existing wind farms are having on military installations in the state. The moratorium does not apply to any new project or expansion of an existing project that received a written "Determination of No Hazard to Air Navigation" from the Federal Aviation Administration, or for which a completed permit application was filed with North Carolina, by January 1, 2017.

The governor, Roy Cooper, is unhappy with this part of the bill. He instructed North Carolina agencies to work with wind developers so that their projects are ready to move quickly once the moratorium is lifted.

PENNSYLVANIA is proposing to tax virtual electricity trades across the PJM grid.

The tax could affect electricity trades as far west as Illinois and Michigan. PJM manages the electricity grid in 13 states and the District of Columbia.

The tax is one of a number of new taxes in a massive budget bill that is in the final stages of the legislative process and is expected eventually to be signed by the governor to plug a $2.2 billion hole in the state budget.

The bill would impose a 5% tax on the "gross transaction amount" of affected trades. PJM would collect it from the person initiating the trade. The tax would be paid at financial settlement.

The tax would affect three types of hedging transactions: decrement and increment transactions, and up-to-congestion transactions.

All the transactions are "virtual" trades, meaning they are settled financially rather than with physical delivery.

A decrement transaction is a cleared offer to supply electricity in the day-ahead market at a price that is no higher than the locational marginal price or "LMP" at / continued page 11

California

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price signals to incentivize storage to be installed so that customers have control over their electricity costs and their loads, and utilities have the ability to tap into that storage instead of paying to keep a peaking plant on reserve.

MS. RANDOLPH: One of the big questions is the point Ed Fenster made. What are the avoided costs that come from all these technologies, and how do you shift that spend from the distribution system to these other resources. That is a tough nut to crack. Trying to identify where there is the greatest value is challenging.

The ultimate addressable market for rooftop solar in California is probably still four to five times current installations.

MR. SMUTNY-JONES: Let me add another level of complexity. The market signals are not there, but they are not there for the existing fleet either. I represent gas generators who basically produce about 44% of the power, 56% of the peak. People are beginning to shut plants down because there are no market signals to keep them around for that late afternoon ramp. Susan Kennedy is right. In the middle of the day, you do not need those plants because you have a lot of solar in the system, but between five and eight o'clock in the evening, you have these ramps that have to be met — some are as high as 13,000 megawatts — which is a lot of batteries to install in place of gas peakers.

MR. ALEXANDER: A lot of people say that energy storage is a form of virtual peaking power plant and maybe the day of the gas peaker has passed. Do you think we still need the gas peakers to support the high penetration from renewables or do you see gas peakers disappearing in the next five years?

MR. SMUTNY-JONES: Not in the next five years. Many of my member companies are in the storage space. One of them just did a storage that is at a peaker, so I think people are looking at storage as an opportunity.

The only problem I have with this storage discussion is sometimes it goes from practical business economics to magic. The solution to a problem is storage. The concern is we may not be doing things we know we have to do in the interim because of a blind faith that storage will solve the problems.

I am prepared for all of this. This is my backup battery. [Holds up a device, spurring laughter from the audience.] For those of you in the room who can't see it, it is a unicorn. [Laughter] So this is how I am spending August 21. I am okay.

MR. ALEXANDER: Last question for Ed Fenster. Some reports predict declining growth or even flat-lining of residential solar. Where do you see the growth of residential solar across the United States, and in particular in California, for the next couple years?

MR. FENSTER: We think across the United States there are still five to 10 years of growth at 20% annual rates if what you are measuring is new installations year over year. There are a couple of forces at work underneath that. The first one is that we are starting to see states respond to the Paris withdrawal and be more supportive of solar energy generally. That is a tailwind. We have a reeducation process to go through in California because of the move to time-of-use rates, which is a little bit of a headwind. We think it is a good policy and we support it. We just have to get through it, and that takes time.

The other thing that is underlying the data is there were a couple companies in our industry that raised an enormous amount of money in the capital markets in the 2012 to 2014 time frame. They went wild without regard to unit economics and are now focused on cash flow and have really pulled their businesses back. These companies represented 40% of the market at one point in time.

The rooftop solar market in California is down year over year. But if you were to graph what the long-term 10-year growth rate looks like in the absence of these companies, you will see a pretty steady growth curve. That said, with the maturing market in California, I do not think we will see more customers going solar this year than last year, but I think the ultimate addressable market in California is probably four to five times what it is today in the fullness of time. ◎

Corporate PPAs

What should one make of the dip in number of new power purchase agreements signed in 2016 to sell electricity directly to large corporate buyers? Corporate PPAs were down almost half from forecasts and down almost a third from the year before. Duncan McIntyre, president of Altenex LLC, which matches independent power producers with corporate buyers, answered the question at the Chadbourne global energy and finance conference in early June.

Let me take you on a very quick tour of the corporate power purchase agreement market in the United States, starting with some high-level reasons why corporations enter into such contracts.

There are two primary motivations.

The first is sustainability. Corporations have been making public statements and mobilizing their work forces to bring sustainability into their cultures. European companies have been doing it for a long time. US companies started becoming interested in sustainability in the last 20 years. It is a growing trend. We have found that companies that make bold statements about sustainability tend to have renewable energy as a component of that strategy.

The second motivation is the economic tool that a corporate PPA provides. Twenty years ago, power markets were more stable. A big corporation arguably had fewer decisions to make. Regulated utilities provided pretty reliable and fairly cheap power. Today, there is more volatility to the energy supply. Companies are more interested in managing how power is procured and brought into the organization.

I want to focus on that second point, which is managing economic risk.

When you think about risk from the standpoint of cash flow, a treasury organization will focus on a handful of things. Foreign exchange and interest rates are two items that have, for a long time, been part of a treasury organization's key areas of focus. Energy prices over the last decade, in certain deregulated markets, have been more volatile than these two items that treasurers fear put cash flow at risk. Energy managers and chief financial officers did not talk much about them in the past, but they are talking more today. The box below / continued page 12

the time the offer is made. An increment transaction is the same thing, but where the LMP exceeds the offer price.

The LMP is the price of another megawatt hour of electricity at a particular location. The price takes into account the difficulty of moving electricity to the location given congestion in different parts on the grid.

An up-to-congestion transaction is a hedge against the gap between LMPs in two locations.

All the transactions take advantage of differences in expected and actual prices in the day-ahead electricity market. They are a way of shedding risk that the prices will vary. They are done not just by electricity traders, but also by independent generators, utilities, municipalities and other PJM market participants.

Joseph Williams, an expert on electricity trading in the Norton Rose Fulbright Washington office, said the tax is certain to end up in litigation. States normally can only tax income that is earned in the state. Both the electricity and the traders in this case may be outside Pennsylvania.

Roughly $2.7 billion in virtual financial transactions were carried out in PJM in 2016. Traders say the tax would have exceeded the profit margin on 87% of 2016 trades.

NEW CORPORATE PPAS signed through June 15 reached 1,240 megawatts, a little ahead of the pace in 2016, according to the Rocky Mountain Institute.

Companies signing power purchase agreements this year to buy renewable electricity are Goldman Sachs, General Mills, Apple, T-Mobile, DeAcero, Anheuser-Busch InBev, Solvay, Facebook and Paypal.

More than 95 US companies have pledged to move to 100% renewables. Google and Lego have hit or are expected to hit their targets this year.

Fortune 250 companies should remain fertile ground for corporate PPAs, especially those in the second tier of the Fortune 250. / continued page 13

Corporate PPAs

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shows the volatility of foreign exchange interest rates and electricity, expressed in terms of relative standard deviation from a mean, over the last 10 years.

The bar graph farther down this page shows the volume of corporate PPAs signed in each of the last six years. The peak was in 2015, with a little over 3,000 megawatts of corporate PPAs signed. There were a little over 2,000 megawatts of new corporate PPAs in 2016. The early adopters were signing PPAs in 2010 and 2011. Sustainability-minded businesses like Google mobilized. They hired energy managers. They hired consultants, and

Asset Class	Relative Standard Deviation
Foreign Exchange (EUR/USD)	10.44%
Corporate Bonds (AAA Rating)	10.33%
AEP Dayton ($/MW)	26.61%
ERCOT North ($/MW)	47.68%
ISO NE ($/MW)	51.16%

they began to look at the concept of how they could procure renewable energy for their operations. They decided there was an economic benefit from locking in a fixed price for energy.

The lines on the same graph show energy prices in key wholesale markets, like Henry Hub, ERCOT, PJM and SPP. These are some of the wholesale markets where renewable PPAs are getting traction. You can see how volatility can be perceived as risk. We were in a bit of a sweet spot for corporate PPAs in 2014 going into 2015. The volatility during this period represented risk. A wave of sustainability was taking hold in corporate America. Production tax credits for wind farms were about to expire.

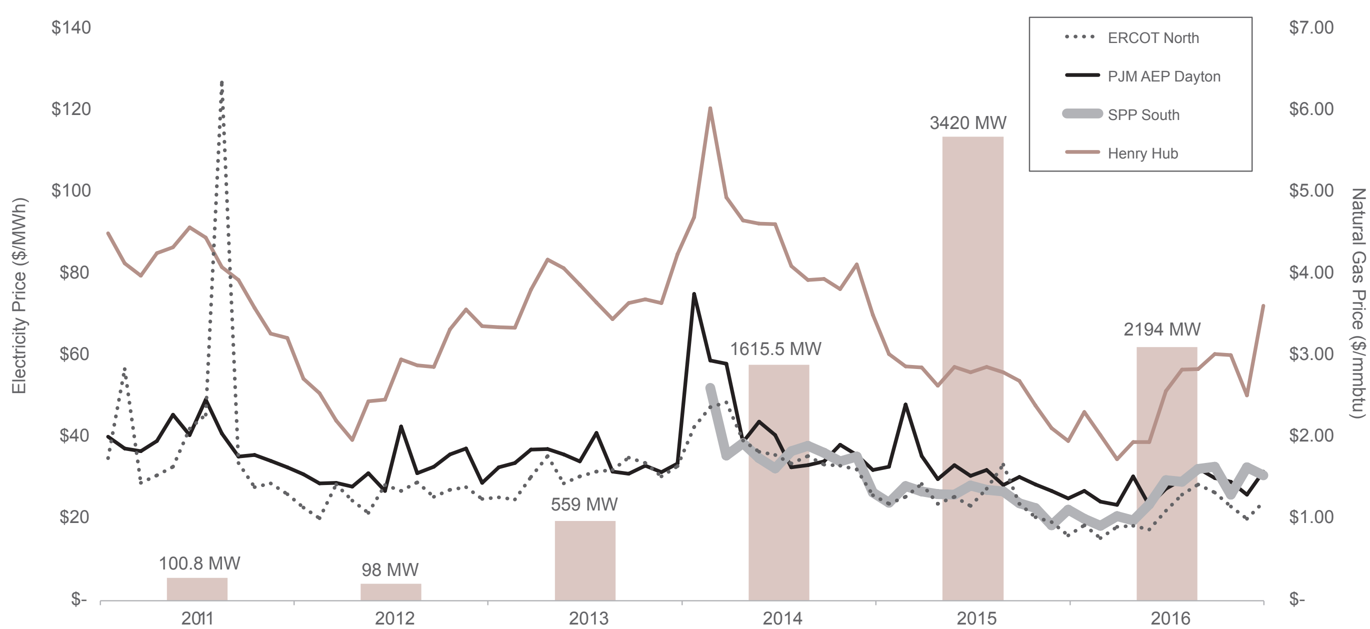
The threat that the tax credits would expire led to a bit of a rush in 2015 to complete transactions. In 2016, the market failed to meet growth expectations.

Why?

First, the value proposition for the buyer around risk management broke down. Natural gas prices hit a 20- or 25-year low in May going into the early summer.

The volume of new corporate PPAs signed in 2016 was lower than the year before, but the drop was not as dramatic as the drop in energy prices. Companies being offered fixed prices under

Historical Electric/Gas Prices & Corporate PPA Flow



long-term contracts were looking at long-term forward price curves that ranged from flat into the future to slightly up.

Every company has a different perception about where energy prices are headed in the future. However, the economic value of a long-term PPA was less attractive at the beginning of 2016 than it was in earlier years.

Fast forward to today. We think 2017 will be a growth year, bigger than 2016. What will the number be? We don't know. We think the sustainability trend is alive and well. The number of companies, states, cities and universities that signed up to comply with the Paris agreement is pretty dramatic. Almost 100 corporations have signed up to go to 100% renewable energy at some point in the future.

Corporate mobilization is on the upswing. Not all companies will do PPAs. Some of them find that the term, size and some of the associated risks are not right for them. But most companies will engage in some manner, whether it is signing a utility-scale PPA or participating in a smaller community choice aggregated solar initiative.

Frankly, the market could be much larger or much smaller in the coming years depending on how gas and electricity prices move. Sustainability starts the wave, but then it becomes a matter of the perceived economic benefit of locking in a fixed price.

Audience Questions

MR. FREEMAN: Rob Freeman from Tradewind Energy. What effect will the phasing out of production tax credits and investment tax credits have on the financial swap value of these contracts, and does it suggest the phenomenon will be a lasting one?

MR. MCINTYRE: In some of the really windy markets, we are seeing PPA prices of $18 and $19 a megawatt hour. The PPA is less valuable than the production tax credits. They are worth $24 a megawatt hour at full value. Production tax credits are phasing out, but new wind farms that were under construction by the end of 2016 have at least through the end of 2020 to be built and claim tax credits at full value.

Something will have to replace the tax credits once they start to phase out.

In a lot of corporate PPAs, especially in PJM, the corporations are not taking any renewable energy credits to which the renewable generator is entitled. The generator keeps them and can monetize them in the market. However, something else will have to make up for the lost tax credits, either / continued page 14

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Thirteen percent of Fortune 100 companies have signed corporate PPAs against 63% that have set sustainability goals. Only 0.6% of companies in the Fortune 101 to 250 have signed corporate PPAs, while 53% have sustainability goals.

Eighty-three percent of corporate PPAs to date have been virtual PPAs in organized electricity markets. Under a virtual PPA, the electricity generator sells the electricity into the local power market and then swaps the actual revenue received for fixed payments from the corporation that entered into the PPA. The corporation uses the floating payments from the generator to buy the electricity it actually uses in the local market. The virtual PPA is a way for the corporation to lock in a fixed long-term price for electricity.

Another potential growth area, besides the second tier of Fortune 250 companies, is in parts of the United States without organized electricity markets, using such structures as green tariffs, direct access or retail sleeves. Under a retail sleeve, the electricity runs through the local utility to the customer via back-to-back power contracts with the utility.

TAX CREDITS may be in play in any tax bill taken up by Congress this fall.

The Trump administration says it wants to have a corporate tax bill on the president's desk by late November. However, talks among the "big six" — Treasury Secretary Steve Mnuchin, White House economic adviser Gary Cohen, Senate leader Mitch McConnell (R-Kentucky), House Speaker Paul Ryan (R-Wisconsin), and the chairmen of the Senate and House tax committees, Orrin Hatch (R-Utah) and Kevin Brady (R-Texas), aimed at producing a common tax plan that could pass Congress quickly in the fall produced only a five-paragraph statement at the end of July that was short on detail, including where to set the corporate tax rate.

Congress is in recess until early September and, when it returns, it will have to increase the federal debt ceiling and pass a budget and as many as 13 appropriations / continued page 15

Corporate PPAs

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Only 0.6% of Fortune 101 to 250 companies have signed corporate PPAs, even though 53% have sustainability goals.

some of form of economic adder or power prices that go up a bit from where they are today.

MR. CARSON: John Carson from Alterra. You said the fact that production tax credits were expected to expire at the end of 2015 led to a rush by corporations to sign PPAs. When the tax credits were extended in 2015, the rush was off. Do you think people are just taking a breath and, in a couple years when companies see the door closing on production tax credits again, a lot of them will be trying to get through the same closing door again?

MR. MCINTYRE: The closing-door phenomenon is not very much in evidence today. We are still seeing a wave of new companies getting mobilized for sustainability. The deals we have seen in the pipeline so far this year would represent growth from last year.

MR. HESSE: Balduin Hesse from Frontier Renewables. Basis risk is a big issue in corporate PPAs. Has there been any new innovation to address it, for example an insurance product or financial hedge? Is there a best practice? If not, are contracts for differences still the norm in this space?

MR. MCINTYRE: The industry has come a long way on basis risk. When you look at the early deals in 2010 and 2011, they were primarily bus-bar deals. For the corporate buyer, that bus-bar was usually not a good proxy for its load. Almost all the deals today are settled at a liquid hub. The generator is responsible for basis from the bus-bar to a liquid hub. For some buyers, the liquid hub is a meaningful location that the retail electricity supplier or the corporation is already using for the electricity supply.

Basis risk is managed pretty well in such cases. However, PPAs are also being done in markets where corporations do not have a retail load. Sometimes this is part of a sustainability initiative. Sometimes it is part of a deeper strategy around hedging broader exposure to long-term pricing in the United States. In those cases, there is more meaningful basis risk for the corporation.

We are hoping that the investment banks with big balance sheet can figure out a set of products, swaps or puts to help manage that risk. We have not seen a lot of corporate buyers willing to take basis risk. Where they do, particularly across markets, they charge pretty hefty premiums. To answer your question bluntly, there are not any good tools today.

MR. NEEDHAM: Rick Needham with The Rise Fund. I have one comment and then a couple questions.

Perhaps another reason for the drop is there was a big run-up to the Paris climate agreement in 2015. Some companies — Google, for example — had already gotten pretty close to 100% renewable energy through the 2015 procurement. So it may be that some of the larger buyers simply had no need for any further electricity.

Here are my questions. What is the mix of customers you see: larger or smaller, repeat versus new customers? And are there any interesting structures to pool those customers? A single customer might not be able to procure 100 megawatts. Are you pooling smaller customers to get there?

MR. MCINTYRE: We have a stable base of repeat customers, but more of the activity is from new companies entering the market. Pooling is a big unmet need in the market. The average company cannot buy 100 megawatts of power. Even Fortune 1,000 companies would prefer to have 10 megawatts here, 15 there, an appropriate mix based on local loads at multiple locations. We have come out with a product called power blocks, where we sign a PPA with partners for the full project, and then we have a warehousing period where the power can be sold down to smaller buyers.

That is one option. The way this has been done historically is advisors have grouped buyers together and tried to line up simultaneous closes. That is a clunky way to do it. It has never worked very well. I think the market would be better off if more people with big balance sheets were willing to take that market-making position. Frankly, Google could be a great company to do that. Take a position, offer it to other corporations, help make that market. The biggest issue is Google would wear some merchant risk for the period of time when there is uncertainty around whether the smaller buyers will show up at the table. ◎

Community Solar Risks and Landscape

Five community solar executives talked about where community solar is getting traction, the different business models, the principal risks in deals and how the market is addressing them during the opening panel at the first annual community solar summit in Denver in late July. The summit was organized by the Coalition for Community Solar Access and Infocast.

The panelists are Zaid Ashai, chairman and CEO of Nexamp, Eric Bank, co-founder and executive vice president of Community Energy, Tom Sweeney, chief of strategic markets for Clean Energy Collective, Ed Scarborough, vice president of network development for Distributed Sun, and Tom Matzzie, founder and CEO of CleanChoice Energy. The moderator is Keith Martin with Norton Rose Fulbright in Washington.

Key States

MR. MARTIN: Tom Sweeney, in what states besides Minnesota, Colorado, and Massachusetts is community solar getting traction?

MR. SWEENEY: It has made broad progress across a number of states. Obviously Massachusetts is one that people recognize pretty clearly along with Colorado, but New York is in an implementation phase right now. The same thing is true in Rhode Island and Maryland, as final rulemaking has been put in place. Oregon just passed a legislative / continued page 16

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bills or an omnibus "continuing resolution" allowing the federal government to remain open past September 30 when the federal fiscal year ends.

Various groups are angling to tee up tax credits to be addressed as part of any tax bill.

The House voted in June to allow new nuclear power plants completed after 2020 to qualify for production tax credits on their electricity output and to allow the credits to be more easily transferred. They are $18 a megawatt hour and run for eight years after a project is first put in service. The credits can be claimed on only the first 6,000 megawatts of nuclear capacity built nationwide. Developers must apply for an allocation. The IRS required applications to be submitted by January 2014.

The House bill would require the Internal Revenue Service to allocate all the remaining capacity first to any new nuclear power plants that are put in service by 2020 and then to any such plants built after 2020.

It would also allow any municipal or other government utility or electric cooperative to transfer tax credits to which it is entitled to any partner in the project, equipment vendor, construction contractor or supplier of nuclear fuel rods.

Offshore wind companies want Congress to allow a 30% investment tax credit on offshore wind farms on which construction starts by December 2025. "Offshore" for this purpose includes project in the Great Lakes and other "inland navigable waters."

Both Democrats and Republicans are thinking about whether there is a way to combine the existing tangle of tax credits for various energy-related activities into a single tax credit. It is unclear whether there will be a meeting of the minds. Democrats have tended to want any combined credit to vary based on the extent to which the energy source contributes to carbon emissions while Republicans have been more interested in neutralirty across fuel types.

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enablement, so rulemaking will come next. California has had a community solar program for the last couple years, but it has some disabilities related to the economics and, of course, Hawaii is very close to enabling its rulemaking process as well.

MR. MARTIN: What is the principal disability in California?

MR. SWEENEY: It is primarily the economics. The retail rate that the utility would pay for the power is too low to make typical community solar programs work.

MR. MARTIN: Zaid Ashai, you are based in Boston. How would you characterize the state of community solar in Massachusetts?

MR. ASHAI: We should not take it for granted. A lot of the community solar success to date was an outgrowth of the SREC II program, which was based on virtual net metering. As many of you in this room know, we are going through a new program design called the Smart Program, where there will hopefully be an adder for community solar projects. We are working through that. It seems like all sides are still committed to having a robust community solar program. We find very little disagreement among our legislators, whether they are Republicans or Democrats. It will come down to how the new program is implemented. The new program will have elements of net metering, but it will be a hybrid program.

MR. MARTIN: "Hybrid" in what sense?

MR. ASHAI: We are not going to have SRECs anymore. We will have fixed incentives for 15 years. There is a baseline incentive that you cannot go above. There are adders for different types of projects, community solar being one of them.

MR. MARTIN: Correct me if I am wrong, but in Massachusetts, SREC sales account for a very large share of the revenue, maybe 65% of the revenue from a community solar project.

MR. ASHAI: That's correct.

MR. MARTIN: Will the economics work if you will no longer have SRECs?

MR. ASHAI: They will. It will be a different style of project. The challenge that we have had in Massachusetts with any solar project is we have had 10 years of SRECs, and we are financing typically with nine- or 10-year loans, after which the capital stack is all equity after year 10.

The new program will provide an incentive for 15 years, which will allow longer-term debt. The goal of the policymakers is to try to make a more efficient program where there is less leakage in the financial markets. With SRECs, there was too much leakage. The program could be made more efficient for ratepayers.

MR. MARTIN: Too much leakage meaning not enough of the benefit goes to the developer?

MR. ASHAI: Not enough goes to the developer or a lot of the costs are passed through to ratepayers.

MR. MARTIN: Are there other states to add to the ones that were mentioned so far?

MR. SCARBOROUGH: Illinois. We expect to see a draft from the Illinois Power Agency in the next 60 days of what the REC program will look like for community solar there. The program is much broader than just community solar, but community solar should benefit from significant REC incentives. We are waiting to see how the economics work. It is an interesting market. You can basically sell electricity to anybody within the utility territory.

MR. BLANK: We also see Illinois as a promising market. In the category of two steps forward and one step back, we are seeing revenue declines in Minnesota similar to what is happening in Massachusetts. There is also a ratcheting back of rates and revenues in New York, and Colorado is now subject to competitive bidding.

All of the markets are viable, but there has been a pullback similar to what was described in Massachusetts.

MR. MARTIN: Is there a lot of new development in Minnesota if the revenues are going down, especially given the cap on project size that Xcel persuaded the regulators to adopt?

MR. BLANK: It is an increasingly challenging business, but we still see it as viable. It is just more competitive than it had been.

MR. MATZZIE: One of the headwinds that we face generally is the deflationary energy market.

MR. MARTIN: Electricity prices are coming down?

MR. MATZZIE: Our primary business is as a retail electricity provider, and the price we can charge for our goods has declined every year we have been in business since 2013. It is not just because natural gas prices are low, it is heat rates on gas plants are falling and the uneconomic units are being squeezed out. Reserve margins are decreasing, so capacity is decreasing. That is a headwind. It makes getting the tariff right and the policy work that the Coalition for Community Solar Access does much more important.

MR. MARTIN: Is this a greater challenge in community solar than independent power generally? Independent power producers lock in a long-term offtake contract and then seek financing for their projects. With community solar, in theory you lock in a revenue stream, but the subscribers can cancel with short notice.

Cash Waterfall Issues

MR. SWEENEY: That's right. Two points. What Tom Matzzie is pointing out is that as an industry, what we have not successfully done yet is to argue for what the true value of solar is, and because that has not happened, we end up being subject to somewhat arbitrary views as to where to set rates for the purchase of our electricity.

The second point is what you mentioned, which is the administrative cost to have a community solar program with multiple subscribers and net metering credits. This is another place where policy can help us. Without an on-bill debiting enablement where we take advantage of the utility's billing and collections process, we end up having a much higher soft cost and a much higher administrative cost overall, and it translates into a different risk profile for the financiers. Those two things are worthy of real attention.

MR. MATZZIE: The policy has to be right. Retail electricity has an on-bill advantage. There are a lot of people who would rather see the customers receive a single bill, and then everyone involved in delivering the electricity divides up the cash flow. You have to think about the cash flow waterfall. Who gets paid first: the utility or the community solar company? Unless you have a very clear tariff, it becomes a nightmare. We have lost hundreds of thousands of dollars in the retail markets because there was not a clear cash flow waterfall.

MR. MARTIN: How does that come into play? The subscribers pay the community solar project directly. The electricity usually ends up with the utility. The utility provides the subscribers with bill credits. How does the cash waterfall come into play?

MR. MATZZIE: The billing relationship is entirely managed by the utility. The community solar company transacts with the customer and then enrolls the customer with an on-bill service at the utility. The difficulty is the community solar company is then relying on the utility for all the customer service. The customer can cancel through the utility without ever talking to the community solar company.

MR. SWEENEY: I would describe it this way. The current environment is that we have utilities posting credits to the customers' utility bills, and those credits have a */ continued page 18*

IN OTHER NEWS

At least 25 US Senators have lined up behind a bill to extend and modify an existing tax credit for carbon dioxide sequestration. The current tax credit is $20 per metric ton of CO_2 sequestered from power plants and other industrial facilities that produce more than 500,000 tons of CO_2 a year. The sequestered CO_2 must be put in secure geological storage. The credit drops to $10 a ton for CO_2 used for enhanced oil or gas recovery. The credit amounts are adjusted for inflation after 2009. The credits stop after the year in which the US Environmental Protection Agency certifies that 75 million tons of CO_2 have been sequestered. The bill would increase the credit amount for carbon capture equipment put in service after enactment and allow credits to be claimed on the CO_2 captured for the next 12 years after carbon capture equipment is put in service.

Advocates for energy technologies that were left out when Congress voted in late 2015 to extend tax credits for wind and solar projects hope to see an "orphan" tax credit package enacted. The package would extend a 30% investment tax credit for fuel cells and small wind turbines on which construction starts by the end of 2019, with a two-year phase down of the credit amount for projects on which construction starts in 2020 or 2021. It would extend a 10% investment credit for combined heat and power systems and geothermal heat pumps on which construction starts by 2021.

Finally, energy storage companies want a 30% investment tax credit on all types of energy storage — whether or not they are part of renewable energy facilities — on which construction starts by the end of 2019, with a two-year phase down after that.

Any tax bill Congress passes this year or next is likely to be centered around a cut in the US corporate income tax rate. In general, Congress will be looking for ways to strip tax credits and other tax benefits from the US tax code to help pay for the rate reduction rather than to add to existing tax credits.

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corresponding debit that must be delivered to the customer. Currently, a project owner must bill that customer independently. That is where the extra cost and risk of collection arise.

If a utility were posting both the credit and the corresponding debit transaction at the same time, then the effect on the customer's bill is a net decrease in cost. The community solar company still has to have a contract with the customer to participate in the program, but Tom Matzzie is pointing out that when you use the utility to collect receivables, there are other risks that come with it. A correctly structured policy can help. This is a big issue for us in the industry.

MR. MARTIN: Before we leave this topic, let me ask in which state do you think community solar will grow the fastest over the next year or two?

MR. SWEENEY: Minnesota will probably be close to number one this year and next year based on the volume that is being built currently, but Massachusetts still has a pretty large volume going through its development cycle. New York has an opportunity to put some pretty big numbers up, but there are still significant challenges with getting interconnection built and put in place.

MR. MARTIN: Any disagreement about that list? Ed Scarborough.

Some community solar companies are dispensing with long-term contracts and credit scores.

MR. SCARBOROUGH: No disagreement. I would like to go back to the billing issue for a second, specifically in New York, and about how woefully unprepared the utilities are for this. In their filings on May 1, the utilities basically said it will be a year and a half to two years before they can automate their systems. They will be managing our billing process in the meantime using spreadsheets, which is going to be a lot of fun.

It is not clear when they put the credit on the bill that they will say what the source of that credit is, so there will be this magical credit on the bill that will not say it is from a community solar project or even what month of production it represents, and since credits will vary from month to month, it will be very difficult for subscribers to understand what is on the bill.

As new states make room for community solar, we find in Illinois, for example, that remote net metering is new to the utilities. It is a challenge for them to adapt. That is part of what we need the Coalition for Community Solar Access for: to help identify limitations and have open discussions with the utilities so that we can create an environment in which we can all function.

Evolving Business Models

MR. MARTIN: How many different community solar business models are there? Zaid Ashai, what is your business model?

MR. ASHAI: When we go to town meetings, community solar is an asset. We go into communities that are worried about land and create opportunities where standard solar projects cannot. Our business model is we are typically using virtual net metering in Massachusetts. We bill customers directly. They receive bill credits on their utility bills. We are managing all of that internally.

MR. MARTIN: So you sign up subscribers. Are you selling them net metering credits or a share of the electricity output from a community solar array?

MR. ASHAI: We are selling them net metering credits.

MR. MARTIN: And the electricity actually goes to National Grid or another utility. The utility gives you the net metering credits in exchange for the electricity that you then transfer to the subscribers.

MR. ASHAI: Eversource. Correct.

MR. MARTIN: How long are the subscription agreements?

MR. ASHAI: There are no long-term contracts and no credit scores. We have designed our whole financing stack, our whole asset management stack, to deliver that, and it has led to lower soft costs and higher returns for investors.

MR. MARTIN: Eric Blank, is your business model the same?

MR. BLANK: It is a little different. We started off primarily as a utility-scale developer and found community solar to be a valuable adjunct for creating a more stable revenue stream. We are in Colorado, Minnesota, New York and Massachusetts. We view community solar primarily as a development opportunity. Most of our value add is on the development side. We own and operate a number of community solar projects, but we often find partners in each individual market.

The best partner in Massachusetts is different from the best partner in Minnesota where you have more residential customers, and is different from the best partner in Colorado where the customers are mainly commercial. It is much like utility-scale solar. We see it as primarily a development business with fragmented markets.

MR. MARTIN: Do you also use local partners to find the subscribers? What mix do you have of residential and commercial?

MR. BLANK: We do the customer acquisition internally as part of the development process. In Minnesota, we sometimes have 100% residential customers. In Colorado, we might have 0% residential. It depends on the dynamics of each market and what makes the most sense. In Minnesota, there is a significant premium for residential over commercial. In Colorado, there is virtually no premium.

MR. MARTIN: Zaid Asahi said that Nexamp does not ask customers to sign on for any particular period of time. Do you have a time period?

MR. BLANK: We try to sign term contracts with modest escalation and reasonable termination provisions. However, they are not a critical part of the value creation process because we expect to substitute customers in and out over time.

MR. MARTIN: Tom Sweeney, are there any differences in your business model?

MR. SWEENEY: Maybe the most important distinction is that we are an enabler of community solar programs. We do not build the projects ourselves. We work with utilities to use our software platform to develop community solar programs. The same set of software and services can be available to other participants in the market as well.

MR. MARTIN: Ed Scarborough, are there any differences in the Distributed Sun business model?

MR. SCARBOROUGH: We look for / continued page 20

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US BANK REGULATORS may roll back part of regulations put in place to implement the Volcker rule.

The US Comptroller of the Currency asked for comments on August 7 about how the Volcker rule is working, with particular emphasis on what banks and activities should be caught in its net. Comments are due by September 21.

The Volcker rule, named after former Federal Reserve Board Chairman Paul Volcker, is supposed to keep banks out of risky investments that might cause a bank to collapse and draw on federal insurance for bank deposits. Volcker wrote out his original idea in a page and a half. The implementing regulations (including the preamble explaining them) are more than 900 pages.

The Volcker rule was enacted in July 2010. It prevents banks with federally-insured deposits and their affiliates from engaging in "proprietary trading" — defined as trading in securities for the bank's own account to benefit from short-term price movements — and from investing in any "covered fund" — which the bank regulators have defined as a subset of entities that would be considered "investment companies" by the US Securities and Exchange Commission. While it is not always clear whether an entity is an "investment company," a company that is engaged directly in an active business or as a holding company whose sole assets are shares or other ownership interests in an active business company is generally not an investment company.

The Comptroller listed a number of complaints that banks have about the Volcker rule. They include that the implementing regulations are "overly complex and vague," banks "sometimes are not able to distinguish permissible from prohibited activities" despite their best efforts to do so, and the net has been cast so broadly that banks have been forced to curtail market-making, hedging and asset liability management that is economically useful. (For a discussion about the how the Volcker rule affects bank participation in tax equity transactions, see "The Volcker Rule" in the February 2014 *NewsWire*.) / continued page 21

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customer agreements with a seven-year term. No escalator. There is always a discount to the credit value. We attend state fairs, farmer's markets, go into residents' homes to do direct sales, and we are getting a good response.

MR. MARTIN: What is your mix of commercial and residential subscribers?

MR. SCARBOROUGH: 100% residential.

MR. MARTIN: Zaid Ashai, I did not ask your subscriber mix. What is it?

MR. ASHAI: It depends on the state. In Massachusetts, we typically do 50% commercial with an anchor offtaker and 50% residential. In New York, we will be 100% residential.

MR. MARTIN: Tom Matzzie, are there any differences in your business model?

MR. MATZZIE: We are not a developer. That is the big one. We are a customer aggregator. We have in our retail electric business, which is renewable energy, nearly 100,000 customers already, and we look to apply what we know about acquiring and managing customers to the community solar market. There are other people who are excellent at development. It is a very specific local skill; you have to fight in town meetings sometimes. We do not have to do that. The ultimate financing depends on the customer contract. That is the cash flow, and we take a very specific approach to it.

Possible Inflection Points

MR. MARTIN: Most of the solar industry is focused on the threat of import tariffs on solar panels being imposed perhaps by the end of the year. People are rushing to try to get panels across US Customs before any tariffs are imposed. How does that threat affect your ability to enter into subscription agreements? Who takes the risk that you will be unable to deliver power for the prices currently on offer to subscribers?

MR. SWEENEY: The risk starts at the project level rather than the subscriber level. The reality is that if you are developing a project today and not taking delivery of panels prior to a tariff being implemented, you have that risk as the developer. After that, any tariff will have to be folded into the economics to determine whether a project will pencil out.

From our perspective, that tariff will be an absolute crippler of the industry. It is the worst possible outcome that we could have.

MR. MARTIN: What other potential inflection points do you see in the next couple years that could change the direction of this industry?

MR. MATZZIE: As someone with a retail business, we see opportunities to create what I call synthetic community solar using retail electricity and wholesale markets. The costs are not there yet. It depends on the state. You could do it in New Jersey with a given SREC value. You could do it in Texas given the high insolation there.

MR. MARTIN: What does that mean, synthetic community solar?

MR. MATZZIE: It is not created through a tariff. Community solar today relies on a tariff or some sort of compensation for value of solar. Instead, we would rely on the FERC jurisdictional markets and the various counterparties that exist there. So can you get a revenue put option from a bank against a solar facility in Texas and then upsell for the retail markup?

MR. MARTIN: In other words, you can bypass the state. You do not have to rely on the state to enact a statute.

MR. MATZZIE: That's right. But not just bypass the state at the retail level, like are you on the customer's bill or not, but you could have a solar facility in Texas and sell the output and economic value anywhere in the world. You also bypass the state since you operate in a wholesale power market under jurisdiction of the Federal Energy Regulatory Commission or ERCOT or its equivalent.

MR. MARTIN: I am going to throw out a word — blockchain — that people use, but that is hard to explain what it is. Does it have a potential role in community solar?

MR. ASHAI: Yes. We are looking at it given that my previous background is in technology. Our team has looked at the applications within data storage and crypto currencies. I don't want to go into too much detail because we are still early in the process. There is a lot of hype, unfortunately, and the hype has gone further than the reality, but I think two to three years from now, there will be a role.

We have seen very small activity in emerging markets where people are using solar to mine crypto currencies. They are using their storage facilities essentially to create Ethereum or other types of currencies and using solar energy to do so because solar

Financing depends on confidence that departing customers can be replaced promptly.

is cheaper than other forms of energy in those countries. That is one application.

There could be potential other applications in the US. There are some advantages from an accounting standpoint, but it is early and still a lot of whiteboard material right now. It requires more research.

MR. MARTIN: Can you explain in a sentence what blockchain is?

MR. ASHAI: Not in one sentence, no. We would probably have to have another panel to go through it and a whiteboard to write on.

Risks

MR. MARTIN: Let's move to risks. It seems like the principal risk in community solar is the ability of the customers to walk away and the revenue to stop. How is that risk handled?

MR. ASHAI: Through program design. For example, in New York if you have a customer walk away, you have up to a year to sell the net metering credits to another customer. The financing community has not gotten up to speed. Financiers ask you to do long-term contracts with customers. Customers do not like long-term contracts. There are also restrictions in New York about the amount of termination fee a customer can be charged.

As long as the program design allows you to substitute customers within reason, the risk can be mitigated. If that is not a feature of the program design, then it becomes a much larger risk. We usually oversubscribe our projects. We tell people that they are on the wait list and as soon as someone drops out, we bring them in.

Our customer attrition rate is something like .9% a year.

MR. MARTIN: Over how many years?

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CALIFORNIA will not collect sales and use taxes on equipment bought after this year for use in electricity generation, storage, transmission or distribution.

The exemption will not apply to generating equipment used to make electricity from a conventional power source, meaning nuclear energy or a hydropower facility greater than 30 megawatts in size or a fossil fuel power plant, unless the fossil fuel is used for cogeneration of more than one useful energy output.

The exemption is in a bill, A.B. 398, that the governor signed in late July.

California, like other states, has a "manufacturing exemption" from sales and use taxes. Sales taxes are collected on equipment purchased in state. Use taxes must be paid on equipment purchased elsewhere and brought into the state for use there. However, equipment purchased for use in manufacturing is usually exempted from sales and use taxes. Many states view electricity generation as a form of manufacturing. Not all do. The exemption in A.B. 398 is language added at the end of the existing manufacturing exemption.

The person buying the equipment must be engaged in a power-related business. Purchases by construction contractors installing equipment for such persons are also exempted.

SALE OF A SERVICE CONTRACT produced capital gain rather than ordinary income, the US Tax Court said in June.

The key was the contract qualified as a "franchise" to provide services in a particular geographic area.

Three partnerships held contracts with Tehama County and the cities of Red Bluff and San Jose in California to collect garbage and recyclables and to dispose of the garbage. The partnerships won the contracts by bidding for them after the municipalities issued requests for proposals. The contracts had limited terms. They could be renewed by agreement of the parties. The partnerships invested in garbage trucks,

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MR. ASHAI: About two years. Community solar is young. These data sets are small. We had modeled 5%, so it looks a lot better than what we expected.

MR. BLANK: The key thing is to have the customer contracts have attractive terms. If you offer somebody a 10% discount and a relatively modest escalation rate and that customer goes away, then the value proposition is attractive enough that the departing customer is relatively easy to replace with a manageable acquisition cost. If you have a customer contract that is long-term and has 6% annual escalation, that is a very different risk profile.

That said, we primarily view utility credit as standing behind the community solar gardens as much as the individual customers.

MR. MARTIN: How?

MR. BLANK: If you lose a customer in Colorado or Minnesota, Xcel gives you an extended period of time to substitute a new customer. It is really the stability of the utility that is key as long as the customer proposition is fair and in market.

MR. MATZZIE: I think these guys are being modest. It is actually their strength as aggregators that is the other piece of it: the fact that you will replace the customer.

MR. ASHAI: It is also the financial institution's belief in our platform and the ability to replace those customers.

MR. BLANK: That's right.

MR. ASHAI: As long as they have faith that you will be around and can replace those customers, that will work. The one caution is we have seen certain players that are trying to play games. They do a customer contract that has a low price for two years and then a higher rate in year three.

I think the last thing we want to do as an industry is make it a game where you are playing tricks with customers and being less than completely transparent. We have seen some companies doing this. The risk is that the regulators step in and take a draconian approach to stop it.

It is important for the industry to regulate itself. Make sure customers understand what they are signing.

MR. MARTIN: Andy Redinger at Keybanc said he argues internally that banks should be able to lend even to sponsors who have not locked in a revenue stream. The bank lends to McDonald's on the strength that a steady stream of customers will buy hamburgers. Eric Blank, you seem to be of that school. As long as you keep the discount below the retail electricity rate, things should be okay. That has not worked for the rooftop solar companies. Some of them have tried that model and have not been able to raise financing. Why should community solar be different?

MR. BLANK: In Boulder, we are seeing rooftop net metering contracts that escalate at 6% on a rate structure that has escalated at 2% over the last 20 years. If you are trying to monetize the future contract value upfront, that is a significant risk. If you lose that customer, you have really destroyed value.

But if the rate of escalation is more consistent with an historic growth rate, then it is much easier to replace those types of customers. The point is the upfront fairness that allows you to replace customers at reasonable terms is key.

MR. SWEENEY: I would say it a little differently. To have a sustainable base of customers, whether they are residential, commercial or government, you have to deliver an economic advantage for participating in community solar. If you think you are going to charge them a premium to what they are receiving as net metering credits, you will probably fail. So they have to have an economic incentive to participate.

MR. MARTIN: Got it. Next issue: securities. There had been a fear that subscription agreements are securities and, therefore, how you market them is regulated more heavily. Have there been any developments in that area?

MR. SWEENEY: That was a concern early on because of the early type of structure that was being used. You can create programs that look like what has been described, which is like a power purchase agreement where electricity is paid for over time. Those should not be considered securities.

We have seen multiple opinions from counsel at this stage confirming this. There has also been work done by the US Securities and Exchange Commission. There is not a securities issue unless you work really hard to create one.

MR. MARTIN: So the market is getting comfortable. Net metering: there have been disputes between utilities and the rooftop companies over net metering. Those have spread to multiple states. How much does community solar depend on net metering for the business model to work?

MR. ASHAI: It is critical. Back to your question a few minutes ago about what is the biggest threat. It is whether utilities start winning this argument and push back effectively on virtual net metering or they are able to degrade the value of solar within net metering so much that the projects are no longer economic.

MR. MARTIN: Explain why net metering is critical.

MR. ASHAI: Because it allows you to go to customers offsite, and it allows you to swap in customers. It allows us to keep the financing costs low. Those three things are critical.

Customer Costs

MR. MARTIN: The cost of acquiring customers in the rooftop market can be as much as 25% of the cost of the installed solar system. What percentage is it in community solar?

MR. SCARBOROUGH: It is not as high as 25%, but we still have to have a certain amount of door-to-door sales in order to get to the numbers we need. So it is still a significant number, probably on the order of 15% to 20%.

MR. MATZZIE: I think you have to look at the cost of acquiring one customer versus the cost of having a customer aggregation-like engine that can guarantee you have customers for the life of the project. The latter has very different unit economics. It makes the customer acquisition cost a small fraction of what it is in rooftop solar.

MR. ASHAI: I don't think you can survive if your costs are greater than 5% of your project. I really don't.

MR. MARTIN: How do you bring them down?

MR. ASHAI: It is hard to do with a lot of people going door-to-door. If you look at any great retail businesses, no one is going door-to-door anymore. You have to use effective digital tools. There are great platforms that can target customers with the exact preferences for which you are looking and the right geographies. The energy industry has been slow to adopt them.

MR. BLANK: If you have a structure that provides economic benefits to the customer, it reduces the acquisition costs.

MR. MARTIN: Build it and they will come.

MR. BLANK: Not quite, but I agree with what Zaid said. It has to be more like 5% of the project cost.

MR. MARTIN: Many community solar companies rely on local contractors to find subscribers. Any consumer-facing business always has to worry about sales practices. How do you protect yourselves from problems later?

MR. SCARBOROUGH: You have to enforce that through your contract with the local contractor and through oversight. If the local contractor is representing you as an agent, then you will be liable for anything it does in that sales process, so you have to be sure to control how any agent does its job.

Coming back to "they will come to us," we are building too much just to wait for subscribers. Once we see a surge in subscriptions, we can back off. We find that / continued page 24

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trash bins and other equipment.

An outside consultant approached the partnerships in 2002 about selling the business. A sale was arranged later the same year to Waste Connections for $46 million.

The parties allocated the purchase price among the three partnerships and among three categories of assets: covenants not to compete, the trucks and other tangible assets, and goodwill and going concern value.

The partnerships reported the gains largely as capital gains. The IRS audited in 2009 and insisted that the sellers had to report everything as ordinary income. Individuals are taxed on their capital gains at reduced rates. There is no difference in tax rates on corporate capital gains, but any capital losses a corporation is carrying forward can only be used to offset capital gains.

By the time the case got to court, it had come down to one issue: whether sale of the service contracts produced capital gains.

The court said yes. It said the contracts are "franchises" within the meaning of section 1253 of the US tax code. A taxpayer is allowed to report any gain from the sale of a franchise as capital gain as long as it does not retain a continuing interest in the franchise after the sale. A contract qualifies as a "franchise" if it is "an agreement which gives one of the parties to the agreement the right to distribute, sell, or provide goods, services, or facilities, within a specified area."

The case is *Greenteam Materials Recovery Facility PN v. Commissioner*.

STATE PLANS to award "zero emissions credits" to nuclear power plants were upheld in two widely watched lawsuits in New York and Illinois.

The credits — called ZECs — have some features in common with renewable energy credits offered under state renewable portfolio standards.

Five independent generators, the Electric Power Supply Association and the Coalition for Competitive Electricity tried to block New York from awarding zero / continued page 25

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we become intimate with the community while working to develop a project. We have to go into people's homes. We have to visit not just with the town council, but also with individual residents to get the permits approved, and that builds a base for subscriptions. But for us at least, it remains a one-to-one conversation. As soon as we see the surge of subscriptions from the internet, we will back off.

MR. MATZZIE: If you don't have to worry about FICO scores and you don't have to have 20-year contracts, then you will have very low customer acquisition costs. There are plenty of people who pay their bills every month who do not have 700 FICO credit scores. FICO is only good for six months anyway.

The key is to design the product so that it is customer friendly. The retail electricity industry has gotten away from this basic law of business, and it is a source of problems. Community solar is much more dependent on regulatory involvement and the value-of-solar tariff. We cannot have anything but very friendly customer contracts. The term needs to be what the customer wants. We should not have a credit qualification. The fact that we can replace the customer should be enough.

Financeability

MR. MARTIN: I spend a lot of time with financiers, and you guys have said three things that would be anathema to any financier. First, you do not want to lock in the revenue stream because the customers should be able to come and go. Second, you do not want to have to find customers that meet minimum credit standards. Third, the price customers pay should float with retail electricity prices, which may go up or down.

Any one of these would probably be fatal to the ability of a solar rooftop company to secure tax equity or debt. What success have you had selling this to the financial community?

MR. ASHAI: We have been very successful in selling this.

MR. MARTIN: Do the financiers raise these as potential issues?

MR. ASHAI: They do. Of course these are issues. We spent probably three years in the capital markets on how we design our debt and tax equity stacks to accommodate those risks. As long as they have faith in the platform that you can deliver those risk mitigation techniques, they get comfortable.

One thing to add on the FICO scores is there is no evidence that someone with a lower FICO score is going to pay his or her energy bills less frequently than a wealthy person. In fact, we have observed the inverse where a wealthy household is more likely to forget about the bill because it is so nonconsequential. With lower income households, the bill is so consequential that they stay on top of that. Some banks do get it, but some banks will not.

MR. MATZZIE: In Greece when people were not paying their taxes, the government started adding taxes to electric bills because people always pay their electric bills.

MR. MARTIN: Are there any audience questions?

MR. KANZER: Bill Kanzer with Relay Power in Massachusetts. We do customer acquisition. I wanted to follow up on the question about different flavors of community solar. What percentage by kilowatt — not by number of customers — for each of you are residential customers as opposed to commercial customers?

MR. SWEENEY: I will posit this guess. Our customer base stretches across all of the states that have enabled community solar so far and some that have not. In terms of total offtake, our commercial and residential split is probably 65% to 70% commercial and the balance is residential, but there are particular markets or projects that are all residential.

MR. REED: Andrew Reed with Borrego Solar. What other

Net metering is critical to making community solar work.

third-party services are surfacing to service the community solar market, like software platforms or billing or reconciling the utility credits and things like that. Can you comment on a couple of boutique industries that are growing out of this?

MR. MATZZIE: We offer that as a service to people for whom we do customer aggregation.

MR. SELIGMAN: Jake Seligman from NRG. I want to drill down on one point about which Keith asked. Have any of you convinced lenders to size against the residential contracts that do not have terms or FICO scores? I could see having success where such contracts are part of a mix in a project with, say, an anchor customer, but have you gotten sizing against those contracts?

MR. ASHAI: Yes, we have.

MR. BLANK: We have been forced to establish FICO scores by the investors with whom we work.

MR. MATZZIE: We have had to chase down certain FICO scores on projects that were 100% residential.

Policy Goals

MR. MARTIN: What needs to be done to make community solar better?

MR. SWEENEY: Collectively as an industry we have to be advocates for good policy. Good policy is not just enabling community solar, it is also doing so in the right way. On-bill debiting is an example. We need to make sure we have a right to interconnect and have access to the utilities, customer information systems and data. That is probably the most important thing we can do as an industry.

MR. BLANK: We need to honor the spirit of what animates community solar. In a setting like Minnesota where there were gaps in the rules, people were trying to co-locate 40 megawatts of community solar on one site. In New York, many interconnection queue positions have been filed without land control. There needs to be some collective responsibility to stick with what the underlying spirit of community solar is and not try to take advantage, which I think harms all of us. It forces the regulators to ratchet back the rates, change the rules, and sometimes overreact and pull back too far.

MR. MARTIN: Last question. The investment bankers say there is a wall of money looking for projects. Are you having more money thrown at you than you are able to use effectively?

MR. ASHAI: Yes. I think our problem at Nexamp was probably three years ago. We had more projects and not enough capital, and now it is the reverse.

MR. MARTIN: Of the various types of capital — true equity,

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emissions credits worth $17.48 a megawatt hour in 2017 and 2018 to owners of nuclear power plants in the state. The value of the credits will be reset after 2018. The program is expected to run 12 years.

A US district court upheld the plan in late July.

The case was a test of whether a state can offer such credits as a supplement to wholesale power prices without running afoul of federal law. Only the Federal Energy Regulatory Commission can set wholesale power rates for electricity sold in interstate markets. States retain the right to regulate retail sales of electricity within their borders.

At least three of the six nuclear plants in New York are expected to receive the credits. The credits were approved by the New York Public Service Commission in August 2016 in an effort to keep the plants open. Nuclear power accounts for roughly 31% of total New York generating capacity. The state says the nuclear plants are important to limiting carbon emissions.

The nuclear plant owners will sell the credits to the New York Research and Energy Development Authority, NYSERDA, at the price established by the New York Public Service Commission. NYSERDA then will resell them to New York utilities on a *pro rata* basis in proportion to each utility's share of total New York electricity load.

Low natural gas prices are forcing nuclear power plants in parts of the country with competitive power markets to shut down.

The credits represent a significant subsidy on top of what the nuclear plants are being paid currently for their electricity. The generators, who compete with the nuclear plants for a share of wholesale power sales, argued that the program is illegal state interference with the wholesale power market because it will artificially depress wholesale power prices by keeping generators in business who would otherwise have dropped out of the market.

The US district court / *continued page 27*

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tax equity, development capital, debt — is any of these in scarce supply?

MR. ASHAI: No. Tax equity is there, but the terms are still challenging.

MR. MARTIN: Any competing views?

MR. SWEENEY: Capital is plentiful. The challenge is we have a job to do to educate the various sources of the capital so they become familiar with how community solar works and the intricacies of these subscriber agreements and the transferability capabilities. That is something we could do collectively that would be helpful.

MR. BLANK: There is too much capital chasing too few well-developed projects. If you have projects, you can create a lot of value, but it is creating enormous competition on the project side. We are seeing prices being bid way down in competitive utility processes, and on the land and interconnect side, the competition is enormous even for community solar gardens. ◎

New Trends

A panel of veteran investment bankers and one commercial banker had a wide-ranging discussion at the Chadbourne global energy and finance conference in June about new trends in the market, with a focus on where 2017 and 2018 deal flow is likely to come from.

The panelists are Andy Redinger, managing director and group head, utilities, power and alternative energy, KeyBanc Capital Markets, Ray Wood, managing director and head of global power investment banking, Bank of America Merrill Lynch, Michael Proskin, managing director, power and utilities investment banking, Credit Suisse, Ted Brandt, CEO of Marathon Capital, and Ralph Cho, co-head of power for North America for Investec. The moderator is Rohit Chaudhry in the Norton Rose Fulbright Washington office.

MR. CHAUDHRY: What new trends do each of you see in the market?

MR. REDINGER: Four come to mind. One is the birth of US offshore wind. Two is the continued erosion of competitive electricity markets in the United States. Three is the market going long on wind turbines. A back-of-the-envelope calculation suggests that it is long by 20,000 megawatts. Four is the changing business model in the residential solar space.

MR. PROSKIN: One trend is the lower market-clearing prices in the recent PJM and NEPOOL competitive generation capacity markets, and specifically how they could potentially change the dynamic for construction of new conventional power plants across the country.

Another trend is the rapid decline in the cost of renewable generation. Utilities — Xcel is an example — are now saying they plan to build thousands of megawatts of wind or solar not just because it is green, but also because it is the best option for their ratepayers. They just want to be in a position to deliver electricity at lowest cost.

I don’t know how much offshore wind we will see built ultimately in the United States, but we will see some, and that sector is starting to get attention.

We are seeing a shift in the LNG market. Offtake contracts will be much smaller going forward rather than a single contract to sell the entire output from a production train to a single buyer. We will see LNG offtake contracts with small counterparties with poorer credits than a Shell or BP.

MR. CHO: We think M&A will be a big theme this year. Acquisition finance is a potential growth area for the banks.

The US market remains awash in liquidity. Many lenders are being super flexible in terms of what they are willing to do for sponsors in order to get some transaction volume going.

At the same time, we see growing weariness among lenders about quasi-merchant gas-fired power plants in PJM, which was a huge chunk of financing activity over the past several years. This is especially true after the recent capacity auctions.

I agree with what Andy Redinger said about residential solar. That financing model is in a transition phase.

MR. BRANDT: Five years ago, we were all talking about projects with 20-year power purchase agreements to sell their output to utilities. The stark new reality is the lack of long-term contracts across not just gas, but also renewables.

Low-cost renewables are something with which the market has not had to deal in the past. We are in the midst of a rotation away from expensive and dirty to clean and inexpensive. Nuclear and coal are at a disadvantage against cheap natural gas and renewables, which are gaining market share.

The other trend is abundant capital. There are massive amounts of capital looking for yield. This will remain true as long as the fixed-income markets and most of the developed economies do not offer much of a real rate of return.

MR. WOOD: There is a real dichotomy in the market. We have a wall of liquidity. Institutional investors looking for places to invest are now willing to invest in projects at the notice-to-proceed stage.

It has not been lost on pension funds, sovereign wealth funds and insurance companies that solar and wind are now mainstream assets. Such investors are sources of patient capital that are looking for the equivalent of contracted annuity streams.

At the same time, we have seen zero equity issuances by renewable generators. This is a market with a broad base of private capital, but it has not been a public equity play. That has also been true of the debt flowing into the sector. It has been primarily a bank market play and not really a bond play, although that might change in the future. Private but not public is one dichotomy.

The other dichotomy is that the wall of money and broad interest in global markets in renewable energy exist at the same time the new US administration is trying to rebalance energy supply toward fossil fuels. The market is weathering the potential disruption caused by Trump administration policies remarkably well: potential solar import tariffs, abandoning the Clean Power Plan, pulling the US out of the Paris climate accord, dismantling existing environmental regulations. As energy storage becomes more relevant and as electric vehicles become more cost competitive, there will be other disruptions.

The potential for change makes this a very exciting market. There is great money flow, but also a fair amount of uncertainty.

Merchant Gas

MR. CHAUDHRY: Michael Proskin and Andy Redinger both mentioned the PJM auction a couple weeks back as an important trend. Ralph Cho, what happened?

MR. CHO: PJM — the part of the US electric grid that serves 13 states starting from a mid-Atlantic core of Pennsylvania, New Jersey and Maryland and then working west all the way to parts of Illinois and Michigan — held an auction for generators who want to supply capacity. The winning bids were so low in some parts of PJM as to call into question whether very much new capacity will be built.

PJM has a lot of sub-regions. The capacity price in probably the largest sub-region was about $76 per / *continued page 28*

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disagreed. It said the credits will not directly affect wholesale power prices. It would view the plan differently, it said, if the plan required nuclear generators to bid into a capacity auction and then the credits supplemented whatever market-clearing price the generators were awarded by auction but, since it does not, any effect on wholesale power prices is "incidental." The court said the ultimate failing of the generators was their inability to show a difference between ZECS and RECs awarded to renewable energy generators. It said FERC has not seemed troubled by the use of RECs by states to promote renewable energy.

The generators also argued that ZECs are an impermissible interference with interstate commerce; they are an effort to "save jobs at subsidized generators . . . to preserve the local industry from the rigors of interstate competition." The "dormant" commerce clause to the US constitution bars state actions that discriminate against or unduly burden interstate commerce.

The district court said the generators failed to allege discrimination against interstate commerce. It said their complaint is with the type of generation being favored.

The case is *Coalition for Competitive Electricity v. New York Public Service Commission*.

An environmental group filed a separate suit last November 30 to block the credits in state court. It charges the program violates the state constitution. The case in state court is *Hudson River Sloop Clearwater v. New York Public Service Commission*.

Meanwhile, a US district court in Illinois upheld a similar program in that state in mid-July, just 11 days before the New York decision. Illinois is expected to award roughly $235 million a year in ZECs to Exelon to help keep open two nuclear power plants in Illinois for another 10 years.

The utility has two large nuclear power plants in the state with a combined capacity of about 3,000 megawatts. ZECs will be awarded under the Illinois program to any power company that is capable of / *continued page 29*

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megawatt day. That was down from $100 in the last auction. A lot of people were expecting it to be at the same level or slightly higher than before.

Other parts of PJM did okay. For example, the capacity price in the part of the grid owned by Commonwealth Edison was $187 or $188 a megawatt day. We have a financing currently in the market for a portfolio of gas peaking plants in the Con Ed service territory. It benefitted from the auction results.

MR. CHAUDHRY: Every time another new quasi-merchant gas-fired power plant has been financed in PJM in the last couple years, someone says this will probably be the last one to be financed. Yet the financings continue. What is the future for financings in PJM given these capacity prices?

MR. REDINGER: They will be difficult. However, all the recent financings have required the lenders to take a view about the long term. As I have said many times, lending to these projects is more art than science. For any more projects to get done in PJM, you need to be more artistic. You need to have a long view about the future that may be more optimistic than what the present is telling you.

The US market remains awash in liquidity. A wall of money is chasing deals.

MR. CHAUDHRY: An artistic banker. [Laughter] What does that take? What is the art we are looking for? So there are a few levers on which bankers lending in the PJM market focus. How will those levers change in light of these capacity prices?

MR. REDINGER: The levers on which banks focus are leverage, cash sweeps, pricing and the size of the balloon payment required at maturity. These financings have all been done with around 55% to 60% leverage. There is some level of cash sweep, but definitely not 100%. The banks do not want the balloon payment to exceed $375 a kilowatt of installed capacity.

There have been more than three dozen of these transactions. The majority have been greenfield projects. There are a couple new deals that are set to go to market over the next quarter. One is the Hickory Run project for Tyr and another is the Southfield project for Advanced Power.

The first thing to watch is what the updated forecasts of future capacity prices look like from the consultants. The banks will then plug the forecasts into a sizing formula to determine how much to lend. If the sponsor wants to raise more debt, it will have to lock in higher prices with a revenue put or other form of hedge. That has a cost, but it also produces more leverage.

The last transaction we did closed in February and was for Ares EIF. It had about 45% leverage. That shows the sponsors have a lot of skin in the game.

The latest capacity auction results mean the market will be moving toward lower leverage and a lower balloon payment at maturity, especially if you believe the equity valuations of the projects will fall as a consequence of the auction.

MR PROSKIN: If a couple of years ago, you had a downside case that had $80 a megawatt day for the 2020/2021 year, you would have found it not credible. That would have been viewed at the time as an obnoxiously low number. We saw leverage in the 45% to 60% range in the recent past. The latest prices will affect both leverage and sponsor returns.

MR. CHAUDHRY: The next deal on deck in PJM is Hickory Run. Ray Wood, if I am not mistaken, BAML is one of the leads on this. What interest are you sensing from the market? What is changing?

MR. WOOD: Leverage may be lower as a percentage of project cost. However, it is not lower against projected cash flow. We have a new set of forecasts that must be socialized. The stress point is not the availability of bank capital because we are talking about a loan-to-value ratio in terms of construction cost that is relatively conservative. The real issue is what are the investor's returns? Maybe Andy Redinger is right that lenders will be looking at terminal value and ancillary service markets and a future 15 years from now to the extent they are using intrinsic value models. There is also an effect on ability to raise institutional capital behind the bank debt.

MR. CHAUDHRY: Michael Proskin, is it harder to raise debt or institutional equity for these projects?

MR. PROSKIN: There is no lack of bank capital. There is no lack of institutional and pension fund money. Neither one just got dramatically harder, but the numbers have changed. So, if a sponsor was expecting a return in the mid-teens on a merchant project, the numbers have come down.

There is less capital for a given project. It is not because of a lack of money chasing projects. It is because the cash flow projections have changed.

MR. CHAUDHRY: Andy Redinger, in light of these challenges — the low capacity prices in PJM — where are the opportunities in other markets? Where are people going to focus attention?

MR. REDINGER: You have to look at reserve margins. The region with the lowest reserve margin is ERCOT. The New England ISO is two or three on that list. Maybe New York is in the top four. PJM has double the reserve margin of these other regions.

M&A

MR. CHAUDHRY: Moving to a different topic, M&A transactions. Ted Brandt, give us a sense of M&A transaction volume so far in 2017 and how it compares to last year.

MR. BRANDT: We focus on renewables. The big one that was announced first quarter was the sale of sPower. That was almost $1.7 billion in enterprise value for a utility-scale solar company. The bidding was robust. My sense is that anything with operating assets and contracted inventory is moving very quickly. The bidders are enthusiastic.

EverPower is in the market now and has almost 500 megawatts of uncontracted, but fully constructed, wind projects without tax equity in it. The projects were all done with section 1603 payments from the US Treasury in place of tax credits. All reports are that the bidding on EverPower has also been robust. My sense is that the wall of money looking for assets is having an effect.

There is some inventory. A couple developers are for sale. There is an awful lot of what the European utilities call asset rotation. We are as busy as we have been in a / *continued page 30*

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generating zero emissions electricity equal to about 16% of what the state retail load was in 2014. Illinois utilities must enter into 10-year contracts to buy the ZECs from facilities that are awarded the credits at the "social cost of carbon," reduced potentially by a price adjustment to the extent the price exceeds a baseline market price index. The social cost of carbon will be set by an interagency committee.

The US district court in Illinois used similar reasoning as the court in New York to reject complaints about the program.

It said the Illinois program does not usurp federal authority to regulate wholesale power prices because the credits are awarded to nuclear generators merely for generating electricity and are "not directly conditioned on clearing wholesale auctions" and, therefore, they do not "alter the amount of money that is exchanged for wholesale electricity." It rejected the argument that the program interferes with interstate commerce. The program does not prevent out-of-state generators from submitting bids, the court said, and it would not assume that state agencies charged with awarding ZECs will discriminate, but even if the credits end up going entirely to Illinois nuclear plants, there could be legitimate reasons for favoring such plants, such as they are more likely to reduce pollution in Illinois.

The Illinois decision has already been appealed. The appeals court agreed in late July to an accelerated briefing schedule, which could lead to a decision by year end.

The district court issued a single opinion to decide two lawsuits: one called *Village Old Mill Creek, v. Star* brought by a group of Illinois electricity customers and the other called *Electric Power Supply Association v. Star* brought by the generator group.

Meanwhile, a bill to award ZECs to nuclear plant owners in Ohio has stalled in the state legislature at least until autumn. The bill would award ZECs worth $17 a megawatt hour for the first 16 years of the program to FirstEnergy, which has two nuclear power / *continued page 31*

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couple years. I think the 2017 numbers will be way up from 2016. And looking forward, 2018 looks pretty good, as well.

MR. CHAUDHRY: Michael Proskin, do you agree with that? Are we in a deal-constrained market because of a paucity of deals or are there abundant opportunities to buy assets?

MR. PROSKIN: Ted talked about the renewables side. There has been plenty for sale on the conventional side in PJM.

You asked earlier what is next if not PJM. I still contend it is the best house in a bad neighborhood. ERCOT has a lower reserve margin, but good luck. That is a tough place to do business and stay solvent. NEPOOL has had a pretty big reduction in capacity price as well. California is a beautiful state, but I am not sure I want to own a power plant in California.

A lot of the assets put up for sale in PJM in the last year have been sold. Some have not been. There has been a lot of interest among Asian buyers, largely Japanese and Korean. There has been both buying of whole plants and use of subscription processes where buyers are paired in a consortium that either forms itself or is put together with the help of an M&A adviser.

I think we will still see more in PJM. However, the recent capacity prices could eventually lead to a disconnect between what sellers want and what buyers are prepared to pay unless a particular plant has special attributes like a very low heat rate or advantaged gas. It is hard to say where that happens for any given seller.

MR. CHAUDHRY: Ted Brandt, how are buyers valuing renewable energy projects? Do they simply discount cash flow or are valuations becoming more complicated?

MR. BRANDT: The approach to valuing operating assets has not changed. Spreads have probably tightened a bit given the demand for operating assets. The typical metric we see is 30-year discounted cash flow for wind and 35 years for new solar.

Projects that have not been built yet, but that have long-term power purchase agreements, still trade around net present value against some type of typical build cost.

Where the discounted cash flow approach to valuation really falls apart is when bidding for a development company. That tends to be more of a probabilistic scenario where you have to take a view on how much of the uncontracted development pipeline per megawatt will turn into positive net present value. sPower is an example where there was real money paid for a development company.

MR. WOOD: It really is both return of and return on capital. One bidder may be satisfied with a 9% internal rate of return and another needs 10 1/2% or 11%. We are seeing the cost of capital continue to come down which is a reflection of the wall of money and growing comfort with the asset class. People buying a development company with a portfolio may sometimes over allocate money to the operating side and take the position that they are getting the development pipeline for free. This is a psychological thing. When we look at development companies, we look at the kind of returns on capital the company has been getting. Such companies are currently in a great place in the economic cycle.

A preponderance of the value in the renewable energy business has moved downstream. When the cost to build projects declines, it hits the upstream side first. Margins have been tough particularly for the solar panel manufacturers. Developers winning PPAs in places like California wait 18 months to procure the equipment hoping that solar panel prices will have fallen further by the time they have to lock in costs. Developers are effectively short the panel price. They sell part of the project at the start of construction, which is effectively how developers monetize the investment tax credit on the project, and avoid a change of control after construction. This has allowed developers to earn a big gain.

When people see three or four years of big gains and an increase in installed volumes in solar because of the compelling unit economics, there is a rush to get into the development business. Then they have to decide what to pay for a development company that has been making four or five times invested capital per project in the past. They either take a leap and buy the company outright, as happened with sPower with its big fleet of assets, or they use some sort of preferred distribution structure that provides some downside protection but that means once they have hit an agreed multiple return on investment, they are taking less cash flow and the rest goes to the developer. That is called an earn-out model.

We are also seeing M&A volume in the regulated utility sector. It may have slowed somewhat year over year because of regulatory risk. Look at what happened with the Oncor sale in Texas. There is logic to trying to get scale on the wires side of the business.

There is also logic to trying to get scale on deployment of renewable energy projects. We are seeing this not only in Europe, but also in India, Latin America and parts of Asia. There is no lack of strategic dialogue with all the policy changes and changes in cost of equipment and capital. There is active interest among a number of strategic players to get more engaged in the sector in a hurry.

Private Yield Cos

MR. CHAUDHRY: One of the big drivers for M&A in the last two years was the demand from yield cos. That demand pushed up valuations. What replaces yield cos?

MR. BRANDT: The answer is we return to the underlying demand that was there before yield cos. Eight years ago, you would see private equity firms that would price development risk and operating risk the same way. That changed five years ago when private yield cos appeared and pension funds began to take a greater direct interest in the sector by recognizing that the risks should be priced differently.

Acquisition finance may be a growth area for banks.

They would make a commitment, often just before notice to proceed with construction, to buy or invest at the end of construction. This gave the developer a predictable cost of capital. The investor recognized that there was very little risk transfer. There was not an expectation of growth in cash flow over time as developed once the public yield cos appeared on the scene starting three to four years ago.

No one wants to be a public yield co today. Everyone wants to be a private yield co with a patient investor who is getting an 8% leveraged return. The developer retains the upside. There are some structures with preferred distributions, some P50 structures, but that seems to be what has been filling the void.

MR. CHAUDHRY: How do private yield cos work? Does the developer get a commitment from a pension fund like you mentioned for a blind pool of assets or only for specified assets?

MR. BRANDT: The developer usually has a group of projects under development. The private yield co / continued page 32

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plants in the state. FirstEnergy announced plans last February to close or sell the plants by the middle of next year.

Connecticut Governor Daniel Maloy ordered two state agencies in late July to investigate and report back by February 2018 whether Connecticut should provide some form of financial support, such as zero emissions credits, to keep a 2,100-megawatt nuclear plant near Waterford operating. Dominion, which owns the plant, said a decision in 2018 will come too late to keep the plant open.

A RENEWABLE PORTFOLIO STANDARD in Connecticut withstood challenge again in court.

Solar developer Allco has been waging a multi-year effort to invalidate the results of auctions the state government has run to buy renewable energy.

The state legislature authorized the Connecticut Department of Energy and Environmental Protection in 2013 to solicit proposals to supply renewable energy for up to 4% of the state's electricity supply and to order the two main utilities — Connecticut Light & Power and United Illuminating — to enter into power purchase agreements with terms of up to 20 years with the winners.

Connecticut selected two winners in the 2013 auction: a large wind project in Maine and a small solar project in Connecticut.

Allco sued to have the results set aside and lost both in a federal district court and on appeal. It lost in part because the courts said it should have taken its complaints first to the Federal Energy Regulatory Commission.

The state asked for more bids in 2015 after the Maine wind farm failed to meet milestones in its power contract.

Allco sued again in an effort to prevent Connecticut from accepting bids from any projects that are more than 80 megawatts in size and, therefore, too large to be "qualifying facilities" — or QFs — under the Public Utility Regulatory Policies Act, a / continued page 33

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or pension fund writes a check to the developer at notice to proceed for part of the purchase price to buy an interest in each project — 49%, 51%, 80% — and pays the rest of the purchase price at the end of construction. There is almost always some kind of forward commitment for the full portfolio around an agreed underwriting box where the investor commitment stands for the next three years as long as the underwriting hits these six or seven criteria.

The dirty word across the sector is blind pool. This is almost always deal-by-deal underwriting. There is some type of approval process on a deal-by-deal basis as new deals come in, but the basic construct is a forward commitment at an agreed discount rate. The rate is indexed. Virtually the entire commercial and industrial solar rooftop business is being funded that way, and more and more utility-scale developers are working this way.

The residential solar financing model is in a transition phase.

MR. CHAUDHRY: Andy Redinger, is that what replaces the public yield cos?

MR. REDINGER: I agree with what Ted said. We are seeing the same thing. The difference between a private yield co and a public yield co is the public yield cos promised 12% to 15% returns that were unrealistic. A private yield co is what a public yield co should have been without the growth.

Shiny New Toys

MR. CHAUDHRY: Moving on, Andy Redinger, offshore wind was one of your new trends. How big will that sector be? Is it the next shiny new toy?

MR. REDINGER: It is hard to build new power plants on land near population centers along the US east coast. Capacity prices are increasing along the east coast from Delaware all the way into New England. These are constrained markets, either from a fuel perspective or transmission perspective. The best place to build may be offshore. There is a great wind resource offshore, and it is easier to build a new transmission line to bring the electricity to shore than it is to build a new line to move electricity long distances onshore.

Five states have now put out almost 5,000 megawatts of mandates for offshore wind. We are seeing the beginnings of an offshore wind industry in the northeast. I do not know whether it will head further south than Delaware and Maryland. We will see.

MR. BRANDT: Deepwater just got a PPA in Maryland. I agree with Andy that offshore wind will be the next new thing. My favorite example of this is that DE Shaw got a PPA to supply electricity to the Long Island Power Authority for something like 16¢ or 17¢ a KWh, which you would think is really expensive power, but it is a good price when you compare the 16¢ or 17¢ to zero need for LIPA to upgrade infrastructure to accommodate new capacity on land. When you add the infrastructure cost, the cost of competing power would have been something like 24¢. What these guys are doing is delivering 90 megawatts right at Montauk on the tip of Long Island. There is no other way to inject kilowatts in that area.

We think US offshore wind will be thousands of megawatts. You are clearly starting to see big global money coming into the sector. [For more discussion, see "Is US Offshore Wind About to Get Traction" in the June 2016 *NewsWire* and "Lessons from the US Offshore Wind Projects to Date" in the September 2015 *NewsWire*.]

MR. CHAUDHRY: Ray Wood, I want to get your take on what is the next shiny toy. Is it offshore wind or do you put your money somewhere else?

MR. WOOD: I think offshore wind is one answer for all the reasons that have just been mentioned. Technological improvements are making offshore wind competitive notwithstanding the collapse in the price of gas. There is a need for it. I don't know if it is a shiny toy, but it meets economic and social needs in some key states in the northeast because of the unemployment levels and economic malaise in some of these towns. These are communities that can use the jobs. It is becoming politically expedient for senators and governors to support, and it is making more economic sense.

The truly next big thing is energy storage because it will transform the entire power sector. It is not a this year or next year's story. We are probably seven to 12 years away from mass adoption. Storage is something to stay focused on, for sure in terms of major capital deployment and economic disruption to the existing business models.

MR. CHAUDHRY: Let me throw in a third possible shiny new toy and get the panel's take on it: community choice aggregators, or CCAs, in California. At least one large solar project has been financed to date on the basis of a power purchase agreement with a CCA. Do CCAs have legs? Will we see a large number of deals done with CCAs?

MR. CHO: Our bank financed a project with a CCA as the offtaker. Do I think there will be a lot of transaction volume? I don't know. We look at CCA projects almost like community solar projects where the real credit behind the revenue from electricity sales is a bunch of consumers. The issue for the banks is the CCA does not have a credit rating or financials. It is basically a pass through to the consumers. We end up structuring triggers and cash traps similar to a residential solar deal. The risks are slightly different, but ultimately you are looking to the consumers to pay. We have not seen too much activity around CCAs yet, but we are open to doing more than the one we have already done. [For more discussion about CCAs, see "Financing Projects with Community Choice Aggregators" in the June 2017 *NewsWire* and "Huge Potential New Demand for Power" in the October 2016 *NewsWire*.]

MR. CHAUDHRY: Michael Proskin, what are your thoughts on the next shiny toy?

MR. PROSKIN: I'm just concerned about somebody in Washington breaking the toys. [Laughter]

When we talk about the next shiny toy, we always have to be aware of external forces changing the rules of the game.

We have not talked about how the US energy secretary, Rick Perry, has commissioned a report that may find that intermittent sources of electricity, like wind and solar, are a threat to reliability of electricity supply and require government / *continued page 34*

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1978 federal law that requires regulated utilities to buy electricity from cogeneration facilities, and from other independent power plants of up to 80 megawatts that use waste or renewable energy, at the "avoided cost" the utility would spend to generate the electricity itself.

The latest lawsuit is, at heart, a challenge to the state's renewable portfolio standard, since the state's solicitation is based on the RPS law.

Allco lost in federal district court in August 2016 and again in a US appeals court at the end of June. The case is called *Allco Finance Limited v. Klee*.

The federal government has sole authority to regulate wholesale rates for power sold in interstate markets. The US Supreme Court held in a case called *Hughes v. Talen Energy Marketing* in April 2016 that Maryland and New Jersey strayed impermissibly into wholesale ratemaking when they ordered utilities in their states to sign power contracts with an independent generator for electricity from two gas-fired power plants. The power contracts had the effect of setting the price the generator would receive for its electricity, the court said. (For more detail, see "Supreme Court Nixes Two PPAs" in the April 2016 *NewsWire*.)

Not so in Connecticut. The appeals court in the Allco case said the Connecticut actions were well within broad powers that states possess to direct the resource decisions of utilities under their jurisdiction. For example, the court said, states can order utilities to build renewable power plants themselves or to buy renewable electricity from other generators without that being considered state regulation of the wholesale power market.

The court also rejected complaints by Allco that the Connecticut RPS program discriminates against renewable energy generators in other states. Connecticut honors RECs from renewable energy projects in and around Connecticut that will have a measurable effect on clean air in the state.

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policy to shift in favor of encouraging more baseload power plants.

We have not talked about the threat of import tariffs on solar panels. Such tariffs could be imposed later this year. Solar tariffs could lead to a pretty big shift in the cost curve. One news network trumpeted the potential for such tariffs to save a couple thousand jobs. Another news network focused on the potential for any tariffs that are imposed ultimately to jeopardize a couple hundred thousand jobs. I look to counsel from the esteemed folks at Chadbourne, but I think that the president can pretty well just do what he wants, regardless of the recommendation from the US International Trade Commission. [For more discussion about the threat of solar import tariffs, see "Solar Companies Evaluate Tariff Options" in the June 2017 *NewsWire*.] ◎

Solar + Storage: US Regulatory Issues

by Caileen Kateri Gamache, in Washington

Battery storage is the sexy newcomer to the rooftop solar industry. Technology has rapidly improved, while prices consistently decline. Its manageable size makes it a well-suited match for rooftop solar, and it brings out the best in its partner – expanding capacity, extending service into the night, and providing support when the solar unit falters. It also has many admirable characteristics in its own right, as it is able to offer energy, capacity and various ancillary services independently to the grid.

However, adding batteries to rooftop solar systems raises regulatory questions.

The main issue is whether adding a battery could subject the owners of the system — the solar rooftop company and any tax equity investors — to federal regulation.

Background

To understand the regulatory issues, it is first necessary to understand solar as a singleton.

Solar rooftop companies install solar panels on customer roofs and either lease them or use them to sell electricity to the customer. In the latter situation, the company is making retail sales of electricity. The customers may be residential, commercial and industrial, or government agencies, schools and other tax-exempt entities.

The customer will normally consume all of the energy produced by the solar system and draw the remainder of its power needs from the local utility via interconnection with the grid. Customers are, in turn, typically subject to state "net metering" rules that allow the customers in limited circumstances to send any extra power from onsite generation to the local utility.

Most states have adopted net metering rules, but the specific terms vary by state and utility. The basic principle of all net metering programs is the amount of power a customer puts onto the grid from a rooftop system is netted against the amount of power the customer draws from the grid. The customer benefits from the delta between the retail price of energy from the utility and the sum paid under a power purchase agreement governing the sale of energy from the rooftop system or lease of the system. The rest of this article is limited to the popular PPA structure. Leases are subject to a different analysis.

The Federal Energy Regulatory Commission has broad jurisdiction over sales of energy at wholesale in interstate commerce and the transmission of energy in interstate commerce. A solar rooftop company that sells energy to a customer from a rooftop solar system, who then "resells" the electricity to the local utility for net metering credit, could be viewed as making wholesale sales in interstate commerce. This is an issue only if the amount of excess power fed by the customer into the grid in any billing period exceeds the amount of power the customer takes from the grid. It would make the solar rooftop company subject to regulation by the Federal Energy Regulatory Commission. Electricity sellers must get prior authorization from FERC before making wholesale sales.

Confronted with this possibility, in 2009 SunEdison petitioned FERC for a declaratory order that the sales by its affiliates from rooftop solar systems to customers who engage in net metering are not wholesale sales subject to FERC regulatory jurisdiction.

FERC issued a declaratory order, finding that the sales would not subject SunEdison to wholesale sale regulations so long as the customer is a net consumer of electricity from the grid during a billing period. Because the order is an adjudicatory order, rather than a policy statement of general applicability, it is limited to the specific facts presented by SunEdison.

The SunEdison order does not address what happens if the rooftop company or customer is using the system to provide ancillary services or capacity to the grid.

QFs

Rooftop solar companies usually qualify for broad exemptions from FERC regulation under a 1978 law called the Public Utility Regulatory Policies Act or PURPA. Most rooftop systems are under 20 megawatts in size, which is one of several dividing lines in the statute.

Generating facilities that are exempted from FERC regulation under PURPA are called "qualifying facilities" or "QFs." One type of QF is a generating facility whose fuel is at least 75% from biomass, waste, renewable energy or geothermal steam or fluid and is under 80 megawatts in size. There are strict limits on the amount of oil, natural gas and coal that may be used by the facility. Rooftop solar systems easily meet these size and fuel use requirements.

The solar rooftop company may have to file a Form 556 with FERC either "self-certifying" that the rooftop system is a QF or asking FERC to confirm that it is a QF. Such a form must be filed for any rooftop system that is greater than one megawatt in size, alone or in aggregate with affiliated solar systems located within one mile.

Now introduce a battery storage system to rooftop solar.

The first issue is what the battery does to the QF status of the solar system. If the battery increases the total capacity of the solar system, then it might trigger an obligation to file a FERC Form 556 to continue benefiting from regulatory exemptions if it bumps the size of the system over one megawatt.

The next issue is whether the battery may be considered part of the solar QF system so that it benefits from the QF status of the rooftop system or, alternatively, may qualify independently as a QF. There is no definitive precedent to date on whether battery storage satisfies the requirements for QF status, either alone or as part of a solar system. FERC staff has informally provided mixed guidance.

Recall that there are limits on the type of energy or fuel that may be used by a QF. It is likely that a battery that is charged solely by the solar system would be found to meet the fuel use requirements. However, a battery handles electricity produced from sunlight rather than solar energy directly.

A few rooftop companies have self-certified their solar systems plus batteries as QFs.

The relationship between the solar / continued page 36

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Other recent court decisions have tested whether renewable portfolio standards and laws to discourage the use of coal to generate electricity impede interstate commerce. (For additional information, see "Renewable Portfolio Standards" in the September 2015 *NewsWire* and "Minnesota Carbon Statute Invalidated" in the August 2016 *NewsWire*.)

A FOREIGN PARTNER in a US mining business did not have to pay US taxes on most of its gain when it sold its share back to the mining company, the US Tax Court said in July.

The case is *Grecian Magnesite Mining v. Commissioner.*

Most foreign investors are careful to hold US investments through a US "blocker" corporation. The blocker might be a US limited liability company that the investor has chosen to treat as a corporation for US tax purposes. Foreign investors doing this should be able in most cases to avoid a US income tax when exiting a US investment by selling the blocker. Not so where the investor invests directly in a US partnership or limited liability company treated as a partnership.

The investor in the Grecian case invested directly in a US partnership. It eventually sold its partnership interest back to the partnership for a $6.2 million gain. The IRS said it should have been taxed on the full gain. The Tax Court said it should have been taxed on only $2.2 million of the gain.

Some foreign investors who paid full taxes in similar situations may be thinking about filing amended US tax returns requesting refunds of US taxes paid.

The IRS has not decided whether to appeal. The Obama administration proposed in 2013 that Congress change the US tax code to avoid the result the Tax Court reached. Congress could close the door in any corporate tax reform bill this fall.

Grecian, a Greek company in the business of mining magnesia and magnesite in Greece, bought a 15% interest / continued page 37

Storage

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system and the battery becomes more complex to the extent the battery receives any charge from the grid.

If the solar-plus-storage facility is treated as a single QF, there is challenging case law that indicates other equipment associated with QFs, such as interconnection facilities, may only be viewed as part of the QF if its purpose is strictly limited to conveying QF power (with certain limited exceptions). Neither a battery nor an intertie used to carry electricity from the grid to the battery can be definitively said to be used solely to transmit QF power. FERC is still wrestling with whether energy storage should be treated as generating equipment, transmission equipment or a hybrid of the two for broader regulatory purposes.

If the battery will store electricity from the grid, then the fuel use limits may cause issues because the electricity from the grid is not strictly from permitted energy sources. The grid energy might also be used for purposes other than those expressly permitted. This is a problem whether the rooftop company intends the battery be considered part of a single QF with the rooftop system or a QF in its own right.

Options

There are two main options for the owner of a rooftop solar system faced with this situation.

One option is to ask FERC to confirm the QF status of a solar-plus-storage system or the independent status of the battery as a QF. This is done by filing a Form 556 as an "Application for Commission Determination of QF Status" rather than as a "Notice of Self-Certification." The application requires a filing fee, which is currently $22,050. FERC has 90 days to act on the application. If FERC does not act within 90 days, then the application will have been deemed granted.

Another approach that might provide broader comfort to the industry would be to ask FERC for a declaratory order. The filing fee for a declaratory order is currently $25,640. The drawback of asking for a declaratory order is that there is no statutory time limit for FERC to act.

PUHCA

The Public Utility Holding Company Act or PUHCA may subject upstream owners of battery storage systems to utility regulation. PUHCA is administered by FERC. A full discussion of PUHCA was published in the February 2016 *NewsWire*.

PUHCA imposes detailed recordkeeping requirements on any entity considered a utility holding company. The books and records must be maintained and retained pursuant to comprehensive FERC regulations, including by conforming to a uniform system of accounts in some circumstances. State regulators also have review authority over them.

PUHCA applies to "[a]ny company that directly or indirectly owns, controls, or holds, with power to vote, 10 percent or more of the outstanding voting securities" of an "electric utility company."

An "electric utility company" includes any entity that owns or operates facilities for the generation or transmission of electricity for wholesale or retail sale. Entities making sales of electricity to customers from rooftop solar-plus-storage systems are electric utility companies. Therefore, all direct and indirect upstream owners with at least a 10% ownership interest in the facilities, including tax equity investors, are utility holding companies under PUHCA.

All but a select few exempt utility holding companies are required to file a Form 65 "Notice of Holding Company Status" with FERC identifying all affiliates and subsidiaries and their corporate relationship to each other and status under PUHCA.

Utility holding companies are exempted from filing if all they own are QFs (and a couple other types of entities). Therefore, the QF status of the battery is important to PUHCA regulation.

FERC also has authority to

Adding batteries to rooftop solar systems raises regulatory questions.

review and approve or deny some acquisitions where a utility holding company directly or indirectly acquires another entity that owns or operates facilities that make wholesale sales of electricity or transmits electricity in interstate commerce. However, a utility holding company that only owns QFs has blanket authority to acquire additional interests in QFs. Other parties to the transaction may still require prior approval.

So What?

What is the risk of ignoring the potential regulatory issues?

Sanctions for violating FERC regulations are capped at $1 million a day per violation, plus disgorgement of any improper profit.

The executives involved may also be referred to the Department of Justice for criminal penalties, including prison time, upon a finding of criminal intent. Candidly, neither criminal nor significant civil penalties are likely for violations of the regulations discussed in this article absent bad faith, a history of repeat offenses, fraud or willful disobedience.

If FERC were to find in the future that a battery or solar system plus battery does not qualify as a QF and has made sales at wholesale in interstate commerce of electricity, capacity or ancillary services without the required FERC approvals, it may order refunds. FERC usually only orders refunds to the extent there were profits above operating costs. It may be more apt to order refunds for sales of ancillary services and capacity that "pass through" the customer directly to the grid from a system without proper authority.

In egregious circumstances, FERC can limit a company's ability to engage in regulated activities. This could affect anticipated revenue streams. There is the potential for damage to corporate reputation, and there are possible effects on closed transactions.

The regulations in this area should eventually catch up with technology. In the meantime, it may be prudent to pursue one of the options for gaining greater certainty. As always, it is important to scrutinize regulatory representations and indemnities in relevant transaction documents. ◎

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directly in a US partnership, Premier, that mines magnesite in Nevada, Florida and Pennsylvania. Premier has its head office in Pennsylvania.

Another Premier partner, IMin Partners, approached Premier and offered to sell its interest back to the company in 2008 for $10 million. Premier accepted the offer and was then obligated to offer to purchase each other investor's interest for an equivalent price.

Grecian was the only other partner who chose to sell.

Grecian agreed in July 2008 for Premier to redeem its interest for $10.6 million in two installments. It had a gain of $6.2 million.

The problem with owning an interest in a US partnership directly — rather than through a US blocker — is the foreign partner must pay US taxes at a minimum on any gain attributable to US real property owned by the partnership. Of the $6.2 million in gain, $2.2 million was attributable to real property. Grecian failed to file any US tax return on faulty advice from its US accountant.

On top of that, the IRS takes the position that the rest of the gain is also taxable, as if the partnership sold its assets and allocated a share of the income to the Greek partner. The IRS said the Greek investor should have reported the entire $6.2 million gain as ordinary income, citing a 1991 ruling (Revenue Ruling 91-32) that treats a foreign partner disposing of an interest in a US partnership as if the partnership sold all its assets and allocated the foreign partner its share of any gain at the partnership level.

Foreigners are subject to tax fully in the US on any "effectively connected US trade or business income" — basically income earned through a US office. A partner in a partnership is usually treated as engaged directly in whatever business the partnership is involved.

The Tax Court declined to follow this approach. It treated the partnership as if it were a separate company and treated Grecian as if it sold shares in the company. Any gain on sale of a partnership interest is */ continued page 39*

US Offshore Wind

What to make of the growing interest in US offshore wind projects given the conventional wisdom that offshore wind cannot compete in a market with no scarcity of land for onshore projects that can generate electricity more cheaply?

A panel talked about this and other questions at the Chadbourne global energy and finance conference in early June. The panelists are Laura Beane, CEO of Avangrid Renewables, Thomas Brostrøm, president, North America, of DONG Energy, Salvo Vitale, chief legal officer of US Wind Inc., Alexander Krolick, managing director, energy and infrastructure, Macquarie Group, and Christopher Hunt, partner and managing director of Riverstone Holdings. The moderator is Ben Koenigsberg with Norton Rose Fulbright in New York.

MR. KOENIGSBERG: There are five US states today that have leases for offshore wind: Massachusetts, Maryland, Virginia, New Jersey and New York. The lessor in each case is the federal government through the Bureau of Ocean Energy Management or BOEM. There has been increasing interest among these states to promote offshore wind.

US Wind and Deepwater were just awarded OREC or ocean renewable energy certificate contracts for projects off the coast of Maryland. The contracts are not just to sell renewable energy credits but also take into account the value of the electricity. They are bundled contracts.

In Massachusetts, there is a draft request for proposals out to build up to 800 megawatts of offshore wind. Ultimately, Massachusetts has plans for 1,600 megawatts, and the number is expected to increase above that. Bid are expected before year end for two to four projects with a total capacity of 800 megawatts.

Deepwater, which developed Block Island, the only offshore wind project currently operating in the United States, has a contract with the Long Island Power Authority to build a 90-megawatt project. That bid was won in a competitive market with no advantage to offshore wind.

Thomas Brostrøm, starting with you, you have a lease off Massachusetts that can accommodate up to 1,000 megawatts of offshore wind capacity. Why did Massachusetts break the 1,600 megawatts it plans to solicit into two or more bid rounds, with only 800 megawatts up for bid this year?

MR. BROSTRØM: The Massachusetts offshore wind market was stone dead two years ago. You had Cape Wind basically come to a stop. In the last two years, I think we have come a long way.

In addition to the states you mentioned, Governor Cuomo in New York is talking about 2,400 megawatts of offshore wind by 2030. Some of the candidates for governor in New Jersey are talking about 3,500 megawatts of offshore wind there by 2030. Massachusetts plans to procure 1,600 megawatts of offshore wind over the next 10 years.

From our standpoint, it is important for the market to try to move to scale rapidly. It was great to see Block Island built, but it was only a 30-megawatt project and came at a high cost. So we have been advocating strongly to go quickly to scale. You can have the same benefits we have seen in Europe where the cost has fallen to below 10¢ a KWh.

Offshore Outlook

MR. KOENIGSBERG: How do you see offshore wind unfolding in the United States?

MR. BROSTRØM: Europe has paved the way. It has also taken it on the chin. Offshore wind has been highly subsidized over the last 20 to 25 years. You now have an industry that is growing by 25% a year. It is going global. It is moving from 12,000 to 15,000 megawatts of installed capacity today to about 40,000 megawatts by 2025. These volumes create competition. The supply chain is driving down costs. This has paved the way for the Massachusetts bids to offer fairly good prices and that should lead to more procurements in the future.

MR. KOENIGSBERG: Laura Beane, Avangrid also has enough area under lease off Massachusetts to build up to 1,000 megawatts. What factors do you think will influence whether the state ramps up the procurements quickly?

MS. BEANE: Price, clearly. That will be at the forefront. Market conditions will also play into it. I sense a healthy competition developing among the Northeastern states. Jobs are another factor. Massachusetts will be weighing how many direct jobs are likely to be created in the state under the different bids received.

MR. KOENIGSBERG: Do you think if the state awards the entire 800 megawatts to just one project, that will make it more difficult for the industry to take hold?

MS. BEANE: When I look at the existing players, it looks like a pretty level playing field. All of the parties expected to bid are credible. They have a lot of experience in this space in Europe. There are definitely first-mover advantages, where you will be paving the way with a regulator and establishing relationships. I assume Massachusetts wants to stagger the procurements in the hope that it will benefit over time from falling prices. The hope is the second phase will benefit not only from the knowledge and maybe some of the mistakes that are made in the first phase, but also from lower costs and a more advanced supply chain.

MR. KOENIGSBERG: Salvo Vitale, turning to Maryland, the state Public Service Commission forecasted almost 9,700 jobs and $1.8 billion in spending over 20 years because of the two projects to whom it just awarded contracts. The ORECs are worth about $130 per megawatt hour generated. The PSC has said that the average resident in Maryland will see his or her bill rise by no more than $1.40 a month. Spread out, that is not a huge number. How do you think Maryland will benefit from the two contract awards?

MR. VITALE: Maryland wants to seize first-mover advantage. Having the biggest two offshore wind farms in the United States may allow it to become a hub for offshore wind that could serve future projects from Boston to the Carolinas. I agree with Laura Beane. Future projects should end up competing more on price rather than what we had to do, which was demonstrate a big commitment to Maryland in the form of creation of new jobs and net economic benefit for the state.

I see an advantage to the state from awarding two contracts. I do not see a lot of advantages for the developers. These are two separate projects with their own timetables. We expect to have installed 248 megawatts by 2021 and the other project is expected to be in service by 2023.

MR. KOENIGSBERG: Are there any lessons learned from having gone through the bid process in Maryland?

MR. VITALE: The bidders in the next rounds will also have a high level of expertise that was earned in Europe over the past decade. The competition will probably just come down to a matter of price.

Lessons Learned

MR. KOENIGSBERG: Alex Krolick, you led the financing for Block Island and also were heavily involved with offshore wind in Europe. What have you learned about how to do offshore wind?

MR. KROLICK: Some of the lessons are obvious in hindsight. It was important that we started small. We are building an industry here. It is fragile in its early stages, and we cannot afford many failures. Thirty megawatts was the right size at that moment. It was $350 million or so in capital costs, so it / continued page 40

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normally taxed as capital gain. The only way a foreigner would be taxed on such a gain, the court said, is to the extent the gain can be traced to US real property or if the gain is considered from a US source. A partnership interest is "personal property," the court said. Under US tax rules, gain from the sale of personal property has its source where the seller is located. Since this seller was in Greece, the court said, there should not have been any tax beyond the share of gain from US real property.

TWO US TAX REGULATIONS that affect the project finance market are in limbo.

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

The Treasury said in Notice 2017-38 in June that had it reviewed 105 regulations issued during the time period and identified eight that it said merit further review. It asked the public for suggestions for how to deal with the regulations by August 7.

The eight include two that affect project finance transactions.

One addresses when a developer forming a partnership with a money party to own a project on which the developer has been working will be treated as having made a taxable sale of the project to the partnership rather than a tax-free capital contribution. A developer is assumed to have made a "disguised sale" of the project if the developer is distributed cash by the partnership within two years after contributing the project.

This basic principle is not in limbo, but detailed rules the IRS issued for calculating the amount paid by the partnership for the project in cases where there is existing project-level debt will be revisited. This / continued page 41

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was not tiny in terms of money required.

Now we have 90-, 120- and 248-megawatt PPAs. LIPA will probably do another 210 megawatts in the next few months, and then Massachusetts will award 400 to 800 megawatts. I hope we stick to this trajectory.

Offshore wind construction is hard. This is really a marine industry more than it is a wind industry, and things will go wrong. It will be important to make sure that the financing people behind you are pragmatic and experienced because the last thing that a developer wants is to have problems on top of problems. Finding a lender group that has experience institutionally with offshore wind is important. Most likely, we will have projects that are closing over some sort of litigation risk. You need to have lenders that are able to get their heads around that.

Tax equity for offshore wind is complicated. The US tax equity market is a 12-month forward market. It is hard to get tax equity providers to talk seriously if you are more than 12 months out from your project, and the offshore wind projects in the US have 24-month construction periods. As the projects increase in size, we are talking about a much larger quantum of tax equity. Raising $500 million in tax equity for a single project is a big challenge.

One of the lessons we learned on Block Island is that the ability of turbine vendors to bring tax equity as part of the turbine sale will be critical to the success of the next round of projects. Vendors can play an active role, but will not be able to cover the whole amount. So, like on Block Island, you have to come up with a structure where somebody bridges the tax equity gap. The bridge is likely to be a combination of equity and debt. Then halfway through a complex construction period, when you are 12 months away from completion, you start engaging with the tax equity. The closer the project gets to the end of construction, the less leverage there is on the sponsor side. There is a real risk of value leakage. Managing that process will be important.

MR. KOENIGSBERG: Do you want to add anything else about the financing strategy? For example, would project bonds make sense?

MR. KROLICK: For smaller projects up to 400 megawatts, the construction debt can be raised pretty easily in the commercial bank market. That is the financial sector that is most attuned to dealing with the challenges. As projects get larger, debt funds are probably going to be the next players to come in.

MR. KOENIGSBERG: Chris Hunt, Riverstone is a major backer of Pattern Energy, a successful US wind developer that has eschewed offshore wind and Riverstone has chosen not to invest directly in offshore wind developers. Why not? You have made some investments on the supply side.

Decision to Pass

MR. HUNT: We made a conscious decision not to do offshore wind. We invested several years ago in specialized rigs that that are used to build offshore wind farms. We made the investment in 2010 and for a while, we owned a fair percentage of the fleet in Europe that was constructing plants. These are rigs that have the cranes and capacity to house workers and store equipment to build offshore. Given the enormous size of the turbines, they are expensive ships. A lot of people overlook the enormous supply chain that is needed to deliver these projects. The supply chain alone will require billions of dollars in investment.

We are happy with the choice we made. The supply side turned out to be a very profitable endeavor for us, and we did well on the investment. Now that we have done full cycle — we entered and grew the business and exited — we have thought about whether we want to go back in. I think for now, we will sit on the sidelines for a few reasons.

First, we are very busy with onshore projects and have plenty to do. Second, it is

> Offshore wind is starting to take hold in Goldilocks locations in the US. A project can feed electricity straight into Boston from 20 miles offshore.

becoming a big balance-sheet game. Owning and building offshore wind farms requires a balance sheet and, for private equity guys like us, that is not necessarily a strength that we bring to the table. Third, this is a maritime exercise in very rough and windy seas and there are lots of things that can go wrong. It is just not a risk that we are interested in taking right now.

MR. KOENIGSBERG: If you were a balance-sheet player, do you think you would be more likely to jump into the fray?

MR. HUNT: Yes. We watched the industry grow up in Europe and, frankly, the industry if anything over delivered on expectations. Projects have been built and have delivered returns. Companies in Europe have done very well. The projects have been good not only for developers, but also for turbine suppliers and the banks. It has been a positive experience in Europe, and I think it will be a positive experience here. It is just not an industry that is for the faint of heart.

Goldilocks Locations

MR. KOENIGSBERG: Skeptics of the offshore wind industry point to the high cost per installed megawatt. The projects are not competitive if tested solely against that metric. Laura Beane, what do you say to the critics?

MS. BEANE: Offshore wind makes sense currently only in specific markets. The predicates for it to make sense are coming together in the Northeast. That region has huge amounts of load. It has aggressive renewable energy targets. The regulators want to make it happen. New England has huge transmission constraints. There is a lot of NIMBY resistance. Nobody wants to build additional high-voltage transmission, and it is hard to site additional power plants on land within the geographic footprint where the electricity load is located.

New England is looking at importing the power it needs from outside the region. Offshore wind feels like it is outside the state. The installed cost of offshore wind is high currently, but the cost has to be compared against the cost not only of building additional capacity on land, but also new high-voltage transmission that would have to be built alongside it.

MR. BROSTRØM: The cost has always been our Achilles heel. But look at what has happened over the last three to four years where the cost of offshore electricity has moved from something like $180 to $200 a megawatt hour to something like $60 to $70. Costs are even lower today in Europe.

Competition is picking up in the supply. Large turbine vendors like Siemens, Mitsubishi, Vestas and GE are all competing. Turbines are now eight, nine and 9 1/2 / *continued page 42*

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is most likely to affect tax equity partnerships formed to finance projects that are already subject to construction or term debt. (For more information, see "Tax Triggered When Partnership Formed?" in the October 2016 *NewsWire*.)

The other regulations put in limbo deal with affiliate or shareholder debt.

Many foreign investors investing in US projects form US holding companies to hold the investments and inject capital into the US partly as equity and partly as a shareholder loan to the US holding company. The loan allows the foreign investor to "strip" US earnings by pulling them out as interest on the shareholder loan. Earnings pulled out as interest are not taxed in the United States, since the US holding company paying the interest can deduct it. The only tax is a possible withholding tax on the interest at the US border, but many US tax treaties reduce or eliminate any such withholding taxes.

The IRS said in 2016 that it would require companies with shareholder debt to have four kinds of documents to prove the loans are really debt. The documentation was considered burdensome. Therefore, the IRS was only requiring it where the shareholder making the loan owns the holding company at least 80% by vote or value and then only in cases where a publicly-traded company is involved somewhere in the ownership chain or else the entire chain of affiliated companies has more than $100 million in assets or revenue of more than $50 million a year in any of the three prior years.

The IRS said in early August that it will delay the need to produce such documentation until 2019. The IRS made the announcement in Notice 2017-36. The documentation will be required for shareholder debt issued after 2018.

The part of the regulations that reclassify some shareholder debt as equity have not been delayed. (For more detail, see "New US Tax Rules Could Reclassify Debt as Equity" in the April 2016 *NewsWire*.) / *continued page 43*

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megawatts when they were only 3/4ths of a megawatt several years ago. There is big competition to supply every component of the wind farm.

A month ago, we put in a subsidy-free bid in Germany to supply offshore wind at the prevailing wholesale market price. We said we plan to install 13- to 15-megawatt turbines to make it work.

I agree with Laura Beane that a lot of things are coming together in New England. It is a big advantage to be able to put an offshore wind farm just 20 miles from Boston where you cannot see it, but the project is close enough to feed the electricity straight in.

MR. KOENIGSBERG: Alex Krolick, Europe used feed-in tariffs to develop a renewable energy industry. We use tax credits. Raising tax equity for offshore wind is challenging for the reasons you said. Do you think these projects can get done without tax credits?

MR. KROLICK: Oy! Tax equity is undeniably a big contributor of value. Keith Martin said the typical capital stack for an onshore wind farm is 50% to 60% tax equity. Maybe it is 40% to 50% for offshore wind because of value leakage. You lose value on fees, transaction costs, increased debt costs because of the structural complexities, but the tax credits are still value. Without tax credits, the electricity will be more expensive. The issue is whether that price is palatable.

As Laura and Tom said, offshore wind is starting to take hold in Goldilocks locations in premium constrained markets where offshore wind is a competitive solution for delivering megawatts. I think you can see this happening eventually without tax equity. With the tax credits already phasing out, I think we may be there sooner rather than later.

MR. KOENIGSBERG: Salvo Vitale and Chris Hunt, where do you think US offshore wind will be in five years?

MR. VITALE: We expect confidence in the sector to grow over the next five years. Turbines will increase in size, making the projects more competitive. This is an industry that still needs political support to prosper. Hopefully the need for political support will diminish over time.

MR. HUNT: I don't mean to sound negative, but I think things are going to take longer and go slower than the industry expects. Europe has had a boom in building and it has been a great experience, but people forget that most of the projects that were built were 10 to 15 years in gestation. It takes a long time to get the supply chain up and functioning. Some of that is transferable from Europe to the United States, but not all. For example, you can't use a construction vessel that has been operating in the North Sea because US law does not allow the vessel to be used here. It takes time to build new vessels and train people to use them.

I hesitate to guess how many megawatts actually get developed in the next five years. Europe is biting the bullet and experimenting with 10- to 15-megawatt turbines that are astonishingly large and experimenting with floating platforms and different base technology that will reduce the installation cost. A lot of what happens in the US is going to depend in part how the Petri dish projects in Europe perform.

MR. KOENIGSBERG: Thomas Brostrøm and Laura Beane, with the size of your balance sheets, you do not really need to use project finance.

MR. BROSTRØM: In Europe, we used our balance sheet to issue bonds at the corporate level. We take construction risk. Once the project is built, we have looked to sell 50% of the equity to financial investors who are looking for long-term stable cash flows.

That model has worked well in Europe. We may start with it here, but the US is a different market when it comes to debt and equity investors. Then you add tax equity structures, which add another layer of complexity that we are still trying to get our heads around. The balance sheet gives us flexibility.

MS. BEANE: My answer is nearly identical, but ultimately, it is too soon to tell. A lot can happen between now and when projects go into the construction phase. We will evaluate the environment at that time and make the most economic choice.

MR. KOENIGSBERG: Are there any audience questions?

Audience Questions

MR. EBER: John Eber, J.P. Morgan. Is the $60 to $70 megawatt hour projection current pricing or are you looking down the road a few years, and does it assume an ability to monetize the tax benefits?

MR. BROSTRØM: I think if Salvo and Laura would talk about what their price expectations are, I will tell them what mine are. [Laughter] Let me put it this way. The wind conditions or wind speeds off New England are on par with what we know in the North Sea. Give and take. We should be able to tap into the same cost reduction curve.

I don't think prices will start out as low here as in Europe for the reasons that Chris Hunt mentioned. It has taken 25 years to get to that point in Europe with now mature markets.

MR. MURPHY: Drew Murphy with Edison International. My recollection, having been involved in the effort to do the first round of US offshore wind projects eight to 10 years ago, is that the environmental and permitting issues were significant challenges. Has that situation improved?

The global offshore wind market is moving from 12,000 to 15,000 MWs today to 40,000 by 2025, driving down equipment costs.

MR. VITALE: I was not here 10 years ago, but we are in the advanced stages of permitting our Maryland project. The process seems fairly streamlined. Maybe it's because I am coming from Italy where everything is a huge mess, but I was impressed by the precision, by the timing of the delivery of every permit so the US authorities must have done a lot in the last 10 years to improve the process.

MR. VOLPE: Tony Volpe with Falck Renewables. Do you foresee a time when the levelized cost of energy for offshore wind will be systematically below onshore? Do you see that coming in Europe sooner than in the United States, if ever? Part B of the question is how do you plan to finance subsidy-free projects?

MR. BROSTRØM: We are close in Europe to being on a par with onshore wind. I do not think we can do that anytime soon in the United States if you include wind prices in the US interior because you are looking currently at $18 to $20 a megawatt hour in the Midwest. It is easier to be competitive in Scandinavia, the UK, Germany, the Netherlands where there is only limited room for additional onshore wind.

You are basically capped at turbines of three to four megawatts in size on land. Not so offshore.

MR. HUNT: I am actually bullish on the cost projection. One turn of the rotor of the larger offshore wind turbines in the United Kingdom can power a home for an entire day. Do not underestimate the enormous benefit of / continued page 44

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The Treasury has until September 19 to report to the White House on specific actions it will take to cancel or fix regulations it put on the list to revisit.

CUSTOMER ACQUISITION COSTS are increasing for solar rooftop companies.

GTM Research says that 17% of the installed cost of the average US solar rooftop system today is the cost to acquire the customer. The figure is expected to increase to 20% to 21% for the period 2018 through 2022 as solar equipment costs fall faster than marketing costs.

The three leading solar rooftop companies — Tesla, Sunrun and Vivint — spent 90¢ a watt to acquire customers in the first quarter of 2017, according to GTM. Rising wages and additional hires for the sales force are the main culprits, as are lower closing rates as sales people go after customers to whom it is harder to make sales.

Smaller local installers have costs of only 28¢ to 36¢ a watt. GTM says they benefit from marketing being done by the larger rooftop companies.

MINOR MEMOS. The Solar Energy Industries Association estimates that the solar tariffs sought by US solar panel manufacturer Suniva would cost the United States 88,000 jobs . . . . A new ordinance in South Miami that takes effect September 18 will require all new homes to have solar panels on the roof. The ordinance requires 175 square feet of solar panels to be installed per 1,000 square feet of sunlit roof area. Home renovations will trigger the requirement if the existing structure is expanded by more than 75% or more than 75% of it is replaced. San Francisco began requiring all new commercial and residential structures of up to 10 stories to have solar panels on the roof at the start of this year . . . . Massachusetts set a target in June for utilities in the state to have installed a total of 200 megawatt hours of energy storage facilities by January 1, 2020. Storage / continued page 45

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increasing the size. If Europe can prove some of these giant wind turbines, we will see a dramatic reduction in levelized cost of energy. It will take time, but I am bullish about getting there.

MS. BEANE: MHI Vestas unveiled a 9.5-megawatt turbine. People used to talk about a future with 10-megawatt turbines. We are pretty much there.

MR. MARTIN: A member of the audience wanted the following question to be asked anonymously. How do the developers on the panel plan to qualify for tax credits for the Massachusetts and Maryland projects that seem important to the project economics?

MR. BROSTRØM: The US tax credits were really not designed for offshore wind given the long lead times required to develop such projects. We are looking at all the options for starting construction to qualify. It is a little out of our hands because we have no control over the permitting process and, therefore, how soon we will be able to be in the water doing actual construction and, therefore, how long the projects will take to finish.

MS. BEANE: Same answer for us. Occasionally, through our policy group, I see news of new proposals in Congress to provide tax credits specifically for offshore wind. Hopefully something like that will be enacted and make it a clearer picture for all of us.

MR. KROLICK: There is an arbitrage that needs to be thought through on the part of the developer because you can lock in tax credits by procuring equipment, but that means you are locking into today's technology in a market with rapid improvements in things like turbine size and blades. It is a gamble unless you can lock in with equipment that is not tied to the turbine. ◎

As Solar Ascends

Solar electricity is expected to be the cheapest generating source by the middle of the next decade. The winning bids in auctions to procure solar projects were 2.91¢ a KWh last August in Chile and 2.42¢ in September in Abu Dhabi. Upcoming tenders in other countries are expected to draw even lower prices. Five heads of US renewable energy companies talked at the Chadbourne global energy and finance conference in June about what the rapidly falling cost of solar means for the broader US power sector.

The panelists are Tom Werner, chairman and CEO of SunPower Corporation, Tom Buttgenbach, president and co-founder of 8minutenergy Renewables, Gabriel Alonso, CEO of EDP Renewables North America, Rob Freeman, CEO of Tradewind Energy, and Craig Cornelius, president of NRG Renewables. The moderator is Keith Martin with Norton Rose Fulbright in Washington.

Shifting Resources

MR. MARTIN: Solar surpassed wind last year for the first time in terms of new capacity additions. There were 42% more solar installations worldwide than wind. Solar generates during the day. Wind produces its maximum output at night. Gabriel Alonso, does this ensure an enduring role for both, or is solar about to blow past wind?

MR. ALONSO: The market will decide that. The market will demand the cheapest source of renewable energy that provides the highest value for consumers and the largest amount of flexibility.

I think solar has an advantage. There are many places in this country where wind remains more competitive than solar. From a value perspective, solar produces during the day, and wind produces both during the day and at night. Solar offers the flexibility of offering projects of 100 megawatts, 20 megawatts, five megawatts and distribution-level generation that wind does not offer. If I have to think long term, I can see solar offering a cheaper product with more value for consumers and providing a higher level of flexibility.

MR. MARTIN: Are you shifting resources into solar and, if so, to what degree?

MR. ALONSO: We are. We still see a lot of opportunities for wind. There are still many areas in the US where wind is more competitive, but with every passing year, the map that contrasts wind to solar opportunities is becoming more yellow.

We are shifting resources from wind into solar. We are building solar as we speak. We are entering into solar power purchase agreements for the next year and marketing other projects for future years. We also see a fiscal asymmetry in the early part of the next decade when solar will still qualify for an investment tax credit after the production tax credits for wind have expired. That will give solar a further advantage.

MR. MARTIN: Rob Freeman, is TradeWind solely a wind company?

MR. FREEMAN: We made the decision five years ago to jump into solar. We did wind exclusively for eight years leading up to that. We are focused solely on utility-scale projects. We now have a development pipeline of four to five thousand megawatts of solar. It is about two thirds the size of our wind project pipeline.

MR. MARTIN: Is solar your future?

MR. FREEMAN: Yes, I have been thinking that at some point we will build smaller and smaller amounts of wind each year. Wind will endure, but probably not at 6,000 to 10,000 megawatts a year of new capacity. Most of the consultants are predicting new wind capacity additions will fall into the 2,000 to 4,000 range. I have been expecting a big solar wave to hit. Probably the one thing that gives all of us pause is the Suniva case.

MR. MARTIN: We will come back to Suniva. Craig Cornelius, you see the market perhaps more broadly than the rest of the panel because you work for a company — NRG Energy — that has dabbled in the full range of technologies. What effect do you see the rapidly falling costs for solar having on the broader power sector?

MR CORNELIUS: The effect is already visible. The impact of behind-the-meter solar as well as utility-scale solar injected into the grid in places like California is to cap prices during the parts of the day when the grid is experiencing peak gross load. That has happened with just the solar that is in the system today, and it is very easy to add incremental solar generation. This means that wholesale power prices will remain low for the foreseeable future.

MR. MARTIN: Does solar have an advantage because it alone can continue to supply at lower and lower prices?

MR. CORNELIUS: Yes, but that is not the only thing we see. It was interesting to hear the perspective from some of our fellow wind developers. There are some parts of the US where wind continues to have a distinct advantage. When we look at the US, we see a patchwork as Gabriel Alonso said he sees at EDP. There are parts of that patchwork in ERCOT, the */ continued page 46*

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advocates had been pushing for a target of 600 megawatt hours by 2025 based on a "State of the Charge" report that the state released in September last year. To put the Massachusetts target into perspective, California has a target of 1,350 megawatts of storage capacity. Oregon set a target of 5 MWhs per utility. New York is expected to set a storage target by the end of this year.

— contributed by Keith Martin in Washington

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Southwest Power Pool, much of MISO and much of the Pacific Northwest where end-use customers and regulators aim to expand the share of electricity generated from renewable energy and where we expect wind to remain the least-cost best-fit solution. Solar will not necessarily beat wind in these areas. However, both wind and solar benefit from a lack of fuel price risk over the long term.

MR. MARTIN: Tom Werner, do you see solar transforming the US power sector, and if so, how?

MR. WERNER: What we have seen in California is an inverted peak. The utility regulators are responding by changing the electricity rate structures to encourage moving the solar energy generated to other parts of the day. This is creating interest in storage. It will change the electricity delivery infrastructure. The same thing is happening in other states like New York and Hawaii and will happen in Massachusetts.

Developer Returns

MR. MARTIN: A few years ago, European solar developers came looking at the US solar market, and some of them turned away. They said the returns were too low. They went back to Europe or to Africa, Latin America, the Middle East. Have solar developer returns improved in the US and where are they in relation to what a wind developer might earn?

MR. ALONSO: We looked into solar years ago and decided not to make the move for two reasons. One was the low returns. We were talking about 150 to 250 basis points difference in unlevered after-tax returns between wind and solar. We did not have endless capital. The wind opportunities were enough to help us keep growing with the capital we had available.

The reason we are now looking into solar is not that we now have significantly more capital or the returns are converging. We still earn a higher return on wind projects. However, solar is becoming more and more competitive. It is more competitive than wind in states where wind had a clear advantage only a couple years ago. Utilities and corporate customers are demanding the cheapest source of electricity, and solar is the cheapest one.

MR. MARTIN: Solar is a way to win a power contract.

MR. ALONSO: Exactly. We are a renewable energy player. We will offer the cheapest source of electricity. If that is wind, we will offer you wind. If that is solar, we will offer you solar.

That is what is driving us to shift resources into solar, even though we still do not see the returns on the two types of projects converging.

The wind companies will eventually have to pull up our socks and accept the fact that some of the traditionally windiest days will no longer be as windy. They will be more sunny. The winter winds will diminish. Wind projects will earn lower returns, leading to a convergence in the future.

MR. MARTIN: What are current returns for wind and solar projects?

MR. ALONSO: The after-tax unlevered returns for both wind and solar are in the single digits, but I still see a spread of 100 to 150 basis points between the two.

MR. BUTTGENBACH: Would you see the same spread if the returns are adjusted for risk? Solar is much more predictable. Our P90 output projections are very close to our P50 projections, which is not the case for most wind farms.

MR. ALONSO: That is a very astute question. When we look at the difference between P50 and P90 risk-adjusted return, taking into account volatility around wind resource on a year-to-year basis, and especially once you start to look at shape risk around projects where the developer is taking basis risk, the returns are more equivalent.

MR. MARTIN: Same gap otherwise: 150 basis points?

MR. ALONSO: Maybe not quite that much but there is still a significant premium for a wind project over solar. One of the things that is often lost in these discussions is the capitalized dry-hole cost for wind development tends to be more significant. If you look at the full life cycle of development and the returns that are realized by developers on successful projects are offset by the costs of projects that are not completed, there is a little more of a convergence in returns for wind and solar.

MR. WERNER: There is another interesting aspect here, and that is the breathtaking drop in PPA prices for solar. The winning bids for solar two years, 12 months, even four months ago look really good for a developer compared to what a developer can get for solar electricity today.

MR. MARTIN: How is that affecting developer returns?

MR. WERNER: The price is a factor in the return. The developer must figure out how to get to those numbers. We do a spreadsheet in order to back into the number. We look at the solar panel prices and balance-of-system cost that will be required to deliver electricity at these prices and what that leaves in terms of developer return.

The solar equipment providers bailed out the developers the last couple years on forward pricing. Can that go on forever? I think that is highly unlikely. We are running out of room to sustain the same rate of solar panel price decline, and yet the bids assume that costs will continue to come down at the same rate. In the next couple years I think things will become really interesting on the solar side.

US wind developers are shifting resources into solar.

MR. MARTIN: The business model of many solar developers was to win power contracts by bidding at prices that cannot be delivered today with the expectation that by the time deliveries must start under the contract, solar panel prices will have fallen further, making the contract economic to perform. You are a vendor as well as a developer. Isn't it in your interest to say the rate of cost decline is unsustainable?

MR. WERNER: The profit and loss performance of the publicly traded solar module manufacturers last quarter was terrible. I don't mean to sound like a whiner. I am just saying we have done the math, and we do not believe the recent rate of decline is sustainable. Over the next couple years, will costs continue to come down? Yes. Will they come down at the rate that developers are assuming in recent bids? I have my doubts.

MR. MARTIN: Gabriel Alonso, EDP is shifting resources to solar in the US. Is it doing the same thing outside the US?

MR. ALONSO: We are looking at solar opportunities elsewhere, but the European market is not active in either wind or solar, apart from offshore wind. That said, we are open to doing both wind and solar wherever we are.

Returning to the subject of risk adjusted return, we still see higher wind returns on a risk-adjusted basis. We have 5,000 megawatts of wind capacity in the US running at 98% availability. When I go to my board with a solar project and explain that it is just a bunch of solar panels that will remain in place for 30 years with no operational risk, it is not really reducing my incremental operating risk by much because of the way we run our winds farms.

I can understand how others may not look at it that way. For example, the way the two tax credits work — a 30% investment tax credit taken at inception on the cost of a solar project versus production tax credits taken over time on the electricity output from a wind project — can show a higher net present value to the after-tax cash flow from a solar project than a wind project. The point is the wind industry has come a long way to minimize the P50 to P90 spread.

MR. FREEMAN: As a developer to the extent that we have contracted solar assets, we have seen higher returns on our development capital.

MR. MARTIN: Higher for solar?

MR. FREEMAN: Correct.

MR. MARTIN: Which is the reverse of what I thought you and Gabriel said earlier.

MR. FREEMAN: To be clear, not the return that goes into the project pro forma but the return on development capital. The money that is spent to get a project to the point where it is ready to be built.

MR. MARTIN: Gabriel Alonso, you said the reverse.

Barriers to Entry

MR. ALONSO: I am not disputing Rob's statement. But Rob develops and flips. I own long term.

There are no barriers to enter the solar space. I always tell my team there are two things my grandmother can do: develop a wind farm in Texas and develop solar anywhere in the US. [Laughter]

When you are doing a 200-megawatt wind project in Kansas, you need 40,000 acres. You need to lease a ton of land. There are a lot of studies that have to be performed and a lot of other work that goes into development before the project is marketable. By comparison, very little up-front money is required to develop a solar project. We have been offered deals where people have only a dot on the map. They do not / continued page 48

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even have an interconnection queue position or easements to access the site and they are already bidding the project into utility requests for proposals and winning PPAs. That is not what happens in the wind industry.

MR. MARTIN: Doesn't that frighten you? It is the two guys with the Avis car again, signing up contracts that offer prices so low that the contract cannot be performed. Why go into that sort of market?

MR. ALONSO: The line between craziness and being a hero is very fine. A lot of those crazy people five years ago are millionaires today. So I don't know if I would call them crazy anymore.

We are a renewable energy provider. If the cheapest source of power is solar, then we will have to adjust and play by those rules.

MR. FREEMAN: We are particularly active in SPP and MISO on wind, and we are seeing a lot of interest in solar among investor-owned utilities in what have traditionally been wind-centric markets.

The threat of US import tariffs on solar panels is making it hard to commit to prices in new long-term power contracts.

MR. MARTIN: Are the utilities interested in PPAs or in taking the project from you and putting it into rate base?

MR. FREEMAN: Both, but on the solar side, we are seeing more PPA interest today. They are sticking a toe in the water. Our expectation is that we will see solar projects built in places like Oklahoma or pick your state in SPP and MISO where the delivery cost of solar is higher than wind. It may be considerably higher, but solar has distinct advantages.

MR. WERNER: I could not agree more. Utility-scale solar is being built in 40 states. The investor-owned utilities are embracing large-scale solar. There may be a bit of a breather this year because there was such a massive amount in 2016.

Regarding this fine line between a hero and a millionaire, you hear more about the millionaires than you do about the failures. I agree that two years ago, people were astounded at the bets some developers were making to win contracts and those developers did really well, but that does not go on forever. The forward prices that people are projecting for solar have gotten a little out of hand. I went to see a community choice aggregator that had not even hired a procurement person yet, and it said it is expecting to pay electricity prices in the low $30-a-megawatt range.

MR. BUTTGENBACH: One thing a lot of folks forget is that solar PV is a technology play. It is less of an energy play. When we started our company in 2009, there were 320 developers in California. There are now four, after SunEdison went bankrupt, that have more than 1,000 megawatts of installed capacity. SunEdison showed that if you do not do it right, you can lose a lot of money. We have done well as a company, so it can go either way.

How many of the wind companies have an R&D facility? Do you guys test your turbines?

MR. ALONSO: I always tell my team the same example. When you have a car that breaks, you take it to the shop and you get it back in two days and you do not know what the hell happened, but it is running and you pay for it and you are happy. That is the opposite of how we run. We know our turbines, and we have taught turbine suppliers how the technology performs. We know the technology that we installed, and the goal is to know it better than turbine suppliers. We run tests in partnership with the turbine suppliers. There is no other way.

MR. MARTIN: You may be unique because you were head of wind turbine vendor Gamesa's operations in the US before moving to EDP.

MR. ALONSO: We are looking at technology ideas that we share with turbine suppliers. We have collaboration agreements. We work together on improvements. Do we have an R&D facility where we are testing blades? We do not, but we think we have a cheaper and smarter approach.

MR. CORNELIUS: The major turbine vendors do it themselves, and we make use of data that comes from those R&D facilities to calibrate performance expectation.

MR. BUTTGENBACH: A lot of people do not understand this, but what is happening in the solar industry today is it is becoming vastly more complex. There are a lot of technologies that have been around for quite a while, but they have not been deployed because the focus was on plain-vanilla PV modules. Today, we are looking at heterojunctions. We are looking at bi-facials. We are looking at all kinds of new technologies. We run an R&D facility with 52 different modules that are being tested and evaluated. We are ahead of the industry so that we can remain competitive and understand the materials that go into every module. We monitor that at the factory level. You have to have that kind of insight to be competitive.

I hear the talk about the forward curve in the last couple years during which solar panel prices came way down. Will this trend continue? As a developer, I have to make a well educated guess. If you want to compete in Texas for sub-$30 PPAs, you have to know where the technology is headed and what you can and cannot build and finance.

Storage

MR. MARTIN: Let me take this in a different direction. People expect energy storage to be transformational when it becomes economic to install. Which technology will be helped more by storage: wind or solar?

MR. CORNELIUS: Probably solar based on what we see in the markets we service with both. The reason is the greater ability to boost the effective load carrying capacity of an incremental solar generator with cheap lithium ion batteries than is the case for wind. When we think about how a state can move from a 33% renewable portfolio standard to a 50% RPS or more and the capital that will have to be deployed to produce those megawatt hours, solar will have an outsized share only if it has a cheap means to store solar generation during the sunniest hours for release later in the day. We see a forward trend that leads us to believe that will be possible. We look at developing projects in anticipation of being able to offer firm blocks of power to utilities by making use of batteries. We see fewer opportunities to make wind more competitive with storage.

MR. WERNER: The math for utility-scale storage does not work today.

MR. MARTIN: When will it work?

MR. WERNER: It works today in the commercial and industrial sector where storage can be used to eliminate demand charges by utilities. We are seeing the beginning of a massive ramp up of storage attached to solar systems for the commercial market in California. We will triple the attach rate next year compared to this year. As you get scale, the costs will come down, and then you will start to see adoption in other market segments as well.

MR. MARTIN: Tom Buttgenbach, I read that 8minutenergy Renewables is now focusing on storage. You see it as a growth area. When do you see yourself routinely adding large batteries to utility-scale solar?

MR. BUTTGENBACH: We have 1,000 megawatts of storage projects currently in development. We are working on the first deployment of batteries with lithium-ion technologies in the next two years. Construction starts in 2018 with deployment by the end of 2018. We are talking about 100-megawatt batteries. We see them as already competitive in the right mix. You do not have to have a 100-megawatt battery with a 100-megawatt PV plant so you can right size them. You can solve a lot of problems for the utilities by providing ancillary services that solar companies are not in a position currently to provide without batteries.

In five years, depending on the market, I think the old model of "I build you a PV plant and you have to buy my power whenever I produce" will be dead. I think the utilities and other customers are going to demand power when they need it.

Storage for solar is a very good combination. The more predictable output from a solar project means you can right size the battery more easily with solar than with wind.

MR. MARTIN: Gabriel Alonso, Rob Freeman, that's smack talk. [Laughter]

MR. ALONSO: They are right. I agree that storage will help solar first more than wind because you can postpone the dark portion of the output curve for two to three hours to great effect. You are shifting a much steeper curve than postponing 2 a.m. wind production all the way to 8 a.m.

We are interested in storage. The costs are coming down quickly. While the benefits will be greatest for solar in the short term, it will eventually help put wind projects in a position to provide ancillary services, which is important in a market where we are entering into PPAs with prices in the teens and twenties.

MR. MARTIN: Providing ancillary services will help make up for lost revenue. */ continued page 50*

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MR. ALONSO: One or two dollars more in revenue is another 10% to 20%. It is huge. If we had spoken about this years ago, I would have said you can keep the extra dollar for yourself.

MR. MARTIN: That may be what makes storage economic ultimately.

MR. ALONSO: Even if the economics of storage cannot be made to work, we are working with turbine suppliers on turbines that will enable us to provide ancillary services. The extra one to two dollars can make a big difference to our competitiveness in the market.

Suniva

MR. MARTIN: We are growing short on time. I have two other subjects I want to tackle. One is the Suniva petition. Suniva is a solar cell and panel manufacturer in Georgia. It has asked the US government to impose a tariff of 40¢ a watt on imported solar cells and a floor price of 78¢ a watt on imported modules. Tom Werner, how will the market be affected if tariffs at anything close to these levels are imposed?

MR. WERNER: Terrible effect. The idea that we will impose tariffs to save a small number of jobs and put in jeopardy about 10 times the number of other jobs is ridiculous. It makes no sense.

It is already having an effect. Companies are rushing to buy solar modules to put in storage. This is already putting upward pressure on prices. I don't know what good comes of it. The costs go up for everybody.

MR. MARTIN: Do you think a tariff will ultimately be imposed? Trump has the final word. He announced the other day that he wants to finance the wall on the Mexican border by putting 1,250 megawatts of solar panels on top.

MR. WERNER: Imagine you are the CEO of a solar company and you have to plan around that scenario. [Laughter] There are a number of variables that you would have to take into account for purposes of planning. The interational trade commission will look at this first and then it goes to the President. We will know whether a tariff will be imposed by the end of this year or early next year.

MR. MARTIN: I did the math. If you take Suniva at its word about the percentage of US solar panel manufacturing capacity it represents, we are talking about 979 jobs being saved against some significant share of 260,000 other jobs in the US solar sector put at risk.

MR. CORNELIUS: When we look at addressable market, even with average panel prices floating up to 45¢ a watt, a tariff at these levels would eliminate at least half the incremental capacity additions that folks had expected to see happen over the next three years and puts them out of reach. What we have heard over the last few weeks as conventional wisdom from some suppliers, which is absolutely faulty, is that the industry can maintain returns at a constant level by increasing PPA prices to accommodate something like a 45¢-a-watt panel price. What is setting the prices in new PPAs today is not solely the competition among developers. We are competing against utility avoided costs. We are at multi-decade lows in real terms for wholesale prices because of how efficient new gas-fired generation or wind is. Since load is not growing, those prices are not going up.

With PPA prices for onshore wind falling below $20 a MWh, the ability to earn one or two more dollars by adding storage is huge.

MR. MARTIN: Are we already feeling an effect of the Suniva petition? You are bidding for PPAs in the solar market. How do you bid not knowing whether such a large tariff will be imposed?

MR. BUTTGENBACH: Carefully. [Laugher]

MR. CORNELIUS: Agreed.

MR. FREEMAN: I think the assumption is that people are going to look for a way out. They are going to have to have some ability to terminate contracts.

MR. MARTIN: Question from Jack Cargas, managing director of the tax equity desk at Bank of America Merrill Lynch.

MR. CARGAS: What does the panel think about risk allocation tied to the potential solar tariffs? Tom Werner says the possibility of a tariff is already causing market disruptions. Others are saying that maybe developers will ask for the ability to terminate contracts. But what about deals that are getting done currently that are expecting to have solar panels delivered shortly after the potential imposition of tariffs? Who is taking that risk? Are developers taking that risk? Are sponsors taking that risk? Financiers will not take that risk.

MR. FREEMAN: People are locking up their panel purchases. There has been a big run on panels and maybe that capacity is gone at prices that can support current bids.

MR. CARGAS: My understanding is that the president will decide in November whether to impose tariffs, and the imposition will be immediate.

MR. MARTIN: Trump has 60 days after the US International Trade Commission makes a recommendation on November 13.

MR. CARGAS: So what happens if and when the tariff is imposed, a project is expecting panels, but the panels have not crossed the US border.

MR. ALONSO: If that happens, you have a problem. I mean, what can I tell you? You know the answer but are looking for someone to say something better. [Laughter]

MR. MARTIN: So the financiers are not taking the risk. Developers are not taking the risk. Tom Werner, I guess it comes down to you.

MR. ALONSO: Actually, developers are. If President Trump slaps a tariff on wind turbines and I have a project at which I plan to use the turbines being built next year with a PPA in place that I cannot terminate and I am locked into the turbine purchase, then I have a problem. I cannot deny it.

MR. WERNER: Somebody loses for sure if this happens. There are ways to mitigate the risk without breaking your balance sheet. You can only buy so many solar panels. If you can buy a couple years of solar panels, I definitely want to see you after this session. I have a deal for you. Don't pay attention to the tariff figures in the Suniva petition. If you are Suniva, of course you ask for the sky and the stars. We will see what happens, but if tariffs end up anywhere close to what Suniva is requesting, then somebody is going to lose for sure, and we don't need to negotiate live who that will be because, looking at two developers on either side of me, I don't like my odds right now. [Laughter]

MR. CORNELIUS: We are only in week three after the US International Trade Commission announced it would launch an investigation into whether solar panel imports are causing enough injury to domestic manufacturers to warrant tariffs or other import relief. We had stop-start experiences around fee and tariff reductions in various countries in Europe throughout the 2000s. If there's anything that the photovoltaic supply chain and industry have demonstrated over these last 15 years of growth, it is an ability to be nimble and adjust with commercial and supply chain structures that sustain growth.

For our near-term projects that are entering the financing phase, we have solved the problem already. We have the solar panels in hand. For projects that are not yet at that state, we plan to wait to assess options and figure out commercial structures that accommodate whatever happens with the tariff. We hope ultimately that we will see that the public policy and economic interests of hundreds of thousands of employees will supersede the financial interests of a few investors who made a bad investment in a small solar panel manufacturer.

Biggest Challenge

MR. MARTIN: Last question. I will go across the panel. Just give me a short answer. What is your single biggest challenge as a developer?

MR. FREEMAN: The transmission system.

MR. MARTIN: Not enough transmission.

MR. WERNER: Risk-adjusted buyer IRRs in Mexico.

MR. MARTIN: Say more.

MR. WERNER: Mexico sort of blew up post-Trump putting lots of supply projects that won contracts by bidding low prices in auctions in a more challenging position. The developer IRR assumptions changed significantly. They did not change as much in some other Latin American markets. Managing that is an issue.

MR. CORNELIUS: Discipline among fellow market participants in the contract structures.

MR. MARTIN: So your competitors are bidding unrealistically low prices. Tom Buttgenbach?

MR. BUTTGENBACH: The Suniva petition keeps us awake at night even though we have hedged for all projects we are building in the next 24 months.

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MR. MARTIN: Hedged by bringing in panels already?

MR. BUTTGENBACH: And by having contracts with US manufacturers that are not affected by the tariff.

MR. MARTIN. Gabriel Alonso, you get the last word.

MR. ALONSO: There is additional basis risk that we are taking with most of the newer corporate PPAs. That and grid congestion are the two biggest concerns. The inability to upgrade existing transmission lines or to build new ones in this country is a serious problem. ◎

Renewable Energy Finance: State of Play

Four project developers did a rapid survey across the renewable energy finance landscape at the 14th annual Wall Street Renewable Energy Finance Forum in New York in late June. The conference is organized by the American Council on Renewable Energy and Euromoney.

The four are Jim Murphy, president and chief operating officer of Invenergy, Gaetan Frotte, senior vice president and treasurer of NRG Energy, Jim Trousdale, chief financial officer of Apex Clean Energy, and Michael Silvestrini, CEO of Greenskies Renewable Energy. (Silvestrini left Greenskies in July to become managing partner of Energia, an international project developer specializing in the commercial and industrial solar markets in Latin America and Asia.) The moderator is Keith Martin with Norton Rose Fulbright in Washington.

Wall of Money

MR. MARTIN: A panel of investment bankers at the annual Chadbourne global energy and finance conference earlier this month said there is a wall of money looking for projects. You are all project developers. Do you feel the wall of money?

MR. MURPHY: There has certainly been an increase in the capital available in the market, especially on the equity side. The supply of tax equity and debt has been pretty steady throughout, but as yield cos have moved to the side, there has been a lot of pent-up demand coming from institutional investors.

We see it, but it is differentiated money. Contracts are king. We have seen some interest in investing even at the development stage, but it is mainly money chasing contracted projects.

MR. MARTIN: So it is fussy money.

MR. MURPHY: Somewhat.

MR. MARTIN: Gaetan Frotte, are investors throwing money at you?

MR. FROTTE: Not entirely. I agree with Jim Murphy, with a couple caveats. There was a bit of a slowdown in tax equity at the beginning of the year. We were not seeing as much appetite because of the uncertainty in the wake of the presidential election last November. But the tax equity market has made a comeback.

Moving to debt, there is a lot of interest from lenders. We have been able to raise money on a back-levered basis from institutional investors at good rates.

MR. MARTIN: Mike Silvestrini, your experience may be a little different as a smaller developer.

MR. SILVESTRINI: Yes. Not only are we a smaller business, but we are also focused on the commercial and industrial solar sector. As the yield co market has shrunk, we are seeing that there are plenty of resources available for the utility-scale projects, but commercial and industrial solar is still pretty much in the same place it was three years ago. There is ample capital to build out our segment of the industry, but I definitely would not call it a wall of money.

MR. MARTIN: Jim Trousdale, there have been times in the past when CFOs have said people are throwing money at them. Is this such a time?

MR. TROUSDALE: It feels like it, to a degree. I started in the wind business in the early 2000s as a banker when wind was still a nascent market. Now it has matured to such a level that global balance sheets are coalescing around this asset class. The US is a good destination. We have a strong rule of law, stable currency and other attributes that are favorable.

There are maybe 35 or so tax investors in solar and wind. That is higher than we have seen in the past. On the lending side, there are probably 50 to 60 banks chasing deals, with new banks wanting to come to the market from places like Korea and Australia. Then on the equity side, like Jim Murphy, we are seeing countless new entrants. We hear from new potential investors every month, and the appetite appears strong.

MR. MARTIN: So let me break that down a bit. It seems like the scarcest item in this market is not money but developers like you. Does it seem like there are fewer developers building up pipelines of projects?

MR. TROUSDALE: It feels like just before the financial downturn of late 2008 when it was a turbine-constrained market, and anyone who had projects was in a good spot. There are a lot more turbines today, but good projects are scarce.

Sectors

MR. MARTIN: Let's talk about whether the wall of money distinguishes among types of projects; wind, solar, storage, gas. All of you are involved in some of those segments. Does the money differentiate among the sectors?

MR. FROTTE: I think it does, but the main differentiating factor is everyone wants projects with long-term offtake contracts, and it is long-term contracts that are scarce.

The wall of money is mainly interested in projects with power contracts.

MR. MURPHY: What we have seen differentiating renewables from gas-fired — we are in both spaces — is the interest in merchant. I don't mean merchant from day one, but maybe a project with a merchant tail. Investors seems to be more interested in merchant renewables than in merchant gas projects. Why? I guess because gas-fired power plants have significant fixed costs when the initial contract term ends that you do not have with renewables.

MR. MARTIN: The interest is in merchant wind, but not solar, correct? Why not solar? Or do you see it as well in solar?

MR. MURPHY: We see it as well in solar.

MR. MARTIN: There are no power hedges yet for solar.

MR. MURPHY: I was talking about projects where you have a contract for some period of time with merchant risk on the back end.

MR. SILVESTRINI: We look for financing for smaller distributed solar installations. You have to assume that you can assemble a large quantity of C&I solar assets in our case and an even larger portfolio for the residential guys and get them all to behave in a certain way and the contracts have to be relatively uniform.

There is no shortage of capital. The challenge is in putting together a financeable portfolio. Luckily, there has been a reduction in competition in C&I solar, at least at our level.

MR. MARTIN: To what do you attribute that?

MR. SILVESTRINI: I think people overestimated the growth trajectory of C&I solar. A lot of people expect it to have a hockey-stick growth profile, but if you look at it on a global basis, it has been 15,000 megawatts a year over the last three years. It has been relatively stagnant. What creates the sensation of growth is that it is an undulating marketplace. Markets come and go. They get hot. There is a pop of growth. It feels like growth, but every time that happens, there is another market segment that is getting turned off either for policy or economic reasons. It is more of a bubbling type of marketplace rather than a pure growth marketplace.

Companies that bet on a hockey-stick growth strategy and put a lot of debt on the balance sheet have suffered the consequences over the last couple years.

MR. MARTIN: Jim Murphy and Gaetan Frotte said everyone wants contracted assets. So I am guessing capital still is not plentiful at the development stage.

MR. TROUSDALE: We have been successful raising development-stage capital. It is more expensive capital, so we raise it sparingly. Tax equity and term equity are where capital is most plentiful.

MR. MARTIN: Where is the development-stage capital coming from? Is it from private equity funds?

MR. TROUSDALE: We have a group of family offices and wealthy individuals with whom we have built a good relationship over the years. The same group invested */ continued page 54*

Financing Renewables

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in a couple successful predecessor companies.

MR. MURPHY: I would add that we have seen some interest from sovereigns and from institutional investors looking on their behalves. We hear from the investment bankers that folks are looking for a platform. We have not heard that since about 2007. I am not sure how real that is, but we have been hearing it now much more than in recent years.

MR. MARTIN: People want to buy a development platform. I imagine your company is not interested in selling itself to someone.

MR. MURPHY: That's correct.

MR. MARTIN: NRG is a public company. Gaetan Frotte, you have a different option than the others for raising equity. How hard is it in the current market to raise equity? When did you last raise public equity?

MR. FROTTE: We usually have enough cash on hand to finance a project, especially in the early stage. Four years ago, we created our own yield co that we used to raise equity capital. We have not done a big equity deal in a year and a half, but our public vehicles allow us to raise equity in the market when we want to, and that is how we would usually do it on the renewables side.

MR. MARTIN: Jim Murphy, Jim Trousdale, both of you are with very successful companies. You could go public if you wished. You have chosen not to. Why not?

MR. TROUSDALE: We have not needed to do so to date. We have had pretty good access to holdco-type risk capital. We have accessed or placed about $3.5 billion or more of asset-level financing among the equity and tax equity and debt. We have been able to raise the capital we need without having to go public.

We keep our options open. We have good controls and best practices in place, and we have audited financial statements from inception, so we certainly have an option to go public if it ever made sense. Our team has been focused on execution at the asset level, on getting projects built.

MR. MARTIN: Jim Murphy, when did Invenergy last raise equity?

MR. MURPHY: In our renewables business, we have been focused lately on monetizing assets as a way to raise equity. We felt that was a more efficient execution.

Typical Capital Stack

MR. MARTIN: Going across the panel, tell me what is the typical capital stack for your projects? How much debt, how much equity, how much tax equity? I am focused on renewables.

MR. FROTTE: It varies a lot depending on the type of project. For solar, the capital stack is usually about 40% tax equity, 30% to 40% debt and the balance true equity. I am talking about the operating phase.

MR. MARTIN: The debt is behind the tax equity in priority of repayment?

MR. FROTTE: Yes.

MR. MARTIN: Jim Murphy, what is your typical capital stack?

MR. MURPHY: About the same. We are more focused on wind where tax equity can sometimes push up to between 50% and 60% of total capital. The numbers are otherwise similar to what Gaetan said.

MR. MARTIN: The debt is back-levered debt?

MR. MURPHY: Back-levered debt. Sometimes the amount of back leverage available is just not worth the transaction cost.

MR. MARTIN: Jim Trousdale.

MR. TROUSDALE: Our average may be about 60% tax equity, 20% equity, 20% back leverage on projects where we have done all of those tranches.

MR. MARTIN: Mike Silvestrini, what is the typical capital stack in the C&I business?

MR. SILVESTRINI: It is similar to

The capital stack for most US renewable energy projects is at least 20% equity.

what NRG sees in solar: 40% tax equity, 40% debt and 20% true equity.

MR. MARTIN: Do any of you think that debt will return to the project level and be ahead of the tax equity in the capital stack? Why is it behind the tax equity currently?

MR. SILVESTRINI: The debt is usually senior to the tax equity in our financings. That requires negotiating an inter-creditor agreement.

MR. MARTIN: How much of a yield premium do you think you end up paying for the tax equity in such a structure?

MR. SILVESTRINI: It is tough to say, but I think it has been fairly nominal.

MR. MARTIN: Nominal, not 500 to 700 basis points?

MR. SILVESTRINI: Because of the uniqueness of our asset class, a limited number of market participants can swallow a portfolio of 100 individual projects that spread across 12 states. We have been seeing pretty consistent pricing.

MR. MARTIN: Does anyone think debt will return at the project level in renewables? Jim Murphy?

MR. MURPHY: Not in the next few years. I think tax equity is still more scarce than debt and, in the negotiation between the two, tax equity comes out on top.

MR. TROUSDALE: I agree with that. We have only done back leverage. It has been difficult to get tax equity to agree to be subordinated to the debt.

Debt Terms

MR. MARTIN: All of you watch money rates. You have to raise money. The Federal Reserve Board is increasing the federal funds rate, yet we have 50 to 60 project finance banks saying they cannot find enough projects. Which direction do you think interest rates are going in this market?

MR. FROTTE: I think the spreads will remain where they are at the moment. We see them at 100 to 200 basis points above LIBOR. LIBOR may increase, but the spreads should not change. Perhaps the median spread is around 175.

MR. MARTIN: That is on back-levered debt because you are not seeing project-level debt?

MR. FROTTE: That is what we see for senior-level construction debt and back-levered permanent financing.

MR. MARTIN: For solar and also wind?

MR. FROTTE: For utility-scale solar. The spreads might be higher for community solar or distributed solar.

MR. SILVESTRINI: They are.

MR. MARTIN: In January during a Chadbourne cost-to-capital webinar, the bankers said spreads are 162.5 to 200 basis points over LIBOR for bank debt. Gaetan Frotte, you just raised institutional debt on a gas-fired power plant in Carlsbad, California. What were the rates for it? That debt was priced off Treasury bonds and was fixed-rate debt?

MR. FROTTE: Yes, it was BBB+ from Fitch, so investment-grade, 20-year debt, and it was the Treasury yield plus 170 to 200 basis points. It was a fairly cheap debt.

MR. MARTIN: The Carlsbad project has a power contract with whom?

MR. FROTTE: San Diego Gas and Electric. We raised some back-levered debt on a utility-scale solar project with a DOE loan at the project level and no tax equity, and that the spread was 100 basis points over LIBOR.

MR. MARTIN: What tenors are you seeing on term debt or back-levered debt?

MR. MURPHY: We see term lenders willing to go out closer to the full PPA term.

MR. MARTIN: For bank debt?

MR. MURPHY: Including banks, yes. The number of banks willing to lend that long has thinned out compared to where the number was a year ago. But we still see some banks — not US banks — willing to lend for that long.

MR. MARTIN: In the past, it has been the Japanese, Canadian and some European banks that have been willing to lend that long.

MR. MURPHY: You called it. It is Japan, CoBank in the US, and a few European banks.

MR. MARTIN: So the story on debt is no upward pressure on interest rates at the moment because of the large number of banks chasing deals. Longer tenors are available. Have the rest of you seen such tenors? Usually the bank market is seven to eight years.

MR. SILVESTRINI: Our PPAs in the C&I space tend to be a little shorter. We have a lot of 15-year deals and some even shorter than that, and we are seeing 15-year fully amortizing debt or 15-year amortization with a bullet payment for the balance at the end of 10 years.

MR. MARTIN: Gaetan Frotte has done institutional debt or project bonds that run usually the term of the power contract. Have any of the rest of you gone into the institutional market?

MR. TROUSDALE: Apex has not accessed the institutional market yet at the project level. The long-term bond market requires make-whole payments that are a barrier to refinancing. A lot of our projects have been shorter dated with merchant exposure on the back end. Such projects */ continued page 56*

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are more suitable for the bank market.

MR. MARTIN: We are at historic low interest rates. The trend in the longer term seems to be up and yet you do not want to lock in interest rates because the need to make a make-whole payment. Explain what that is.

MR. TROUSDALE: It is a prepayment penalty to prepay the bond. I agree that as interest rates start to increase, it becomes more attractive to borrow in the fixed-rate bond market. But fixed-rate bonds work best for projects with long-term offtake contracts with utilities to get the most efficient financing.

MR. MARTIN: Jim Murphy, you have done portfolio debt. Was it in the institutional market or the bank market?

MR. MURPHY: We have done both.

MR. MARTIN: How do you decide which makes more sense?

MR. MURPHY: We tend to favor the bank market for the same reason that Jim Trousdale mentioned. We do not like make-whole payments. It is a very expensive proposition to trigger the make-whole because you are basically making a payment equal to the net present value of not just the difference in the underlying rates, but also the margin.

MR. MARTIN: Have any of you tried green bonds? They are a form of corporate-level debt.

MR. TROUSDALE: Apex has not directly, but we believe some sponsors who have purchased our projects have tapped the green bond market to raise the purchase price.

MR. FROTTE: We acquired a wind farm two or three years ago and issued $500 million of high-yield, 10-year bonds to do so. Because it was a renewable acquisition, the bonds were considered green bonds. It was a good experience. There was not a lot of incremental demand for the paper, but that was several years ago. I understand the market has improved since then. There is growing interest among institutional investors in investing in renewable assets.

MR. MARTIN: As a public company, if you have a choice among bank debt, institutional debt, green bonds, how do you decide which to take? We just heard make-whole payments turn people away from project bonds. Beyond that, is it just a matter of the cost of the money?

MR. FROTTE: Exactly. To be clear, I am totally in line with my fellow participants. I did not like the make-whole at all a couple years ago. We did not do institutional debt before, but that market has been a lot more efficient and better priced, and we decided to raise fixed-rate institutional debt for some projects that are already stable in operation. But at the end of the day, it is a question of economics and terms.

New Debt Trends

MR. MARTIN: Are there any other new trends in the debt market?

MR. TROUSDALE: Full underwriting has returned, with a sell down in the syndicated market.

MR. MARTIN: Full underwriting means a bank will offer to bring in others in a syndicate, but if it cannot find others, it will put up all the money. There was full underwriting in the distant past. How long ago was it before now when one last saw such underwriting?

MR. TROUSDALE: Feels like a long time to me, maybe even going back to before the financial collapse in 2008.

MR. MARTIN: Is its return a sign of the desperation among banks to find deals?

MR. TROUSDALE: The smart banks can do the work and understand the risks. We had a successful sell down, so we would like to think the bank we did it with was smart and did a great job. The other trend is the bank market can take down $1 billion or more on a single asset deal. Our transactions do not get that large, but it is a sign of the depth of the market.

MR. MARTIN: What other new trends has anyone seen?

MR. FROTTE: We are starting to see more acceptance for community solar deals. It seems like banks are getting more comfortable with the risk profile.

MR. MARTIN: I count five community solar tax equity deals to date, plus one large revolving debt facility. Has there been broader acceptance than this by the financial markets?

MR. FROTTE: We were doing it with one or two banks, and now one of those banks is waiting to underwrite the whole thing as a plan to syndicate it to a number of other banks that are looking at that market. Time will tell how many come into that syndicate, but there is broader acceptance.

MR. MARTIN: Any other new trends? Jim Murphy, you are at the center of a lot of financings.

MR. MURPHY: One thing that was new this past year was banks providing equipment financing, and it was a little different style of financing than we saw before the financial crisis. People were taking positions in wind turbine equipment to satisfy the 5% test so that projects using this equipment are considered under construction in time to qualify for production tax credits, and financial players were coming in behind to underwrite part of that, with some pretty strict rules and conventions about how the debt would have to be amortized, and how quickly the equipment would have to be allocated to projects. That was a new product this year.

MR. MARTIN: What is the difference between that and a turbine loan?

MR. MURPHY: It could be the same thing. The equipment could be turbines. It could be other things as well.

MR. MARTIN: According to press reports, there could be enough turbines stockpiled to allow another 30,000 to 70,000 megawatts of new wind farms. Existing wind capacity is 83,000 megawatts. It seems like the market is fairly long in turbines.

MR. MURPHY: People were making an educated investment in the equipment knowing that they have a four-year window during which to place it, and there would be other alternatives, likely simply using the equipment in new projects whether or not it serves as a basis for qualifying for production tax credits.

MR. MARTIN: Are there other new trends?

Spreads in the debt market range from 100 to 200 basis points above LIBOR, with the median around 175 basis points.

MR. SILVESTRINI: Our business is pretty stable in terms of financing. It is a flow business. The principal challenge for us is trying to maintain a steady flow. We look for the right banking partners who can close repeat transactions with a rhythm that can take advantage of the C&I market.

MR. MARTIN: The C&I market is fine without new trends. It just wants predictability.

MR. SILVESTRINI: Consistency, that's right.

MR. MARTIN: Tax equity yields have fallen into the 6% range for utility-scale solar, the 7% range for wind, and are still probably around 9% for distributed solar. What new trends, if any, are you seeing in that market aside from falling tax equity yields? Gaetan Frotte, you are shaking your head no, meaning no new trends?

MR. FROTTE: Not much.

MR. TROUSDALE: The tax equity investors have been more willing to underwrite more complicated structures, like corporate PPAs and proxy revenue swaps. I am not sure it would have been possible to finance projects with such contracts a couple years ago.

Tax Debate

MR. MARTIN: Other new trends?

MR. SILVESTRINI: The risk that Congress would cut the corporate tax rate was like a speed bump in the first quarter this year. The tax equity market slowed while investors tried to evaluate the effects. The potential for a 2017 rate reduction seems to have receded.

MR. MARTIN: Let me see a show of hands from the panel. How many of you think a corporate tax bill will be enacted this year? [Pause] Zero. How many of you think one will be enacted next year? [Pause] Half our panel.

Let me ask the audience. How many of you think a corporate tax bill will be enacted this year? [Pause] No one. How many think one will be enacted next year? [Pause] A distinct minority.

Gaetan Frotte, what effect has the threat of corporate tax reform had on NRG?

MR. FROTTE: We have had to tinker with our tax equity structure. The tax equity investment will be re-sized when the project is completed. There could be a cash sweep to return part of the investment to the investor, depending on where tax reform settles.

MR. MARTIN: So the tax equity investor sizes its investment based on current law. If the law changes, it may get part of its investment back in a re-sizing of the investment.

How has talk of tax reform affected Invenergy?

MR. MURPHY: We see investors sizing their investments in anticipation of tax reform being enacted. That means they are investing less at the front end. They may invest more if the final tax rate ends up higher than they / continued page 58

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assumed.

MR. TROUSDALE: We have had to run sensitivities early in the year showing what happens at various corporate tax rates. To Mike Silvestrini's point, it feels like a rate reduction this year is no longer expected. We are easing up on that internal exercise. People are trying to work constructively to address the risk in 2018. Can we pass some of it to the offtakers in power prices that are already very competitive and cheap?

MR. MARTIN: In your modeling, did you conclude that lower tax rates will mean a higher cost of capital overall?

MR. TROUSDALE: Potentially, depending upon the timing. Returns could increase if the rate reductions are phased in over time, giving us time to claim most of the depreciation against the current tax rate. The longer the gap between when the project is completed and when the rate goes down, the more likely the return is to increase.

MR. MARTIN: In cases where the lower rate leads to a higher cost of capital, can you quantify the hit?

Full debt underwriting has returned as banks become more eager for deals.

MR. TROUSDALE: That is difficult to say because we find ways to optimize. We think we can get back to where we were.

MR. SILVESTRINI: The challenge in the C&I market is being caught flat footed by a rate reduction with projects that are caught somewhere in the development lifecycle where they have exposure to construction finance, but the features of the takeout may have changed as a result of the tax rate change. The fact that we are a flow business leaves us somewhat more exposed. That said, our exposure is nothing like getting caught at the wrong phase of development or construction of a billion-dollar energy project.

MR. MARTIN: One of the things under discussion in tax reform is to deny interest reductions on debt. Are you worried about that? Some people had talked about locking in debt in advance of any vote in the House tax committee this fall so that the interest remains deductible under transition rules.

MR. FROTTE: It is too hypothetical.

MR. MARTIN: Another thing under discussion is a reciprocal tax. That is Trump's term. The House Republicans' term is a border adjustment where you do not get any cost recovery on imported equipment. Has that affected how you negotiate for vendor contracts. Do you focus on where the equipment comes from?

Suniva

MR. SILVESTRINI: The potential for a solar import tariff is the only thing we are focused on right now.

MR. MARTIN: So it is hard to feel worried about a sore foot when your head is aching badly.

MR. SILVESTRINI: Yes.

MR. MARTIN: Suniva filed a petition in late April asking for high tariffs on imported solar equipment.

MR. SILVESTRINI: We need to think about what types of partnerships we want to form to head into the fray. One of the techniques used in these times is to stockpile equipment. Obviously there are financial consequences from holding onto things that you hope become more valuable if they are bought before the tariff is applied. It is a major distraction for a company interested in developing projects.

MR. MARTIN: Does it affect the price you promise customers today for electricity?

MR. SILVESTRINI: It does. Some customers are willing to keep an open outlook and let us to come back and discuss a price adjustment if a tariff is applied. Sometimes it is a take-it-or-leave-it scenario and we have to hustle to get projects in the ground. At some point we will have to cut off those types of transactions if the risk profile seems like it might put us upside down economically.

MR. MARTIN: Can you buy insurance for this risk?

MR. SILVESTRINI: Not that I'm aware of.

MR. MARTIN: Jim Murphy, are you affected by the threat of tariffs?

MR. MURPHY: It is not something you can price in at this point in a utility-scale solar project. If you try to build it into pricing, you are not going to win anything. We are seeing a number of contracts from the offtakers that are very rigid on change-of-law risk. The developer is going to wear that risk.

MR. MARTIN: Can you push the risk off on vendors?

MR. FROTTE: We are trying. We are talking to all of our vendors about how best to mitigate the risk. No one knows where things will end up. The risk is impossible to price.

MR. MARTIN: How many of you are trying to get equipment past US Customs before November 13 when the US International Trade Commission must make a recommendation to the president? [Pause] Two.

Trump said he wants to put 1,250 megawatts of solar panels on the wall he wants to build between the US and Mexico to pay for the wall. He has not yet made a connection between the tariffs and the cost of the wall. How many of you think tariffs will ultimately be imposed on solar panels? [Pause] None.

MR. SILVESTRINI: It is really difficult to say because this president is so hard to predict. It would be so detrimental, particularly to utility-scale projects, that it is hard to believe a tariff would be imposed.

MR. MARTIN: No one on our panel thinks a tariff will imposed. What about the audience? How many of you think Trump will ultimately impose tariffs? [Pause] Out of an audience of a couple hundred people, three.

Special Financing Challenges

MR. MARTIN: Jim Murphy, you mentioned that developers are moving to proxy revenue swaps and corporate PPAs. What special financing challenges do such arrangements present?

MR. MURPHY: I see a couple things. Number one is the credit of the offtake is different than what people have been used to underwriting with utility credits. The view of a utility credit was there is a customer base sitting behind the utility. A bank can feel confident the financing will be repaid based on the creditworthiness of the utility. It does not have the same level of confidence with a corporate PPA because that is a different business model.

We have also seen commercial and industrial customers being unwilling to offer their parent support behind the credit for the contract. That has led to some interesting discussions about what is the appropriate level of credit required for the offtaker. Those are tough conversations because there is no science to it.

MR. MARTIN: Does anyone see other special financial challenges beyond what Jim Murphy mentioned?

MR. TROUSDALE: Apex was an early adopter of the proxy revenue swap when it was a new product. We had three tax equity investors, a lender and an 85% owner who had to get comfortable with the product. The effort added time to our financing schedule, but at the end of the day, we closed on the financing, and we did a second one.

MR. MARTIN: So the market is figuring out how to get comfortable with such arrangements. What about community choice aggregators in California: unrated entities organized at the county level to buy renewable energy for county residents under long-term contracts? Has any of you done a CCA contract?

I see four people shaking their heads "no."

Gaetan Frotte, you mentioned community solar. What special challenges are you running into trying to finance such projects?

MR. FROTTE: It is a hybrid type of project where you are selling subscriptions to a mix of residential and commercial and industrial customers. The projects rely on net metering to give the subscribers bill credits for the shares of electricity to which each subscribes. The electricity goes to the local utility. Community solar is limited to certain states. We are doing it mainly in Colorado, Minnesota and Massachusetts. We are starting in New York, as well.

MR. MARTIN: Mike Silvestrini, you could do community solar. It is not much of a switch, and yet you have chosen not to do it. Why not?

MR. SILVESTRINI: I look at community solar as sort of an artificial pricing mechanism where solar can avoid transmission and distribution charges. That makes me wonder how sustainable the business model is long term. Being */ continued page 60*

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behind the meter gives us a better argument for deserving transmission and distribution discounts, and so we focus on getting behind the meter, staying on the roof, and staying onsite with our customers. There is still plenty of room for growth in the rooftop market.

MR. MARTIN: Jim Murphy, *The Financial Times* quoted Francesco Starace, CEO of Enel, this morning. Starace said he thinks storage will surprise people by becoming transformational much sooner than the market currently expects. You are doing standalone storage. How are you financing such projects?

The challenge for C&I solar developers is maintaining a rhythm. They have lots of power contracts, but lumpy financing.

MR. MURPHY: We have not done project financing on storage. We have only done vendor financing. I do not know whether the bank market is ready to finance projects whose revenue stream comes from providing frequency regulation to the grid. You need predictable capacity payments.

MR. MARTIN: Is anyone else doing storage?

MR. SILVESTRINI: We are adding some storage to our commercial and industrial solar installations. The storage is folded into the financials for the solar system. We have several of those in different states. It has not been a problem.

New Financial Products

MR. MARTIN: What new financial products have investment bankers or anyone been pitching to you in the last year?

MR. SILVESTRINI: We are seeing a lot more interest from family offices in providing tax equity, which obviously creates challenges with passive loss and at-risk rules. We have not closed a deal with one of those types yet, but there is definitely growing interest from such investors.

MR. MARTIN: Is anyone else seeing any new financial products?

MR. TROUSDALE: It may not be new, but we are seeing construction debt that converts into back-levered debt after construction. It is a way to get the advance rate on construction debt as high as possible. It is helpful for companies like ours that do not have big balance sheets.

We are also being pitched equity with preferred cash distributions that have features in common with debt. We have not executed on it, but we are being sent proposals.

MR. MARTIN: What are the advance rates currently on construction debt? 90%, 95%, less?

MR. TROUSDALE: I think 80% to 90% on the construction loan, and you can get as high as 95% if you include some mezzanine debt.

MR. MARTIN: Jim Murphy and I are old enough to know you could go over 100% at some points in the distant past. What other new financial products are you being pitched? Gaetan Frotte, you mentioned hybrid debt, bank and institutional debt at the same time. Why would one do that?

MR. FROTTE: We see it more with conventional power plants. We have not done it yet for a renewable energy project, but there is no reason why it would not work. You have a tranche of bank debt that is fully amortizing over seven to 10 years, and then a tranche of institutional debt that has a term equal to the PPA term and that requires less amortization up front. It is a better way to maximize the amount of debt on a project and match the tenor of the PPA without having refinancing risk at the end of a typical mini-perm instrument.

MR. MARTIN: So you end up borrowing more. How much extra leverage do you get?

MR. TROUSDALE: These are called A/B structures. You should be able to borrow 5% to 10% more.

MR. MARTIN: Are there any questions from the audience?

MR. MENDELSOHN: Michael Mendelsohn from SEIA. Is NRG moving down into unrated credits and does anyone on the panel have any evidence that there is a difference in cash performance between rated credits and unrated credits as offtakers in the C&I sector?

MR. FROTTE: In our community solar and distributed solar deals, we look at the offtakers on a portfolio basis. We will accept a percentage — say 10% to 20% — of customers who are sub-investment grade. The banks set the limits. They will usually accept some sub investment-grade types or lower FICO scores, say below 650, in some of those deals.

MR. MACK: Larry Mack from Key Bank. Are you paying more for underwritten debt and, if so, why do you need an underwritten transaction rather than a best-efforts deal?

MR. TROUSDALE: The greater certainty about timing may be worth it. In large utility-scale wind deals, there are a lot of banks that have to come together and that can be a bit unwieldy, so having a single bank that can run it and get it done quickly, and then syndicate afterwards, sometimes has value.

MR. MARTIN: We are down to our last question, and let's go across the panel. What is your biggest current financing challenge?

MR. FROTTE: The biggest challenge is finding offtake contracts.

MR. MURPHY: I agree. This is a good time for financing. It is a difficult time for developers looking for offtake contracts. This industry has a tendency to race to the bottom. Staying disciplined is a challenge.

MR. TROUSDALE: The business uncertainty under the new administration is a little disruptive.

MR. MARTIN: You are a master of understatement.

MR. SILVESTRINI: We have an almost opposite scenario. We have always been contract heavy, and delays in project financing and getting that velocity to line up with our ability to acquire new customers has been our greatest challenge since we opened our doors, and it remains the biggest challenge today.

MR. MARTIN: Is that because it is time consuming to arrange financings or the capital is unavailable?

MR. SILVESTRINI: They are complex transactions because of the number of offtakers in multiple locations and variations in offtake contracts. There is quite a mix in a 100-megawatt portfolio. It takes a lot of brain damage to get across the finish line. Ideally, you could raise a war chest and then find customer contracts, but that is too complicated to finance, so we are always playing catch up to put the financing in place.

It is a little clunky. We would prefer to wash, rinse and repeat, but it requires a lot of effort by the financial sector to help companies like ours find an acceptable rhythm. ◎

Environmental Update

The US Environmental Protection Agency has decided to move forward with plans to designate which cities and counties are in compliance with new federal ozone limits, imposed in 2015, on pollutants that contribute to urban smog, and which are not, by October 1.

EPA Administrator Scott Pruitt had said as recently as June that the agency would delay any such designations for at least a year. Pruitt had suggested the agency needed more data before making the determinations.

The reversal in early August appears to have been precipitated by a recent court loss by the Trump administration in its effort to back off federal limits on methane emissions from new oil and gas drilling operations and other methane sources and by the filing of multiple lawsuits against the proposed ozone stay by states and environmental groups.

In July, a US court of appeals overruled Pruitt's attempt to freeze Obama-era EPA rules that set limits on methane emissions after determining that the agency's delay violated the Clean Air Act, putting the rule back into effect. After Pruitt announced that he would delay the ozone designations, 16 states sued, charging that the delay also violated the Clean Air Act.

The appeals court decision in the methane case may be used by states and environmental groups to challenge other Trump-era efforts to delay Obama-era rules.

Challenges are pending to Pruitt's efforts to delay implementation of Clean Water Act power plant effluent limits, deadlines for companies to comply with safety requirements to prevent explosions and spills at chemical plants, enforcement of landfill methane limits, and various other environmental regulations. While the recent setbacks to Pruitt on the methane and ozone rules demonstrate there are limits on an agency's discretionary authority to postpone regulation, the legal issues at the heart of each pending challenge differ and will have to be decided on a case-by-case basis.

Pruitt had challenged the 2015 ozone limits while attorney general in Oklahoma.

Climate Regulation

EPA sent a proposal to withdraw the Clean Power Plan, which sets limits on greenhouse gas emissions by existing power plants, to the White House Office of Management and Budget for review in June, but the agency has not said when further action will be taken.

There is also still no indication whether EPA will try to reexamine its own finding from 2009 that greenhouse gas emissions must be regulated under the Clean Air Act, the so-called "endangerment finding." That finding is the legal foundation on which all of federal greenhouse gas regulations are built. Its demise could lead to elimination of all federal climate rules.

Pruitt said in July that a recently launched process to "critique" climate science is not aimed at undermining the endangerment finding. He said there could be a legal basis to challenge the finding, but he would prefer that Congress address the issue.

After Paris

The Trump administration notified the United Nations in early August that the United States is withdrawing from the Paris climate accord.

With the withdrawal, efforts to reduce greenhouse gas emissions are devolving from the federal level to states and municipalities. Various states, cities and businesses have

Some US states and cities are organizing to reduce US greenhouse gas emissions by 28% below 2005 levels.

The Trump administration is moving to give western states greater flexibility on protections for sage grouse.

said they intend to work toward ensuring the United States meets its pledge to reduce greenhouse gas emissions and have formed partnerships with such names as the US Climate Alliance of States, the Climate Mayors coalition, and the "We Are Still In" declaration. The United States promised to reduce greenhouse gas emissions to approximately 28% below the 2005 level by 2025.

California Governor Jerry Brown and former New York City Mayor Michael Bloomberg launched an initiative in July to build on the state and local movement. Their initiative will track climate-related activities in the United States with the aim of reporting on them at the United Nations' 23rd Conference of the Parties to the Framework Convention on Climate Change — COP23 — in November 2017.

Enforcement

EPA instituted a new policy in July that requires its regional offices to get approval from EPA headquarters before asking companies for information that would show whether they are complying with federal environmental statutes. Such information requests under the Clean Air and Clean Water Acts have been common, and are usually issued in advance of site visits or other regulatory action.

The agency said the move will improve efficiency. The need for all information requests to run through headquarters could create a bottleneck that delays or reduces the number of enforcement actions.

Sage Grouse

The US Department of Interior ordered nine broad changes on August 4 to an Obama-era plan to protect sage grouse. The recommendations are general directions requiring further agency study and action, but are clearly intended to give states more flexibility to deal with habitat management, waivers, mineral leasing and other development.

Meanwhile, three lawsuits brought by affected industries and states over the extent of Endangered Species Act protections for the greater sage grouse were frozen in July to give the US Department of the Interior time to reconsider its strategy for protecting the birds.The plaintiffs in the lawsuits assert that land use limitations issued in September 2015 to protect sage grouse habitats could block mining, oil and gas drilling, livestock grazing and other activities on millions of acres across the 15 states where the bird lives, with the most pronounced effects in Idaho, Nevada, Utah and Wyoming. The three cases are *Am. Exploration & Mining Ass'n v. Interior, W. Energy Alliance v. Interior,* and *Otter v. Zinke*.

Estimates of sage grouse range between 200,000 and 500,000 birds.

Water

EPA and the US Army Corps of Engineers released a joint proposal in late June to rescind and eventually replace a "Clean Water Rule" issued in 2015. The rule defines the extent of federal jurisdiction over "waters of the United States" under the Clean Water Act. The rule has been in limbo since a US appeals court blocked implementation in October 2015.

The Clean Water Act requires companies to have federal permits before discharging any pollutants or dredged or fill material into "waters of the United States."

Congress did not define the term. The US Supreme Court gave its view of what the term means */ continued page 64*

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in 2006 in a case called *Rapanos v. United States*. Justice Scalia, writing for a plurality of four of the nine justices, defined "waters of the United States" as "relatively permanent, standing or continuously flowing bodies of water," as well as wetlands with a "continuous surface connection" to such waters. A concurring opinion by Justice Kennedy suggested the term should be defined more broadly to include wetlands that have a "significant nexus" to traditionally navigable waters and "either alone or in combination with similarly situated lands in the region, significantly affect the chemical, physical and biological integrity of . . . [such] covered waters."

EPA basically adopted the definition suggested by Justice Kennedy in 2015.

While the 2015 rule remains in limbo, *Rapanos* and agency guidance issued in 2008 have remained in effect.

President Trump issued an executive order in February 2017 directing EPA and the US Army Corps of Engineers to work toward "revising or revoking" the 2015 Obama-era definition. A newly proposed "interim rule" is the first step in this reconsideration.

The interim approach is to leave in place the definition of "'waters of the United States' as it is currently being implemented, that is informed by applicable agency guidance documents and consistent with Supreme Court decisions and longstanding practice." According to the two agencies, this approach "simply codifies the current legal status quo while the agencies engage in a second, substantive rulemaking to reconsider the definition of 'waters of the United States.'"

A formal withdrawal of the 2015 definition is expected.

The withdrawal is a form of insurance by the Trump administration in case the US Supreme Court decides that the US appeals court that froze implementation of the 2015 definition lacked authority to do so. The Trump administration is expected to issue its own definition in December 2017. ◎

— contributed by Andrew E. Skroback in Washington

CHADBOURNE MERGER

Chadbourne & Parke merged into Norton Rose Fulbright on June 30. The combined firm has 4,000 lawyers in 59 offices in 33 countries.

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