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Financing in an Era of Shorter PPAs

What is the future for project finance when corporate PPAs and hedges make up a growing share of the market, and corporations are losing interest in committing to contracts even with 10-year terms? Banks finance hamburger chains without locked-in revenue streams. What happens when they have to do the same for power plants?

The following is an edited transcript of a panel discussion at the 30th annual global energy and finance conference in California in June. The panelists are Ted Brandt, CEO of Marathon Capital, Jonathan Kim, head of infrastructure finance for North America for Natixis, Alexander Krolick, head of infrastructure and energy finance for the Americas for Macquarie, and Himanshu Saxena, CEO of the Starwood Energy Group. The moderator is Ike Emehelu with Norton Rose Fulbright in New York.

MR. EMEHELU: Himanshu Saxena, which is riskier, an investment in a merchant gas-fired power plant in PJM or in a solar project with a 10-year power purchase agreement?

MR. SAXENA: Investing in a solar project with a 10-year PPA is riskier, but it depends on the electricity price. We have seen solar PPAs in California with fixed power prices of $25 a megawatt hour for 10 years. We have seen wind PPAs fixed for 10 years at $14 that don't cover the variable costs of running a wind farm. On a cash basis, the assets are negative.

At the end of a 10-year PPA, maybe we have 20% or 30% of our invested capital back, and we would have to rely on the merchant cash flows after year 10 to get back the rest of our investment and earn a return. We would have to take a view on / continued page 2

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AN INVESTMENT TAX CREDIT EXTENSION is back before Congress.

The solar industry is making a major push, but the proposal faces long odds before the November 2020 elections. The chances improve after 2020 depending on the election results.

The House tax-writing committee may vote this fall to extend renewable energy tax credits. The House is controlled by Democrats. The challenge is to get any such measure through the Senate, which is under Republican control.

Identical bills introduced in the House and Senate in late July would allow another five years before the investment tax / continued page 3

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merchant cash flow starting sometime in 2029, for example, running for another 30 years.

In my mind, that is riskier than buying a gas-fired power plant in PJM, where you have certainty on capacity prices for the next three years and can hedge the next five years, if desired. You cannot hedge the electricity from a solar plant 10 years out. So depending on the PPA price and location, you could make a case that a merchant gas-fired power plant is less risky than a 10-year contracted solar plant with a low PPA price.

MR. EMEHELU: Alex Krolick, I can't tell if you are agreeing or vehemently . . .

MR. KROLICK: I am sort of . . . debating in my head actually.

It depends on the market. We have been so focused on quasi-merchant gas plant financings in PJM that they feel almost commoditized at this point.

We are working on the first semi-contracted combined-cycle combustion turbine project in Mexico. It will be the first financing of that type in Latin America. We are comfortable with the risk profile. Market spreads are around $55. There is a real urgency on our part to get it done. If I had the choice of being in Mexico with a $20 PPA or I could capture $80 around the clock on a merchant basis, personally I would go for the $80 and try to do a large portion of that unhedged. The economics are compelling, and there is a first-mover advantage.

MR. EMEHELU: Jonathan Kim, merchant gas versus 10-year contracted solar PPA?

MR. KIM: I agree with Himanshu and Alex. The gas-fired assets, particularly in PJM, have been proven. PJM is more predictable versus a partially contracted solar project in California where the visibility at best is opaque. It is difficult to forecast prices in California, but at least you can take a view in a more established market like PJM.

The big challenge in Mexico is there is no established merchant market, but there is price data. We are financing some of these projects where solar is partially contracted with a sweep structure to reduce the amount of exposure to the merchant tail. It is a structure that has been proven in other markets. However, I don't think we are going to be open to a purely merchant price without some underlying contracted revenue source.

MR. BRANDT: The devil is in the details. It is one thing to do a brand new H-class, lower heat-rate gas-fired power plant and another to buy a 10-year-old or 12-year-old plant.

The market you are in also makes a big difference. If you are doing a solar plant in PJM where there is a liquid market, there is more confidence about the price forecast. We see a lot of projections that have avoided costs at the end of 10 years. This gets into complications predicting the avoided cost of the local utility and regulatory risk that there will still be a utility purchase obligation 10 years from now. There are not a lot of checks and balances in places like North Carolina, and there is pretty much only one buyer in that market.

That said, I will tell you, as someone who raises capital for a living, that it is easier to raise capital for a contracted project with a 10-year PPA than for a merchant plant. You have to have contrarians like Himanshu; that is what makes markets.

Tax Equity Barrier

MR. EMEHELU: Himanshu, do you agree that raising debt for a solar project with 10 years of contracted revenue is easier even though, in your view, merchant gas might be less risky?

MR. SAXENA: I don't think that debt is the issue. We went to the term loan B market last year to raise debt for a 2,000-megawatt merchant gas portfolio, and the

An equity investor may have recovered only 30% of its investment by the end of a 10-year PPA.

offering was three times oversubscribed. There is no shortage of debt to finance merchant gas deals pricing in the 350-basis-point range. There is also no shortage of debt for contracted solar.

The challenge is to raise tax equity. I think finding tax equity for a merchant solar project would be hard. All of these deals are getting done around the needs of the tax equity players.

Developers who are signing seven- to 10-year hedges are not doing it because they believe in the value of those contracts, but because tax equity does not want to take any risks and, without tax equity, you can't do these deals.

If I had tax capacity, I would be king. I would be getting returns in the 6% to 8% range on an after-tax basis, and I would be senior to the debt. Facebook just announced it did its first tax equity deal. Facebook has done something like 2,000 megawatts of PPAs. It just shows that smart people are saying that tax equity is over-priced.

Everybody is signing non-disclosure agreements to get a look at all the deals that are coming to market. A lot of capital is being raised from ESG investors. Capital Dynamics is raising a fund. Carlyle is raising a fund. There is probably $9 billion worth of new capital that is currently in the process of being raised solely to invest in contracted solar and wind farms.

There is not enough product to go around to satisfy this massive amount of capital, which is why the cost of equity to buy solar projects is being driven down to 7% and below. Why is it that cash equity returns are lower than tax equity returns when all the residual risks are sitting with cash equity? It is completely upside down.

MR. EMEHELU: We have now had a few years of experience with corporate PPAs. Alex Krolick, what lessons has the market learned about them?

MR. KROLICK: We reached financial close a few months ago on what I believe is the largest and longest corporate PPA ever done. It was a wind farm in Sweden with a 29-year offtake agreement with Norsk Hydro.

We are also focused on smaller startup load-serving entities and retail electricity suppliers in different jurisdictions around the world and trying to play off the spread between what a project needs to be paid and the electricity prices that these retailers are able to collect from C&I customers.

We have a strong commodities arm and provide credit enhancement for the revenue stream. That allows us to clip a ticket twice and provide a risk profile that is acceptable to the lenders on the project side. We have / continued page 4

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credit starts to phase out on solar projects, fuel cells and small wind turbines. Such projects qualify currently for a 30% investment tax credit if under construction by the end of this year, a 26% tax credit if construction starts in 2020 and a 22% tax credit if construction starts in 2021. All such projects must be completed by the end of 2023 currently to qualify for tax credits at these rates.

All the dates would be pushed back five years. Thus, the deadline to start construction to qualify for a 30% tax credit would be the end of 2024. The two-year phase down would occur in 2025 and 2026. Projects would have to be completed by the end of 2028.

The House bill has 29 co-sponsors, including four Republicans. The Senate bill has 16 co-sponsors, but no Republicans.

As under current law, solar generating equipment that misses the new deadlines would still qualify for a 10% investment tax credit. Fuel cells, solar fiber optic equipment and small wind turbines that miss the new deadlines would not qualify for any tax credit.

Geothermal heat pumps and small cogeneration facilities qualify currently for a 10% investment tax credit if under construction by the end of 2021. This would be changed to the end of 2026. There is no statutory deadline to finish, but such a project must be completed within four years or the owner must prove there was continuous work on the project after the year construction started.

Geothermal power plants qualify currently for a permanent 10% investment tax credit or the owner can elect under section 48(a)(5) of the US tax code — as can owners of wind, biomass and other projects that qualify for production tax credits — to claim a 30% investment tax credit if under construction by the end of 2017 (2019 for wind). The bills would not extend this option.

A 30% residential tax credit for homeowners who buy new solar electric systems, solar hot water heaters, fuel cells, / continued page 5

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seen projects that were backed by casinos to automotive manufacturing to data providers and internet giants.

MR. EMEHELU: Jonathan Kim, how else are you seeing the market address the lack of standard longterm PPAs?

MR. KIM: We are not in many renewable energy single-asset deals because the spreads are too low, the fees are low, and it is a disintermediated market, meaning there is no need for an underwriter. Maybe Ted Brandt can raise the equity capital quickly and cheaply. Sponsors can do the same with debt, both fixed rate and floating rate, by going directly to lenders.

We are ESG driven, but it does not mean that we will sacrifice profitability, so we are focused more on merchant gas projects and holdco financings where the returns are more commensurate with the risk.

Strategic investors are using their balance sheets to de-risk the projections and then sell down 50% to 80% of projects to pension funds.

De-Risking Projects

MR. EMEHELU: Ted Brandt, you have foreign clients who come looking for assets in the United states. What is the attraction given that the market is moving toward more merchant risk?

MR. BRANDT: Yields are higher here, at least on a nominal, after-inflation or real basis, by about 200 basis points over what they are seeing in Europe. They may also be higher than in Japan. I am not sure that you can generalize around all of Asia.

We are watching strategic German, UK and French companies coming over with lots of capital and bidding at low discount rates, because that is what they have been used to doing. ENGIE bought Infinity about a year ago. All they have being doing is hedges and corporate deals.

The strategics use their balance sheets to de-risk the projects and then almost all of them sell down 50% to 80% to a pension fund or other nondilutive passive capital. That's the game. They are left with decent risk-adjusted returns as the developer. Maybe as it should be, most of the reward in this game is going to the developers.

MR. EMEHELU: Go ahead Alex.

MR. KROLICK: I am nodding emphatically.

MR. SAXENA: I was going to wear a t-shirt today that says, "Who needs returns when you have solar?" [Laughter]

MR. EMEHELU: I am going to trademark that, by the way.

Evolving Corporate PPAs

MR. SAXENA: You know you can't. All of us are witnesses here. [Laughter]

We have been doing corporate PPAs for a while. We did one with Facebook, one with Target and most recently one with General Motors. Every week there is a new RFP from Lululemon to Facebook to General Motors to Walmart looking for renewable energy.

The companies putting out these solicitations are getting smarter as time passes. There used to be two differences between a corporate PPA and a utility PPA. The electricity is sold at the hub rather than the busbar, and corporate PPAs were a little shorter in duration, but beside that, the two types of contracts looked similar.

The utility PPAs have not changed — they still look the same as 10 years ago — but corporate PPAs have evolved to shift more risk to the project owners.

We saw a 10-year PPA recently for a project in Texas with a tracking account to track the extent to which the prices paid for electricity under the contract exceed current market prices during the contract term. Any negative balance in the account must be repaid to the corporate customer at the end of the contract term. The reason the payment is at year 10 is that is what the tax equity demands for risk management. If there is a large negative tracking account at year 10, the tax equity is out and the owner is stuck with that risk.

Whether it is tracking accounts, caps and floors, exit or termination rights, corporate PPAs are evolving. Microsoft has come up with a new corporate PPA that is shape-neutral and hub-neutral. This evolution is not helping what the cash equity already sees as an imbalance between risk and reward. The corporates know that they have bargaining power, so we see an evolution that is making corporate PPAs less and less financeable.

Credit is another issue. One large entity that has been one of the most prolific buyers of renewable energy makes a special-purpose entity the electricity purchaser and offers a guarantee from the parent for one year. For one year of revenue! Where is the credit? If the market goes down by $30 a megawatt hour, they effectively are liquidating their damages with one year of revenue. We built the project for 25 to 30 years with what is supposed to be 12 years of contracted revenue.

Financing McDonald's

MR. EMEHELU: Let's go back to a question the program suggests this panel will address.

If you are in this business, you should have a better sense of where future electricity prices will be than a corporate buyer who is not in the business. Therefore, isn't it fair that we should reduce the emphasis on contracted revenue and outsourcing of price risk?

MR. KIM: I think the question was, "Why can't we finance projects like we finance a fast food place, for example, McDonald's?" Does anybody know how many McDonalds are in the US? There are 13,905 at the end of 2018.

The difference between a retail outlet like McDonald's and generators is the customer interface. There is a business that gets financing just like McDonald's, and it is called a utility. Utilities have the direct retail interface. If there is a desire to get that type of financing, it is not going to be 80% debt to 20% equity. It will look more like McDonald's where it is 40% or 50% leverage with some ratings put on it. Nobody knows what the price of a Big Mac will be next year, let alone in 10 years, and if that is the paradigm we are in, then the financing is going to change. There is a level of debt that you can get for merchant solar. It is not going to be a happy number for most people.

MR. EMEHELU: If I want to open a / continued page 6

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small wind turbines and geothermal heat pumps that they will own and put to personal use would also be extended. The bills would extend it for the same period with the same phase down as for the solar investment tax credit, except the deadlines would be deadlines to place such equipment in service rather than merely to start construction.

The wind industry has not made a push so far to extend tax credits for wind projects. Wind is expected to enjoy an advantage of 1¢ a kilowatt hour in the levelized cost of energy versus solar after 2023 once tax credits phase out. The advantage will erode if solar projects continue to qualify for large tax credits while wind projects do not.

The House tax-writing committee voted in June to allow wind projects that start construction in 2020 to qualify for tax credits at 40% of the full rate. Wind projects qualify for production tax credits on the electricity sold to third parties for the first 10 years after a project is first put in service. The tax credits are $25 a megawatt hour for projects that were under construction by the end of 2016. Projects that started construction in 2017, 2018 or 2019 qualify for tax credits at 80%, 60% or 40% of the full rate. An investment tax credit can be claimed instead. The investment tax credit is 30% of the "tax basis" the owner has in the project. The percentage phases down over the same construction-start schedule.

Meanwhile, offshore wind companies are lining up behind two competing bills that were introduced in the Senate in July to allow more time for offshore wind projects to start construction to qualify for a 30% investment tax credit. The extra time could not be used to qualify for production tax credits.

One bill, sponsored by Senators Ed Markey (D-Massachusetts) and Sheldon Whitehouse (D-Rhode Island), would allow a 30% investment tax credit to be claimed on any offshore wind project that is under construction by the end of 2025. The / continued page 7

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McDonald's franchise, I would put down, what — 40% equity? — for an operating asset? I get a seven-year loan, no questions asked. If I come to you with a solar facility and I am willing to put down 25% in equity, how would you structure the debt?

MR. BRANDT: The moot point, and Himanshu said this, is that the tax equity won't come in. I don't know any tax equity that would take that bet even though they are in a first-lien position. You do not get to the debt question until you can raise the tax equity.

M&A deals go to the bidder who is most bullish on post-hedge and post-PPA electricity prices.

MR. KROLICK: I agree. A lot of thought is going into how to structure such a loan. What is the minimum structure that you need to have in order to make tax equity comfortable?

MR. BRANDT: It is being tested now in Texas. We have some assets in the market with a seven-year hedge. We will get that deal done.

MR. EMEHELU: Since everyone is deriding tax equity, let's see if any tax equity investor in the audience wants to defend . . .

MR. BRANDT: Let's stipulate that there is a hedge running to 2026.

MR. EMEHELU: . . . you are agreeing that you are responsible for this problem.

MR. SAXENA: Just for the record, we love tax equity, we need you, we are your best customers, we love you. [Laughter]

MR. KROLICK: We are hosting an after party for tax equity investors. [Laughter]

MR. KIM: I wish banks were treated that way, you know, all we hear is, "Come along or shut up." [Laughter]

MR. KROLICK: The banks are paying for the after party. [Laughter]

BOT Paradigm

MR. EMEHELU: Another thing we see are build-own-transfer transactions where the utility ends up with the project at the end of construction as a way to deal with the lack of power contracts.

MR. BRANDT: We started seeing this about four years ago. I think that the big winners have been NextEra.

A utility will do an RFP that says, "We are interested in projects that can supply electricity at the following nodes." NextEra would say, "We have sites in all of those places, but what we are not willing to build-own-transfer on everything. What we are willing to do is build-own-transfer on four of them, and then we want PPAs on the other six." NextEra has been sweeping auctions, not 100%, but doing very well with that strategy. It is not exactly losing money on the build-own-transfers. There is a developer margin there, but it appears to be doing this primarily to get PPAs.

MR. EMEHELU: What has been your experience with using a hedge as a substitute for a PPA?

MR. SAXENA: Hedges have more risk than traditional PPAs. They range in risk from fixed-shape settling at the hub, versus delivered shape settling at the hub, versus delivered shape settled at the node. Hedges work well if they are done right, if the shape, volumes and location are right.

We have seen some hedges go very wrong. If you are building a wind farm in the heart of the Texas panhandle where you have a massive amount of congestion and you are settling your hedge at ERCOT North, you may as well settle it in Germany. It is so far away that there is no correlation between the price of power in the panhandle and the price in ERCOT North.

There have seen some basis blowouts of $12 to $14 a megawatt hour. If the price of the hedge is $14 and your basis is $14, guess how much money you are going to make on that hedge.

What happens in our sector is some things work and then people extend them to the far extreme, so that the same technology that seemed to work really well in select situations ends up getting bastardized across projects that should never have it.

A hedge is a tool. It is a tool that can be beneficial if appropriately structured for certain projects in the right locations, but if it is misused, you will get cuts.

Debt Sizing

MR. EMEHELU: I am going to push this question one more time. Assuming that tax equity can be found for a merchant solar deal, how would you size the debt?

MR. KROLICK: We run into this more frequently with merchant tails in contracted projects than projects that are fully merchant from day one. The question is how to monetize the post-hedge revenue. There are three ways to attack the problem, but they all lead to the same question: what is your balloon at the end of the contracted period?

The predominant approach is that we all talk, debate and disagree about what merchant forecasts to use. We apply a haircut to them. We come up with a higher sizing ratio, and we argue about how many years of credit the lender will give. I would love the lenders to give me credit up to the useful life, but the reality is we probably end up in the three- to five-year range after a 12-year hedge.

Another way that people are looking at it is to look at the projected levelized power price when the balloon comes due that can, with a reasonable debt service coverage ratio, amortize the balloon down to zero.

The third way to do it is really to use shorthand, which is to come up with a debt-per-KW metric similar to what we have in PJM, and let's just use that because it is simple and we are familiar with it even though I think it is being misused.

We are watching this play out in real time. There is no consensus that I am aware of among the banks.

MR. EMEHELU: Jonathan Kim, Natixis has done merchant projects in Latin America. Is there anything we can learn from your experience?

MR. KIM: The difference between Latin America, particularly Mexico, and the US is that Latin America is a growing market so prices are still high versus the US, which is potentially a deteriorating market in terms of price.

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other bill, backed by Senators Tom Carper (D-Delaware) and Susan Collins (R-Maine), would allow a 30% investment tax credit to be claimed on offshore wind projects that start construction by the end of 2026 or, if later, the end of the year the US reaches 3,000 megawatts of installed offshore wind capacity, not counting Block Island and any other projects that are under construction for tax purposes by the end of this year.

TARIFFS remain a significant hazard for developers who must commit to supply electricity at fixed prices only to have the US slap an import tariff on key equipment before the project can be built.

The US Trade Representative granted an exemption from solar panel tariffs for bi-facial panels that absorb sunlight from both sides of the panel in June after a 16-month process. First Solar, Hanwha and Suniva began pushing promptly to have the exemption cancelled. There is risk that the exemption may be rolled back. US solar developers are urging the government to focus instead on guidance to prevent the exemption from being claimed more broadly than intended: for example, by limiting it to panels that are specially designed to receive light from both sides and by requiring a bi-faciality ratio of at least 50%.

Some US developers have switched equipment sourcing from Chinese suppliers to other suppliers in places like India and Vietnam after the US imposed steep tariffs on Chinese products. President Trump told Fox Business Network host Maria Bartiromo in June, "A lot of companies are moving to Vietnam, but Vietnam takes advantage of us even worse than China." The US is concerned about transshipments from China to avoid tariffs on Chinese products. US imports of solar cells from Vietnam jumped 656% in June from a year ago. Solar panel exports from China to Vietnam were $739 million in Q1 2019 compared to $0 a year before.

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You have a much better chance of debt repayment in Mexico than you have in PJM, for example. It is more difficult to do merchant in an established market where there is continuing downward pressure on electricity prices.

Audience Questions

MR. EMEHELU: Are there any audience questions? Keith Martin.

MR. MARTIN: Jonathan Kim, you said that lenders cannot finance generators like they would a McDonald's franchise because a generator sells wholesale to a single customer while a McDonald's store sells at retail to thousands of customers. But is the analogy to McDonald's a better one where the generator sells on a merchant basis into the spot market?

MR. KIM: I think that is a different paradigm. McDonald's sells — I am not a McDonald's junky, by the way. [Laughter] Each McDonald's sells on average 167,000 Big Macs a year, and presumably it is not to one person. [Laughter] If there are that many customers, then there are choices in terms of going to a different customer whereas a generator is usually trying to sell all of its power to a single entity or into a single market. The prices in that market fluctuate. Lenders take the single offtaker risk or the more uncertain revenue stream into account.

MR. KROLICK: Burgers don't have basis risk. [Laughter]

MR. KIM: Basis risk is a risk that absolutely nobody wants to take. No one is offering a hedge to cover it. The project owner ends up with it, so in a hedged project where there is at least a floor under the electricity price, a lender also has to take basis risk into account.

MR. BRANDT: I would take the other side and say we will see merchant solar. Solar is a zero variable cost asset. If I were raising capital for it, I would want to have eight or nine different assets and to think about financing a portfolio as opposed to a single asset.

MR. EMEHELU: More private equity rather than project finance?

MR. KIM: A little less debt. You are basically financing with more equity.

MR. MARTIN: In what sense is using your own equity "financing"? [Laughter]

MR. BRANDT: It is an old-fashioned idea. [Laughter]

MR. SAXENA: You can look to Mexico to get to the answer. The capital structure for a merchant solar project in Mexico is a 50-50 debt-equity ratio. If you have a project with a long-term offtake contract with the national utility, CFE, you are looking at something close to 80% debt and 20% equity.

Mexico is an open market. It is not like PJM where you have capacity pricing upsetting the pricing of energy and vice versa. The closest to a parallel market in the US is Texas. I agree with Ted Brandt that lenders should be financing merchant solar projects in Texas. They won't finance it with 80% debt, but something closer to 40% to 50% debt. The overall cost of capital will be expensive.

MR. KROLICK: I sometimes struggle with the analogy of merchant solar to river hydro. River hydro has a similar risk profile and close to a zero marginal cost to operate. A portfolio of uncorrelated assets would be better to remove some of the resource risk, but at the end of the day, it will be a question of leverage and location.

MR. WOODRUFF: Mark Woodruff with I Squared Capital. To what extent do you believe corporations looking to enter into PPAs are motivated by trying to lock in electricity prices versus branding and virtue signaling?

MR. BRANDT: We have a unit that has been working with corporates, and I would say the second is the bigger driver, but the decision to buy is not made by a single person. The chief environmental officer will be an MBA with a bit of tree-hugger mentality. He reports to the CFO, and the CFO is absolutely looking at dollars and cents, historical costs and projected costs. Ultimately, you have to satisfy both constituents. The deal has to be economic, and it has to help the company reach sustainability goals.

MR. SAXENA: Most corporate buyers have an advisor who will run an NPV analysis.

MR. MARTIN: Ike, let me ask another question. All of you make it sound like if the tax equity would agree to finance based on an uncontracted revenue stream, then the banks would lend. The tax equity investors are just another group of banks. They are willing to accept part of the their payback in a form of tax benefits and the rest in cash. Why are they so different? Are they really the stumbling block to financing merchant projects?

MR. EMEHELU: I am really hoping that a tax equity investor here will volunteer.

MR. BRANDT: I would answer with a little bit of a smart-aleck remark that the DC Solar deal did not exactly help the tax equity market with this kind of thing. That was a rental fleet that turned out to be a total fraud, and about $700 million in tax equity investments had to be written off. I think it would have to be sponsor-specific. If NextEra wanted to do this, it could raise the tax equity.

MR. KIM: The nature of a tax equity investor is also different from a bank. For example, Natixis is driven by client relationships and by a desire to be excellent in a particular sector. I don't think tax equity says, "I want be excellent in power, and all I am going to do is deploy tax equity in this sector."

MR. BRANDT: The focus is on absolute risk-adjusted returns.

MR. KIM: They have a range of possible places to invest and risk-reward outcomes. They are relative investors.

MR. SAXENA: Keith, I can tell you this. We have a lending relationship and a tax equity relationship with Citigroup. When I go out to lunch with the lending guys, they pay for lunch. [Laughter] When I go out with the tax equity guys, I pay for lunch. [Laughter] So you know where the power sits. [Laughter]

MR. MARTIN: I have one more question for Himanshu. You said, if I heard you correctly, that you get about 30% of your capital back by the end of a 10-year power contract, and you have to rely on the merchant tail for the other 70%. Are those the right numbers?

MR. SAXENA: It depends on the project. It used to be that you got your capital back during the life of the PPA, and that doesn't happen anymore. In every new deal that we are seeing, you get 30%, in some deals it's 40%, but you are not getting your capital back during the PPA period because the PPAs are short and the PPA price is low. So any equity investor is taking a merchant energy price risk.

MR. KROLICK: The deciding factor on every M&A transaction that we have seen recently in the renewables space is people's views of out-year electricity prices.

We recently sold a portfolio of behind-the-meter batteries in southern California. We had a 10-year contract for the capacity. The deciding factor in the auction was the willingness of the equity investor to believe in post-contract revenue. People on the equity side are taking a view about this sort of thing every day, and the lenders are trying to play catchup.

MR. MARTIN: And the most optimistic forecast is the one that wins the bid?

MR. KROLICK: Absolutely.

MR. BRANDT: The cost of capital also counts.

MR. KROLICK: A little bit. [Laughter] ◎

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The US Treasury added Vietnam to a watch list of countries in May that are being monitored for possible currency manipulation.

The US announced on May 31 that it was rescinding an exemption that India has enjoyed from US import tariffs on solar panels. The rescission took effect five days later on June 5.

The US had put India on notice on March 4 that it was planning to revoke India's status as a beneficiary developing country under the generalized system of preferences (GSP) program. GSP beneficiaries are exempted from the US solar tariffs as long as their solar panel exports to the US do not amount to more than 3% of total US panel imports and as long as all developing countries whose individual exports are less than 3% each do not collectively account for more than 9% of total US panel imports.

The US is in the preliminary rounds of imposing anti-dumping duties, countervailing duties or both on wind towers imported from Canada, Vietnam, South Korea and Indonesia. The Commerce Department has an investigation underway into whether such towers are being dumped in the US at prices below fair value or are benefiting from unfair subsidies. The US International Trade Commission is looking separately into whether domestic wind tower manufacturers are being injured. Preliminary anti-dumping and countervailing duty determinations could come as early as year end.

Meanwhile, in July, the Trump administration rebuffed for now a request by two US uranium mining companies to impose a quota on uranium imports. Federal agencies are looking for other ways to help domestic mining companies. The mining companies wanted a quota requiring at least 25% of domestic uranium consumption to be met by US producers. At present, 93% of US uranium used is imported. The largest suppliers are Canada, Australia and Russia.

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The Shift to Electric Vehicles

The transportation sector is headed toward mass electrification. It accounts currently for 29% of energy usage in the United States. Some utilities are counting on the shift to increase demand for electricity, but some experts say the shift will merely change time of use without affecting overall demand. Interesting new business models are emerging for ownership and financing of EV charging infrastructure. What is likely to occur and on what timetable, and what does it mean for independent generators?

A group of experts talked about these are other issues at the 30th annual global energy and finance conference in California in June. The panelists are Cassie Bowe, vice president of Energy Impact Partners, a $700 million venture capital fund, Jeffrey Logan, chief analyst in the strategic energy analysis center at the National Renewable Energy Laboratory, Dr. Sergej Mahnovski, director of growth and innovation for Edison International, the parent holding company of Southern California Edison, and Nick Nigro, founder of Atlas Public Policy. The moderator is Noah Pollak with Norton Rose Fulbright in Washington.

MR. POLLAK: Cassie Bowe, give us a snapshot of where electric vehicle deployment stands today, both globally and in the US.

MS. BOWE: We are in the first inning of EV deployment. We see three distinct global markets: China, North America and Europe.

China is basically half of the passenger EV market, the US is 25% and Europe is 25%. When you take it down to different electric vehicle types, China is 99% of the electric bus market. China will account for the vast majority of electric vehicle demand going forward, and it is also deploying most of the electric vehicle charging infrastructure.

There is also growth in Europe and the US. There are about five million vehicles deployed globally. One million of those are in the US. The US is basically California and everyone else. Fifty percent of electric vehicles are in California.

Three distinct markets are emerging in terms of the charging infrastructure as well. China by far is the farthest along in deploying charging infrastructure. China has the highest density of public chargers per electric vehicle even though it has way more electric vehicles. After that are Norway and a few other European markets. The US has the lowest density of public chargers of any major market.

We also see a few distinct spaces within charging infrastructure. They are residential, work place and public charging. Then you also have slow AC chargers and fast DC chargers. There has been an interesting debate about the relative importance of residential versus public and also the place for slow versus fast chargers.

Effect on Electricity Demand

MR. POLLAK: So if we are in the first inning, Jeff Logan, how long will it take to get to the second and third and finally the ninth inning?

MR. LOGAN: The change that you envision occurring in one year often does not become visible as quickly as you might want, but if you look at it from a 10-year perspective, the rate of change often surpasses initial expectations.

We see a number of different forecasts for rollout of electric vehicles ranging from Bloomberg New Energy Finance, which is one of the more aggressive ones, to what the US Energy Information Administration says, which is basically a flat line.

One question this panel was asked to address is whether the EV sector will create new electricity demand. The general, back-of-the-envelope calculation in terms of the effect of electric vehicles on electricity demand is that for every 10 million electric vehicles deployed, there is about a 30 terawatt-hour growth in electricity demand and a corresponding reduction of a quarter million barrels per day of oil demand. These are rough ballpark numbers.

They suggest that replacing all the light-duty vehicles in the United States with electric vehicles would lead to a 600 terawatt-hour increase in electricity demand. There are around 200 million vehicles. Electricity demand today is 4,200 terawatt-hours. That would be a 14% increase.

The reduction in oil use would be about 5 million barrels a day. US oil demand is 20.5 million barrels a day, so that would be a 24% decrease.

I throw out these numbers as benchmarks against which to think about things.

Adoption Curve

MR. POLLAK: If we are only at one million electric vehicles in the United States today, what does the future adoption curve look like? Is it a typical S curve for new technology? Or is it something else?

MR. LOGAN: I think it is a typical S curve. You can go all the way back to the introduction of the first internal combustion engine or more recently to cell phones to see how they entered the market. They entered very slowly initially, and then they entered a period of very rapid growth. Then as the market saturates, it levels off again. Almost all technologies that are successful follow a similar pattern.

For successful adoption, the "theory of change" must be accommodated. The theory of change requires that the technology not only be cost competitive, but more importantly that it also deliver consumer benefits that are not achievable with the incumbent technology. EVs are three or four times more efficient in their drive trains than internal combustion engines. They have far fewer moving parts, and they are fun to drive. At least in theory, they satisfy the theory-of-change requirements.

MS. BOWE: We are used to thinking about power in terms of somewhat rational actors and what is best for the grid, but car ownership is not rational. The way that people decide how to buy cars is not rational.

As a millennial, I have no desire to own anything, and so I have approached buying a car from that lens. And that's true for a lot of people. When you look at it from that lens, it becomes a little harder to predict exactly how quickly the fleet of passenger vehicles will turn over.

Axios asked consumers in the market for cars how likely they are to buy an electric vehicle. More than 60% said not very likely, and the number one reason was the lack of charging stations. While that is a real concern in a lot of places, in others it is just a perceived lack of infrastructure for a minority of the trips they might ever take.

What really underscores for me the irrationality of this whole segment is the number three reason, which 37% of them said, is that they just prefer gas power.

Michael Zenker said a word in the previous session that I had never heard anyone say before, which is "inforecastability." I think it adds a layer of inforecastability to this whole segment.

MR. POLLAK: I am going to push Sergej Mahnovski for one final try to get some forecastability. When do you think the really rapid increase will occur?

MR. MAHNOVSKI: It is impossible to forecast, but we look at this in the context of the most cost effective and feasible path to reach California's greenhouse gas emissions and air quality goals.

Our plan is by 2030 to have an electric grid supplied by roughly 80% carbon-free energy that can deliver / continued page 12

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CAPITAL GAINS INDEXING could affect tax equity deals.

Conservatives have been pressuring the Trump administration to declare that the tax basis in capital assets can be adjusted for inflation.

A decision could come as early as this fall.

Most partnership interests are capital assets.

Each partner has an "outside basis" in its partnership interest that affects the timing of when tax losses can be used and how much cash the partner can be distributed tax free.

It is not yet clear to what assets or instruments indexing would apply.

The US Department of Justice advised in 1992, during the George H.W. Bush administration, that indexing would require Congressional action, as the Treasury lacks authority to adopt indexing on its own. The current attorney general, William Barr, was also attorney general then.

Treasury Secretary Steve Mnuchin said at the G-7 finance ministers meeting in France in mid-July that indexing remains under consideration, but no decision has been made. Forty-one Democratic Senators sent Mnuchin a letter in early August urging Treasury not to index on grounds that government revenue would be reduced largely for the benefit of wealthier Americans with significant investments. Twenty-one Republican Senators sent Mnuchin a letter at the end of July urging him to index.

President Trump is weighing whether to issue an executive order bypassing Congress.

DEVELOPER FEES are in less favor after a decision by the US claims court in June to bar a wind developer from adding developer fees to the tax basis it used to calculate Treasury cash grants on two wind farms.

The decision has been appealed.

The developer's brief in the appeal is due on September 6. / continued page 13

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clean energy to electric vehicles and support deep electrification of buildings, more distributed energy and market participation by customers.

We envision seven million EVs in California by 2030, representing roughly 25% of the light-duty, 15% of the medium-duty and 6% of the heavy-duty vehicles on the road.

Again, that's not a forecast necessarily, but what we think is a feasible and lowest cost pathway to reduce greenhouse gas emissions by as much as the state has targeted. We believe the pace of electric vehicle adoption should accelerate in the mid-2020s. The turnover cycle for replacing water and space heaters in buildings is longer than for cars.

Replacing all 200 million US cars with electric vehicles would lead to a 14% increase in electricity demand.

Government Actions

MR. POLLAK: Nick Nigro, what role do governments play in EV deployment? What tools have been used so far, whether in the United States or abroad, to promote EVs? Which of those are most successful?

MR. NIGRO: I don't think we would be anywhere close to where we are today when it comes to transportation electrification without public policy. The reasons that China and Europe's markets are so strong are not because their transportation actors are more rational. It is because public policy has been pushing much harder on vehicle electrification.

In Europe, you have high taxes on motor fuel, and you have increasing incentives and mandates from governments across Europe to encourage the purchase of these vehicles. A good example of that is Norway where more than half of all new vehicles purchased are plug-in vehicles. That defies all the stereotypes of these vehicles being unable to perform in cold weather.

We see a similar situation in China where policy is more stick-and-mandate driven.

The big game changer in the last year or two has been the declining cost of batteries, making the electrification of a much broader segment of transportation now possible. You see hundreds of electric trains and buses being deployed in provinces in China, but now also here in the United States. As you get into these bigger vehicle segments, like municipal bus fleets, you start to see more rational actors.

On the passenger side, here in the United States, California, as was already mentioned, has half the market share. That is because of California's public policies, from a zero-emission vehicle program, which is a mandate to increase the offering of EVs for sale in California, to rebates for consumer purchases and other kinds of incentives to deploy charging infrastructure. The challenge we face in the United States is the American consumer remains drawn to gasoline vehicles because motor fuel is so cheap right now.

How do we electrify much larger vehicle segments? That is the open question among US policymakers. It is not yet clear whether the US will enjoy the same S-curve adoption as China and Europe or just meander along.

Let's also not overlook the investment opportunity of this space. More than $350 billion has gone into mostly passenger vehicles at this point, but also medium- and heavy-duty vehicles and infrastructure worldwide. Well over half of the expected near-term investment will be in China and Germany. The US is slated to get only about 10% of near-term investment. We have to look at this not just from a climate and energy standpoint, but also from a competitive standpoint. The future of transportation is electric, and there still needs to be stronger policy here in the US if we are going to be in a leadership position.

MR. POLLAK: If there were one or two policies to implement that would really kick-start EV adoption in the United States, what would they be?

MR. NIGRO: The vehicle incentives that we have in place at the federal level are strong and are a big part of what helped get us to where we are today. I think those need to be reformed. They are currently penalizing the leaders in the space: Tesla and General Motors. The tax credits disappear after a cap is reached based on the number of vehicles sold. The early leaders ended up making the investments needed to open markets, and now the fast followers in the industry are taking advantage of that and getting the lower-cost batteries, and purchasers of their vehicles qualify for tax credits while purchasers of the early leaders' vehicles do not.

Another key area is infrastructure reform. That is where electric power comes into play. As we look ahead to where the autos are going with market offerings, it is longer range, it is higher power, it is faster charging. We need the electric power sector positioned to provide infrastructure for those vehicles. People need to see the charging infrastructure deployed before they will purchase these vehicles even though we expect 80% or more of charging to occur at home. The road trip mentality in the US is still strong.

MR. POLLAK: Jeff Logan, that goes to the chicken-and-egg question of what is needed first: the vehicles or the charging. Nick Nigro just said his view. What is your view?

MR. LOGAN: I think at this point equal emphasis has to be placed on making EVs accessible and affordable and rolling out the charging infrastructure so that people feel secure that they will not run out of battery power when they need it. In time, there might be a different emphasis on one versus the other.

Deploying Charging Stations

MR. POLLAK: So who is going to deploy the charging infrastructure? Cassie Bowe, is it the utilities, governments or private companies?

MS. BOWE: Just to underscore how far we are from equal emphasis on both new vehicles and new charging infrastructure, in the US in 2018, new electric vehicle sales increased by 40% and, in the same time period, we only increased the number of public charge points by 2%.

We have seen start-up companies in the US in this area needing to follow the money. A big inflection point will be when we see charging infrastructure being / continued page 14

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In the meantime, developers have shifted to selling the project company at mechanical completion to the tax equity partnership for the projected value at the end of construction as determined by an appraiser. The developer remains obligated to finish the remaining construction.

Most renewable energy projects owned by larger developers are financed in the tax equity market. The amount of tax equity that can be raised is a function partly of the tax benefits that can be claimed on the projects. Investment tax credits and depreciation are calculated on the tax basis the tax equity entity has in the project. The higher the tax basis, the higher these tax benefits.

Most developers have been required to represent to the tax basis that can be used to calculate tax benefits after the US Treasury began questioning the tax bases claimed on some solar projects in 2010.

Tax insurance is sometimes purchased to cover basis risk. Insurance premiums have inched up in the wake of the US claims court decision. They had fallen to as low as 2% to 3% of the potential insurance payout as the market became more comfortable with risk, but are back to 3% to 4%.

US wind developer Invenergy paid itself a developer fee of $50 million on the 200-megawatt California Ridge project in Illinois at project completion in late 2012. The fee was about 12.3% on top of construction cost. The company applied to the US Treasury for a cash grant for 30% of its tax basis in lieu of claiming federal tax credits on the project. It asked for a grant of $136.9 million on a tax basis, including the developer fee, of $456.2 million. The Treasury paid $9.2 million less after reducing the developer fee to 4.8% of construction cost.

Invenergy sued for the difference.

The government then filed a counterclaim urging the court to deny any developer fee. (For earlier coverage of the case, see "Treasury Cash Grant Update" in the / continued page 15

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deployed to follow where the vehicles are as opposed to the money sources.

The money sources fall into three categories: utilities, cities and auto manufacturers. Greenlots, an EV charging software company, for example, has a revenue breakdown that comes in roughly equal parts from those three segments. It is an open question which of the three will end up deploying the most money.

MR. MAHNOVSKI: The manner in which consumers interact with charging stations will probably be fundamentally different than how we are used to refueling with gas.

Let me touch on fleets for a second because that is a very important area for us. We are hoping over a five-year period to install electric infrastructure at customer sites to support charging plug-in for buses, medium- and heavy-duty trucks, forklifts and other non-road cargo handling equipment.

Our team at the parent company is looking at opportunities to work with start-up companies that are making it easier for fleets to convert and to identify new business models that may fundamentally change how customers interact with charging infrastructure. We have worked with Cassie's team as well on this. The issue for many fleet owners is how to reduce the complexity and risk of conversion to electric, including selection and management of hardware, software, vehicles and contractors, and how to master energy pricing, tariffs and utility infrastructure. We have looked at opportunities to wrap everything together to make it simpler for fleets to convert.

MR. POLLAK: What fleets, naming some specific companies, would you would like to see adopt EV vehicles?

MR. MAHNOVSKI: We have a small investment in a company, Proterra, that is a leading electric bus manufacturer. Some of the big transit fleets are starting to electrify, in part, because of federal policy support in that sector. Medium-duty parcel delivery services are also a great candidate for electrification, particularly as new class 4, 5 and 6 electric vehicles become available over the next several years. We also see a great opportunity for light-duty ride-hailing and car-sharing fleets.

V1G and V2G

MR. POLLAK: I am fascinated by some of the potential second-order effects. What are some of the ways vehicle batteries may be used that are not just to push a vehicle along?

MS. BOWE: One of the things people talk about a lot is vehicle-to-grid, meaning taking battery power from the vehicle and putting it into the grid. The shorthand term for it is V2G. We are very far from that at scale today. We have seen a few start-ups working on it with vehicles that are able to have this functionality.

Something more near term is demand response with EVs. If I look at all the companies in which our venture fund has invested, more than half of them will probably compete in the near term for demand-response revenue. That is even before you have electric vehicles coming and trying to compete for the same revenue pools. There are few markets today where vehicle-to-grid makes sense economically. Once you have more vehicles that are in fleets, especially mid-duty fleets, I think we will see more activity.

MR. NIGRO: The V1G aspect of transportation, meaning smart charging during off-peak hours to reduce the cost of charging, remains in its infancy. We have very few wide-scale or even pilot smart-charge programs today across the country. There is a lot of value potentially in getting electric vehicles to charge during off-peak hours, and utilities are starting to experiment with how to encourage drivers in particular. Individual consumers can be the most finicky to get to change behavior.

A good example of V1G is the smart-charge program of Con Edison in New York City. A dongle on the vehicle records when you are charging in Con Ed territory. If you charge during off-peak hours, you receive an incentive directly from the utility.

There is an incredible amount of value not just to individual consumers, but also to ratepayers more broadly by just doing V1G well because it lowers the average cost of delivering electricity. This can help cover some of the societal costs of deploying more charging stations.

The business model for selling electrons as a transportation service is very difficult. It is not just because the market is small, it is because you are also competing with home charging. It is tough to try to change an ingrained pattern, which is people drive their cars to work every day and then come home and plug into the garage. Fast charging services trying to compete with that face stiff competition.

The business models that will succeed in the near term are ones that look not just at the electrons and the service as an offering, but also at ways to pull in other value. Think about what gas stations owners do today by selling additional products to their consumers while they fill up. That is one model. The electric utility as a partner to benefit the ratepayers is another model. We are all familiar with what Tesla is doing as a model, essentially deploying charging infrastructure as an advertising platform.

Low-Hanging Fruit

MR. POLLAK: Many people, including the one-third of all homes that are occupied by renters, may be reluctant to install charging infrastructure. The cost is between $2,000 and $7,000 depending on the speed of the charging that you put in. Add that to the trend toward car, bike and scooter sharing and ride sharing. What does this suggest about who will end up owning the charging infrastructure?

MR. NIGRO: Electrifying shared mobility services is one of the most exciting opportunities for charging infrastructure providers. I just spent a few minutes talking about how tough the charging business model is. If there is one awesome business case for charging, it is getting Uber and Lyft drivers into electric vehicles. Something like a third of the electrons supplied by one of the largest charging providers, EVgo, were from Uber and Lyft drivers last year. That is where we can make rapid progress if we can get policies in place to make it easier for Uber and Lyft drivers to get into these vehicles. Many of these drivers do not own the vehicles that they operate. They rent them from a third party.

An example of that is a program from General Motors called Maven Gig, where drivers who need to work for ride-sharing or delivery services can rent a vehicle for a week or month at a time. Making sure that those vehicles are electric is a priority for cities. They are seeing increased vehicle miles traveled by these vehicles, and what they don't want is increased emissions.

There is also the potential for Uber and Lyft drivers to earn more money. Whatever policies are adopted in urban environments to encourage electrification of mobility services has to result in more money going into the pockets of Uber and Lyft drivers because otherwise they won't go electric.

MR. MAHNOVSKI: Ride hailing and car sharing are well positioned to electrify due to high use of the vehicles and the wider choices for electric vehicles in the light-duty space. We are looking at opportunities to accelerate electrification of these platforms, particularly as they account for a larger part of the vehicle miles travelled in the economy

How vehicles are charged will evolve with the business models. For example, companies such as Envoy are developing electric car sharing and charging services as amenities for tenants in multi-family housing complexes, increasing value for landlords and potentially reducing parking needs. / *continued page 16*

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February 2016 *NewsWire* and "PPAs and Developer Fees" in the February 2018 *NewsWire*.)

The claims court said that developer fees are allowed to be added to tax basis, but the fee in this case lacked substance.

Invenergy made a capital contribution to the project company that the project company used to pay Invenergy the fee. The court called the fee a "round-trip wire transfer that began and ended in the same bank account, on the same day."

Invenergy went to the trouble of putting a development services agreement in place between the project company and its subsidiary that received the fee. However, the court said that while the development services agreement listed work that Invenergy did to earn the fee, none of services had a specific charge next to it as would have been true had an independent contractor been hired to do the same work. The fee was the difference between the construction cost and the appraised market value.

Invenergy suffered the same result in a second wind project called Bishop Hill. The claims court consolidated the two cases under the name *California Ridge Wind Energy v. United States*. The Bishop Hill facts were similar, with slight variations in dates and dollar amounts.

Developers are drawing a number of lessons from the decision.

There is a danger of coming out in a worse position than before by suing the Treasury for a cash grant shortfall.

Any developer fee should be paid out of capital contributed by the tax equity investor or remaining construction loan proceeds at the end of construction: for example, as a reward for bringing the project in under budget.

The amount should reflect the capital the developer had at stake and the time and difficulty it took to develop the project. The Treasury suggested in 2010 that developer fees should not normally exceed 10% to 20% of the cost of a solar project, but / *continued page 17*

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We also made a small seed investment in AMPLY Power, a startup that offers "charging-as-a-service" for fleets, helping to de-risk some of the operational and financial risks of electrification by offering a fully managed solution, including system design and maintenance with set pricing terms.

MS. BOWE: There are two countervailing forces to the notion that people will do most of their charging at home. They are, one, the future is autonomous and, two, the future is fleets.

Millennials make the EV adoption rate harder to predict. They are less interested in owning cars.

More and more passenger vehicles will be owned in the future in fleets. That includes autonomous vehicles that almost entirely are going to be owned by fleets. And all of that load will be charged some place other than private homes. We haven't even begun to scratch the surface there. For a lot of folks in this room, that is the main opportunity.

MR. POLLAK: How quickly will autonomous vehicles become a reality, and how much will they affect the EV landscape?

MR. LOGAN: We are going to have a longer rollout of the autonomous sector than we will with just the EV segment itself. There are a lot of very complicated issues to solve. Lots of great work is getting done in that space, but there is still a long way to go.

MR. POLLAK: One of the primary questions that was presented to us for this panel was how the conversion to electric vehicles will affect the grid.

MR. MAHNOVSKI: It will increase electricity demand over time. The questions are where and when?

If you look at it from a system standpoint, there are several trends that are developing at the same time. They include customer adoption of distributed energy resources, electrification of buildings, and new ways that consumers interact with energy products, services and vendors.

The rollout of electric vehicles also varies by geography. On balance, we should start seeing an acceleration in electrification of the transportation sector in the mid-2020s.

In terms of the impact on the grid, in theory, "uncontrolled" charging could increase load on parts of the distribution network, particularly in residential areas as people come home in the evening and plug in. However, on-site generation and storage, new smart-charging technologies, new business models, and utility time-of-use rates, incentive programs and targeted buildout of infrastructure will shape demand patterns and help utilities manage.

Getting It Wrong

MS. BOWE: There are two opportunities for utilities. One is the increased load, and the other is the potential for additional rate-based investments in infrastructure.

Estimates are that the charging infrastructure will require $6 trillion globally.

There is a distinct possibility that we will look around in five to 10 years and say, "Oh God, why did we deploy the charging infrastructure where we did?" We misjudged where the electric vehicles would be, how people would use them, and how fast the chargers would be. There could well be a second wave of grid infrastructure investment to undo or redo what we did in the first wave.

MR. MAHNOVSKI: So we are going to mess it up the first time?

MS. BOWE: I just see a lot of opportunity for start-ups.

MR. POLLAK: Nick Nigro, are we going to build it out the right way?

MR. NIGRO: This is critically important. Think back 10 years about what was available from a technology standpoint. If we went all in on electric vehicles 10 years ago and built out infrastructure for a bunch of plug—in hybrid vehicles that travel 20 to 30 miles, that would have been that worst-case scenario that we were just talking about.

Instead, for better or for worse, we held back a little, and now what we are looking at is battery costs reaching a point where the long-range all-electric vehicle is the main offering that we will see from most auto manufacturers within the next five years.

We are in a much better position now, frankly, to do proper planning, but we must always keep in mind what are our end goals. What are we trying to accomplish? Greenhouse gas emission reduction, for sure. Improved use of existing assets on the grid. All of these factors are driven at the societal level. We need to have good strong public policies in place so that the individual consumer choices end up helping to solve these challenges rather than making them worse.

The biggest challenge is the unevenness of how policy is distributed in a market like the United States where so much is done at the local level. We could see, five to 10 years from now, huge pockets of electrification in cities because they have electrified their entire transit systems, cities like Seattle and Washington, DC. And then in other major metro regions that are less inclined to engage, let's say Houston or Dallas, things may not look very different than they do today.

Policies will adapt over time based on market changes and what we learn along the way.

MR. POLLAK: Most EVs use lithium-ion batteries that are good for light—duty and medium—duty vehicles. Is there a reasonable pathway to get heavy-duty vehicles, long-haul trucks, to be adopters of EV?

MR. LOGAN: Elon Musk already announced Tesla will roll out a heavy-duty truck with a lithium-ion battery. People are experimenting today with a lot of different battery chemistries. If a fundamental breakthrough were achieved in a new metal battery, it would take 10 years before it really entered the market and began to displace lithium ion. So for the time being, we are stuck with that technology for better or worse, but that technology also continues to improve and the costs keep coming down. I think it does have a role. Whether or not hydrogen fuel cells or some other variant on the electric battery is more suitable in the heavy-duty space remains an open question.

MR. MAHNOVSKI: Most of the duty cycles, for example, medium duty, appear to be well suited for electrification. The one that might be a little more difficult is class 8 long haul, due to the long-range driving requirements. I always leave room to be surprised.

MR. NIGRO: There is a significant amount of travel that occurs in the class 8 space that is under 500 miles a day. That is suitable for lithium-ion batteries. That is why companies like Tesla and Freightliner will be introducing electric vehicles in the class 8 space in the next five years. They see a market opportunity.

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quickly backed away from that number, coming eventually to believe that such fees should normally be in the 3% to 5% range absent unusual circumstances. Many tax equity investors have been placing a cap on the permitted step up in tax basis above construction cost of 15% to 20%.

Developer fees have become less common in the last 18 months. The market had already moved by the spring 2018 to sales of project companies as a better way to step up tax basis. Inverted leases have also made a comeback in the solar market. In an inverted lease, the tax equity investor leases the project from the sponsor. The sponsor keeps the depreciation, but makes an election to let the lessee claim the investment tax credit on the project. IRS regulations allow the tax credit to be claimed in such cases on the fair market value of the project.

Separately, WestRock, a paper and packaging company, lost an appeal in late June in another Treasury cash grant case called *WestRock Virginia Corp. v. United States*.

The company built a new cogeneration facility in 2013 to serve a paper mill in Covington, Virginia. The company retained one of eight boilers it had used previously to supply energy to the mill and added one new boiler. The new boiler burned biomass. The older, retained boiler burned fossil fuel and black liquor, a by-product of papermaking. Steam from both boilers was then run through a steam turbine to generate electricity for use in the mill. Some of the steam exiting the turbine was used as process heat in the mill.

The company applied for a Treasury cash grant of $85.9 million, or 30% of its $286.2 million tax basis in the facility. The Treasury paid a grant of only $38.9 million.

The Treasury's position is that any power plant that produces both steam and electricity must allocate the cost between the two functions. A grant is paid only on the electric generating equipment. / continued page 19

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Because the battery costs have declined much faster than people thought was possible with lithium ion, I think we are going to see medium- to long-haul trucks that are powered by lithium-ion batteries within the next decade. That is something I don't think hardly any researchers thought was possible five or 10 years ago.

Audience Questions

MR. POLLAK: Are there any audience questions?

MR. SHORE: This is Bill Shore from Hanwha 174 Power Global. I'm wondering if you could address battery degradation and how that affects willingness to own electric vehicles and what the long-term expectations are in terms of what happens to vehicles as the batteries degrade. Will the batteries be replaced? Will vehicles be scrapped?

MR. LOGAN: It certainly is a key question in a lot of consumers' minds when they decide whether to buy. The answer is I don't know.

MR. POLLAK: I read that the degradation after about seven years makes the battery no longer good enough for a car, so the battery must be swapped out. I have been interested in what happens to the spent battery. Cassie, we were talking about the fact that battery prices are coming down so much that there really isn't, at this point, a viable second use.

MS. BOWE: I think the auto manufacturers will be on the hook to figure out what to do with these batteries.

MR. PICKER: Michael Picker, I work for the state of California.

I am confronting a central policy choice as to how we design the electric infrastructure for charging. I am someone who wakes up every morning with three Jump electric bikes parked on my front lawn waiting to be picked up to be charged and gig cars that are there when the garbage truck drivers are trying to come pick up my garbage.

It seems like transportation as a service is a pretty rapidly evolving area. I know that there are still logistical challenges to deal with autonomous vehicles, but all of these transportation-as-a-service-type emerging opportunities call for a really different kind of an infrastructure than what I hear you talking about, which is to get consumer adoption, customers must be able to recharge their electric vehicles at home at night.

That seems to me to present two really different public policy choices and suggest two different expenditure patterns, probably in the range of billions of dollars. I don't know how to decide the right way to bet.

MS. BOWE: On the light-duty side, no one knows yet what to do with the charging infrastructure. Bird, for example, which is the scooter company, charges a majority of its scooters by leaving charging to the free market. Bird says if you pick up a scooter and charge it at your house overnight, we will pay you something like $5 a scooter. A whole industry is growing up on something called Bird hunting, where people at the end of every day are going around picking up scooters at night in massive trucks and charging them at home. Scooters are not allowed to be used at night. I think we could opine on what use patterns will develop, but we are very early in figuring out what that will look like. It is probably going to get a little more messy before it gets better.

MR. PICKER: We are already starting to see the impact on specific feeder circuits with large apartment buildings in beach communities. That's absolutely unintended, and I am concerned that we are placing too many bets in the same place. ◎

FOIA: Keeping Information Confidential

by Kenneth Hansen, in Washington

A US Supreme Court decision in late June will make it easier for federal agencies to withhold confidential information received from private companies from public disclosure when responding to Freedom of Information Act requests.

Protection is no longer limited to "confidential information whose release would cause substantial competitive harm" to the supplying company. Now, to be withheld from release in response to a FOIA request, the information only needs to be "confidential."

At the same time, some members of Congress are considering amending the FOIA to require agencies to release such information.

The Supreme Court decision was in a case called *Food Marketing Institute v. Argus Leader Media*.

The Freedom of Information Act is a 1966 statute that requires US government agencies to disclose information requested by the public in the belief that government transparency is a good organizing principle in a democracy.

Companies that submit information to the government worry that the information will fall into the hands of competitors. About 10% of FOIA requests are filed by news organizations. The remaining requests come from law firms, companies and individuals.

Agencies responding to FOIA requests send a notice to the person whose information it is before disclosing the information. Some types of information are not disclosed. See the sidebar on page 20.

Areas of Controversy

Under the FOIA, federal agencies are obligated to release any information requested by a member of the public unless an exemption applies. If an exemption applies, then they have the right, but not an obligation, to withhold the requested information, unless some other statute requires that the information be withheld.

The relevant exemption for business confidential information is "exemption 4," which excuses from / continued page 20

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A further allocation must be made between the biomass and fossil fuels since tax credits may only be claimed on electricity generated from biomass.

Two other cases have upheld this principle. (See discussion of *W.E. Partners* in "Treasury Cash Grants" in the February 2015 *NewsWire* and of *GUSC Energy* in "Treasury Loses Key Case" in the December 2016 *NewsWire*.)

The Treasury determined that only 49.1% of the WestRock plant costs were tied to electricity produced rather than steam. It reduced the basis by another 0.22% because the plant uses fossil fuel for startup and flame stabilization. Black liquor is considered biomass.

THE FOUR-YEAR WINDOW to finish some renewable energy projects to qualify for federal tax credits will be extended in one situation, the IRS said.

The IRS made the announcement in July in Notice 2019-43.

The extension will apply in cases where the US Department of Defense raises national security concerns about a project that require getting "new or additional permits or licenses." In that case, the four years will be extended by the number of days it takes to get the new or additional permits or licenses.

The period of time added to the four years starts when the DoD first notifies the project owners in writing of a problem and ends when the new permits or licenses are issued and the period for administrative or judicial review has run.

No more than another four years in total may be added.

Defense officials asked the IRS to make this special exception. The principle does not apply more broadly.

An example in the notice suggests the request was prompted by a project whose intertie to connect to the grid will run adjacent to a US military base or / continued page 21

The Nine FOIA Exemptions

The Freedom of Information Act provides the following nine exceptions to what is otherwise an federal agency's obligation to release information requested by a member of the public:

Exemption 1:
Information that is classified to protect national security.

Exemption 2:
Information related solely to the internal personnel rules and practices of an agency.

Exemption 3:
Information that is prohibited from disclosure by another federal law.

Exemption 4:
Trade secrets or commercial or financial information that is confidential or privileged.

Exemption 5:
Privileged communications within or between agencies, including those protected by the:

a. deliberative process privilege (provided the records were created less than 25 years before the date on which they were requested);
b. attorney-work product privilege, or
c. attorney-client privilege.

Exemption 6:
Information that, if disclosed, would invade another individual's personal privacy.

Exemption 7:
Information compiled for law enforcement purposes that:

a. could reasonably be expected to interfere with enforcement proceedings,
b. would deprive a person of a right to a fair trial or an impartial adjudication,
c. could reasonably be expected to constitute an unwarranted invasion of personal privacy,
d. could reasonably be expected to disclose the identity of a confidential source,
e. would disclose techniques and procedures for law enforcement investigations or prosecutions, or would disclose guidelines for law enforcement investigations or prosecutions if such disclosure could reasonably be expected to risk circumvention of the law, or
f. could reasonably be expected to endanger the life or physical safety of any individual.

Exemption 8:
Information that concerns the supervision of financial institutions.

Exemption 9:
Geological information on wells.

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disclosure information supplied by a company that consists of "[t]rade secrets or commercial or financial information that is confidential or privileged." While the scope of exemption 4 has generated a great deal of litigation over the years, with various federal district and circuit courts having different views, it has never before been considered by the Supreme Court.

Non-disclosure of trade secrets and privileged information has not been particularly controversial. Trade secrets are protected by the Uniform Trade Secrets Act, which not only permits but obligates an agency to withhold trade secrets supplied by a company and makes unauthorized disclosure by a federal employee a crime. Thus, where business confidential information arguably constitutes a trade secret, agencies are understandably inclined to protect it. When in doubt, agencies have often left it to the courts to require them to release the information.

Neither has much controversy arisen as to privileged information, the scope of which is relatively clear.

The key controversy has been with respect to what constitutes confidential information for purposes of protection from disclosure under exemption 4. That was the question in *Food Marketing Institute v. Argus Leader Media*.

The case arose from an FOIA request filed by Argus Leader Media, owner of the *Argus Leader*, a South Dakota newspaper, with the US Department of Agriculture. The newspaper was seeking release of the names and addresses of stores participating in the US food stamp program (the Supplemental Nutrition Assistance Program or SNAP) and each participating store's SNAP redemption data for the preceding five years. The USDA tried to meet the newspaper half way by identifying the participating stores, but would not release the redemption data, basing its refusal on exemption 4, which protects "trade secrets and commercial or financial information obtained from a person and privileged or confidential."

As summarized by the court:

> Unsatisfied by the agency's disclosure, Argus sued the USDA in federal court to compel release of the store-level SNAP data. Like several other courts of appeals, the Eighth Circuit has engrafted onto Exemption 4 a so-called "competitive harm" test, under which commercial information cannot be deemed "confidential" unless disclosure is "likely . . . to cause substantial harm to the competitive position of the person from whom the information was obtained.

The US district court applied the competitive harm standard and found in favor of Argus. USDA appealed to a US court of appeals, where the Food Marketing Institute, a trade association for retail groceries, intervened in support of USDA's position. When the appeals court affirmed, maintaining the "substantial competitive harm" test, the Food Marketing Institute appealed to the US Supreme Court.

The Supreme Court took a different view. Justice Gorsuch's opinion reflected the court's unanimous rejection of the substantial competitive harm standard for business confidential information to be protected from disclosure by a federal agency. Writing for the majority (himself and five other justices — Roberts, Thomas, Alito, Kagen and Kavanaugh), Gorsuch concluded that the plain meaning of "confidential" should guide non-disclosure. Justice Breyer (joined by Justices Ginsburg and Sotomayor) dissented in part, arguing that some "genuine harm" should come from disclosure if it is to be blocked, but the / continued page 22

other defense installation. DoD "raised concerns with the permitting authorities regarding the location of the proposed transmission line."

Renewable energy projects face deadlines to be under construction to qualify for tax credits. It is not enough to start construction in time; there must also be continuous work on the project after the year construction starts. The IRS does not require proof of continuous work for any project that is completed within four years after the year construction started. Solar projects face an absolute deadline to finish by the end of 2023. There is no absolute deadline for other projects.

THE LIBOR TRANSITION is getting high-level attention in Washington.

The US Securities and Exchange Commission urged companies in a "staff statement" in July to identify existing contracts that rely on LIBOR and begin negotiations now if a contract is unclear about what happens once LIBOR is discontinued. It also recommends using an alternative benchmark rate called SOFR for future transactions that use US dollars.

The interest rates on most floating-rate loans are tied to LIBOR, as are swaps and other contracts where the parties have payment obligations to each other that accrue interest when payments are delayed.

Banks that currently report information that is used to set LIBOR are expected to stop doing so after 2021. Thus, loans, swaps and other contracts that run past 2021 are potentially affected.

Working groups have been formed in each of the United States, United Kingdom, European Union, Japan and Switzerland to recommend alternatives to LIBOR for transactions in the different currencies. An alternative reference rates committee — ARRC — in the US, led by the US central bank, identified the "secured / continued page 23

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minority justices agreed that the prevailing standard was misguided.

New Standard

Going forward, the standard is that confidential business information provided to the government should be protected regardless of whether its release would cause substantial competitive harm or, in fact, any harm at all, as long as it is confidential.

But just what is "confidential information"?

To determine what constitutes confidential information for purposes of exemption 4, the Court said, "the term 'confidential' meant 'private' or 'secret'" and referred to contemporaneous definitions of "confidential" in leading dictionaries in 1966 when FOIA was enacted. The court said those dictionaries suggested two requirements for information to be confidential:

> In one sense, information communicated to another remains confidential whenever it is customarily kept private, or at least closely held, by the person imparting it . . . . In another sense, information might be considered confidential only if the party receiving it provides some assurance that it will remain secret.

The court then asked whether both tests are needed:

> Must both of these conditions be met for information to be considered confidential under Exemption 4? At least the first condition has to be; it is hard to see how information could be deemed confidential if its owner shares it freely.

Thus, a necessary condition for information to be confidential is that the company treats it as such.

As to the requirement that the relevant agency promise to keep the information confidential, the court asked:

> Can privately held information lose its confidential character for purposes of Exemption 4 if it's communicated to the government without assurances that the government will keep it private?"

The Court did not answer that question because there was no need. The USDA had "long promised retailers that it will keep their information private." Whether information qualifies for such protection only if the agency has promised to protect it, or what degree of protection an agency would have to offer in order for exemption 4 to apply, remains an open question.

It might be easily answered if the government were not involved. If I share a secret with someone without extracting his or her promise to keep the information confidential, it may no longer be a secret. One could argue the same outcome should apply to information shared voluntarily with a government agency without a promise of confidentiality.

But what if companies are legally obligated to share that information, such as in connection with the audit of a federal contractor? Also, there are degrees of volunteering. Information can be mandatorily required to support an application for a federal loan program, even though the decision to apply in the first place is wholly voluntary. Should such information not be protected? There can be strong public interests in having companies volunteer information needed to inform government programs and policies. Whether exemption 4 protection should be lost because information was provided voluntarily is not so clear.

In any event, businesses that find themselves sharing confidential information with the government, whether voluntarily or not, can take comfort from the *Food Marketing Institute* decision that the information they provide is more likely than before to be kept confidential.

Congress Gets Involved

The Supreme Court decision has raised concerns in Congress.

The Hill newspaper reports that Congressional discontent is rising with respect to the degree of governmental transparency offered by FOIA. Much of that concern relates to agency compliance with FOIA generally, such as failures to respond in a timely fashion to FOIA requests. Additionally, both the Environmental Protection Agency and the Department of Interior have drawn criticism for adopting new FOIA regulations that provide for enhanced review of FOIA requests by political appointees.

Some influential members of Congress have raised the possibility of reversing the new protection provided for confidential business information coming out of the *Food Marketing Institute* decision.

Senator Chuck Grassley (R-Iowa) said, in a speech on the Senate floor:

> Transparency laws like the Freedom of Information Act help provide access to information in the face of an opaque and obstinate government. Unfortunately, a recent Supreme Court ruling and new regulations at EPA and the Department of Interior are undermining access . . . . The public's work ought to be public. So, I'm working on legislation to address these developments and promote access to government records.

It has become easier to protect confidential information given to government agencies from public disclosure.

Grassley was chairman of the Senate Judiciary Committee, which oversees the FOIA, before moving this year to head the Senate tax-writing committee.

His speech followed a letter from a bipartisan, bicameral group of members delivered to the Government Accountability Office, the investigatory arm of Congress, requesting a review of agency compliance with FOIA. The letter said:

> In 2016, Congress passed the FOIA Improvement Act of 2016 to expand public access to government records . . . . Among other reforms, the 2016 Act codified a presumption of openness, allowing agencies to withhold records only when there is foreseeable harm to an interest protected by an exemption or a legal requirement preventing their release. Some agencies are not fully implementing the 2016 improvements and continue to burden requesters with unlawful delays and denials. For these reasons, we */ continued page 24*

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overnight financing rate" or SOFR as its preferred alternative.

SOFR is a measure of the cost of borrowing overnight cash using Treasury securities as collateral. The overnight lending market has $800 billion in daily volume.

The SEC paper, called "Staff Statement on LIBOR Transition," recommends that companies first identify existing contracts that run past 2021 for potential exposure to LIBOR and make sure the parties agree on what happens once LIBOR is discontinued.

The alternative reference rates committee has published separate fallback provisions for use in new floating rate loans, syndicated loans, bilateral loans and securitizations. The International Swaps and Derivatives Association (ISDA) is still working on fallback language to use in swaps.

The disappearance of LIBOR could also affect base case models and tracking models in tax equity deals. The SEC staff recommended that companies focus on the potential effects on "strategy, products, processes and information systems."

ANYONE HOME?

Taxpayers got through to the Internal Revenue Service, when calling during the last filing season about compliance issues, only 33% of the time after an average wait of 41 minutes, according to Nina Olson, the outgoing IRS national taxpayer advocate.

This is a growing problem with US government agencies. Years of budget cuts have left some agencies understaffed and unable to field questions about federal programs or laws.

A caller to US Customs headquarters in Washington was warned that the trade remedies section, which fields questions about Customs duties, no longer answers the phone. Customs agents at busy US airports are sometimes bewildered about what tariff rate to apply to goods that */ continued page 25*

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> request GAO build on its 2018 assessment and conduct a comprehensive review of compliance with FOIA since the 2016 amendments.

Among the provisions in the FOIA Improvements Act of 2016 is one that provides that agencies "shall withhold information" under FOIA "only if the agency reasonably foresees that disclosure would harm an interest protected by an exemption" (or if disclosure is prohibited by law).

The 2016 amendments were not discussed in the *Food Marketing Institute* opinion. Perhaps they should have been. FOIA issues are not constitutional, but matters of statutory interpretation, where a more recent statute will trump the language, and any judicial interpretations, of an earlier law.

While the Supreme Court concluded that exemption 4 applies where business-supplied information is confidential without the need to show its release would cause substantial competitive harm, the revised FOIA provides that the information, even though subject to the exemption, should still be released unless the "agency reasonably foresees that disclosure would harm an interest protected by an exemption."

Best Advice

The FOIA seems likely to remain a work in progress.

Federal agencies that collect information from private companies will necessarily be revising their FOIA procedures to eliminate the finding of a risk of substantial competitive harm as a condition of withholding company-supplied information.

Between the question left unanswered by the Supreme Court as to whether agencies need to promise protection in advance in order to provide it (absent a statute requiring it), on one hand, and the possibility of Congress legislating different outcomes, on the other, companies providing federal agencies with information that they want to be kept confidential would be well advised to seek assurances in advance from the agency that it will do so if it legally can. ◎

California on Edge

What does the PG&E bankruptcy suggest for the utility business model? Some banks have stepped back from financing new projects in California for fear that future wildfires may threaten other utilities. As much as 85% of the electricity load is expected to have shifted from investor-owned utilities to community choice aggregators by the mid-2020s. State regulators are still wrestling with exit fees to pay for stranded utility assets and are worried about the challenge a fickle customer base presents for CCAs. Is the road ahead one of opportunity or challenge?

Five key participants in the California market discussed these and other questions at our 30th annual global energy and finance conference near Laguna Niguel in June. The panelists are Michael Picker, president of the California Public Utilities Commission, Kevin Sagara, chairman and CEO of San Diego Gas & Electric, Tom Buttgenbach, CEO of 8minute Solar Energy, Tom Werner, chairman and CEO of SunPower Corporation, and Jan Smutny-Jones, CEO of the Independent Energy Producers Association in California. The moderator is Todd Alexander with Norton Rose Fulbright in New York.

MR. ALEXANDER: Michael Picker, would you agree that the current market structure in California is unsustainable?

It is not just the wildfire liability that has driven PG&E into bankruptcy. You have investor-owned utilities that are losing some of their best customers to distributed energy. They lose revenue streams while retaining the full cost of maintaining the grid. Then you have less regulated community choice aggregators entering into long-term contracts to buy electricity, but not under the same rules as the IOUs. The whole independent power business is built around having long-term contracts with credit-worthy entities.

Is this sustainable? Do we need major reforms in how the California market works?

MR. PICKER: I want to take a second to notice the passing of Ron Nichols, who has been a longstanding colleague and a major player here in California, with Navigant, then with the Los Angeles Department of Water and Power, and recently with Southern California Edison. He was a person of extreme kindness and grace; we all miss him.

The last time I was here, I think the panel I sat on was asked whether the utilities were in a death spiral at the hands of SunEdison and SolarCity. I have the same reaction to this question. Our customers in California can get electricity from a variety of technologies and suppliers. The incumbent utilities are becoming transmission and distribution companies.

We think we have the business model of the future, but we have the rate structure of the 1950s.

Regardless of the degree to which customers are procuring their own electricity, all of the fixed infrastructure that the utilities will continue to provide is being funded based on the volumetric sales of electricity. Recent legislation has started to correct that by allowing utilities to charge customers who install rooftop solar a $10 flat charge, but that amount is capped. The challenge will be, as we continue to see evolution in customer choice, to provide the utilities with a predictable source of revenue for the utilities so that they can maintain the grid. The grid is a natural monopoly. It is the equivalent of a public highway.

MR. ALEXANDER: Kevin Sagara, SDG&E has said publicly that it wants to become a poles and wires company and get out of electricity generation. How do you see the future?

MR. SAGARA: Well, we have our principal regulator sitting right next to us, so . . . [Laughter] I totally agree with everything that President Picker just said. [Laughter]

I actually do. Obviously there is an issue around sustainability of the utilities in the state given their exposure to wildfire liabilities. I am confident it will be addressed. Once we get past that, we need to move to a modern rate structure. The current rate structure does not work in an era of customer choice. We are going to have more electric vehicles, more direct access, more rooftop solar and more CCAs. The rate structure is not designed for that.

In our service territory alone, rooftop solar is a $450 million-a-year rate subsidy going from one class of customers to customers who have rooftop solar. That is the share of grid costs that is shed by those installing rooftop solar on their homes to customers who continue to buy all their power from the utility.

That is a failure of rate design and is not sustainable. It is the same thing with the CCAs. You have customers exiting to take their electricity from local CCAs. You cannot have this and, at the same time, expect the utilities to bear the full costs of legacy power contracts they entered into in the past to comply with state policies to serve customers who have now moved to CCAs. The CCAs must take their fair share of those legacy costs along with the customers. More than 45% of the electricity that SDG&E supplies today is from renewables. We support customer choice. We just want to make sure that there are not unfair rate shifts among customer groups. / continued page 26

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returning Americans bring back with them from overseas. The US tariff schedules run 3,892 pages.

CRYPTOCURRENCIES are in the IRS crosshairs.

The agency started sending warning letters to 10,000 taxpayers in late July whom it believes have traded cryptocurrencies and failed to report the income.

Cryptocurrencies are treated currently as property rather than currency for US tax purposes. (For more detail, see "Bitcoins" in the April 2014 *NewsWire*.) This means anyone holding bitcoins, ethereum or other cryptocurrencies risks having to pay a tax on gain when the coins are used. A person is treated as if he or she sold property and used the cash to buy goods or services. This makes it impractical for individuals and businesses to use such currencies for ordinary course transactions because of the need to track gains and losses.

Taxpayer compliance is low. Credit Karma, a free on-line tax preparation service, reported in January 2018 that fewer than 100 of the 250,000 tax returns it filed that month reported owning cryptocurrency for tax purposes, a far smaller percentage than the 7% of Americans that are believed to own such currencies, and only one reported a gain or loss despite the huge swings in bitcoin prices during 2017.

The IRS is using "data analytics" to find traders. Some could be subject to criminal prosecution where there has been money laundering and perhaps in other cases.

The current IRS analysis of cryptocurrency tax treatment is in Notice 2014-21. The IRS said new guidance will be issued "in the near future."

SOME TRANSACTIONS must be reported to the IRS as potential corporate tax shelters.

The IRS requires reporting any transaction that has one of five features. One of the five is that the transaction is / continued page 27

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A modern rate structure is essential to serve other policy goals. You are not going to get lots of people buying electric vehicles if they have to pay 40¢ to 50¢ a kilowatt hour to do so. Yet under our volumetric rate structure, that is what we have today in California at the upper volume levels.

I came from the solar and wind development side of Sempra. Prices for wholesale solar and wind electricity are very low. You will sell a lot of electric vehicles if the electricity costs 4¢, 6¢ or 7¢ to charge a car. The same is true for electric water heaters and a lot of other places where electrification wants to go. We need a more modern rate structure.

MR. ALEXANDER: Tom Werner, your take? Do you agree that the remaining utility customers are bearing an unfair share of the cost to maintain the grid?

MR. WERNER: I agree that customer choice has moved faster than policy. As the cost of storage comes down, it will just compound the effects. The model is not sustainable. However, I struggle with the idea of imposing a fixed charge on solar rooftop customers. It is not a good solution because it does not encourage the right behavior for energy use. There are probably better rate structures.

MR. ALEXANDER: Do you think distributed energy will continue to take a larger and larger market share?

MR. WERNER: The payback period for a commercial solar customer to recover its investment in a solar-plus-storage system is nearing two to three years. At such rapid paybacks, installing solar is a fairly easy decision. The equipment is warranted for 25 years. If the market evolves in such a way that ancillary services get compensated, then the payback period improves even more and this trend, I think, is inevitable.

California Financings

MR. ALEXANDER: Tom Buttgenbach, you have built one of the most successful utility-scale solar developers in the country. Do you think the current market structure is sustainable, and do you see distributed energy continuing to gain market share?

MR. BUTTGENBACH: I do not think the current market is sustainable. I think that California is headed towards a potential disaster unless we fix it. I do also think that the PG&E bankruptcy is a good thing. Sorry to say that, Kevin, but . . . .

MR. SAGARA: We had a renewables business that had PG&E as an offtaker, but we sold it last year.

MR. BUTTGENBACH: We didn't buy it.

The PG&E bankruptcy is forcing all of us to take a hard look at the future in California. The wildfire liability is a totally different problem. What Michael Picker just discussed is the grid design, and I think we all agree that it is due for a major overhaul.

The CCAs are a big problem. They were created without an adult in the room. The largest CCA, Team Power Alliance in Los Angeles County, had something like 30 cities sign on. Someone said we will give you 12 chairs and one office, and now go run a multi-billion dollar business.

It has no balance sheet. There are now two financeable CCAs. That reminds me of 2006 or 2007 when I drove through LA and there were posters hanging on the light posts saying, "No job? No problem. We'll finance you to get a house." Those people were financeable in 2006 and 2007. Not much longer. I think the CCAs are in a similar stage. We are thinking about entering into PPAs with CCAs, and the bankers tell us, "There is a lock box that will lock up six months of cash." The PPA is 20 years. What good does it do me to have a six-month lock box? I have no idea.

Maybe my perspective is colored by our situation. I own the company. When I sign a PPA, it is my personal funds on the line. I am struggling with the idea of signing a large, 20-year PPA with someone who has a credit

> Half of all new houses in California are being built in areas that the state considers to have extreme fire risk.

rating suggesting he may be able to pay his bills for the next two years. The CCAs have no assets. So what is that credit rating based on? I have no idea. Mortgage-backed securities were also credit-rated until suddenly they were not.

I am really concerned about the future of the market, mostly driven by CCAs going bust. First, they drive the IOUs into bankruptcy, because it is impossible to run a business when half your customers are walking away. Then some of the CCAs are going to screw up. I am not saying all of them, just some, but that will be enough to take the whole ship down because the guys in New York will stop answering the phone.

At some point the music will stop, and all of these projects that are signing contracts with CCAs will not be financeable. To my mind, that is a huge problem. We have to tackle that. It probably requires a legislative solution.

The funny thing is the ratepayer is in good shape. Joe, in his home, will pay his bill. I, as an independent power producer, am okay. I am happy to sell. It is the people in the middle who are a mess right now. It is the IOUs and CCAs. The only stable ones are the municipal utilities.

We have to figure out how to stabilize that market going forward. The PG&E bankruptcy is an opportunity to force a redesign of the way the IOUs and CCAs interact.

Provider of Last Resort

MR. PICKER: I have a slightly different perspective. I think part of the reason why we see such anxiety about this is not just the fact that there is a new player that is moving into a field traditionally served by the electric utilities. It is also that the independent power producers on this panel did too good a job. Too many contracts were signed, and too many projects are still being built, leading to a flattening of wholesale prices.

The fact that we are returning to a disaggregated procurement system is not new.

There are similarities between what is happening today and what happened during the California energy crisis in 2000 and 2001. We know what mistakes we can make. And yes, we are making them again. We spent two years conducting workshops and hearings and writing two reports to examine whether we are drifting back into the same set of patterns as in 2000 and 2001. I think we have learned a lot, but clearly not enough.

The California legislature read the reports, and there are competing bills to create a backstop procurement system in California. I expect something will pass. I think it will help to stabilize the market. I am not so alarmed / continued page 28

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a "listed transaction" that the IRS has said it does not believe works or is "substantially similar" to such a transaction. The IRS has identified 36 listed transactions to date. Reporting makes an audit more likely.

A US appeals court said in late June that a purchase of a cash value life insurance policy by a corporation for its sole shareholder and employee was "substantially similar" to one of the 36 listed transactions and should have been reported. The corporation had asked the court to waive the fines for not reporting.

A cash value life insurance policy differs from term life insurance. A term insurance policy is in effect for a definite term. There is a payout if the policy holder dies during the term.

With a cash value policy, a portion of the premium goes into an investment account. The policy holder controls how the funds are invested. When the plan terminates, the policy holder can withdraw the funds that have accumulated.

Interior Glass Systems, Inc. paid the premiums each year for a cash value policy for its sole shareholder and deducted the amounts as a business expense.

After the IRS made any transaction involving such a policy a listed transaction in 2007, the company made changes in how the policy was structured, but continued putting money into it.

The 2007 IRS notice described cash value life insurance policies that have four elements.

The modified policy still had three of the four element. The one missing element was the cash value policy was arranged through a tax-exempt business trade group rather than a trust or welfare benefit fund. The revamped policy also provided some group term life insurance benefits as well as a cash value life policy.

IRS regulations say a transaction is "substantially similar" if it is "expected to obtain the same or similar types of tax consequences and . . . is / continued page 29

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about those challenges. There will be failures, so we need to create a provider of last resort that we do not have currently and that will be the ultimate backstop.

The good news is how easy it has become to buy renewable energy and the degree to which such energy has become a commodity.

MR. ALEXANDER: One proposal is to make the IOUs the electricity provider of last resort.

MR. PICKER: That is the current situation. Our experience in 2000 and 2001 was that when all of a sudden an undercapitalized third-party provider fails — in that case, it was an electricity service provider or a direct access provider, people use those terms interchangeably here — in a really turbulent market, it dumps back on the incumbent utility an obligation to procure a lot of power in the spot market at peak prices.

That doesn't work. The costs are passed along to all the ratepayers, and there is a cascading effect. We are going to guard against that by creating a central POLAR, a provider of last resort. Some utilities may decide they want to participate in providing that service, but everybody else will have to fund that insurance. It will force us to focus on the different risks that third-party providers impose on the system. They are going to have to contribute toward the insurance in proportion to risk.

MR. ALEXANDER: Tom, do you think it will work?

MR. BUTTGENBACH: I think, yes, but it needs also to include the contract. It is not enough just to have a provider of last resort.

MR. PICKER: You guys are commodity providers. You are at the point where it is so cheap that it is truly a commodity. Will you continue to operate in this bilateral system? Will you be competitive on that level? Will we see the renewables industry go truly merchant?

MR. BUTTGENBACH: I wish. It is not a reality right now. I can't finance a plant based on merchant sales. I wish I could. Today we are relying on long-term power purchase agreements, but long-term has changed. It used to be 20 to 25 years, and now it is 15 to 20 years.

MR. PICKER: So then the statewide central procurement vehicle becomes very important.

MR. BUTTGENBACH: Right. The problem with central procurement is that the CCAs absolutely hate it and will fight it tooth and nail. They happen to be the political darlings right now.

MR. PICKER: No, they're not. They are losing that fight.

MR. BUTTGENBACH: Good. I am all for it.

What we have to provide is a financing environment where California is not seen as the next Venezuela. I can tell you we have a project in the market and about 50% of potential buyers have said, "California, we're not looking at it right now. I don't care who the project is with, doesn't matter."

MR. PICKER: We do not have growing demand for such projects, so why would they look at us?

MR. BUTTGENBACH: There is quite a bit of demand.

Seen a Thing or Two

MR. SMUTNY-JONES: This brings to mind an old Jim Morrison line about the future is uncertain, and the end is always near. Welcome to California. [Laughter]

I think it is a good time for a walk down memory lane. In 2008, there were 300 megawatts of utility-scale solar in California, primarily parabolic mirrors out in Kramer Junction. The price of utility-scale floatable tags was something like 50¢ or 60¢ a kilowatt hour. There are now 12,000 megawatts of utility-scale solar in California, and the price is now less than 3¢.

Ten years ago, rooftop solar was pretty much non-existent. Today, there are another 6,000 megawatts of rooftop solar. We have not built a new conventional power plant in California in a very long time. We built 16,000 megawatts of gas generation in the 15-year period leading up to the California energy crisis. That is all there is backstopping all this.

Then the CCAs roll in. In 2002, no one talked about 80% of the load shifting to CCAs. That was what they were going to do in Davis, in Berkeley and in a few other places, but that was going to be about it.

All of the post-energy crisis policy initiatives were successful in reaching their individual goals, but as these policies now converge, they are creating issues. They are part of our infrastructure. They cost money. We are going to be paying for them in the future. You put on top of that the wildfire liability and the bankruptcy, and it leads to a significant amount of uncertainty.

I represent a broad range of both renewable and gas generators, all of which have PPAs in California. We are a PPA-based system here. No one has built a merchant power plant here in a very long time. What we do in the future is a big concern.

I find it ironic that after 25 or 30 years of promoting deregulation and having multiple buyers and multiple sellers, the solution to this is to create a state entity that will buy power.

We have been able to work our way through things in the past. That will happen here again.

Some banks are saying no to California projects currently in the market for financing.

There will be some rough sledding for a while. Tom Buttgenbach and Michael Picker have accurately described some of the challenges with the CCAs. It is not a given that all of them will succeed. I can't think of any human endeavor where everybody is 100% successful.

We will have to spend time trying to figure out how to bolster the existing CCAs to address the issues around creditworthiness and long-term viability and to provide some place to go for customers of any CCAs that fail.

The bottom line is that there are a whole lot of people in this state who don't want to think about electricity. They want to hit the light switch, and they want the lights to come on. They are not interested in being prosumers. They are not interested in anything except reliable electricity that they can afford, and preferably clean. That's our market, and we have to keep that in mind.

MR. WERNER: It occurs to me that we want the audience to finance us, so we probably ought to pull back a little bit. [Laughter] Life isn't that bad. There will be a lot of good stuff mixed in.

That said, to pile on the CCAs, it is not good to have asymmetrical risk. You sign long-term PPAs, and you have short-term buyers. On the flip side, some of the capital that would have been invested in the past in traditional IPPs is moving to C&I. Things are getting very complex, but that's the beauty of software. In time, we will solve everything.

There is too much complexity in the near-term, but it creates opportunity for companies like us. And, by the way, the shift to C&I is to a form of project that is very financeable. [Laughter]

MR. SMUTNY-JONES: On the positive side, because you're right — I was just joking about that Jim Morrison line, by the way [Laughter] — you are in a state where */ continued page 30*

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either factually similar or based on the same or similar tax strategy."

Interior Glass argued that this standard is too vague.

The court said the differences between the revamped policy and what the IRS said does not work were immaterial. Both policies have the effect of shifting pre-tax earnings of the business into the shareholder's personal investment account. The amounts put into the cash value policy should have been reported as dividends to the shareholder or as compensation in his role as the sole employee.

The case is *Interior Glass Systems, Inc. v. United States*.

START-UP COMPANIES can be actively engaged in business even though there are no sales.

This is important because ordinary business expenses can be deducted once a company is considered actively engaged in business. In contrast, start-up costs accumulate and must be amortized over 180 months after a company starts business.

Steven Smith worked for Pepsi on its international beverages sales and then got a Ph.D. and started teaching at university level. He was a vegan and was surprised by how difficult it was to find vegan food while teaching in an exchange program in Brazil. He started a company called Vegan Worldwide, LLC to export vegan food from the US to foreign markets.

He completed a business plan in 2013. By early 2014, he had an exclusive license from Taft Foodmasters to resell certain Taft products under the Vegan Worldwide label in Brazil, Argentina, Colombia, Jamaica and the Dominican Republic. Taft made a wheat-based meat substitute called Seitan. Smith signed an agreement with Butler Goods later in 2014 to buy and resell a Butler product called Soy Curls. He traveled to Colombia, Brazil, Jamaica and the Dominican Republic */ continued page 31*

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we adopted a 100% clean energy policy, whatever in the world that means, but we are working on that. It is a huge market: the fifth largest economy. There is a lot of work to be done between now and 2045, so we need to get over this rough spot in the road to get on with it. We do not want to be spending our time on more bankruptcies.

Utility Future

MR. ALEXANDER: Kevin Sagara, the investor-owned utilities seem trapped in a political struggle. They face strict liability for wildfires. Their only source of money to pay the cost is to pass through the liability to their ratepayers. It is not exactly clear when they will be allowed to do so. This has led the rating agencies to downgrade the IOUs. Where does this lead?

MR. SAGARA: The inverse condemnation law imposes strict liability on the IOUs for wildfire damage. We have less-than-clear rules about when that cost can be passed through to ratepayers. The destructive wildfires are a product of climate change. We spent $1.5 billion over the last 10 years on hardening our system and putting 170 weather stations and 100 digital cameras into the field.

The potential instability of community choice aggregators is a significant issue.

The costs of climate change mitigation will fall of necessity on ratepayers or on taxpayers generally. The investors will not bear the full costs in the end because they can simply pack up and invest somewhere else. We are going to have to decide whether cost recovery comes in the form of passing through directly in rates or we pre-collect and put the money into some kind of insurance fund, for example, through a securitization or other form of financing.

MR. ALEXANDER: President Picker, what is achievable politically?

MR. PICKER: I absolutely agree that we are seeing the effects of climate change. I spent a number of years thinking we were being successful in averting the impacts of climate change in California by helping to green up the electricity supply. We have done a good job. The electricity grid here in California accounts for only 17% of all the carbon emissions in the state. Transportation is 40%.

But we were practicing a form of climate denial when we assumed that this was enough. Last year, there were 8,000 wildfires in California, consuming about two million square miles. That's a lot. It is also abnormal, never having been experienced before in the meteorological records. Only one in 10 of the wildfires was related to electric utility infrastructure.

So we have a much larger problem, and we have to look at larger mitigation strategies. The utilities are now the largest forestry operation in the western United States, charged with removing trees on narrow corridors around their infrastructure. They are becoming the most granular weather system in the state of California. SDG&E has digitized most of the landscape behind the city of San Diego, and it provides better weather reporting on a more granular level than you can get from the National Weather Service.

Our utilities are the vehicle by which we transform the infrastructure in California. That infrastructure is increasingly focused on adaptation to the effects of climate change.

MR. SMUTNY-JONES: Last summer, we had a fire in Redding that started by hauling a trailer uphill with a flat tire. It destroyed half the town.

The utilities have become very serious about trying to address wildfires, and it will take money to do so. This is not just an investor-owned utility problem. I am a SMUD customer in Sacramento, and the SMUD general manager made it clear that if they burn down Placerville this summer, I, as a ratepayer, will be strictly liable for the cost. There is a small public utility district in Trinity County that is being sued for more than $32 million. Its annual budget is $12 million, okay? It is a small little PUD.

There is a lot of marketing going on that if we would just switch to micro-grids, no problem. The Tubbs fire, which you all know as the "wine country fire," got started by a privately owned electrical set up — a micro-grid, basically — of, I think, four poles and a bunch of wires going to pumps and wine cellars. If you learn nothing else listening today, the point is that a hot wire and dry brush cause fire, and if you put wind behind it, you have real problems.

This is a big problem that is taking up a lot of the legislature's time this year. There are something like 700,000 homes in what they call the "urban wild land interface."

MR. PICKER: Fifty percent of all new housing in California built since 2010 is in areas that now we consider to have extreme fire hazard risk. We make the utilities build wires and poles to all those new homes.

PG&E Contracts

MR. ALEXANDER: Changing topics, what will happen to the power purchase agreements that independent generators have signed with PG&E?

MR. BUTTGENBACH: Nothing. Twenty years ago, the same judge preserved the utility's non-executory contracts. I am not worried about the contracts with PG&E. I am much more worried about the state being viewed as an area where future projects are unfinanceable. If PG&E were to decide to cancel some of its PPAs, the independent generators will sue. The costs of the litigation will be borne by its shareholders, if it loses. The upside, if contracts are cancelled, would benefit the ratepayers. So if I am PG&E, why would I cancel a contract when I don't capture the upside and I only capture downside?

MR. SMUTNY-JONES: Tom is one of my board members, and he is one of the calm ones. [Laughter] He may be the only calm one, as a matter of fact.

We are spending a lot of time on this issue, and I have to say that the CPUC, President Picker in particular, as well as our governor have been very clear about their expectation that PG&E will continue to honor the contracts. These contracts were executed as part of our climate change policy and for resource adequacy. They are fundamental to the integrity of how we operate our electric system.

If the utility starts rejecting contracts, there are liquidated damages provisions in those contracts that will still have to be paid by the utility. / continued page 32

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the same year to attend food shows and meet with distributors and retailers in an effort to sell his products. When he identified potential customers, he sent them samples. He came close to a deal to supply Soy Curls to a hotel group in Colombia, but it fell through.

Vegan Worldwide had no sales in 2014.

It deducted $39,423 in costs.

The IRS disallowed the deductions on grounds that they were start-up costs that section 195 of the US tax code requires be amortized over time.

The US Tax Court said Vegan Worldwide was in business in 2014 despite the difficulty getting retailers to clear shelf space for its products.

The case is *Steven Austin Smith v. Commissioner*. The court released its decision in July.

The court said to be in business, a company must intend to make a profit, be regularly and actively pursuing sales, and actually have started business operations. The dispute was over whether the company had started business operations. The court concluded the company was not engaged in mere research whether to get into business.

FLOATING SOLAR PROJECTS may not command the same market share ultimately as offshore wind, but they are starting to get traction. The immediate appeal is in countries where land is scarce.

The South Korean government approved construction of a 2,100-megawatt floating project in late July that will sit behind the Seamangeum seawall off the southwest coast of the Korean peninsula. The seawall is a 21-mile dyke that was built to recover land from the sea for use in farming. A freshwater reservoir sits immediately behind the seawall.

The project is expected to cost $3.9 billion and require 5.25 million solar panels. Construction is expected to start in late 2020.

Other floating solar projects are in the works. / continued page 33

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The elephant in the room is that if California moves from one wildfire season to the next facing the same issues, I am not sure how many people in this room are going to be interested in investing capital in California to do all the wonderful things — the batteries, the electrification of the transportation fleet — that we will need to achieve our longer-term goals. Honoring contracts is fundamental.

MR. WERNER: We built around 1,500 megawatts of projects in California. The risk we were taking when we built one of the projects, called Solar Star, north of LA, were as big as the company. It was a massive bet, so we needed a reasonable return. Does the utility get a do-over? Of course, we are all brilliant in hindsight, but the risk at the time is unchanged. I don't think you get a do-over. I just wonder what the impact will be on our ability to reach our 100% renewables goal if we start to change legacy contracts. It will increase financing risk and make renewable energy projects more expensive to build. We have seen what happens in other countries, like Spain, when this happens.

MR. BUTTGENBACH: Let's be clear. The reason why those contracts were high-priced is not because the risk was so high back then. It is because the technology was so expensive. We paid $3 a watt in capital costs back then to build a large solar project. Today, the cost is 35¢. These contracts were signed to meet the state renewable portfolio standard. That was the cost at the time for such contracts.

There is debate about whether to create a central procurement authority to act as an electricity supplier of last resort.

Today, we are signing contracts to supply electricity for around 2¢ a kilowatt hour, from solar projects like our project in Nevada, and we will be announcing a very large project that is between 3¢ and 4¢ that includes massive amounts of storage at the gigawatt hour level.

These very large power plants have capacity factors that allow them to provide reliable power. They are not intermittent any more from seven in the morning until 11 o'clock at night. They can match exactly the load profile of the utility. That's what the utilities are looking for, and it is now cheaper than a new gas plant. We are below 4¢ a kilowatt hour, including storage.

We can design a system that is 100% reliable because the sun is highly predictable, which is different from wind where the storage is actually more expensive for a wind plant because you have a lot longer periods of potentially no wind. Solar plus storage creates a more reliable, more cost-effective system in the future, and I think a lot of the distributed generation will start going away because its appeal is going away. There is a better, cheaper and faster solution that the market will adopt.

MR. PICKER: The challenge is that, early on, there were many expensive contracts because nobody had built a large-scale renewable project in recent memory in California. You had to go back to Kramer Junction to see such a project. So investors wanted a premium. It is the older expensive contracts that people tend to focus on in terms of trying to do cost reduction. PG&E does not own those generating facilities. We made it divest most of its generating assets years ago. It is basically wheeling a commodity from a contract from a third party to consumers, and it gets to collect a little money on this. It is not a good business proposition. You can ask Kevin Sagara about that.

MR. SAGARA: We don't want to be in it. [Laughter]

MR. PICKER: It is an increasingly thinly priced commodity. There are some who would like to see those contracts renegotiated. There are some probable owners of those contracts who may be willing to do that. The CPUC does not break contracts. However, we will consider whether it is in the ratepayers' interest if two willing parties — as happens on a regular basis — have decided to renegotiate a contract. It is our position, and has always been our position, that we have to approve things that come out of bankruptcy.

Opportunities

MR. PICKER: I think that all this is focused simply on the generation side, and I'm sitting next to three people who've excelled at that. The reality is SB 100 is probably unnecessary, not harmful, but also absolutely insufficient to the task. The legislation that we should all think about is not SB 100 — the renewable portfolio standard was intended to direct investment to technologies that were not present in the marketplace — but rather another bill, SB 350, that requires us to meet a declining greenhouse gas standard.

We will not get to our 2030 carbon reduction goal, much less our 2045 goal, on 100% renewable electricity. We have to electrify the transportation sector, we have to de-carbonize buildings, and we have to figure out what we are going to do about those large industries that are much more difficult to de-carbonize.

One significant tool that we have always used in California is on the demand side. The heavy expenditures in energy efficiency, in appliances and building standards have made a significant difference in terms of demand in California.

If you are looking at California as primarily a place to invest in projects, there will be some business here. We will start procuring again shortly. But I think that looking at all these other needs is probably where the real opportunities will be in the future, and I encourage people not to remain so narrowly focused because the underlying structure of policy is going to move away from RPS to de-carbonization.

MR. ALEXANDER: Tom Werner, we are just about out of time, but I will give you the last word.

MR. WERNER: Changes create opportunity. As a businessperson, if you don't have change, then it is just a commodity business. So how do we capitalize on the changes? How do we electrify? How do we bring software? How do we make the power plant more flexible? I think there is lots of business to be had here.

I wouldn't be so extreme to say that solar power plants win. Consumers have a choice. They may want to produce themselves. I think storage is inevitable. The wholesale markets are going to change so that there will be more value for ancillary services. The utilities will become transmission and distribution companies.

The question is pace. There is lots of opportunity. ◎

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A Dutch consortium is planning a project off the coast near The Hague. A Belgian consortium is looking at the North Sea for a "high-wave" project. Dubai put out a tender in June for consultants who can work on a floating project. A five-megawatt floating solar project is under construction in Singapore.

There are currently 1,100 megawatts of floating projects on inland water. Output for projects at sea could be 5% to 15% higher than similar projects on land.

BASE CASE MODELS in tax equity deals can take a person quickly into the weeds, but the details are important.

Final regulations the IRS issued in July are a reminder not to increase the "outside bases" of partners in the lessee in an inverted lease by the income they have to report on account of claiming an investment tax credit.

Inverted leases are a form of tax equity structure used in the solar market.

The lessee in an inverted lease claims the investment tax credit on solar equipment, but must report half the credit as income over five years.

The lessee is usually a partnership between the tax equity investor and the project developer. The developer keeps a tiny interest as the managing member.

Each partner has an outside basis that it uses to calculate its gain or loss on sale of its partnership interest. The outside basis normally increases as the partner is allocated income.

Some tax equity investors were using this so-called section 50(d) income to push up their outside bases and then claim a capital loss for the same amount by withdrawing from the partnership after the flip date when the investor's interest in the lessee falls to a small percentage.

The IRS put a halt to the practice of claiming a later loss equal to the section 50(d) income in temporary regulations in 2016. (See "IRS Addresses an Inverted / continued page 35

Buying a Wind Farm

by Jim Berger and Amanda Rosenberg, in Los Angeles

Anyone buying a wind farm should be aware of a number of issues that can affect the value or even viability of the project.

Offtake and Interconnection

Most wind projects derive much of their value from a power contract.

Terms like the electricity price, the remaining contract term, security that must be posted to secure performance, the deadline to start electricity deliveries for any project that is still under development, and the minimum number of turbines that must be operating to avoid a de-rating are obviously important.

It will be an uphill battle to finance a project with an unrated offtaker. Financeability analyses are becoming more complicated as more projects rely on corporate offtakers. Power purchase agreements with corporations are evolving. They are becoming shorter in term with longer "merchant tails" where the owner must rely on uncontracted revenue. Recent corporate PPAs sometimes have tracking accounts to track the extent to which the contract price for electricity exceeds the current market prices during the contract term, and the overage must be paid to the customer. (For more on these challenges, see "Financing PPAs With Shorter Terms" in this issue.)

Many power contracts contain change-of-control provisions. Determining whether the potential acquirer fits into an exception, if there are any exceptions, and whether the transaction requires the consent of the electricity purchaser are gating issues. Consents can take time to obtain.

The project location is important in an era of grid congestion. Some wind projects have been "curtailed," meaning ordered by the grid to scale back output, by up to 97% at times. This obviously affects revenue. A technical consultant should be brought in to analyze curtailment risk.

A project in an organized market where a regional transmission organization and independent system operator has been put in charge of the grid has more options for where to sell its power unlike a project in Florida or Idaho, for example, where there is no spot market. Regulated utilities in areas without alternative outlets for power are required by law to buy the output at their "avoided cost," or the amount they would spend to generate the electricity themselves. However, this purchase obligation, while a matter of federal law, is administered by state public utility commissions. Enforcement varies by state. (See, for example, "PURPA and Solar" in the April 2017 *NewsWire* and "New Technologies and Old Issues Under PURPA" in the February 2018 *NewsWire*.) There may be restrictions in some states on direct sales to end users of the electricity; the local utility may have a monopoly on electricity supply.

Numerous wind projects, particularly in ERCOT, lack a traditional power contract. They sell into the local grid and rely on hedges or swaps to put a floor under the electricity price so that the projects can be financed. Three types of hedges are commonly used: fixed-volume price hedges (where a fixed amount of output each period is hedged), virtual PPAs with corporate offtakers (which are power contracts that are financially settled, so that they act as hedges and the volume matches the actual output) and proxy revenue swaps (which hedge both price and weather risk).

Hedges require careful analysis. Key factors on which to focus are whether the hedge is physically or financially settled and what liens and other credit support the hedge counterparty requires.

In most projects with hedges, basis risk is the central concern. In a hedged project, the electricity is sold to the grid at a floating market price determined at a "node" on the grid. The project then pays a floating amount to a hedge counterparty in exchange for a fixed price in return. The two amounts are netted, and one party pays the net amount to the other. The payment by the project under the hedge is a floating price determined at a "hub," which is not the same as the node. The price gap has reached as much as $12 to $14 per megawatt hour in the Texas panhandle. The potential for a gap in price is called basis risk.

New projects usually have to pay the cost of "network upgrades" to the grid to accommodate the additional electricity. Payments may also have to be made to upgrade neighboring grids to relieve congestion. The payments can run into the millions of dollars.

Tax Credits

Production tax credits can be claimed on the electricity output from wind farms in the United States. The credits may be claimed only on electricity generated and sold to unrelated persons for the first 10 years after a facility is originally placed in service. The credit is currently 2.5¢ a kilowatt hour. The amount is adjusted annually for inflation.

Anyone buying a project should get a non-imputation endorsement to the title insurance policy.

A facility only qualifies for credits if it is under construction by the end of 2019, and it only qualifies for credits at full value if it was under construction by the end of 2016. Facilities on which construction begins in 2017, 2018 and 2019 qualify for credits at reduced levels of 80%, 60% and 40% of the full rate.

Anyone buying the development rights to a project that has not been built yet should determine when the project started construction, if in fact it is under construction. A weak start-of-construction fact pattern may limit the ability to finance the project. If a project has already been financed, then be sure to check the start-of-construction representations made to investors and assess how much risk the buyer will take if it steps into such a representation.

There are two ways to start construction. They are by starting "physical work of a significant nature" at a factory on equipment for the project or at the project site, or by "incurring" at least 5% of the project cost.

Turning first to off-site physical work, some wind companies had work start at the factory on a transformer for the project.

The manufacturer should do as much work on the transformer as possible before the construction-start deadline and deliver the transformer before the deadline or as soon after as possible. Many transformer manufacturers are not in a position to do any manufacturing themselves, so they order components from suppliers to put in a basket with the name of the project on it for use later in manufacturing the transformer. Some tax counsel want to see work by the manufacturer itself. The more that was done before the construction-start deadline, the better. Many tax counsel like to see such work cost at least $250,000 and take at least 250 man hours to complete. Non-physical work, like design or engineering, does not count as part of the man hours. The focus is on physical work.

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Lease Issue" in the August 2016 *NewsWire*.)

It said the section 50(d) income is not really partnership income. It starts with the partners. Therefore, it does not run through partner outside bases. The IRS reaffirmed this position last month in final regulations.

DATA POINTS. Moody's said in early July that it expects coal to account for as little as 11% of US power generation by 2030. "The electricity mix in the first quarter 2019 was 26% coal, 34% natural gas, 18% renewable energy and 20% nuclear . . . . Chinese demand for solar panels is expected to add to upward pressure on panel prices this year. Prices have already been pushed up by US demand for equipment to stockpile ahead of a construction-start deadline at year end to qualify for investment tax credits. The Chinese National Energy Administration announced on July 11 that it will subsidize 22,800 megawatts of new solar capacity additions in 2019. This is expected to lead to 40,000 to 45,000 in new capacity additions in China overall in 2019, with 30,000 megawatts of new construction compressed into the second half of the year. Chinese solar capacity additions were 53,000 in 2017, but they fell in 2018 after the central government announced at mid-year that it was scaling back support for new utility-scale solar projects and placing a low cap on distributed solar deployments.

— contributed by Keith Martin in Washington

Wind M&A

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Another common form of physical work is to dig a percentage of the turbine foundations — at least 10% would be ideal — and to have put in at least a mile of turbine string roads. Access roads to the highway generally do not count. The turbine foundations must be used in the project. They cannot have washed away. The road should be finished to the permanent surface.

The contract for the work had to be binding on the parties before the work started. If there was a right to cancel the contract, the contract should have required payment of a termination fee of at least 5% of the remaining contract price, plus payment for work completed. A contract with a termination for convenience is not binding if no damages have to be paid. Any subcontracts also must be binding to count physical work done under them.

The second way to start construction is to "incur" at least 5% of the project costs. Costs are not incurred merely by spending money, with one exception. Equipment or services must normally be delivered to count the costs. The exception is a payment before the deadline counts if there was delivery within 3 1/2 months after the payment.

Title transfer may have been enough technically, but it is best if there was actual delivery of the equipment. In order to count a payment for services, then all services must have been completed within the 3 1/2 months.

It is fine if delivery occurred at the factory. However, there should have been formal acceptance. The developer should have had a representative inspect the equipment and formally accept the equipment by signing an acceptance certificate with serial numbers of the equipment and other basic information. Any sales, use or value added taxes triggered by delivery should have been paid. Title and risk of loss should have passed to the developer on or before delivery.

If the equipment was stored by the manufacturer, the developer should have paid for storage and insured the equipment against loss after it was considered delivered.

If payment was made at year end with delivery within 3 1/2 months, make sure that the contract was binding and identified the specific equipment being purchased. There should not have been a right to unwind the transaction and get a refund of the purchase price.

A common problem is a down payment or deposit made when the contract was signed. Equipment delivery is rarely within 3 1/2 months after such a deposit.

It was not enough merely to have started construction in time, there must also be continuous work after the year construction started. Starting construction starts a four-year clock to run on finishing the project. Under US tax rules, a project must be completed within four years after the year construction started or the developer must prove continuous work. This may be difficult to do. Any project that started work under the physical work test must prove "continuous construction." One that started based on incurring at least 5% of the project cost must prove "continuous efforts."

Be sure to investigate whether physical work was done or costs were incurred in an earlier year than the developer said construction first started.

Some developers have tried to buy more time to complete projects on which physical work started by discarding the physical work and starting over under either the physical work or 5% test. There must have been a

Common problems are where a developer failed to spot protected wetlands or someone else holds rights to subsurface minerals.

clear business reason why the earlier work was not used: for example, the project had to be moved to a different site.

Other Contracts

Contractors who build wind farms or supply equipment are already short of capacity in 2020 to take on more orders. A glut of wind farms that started construction in 2016 must be on line by the end of 2020.

Even in cases where contractors have been lined up by the seller of a project, look for a duty for the contractor to pay liquidated damages as a stick to get the work done by the deadline. A project that slips past the deadline and cannot prove continuous work will be out of luck. Tax credits may only be claimed on the electricity output from the share of the project that is put in service by the deadline.

Finger-pointing risk is inherent in all projects with more than one construction contract where the contracts are not fully wrapped. With a wind project, the turbine supplier is responsible for the turbines. A balance-of-plant contractor may erect them and build the substation and the remaining parts of the project. A prospective purchaser of development-stage projects should ensure that there are no "seams" in the contract arrangements with the turbine supplier and balance-of-plant construction contractor so that at least one of them will be responsible to fix any issue or to pay compensation.

The contracts should fit together. For example, the point of delivery under both the turbine supply agreement and BoP construction contract should be the same location, and the BoP contractor should be prepared to receive deliveries on the same schedule (and at the same rate) as the turbine supplier will deliver turbines under the turbine supply agreement.

The turbine supplier often acts as the contact operator to maintain the turbines for the period the turbines remain under warranty. The operation and maintenance agreement will typically have a performance guarantee of at least 95% to 97% availability. The liquidated damage and bonus amounts are often tied to the contracted electricity prices for the project, but a potential purchaser should ensure that the liquidated damages are adequate compensation for lost performance and there will be enough operating cash flow to pay any bonus that has been promised to the operator for exceptional output.

Force majeure events that excuse the operator should also excuse performance under the offtake contract.

A prospective purchaser may not have much say about maintenance agreements already in place, but it should understand the risks created by them. Does the contract operator have a good reputation in the market? This may be important if the project will be resold or have to be financed or refinanced.

Take note of any caps in indemnities or liquidated damages and whether there have already been payments that reduce the remaining caps.

Financing

Most wind projects have tax equity financing and some also have debt in place.

An important issue when reviewing the financing arrangements is whether there is any change-of-control restriction that would prevent the project sale.

Some change-of-control provisions only reach up to a certain corporate level, such as the first entity in the ownership chain that has substantial assets other than the project. Others go much higher, such as to a private equity owner.

Some change-of-control restrictions do not apply if the buyer meets certain pre-determined criteria, such as a financial test and an experience or ownership test.

At a minimum, notice will have to be sent to the financiers.

If consent will be needed from the financing parties for the sale, leave plenty of time.

Many financing documents require credit support from an upper-tier sponsor entity. For debt, this may take the form of a cash sweep guarantee where a sponsor parent promises a lender that it will contribute cash to pay debt service if cash from electricity sales is diverted to pay an indemnity to the tax equity investors. For tax equity, there is always a sponsor guarantee that ensures payment to the tax equity investor of indemnity claims. There may be other required guarantees or credit support.

A buyer will usually have to provide substitute security. However, in a "platform sale" of the developer together with all of its projects, it is possible that all entities providing credit support are being acquired, so the existing credit support can remain in place.

Many wind farms are financed in the tax equity market using partnership flip structures. (For more on how such transactions work, see "Partnership Flips" in the April 2017 *NewsWire*.) What happens in partnerships is more complicated than what the documents say. Complicated partnership accounting rules limit the economic benefits that a partner can pull out of the partnership. A buyer should have someone experienced at looking at partnership models review */ continued page 38*

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the updated tracking model used by the partnership to track how close the tax equity investor is to reaching its target yield. There may also be cash sweeps that divert cash to the tax equity investor. An example is where the investor is late reaching the target yield from what was expected when the deal closed. The investor may also have a right to adjustments if there is a tax law change.

Most partnership flip transactions allow the tax equity investor to sweep between 50% and 100% of cash flow to pay any unpaid indemnity claims: for example, for disallowance of tax benefits on which the investor was counting. This means what cash is distributed to the sponsor may be too little to pay debt service on any back-levered debt at the sponsor level.

The buyer should be sure to have recourse against the seller under the purchase agreement for any indemnities that must be paid to the tax equity investor because of something that happened in the past.

If there is also debt on the project or at the level of the sponsor partner, there are conditions that must be satisfied in order for the sponsor to take cash distributions. These conditions may include maintaining a minimum debt service coverage ratio. Check past performance for how close to the line the project has been performing.

Real Estate

Real estate can be the most expensive part of diligence. The project needs not only the right to be on the site, but also easements for rights of way for things like power lines and the project substation to move the electricity to market.

Common problems are where a developer failed to spot protected wetlands or where someone else holds rights to subsurface minerals and the exercise of those rights might disturb use of the surface for a wind farm. Title insurance should be in place with a "non-imputation endorsement" covering all of the land rights.

A non-imputation endorsement allows a buyer of the project to receive the full benefit of the title insurance policy by denying the title company the ability to reject coverage by imputing knowledge to the buyer that only the former owner (seller) had. Without such an endorsement, the insurer could reject a claim if the title defect was created or known by the prior owner.

The title company will require a non-imputation affidavit from the seller. Each title company has its own form. The form should be included as an exhibit to the purchase agreement or the buyer should make it a condition to closing that the seller sign an affidavit sufficient for the title company to issue a non-imputation endorsement satisfactory to the buyer.

Be on the lookout for severed wind rights. In some projects, landowners may have severed their wind rights from ownership of the underlying site. Someone other than the site owner may own the wind lease. State law is unsettled on whether wind rights can be severed. To address this, the purchase agreement should include a condition that the seller secure estoppels from any third party owner of wind rights confirming that it does not have a claim against the site owner, for example, for back payments.

Environmental and Permitting

Make sure the project site is not contaminated because anyone using the site could have to contribute to the cleanup cost. A buyer may qualify for certain defenses against liability under federal law if it did not cause the contamination or make it worse. One requirement to qualify is to have done "all appropriate inquiry" before buying the wind farm. This is usually begun by conducting a phase I environmental site assessment and, sometimes, a phase II investigation. The results of the assessments may suggest rethinking the purchase price, protections in the purchase agreement, environmental insurance or even the purchase itself.

The project must be in compliance with federal and state species and habitat protection laws, such as the Endangered Species Act, the Migratory Bird Treaty Act and the Golden Eagle Protection Act. Failure to comply with these laws can lead to significant fines, curtailment or even criminal sanction.

Other environmental statutes come into play if the project has a federal connection, such as it is on land leased from the federal government. In that case, a more involved environmental impact statement may be required under the National Environmental Policy Act. The National Historic Preservation Act requires federal agencies to "take into account the effect of the undertaking on any district, site, building structure or object that is included in or eligible for inclusion in the National Register" and consult with the state historic preservation officer. A federal permit will be required under the Clean Air Act if there will be storm water runoff during construction into US rivers or lakes.

A series of special permits may be required. These include permits where federal or state waters or wetlands may be affected, county or municipal land use permits, permits to deal with state or local noise limits, possible regulation of "shadow flicker" under state or local law, and demonstration that there are no hazards to aviation if turbines or other equipment exceed certain height limits by obtaining a "determination of no hazard to air navigation" from the Federal Aviation Administration.

The purchase agreement should have indemnities, insurance or purchase price holdbacks to address any issues.

R&W Insurance

Representations and warranty insurance is becoming more common in acquisitions.

Sellers are suggesting that buyers rely solely on it rather than make claims against the seller or require a cash escrow or holdback to cover potential claims. This is particularly common where the seller is a private equity fund that will want to distribute the full sales proceeds immediately to its investors.

R&W insurance does not cover breaches of covenants by the seller.

Offering to purchase R&W insurance could enhance a bidder's position in a competitive auction. R&W insurance could also help in the future when some of the sellers will remain part of the management team by reducing internal friction if there ultimately ends up being a claim for a breach of a representation.

The cost of such insurance may be below 3% of coverage limits with deductibles of 1% of deal value or less, depending on the size of the transaction. The buyer often pays the insurance premium because it is purchasing the policy, but sometimes the buyer and seller split the cost.

An R&W policy can be bound in as little as a week. Two to three weeks is more typical, but it is not uncommon for it to take longer when there is a large portfolio requiring a significant amount of diligence. During the underwriting phase, the underwriter will review the purchase agreement and due diligence reports or memos. The underwriter will usually want a call with the buyer and its advisers to go over the diligence in detail. The buyer and its advisers should spend time preparing for the call.

Transaction Structure

The seller usually wants to sell a legal entity.

The buyer would prefer to buy assets so that its purchase price can be reflected in the tax basis in the assets and can be recovered through depreciation. Another reason to buy assets is to avoid inheriting any legal liabilities at the entity level.

Buying assets may not be possible where it would require transferring permits and contracts. The buyer should also be able to have its purchase price be reflected in asset basis by buying an entity that is fiscally transparent for tax purposes.

In a "platform sale," where an existing wind development company, including employees and management, is being purchased, the transaction may take the form of a merger in order to force all the owners to sell. With a merger, as long as equity owners that hold at least 51% of the equity approve the merger, then the transaction will close even if some equity owners are opposed, the target will merge with an acquiring company, with one of the entities remaining and the other ceasing to exist. The merger will be called a reverse or forward subsidiary merger, depending on which of the merged companies survives.

Anyone using a contaminated site may have to contribute to the cleanup cost.

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Filings

The buyer may have to make various government filings.

Foreign buyers must consider whether to make a filing with a US government committee that reviews inbound investments in US companies or projects that may have national security implications. Most filings are voluntary, but the danger of not filing is the government can force the investment to be unwound later. The committee — called CFIUS for Committee on Foreign Investment in the United States — historically has reviewed transactions in which a foreign person gains control over a US trade or business. However, Congress expanded its authority in 2018 to cover acquisitions of certain non-controlling interests and to make filings mandatory for certain types of transactions. Deals involving critical technology and critical infrastructure are subject to heightened scrutiny and may be subject to a mandatory filing. (For more information, see "US to Review More Inbound Investments" in the August 2018 *NewsWire* and "CFIUS and China" in the February 2018 *NewsWire*.)

A filing may also be required with the US Department of Agriculture if the project is on farmland. The Agricultural Foreign Investment Disclosure Act, or AFIDA, requires foreign companies, and US companies in which a foreigner has a significant interest or substantial control, to report transfers of interests, including leases, in US farmland. There are significant fines for failure to comply. Several US states also have limits on the amount of land a foreign entity can own, while others ban foreign ownership of agricultural land completely.

A section 203 filing may be required with the Federal Energy Regulatory Commission. Such filings are required before any operating wind farm that is 30 megawatts or larger in size can be transferred. A transfer of 10% or more of the direct or indirect equity interests triggers an obligation to file. Jurisdictional facilities requiring such filings include physical assets such as the interconnection facilities associated with a wind project and "paper facilities" such as a project company's FERC-approved tariff. Federal filings are not required for assets in most of Texas. FERC usually clears the transaction within 30 and 60 days where a transfer is uncontested.

Finally, the Hart-Scott-Rodino Act requires parties to a transaction that is larger than a certain size to notify both the Federal Trade Commission and the US Department of Justice and to wait out a statutory waiting period (usually 30 calendar days) before closing on the transaction. The size thresholds are adjusted annually based on changes in the gross national product. The filing obligation is triggered currently if the transaction value is more than $90 million, either the acquiring or the acquired party has annual sales or total assets of at least $180 million, and the other party to the transaction has annual sales or total assets of at least $18 million. There are various exemptions that may apply. An exemption that commonly applies to wind farms that are under development and have not generated any revenue is the exemption for "unproductive real property." This exemption would not apply to an acquisition of an operating wind farm or one that is on the verge of beginning operations. ◎

Raising Capital in a Market in Transition

Capital is usually harder to raise during periods of uncertainty about government policy. Lenders and investors adjust to changes in the market itself. The taps are wide open this time through both mild policy uncertainty and significant market changes. The first panel at the annual Renewable Energy Finance Forum in New York in late June talked about why, and how the various sources of capital are adapting. The following is an edited transcript.

The panelists are Ted Brandt, CEO of Marathon Capital, Catherine Helleux, head of transactions in the Americas for Allianz Global Investors, Andrew Redinger, managing director and group of head of project finance at KeyBanc Capital Markets, and Himanshu Saxena, CEO of the Starwood Energy Group. The moderator is Keith Martin with Norton Rose Fulbright in Washington.

MR. MARTIN: Greg Wetstone, in his presentation immediately before this panel, talked about some of the transitions currently underway in the market. We are moving to a corporate PPA and hedge market. The tax credits for wind and solar are phasing out. Storage is coming; we haven't yet reached a tipping point, but you can see it coming. The customer base is moving in places like California away from the utilities to community choice aggregators. Eventually blockchain may displace them. The shift to electric vehicles has the potential to increase demand for electricity.

Are there any trends to add to this list?

MR. SAXENA: Did you say data centers?

MR. MARTIN: I did not. What about them?

MR. SAXENA: I think they may be a very significant source of demand going forward. Microsoft says it is building a data center a month in some parts of the world. I see that as a pretty significant demand driver, especially for renewables because they want to connect these to renewable energy. All the cat videos that people are putting out use a lot of space. [Laughter]

MR. MARTIN: Any other contributions to the list? What about cryptocurrency? Bitcoin uses an enormous amount of electricity through data mining.

In a market that is in transition, one would think raising capital would be more difficult, and yet it is not. Why not?

Awash in Capital

MR. BRANDT: There just seems to be a tremendous amount of it. The volume is overwhelming.

MR. MARTIN: Is the fact that we are awash in liquidity a sign that we are so affluent that we don't know what to do with our money?

MR. BRANDT: I don't know that liquidity and affluence are the same thing. I think what we are seeing is the logical result of about 11 years of accommodative central bank policy. There has not been a lot of tightening. Institutional investors tell us they are not making much on their fixed-income investments. Many think that public equities are nearing the peak, so they are allocating money away from those two buckets and into infrastructure. Billions and billions of dollars have been raised to look for real rates of return around the world in the developed economies.

MS. HELLEUX: There is indeed a lot of money being raised, but the fact that it is deployed means there is a need. It would be an issue if the money were raised and sat dormant. There are a few markets where the deployment is a little bit slow, but all this capital finds a home.

MR. SAXENA: There is about $130 billion of private capital that is being raised currently. For example, Blackstone is raising a $40 billion infrastructure fund. GIP has just raised a $20 billion fund. Stonepeak has just raised a $7.5 billion dollar fund. These are US-based investors that are investing fairly large amounts of capital. Brookfield led another $20 billion. Capital Dynamics has just raised a fund.

Not all of the $130 billion is dedicated to renewable energy, but a significant portion is. There are not enough assets to go around for this much capital, and that is showing up in a pretty significant compression in discount rates.

MR. MARTIN: But there must be something right about renewables because the money is not going to the areas of greatest need. We are not rebuilding our bridges or our crumbling roads.

MS. HELLEUX: A bridge is a little bit more exposed to the highs and lows of economic cycles. And most such projects have a government entity as opposed to a private offtaker as a counterparty to the revenue contract.

MR. MARTIN: *The Financial Times* reported yesterday that there are $12 trillion in government bonds that are now paying a negative yield. People are paying governments to take their money. Is that affirmation that there is too / *continued page 42*

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much money sloshing around, or what does it say?

MR. BRANDT: The investors putting their money into such bonds are largely in Europe and Japan. There is a clear fear of deflation in those economies. You don't see that in the United States because people believe that inflation still will be a positive number. The 10-year treasury bond pays about 2.1%, in an economy with an expected inflation rate a little over 2%, so the rates of return are still about zero. It is all about the inflation-deflation expectations.

Financing Merchant Revenue

MR. MARTIN: So if you are going to have a transition, when it would normally be tough to raise money, it is good to do it while there is so much money that you don't feel the pain.

One of the other transitions we did not talk about is getting used to doing business on a trampoline with a slightly overweight 70-year old bouncing up and down while you are negotiating deals. Let's drill down into some of these issues.

Andy Redinger, you said famously a couple years ago that you have been trying to persuade KeyBank that it should be willing to finance projects that are wholly merchant because, after all, it finances McDonald's hamburger stores and they don't have forward hamburger sales agreements. How is that coming? [Laughter]

MR. REDINGER: It's actually coming along very well. But the point of that statement is that we finance lots of industries that don't presell their output. The energy sector is interesting in that financial institutions like mine usually require project owners to presell their output. I was always frustrated by that.

We are able to finance merchant. Everyone says that's great, but they want the same terms for merchant as for financing contracted projects. KeyBank can finance merchant projects, but we can do it at three or four times leverage on EBITDA. We do not finance merchant projects under the same structure that we are financing contracted projects, so it is coming along very well. It is just the market will not accept when I say, "Listen, we'll do merchant, but it is three times EBITDA." The developers say, "Okay, but that means less debt. How do we fill the hole?" And I look at the equity and say, "Okay, it's you." And they say, "No, I can't do that."

So there's a little back and forth going on.

MR. MARTIN: Is McDonald's an appropriate analogy? The average store sells 167,000 Big Macs a year. It has a diverse customer base. Power projects have a single off-taker.

MR. REDINGER: My definition of merchant is you are selling into a broad and very liquid marketplace. A merchant project is selling into a liquid market every day to many buyers.

MR. MARTIN: If we move to blockchain as a way to sell electricity, would that open up more financing. Maybe not three times EBITDA, but less?

MR. REDINGER: I think so.

Longer Merchant Tails

MR. MARTIN: Himanshu Saxena, you said a couple weeks ago that in the shorter-term PPAs, you end up getting back maybe only 30% of your capital by the end of the power contract. That's a problem. How common is it?

MR. SAXENA: What we are seeing is a transition. Corporate PPAs used to be 15 years. Now they are 12 years. RFPs today propose PPA terms of anywhere from seven to 15 years. For solar PPAs, the suggested contract terms are getting even shorter, on the order of five to seven years.

The electricity price is going down and the tenor is getting shorter. If you were to do a calculation of what is the ratio of your contracted cash flows to merchant cash flows over the life of the asset, let's say 30 to 35 years, those ratios are shrinking very significantly.

The project may look contracted for 12 years, but if you look at the cash flows over the entire 35 years, they are close to 80% to 85% merchant and 15% contracted, and that is effectively putting a lot more risk on equity than it has had in the past. Equity is taking a risk of the forward price curve for power. There are obviously many consultants willing to advise on where the power curve is headed, but there is significant risk. The merchant tails are getting longer.

All the investments that are being made on the equity side are betting on the price of power remaining strong. These assets are not dispatchable so, in many cases, you are not benefiting from the volatility of the markets like you can with a merchant gas-fired power plant in PJM. Most of the time, you are effectively just long power with an uncertain shape.

New 25-year contracts are simply not available. We sold a transmission line with a 20-year contract recently. We had 76 non-disclosure agreements signed on that deal, so the demand is immense for contracted cash flows, but it is hard to get your invested capital back during the contract term for the newer contracts that are on offer in the market, which means that a return on that capital is effectively coming almost entirely from the merchant cash flows. That is the new business we are in. We are all in the merchant business.

MR. MARTIN: Catherine Helleux, you are investing equity or attempting to do so. This suggests you are taking a lot more risks. Are you able to find returns commensurate with the risk?

MS. HELLEUX: Even if you find a 25-year PPA, the return will be low, so it is better to go to the extra risk of merchant, as it comes with an extra return, as it should. That is really becoming the market now.

There is a market for refinancing de-risked assets that are operating under long-term PPAs with a decent price where there is a need for fresh capital. There is a separate market where people are adding greenfield capacity to the grid and, like Himanshu said, it is really tough to isolate those assets from some level of merchant exposure.

MR. MARTIN: Michael Polsky said last year that if you don't get your capital back by the end of your power contract, you will never get it back fully. Does anyone agree with that statement?

MS. HELLEUX: I hope the industry as a whole disagrees. Otherwise, we are not going to see a lot of megawatts built this year.

MR. MARTIN: Fair enough. So the power contract terms are shortening. How are the capital markets responding?

Tax equity investors are still insisting on contracted revenue for the period they are in the deal.

MR. BRANDT: Tax equity is still insisting on a contract for the pertinent horizon that it is in the deal, so you are seeing a minimum 10-year corporate PPA for a wind deal on which production tax credits will be claimed.

It is interesting to watch the Texas solar market. There, people are testing how long a hedge is required. They are looking at hedges of something like 6.5 years. I think the economics are reasonably compelling to go pure merchant if you look at the forward price curves, but you would have to go with tax equity or do an internal hedge.

MR. MARTIN: Andy Redinger, how are the banks responding to shorter contract terms?

MR. REDINGER: The spreads or margins have tightened pretty dramatically in the last 12 months. The banks are providing more leverage and getting less margin, which doesn't make sense, but that is what the bank market is doing because there is intense competition for projects, and the market right now is valuing banks on loan growth. So to get a higher stock price, banks need to make more loans.

The other response is we are getting pushed to make up the hole in the capital stack as the market moves to shorter contract terms and to do other things around the loan structure to get more leverage in the deal.

Debt Terms

MR. MARTIN: Are you seeing sub-100-basis-point construction debt?

MR. REDINGER: Yes. That's pretty common.

MR. MARTIN: How low?

MR. REDINGER: I think 75 is probably center fairway.

MR. MARTIN: Center of the fairway. 75? So that suggests there are loans below that.

MR. REDINGER: There could be. Yes.

MR. MARTIN: And permanent debt, 137.5 basis points over LIBOR? 175 over?

MR. REDINGER: I hate quoting all this stuff. We are doing twice as much business as we did two years ago from a loan volume perspective.

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MR. MARTIN: But earning less.

MR. REDINGER: We are earning less. Those numbers you quoted are pretty accurate. Maybe an eighth lower.

MR. MARTIN: Fred Allen was a radio comedian in the 1940s. He had a down-east Maine character to whom he used to talk. The character told him he bought a pig for $100 at the start of the year and sold it for $80 at the end of the year. Fred Allen said, "Well, that's terrible." The Maine farmer said, "Weren't bad. I had the use of the pig all year." This sounds a little like what the lenders are doing.

MR. MARTIN: Himanshu, how relevant are the lenders to the structure of the deal? Who is driving the bus on structure at this point?

MR. SAXENA: It feels great to talk about 75 basis points, 72.5 or 93.24, but it doesn't make a difference. The construction tenor is so short: less than 12 months. If you look at the financial model and say, "I borrowed 70% at 11 basis points cheaper for a year" the savings would pay for lunch. It has almost become a game where the lenders say, "We can give you 75 basis points above LIBOR." We say, "Fine." It doesn't make a difference. If it was a longer-tenor debt, then the pricing matters.

Really the driver on deal structure in the current market is tax equity. In my mind, tax equity pricing is still very high, and we love our tax equity friends in the room, but why are you so expensive? [Laughter] We are seeing pricing in the 7% and 8% range for the part of the capital stack that takes the least risk.

Meanwhile, we have seen return compression for everybody else. Debt is free. Equity is practically free. Tax equity is super expensive. I wish I had tax appetite. I would start doing tax equity investments because, on a risk-adjusted basis, that is the best part of the capital structure.

The other thing that is driving the market is the phase out of tax credits for renewable energy. There is no reason why folks should be building some of these wind farms and solar projects that are taking this much merchant risk. A lot of people are doing it because it's like the ads on late-night TV shows: If you order within the next hour, we will cancel one of your four payments. And right now, the federal government is cancelling one of the four payments. People are making investments because of the tax credits. Capitalization of these deals used to be 60% tax equity and the balance cash equity and back-levered debt. It is starting to look like 80% tax equity.

MR. MARTIN: Is that solar?

MR. SAXENA: We have seen this for solar and wind. Wind PPA prices are down to $15 and $16 a megawatt hour. In one case, I saw a $9 price for a hedge that would not cover the variable cost to operate the project.

I am begging all of the developers to stop signing these PPAs that you cannot deliver. Stop signing these hedges you can't deliver. Xcel has come to the market twice to replace PPAs on which the developers could not deliver.

The sad irony is that there are still investors that are buying such projects. At some point, the music will stop, and I am hoping the tax credits go away and then rationality will return to the market and the PPA prices go up to a point where projects are financeable without the tax credits. If you keep doing deals where nobody makes money, at some point the market will break.

MR. BRANDT: You can tell Himanshu was on a red-eye last night. [Laughter]

MR. REDINGER: Can I make the point, there is still a lot of profit in development, so it is not all dire.

MR. SAXENA: I said this in another conference. We should all wear t-shirts that say, "Who needs returns when you have solar?" [Laughter]

MR. MARTIN: Your fellow panelists are voting you off the island. [Laughter]

Andy Redinger, let me come back to you. So we are shortening the PPA terms. We have crappy prices according to Himanshu. So far it seems that lenders are willing to lend on shorter terms, but they will credit only two or three years of merchant tail revenue, is that correct?

MR. REDINGER: It varies by developer, but yes, that's typically correct. As I said, I have seen as many as five years. We will do merchant all day long, but we cannot provide the same quantum of debt as if the revenue stream were contracted.

MR. MARTIN: What happens when the power contracts go to five-year terms?

MR. REDINGER: The tenor of the contracts determines the amount of debt, so there will be less debt, and the equity or some other person in the capital stack has to fill the gap.

MR. MARTIN: You will discount the post-five year revenue stream, but just use a higher discount rate, correct?

MR. REDINGER: Yes, we would do that.

MR. MARTIN: How do the debt service coverage ratios change as the power contract term shortens?

MR. REDINGER: To be honest with you, I don't think they would change at all. There will just be less debt. We look at it differently. There will be less debt, with the amount determined as a multiple of EBITDA, versus the amount determined by discounting the contracted revenue over 20 years at some DSCR coverage ratio.

MR. MARTIN: Some lenders are saying now that the spreads and fees are so low on single-asset renewable energy deals that they just can't compete, so they are more interested in merchant gas projects and portfolio financings of renewable energy projects where the risk is more in line with the yield.

Catherine Helleux, where is the best risk-adjusted return currently for an equity investor?

MS. HELLEUX: In the greenfield market. We also see pockets of opportunity to grab a little bit more yield without adding appreciably to risk by financing emerging technologies like storage.

Asset Shoppers

MR. MARTIN: So low yields are driving capital to places where it is really needed to help develop new technologies. Ted Brandt, you said before this that the M&A market felt a little different this year. People are coming to the market with a particular shopping list. They are not going to put their money into a blind pool.

MR. BRANDT: What we are watching is people coming in after studying the market and saying, "We want to buy a solar C&I company," or, "We want to buy a utility-scale wind developer," and they have very specific shopping lists as opposed to satchels full of Euros or Yens as in previous years effectively wanting in on the market and not being specific in terms of targets.

MR. MARTIN: What discount rates are successful bidders using to buy contracted solar or wind projects?

MR. BRANDT: That is a hard question to answer because these are 35-year assets that may have contracted revenue of only 10 to 15 years. We are seeing use increasingly of dual discount rates. A low discount rate of maybe 6% or 6.5% might be used to discount the contracted-period revenues from a solar project, and a 10%, 11% or 12% discount rate used to discount the merchant cash flows.

Overall, this works out to something like a leveraged 8% rate for solar and a leveraged 9% or 9.25% for wind for the whole period.

MR. MARTIN: So it seems like still a good time to sell. There is not a wide buy-sell spread that would keep deals from closing. The offer prices are satisfactory to the sellers.

MR. BRANDT: There is still a lot of liquidity. Sellers are getting their prices. Bidders are bidding aggressively. I think it is still a very good time to sell. In particular, it is great to be selling not just operating assets, but also pipelines of development assets.

MR. MARTIN: In the interest of full disclosure, you are usually on the sell side, correct?

MR. BRANDT: Usually, yes.

MR. MARTIN: There may be others in the audience on the buy side who would say the discount rates should be higher, so they would pay less. Perhaps?

MR. BRANDT: Well, Himanshu would always say that. [Laughter]

Deal Volume

MR. MARTIN: Let me shift gears. Another transition is the phase-out of tax credits. Greg Wetstone put up statistics that showed 2018 was a pretty strong year in terms of renewables deployment. How does 2019 feel to those of you who are deploying capital?

MR. REDINGER: Better than last year. And I think 2020 will be better than 2019, so as we look forward, there is a lot of activity. It's just that we are making a lot less money.

MR. MARTIN: How does it compare to 2009 when it seemed like the market had gotten on a treadmill turned up to warp speed?

MR. REDINGER: It does not feel like we are overheated.

MR. SAXENA: I think that 2009 is so far away. From what we see right now, 2019 and 2020 are probably 20,000-megawatt markets for wind. That is what the wind turbine suppliers are telling us. They expect to install 20,000 megawatts this year, 20,000 megawatts next year, and then it will go down. And if you do the math, building 20,000 megawatts at somewhere near a cost of $1.2 million an installed megawatt requires a $24 billion investment. We are talking something close to $40 to $50 billion in investment in wind over the next two years. Add solar and the figures are much higher.

After Tax Credits

MR. MARTIN: A lot of people think that when the tax credits go away, the bidding down of electricity prices will stop. Is that a realistic assumption given how much competition there is for power contracts?

MR. SAXENA: I think we already see that PPA pricing for 2021 projects is turning up somewhat from 2020 deliveries. The PTC is currently $25 a megawatt hour. As you roll projects forward past 2020, there is loss of 20% of the PTC value each year, so say

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$4 to $5 a megawatt hour. Roll it forward another year to 2022 and that's another $4 to $5. Who covers the loss is the question.

Equity returns are already super low, so there is not a lot of room there. You can't squeeze much out of lenders, so your capital structures have to change. Maybe there is more debt and less tax equity. Every party, whether it is the construction contractor or turbine supplier or PPA counterparty, will to have to reach into its pockets to make the numbers work. We see an upward pressure in PPA pricing already for 2021 projects.

Construction debt is pricing at 75 basis points over LIBOR.

MR. MARTIN: Catherine Helleux and Ted Brandt, if tax equity remains for solar, because there is a permanent 10% investment tax credit, but the tax credits have disappeared for wind, how will that affect the relative attractiveness of those two investments?

MS. HELLEUX: We see such a rush currently for wind that, in a few years, there will be so much wind added to the grid that solar will be lagging behind, and with the benefit of a flat, clean 10% ITC, we should expect more capital going into solar.

The current rush to wind is occurring in the most unhealthy way. Wind turbine prices have been bid up in the rush to stockpile equipment to start construction of projects. EPC contracts are overpriced because of artificial demand to finish projects to comply with tax deadlines.

MR. MARTIN: Ted Brandt, how does the disappearance of tax credits affect the value of project portfolios, if at all?

MR. BRANDT: I think Catherine is exactly right. We are seeing more and more developer energy and capital moving toward solar and away from onshore wind.

MR. MARTIN: Is that because solar is more competitive, or do the tax subsidies play a role?

MR. BRANDT: It is a little of both. When you look at the subsidized levelized cost of energy of solar, it is getting cheaper and is correlated with load. A lot of markets — Texas, for example — are pretty flush with wind, but there are still some interesting opportunities, and solar is still pretty nascent. We are clearly seeing much more emphasis on solar.

From an M&A standpoint, wind developers are still valuable because they have all effectively been consolidated with one or two exceptions, so they are fewer in number. Solar is a bit more of a commodity. If I am selling a contracted project, I would probably rather be looking forward at solar.

MR. MARTIN: Gabriel Alonso, former CEO of EDP Renewables, said several years ago that there are two things his grandmother can do: one is develop a wind farm in Texas, and the other is develop a solar project anywhere in the country. That speaks to the low barriers to entry in the solar market. What happens as tax equity becomes a smaller part of the solar capital stack and the wind tax credits disappear? What happens to the cost of capital for the solar market?

MR. BRANDT: That's an interesting analytical question. I think you will see more developers keep the 10% tax credit to carry forward and self-shelter. I also think that you will see leveraged tax equity that we have not seen for about 15 years.

MR. REDINGER: I have a hard time seeing the cost of capital change. I'm with Himanshu. I think what happens is power prices increase. I think capital stays the same. It has to. I think that the pressure is on power prices, because capital has been pretty much beaten down to the minimum we can accept. The only possible movement here is in tax equity yields. Tax equity has never been beaten up. They are getting 400 basis points more in return than I am, and I am taking a lot more risk. I like to say tax equity is super senior debt, and they are getting 400 basis points more, but I am going to get off my soapbox. I did not take a red-eye last night.

MR. MARTIN: Himanshu Saxena, this is your favorite soapbox.

MR. SAXENA: We love tax equity. They're the best. [Laughter]

Look, I think if you want to see what happens when tax credits go away, just go south of the border and look at what is happening in Mexico. That is a live case study. CFE 20-year contracts were being priced at $20 a megawatt hour. I am talking about prices in the third auction. Those deals were highly financeable with 80% debt-to-equity ratios. Pricing on debt was in the 200s above LIBOR, because there is a bit of a country premium. A lot of European investors did these deals. I don't know how anybody makes money on a $20 PPA, but those deals were getting done.

Now you are seeing deals that are being done on a merchant basis in Mexico. Every other deal we see today in Mexico is merchant solar or merchant wind and, in many cases, projects are going completely merchant and the lenders are financing them. They are talking about 50% debt to equity. The pricing is higher, but the market is taking a view that it is a growing economy with 46,000 megawatts of expected power demand in the next 10 years. There is more risk, but is it any more risk than taking views on the value of energy in year 16 through year 35 in Texas? Or in California, where nobody knows how the markets will look in year 16?

Storage

MR. MARTIN: So Mexico is the future for us in terms of how a market works without tax subsidies.

Let's switch gears. I have two remaining questions. One of the transitions we are undergoing is to storage. Storage seems to add about a penny a kilowatt hour to the cost of a project. Does it feel like we are at a tipping point already? If not, does such a tipping point seem close, where all projects will be bid with storage?

MR. BRANDT: I would say 80% of the deals that we are seeing today are solar-plus-storage. Pretty much every solicitation for electricity has a solar option, so I think we are close to a tipping point.

MR. MARTIN: What complications does adding storage make for financing a project, if any?

MS. HELLEUX: Finding lenders that are ready to finance it can be challenging. Banks exist that have the mandate and knowledge of the technology. If your deal is small enough so you don't need all the banks, you need one or two, there is not really an issue. Anything larger may still be a challenge.

From a purely investor perspective, you have to make sure it fits in your mandate. Sometimes we go back to the old question: what is "infrastructure"? Is battery storage infrastructure? Does it make a difference whether it is behind or in front of the meter?

MR. MARTIN: Fair enough. Audience, any questions?

MS. NICKEY: Susan Nickey with Hannon Armstrong Sustainable Infrastructure. We have been talking about how tight a lot of these PPA bids are. Are you seeing import tariffs lead to project cancellations or to projects not being financeable?

MR. BRANDT: I can only say anecdotally that we hear from developers that they are surprised how expensive panel pricing is. We are hearing about acute supply shortages of bifacial panels. We are hearing about some deals that just aren't going to get done. I would say the impacts of tariffs are real.

MR. MARTIN: Last question, as we are at the end of our time. The theme this year is transition and raising capital during a period of change. What do you think we will be talking about next year?

MR. BRANDT: Elections.

MR. MARTIN: Probably. Anything else?

MS. HELLEUX: Even more focused investments.

MR. SAXENA: There may be more distributed generation. It is one of those things whose time is always still to come, but we continue to inch in that direction.

MR. MARTIN: C&I distributed? We already have a lot of residential rooftop solar.

MR. SAXENA: Small-scale distributed generation and more energy efficiency. We would like to make investments in that part of the business, and we don't know how because the opportunities are not there yet, but I think they are coming.

MR. MARTIN: Andy Redinger, you have been remarkably consistent from year to year. One of your themes has been yield cos. Will the return of yield cos in the United States be a theme next year?

MR. REDINGER: I was going to offer two themes. One is residential solar. Our business has changed so much to a point where it is distributed, distributed, distributed. A question was asked earlier, where's the bang for the buck? It is absolutely in residential solar.

MR. MARTIN: That is where Key is putting its resources at this moment?

MR. REDINGER: As much as we can. There are still very good risk-adjusted returns in that market segment. And yes, yield co 3.0. US-based companies are going public on the London exchange in US dollars, and it is starting to look like the yield co phenomenon of a few years ago. They are tapping into the investor base in Europe. ◎

Storage Versus Gas

Developers are pushing ahead with more gas-fired power projects, and lenders stand ready to finance them, but equity may be in short supply. What is the outlook for further development? What about gas peakers? Energy storage can provide the same service more cheaply and is already eating the lunch of gas peakers in California. Will it do the same in other parts of the country? A group debated these issues at the 30th annual global energy and finance conference in California in June. The following is an edited transcript.

The panelists are Ross Ain, president of Caithness Energy, Randolph Mann, president of esVolta, Rob Morgan, CEO of GE Energy Storage, and Joe Tondu, president of Tondu Corporation. The moderator is Caileen Kateri ("Kat") Gamache with Norton Rose Fulbright in Washington.

MS. GAMACHE: Ross Ain, what reception are you getting from financiers for new gas-fired power plants?

MR. AIN: Caithness is in the market with two very large gas plants. One is an 1,850-megawatt combined-cycle plant, three units in Guernsey County, Ohio, and the other is a 620-megawatt combined-cycle plant in Harrison County, West Virginia.

There are ways to attract all levels of the capital structure with a properly structured project. We have been able to achieve that by making innovative use of gas-electric hedges.

The plant we brought on line in September last year, an 1,050-megawatt project called the Caithness Freedom project, used a gas-electric hedge over 10 years that assures us of always being in the money on our energy sales. That takes a lot of risk out of the project and made it possible to attract both the debt and equity needed to move forward.

MS. GAMACHE: There are concerns about the long-term viability of natural gas as a fuel in New England because of constraints on pipeline capacity. That said, Seth Shortlidge, CEO of NTE Energy, who was scheduled to join us today, was called to New England in connection with a natural gas plant in New England. Are there particular regions that are better for natural gas and better for storage, and why?

MR. TONDU: Definitely. Obviously if you are in Texas, natural gas is a different game than if you are in New York. The drivers ultimately are going to be economic. There is lots of opposition to construction of new gas pipelines because there are people in this world who think they can predict weather a hundred years from now within two degrees. Well, okay.

I believe you are going to find there are gas reserves just about everywhere that can serve a lateral market. You have upstate New York, Ohio, Pennsylvania, and a grid system that covers the entire eastern half of the country.

It is difficult to find a place where we can't put a lot of gas on the ground right now.

I drilled gas wells in the late 1970s when we were selling gas for $6 a million Btus. We had no thought that it would ever go down.

Today you can see the future for 15 to 20 years at sub-$3 gas. When somebody starts to get competitive on price, those Aggie engineers will drive it down another 25¢. It is unbelievable what they have done in the last 10 years in the industry.

MR. AIN: Location is critical in the gas market, but there are a couple factors that come into play. Number one, there is a lot of gas. The producers say, "We are not discovering gas, we are just manufacturing gas. We know it's there. We are just moving the rig over when the rig finishes the spot it's in." They are doing three-mile laterals now under the ground.

The amount of gas in the Utica and Marcellus region, where I'm most familiar, is enormous. The critical thing is pipelines. And what you want to do as a developer of an electric generating project is locate where the gas producer will avoid significant pipeline costs to move the gas to market.

So these projects become, in a sense, mine-mouth gas plants. They avoid the new cost of 75¢ to $1.50 that we saw yesterday in new fixed charges on interstate pipelines moving the gas to Henry Hub or moving the gas up to New York City or some other place like Chicago.

Our Freedom project is located next to three Transco lines. Our project in Ohio is located right on top of the Rocky Express 42-inch 1,000-psi line. There is a lot of gas in those lines, and there will be a lot of gas for a long time.

Our company and our investors are very confident that we have a long-term gas supply available to the project.

Turbulence Ahead

MR. MORGAN: Sometimes that conversation is like having the system operator run the unconstrained dispatch model.

If we had no constraints, we would do "x." We have constraints in the system. We can call them policy. We can call them carbon. We can call them other things. Those constraints, say, "Maybe we should do something different." That's where I think battery energy storage comes in. Right now, batteries have won the race.

Storage developers look for places where congestion, power plant retirements or duck curves suggest storage capacity will have value.

Just like the old Betamax-VHS discussion. Lithium-ion batteries are good enough for all the things the system is asking us to do right now. If you run the constraint-dispatch model, you do things differently. So policy matters, too.

MS. GAMACHE: Are you battery storage companies focusing on transmission systems that have a lot of congestion?

MR. MORGAN: Transmission is one. You have distribution. You have markets like California that say, "We have a mandate." And then you start to look at where the market rules and the compensation mechanisms are moving toward paying for the service that a fast response, safe non-polluting asset provides.

MR. MANN: As a storage developer, I spend a lot of time trolling the internet, looking for click-bait, and it is not "Keeping Up With the Kardashians," it is usually "Keeping Up With Retirements." We are looking for places where renewable penetration is increasing, where fossil fuel and nuclear plants are retiring, and where new capacity will have value.

Storage is a perfect technology for that type of situation. It is why California has been a very interesting market because we are seeing a very high penetration of photovoltaic solar. You are seeing nuclear retire. You are seeing fossil fuel have a tough time competing, and so storage is really coming to the fore and becoming a critical part of the grid here.

MR. AIN: In southern California, you have a unique convergence of events that has pushed storage to the fore. Number one, you had no air credits available in the LA basin, so no new fossil fuel units could be built. The only ones that could be built were repowers of old ones where they already had the air credits.

Number two, new transmission lines were practically impossible to site in the dense LA basin.

Number three, you have the duck curve and essentially the free charging of batteries in the afternoon.

Those three factors are critical to why batteries have had a very good jump start to all of our benefit in southern California.

The question as we move to other parts of the country, is whether there is enough of an advantage from the cost savings and the experience with batteries to make them competitive with other forms of energy.

MR. MANN: You are absolutely right. There are certain advantages in California that made storage grow rapidly here.

One slide stood out in the opening presentation yesterday morning: the wholesale power market price in three or four markets is in the $20-a-megawatt hour range and operating costs of coal, gas and nuclear are in the $30s, $40s and $50s.

Then you realize that the cost of wind and solar is going to keep falling, and the cost of storage will keep falling, too. We talked for an hour yesterday about the growth of the electric vehicle market. That market is really driving big manufacturing into battery cell manufacturing, which is driving down the cost of grid storage. So to me, the trends are headed inexorably in that direction.

I agree that some markets will get there much more slowly than others, but I think the long-term trend is toward zero-marginal-cost renewable energy setting the marginal cost. You still need capacity, and batteries can make money even when power prices are negative. */ continued page 50*

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MR. MORGAN: You make a great point. If you think about the grid business, we are a small portion of what batteries are doing across the world.

Look just at China. Last year China sold a million electric vehicles, the first time a market has reached a million. If you do a million electric vehicles times a 50-kilowatt-hour battery per vehicle, that is 50 gigawatt hours. A big storage project is one gigawatt hour.

We are the tail of the dog. We get to have all the benefits of that, but sometimes we don't get the attention we deserve because we are trying to drive cost down for wholesale rather than retail prices.

For a sense of scale, the electric utility industry worldwide will probably only be 10% of the battery market worldwide.

Battery Economics

MR. TONDU: Let me ask one thing. I don't really understand the battery business. I don't know the economics. My concept of a battery I think is wrong. And I don't know how many people here really understand it.

The fact that they are being used in California tells me nothing about the economics. And when somebody says it will be free, the red flags go off in all directions for me.

It seems to me that batteries have a unique spot in the market. When I think of a battery, I think we will run the power plant all night long to charge it, and it will discharge the stored electricity to the grid all day long the next day, and we do that back and forth.

But in reality, they are really unique little spotty moments in time when you fire them up to give yourself ancillary services or you give yourself quick start-ups.

What is the market for batteries? What is the optimum looking little spot for which they fill a niche?

MR. MANN: Fair question. The answer is it really depends. There are a lot of different use cases. Our typical customer is a utility. Sometimes the utility is looking for help with its transmission and distribution system, so it adds storage to a feeder line or a substation in order to manage load growth at that location. Other times it is looking for peaking capacity inside of a load pocket in an area where you cannot site a gas plant or transmission, but it wants to bolster the area with peaking capacity. Other times, storage is really a tool for integrating renewable energy.

Our biggest project to date was for a utility that was trying to retire a natural gas plant and replace the capacity.

The way we are getting paid is a capacity payment, plus an ancillary service value plus an energy arbitrage value.

The storage facility that we operate in California essentially operates 24-7 in one of those modes. Sometimes it is providing regulation-up services, and sometimes it is providing reg-down, depending on what solar and gas are doing in the state. Sometimes we are trading on the margin to earn an arbitrage return. We can sell one type of capability to a utility customer and another type into the wholesale market.

MR. MORGAN: I want to challenge the notion of little spotty moments.

It really depends on the market. The kinds of services that energy storage provides have been embedded in the utility system forever; you have spinning machinery, you have generators, etc.

As we have restructured and de-structured markets, we are getting to a resolution on the different services that is really interesting. It is kind of all of the above. You can provide three services at once as opposed to one at a time.

The whole conversation today about whether storage will displace gas peakers: well, sure. In California, storage is displacing peakers. Elsewhere, in Texas, not

Batteries can make money even when power prices are negative.

yet. In Australia, we are doing solar-plus-storage, and in New York, we are doing solar-plus-storage because that is what the market is asking for. I just challenge that notion that is has a little spot. No, it has a big spot in the market.

Spotty Little Moments

MR. TONDU: How unique of a circumstance do you need to have to make it work?

For example, in Texas, one of the ideas that we talked about earlier was that you can put storage on a gas turbine project so that you can have instantaneous output during the four to seven minutes it takes the turbine to ramp up.

Well, that is interesting in an environment where you have big swings in power where, all of the sudden, you need 60 megawatts or you need 10 megawatts. In Texas, you have that problem non-stop because you have so much wind that you are on and off, on and off, on and off. So in an environment where you need to do that more than a couple times a day, you are up against a wall. You really do need to keep the spinning reserve going in the gas turbine to keep it running in order to be able to respond quickly.

In a market where your primary use is an instantaneous drop of load because you lost a turbine somewhere else in the system, then you need to have that thing banging right now.

I can see that, but how often does that situation exist in reality, and how much are you willing to pay to be able to have power support for a few minutes while you get the turbine running? In a grid like Texas where you have 60,000 megawatts, a 60-megawatt power plant is insignificant.

MR. AIN: Let's not lose sight of developments in the last 20 years that allow gas combined-cycle units to be load following and operate at different levels. When we put our Long Island project into service in 2009, a 350-megawatt combined-cycle unit, we were allowed to go down to 75% of peak load and still be in emission compliance. So we could swing between 75% and 100% with duct firing on top of that. We had, in a sense, a baseload plant with a peaking unit on top at a very efficient heat rate.

In the new plant we just put online in Pennsylvania, we can be in emission compliance on 40% of our full load. So now we have 60% of the plant that can swing and meet those challenges very efficiently and cleanly from an environmental point of view. That really came out of what was going on in Italy and other parts of Europe when they realized they really needed to have swing and fossil generation to meet this kind of change in load.

The second point is the commercial aspect. We are working with GE on a wind project, and we are excited to back up our wind project with storage which we think has great value. Who is going to guarantee the performance of the batteries over 20 years? What balance sheet is going to be behind performance?

MR. TONDU: General Electric's balance sheet?

MR. AIN: We are delighted. That is a very important aspect of the battery industry to ensure we can get the financing we need efficiently for these projects.

MR. MORGAN: Ross Ain made a critical point about the operating profile.

Given our installed base of gas turbines at GE, we have been working to hybridize gas turbines with batteries. We have a couple of projects in southern California where we have now taken that P-Min from 40% down to zero. So you can actually run your gas turbine at zero and get full credit for spinning reserve because the battery picks up the first four or five minutes, and then the turbine can start. You are saving emissions. You are saving fuel, but the system operator looks at it and says that it is a single asset. And you can recharge that five minutes many times a day and still have a lot of cycles to it.

It is making the gas fleet run more efficiently, and we are adding life to the gas fleet, while we have all the renewables coming in. The intermittency of renewables needs that support of the gas fleet.

Subsidized?

MS. GAMACHE: How important are subsidies for storage to get traction in the US market?

MR. MANN: First, let's talk about what the subsidies are. There is an investment tax credit for adding storage to solar, but for a standalone utility-facing storage asset, there are not any direct subsidies.

I'm a pretty simple guy. I don't look at lots of metrics, but one metric I look at is whether we are winning or losing RFPs. The second metric I look at is who won the RFP if we lost.

Looking at states outside of California over the last year, we have participated in probably a dozen RFPs that were all open-source RFPs looking for capacity. They were open to gas, storage, solar-plus-storage, demand response and whatever other ideas bidders could come up with.

I can't think of a single one that we have lost to a new gas asset. We have lost to existing gas. Storage is competing in utility RFPs in unsubsidized form.

We talked during the electric vehicle */ continued page 52*

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panel yesterday about baseball. What inning are we in? We are probably in the bottom of the first inning as far as reaching the potential for storage in the United States. There are a lot of places where we need to improve: whether it is financing or technology or warranties or 20 years of proven performance. But all of that is coming because we are finding that storage is, in fact, competitive against other types of capacity assets.

What has really surprised me over the last two years of doing this business is that we are able to compete in markets across the country where utilities are looking for capacity without a mandate. I spend time reading utility integrated resource plans — for fun. It is hard to find a utility IRP that does not anticipate a meaningful amount of storage to be added to its grid over the next, say, five years. And I would say that almost every one of those IRPs is wrong in terms of the cost of storage by an order of magnitude. They are overstating the cost because they are looking at two-year-old price data instead of two-year forward price data.

Threat to Gas?

MS. GAMACHE: Do you think that the battery energy storage industry is a threat to the natural gas industry long term?

MR. AIN: No. I think they perform different roles, and they have different qualitative benefits and drawbacks, and they will both be in the market over time. Certainly utilities have put batteries in to avoid new substations and other costs. That happened in New York City, in Astoria. And there are other unique uses of storage.

But I am a little bit skeptical of a rapid market penetration of batteries outside of government mandates over the next five years. I think a longer-term view of that would see a pretty significant market penetration of batteries.

MR. MORGAN: I agree with that. It depends on your time frame because, right now, gas and batteries are going to co-exist in a very happy relationship for a long time. But the existential threat is where gas prices will be over time. Where will coal and nuclear plants be over time? My view is that, if you look at a 30-year timeframe, it is absolutely the case that batteries are going to replace big gas peaking capacity and the peaking capacity of grids around the world.

MR. TONDU: I agree, but I think you are missing that gas is going to be — if it is not already — the baseload capacity in the country. Coal is toast, and so is nuclear. I don't think they will

The electric utility industry is probably only 10% of the battery market worldwide.

MR. AIN: I am a little bit more familiar, for instance, with New York, where the governor and NYSERDA announced, I think, a 1,500-megawatt mandated storage program. Is that a subsidy?

MR. MANN: It is mandated in New York. I agree with you, but storage is mandated in only three states.

MR. AIN: I'm just saying, how do you define subsidy if you have exclusive programs set up for batteries. I am not saying they are wrong, but mandates create their own mini-market or maxi-market as it may be.

MR. TONDU: Do you have a feel for what the percentage is between solar subsidized support versus open-market competition in the storage business today?

MR. MANN: Everything we have done so far is pure standalone utility-facing storage, so nothing we have done is subsidized, and some of it is in mandated markets. I agree that a mandate is a subsidy.

build another nuclear plant after Vogtle. I operate a coal plant; those operating cost numbers are right on, if not conservative. I can't run my plant for less than about $60 a megawatt hour, and I can buy gas all day long for $35. That game is over.

Batteries are going to augment or support baseload where it is possible to do whatever you can to make baseload a little bit better. But gas is going to dominate. It will be the only source of baseload here in another 10 or 15 years.

MR. AIN: Let me offer just one statistic. The last generation of gas, Frame 6 units, were about 55% efficient: let's say heat rate of around 7,100 Btus per kilowatt hour. The new H class machines are about 6,300 Btus per kilowatt hour. They are around 62% to 63% efficient. If you multiply that by a $2.50 gas price, you can sell power at about $1.65 to $1.70 a megawatt hour and break even. And anything above that, you are starting to make money.

As much as we talk about technological development, it is very interesting, as one who has been a student of the gas power industry for last 30 years, to see what unbelievable strides the manufacturers have made in terms of efficiency, emissions, etc. We are about to reap the benefits of that in the heartland of America where we are going to replace a lot of the older generation.

MR. TONDU: One last comment; you just reminded me of something. This is unbelievable what has happened in the industry, but it is also one of the greatest opportunities for the United States for economic advantage because we are sitting on the gas. We are sitting on the resource. We have developed the shale, and with these 6,300 heat-rate machines, our cost of energy is going to be the lowest on the planet.

MR. MANN: I think we have to distinguish between combined-cycle gas turbines versus peaking applications. Each market is different.

There is a role for gas long term in the industry. I am not trying to drive anyone out of business in any sense of the word. What I would say, though, is that some of the best days of operation for our CAISO-grid-connected energy storage asset 10 miles from here are days when solar is providing essentially 100% of the load in California, gas is not running because power prices are zero or sometimes negative, and we are providing essential service of reg-down and then reg-up to help the market work.

The future of the electric industry is zero-marginal-cost renewables. So you are right, the duck curve is a big deal in California, but guess what: the duck curve is coming to Arizona and Nevada and Colorado and Australia. Someday it is going to come to Maine and New York, as well. I think when you have an asset that can provide capacity and be paid both when markets are good and when they are bad, that is an asset and technology that you should deploy.

Audience Questions

MS. GAMACHE: Are there any audience questions?

MR. HOWES. Walter Howes with Verdigris Capital. This has been a very interesting discussion, but it is missing one critical variable which is that in the next three to five years, you are going to start to find deployed small modular advance reactors and micro-mini reactors that will have baseload implications at the 100- to 300-megawatt scale.

MS. GAMACHE: So next year we should have a wrestling match with all of the different technologies.

MR. TONDU: I would take the other side of that position.

MR. MARTIN: Let me ask a couple questions quickly. You talked about 20-year warranties for storage. My understanding is that the standard is a two-year warranty and that you can buy an extended warranty, but can you actually buy a 20-year extended warranty for storage? Don't you have to replace too much of the battery at year 10?

MR. MORGAN: You can buy an extended warranty. It's pretty expensive.

MR. MARTIN: But you are basically replacing the whole battery?

MR. MORGAN: Really what we offer is a performance guarantee, and so we are saying you are going to get this much capacity, this much degradation, this much round-trip efficiency, but we are not going to warrant the manufacturer's product. The manufacturer will sell you an extended warranty for a long time, but it is very expensive because it is planning for that five, 10- or 15-year replacement.

MR. MANN: It is part of the economics. You plan for degradation, and you plan for augmentation. It is probably akin to major maintenance on a gas plant.

MR. MARTIN: The other question, Ross Ain, is do you agree with what was said yesterday that you really can't build another gas-fired power plant in New England because of pipeline capacity constraints?

MR. AIN: I have not been developing plants up in New England for a number of reasons. They are back-hauling gas out of Canada back into New England now */ continued page 54*

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because we can't get pipes through New York state. I think the jury is still out on what will happen there. I don't think, as Trump would say, they are going to wait for the wind to blow to turn on their TVs. They will want to have reliable energy over the next 20 years. So we will see what happens. I'm not sure.

MS. GAMACHE: We have time for one more.

MR. BUTTGENBACH: Tom Buttgenbach with 8minute Solar Energy. I would like to make a bit of a controversial point.

We are replacing gas plants today in California with solar. We can do a replacement of a gas plant with solar-plus-storage for somewhere between $30 and $40, depending on how big the battery is. There will be an announcement in the next two weeks about these projects. We guarantee an up-time of 99%. Your gas plant cannot do that. We are replacing an aging gas fleet that has an up-time of less than 80%, mostly driven by unscheduled maintenance. So in terms of reliability, we are certainly cheaper than a gas plant in California.

If you add in all of the emission charges, etc., we are certainly cheaper than a newly built gas plant. The battery is roughly on about a gigawatt-hour scale with a 20- to 25-year performance guarantee from the manufacturer. That is all financeable, and 20- to 25-year matches the PPA term. This technology is here today.

You are absolutely right that we cannot do that in the northeast, in Michigan or other places because we don't have the sunshine to run the power plant that efficiently. But we are going to be moving the Mason Dixon line up north over time as solar becomes more and more cost effective in other regions. This is coming. It is not going to happen in the next five years. Nothing happens in the utility world in five years. But in 30 years you will see solar with massive amounts of storage being the dominant form of generation.

MR. TONDU: Are you guaranteeing it through the night? Is your solar plant running at 3 o'clock in the morning?

MR. BUTTGENBACH: Yes it is.

MR. TONDU: Around the clock?

MR. BUTTGENBACH: It is around the clock. Matches the load curve.

MR. TONDU: For $30, around the clock, including storage?

MR. BUTTGENBACH: Mid 30's. We even run it very early in the morning before the sun comes up because the utilities have in California, at least some of them, what they call the morning peak, which is the load goes up before massive amounts of solar in California hit the grid. That is very expensive peak to fill with gas. You have to run the machines for an hour and a half to pay for all the emissions, etc. We keep capacity in the battery for that. The batteries are designed to match the load.

MR. TONDU: You have to have a gas turbine in the background to back up that entire system. You are not running that around the clock in isolation. You are using that to fill in the blanks.

MR. MORGAN: It is just like any asset. The grid is full of assets, and they are all running at various load levels. If you focus on the marginal assets, then you are missing the system point. There is coal, nuclear, hydro — there are all of those things.

MR. BUTTGENBACH: There is hydro and wind at night, so you can design the system around solar. It works. Does it rely currently on gas generation? Yes. I can make the battery bigger. My battery cost the last five years has gone down 18% per year. Will it continue to go down? Probably not that steeply, but costs will continue to decline. It is not a question of "if" storage will replace peaking capacity; it is only "when" and in "what market."

MR. MORGAN: I just have to say we need to add the "Buttgenbach line" to our vocabulary — it will be somewhere north of the Mason Dixon line. ◎

PJM Capacity, Grid Reliability and PURPA

by Robert Shapiro, in Washington

Several major issues that affect large segments of the power industry remain on the Federal Energy Regulatory Commission agenda as it heads into the fall.

These include the re-establishment of capacity auctions for the PJM capacity market, the evaluation of system reliability issues for various regional transmission organizations in the interstate markets, and a re-evaluation of how the Public Utility Regulatory Policies Act of 1978 (or PURPA) is implemented.

All three subjects have the potential to affect the extent to which renewable energy versus fossil fuels are used to generate US electricity.

PJM Capacity Market

PJM, the largest regional transmission organization in the United States, runs an annual capacity auction to buy capacity to meet the power needs of its 13 state regional markets. PJM operates the electricity grid from the mid-Atlantic states all the way to parts of Illinois and Michigan.

The auctions are run three years in advance of delivery.

The auctions are conducted in a manner that is supposed to provide appropriate market signals to encourage new capacity when reserves are tight and to discourage new capacity when there is excess capacity in the market.

However, with the increasing volume of renewable energy that relies on federal tax credits and the increasing subsidization of large, operating nuclear plants within PJM, PJM proposed in 2018 to revise the auction rules — beginning with the 2019 auction for capacity to be provided in the 2022-2023 delivery year — to mitigate the price-depressing impact from having so much subsidized capacity bid into the auctions.

FERC agreed with PJM in June 2018 that its existing rules were no longer "just and reasonable" due to the subsidies, but it rejected PJM's specific proposals to revise its capacity rules. Instead, FERC, in a three-to-two decision along party lines (with the two Democrats dissenting), came up with its own "tentative" revised plan and then invited interested parties to comment on that plan and to respond to a set of questions.

Many parties commented and many, including PJM, came up with different proposed plans. FERC has not acted on any proposal since then.

When PJM realized that FERC would be delaying its decision, PJM asked and received permission from FERC to delay its scheduled 2019 auction from May to August 2019. When FERC still had not acted by March 2019, PJM decided to go ahead with the auction in August anyway, and proposed to follow both the pre-existing PJM auction rules that had been in place before PJM had requested their modification, as well as FERC's tentative new proposal.

Many objections were filed. On July 25, 2019, FERC directed PJM not to run its 2019 auction in August. FERC appeared to recognize the difficulty in deciding whether an auction run under rules that it had already determined to be unjust and unreasonable could lead to just and reasonable results. It concluded that the auction must be delayed "until the Commission establishes a replacement rate" because it would "provide greater certainty to the market than conducting the auction under existing rules."

There is no deadline for FERC to act. Although FERC recognized the importance of sending price signals significantly in advance of delivery to allow developers and existing operators to make intelligent investment decisions, it has provided no timetable and no inkling of the direction it may take.

A further complication is that, of the five commissioners that voted on the original June 2018 order, only two remain. One is a Republican who voted for it, and one is a Democrat who voted against it. The third commissioner, Bernard McNamee, was confirmed in December 2018, was a lobbyist for the coal industry and was widely believed to be a moving force behind the unsuccessful US Department of Energy direction to FERC in 2017 to subsidize coal and nuclear plant operations in the regional transmission organizations over other sources of power, which would have severely disrupted the operation of the competitive markets.

MOPR

Under the former PJM tariff for capacity before the 2018 proposed changes, certain new generators that had not yet participated and cleared in a PJM capacity auction would have to offer a minimum price to supply capacity in their first delivery year. The requirement to bid a minimum price is known as the "minimum offer price rule" or MOPR. Existing market participants were not subject to the MOPR under the old rules.

Under the old rules, the MOPR requirement applied only for the first auction. If a new generator's bid clears once in an auction, then in subsequent years it would not be subject to a minimum offer price requirement. Also, / *continued page 56*

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under the old rules, the MOPR requirement did not apply to unsubsidized gas projects that meet certain exemption tests, to renewable generators, to anyone offering demand-side reduction or to existing capacity suppliers. However, the MOPR did apply to state-subsidized new gas-fired generation.

In the proposal that FERC rejected in June 2018, PJM said that the existing rules were no longer viable in light of the distorting effects of state subsidies and offered two alternative plans and asked FERC to choose which one it preferred. While FERC agreed with PJM that the existing approach was no longer just and unreasonable, FERC also decided that both of PJM's proposed tariff revisions were unjust and unreasonable, as well. It then offered its own "preliminary" proposal to change the existing PJM capacity MOPR rule in two ways.

First, it directed PJM to expand the MOPR to create a replacement minimum offer rate for all existing and new generating plants, regardless of resource type, with few exceptions.

Absent such a requirement to bid at a minimum price, existing generators and all new price-subsidized renewable generators and nuclear plants could offer capacity as "price takers," meaning that each could offer a zero price that is guaranteed to clear the auction and still receive the auction's market clearing price. With FERC's proposal, on the other hand, there is a risk that such generators will have to offer prices at levels that will not clear the auction and, therefore, receive no capacity payments.

FERC fully recognized that its proposal would mean that the MOPR would apply not only to unsubsidized generators, but also to subsidized generators.

It recognized that by holding subsidized resources to the MOPR standard, some ratepayers may be obligated to pay for capacity twice — "both through the state programs providing out-of-market support and through the capacity market." This could happen if such a generator's bid did not clear in the auction. FERC said the courts have recognized this risk, but that the courts have found the risk is reasonable given that states retain the right to pursue their own generation policy goals.

However, to mitigate the risk of double payment, FERC proposed a second change to the MOPR rule, called the "fixed resource requirement" or the FRR alternative option.

This option would allow, on a case-by-case basis, a utility or other load-serving entity with specific generation that was receiving out-of-market state support to choose to remove that generation from the PJM capacity market along with a commensurate amount of load, for some period of time.

In setting the proceeding for a paper hearing, FERC also asked interested parties to address a number of important open issues. The issues included the following.

First, what should be considered an out-of-market subsidy? PJM had proposed to define such subsidies broadly to include any market payments, concessions, rebates or subsidies received directly or indirectly from any government entity, or received in any state-sponsored or state-mandated processes, that are connected to construction, development, operation or clearing of the capacity in any capacity auction

But PJM wanted to exclude a laundry list of items from the definition. It wanted to exclude subsidies that promote general industrial development in an area. It would also exclude subsidies that encourage a power plant to be put in one county or locality rather than another one. Federal tax credits and other tax benefits that are available to eligible generators regardless of location would also be ignored.

Second, FERC asked for advice on what categories of generators should be exempted from bidding under the MOPR.

Third, it asked whether federal sources of out-of-market support should be addressed by the commission action.

Fourth, it asked how long generators receiving out of-market support who choose the resource specific FRR alternative should be required to remain outside of the auction.

CASPR

In her dissenting opinion, Commissioner Cheryl LeFleur (who left the commission after her term expired in August) would have been willing to work with PJM's proposal, with some modifications to protect resources under state renewable portfolio standards, or have PJM consider a new construct approved by FERC in March 2018. The new construct was ISO-New England's modification to its MOPR for its capacity auction market, known as "competitive auctions with sponsored policy resources," or CASPR, also designed to mitigate the impacts of subsidized resources on competitive market prices.

Under CASPR, ISO-New England maintained its current MOPR rule that applied to new resources. Then it would conduct a second-stage or substitution auction. The capacity price to be paid to all cleared bids would be determined by the first auction results. But in a second, substitution auction, existing generators that made successful bids to supply capacity in the first auction were permitted to offer to retire their capacity in the second substitution auction at a certain price.

Any state-sponsored resources whose bids did not clear in the first auction would be allowed to bid in the substitute auction to acquire the capacity from those existing resources that offer to retire their capacity in the substitute auction. This was expected to allow retiring existing capacity to receive a somewhat lower than capacity-clearing price to exit the capacity market permanently and also allow new state-supported generators to obtain rights to supply capacity at the market-clearing price.

ISO-New England ran a successful 2019 auction under the CASPR method.

Several major issues that affect large segments of the power industry are on the FERC agenda this fall.

Many interested parties filed comments about FERC's preliminary replacement auction plan for PJM, with some simply responding to FERC's questions, still others supporting FERC's plan or offering their own alternative proposals, and others arguing not to change the existing auction rules.

For its part, PJM offered yet another alternative. Under this revised alternative, PJM offered revised MOPR rules and a "resource carve-out" replacement that it claimed was consistent with FERC's tentative suggested approach. FERC has not indicated in what direction it is headed ultimately.

Although it was assumed that, following the untimely death of the Chairman McIntyre in January 2019 and the expiration of Commissioner LaFleur's term in August, President Trump would simultaneously appoint a Republican and a Democrat to fill FERC's two open seats (out of a full quota of five) to speed approval of the nominations through Congress, it now appears that Trump may leave the open seats unfilled; the commission has two Republicans and one Democrat and can act with a quorum of three commissioners.

No one believes that PJM will be left in a position that would prevent any capacity auction in advance of the 2022-2023 delivery year. However, at this point, unless the FERC decides to reverse itself and determine that the current rules were in fact just and reasonable (as the two dissenting Democrats would have ruled in 2018) but would be revised beginning with the 2020 auction for the 2023-2024 delivery year, the results of the 2019 auction process, whenever it occurs, will have a legal cloud over them. A FERC decision is not likely to be forthcoming for the next several months. That decision will itself be subject to a rehearing, and will take several more months for reconsideration and a final decision. Even if FERC denies a rehearing on its final order, that decision would be subject to appellate court challenge, which could take a year or more to resolve.

Moreover, continued uncertainty over a ruling governing the 2019 auction rules will inevitably add to uncertainty over their application in the 2020 auction in light of the expected litigation over the eventual 2019 auction decision.

Grid Resilience

The commission will be considering whether additional steps need to be taken by the various regional transmission organizations (or RTOs) to bolster resiliency of the US electricity grid.

FERC undertook this initiative in response to a proposal by the Trump administration in the fall of 2017 to have FERC order all the regional transmission organizations other than ERCOT, which is not subject to FERC jurisdiction, to pay generators with 90-day fuel supply inventories on site a price for / continued page 58

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electricity that guarantees them full recovery of operating costs and a return on investment.

The transparent purpose was to force FERC to subsidize uneconomic coal and nuclear plants that have fuel storage on-site to the disadvantage of natural gas and renewable energy projects, which have no need for on-site storage. The Trump administration argued that the policy was needed for system reliability. (For more detail, see "FERC Directed to Favor Coal and Nuclear" in the September 2017 *NewsWire* and "Halting Coal and Nuclear Retirements" in the June 2018 *NewsWire*.)

The issues have the potential to affect the extent to which renewable energy versus fossil fuels are used to generate US electricity.

FERC unanimously rejected the proposal in January 2018, but initiated a new proceeding that required the RTOs to provide their views of what bulk power system resilience means and requires, and how each system assesses whether its system is resilient. FERC would then assess the information received and decide whether any additional commission action is needed. The commission expressly recognized that the issue of resilience extends beyond the RTOs, including utilities in non-RTO systems, as well as distribution system reliability and modernization, which are areas beyond the commission's jurisdiction. The docket contains several dozen questions about the definition of resilience and requires an explanation how each system addresses resilience and reliability issues.

The various RTOs provided comments to FERC, as did many other segments of the power industry. Many parties also filed reply comments.

The commission has not responded to these comments despite the fact that it has been many months since the comments were filed. The most recent comments filed concerned efforts by certain groups to get Commissioner McNamee to recuse himself from the docket in light of his history in spearheading the unsuccessful DOE initiative to subsidize coal and nuclear plants. Commissioner McNamee has said that he will not do so.

Meanwhile, the various RTOs have been continually undertaking their own evaluations of their systems' grid resiliency. In particular, both ISO-New England and PJM have been analyzing fuel security resilience in their respective regions. ISO-New England has recently found that the difficulty in siting and completing the construction and operation of new natural gas pipelines is causing stress on system reliability, particularly on the coldest winter days where existing pipeline curtailments occur and fuel switching is required.

ISO-New England made a filing at FERC in March 2019 to implement, beginning with the winder of 2023-24, a program to provide incremental compensation to resources that maintain inventoried energy during cold periods when winter energy security is most stressed. ISO-New England had previously received approval to retain and compensate Mystic gas-fired generating units that would otherwise have retired because of the need for fuel security. But FERC wanted ISO-New England to propose a tariff amendment to address future retention of units to address fuel security concerns. That tariff became effective on August 6, 2019 because FERC failed to act on the filing, claiming that it lacked quorum .

It is unclear when FERC expects to make public an evaluation of the responses on grid resiliency or, following such an evaluation, whether FERC will direct any of the RTOs to take steps that they are not already taking to ensure that the regional systems remain reliable and resilient.

The specific problems with siting of gas pipelines in New England and the consequent fuel constraints in the winter appear to be creating the most significant issues, and the recent efforts by ISO-New England to address these concerns in its current filing may become a vehicle for their resolution.

PURPA

The Public Utility Regulatory Policies Act of 1978, called PURPA, is a federal law that requires all types of utilities (public, private, regulated and unregulated) to buy electricity from renewable energy generators up to 80 megawatts in size at the "avoided cost" the utility would otherwise pay to purchase or generate the electricity itself.

PURPA also greatly reduces the utility regulatory burdens on renewable generators.

PURPA has been amended several times over the years, although the basic FERC rules implementing the statute have largely remained in place. A unique feature of the statute is that while FERC issues implementing rules under PURPA, certain of the federal rules must be implemented by state utility commissions, and the state commissions are given wide latitude in their implementation.

Following a request from Congressional oversight committees more than two years ago, FERC undertook to re-visit its PURPA rules, opening a notice of inquiry and asking a series of questions concerning the existing rules.

The importance of the PURPA rules has diminished nationally over time. This is primarily due to the fact that 30 states have passed their own laws requiring their state utilities to meet a renewable portfolio standard (or RPS), which has led to purchases of greater amounts of renewable power, better pricing and larger projects than PURPA would afford developers.

In addition, FERC found that utilities operating in competitive markets served by RTOs do not have to buy power from PURPA projects (known as "qualifying facilities" or QFs) if the projects exceed 20 megawatts in size. Accordingly, it is primarily in the sections of the country in which there are no RTOs and limited or no RPS standards (principally in the northwest and southeastern US) that PURPA still has relevance.

In its notice of inquiry, FERC sought and received comments on a number of issues. These are whether there should be a mandatory purchase obligation for utilities in organized markets for projects up to 20 megawatts, a FERC rule that limits a utility's ability to curtail QF power, assessments of the current avoided cost methodologies approved by the state commissions, a standard that would trigger a utility's obligation to purchase the electricity at its avoided cost, and whether developers should be able to treat related facilities that are more than a mile apart as separate QFs to stay under the size limits — the so-called "one-mile rule." By far the most contentious issue is the one-mile rule, which allows developers to break, for example, a 160-MW project that would not qualify under PURPA into two 80-MW QF projects in a single location as long all the turbines from one of the projects were a least a mile away from the turbines for the other project.

FERC has given no indication how or when it is going to handle this re-examination of the PURPA rules, and there has been no major effort by the utility industry to undo the statute or the rules, particularly in light of the latitude given to state commissions that can limit or kill potential QF projects through state implementation of PURPA. But there have been periodic statements issued from time to time by a few utilities and congressmen hostile to PURPA that seek FERC's attention to this investigation. A re-evaluation by a Republican-controlled FERC is a distinct possibility. ◎

“Protected” Versus “Registered” Series LLCs

by Andrew Lom and Rachael Browndorf, in New York

Delaware has allowed for the creation of “series LLCs” since 1996.

Sixteen US states, the District of Columbia and Puerto Rico have statutes that allow limited liability companies to create different pockets or cells of investments, each potentially with different owners, a different managing member and different assets. In some of the states, each series can have a separate right, in its own name, to sign contracts, hold title to assets and grant liens and security interests in the assets belonging to that series. The debts of a particular series may be enforceable only against the assets of that series. (For earlier coverage of series LLCs, see “LLCs with Separate Series” in the January 2009 *NewsWire* and “Series LLCs” in the June 2015 *NewsWire*.)

Under the Delaware limited liability company statute, an LLC can create different combinations or series of members, managers, interests or assets by providing for such series in the LLC operating agreement.

If certain statutory conditions are met — in particular, maintaining separate records for each series and providing notice of the series in the certificate of formation — then each series’ assets are shielded from claims that creditors may have against other series or against the LLC as a whole.

While series LLCs have been useful tools for limiting liabilities and segregating assets, they have had mounting difficulty complying with other laws like the Delaware Uniform Commercial Code or UCC.

New amendments to the Delaware LLC statute took effect on August 1 and should address some of these issues.

After the amendments, two types of series can be established in Delaware: a “protected series” and a “registered series.”

Attributes

The phrase “protected series” describes the type of series that can be formed currently. The requirements to form such a series remain unchanged. The LLC certificate of formation must provide notice of the series structure, and the LLC agreement must permit the formation of the different series. Proper records must also be maintained that account for the segregation of assets and liabilities among the series. As the name suggests, these protected series will continue to be shielded from liabilities and obligations of the LLC itself and of other series, whether the other series are protected or registered. No new action is required for any existing series LLC to follow the protected format.

A “registered series” is a new concept. The requirements to establish such series are the same as for protected series. The LLC agreement must allow for such series, and the certificate of formation must provide notice of the series structure. However, a registered series must also file a certificate of registered series with the Delaware secretary of state. The name of a registered series does not have to include the word “series,” but must begin with the name of the LLC and must also be distinguishable upon the records of the secretary of state from the names of other series and other business entities registered to do business in the state. Registered series names can be reserved ahead of time. A certificate of registered series does not have to identify a registered agent because the registered series will use the same agent as the LLC that formed the series.

A registered series will have the same rights, powers and obligations as a protected series as long as the same statutory requirements of notice and recordkeeping are met. However, unlike a protected series, a registered series will be able to obtain a separate certificate of good standing from the Delaware secretary of state. Because a registered series will have many of the same attributes of a separate entity (but not actually be a separate entity), the state will maintain records for registered series, and registered series will be subject to an annual Delaware tax, set initially at $75 per series. Protected series are not subject to this tax.

Problems Addressed

A key question is how a series LLC is recognized under the UCC. Previously, series LLCs did not meet the UCC definition of a “registered organization” because each series was not formed or organized “by the filing of a public organic record” with the state. It was also unclear whether a series LLC met the definition of “person” under the UCC.

This created issues when trying to perfect a security interest against a specific series’ assets.

The amendments provide that a registered series is an “association” and has the required characteristics of a

Series LLCs formed in Delaware will be either “protected” or “registered” in the future.

“registered organization” for purposes of the UCC. This will allow a secured party to be able to file a financing statement in Delaware and perfect a security interest in the assets of a particular series without leaving questions about the effect on other series or the LLC as a whole. Registered series may become more common in secured financing transactions.

Another limitation of the existing series structure was the inability of a series to get a good standing certificate. As already mentioned, good standing certificates will now be issued to separate registered series in the same way that a certificate of good standing is obtained for the LLC itself.

Another problem was that existing series could not merge with other series of the same LLC. The amendments allow conversion of a protected series into a registered series, the conversion of a registered series into a protected series, and the merger or consolidation of two or more registered series. An existing protected series can convert into a registered series by filing a certificate of conversion and a certificate of registered series with the Delaware secretary of state.

Similarly, a registered series can convert into a protected series: a certificate of conversion is filed with the secretary of state, and the previously filed certificate of registered series will be cancelled. Unless otherwise provided in the LLC agreement, conversion requires the approval of members holding 50% of the profits of such series. A merger or consolidation of one or more registered series of the same LLC must also be approved by members holding more than 50% of the profits interests in each merging series, unless otherwise provided in the LLC agreement. This could be a more efficient and practical way to consolidate the assets and liabilities of two series instead of potentially having to deal with transferring all assets and liabilities between entities.

While the amendments provide clarity and offer solutions to longstanding issues in financing transactions, it is yet to be seen to what extent these increasingly “separate” structures will be respected by courts outside Delaware and whether similar issues will still arise in a bankruptcy context.

Furthermore, many of the secured transactions issues addressed by these amendments deal with the Delaware UCC. It remains unclear whether other states will recognize a registered series as a registered organization under the uniform commercial code as enacted in those states. ◎

Developers on Financing Issues

A group of top finance officers at wind and solar developers talked about current issues crossing their desks at the 30th annual global energy and finance conference in California in June.

The panelists are Bernardo Goarmon, chief financial officer of EDP Renewables North America, David McIlhenny, managing director for project finance at SunPower Corporation, Esben Pedersen, chief financial officer of Pattern Energy, and Karen Derenthal Schmidt, senior vice president for project finance at Eurus Energy America Corporation. The moderator is Ben Koenigsberg with Norton Rose Fulbright in New York.

Equity gets its return much faster in real life than it does in Excel spreadsheets.

MR. KOENIGSBERG. David McIlhenny, putting aside advantages related to the abundant liquidity and low interest rates, what do you view as the most significant advantage your business enjoys and most significant impediment that your business faces over the next year?

MR. MCILHENNY: The advantage is that we are very good at identifying and optimizing energy project value, communicating that to customers and then executing to make it happen. We are good at moving from an idea to a real-life project. It is hard to do all of those things. There are lots of moving parts, and to coordinate and not to make wrong steps is a very difficult task.

There are two challenges. One is regulatory change, including changes in import tariffs, net metering rules, state regulations and government policies that affect what we do. Another challenge is other market participants who do irrational things based on unsustainable assumptions. SunEdison is an example of an irrational participant. It hurt SunEdison; the company went bankrupt. It also hurt the industry, including us, by offering PPA rates and lease rates to customers based on faulty finance assumptions that were unsustainable. We lost business and margin.

MR. GOARMON: I'll start with impediments, so the bad news. EDP Renewables is a low-risk-profile DNA organization. We believe this is important in the long run to be able to attract the most competitive capital. It brings challenges for a company that wants to grow by at least 1,000 megawatts of capacity a year. There is a race to the bottom for PPAs in wind and solar, but probably more in solar. At the same time, the nature of the counterparties is changing and their willingness to provide collateral is changing. The whole utility business model is going through a transformation. Community choice aggregators in California are an example.

The balance between risk and return is changing. Quite frankly, if you look from a global perspective and you have to make capital location decisions, the US is losing attractiveness versus other countries, not so much because of risk, but primarily because of declining returns. This is something new.

Now that I have your attention, here is the more positive news. We think our advantages are scale to leverage procurement and to secure optionality. This allows us to take limited technology risks knowing that there will be optionality to allocate risk within the portfolio. This is one advantage.

I believe the second is in-depth knowledge of the market. We are not here selling megawatt hours; we are serving the customer needs, and the arrangements are getting more and more complex. You have to transport power, you have to understand basis risk fully, you have aggregation of PPAs, you have REC agreements, and so forth. We believe we have strong capabilities in all of these areas.

One more thought about technology: storage and offshore wind projects will become a reality. Storage is already here, and offshore wind is a deep pockets game where project scale is important. We have been working on offshore wind projects for 10 years, in the United Kingdom and France, with 2,000 megawatts developed, so we believe we are well positioned to capture market share in the US.

Picking Niche Plays

MR. PEDERSEN: In some ways this conference is inside baseball. We all know well the competitive dynamics here. However, I talk to investors regularly about the fundamental advantage that our industry has and where we are with renewables. It is telling that we take for granted just how significant an advantage renewables enjoys today in the market, and how much this is still not really clear to the investor universe.

The second thing that contributes to our competitive advantage is that ESG has become a dominant driver for investors. It is something that we were not seeing 18 months ago. As evidence, anyone out raising a private equity fund will likely be told today by investors, "You can have my money, but you can't build a coal plant with it."

Pattern is an integrated developer-owner-operator, and that is really part of our advantage. We do not rely on an M&A market. We build for our own account for the most part. We sell a few projects after deciding what we want to own. Our sustaining advantage, frankly, as a company is our expertise in development. We have been doing this for 15 years as a team, and that means we have seen the cycles and can spot irrational exuberance. We are focused on macro-trends and picking our spots. We are not a volume-oriented business, so we don't just build to build. We pick a couple trends.

I'll give two examples of what we are doing.

For example, off-peak power is valuable today in the west. There is an abundance of solar, which means that there is value in delivering electricity outside of the hours when the sun is shining. That is one macro-trend that we have been following.

Another is we invested significantly in Japan. Renewable adoption there is less than 1%. Japan has only 3,000 megawatts of wind generating capacity, yet it is a 250,000-megawatt market. Japan wants to build 30,000 megawatts of wind over the next decades.

In terms of impediments, the market is challenging for all of us. We are in a shifting market. The erosion in the traditional utility model and the competition among different renewables suppliers on the delivery side will be significant challenges over the next two to three years.

MS. DERENTHAL SCHMIDT: I think our advantage is being part of a global group, so that allows us to pivot to markets where the risk-return makes sense.

That drove our move into South America four or five years ago. Being able to pivot back and forth among wind, storage and solar and among geographical markets is an advantage when returns are irrationally low in relation to risk in a particular market.

I think our challenges are the same as everybody else. We are in the midst of a transition from an infrastructure mindset to a commodity market-driven mindset. We have patient shareholders. Our most limited resource is the human capital to spend on endeavors that are going to end up with a project that gets done.

Solar Deadline

MR. KOENIGSBERG: David McIlhenny, returning to you. Solar companies must start construction of remaining projects by year end to qualify for a 30% investment tax credit. What is your thinking as a solar developer about the best way to start construction?

MR. MCILHENNY: If there is an easy way to preserve the 30% ITC, it is worth it, but it is not risk free.

If you start construction by stockpiling solar components to be used in future projects, those components will certainly become expensive components because costs will go down in the future. They can also become technologically obsolete. There is also a cost to buy modules or other equipment today to store in a warehouse for use in 2023. It is not a no-brainer to do it.

However, the value of the ITC is very strong and I think overcomes those problems.

MR. KOENIGSBERG: Developers who lack the money to stockpile equipment have been having challenges persuading lenders to make inventory loans for this purpose. The challenges revolve around collateral. If the lender just has the panels and not the underlying project, foreclosing solely on the panels does not allow the lender to sell them to someone else while preserving their grandfathered status for tax credits. How do you convince lenders to get around that risk if you don't want to offer up a full project?

MR. MCILHENNY: Plan A for the lender should be that the developer will use the modules in a manner that satisfies the safe-harbor requirements.

Lending money to a developer that has / continued page 64

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a long track record of success and a bright future going forward should be a key requirement. The collateral value of the components that you safe harbor will not repay the loan, unless the loan-to-cost ratio is low.

Another way that the lender could structure the transaction is to lend to a special-purpose entity or a joint venture that has more than one developer as an equity partner, so that there are multiple ways to use the safe-harbor modules in future projects.

Lastly, I believe it is very hard to buy modules right now. There is not much supply left, so if you have not started your safe-harbor program, it will be difficult.

MR. KOENIGSBERG: Would you tell someone to go with trackers or other components?

MR. MCILHENNY: If you think trackers or other components are going to be universally useful and not become technologically obsolete, then yes.

Merchant Risk

MR. KOENIGSBERG: Bernardo Goarmon, prior panels have talked about merchant risk. The market is moving toward power contracts with shorter terms, leaving more merchant exposure. How do you think about such risk, and what lessons have you learned?

MR. GOARMON: We see two big trends in the market. One is scale, about which I already spoke. The second is the need to make bigger bets. The bigger bets are in projects with smaller amounts of contracted revenue, leaving higher merchant exposure.

There are two aspects that we think are important when we have these investment opportunities. First, it is really important that the project be in the right place. Electricity basis risk varies by location.

The second is the percentage of merchant revenue. We reviewed the mix recently in our annual growth plan, and the percentage is still relatively modest, so maybe 20% to 25% at most. If you couple a somewhat longer merchant tail with a contracted revenue stream, you are optimizing risk-return. We are not minimizing return. It is something that we cannot ignore, because frankly it is the first time in years where it makes sense to entertain a little bit more merchant risk.

There are some projects where a flat PPA is worse than being exposed to merchant risk with a hedge or collar.

Lessons learned: people have short memories. It is really about leverage and volatility of power markets. Equity gets its return much faster in real life than it does in Excel spreadsheets. [Laughter]

The project really needs to stand on its feet based on intrinsic cash flow and not on financial engineering. No one pays salaries based on equity; they pay salaries based on cash.

Measures like short-term cash yield, five- and 10-year payback periods, percentage of NPV contracted and things of that nature are important. We sponsors are the residual cash flow.

MS. DERENTHAL SCHMIDT: Adding to Bernardo's list, not every good PPA is a good PPA. Even if you are able to leverage the asset at a lower gearing ratio, not every PPA is a good value proposition for a buy-and-hold investor like us. If there is no upside, the price is low and there is not a lot of risk sharing on other aspects of the revenue proposition, then from our perspective, it is not a good PPA.

MR. KOENIGSBERG: There is an interesting dynamic among the investors, the financiers and the developers. It is a question of whether you can convince the financiers to advance enough capital to get the deal done. It doesn't necessarily mean that you should have a long-term PPA.

MR. PEDERSEN: Can I make a comment on merchant risk? It is easy to say I should be able to move from a 20-year busbar PPA to a 10- or 15-year merchant deal if I can get it financed, but the market for owning such a project gets very fickle very quickly.

It comes back to the issue that you need to be at the right location. If you can't persuade yourself that you have a locational advantage, then you really have no hope of creating value.

There is something irreconcilable about where we are now with the build costs still being significant and the predominant driver of what return you can reach over time and having a variable income stream. It is a real challenge. You have to be very careful about the node where you are delivering power and whether it is an attractive location.

Electricity Basis Risk

MR. KOENIGSBERG: That segues into the next really important question, which is basis risk. This is the risk, when you enter into a bank hedge or a corporate PPA, that the node price at which the electricity is delivered to the grid is different than the hub price at which the hedge or corporate PPA is settled. How do you think about that risk? How do you manage it? What advice can you give people about it?

MR. PEDERSEN: First and foremost, you have to understand the dynamics in the project location. You can do things to retain operating flexibility that are valuable, such as being able to trade in the day-ahead market.

If you believe in your node, you may be better off not having a contract. Hedges exact a rent in order to facilitate a financing. You also need to be careful about covariance risk around your asset. It could go the wrong way, and you are stuck with high costs to deliver under a financial hedge that you put in place to facilitate the financing.

A pure merchant play may be a better proposition. We are financing a couple pure merchant deals. There are ways to do it, but it requires thinking outside the box.

MR. KOENIGSBERG: Karen, the lenders and tax equity investors put electricity basis risk solely on the sponsor. Esben Pedersen says finance on a merchant basis. That may not be an option, so how do you think about basis risk?

MS. DERENTHAL SCHMIDT: Shifting it fully to the sponsor is the, I'm sorry to say, brain-dead response of lenders. The alternatives are cash sweeps, lower gearing, reserve accounts, tracking accounts and similar mechanisms.

I think you need a project with enough money and flexibility to use some of those techniques. We grapple with it. It is a new element of our business. You need to be a power trader, you need to have in-house expertise, you need to manage it, and you need to make a determination whether there are other ways of financing.

We are wary about layering on an additional risk with multiple hedges.

We are moving away from single-asset leveraged financing. You need to make sure the financing fits the asset, and with a power plant, if the contracts don't lend themselves to a single asset, then you need to think about a portfolio. You need to think about a quasi-corporate deal. You need to make sure that you do not have the worst of both worlds, which is the cost of a non-recourse financing and a de facto full-recourse deal. So we look at the full range of options for where to source capital depending on the nature of the revenue stream and what we have in front of us.

Utility PPAs

MR. KOENIGSBERG: Are we at an inflection point on price where utilities think it makes sense to lock in long-term PPAs, and will we start to see more of those?

MS. DERENTHAL SCHMIDT: We see only our small slice of the market, so there may be others that have a broader view. We don't see a big jump or a big long-term insurance value.

We are looking at niche markets where there is still value for some sort of a premium on a bilateral basis. We are looking for the uncut diamond. I am not waiting for a big upturn in PPA prices over the next 24 to 26 months. I think it will take more time.

MR. PEDERSEN: There are a couple of factors at work, and they don't move in the same direction.

We are nearing an inflection point where we could see build costs start to change. Once the tax incentives expire, that converts quickly into anxiety about what the prices are going to be. Once the prices start to move up, potential offtakers start clamoring for contracts.

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Developers sometimes end up with the worst of both worlds: the cost of a nonrecourse financing, but a *de facto* full-recourse deal.

Developers

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I don't see that happening immediately; maybe two or three years from now. Macro-policy on carbon pricing could also drive such a change. These are the types of things that make people consider their options.

The factor that cuts in the other direction is we see utilities increasingly wanting to own the generating assets. BOT contracts may turn into the solution for minimizing basis risk. There will still be a role for developers. Utilities have never been very good at developing.

MR. KOENIGSBERG: Bernardo Goarmon, let's talk briefly about offshore wind. EDP has a joint venture with Engie and another joint venture with Shell to develop offshore wind projects. We saw a record price of $136 million paid the other day to buy an offshore site lease. At the same time, the tax credits for wind projects are winding down. There are lobbying efforts to extend the ITC for offshore wind.

How does a company that is just starting work on an offshore wind project compete with others who already have a tax-credit strategy in place? How do you win a power contract auction against other projects that qualify for tax credits?

MR. GOARMON: Let me try to answer in a different way.

Obviously offshore is important to us as we announced two weeks ago a joint venture with Engie with a target of 5,500 megawatts. This is substantial.

I personally never thought offshore would come so quickly to the United States, primarily due to the absence of a supply chain, but the reality is that it is here.

It is unrealistic to expect an industry to be built without having regulatory certainty. The economics don't work with the current technology. There have been instances of people trying to mitigate a little with cables and so forth, but it is unrealistic to expect companies to deploy hundreds of millions of dollars five or six years in advance of start of construction.

Two competing bills are being introduced in the US Senate to extend the deadlines for offshore wind to qualify for a 30% investment tax credit. One of the bills would give developers until the end of 2026 to start construction or, if later, until the industry reaches 3,000 megawatts. This is what the industry needs. It is an industry that will create a significant number of jobs. It is an industry that has an incredible supply chain with a very high multiplier. You cannot expect such a capital-intensive business to work without having certainty.

MR. KOENIGSBERG: Does US offshore wind make sense economically today?

MR. GOARMON: For certain markets, yes, primarily the east coast, particularly the northeast. In areas like Japan and California, it makes sense to deploy a floating technology. We have had such a technology since 2008. Offshore is becoming a price check to some of the onshore PPAs, so it is here.

MR. KOENIGSBERG: Last question. David McIlhenny, how will storage affect your business? Will all of your solar projects have storage in two years?

MR. MCILHENNY: We look at adding storage to, or having storage on, every new distributed solar system we install. They don't all pencil out. We only put storage where it adds economic value, because the customers don't want to pay for it otherwise. We are also looking at our deployed fleet of projects to see where storage might add value as an add-on. This is just a guess, but perhaps 20% to 25% of the projects we are doing now have storage, and I expect the percentage to increase. ◎

Adding a hedge helps with risk, but also adds risk.

C-PACE Poised to Grow in New York

by Patrick Dolan and Anna Lee, in New York

Commercial PACE lending to make energy efficiency improvements and install renewable energy systems in office buildings and other commercial properties is expected to increase in New York after the Energy Improvement Corporation or "EIC" revamped its commercial PACE program.

"PACE" stands for property assessed clean energy. EIC administers the program statewide, other than in New York City.

Local governments encourage private lenders to make loans to finance energy-related improvements to buildings by allowing lenders to take senior liens on the buildings that trump existing mortgages. The borrower repays the debt over time essentially through a special assessment that is like an addition to the property taxes that it is already paying as the building owner. The government makes the property tax collection machinery available, although in the case of the EIC program, the PACE assessment is billed separately. If there is a default on the loan, then the lender can foreclose on the building.

C-PACE refers to PACE lending for improvements to commercial properties. Residential PACE focuses on improvements to homes.

Borrowers like PACE because of the favorable financing terms.

The New York PACE program dates to 2009 and can be found in article 5-L of the state general municipal law. EIC updated its C-PACE program in 2019 to make it easier for commercial property owners to access third-party capital financing on favorable terms. This is the third iteration of the program.

In the prior programs, unlike the current program, if a property owner did not pay the C-PACE assessment, then the local municipality would pay it for him, which introduced the creditworthiness of the municipality into the equation.

PACE assessment payments are bundled together and converted into current cash through securitizations. Between January 2014 and June 2018, the California state treasurer reported that PACE financing in that state has financed over $3 billion in efficiency upgrades. In Connecticut, the Connecticut Green Bank announced in early 2018 that the state's C-PACE program has financed 200 projects totaling more than $114 million.

C-PACE financing in New York dovetails with a Senate bill signed June 8 that requires a 40% reduction in greenhouse gas emissions statewide by 2030 and an 85% reduction by 2050. The June 8 law also requires that 70% of electrical usage must be derived from renewable sources. C-PACE funding is an effective tool for property owners in making these kinds of ambitious environmental changes possible.

What is C-PACE?

The "Energize NY Open C-PACE" program is available to finance improvements to commercial and industrial buildings, including multi-family properties with three or more units, but not single-family residential properties.

C-PACE loans are made by private, third-party lenders and are repaid over a long-term period. As per the law, "[e]very loan made under the sustainable energy loan program shall be repaid over a term not to exceed the weighted average of the useful life of such systems and improvements as determined by" the local municipality.

The property owner pays via a special voluntary assessment placed on the property, similar to property taxes and other municipal charges.

C-PACE is a growing sector of the PACE financing world. Currently, 33 states have enacted legislation enabling property owners to receive up-front financing from private lenders to install renewable energy systems or improve the energy efficiency of existing systems on their property. During 2009 to 2017, $588 million was invested in C-PACE projects, with $251 million of that in 2017 alone, a 75% increase from the previous year.

In New York, the Energy Improvement Corporation (EIC) is the statewide C-PACE program administrator other than for New York City. EIC overhauled its commercial PACE program recently to make program easier for commercial property owners to use. The PACE assessment is billed directly by EIC, on behalf of the local municipality, rather than through the property tax bill on the building, thereby reducing the administrative burden on municipalities of collection and enforcement of PACE assessments. EIC expects to close the first C-PACE financing under the new program this summer.

Improving the energy efficiency of commercial buildings through C-PACE is good for property owners, municipalities and communities at large. Owners who could not afford improvements can do so, and even commercial property owners who could otherwise afford environmental improvements to their buildings may wish to have greater financial flexibility by taking the up-front cost of development off their balance sheets. Because the annual savings generated by */ continued page 68*

C-PACE

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reduced energy needs typically exceed the PACE assessment, many property owners realize an immediate profit.

Local governments also have an incentive to participate in the program because C-PACE funding reduces the cost of doing business and attracts business owners to the community, encourages investment and creates green jobs. C-PACE investments are estimated to have created 5,600 to 8,800 new jobs in New York through 2017, with an $800 million to $1.5 billion impact on local economies.

Lending is expected to increase for energy-related improvements to business properties in New York after the state revamped its C-PACE program.

Finally, C-PACE is attractive to the entire community because when properties are more energy-efficient, air quality becomes healthier, and the entire community benefits. Existing C-PACE improvements as of 2017 are estimated to save 6.3 million megawatt hours of energy over their lifetimes, reducing greenhouse gas emissions by 3 million metric tons, which is equal to the emissions from 345 million gallons of gasoline).

Repayment Structure

In a C-PACE loan, the lender takes a lien on the building where the energy efficiency improvements are made. This is different than the normal home improvement loan from a bank. The special assessment that is the source of loan repayment is attached to the building and not to the individual property owner. Because of this, the financing automatically travels with the building if the building is sold to a new owner.

Interest rates are competitive, and depending on marketing conditions range from 5.75% to 6.75%

In C-PACE transactions, existing mortgage-holders must provide written consent, thereby permitting the "benefit assessment lien" to take priority over all existing mortgages on the property.

However, the local government gets first claim on asset value, in the event of a foreclosure, to cover property taxes and other municipal assessments, such as sewer and water. The benefit assessment lien is subordinated to a lien for taxes of the participating municipality on real property, municipal charges and governmentally imposed assessments.

Parties to Transaction

There are five parties to any C-PACE transaction.

The first is the borrower. To qualify for the program, the borrower must jump through a number of hoops. It must be a "qualified property owner," meaning a commercial entity that owns commercial real property in the municipality offering C-PACE financing. Government entities, such as public universities and school districts, and natural persons owning commercial property are not eligible.

The borrower must not be in bankruptcy, and the building itself cannot be the subject of a bankruptcy proceeding. The borrower must be current on any existing mortgage on the property and its property tax payments.

Eligibility is based on a building's ability to carry the extra assessment burden and to generate savings through the energy upgrades, not on traditional credit metrics.

Another party to the transaction is the local municipality. This can be a county, city, town or village. It must have adopted a local implementing statute establishing a C-PACE program and contracted with EIC to administer the program on the municipality's behalf.

A list of participating municipalities in New York may be found at the following link: https://energizeny.org/municipalities/where-is-pace. Other counties not on the list are currently in discussions about establishing programs.

EIC is also a party to any transaction since it will administer the PACE lien on behalf of the municipality.

Then there is a private lender. Lenders are pre-approved by EIC to participate in the program. Lenders may have different preferences for the types of energy efficiency improvements they are willing to finance, minimum or maximum financing ranges and geographic coverage. Some specialize in PACE financing.

The lender and borrower sign a financing agreement. EIC and the local government are considered third-party beneficiaries with a right to enforce provisions that affect them.

Finally, there is a contractor who does the work. Contractors must be on an approved list maintained by the New York State Energy Research and Development Authority (NYSERDA).

Qualified Spending

New York permits property owners to use C-PACE financing for a variety of projects. Subject to municipal-level regulations, funding may be used for energy audits, building improvements, renewable energy feasibility studies and installation of renewable energy systems (solar, wind, fuel cells, cogeneration units and geothermal heat pumps).

Qualifying improvements must be cost-effective, permanent (no appliances) energy-efficient improvements affixed to the property. Examples are retrofitting windows and doors, installing new lighting systems, caulking, weather stripping, replacing insulation and upgrading heating, cooling and water systems.

Many lenders have verification requirements to ensure that funding is not fully disbursed until improvements have been completed. A local inspector may be asked to sign a certificate of completion.

NYSERDA recommends that the borrower be required to covenant in the financing agreement to maintain the improvements, deliver status reports during construction and allow the municipality access to the property for the first two years after construction to inspect the work.

Some improvements may be owned by third parties, such as a long-term lessee. In such cases, the third party must promise not to remove the improvements until the loan has been repaid and to allow the building owner to transfer the rights to use the improvements to the new owner if the building is sold. ◎

Environmental Update

The US Department of Agriculture has taken a significant step toward finalizing its revisions to Obama-era policies for conserving the greater sage grouse and its habitat in five Western states.

The revisions identify the potential environmental impacts on over five million acres of the bird's habitat in Colorado, Idaho, Nevada, Wyoming and Utah, and adjust how the US Forest Service will address them going forward.

The changes will ease restrictions on grazing livestock and give more flexibility to states to implement local strategies.

The bird's population has been in decline for decades as its habitat has been whittled away by development.

Efforts to protect the birds are controversial in Western states because of the effect on ranching, mining, oil and gas drilling and other businesses.

The Forest Service published its final environmental impact statement on August 2, 2019, beginning a 60-day public comment period. The changes could be final this year.

New Source Review

Power plants, refineries and other industrial facilities may get some relief from the cost of having to obtain air pollution permits for facility upgrades under certain circumstances.

The US Environmental Protection Agency proposed changes to the new source review permitting program on August 1 in an effort to provide relief from the cost of obtaining air pollution permits. The new source review is done under the Clean Air Act.

In general, the new source review program currently requires industrial facilities to install new pollution controls each time a company adds a new facility or expands existing operations.

Under the new proposal, power plants, refineries and other industrial facilities would only have to obtain new source review permits for "net" increases of pollution because EPA is calling for changing the way it calculates emissions from such expansions.

The proposal would change the way EPA calculates emissions of pollutants such as sulfur dioxide and nitrogen oxides for purposes of determining whether a permit is required and will allow industries to get credit for replacing aging inefficient boilers or other equipment with new equipment that may still cause emissions to increase.

EPA essentially suggests that the program should consider emissions decreases as well as increases in deciding whether the change in emissions from a project would trigger the need for an air permit.

Critics suggest that the changes would allow industry to avoid addressing increasing air emissions and inflate the credits that facilities receive from installing new equipment without properly examining the harm to air quality.

For example, a facility could get credit for installing a more efficient boiler, but the new program assessment may ignore the fact that the new boiler allows operational increases that result in more emissions than before the replacement boiler was installed.

The NRDC and other groups are expected to challenge the change in court after it becomes final following agency receipt and consideration of comments from the public.

Changes in greater sage grouse protections in five Western states should take effect later this year.

Water

EPA and the US Army Corps of Engineers have sent the White House Office of Management & Budget (OMB) for review the

Rating agencies are starting to demand answers from coastal cities about how they are preparing for climate change.

agencies' joint final rule to repeal the Obama administration's standards for determining the scope of Clean Water Act jurisdiction.

OMB received the repeal on July 12, beginning a review process that is expected to run for 90 days, but that could take longer.

At issue is whether a discharge of a pollutant into a "navigable water," defined as "waters of the United States," requires the discharger to obtain a national pollutant discharge elimination system permit. How the two agencies define "waters of the United States" will determine what is and is not regulated.

Once final, the new rule will narrow the definition of "waters of the United States" that are subject to federal Clean Water Act jurisdiction, by repealing a broader 2015 federal rulemaking. The repeal will revive a combination of older agency rules.

The repeal will only be the first step by the Trump administration, as a still narrower Clean Water Act standard is set for final action by as early as the end of 2019.

Even before a replacement rule is finalized, the repeal of the 2015 rule would have immediate effect in 23 states and parts of New Mexico. Those areas have been applying the broader 2015 standard. The repeal would end the current situation, where a split among US appeals courts has led to a split where different regions apply different standards.

Meanwhile, the question of whether a Clean Water Act permit is required to discharge pollutants to groundwater that eventually reaches navigable waters will be considered in the upcoming term by the US Supreme Court. The court has agreed to hear an appeal of a lower-court decision in *County of Maui v. Hawai'i Wildlife Fund* on a single question: "Whether the Clean Water Act requires an NPDES permit when pollutants originate from a point source, but are conveyed to navigable waters by a nonpoint source such as groundwater."

The answer will mend a split among the US courts of appeal.

New York Climate

New York Governor Andrew Cuomo signed into law far-reaching greenhouse gas reduction requirements in mid-July. The law sets an ambitious goal for New York of "net zero" carbon emissions by 2050.

The "Climate Leadership and Community Protection Act" requires the state to reach economy-wide greenhouse gas cuts of 85% from 1990 levels by 2050. It also directs various measures to advance reforestation and carbon capture or other technologies to offset the remaining emissions.

The new law requires that 70% of New York's electricity come from renewables by 2030. It directs that 9,000 megawatts come from offshore wind by 2035.

The New York State Climate Action Council will draft a "scoping plan" in the next three years to recommend state policies to achieve the long-term emissions reduction targets.

Last year, California set a goal of reaching net-zero greenhouse emissions by 2045 by executive order rather than by legislation as New York has now done.

Gas Pipelines

A US appeals court shed further light recently on whether the Federal Energy Regulatory Commission must look more broadly at the effects on natural gas production and consumption when evaluating the environmental effects of a proposed new pipeline. The issue is whether this is part of its obligations under the National Environmental Policy Act, or NEPA.

The court criticized FERC for failing to gather such information in a case called *Birckhead v. FERC*. The pipeline applicant had not told FERC the origin and destination of the gas to be transported via the pipeline. The court said FERC had an obligation in such situations to collect the information itself.

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Environmental Update

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Although ultimately dismissed on procedural grounds, the case can be seen as a bellwether for further litigation in the NEPA area involving pipeline construction.

Meanwhile, the Council on Environmental Quality, which reports to the US president, released draft guidance in June for how agencies should consider greenhouse gases under NEPA.

The draft calls for minimal NEPA greenhouse gas reviews. Instead, it suggests that federal agencies should follow "the rule of reason" to "assess effects when a sufficiently close causal relationship exists between the proposed action and the effect." It suggests that "a 'but for' causal relationship is not sufficient."

The pending and expected legal battle over the scope of NEPA greenhouse gas reviews could affect federal agency assessments of new pipeline approvals.

Coastal Areas

Credit rating agencies like Moody's and Fitch have begun to demand answers from coastal cities and other municipalities about how they are preparing for climate change.

The demands have come as the agencies review proposed new municipal bond issuances.

The ratings scrutiny is only expected to increase. Bond issuers are being asked to explain what they are doing to adapt to rising sea levels and other impacts from climate change and how they are going to pay for it. ◎

— contributed by Andrew E. Skroback in New York and Washington

CHADBOURNE MERGER

Chadbourne & Parke merged into Norton Rose Fulbright on June 30, 2017. The combined firm has roughly 3,400 lawyers in 55 offices and four affiliated offices in 33 countries.

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