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# Infrastructure Plan: Outlook in Congress

President Biden unveiled a massive infrastructure plan in late March that includes many provisions of interest to renewable energy developers and the broader project finance market. Four veteran Washington observers talked in early April about the outlook in Congress.

The four are Joe Mikrut, a partner with Capitol Tax Partners and a former Treasury tax legislative counsel under President Clinton and senior legislation counsel on the Joint Committee on Taxation staff, John Gimigliano, head of federal tax legislative and regulatory services for KPMG Global and a former Republican tax counsel to the House Ways and Means Committee, Elissa Levin, director of federal government affairs for Avangrid, Inc., a multi-state utility and owner of one of the largest US wind and solar developers, Avangrid Renewables, and Chris Miller, a partner with AJW Inc. and a former top aide for energy and environment to Harry Reid when Reid was Senate majority leader and a 26-year Capitol Hill veteran. The moderator is Keith Martin with Norton Rose Fulbright in Washington.

## Odds

MR. MARTIN: Joe Mikrut, what odds do you give that some version of the Biden infrastructure plan will pass Congress this year?

MR. MIKRUT: I think the odds are fairly high. There is a lot of interest in Congress in doing something. There is even interest on a bipartisan basis, not to predict that the bill will be bipartisan, but both parties have been talking about infrastructure for years, through several administrations, and I think this time something will actually get done. / continued page 2

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**TEXAS** is considering imposing additional costs on wind and solar projects that are already in operation as well as such projects that are built in the future.

At least four proposals are under consideration in the state legislature. The current legislative session runs through May 31, but the governor can call the legislature back into a special session if needed.

The renewable energy trade associations have sounded alarms about one of the proposals. It would require wind and solar projects to reimburse ERCOT for the cost of ancillary services that ERCOT buys to deal with the intermittent nature of such projects. Details would be left to the Public Utility Commission to work out. / continued page 3

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MR. MARTIN: John Gimigliano, do you agree?

MR. GIMIGLIANO: I do. To put it in tax opinion terms, I would place the odds at "more likely than not," maybe approaching a "should" level. Many things can derail any piece of legislation. That said, I think that Democrats will find a way to pass a significant infrastructure bill this year.

MR. MARTIN: Elissa Levin, what are the odds?

Odds are that some version of the Biden infrastructure plan will pass Congress this year.

MS. LEVIN: I am really optimistic about the chances of something passing this year. It will not be easy. We have an equally divided Senate and a more closely divided House with the news this morning of the passing of Mr. Hastings. Every member counts, and every member will count equally in the search for votes. Their individual issues with the bill are going to have to be addressed, but there is momentum to get something done.

MR. MARTIN: Chris Miller?

MR. MILLER: I think it will happen, and it is just a question of timing. The Senate parliamentarian's decision yesterday made it close to a sure thing this year.

MR. MARTIN: Let's talk about that. The Democrats barely have control of the House — Pelosi can afford to lose only six votes — and the Senate is split 50-50. Every single Senate Democrat has to vote for the bill unless some Republicans break ranks. John Gimigliano, Mitch McConnell says no Republican will vote for the bill. Is he right?

MR. GIMIGLIANO: If the bill is paid for with significant tax increases, as we expect, then, yes, it will be very hard for Republicans to support it. If we are talking about $1 trillion or more in tax increases, which is what President Biden has laid out, it will probably have to be a Democrat-only product.

MR. MARTIN: Every Democrat will have to vote for it in the Senate for it to pass, which makes it a high-wire act and gives every Democrat leverage in exchange for his or her vote. A bill normally requires 60 votes to clear the Senate because any senator opposed to it can threaten to filibuster, and 60 votes are required to cut off debate. Sixty votes for this are impossible, so the Democrats will have to use one of three budget reconciliation cards they have over the next two years that allow a bill to pass by simple majority. They already used one to pass a $1.9 trillion COVID relief bill in March.

Chris Miller, you mentioned a ruling yesterday by the Senate parliamentarian. Did that ruling say that the Democrats can reuse the one budget reconciliation card they already used, or that they can use two cards in one year?

MR. MILLER: They are the same thing. The ruling was that the Democrats can amend the fiscal year 2021 budget resolution they used to pass the COVID relief bill also to make room for an infrastructure bill. That does change the timing a bit.

MR. MARTIN: How does it change the timing?

MR. MILLER: It would need to be done and cleared before the government's current fiscal year ends on September 30.

MR. MARTIN: If it has not cleared Congress by September 30, what happens?

MR. MILLER: Then they could not replay the card they already used and would have to use budget reconciliation card number two. That is for the fiscal year 2022 budget. The Democratic leadership will have to make a decision which card to play early in the process.

### Timing

MR. MARTIN: Joe Mikrut, by when do you expect the infrastructure bill to pass?

MR. MIKRUT: I think they will try to do it by the August recess. The Speaker of the House, Nancy Pelosi, said she wants the bill to have passed the House by July 4. The bill will then be in the

Senate for the month of July. Strange things happen to bills that remain in play over the August recess, particularly if they have revenue raisers. The members go home and start hearing from interest groups who chip away at unpopular provisions. That's why they want to act quickly and have this wrapped up before the August recess.

MR. MARTIN: John Gimigliano, same answer?

MR. GIMIGLIANO: Maybe I am a bit of an outlier, but I think this is a Q4 exercise. I think the ruling from the parliamentarian yesterday appears to be more than it actually is.

There are two steps in the infrastructure plan. The American Jobs Plan is step one to be followed later by the American Family Plan, both of which are going to require tax increases to pay for them. There will be a linkage between the two that will make it hard to do one without the other, for both policy and political reasons. I think they will end up being bundled together in one giant reconciliation bill, and the debate will drag into the fall and get done in Q4.

MR. MARTIN: And use the fiscal year 2022 budget card. Elissa Levin, when do you expect the infrastructure bill to pass?

MS. LEVIN: I wish I could agree with Joe that it will be done before the August recess, but I think it will take into September and maybe even October.

MR. MARTIN: Biden is talking about two types of infrastructure: clean energy and basic infrastructure in his first plan, and then a social infrastructure bill, which is what John Gimigliano referred to. Chris Miller, is it your view that the infrastructure bill with clean energy provisions will pass by September 30?

MR. MILLER: I think the House will have acted before the August recess. The Senate moves more slowly and might end up with a great combo package around December 23.

MR. MARTIN: A wit once said that Congress acts only in two situations. One is when there is consensus, which there isn't in this case, and the other is exhaustion, which is your scenario. Chris Miller, what are the implications of having to use a budget reconciliation card to pass the bill?

MR. MILLER: It makes it hard to do anything other than tax and spending provisions. Anything else is subject to a point of order and can be stripped from the bill. In addition, the Byrd rule bars including anything that will add to the deficit after the budget window, which is usually 10 years.

MR. MARTIN: John Gimigliano, the Biden infrastructure plan calls for spending on infrastructure over eight years, but the tax collections to pay for it are spread over 15 years. I guess that does not violate the Byrd rule because the tax / continued page 4

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ERCOT spends about $380 million a year to buy ancillary services from power plant owners whose projects are connected to the grid, but only about $50 million of that total, relating to regulation service, is triggered by performance of renewable generators.

Ancillary services include such things as back-up power, voltage support and frequency regulation services. The grid tries to maintain the frequency at which electricity oscillates at 60 Hz. As more air conditioners, televisions and lights are turned on, the grid frequency goes down unless the electricity supply increases to match demand. As equipment is turned off, the opposite happens. Maintaining a stable grid frequency is a constant effort.

Grid operators compensate power plant owners for standing by to help, for example, by supplying additional power or voltage support within one to several minutes after being asked.

It is not clear how much of ERCOT's annual bill for ancillary services would be attributed to addressing intermittency from wind and solar projects or how the additional cost would be allocated among such projects.

A version of the proposal that passed the Senate on March 29 would require intermittent generators to "purchase ancillary services and replacement power sufficient to manage net load variability."

The uncertain additional costs would complicate financings and erode the economics of existing projects.

Becky Diffen, a Norton Rose Fulbright partner in Austin, said the proposals are too new to be playing a role yet in any pending financings.

The legislature is also considering requiring all power plant owners to weatherize their projects so that the projects can operate at temperatures below freezing.

It is also considering requiring independent generators who connect to the ERCOT grid in the future to pay the costs of direct interconnection, substation improvements and other "network upgrades" to the grid to accommodate the additional / continued page 5

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collections help to shrink the deficit.

MR. GIMIGLIANO: The hope is that from a budgetary point of view, Congress would see that spending tailing off as we approach the end of the 10-year window, but we would have tax increases that are going to be permanent, at least as Biden outlined them.

MR. MARTIN: One more general question for Joe Mikrut and then we will drill down into details. Do you expect Biden to send legislative language to Congress or is his plan merely a set of broad strokes with Congress left to fill in the details? Put differently, how excited should people be about what they read in the fact sheet the White House released last Wednesday?

MR. MIKRUT: If they like what they read, then they should be excited. We should see more detail coming out, perhaps in mid-May. A new administration generally puts out its first budget in the spring of its first year. We expect that to happen in May. That budget is generally accompanied by a "green book" that the Treasury writes with the details of each of the tax proposals. We will probably not see statutory language, but we will at least have more detail about the tax proposals.

### Tax Credits

MR. MARTIN: Let me now drill down into details and start with Elissa Levin. There are at least three tax proposals to help renewable energy. One is a tax credit for standalone storage. Another is a direct-pay alternative to tax credits, and the third is a "10-year expansion and extension" of renewable energy tax credits. Rank these in terms of likelihood to be in the final bill.

MS. LEVIN: I think all three will end up in the final bill. That said, we should have a good idea where things are headed when the House Ways and Means Committee marks up the tax provisions in June.

MR. MARTIN: Don't we already know what will be in the House Ways and Means Committee bill? The Democrats on that committee already released their legislative text in February.

MS. LEVIN: We will see how the House Ways and Means Committee takes into consideration what Biden has proposed. There may also have to be some consideration given to the tech-neutral approach that Senator Wyden is expected to offer in the Senate. It will not be an easy task to reconcile the two approaches.

MR. MARTIN: Wyden wants to repeal the 44 current energy-related tax credits and replace them with just three: one for clean energy, one for clean transportation fuels and one for energy efficiency improvements. It sounds like you expect that to be in the Senate bill in place of the current production tax credits and investment tax credits to which we are all accustomed.

MS. LEVIN: The tech-neutral approach has been a top priority for Senator Wyden for a long time, and we as an industry need to figure out the effects on our industry and model them. We expect Wyden to release the draft in the next couple weeks. It is a serious proposal.

MR. MARTIN: One of the biggest issues will be transition rules. How do you transition from the current system into it?

Joe Mikrut, do you agree with Elissa that all three Biden tax proposals – a tax credit for standalone storage, a direct-pay alternative to tax credits, and a "10-year expansion and extension" of renewable energy tax credits — are likely to be in the final bill?

MR. MIKRUT: Yes. The only place I would hesitate is whether the energy credits will be extended for 10 years or a shorter period. We have been talking about storage for a long time. It is ripe for action. There is a lot of momentum behind direct pay.

A tax credit extension raises budget reconciliation issues. If you extend PTCs for 10 years, a significant amount of revenue loss is outside the 10-year budget window. The question is whether the revenue offsets that are also in the bill will be enough to cover it.

MR. MARTIN: The Byrd rule barring anything that increases the deficit after 10 years is applied on a net basis by looking at the entire tax title of the bill, correct?

MR. MIKRUT: Yes, each title individually. You could actually take a tax title and break it up into separate titles, like a green title and a different title, but the more you break it up, the harder it is to make the whole thing balance.

MR. Martin: John Gimigliano, how do you rank the likelihood that the three items will be in the final bill?

MR. GIMIGLIANO: I concur with everybody that all three are likely to be enacted, but with one limitation that is the very harsh rules of budget reconciliation.

I view the Biden plan as an opening bid or wish list. There very well may be enough budgetary headroom in the bill to do all of this, but there also may not be. There is a question of how many votes they have for tax increases to achieve long-term budget neutrality. To the extent they lack the votes, they really only have two choices: one is to scale back the tax-increase provisions in some way, either the duration or the absolute number of them, or the alternative is to fall back on deficit financing for part of the cost. I think the latter is a very real possibility.

MR. MARTIN: Joe Mikrut, what does Biden mean by 10-year extension? Do you have any more details?

MR. MIKRUT: No. I assumed that it was just pushing out the start-of-construction date on the various provisions for 10 years.

MR. MARTIN: Chris Miller, Joe Manchin, whose vote will be critical, said last month at an ACORE conference that he is not in favor of extending renewable energy tax credits. Greg Wetstone talked him down a bit from that. Then he said on a West Virginia radio program on Monday that he thinks the infrastructure bill is in trouble. The infrastructure bill obviously cannot pass without his vote. Is it a reasonable assumption that he will fall into line with the other Democrats?

MR. MILLER: Fall into line will probably be in the eye of the beholder, but I think he will come around to supporting some form of extension of those tax credits. I think he will probably make a case that mature technologies, especially those that have significant market share, no longer need additional incentives. I suspect direct pay will be a problem for him beyond a certain number of years. It remains to be seen how fossil fuels fare in any of this, potentially as a pay-for by repealing their tax incentives. Those will be important things to him as he decides whether to support the whole package.

MR. MARTIN: There will have to be something for fossil fuels or coal for West Virginia.

## Labor Provisions

MR. MARTIN: The fact sheet that the White House put out suggests that the extra tax credits will come with a catch. Projects claiming them will have to comply with "strong labor standards to ensure the jobs created are good-quality jobs with a free and fair choice to join a union and bargain collectively." Joe Mikrut, what does that mean?

MR. MIKRUT: The House Ways and Means Committee Democrats had a similar provision in the set of GREEN Act tax proposals that they released in early February. Anyone paying qualifying wages would qualify for an extra tax credit. I assume that is similar to what the President is talking about here.

MR. MARTIN: The labor unions have not been pleased about the shift to green energy. They earn more in fossil fuel jobs; those are more unionized. Wind is about 6% labor, and solar is 4%. The GREEN Act that you mentioned requires payment of Davis-Bacon wages, which are the same wages paid on federal construction projects, or else entering into a collective bargaining agreement. I don't think the GREEN Act provision / continued page 6

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electricity to the extent these costs exceed an allowance that would be set by the Public Utility Commission.

Independent generators in ERCOT, unlike in the rest of the country, do not have to reimburse the grid for the costs to interconnect. They have to post security for the costs, but the security is released once the project is completed. The security is to protect ERCOT from having to spend money on improvements for a project that is not built.

Many power projects in Texas sell into ERCOT at the spot market price for electricity and then enter into a hedge to put a floor under the electricity price so that the project can be financed. Texas limits the maximum spot price. It was $9,000 a MWh, but has now been reduced to $2,000, pending further revision.

The last of the four proposals would require generators selling into the spot market to be paid only their costs to generate the electricity, rather than a full market price, during any emergency when spot prices have hit the cap and remained there for at least 12 hours during a 24-hour period.

Christy Rivera with Norton Rose Fulbright in New York, who handles hedging arrangements, said paying generators only their actual cost would leave them short of the market price they are required to pay hedge counterparties under existing hedges.

**PORT BACKLOGS** are adding to cost and could delay construction of some projects.

Twenty-eight large container ships were still waiting on anchor to enter the ports in Los Angeles and Long Beach on April 4, down from 40 in early February. Another seven ships were expected to join the queue in the next three days. The two ports handle roughly a third of US container imports and are the main gateway for shipments from Asia.

The average wait for anchored vessels to reach the port is eight days. Roughly a quarter of containers then require another five days to reach the dock due to congestion on land.

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would apply to the renewable energy tax credits. Maybe somebody on the call has a different view. It is also, as you said, Joe, a carrot in the form of an extra 10% investment tax credit.

John Gimigliano, do you expect this in the final bill, and do you expect it to be a stick or a carrot?

MR. GIMIGLIANO: I think that is an open question. The minimum-wage provisions were stripped out on the COVID relief bill in early March in budget reconciliation. Whether this particular provision could survive budget reconciliation turns on whether it is considered to have a direct effect on the federal budget. I don't know the answer to that.

MR. MARTIN: Elissa Levin, do you expect the labor provisions to be in the final bill and, if so, what will they look like?

The debate will probably stretch into the fall.

MS. LEVIN: I don't know whether they are likely to be in it. I can tell you that we certainly favor the carrot approach and are working on this with the tax committees. Richard Neal, the House Ways and Means Committee chairman, said right after the tax extenders passed in December that future extensions of credits would come with labor conditions.

We are taking a close look at this. At least half of our workforce at Avangrid belongs to unions. We are used to operating in a union environment. We work with unions around the country when building projects where it is practical to do so and union labor is available. We are committed to using union labor and working with our local communities going forward. While this is an issue that we will watch and monitor in terms of legislative language, we are generally on board.

### Direct Pay

MR. MARTIN: Joe Mikrut, how do you expect the direct-pay alternative to work? How quickly will owners of renewable energy projects receive refunds? Will the refunds be for 100% of the credit value?

MR. MIKRUT: We have seen a number of versions of this floated over the last year. Senator Cornyn had a proposal last year to allow refunds of business tax credits claimed in 2019 or 2020 or carried forward into those two years. Senator Carper has also done some work in this area.

All would treat the tax credits as an estimated tax payment and then provide rules as to when that payment is deemed to have been made. I believe the Cornyn bill was as of the due date for the tax return. These are quick-refund processes run through the IRS.

The main difference between the House and the Senate versions relates to the amount. In the House version, if you make the election, you would be refunded 85% of the tax credit value. In the Senate versions, it is 100%. That is something that will have to be worked out as the bill moves forward.

MR. MARTIN: Are the refunds expected to be available only for two years?

MR. MIKRUT: I think the thought is to tie them to projects that are under construction for tax purposes by a deadline that is either two or three years from now. Once elected, the refunds would be available for any credits from that project.

MR. MARTIN: John Gimigliano, the last time we saw this, the refunds were run through the Treasury Department. This time, they would go through the IRS. Are there other differences?

MR. GIMIGLIANO: It is an open question whether a refund program run through the IRS will run more smoothly than the section 1603 program did. Treasury, at the outset, met the 60- or 90-day obligation to make payments, but then rarely met that deadline as the program went on.

There is a longstanding IRS mechanism to issue refunds in the case of tax overpayments. A direct-pay program would put a lot of pressure on the IRS to issue refunds without really having the opportunity to audit the refund requests. You wonder what they will do to ensure that payments are appropriate. The last thing the IRS wants to have to do is to claw back amounts that it paid that were found to have been unwarranted.

I am not as convinced that this is going to run as smoothly as people think because I believe the IRS is going to want to impose some oversight through some form of real-time auditing of applicants.

MR. MARTIN: The good thing about the Treasury cash grant program was the two women who ran it were very efficient. The program was enacted in February 2009, and they had it standing up by July that year. If you had questions, you sent them an email. You sometimes got answers back in writing within as few as three minutes. If you ask the IRS a similar question, it can take months to get an answer. It remains to be seen how smoothly a program run through the IRS will work.

There is also a requirement in current law for any refund over $2 million to be approved by the Joint Tax Committee refund counsel. Joe Mikrut, will that apply here?

MR. MIKRUT: I believe the answer is "yes" the way these proposals are currently drafted. However, that is something that has been turned off in the past in various situations.

Another difference between this new program and the section 1603 program relates to production tax credits. Under the section 1603 program, the PTCs were converted to investment tax credits and then refunded in the form of one-time lump sum payments. That made sense for a program administered through the Treasury, since it had only to cut one check.

The way the bills work for PTCs is you would get refunds as PTCs are claimed over time. If PTCs are more valuable than an ITC for a project, this form of direct pay is a more efficient mechanism than the section 1603 program.

MR. MARTIN: Normally under the current quick-refund procedure in section 6411 of the tax code, you have to wait until the tax return is filed for a year to apply for a refund. Will people have to wait in this case? Anyone? [Pause]

That is a detail to which we will all be paying attention.

## Clean Energy Standard

MR. MARTIN: Chris Miller, Biden wants a federal energy efficiency and clean energy standard. Do you think that will fall victim to budget reconciliation? It is not a tax or spending proposal.

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Roughly 75% of containers are being returned empty to Asia because it does not pay to wait to reload them in the US.

Freight rates from Asia to the US west coast were up 240% at the end of March compared to a year earlier. Rates were up 500% to Europe.

The average shipping time from factory to destination is now nine weeks compared to four to five weeks a year ago.

Relief is unlikely in the near term as US retailers rush to restock depleted inventories ahead of what they hope will be peak demand in the fall as the US economy rebounds after the COVID lockdowns.

**PRESSURE CONTINUES TO BUILD** to block imports into the United States of solar panels made with polysilicon or other inputs from the Xinjiang region in western China.

Roughly 45% of the world's supply of solar-grade polysilicon comes from the region.

The AFL-CIO asked the Biden administration in a March 12 letter to US Secretary of State Antony Blinken and National Security Adviser Jake Sullivan to have US Customs issue a "withhold release order" blocking affected solar panels. US Customs is currently blocking imports of tomatoes and cotton from the region.

A representative from the United Steelworkers union repeated the request at a Senate Finance Committee hearing on March 18 on "Fighting Forced Labor."

Two US senators, Marco Rubio (R-Florida) and Jeff Merkley (D-Oregon), asked the Solar Energy Industries Association in a March 23 letter what steps its members are taking to ensure that their supply chains remain untainted by forced labor. SEIA responded on March 28 that it has been encouraging its members since last October to move supply chains from the region and that "most solar panel imports will be free of products sourced from" the region by June.

Rubio and Merkley named four Chinese polysilicon suppliers that various publications have suggested may

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MR. MILLER: This has been a matter of intense discussion behind the scenes for close to a year now. Some advocates have offered as many as three different ways they think the standard could be structured to pass muster under budget reconciliation.

Both the Senate Environment Committee and the Senate Energy Committee have been looking at this, but I have the impression that the Senate Finance Committee is not interested. If the committees can miraculously come to an agreement on something, then maybe it has a chance, but it is a very tall order.

MR. MARTIN: Do you agree with that, Elissa Levin?

MS. LEVIN: I do. I think 100% by 2035 is quite ambitious. That is coming from Avangrid, where we were the first utility in 2016 to set a goal of being carbon neutral by 2035. Not all the utilities are on board yet, and so I think it will be a steep hill to climb.

And that is before considering the difficulty of getting anything like this through reconciliation. The idea that people have offered to make a clean energy standard fit into a budget reconciliation bill are detailed and will require additional screening and consideration. Regardless, I think a federal clean energy standard has incredible potential to deploy clean energy, and it deserves consideration.

### Tax Increases

MR. MARTIN: John Gimigliano, Republicans took aim over the weekend at the proposed increase in the corporate income tax rate to 28%. Where do you expect the rate ultimately to settle? And when will the new rate take effect?

MR. GIMIGLIANO: I am most confident answering the last question, although not wholly confident. The new rate is most likely to apply to tax years beginning on or after January 1, 2022. Not only do I think the Democrats do not want to do retroactive tax increases, I am also not sure they have the votes to do retroactive tax increases.

Having said that, the simple question is, "How high does the rate go?", and that goes back to that original question, "How big is this bill going to be?" How much of it are they willing to finance by borrowing? The difference has to be made up by tax increases. You have about $100 billion per point on the corporate rate. If they need $2 trillion of tax increases, I think you have to go all the way to 28% to make the math work. If it's only $1 trillion, then I don't think you need to go all that way, and the rate is more likely to settle at around 25%.

MR. MARTIN: Joe Mikrut, your view?

MR. MIKRUT: If Senator Manchin is correct that he won't do 28% and that he has five Democratic colleagues who agree with him, then I think you almost have to go to 25%. But I do expect the opening bid coming out of the House to be 28%.

### Transmission

MR. MARTIN: Chris Miller, the number one issue for many wind developers is grid congestion. They say they can build projects, but they can't get the electricity to market. Biden said in his fact sheet that he wants "a targeted investment tax credit that incentivizes a build out of at least 20,000 megawatts of high voltage transmission lines," and he also wants to use existing rights of way along roads and rail lines to site such lines.

That last bit sounds like a great idea. Why hasn't it been done to date? Does the federal government really have the ability to push through siting along roads and rail lines?

MR. MILLER: That is a great question, and one on which I have been working since starting to work for Harry Reid when he was Senate majority leader.

There are some great rights of way along rail lines that the federal government still owns and certainly others like the national interstate highway system that could be used. There are some safety concerns. Another reason it may not have been done is that jurisdiction over energy and transmission is in one committee and infrastructure is handled by another committee. We are now merging them together for the first time in a coherent way. I expect some movement on this.

A hard question is whether any statutory changes with respect to rights of way will be able to find a home in a bill that has to pass through the budget reconciliation process.

MR. MARTIN: I imagine one could argue it is a form of federal spending. A new office will be created at the Department of Energy to look into it.

Elissa Levin, you represent a utility that has transmission lines. How likely do you think the targeted investment tax credit is to be in the final bill?

MS. LEVIN: Momentum has really grown over the last six months. I think that both political parties are aligned around recognizing that transmission is critical and that we have to do something. Avangrid is building a transmission line currently that is almost entirely along an existing right of way in Maine, and we have another such project proposed for New York. Anything that can be done to help advance transmission with tax incentives and siting and permitting help is badly needed.

MR. MARTIN: Jon Weisgall with Berkshire Hathaway Energy has said on past calls that you can't love renewables and hate transmission. The electricity has to get from the project to market.

## Carbon Capture and Hydrogen

MR. MARTIN: I have three more questions, and then we are going to audience questions. Joe Mikrut, the White House fact sheet says the infrastructure plan will "expand" section 45Q tax credits for capturing carbon dioxide. Any idea how?

MR. MIKRUT: Unfortunately I don't know.

MR. MARTIN: John Gimigliano, any input?

MR. GIMIGLIANO: No, I don't either, although one gets the sense that this might be something that could be important to Senator Manchin and could give him reason to vote for the bill. As Joe said earlier, this is why we are waiting for the Treasury green book in mid-May to early June that should spell out all the details.

MR. MARTIN: Biden wants a new production tax credit for decarbonized hydrogen demonstration projects in 15 distressed communities. Joe, have you heard any more details on how that would work, and is the focus green, blue or grey hydrogen?

MR. MIKRUT: I don't have any details on that, but Senator Heinrich has been doing some work here, and I think he would pick up the full spectrum of clean hydrogen.

MR. MARTIN: Does anyone have any other insight into that proposal?

MR. MILLER: I would just be very political and suggest that it will have to cover the entire rainbow of hydrogen in order to get through the Senate.

MR. MARTIN: My last question, starting with Chris Miller and asking it of all four of you, is whether there are any other significant proposals in play that affect the power sector that you think might hitch a ride on the infrastructure bill?

MR. MILLER: I would watch the CLEAN Future Act and the LIFT America Act that committee chairmen are behind in the House for other provisions that might end up as part of the infrastructure bill. Also, some of the things that Senator Carper and others have proposed to promote electric vehicles could find a home in the infrastructure bill.

MR. MARTIN: Elissa Levin, any other significant proposals?

MS. LEVIN: I agree. Biden has proposed that a lot of money be put into electric vehicle infrastructure. Other areas we are watching closely are spending on upgrading US ports to facilitate the expected build out of offshore wind / continued page 10

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supply polysilicon produced with Uighur labor. The four are Daqo New Energy, Xinte, East Hope and GCL Poly. Their letter also identified three solar panel suppliers that have acknowledged publicly that they source polysilicon from the region: Jinko Solar, JA Solar and LONGi Solar.

Jinko said in a filing with the US Securities and Exchange Commission last December that some products it sells in the US could contain materials from Xinjiang. The filing said the company may have to reconfigure its supply chains if the US tightens restrictions. It warned investors that any such move by the US "could result in significantly higher manufacturing and other costs to us, delay our product supply to the US market, and reduce demand for our products."

Bipartisan groups of congressmen and senators reintroduced bills in the House and Senate in February to ban "all goods, wares, articles, and merchandise mined, produced, or manufactured wholly or in part" in Xinjiang, unless US Customs is persuaded there is "clear and convincing evidence" that the products were not made with forced labor by Uighur Muslims. A similar bill passed the House nearly unanimously last September, but failed to pass the Senate after lobbying by US companies concerned about their inability to trace supply chains fully. (For more detail, see "Multiple tariff issues in play" in the December 2020 *NewsWire* and "Uighur issues in financings" in the February 2021 *NewsWire*.) Neither house has scheduled action yet on the measures this year.

**US STATES ARE CHAFING** at a provision in the $1.9 trillion COVID relief bill that Congress enacted in March that could tie state and local government hands on enacting new tax relief for renewable energy.

Some commentators have suggested the provision could also prevent local officials from granting new property tax abatements for projects.

The provision would / continued page 11

## Infrastructure

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and workforce training. We really need to encourage more training so that we can put people to work on all these projects.

MR. MARTIN: John Gimigliano, what else might hitch a ride?

MR. GIMIGLIANO: A couple things come to mind that could happen in this bill, but if not in this bill, are probably coming anyway. The 100% depreciation bonus is scheduled to start phasing down after 2022. We also have research and experimentation costs that move from being immediately deductible to having to be amortized over time. I think there is bipartisan interest in extending bonus depreciation and preventing the amortization rule from taking effect. I think we could see both issues addressed at some point in the next year.

At least three renewable energy tax proposals are likely to end up in the final bill.

MR. MARTIN: Joe Mikrut, what else do you expect to be included in the infrastructure bill?

MR. MIKRUT: I agree with what John just said, and also it may address a change in how the 30% cap on interest deductions is calculated. The calculation will change after this year in a way that makes it harder to deduct interest.

A series of international provisions will be in the bill as pay-fors. Biden is also proposing a corporate minimum tax. A big issue will be whether energy tax credits can be used against that tax. That may not be as big an issue if there is a direct-pay alternative to tax credits.

### Audience Questions

MR. MARTIN: Let's go to audience questions. We have a lot of them. The first question is whether direct pay will have negative implications for the tax equity market for renewables.

Two thoughts on that: one is there are some sponsors who are having trouble raising tax equity and some who are able to do so, but will probably think about whether they want to do so if there is a direct-pay alternative. However the tax equity market functioned fine in 2009 to 2016 when there was a Treasury cash grant program that was a direct-pay program. The depreciation on these projects is worth about 14¢ per dollar of capital cost. The tax credits are worth roughly 30¢. Most sponsors concluded during the Treasury cash grant era that raising tax equity made sense if they could do so.

Another question from the audience: Is it possible the direct-pay provision will afoul of the budget reconciliation restrictions? Is it a tax or spending program?

MR. GIMIGLIANO: I think it will be a tax measure by treating what otherwise would be the credit as a payment of tax. I think that gets you within the rules of budget reconciliation.

MR. MIKRUT: It has a budget effect because it at least accelerates the use of credits that might otherwise be carried forward.

MR. MARTIN: A lot of people argue that there is no net cost for the government since the tax credits would be claimed anyway. But you say it speeds up when the tax expenditure shows up in the budget. Have you seen any revenue estimates yet?

MR. MIKRUT: It may also cause some projects to be completed that otherwise would not be. I am less certain whether the Joint Committee will take that into account, in addition to acceleration of the revenue effect. I know from conversations with them that they assume, for purposes of scoring, that credits that would otherwise be carried outside the budget window will be used in full by the end of the budget window. That helps with the Byrd rule.

MR. GIMIGLIANO: I think the section 1603 program was estimated to cost something like $5 million, and I think — correct me if I am wrong — that the program paid more than $25 billion. That is an illustration that not only do you get more sooner, but you also get more. Projects get built that would otherwise not work under a pure tax-credit regime. The Joint Tax Committee learned that lesson after 2009.

MR. MARTIN: We have several questions about the direct-pay alternative to tax credits. Will it end up at 85%, which was in the House GREEN Act, or 100%, which is where the discussion seems to be at present. Elissa Levin, where do you think the percentage will settle?

MS. LEVIN: We hope it will settle at something less than a 15% haircut if not 0%.

MR. MARTIN: Joe Mikrut, several people are asking about the mechanics of direct pay. How would it work, especially for a company with significant tax credit carryforwards?

MR. MIKRUT: The direct pay under consideration is unlikely to address tax credits carried forward into the direct-pay window. I think the view is to try to enact a provision that stimulates the construction of new projects, so it would apply to projects that are not yet in service when the provision is enacted.

MR. MARTIN: At the same time, it does not matter if the company is in a tax-credit-carryforward position? That would not prevent it from getting a direct payment for credits for a new project, correct?

MR. MIKRUT: That's correct.

MR. MARTIN: As we have discussed, any refunds are likely to run through the IRS. An open question is do you have to wait until the tax return is filed for the year to apply for a refund, or could you do it sooner?

MR. MIKRUT: I think you would have to wait.

MR. MARTIN: That would make it worse than the Treasury cash grant program. Under it, you could apply for a grant immediately after the project was placed in service and the Treasury was supposed to pay within 90 days after receiving a complete application.

One thing Biden wants as another "pay for" is a 15% minimum tax on book income. It would only apply to companies with at least $2 billion in book income in a year. Can energy tax credits be used as an offset against that minimum tax?

MR. GIMIGLIANO: That's not a detail that has been divulged yet. It is one of those things that we will be looking forward to seeing in the green book when we get it later this spring. [Editor's note: The US Treasury suggested after */ continued page 12*

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bar states from using $350 billion that the bill gives state and local governments to help with pandemic-related needs to cut taxes.

The prohibition says that states may not "either directly or indirectly offset a reduction in the net tax revenue of such State or territory resulting from a change in law, regulation, or administrative interpretation during the covered period that reduces any tax (by providing for a reduction in a rate, a rebate, a deduction, a credit, or otherwise) or delays the imposition of any tax or tax increase."

The prohibition lasts through 2024.

Sixteen states have sued the US Treasury to block implementation of the ban. West Virginia and 12 other states filed suit in a federal district court in Alabama on March 25. Three other states had already sued separately.

West Virginia and Mississippi have been considering this year whether to repeal their state income taxes, but efforts in both states have been abandoned. West Virginia's share of the $350 billion may account for as much as 25% of the state budget.

US Treasury Secretary Janet Yellen said in a letter to Republican state attorneys general in late March that the provision does not prevent states from eliminating one type of tax and plugging the budget gap with spending cuts or offsetting tax increases.

The US Treasury said in a separate statement on April 7 that the provision does not prevent states from conforming their tax laws to adopt any federal tax cuts. Most state income tax laws piggyback on the federal system by having taxpayers use the income they reported on their federal income tax returns as a starting point for their state calculations. However, many state legislatures must affirmatively embrace new federal tax law changes before they apply to state tax calculations.

The Treasury is working on more comprehensive guidance.

**THE EUROPEAN UNION** is expected to release details of a carbon */ continued page 13*

## Infrastructure

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the call that energy credits can be used to offset the new minimum tax, but without any detail.]

MR. MARTIN: Another question. Elissa Levin, Biden has announced a separate set of actions for the offshore wind industry, and yet he barely mentioned offshore wind in the broader infrastructure plan. Can you comment on what is in play for this subsector and what kind of Congressional politics are involved?

MS. LEVIN: The GREEN Act that the House Ways and Means Committee Democrats released in February would extend the construction-start deadline to qualify for the 30% ITC for offshore wind. We will be looking for PTC optionality for offshore wind as well.

The administration's support for offshore wind is clear. The administration committed on Monday to ambitious goals for developing offshore wind projects over the next 10 years. It said it plans to move forward with the auction of project sites off New York over the next year. It announced port infrastructure funding and other programs. We are very excited.

MR. MARTIN: Elissa, here is another essay question for you from an audience member. He says, "Elissa Levin seemed to feel trepidation regarding the tech-neutral Wyden bill." Senator Wyden, by the way, is chairman of the Senate tax committee. "In her mind, what are the advantages and disadvantages of the tech-neutral proposal versus extension of the current regime?"

MS. LEVIN: One of the things at which we are looking with the tech-neutral approach is how the transition period will work. Another issue at which Avangrid is looking is the impact on offshore wind in particular. We are also waiting to see what labor provisions Mr. Wyden includes in his proposal. I would not call it trepidation as much as waiting to do our due diligence on a new proposal and making sure that we fully understand the impact.

MR. MARTIN: Joe Mikrut, do you know whether there have been discussions with the Senate Finance Committee or Joint Tax Committee staffs about the transition issues with a shift to a new tax-credit regime like Wyden is proposing?

MR. MIKRUT: There have been conversations with the Wyden staff on transition and how it would work.

MR. MARTIN: We have time for one more question. John Gimigliano, do you have any thoughts on a PTC for existing nuclear plants?

MR. GIMIGLIANO: Wow. As one of the people who drafted the existing PTC for new nuclear plants that was not terribly successful, I have not heard of anybody proposing to do that. The experience with the existing PTC for nuclear has been difficult to say the least. It is hard to imagine Congress granting a PTC for plants that have already been in operation for decades, unless it were a carrot to make some sort of modification to the plants.

MR. MARTIN: I know the two South Carolina Republican senators were very interested in this, at least for new plants, but given the dynamics of this bill, you basically need a Democrat who wants it in order to support the bill.

MR. MIKRUT: Senator Manchin has always had an interest in nuclear. The Biden folks have aggressive goals for carbon reductions over the next few years. The question is whether we can get there only with renewables or to what extent we need nuclear to be part of the picture. Several states have answered that question by offering zero emissions credits to nuclear plants to prevent them from shutting down. The federal government could adopt a similar approach if nuclear is important to reaching the goal for emissions reductions. Again, we are waiting for the Biden folks to disclose their entire plan in the next several weeks to see whether nuclear is part of the equation.

MR. MARTIN: One of my favorite books as a teenager was *Advise and Consent* by Allen Drury, an Associated Press reporter who covered the Senate, about the high drama in the Senate attached to a major nomination battle. The infrastructure plan is a monumental program. There will be a lot of drama to watch this year as the plan takes shape and the debate plays out. ◎

# How Much Shareholder Debt?

*by Anne Levin-Nussbaum, in New York*

A question often asked by foreign investors in US renewable energy projects is how much debt they can use to capitalize the US "blocker" corporation through which they invest.

The short answer is: "It is complicated." If you prefer not to read the detail, skip to the last sub-header "Pulling Everything Together."

Foreign companies and investment funds investing directly in US renewable energy projects almost always form an intermediate US entity to hold the investment. The US entity is a corporation for US tax purposes.

This is done so that the foreign company or investment fund will not be treated as engaged directly in a US business as that would require it to file US tax returns.

The problem with investing through a blocker corporation is the blocker corporation will be subject to US taxes at the full corporate tax rate on income from the project. Therefore, investors look for ways to "strip" earnings, which means withdrawing earnings from the blocker in a form that can be deducted by the blocker corporation. The most common way to do this is to lend part of the invested capital to the blocker so that earnings can be pulled out as deductible interest on the loan.

Most countries limit the extent to which earnings can be stripped through rules that either deny interest deductions or re-characterize purported loans as equity investments where the blocker has too small an equity layer.

The US had a bright-line test for determining when a blocker corporation was too thinly capitalized through 2017. However, starting in 2018, it dropped the bright-line test in favor of a cap on interest deductions.

Purported loans might still be re-characterized as equity investments, but the US tax authorities have struggled to draw clear lines. (For example, see "Tax rules could reclassify debt as equity" in the April 2016 *NewsWire* and "IRS revisits debt-equity and disguised sales" in the August 2017 *NewsWire*.")

## Too Little Equity?

In an unleveraged blocker, the foreign investor contributes all the funds to the US corporation as equity.

In a leveraged blocker, the foreign / *continued page 14*

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border adjustment in June. The adjustment would take effect no earlier than 2023.

A border adjustment is a tariff to ensure that products made in other countries that are not making the same effort as the European Union to reduce carbon emissions do not have an advantage over domestically-produced goods because of lower manufacturing costs.

The United Kingdom is considering a carbon tariff to protect British industry.

US climate envoy John Kerry discouraged European leaders in March from adopting such a proposal. Kerry said it should be adopted only as a "last resort" and not before the United Nations global climate conference in Glasgow in November.

**CLIMATE CHANGE** is making output from renewable energy projects harder to predict.

Fitch Ratings reported in March that a comparison of actual production numbers from solar projects that Fitch rated against the P50 forecasts found that 73% of such projects were performing within 5% or better of the original forecasts. Six percent were significantly below the forecasts. However, only 24% of wind projects were within 5% or better than the original forecasts. Nearly a third were more than 15% below.

A separate survey by kWh Analytics last fall found slightly different numbers for solar. kWh Analytics reported after reviewing 30% of the US solar fleet owned by 10 of the top 15 project owners that utility-scale solar projects were underperforming P50 output forecasts by 6.3% on average. (For more detail, see "Overestimation of solar output" in the October 2020 *NewsWire*.)

**ABOUT 15% OF US SOLAR PROJECTS** will reach the end of the recapture period for investment tax credits this year, presenting opportunities for private equity and pension funds looking to buy assets and for lenders looking to do refinancings.

Many US solar / *continued page 15*

## Shareholder Debt

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investor would fund the blocker with a combination of debt and equity. The interest paid on the debt component is generally deductible and allows the blocker corporation to reduce its taxable income. The caveat is that for the interest to be deductible, the debt must be respected by the Internal Revenue Service. This typically requires the terms of the loan to be "arm's length" and the blocker corporation to be adequately capitalized.

Distinguishing debt from equity depends on consideration of the overall facts to determine the bona fides of the debt.

The US courts have identified 11 relevant factors. No one factor controls, so evaluating cases where the factors line up on both sides of the equity-debt divide requires judgment.

Determining what mix of debt and equity to use for US acquisitions requires a two-step calculation.

The factors are (1) whether the purported loan is called a loan, (2) whether it has a fixed maturity date and scheduled payments, (3) whether it bears a fixed rate of interest and requires interest payments, (4) the source of repayments, (5) the adequacy of capitalization, (6) the identity of interest between the creditor and the stockholder, (7) the security for the purported loan, (8) the corporation's ability to obtain financing on the same terms from third-party lenders, (9) the extent to which the purported loan is subordinated to the claims of outside creditors, (10) the extent to which the purported loan is used to acquire capital assets, and (11) the presence of a sinking fund to provide repayments.

What does it mean to be "adequately capitalized"? There is no bright-line test. However, the US Supreme Court suggested in a 1946 case, *John Kelley Co. v. Commissioner*, that a corporation is not too thinly capitalized if it has at least one part equity to four parts debt. However, this was in what lawyers call "dicta" because it was in a discussion in the opinion that was not central to an issue decided in the case. Therefore, it is not considered a binding precedent.

A low debt-equity ratio is not a guarantee against re-characterization of a purported loan as equity. The US Tax Court re-characterized debt as equity where there was a 1:1 debt-equity ratio because it determined there was never a real intention to repay the debt. The court said the fact that the shareholders in the case each held the purported debt instruments and shares in identical proportions suggested the "loans" were not real debt. There is little incentive in such a case to enforce the claim as a creditor if doing so would harm the parties' equity interests.

Different courts have taken different views about how much weight to give to the debt-equity ratio. One US appeals court declined to rule in a case involving shareholder debt, *Rowan v. United States*, that any certain level of debt-equity ratio is needed and said it is for Congress to do so if desired.

Another US appeals court, in a case called *Bauer v. Commissioner*, said the reason to look at a corporation's debt-equity ratio is it helps evaluate the risk that the purported loan will not be repaid. No real lender would make a loan that is unlikely to be repaid, and the interest rate usually varies depending on the riskiness of the loan. Therefore, in the view of this appeals court, the relevant inquiry is not a court-imposed capitalization standard, but whether a real lender would make such a loan.

The appeals court found helpful a letter from a Bank of America loan officer who said he had dealt with the company and was familiar with its financing during the years in question, and the bank would be willing to make loans equal to or greater than the amounts loaned by the shareholders.

Other courts have said the acceptable level of debt to equity depends on the industry involved and the character of the business being conducted. A company may be considered adequately capitalized by the standards of the particular industry.

Some courts have respected debt notwithstanding very thin capitalization. For example, one court accepted a debt-equity ratio as high as 692:1. However, a leveraged blocker is subject to greater scrutiny, especially where each shareholder holds both shares and debt in the same ratio and there is no independent business purpose for the blocker corporation, other than for reasons of tax planning.

Before 2018, there was a bright-line capitalization standard that had to be met in certain circumstances for interest to be deductible by the blocker. Section 163(j) of the US tax code had earnings-stripping rules that limited interest deductions for blockers using related-party debt if there was a debt-equity ratio above 1.5:1. The goal was to prevent the earnings of thinly capitalized corporations from being siphoned off, in the form of interest, by a foreign person or other person that was exempted from US taxes.

If the debt-equity ratio was greater than 1.5:1 at the end of a tax year, the corporation was prohibited from deducting interest paid to a shareholder or other related tax-exempt person during that year. Interest could not be deducted to the extent the total interest — including interest owed to unrelated persons — would exceed 50% of the corporation's "adjusted taxable income" (roughly speaking, its cash flow before deducting interest). Interest in excess of this 50% limit was called "excess interest expense." It could still be deducted if owed to an unrelated-person.

While the 1.5:1 debt-equity ratio is no longer in the US tax code, an investor could still view it as a "safe" ratio.

## Limits on Interest Deductions

Since 2018, the US has moved to a cap on interest deductions that apply to all companies, not just where there may be cross-border earnings stripping. (For more detail, see "Cap on interest deductions explained" in the August 2020 *NewsWire*.)

The cap is 30% of "adjusted taxable income." Interest expense that cannot be deducted in a year because of the cap can be carried forward and deducted in later years. "Adjusted taxable income" is basically EBITDA: earnings before interest, taxes, depreciation and amortization. However, starting in 2022, it is calculated without subtracting depreciation and amortization, resulting in a lower limit and greater difficulty deducting interest.

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projects are financed in the tax equity market. Tax equity accounts for roughly 35% of the capital stack in a typical solar project, plus or minus 5%.

A sale of a project within the first five years after it is put in service will cause part of the investment tax credit claimed on the project to have to be repaid to the US Treasury.

This lock-in effect makes it hard to sell such projects directly for at least five years.

However, private equity and pension funds can still buy the developer interest without triggering significant recapture in cases where projects have been financed with tax equity to the extent the tax equity papers allow the developer to shed its interest during that period. The sale of the developer interest usually triggers recapture at most of only 1% of the investment tax credit claimed.

kWh Analytics expects more refinancings of large solar projects in the next few years as solar projects that were installed in the last five years start to roll off tax equity financings.

Its Lendscape survey of solar project finance lenders in March found that little to none of their business in 2020 was refinancings. About 14,000 megawatts of projects were put in service in 2016.

Seventy-nine percent of lenders surveyed said that their spreads on loans are currently at or below pre-COVID levels.

**UTILITY-SCALE BATTERIES** operated with an average round-trip efficiency of 82% during 2019, the most recent full-year *Power Plant Operations Report* by the US Energy Information Administration.

Pumped-storage hydroelectric projects — sometimes called "water batteries — had an average round-trip efficiency of 79%. The round-trip efficiency is a measure of the energy lost by converting electricity to another form of energy and then converting it back into electricity.

By contrast, making green hydrogen as a way to store renewable */ continued page 17*

## Shareholder Debt

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Thus, the 30% cap creates a debt limitation that involves structuring considerations other than thin capitalization. Accordingly, the owner of a blocker corporation should first determine how much interest it expects to be able to deduct under the 30% cap and then back into how much debt that means. Thin capitalization principles should be applied once the optimal level of debt is determined.

When determining the optimal level of debt, foreign investors should also consider how much interest can be deducted without potentially subjecting the blocker to the US base erosion and anti-avoidance tax, better known as BEAT.

The BEAT also took effect in 2018 and targets earnings-stripping transactions between certain domestic corporations and related foreign persons. The BEAT functions as a minimum tax in that it only applies if the blocker corporation would owe more under the BEAT than it owes in regular tax liability. It also only applies to corporate groups with average annual gross receipts of more than $500 million. (For more details, see "How the US tax changes affect transactions" in the December 2017 *NewsWire*.)

While the underlying interest deduction remains intact, the BEAT, when it applies, requires payment of an additional tax at a 10% rate through 2025, increasing to 12.5% after that.

When applying the thin-capitalization analysis, the question arises whether project-level debt should be included. The reason for a thin-capitalization analysis is to determine if there is a likelihood of repayment and how the capital structure would influence an outside lender's risk assessment if this were not related-party debt.

Given this rationale, it makes sense to include the project-level debt since it directly affects the source of repayment for the blocker's debt. It is worth noting that former section 163(j) required that project-level debt be taken into account as part of the analysis. While the case law does not address this specific issue, the prudent approach would be to calculate the debt-equity ratio including the project-level debt.

Finally, foreign investors should consider the tax implications of receiving interest payments from the US blocker.

Interest payments are subject to a 30% withholding tax unless a "portfolio-interest exemption" applies or the foreign lender is eligible for a reduced rate or complete exemption under an income tax treaty with the United States.

For interest on the loan from the foreign investor to the blocker to qualify as "portfolio interest," the loan must be in registered form, meaning transferable by one holder to another only when the transferee is identified to the blocker. The interest payments cannot be contingent. The foreign investor cannot be a bank lending in the ordinary course of business. The foreign investor cannot own 10% or more of the voting stock of the blocker corporation directly or indirectly.

The last requirement makes reliance on the portfolio-interest exemption impossible in most situations, except where the investment is being made by a foreign investment fund in circumstances where the US allows looking through the foreign investment fund so that the fund investors are treated as owning shares of the blocker directly.

Debt is used to repatriate earnings as deductible interest.

## Pulling Everything Together

Summing up, what should a foreign investor in a renewable energy project learn from this discussion?

The first step is to determine the optimal level of debt taking into account the 30% cap on interest deductions and the BEAT, which is primarily a calculation exercise.

Then, thin-capitalization principles should be applied to determine whether the optimal level of debt is likely to be respected as debt for US tax purposes. There is no clear standard. The US no longer has earnings-stripping rules that impose a strict two-parts-equity-to-three-parts debt standard. Rather, common law principles control.

While not legally relevant, one could use the 1.5:1 debt-equity ratio from the old earnings-stripping rules as a "safe harbor," as it seems unlikely any court would view such a debt-equity ratio as "thin" capitalization. However, most people would view this as too conservative and a debt-equity ratio up to 4:1 seems to be a reasonable benchmark if one is looking for a clear-cut standard.

Based on the case law, it is also reasonable to conclude that there is no set debt-equity ratio required. Rather, it comes down ultimately to whether a third-party lender would be comfortable lending on the same terms. An evaluation from an independent rating agency or a bank letter would be helpful to have in the file.

The other take-away to remember is that thin capitalization is just one factor. It is crucial to follow all the formalities of a commercial debt instrument, including having a market interest rate and a fixed maturity date. ◎

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electricity and then turn it back into electricity has a round-trip efficiency of less than 40%. In such a process, renewable electricity is used to power an electrolyzer that separates hydrogen from oxygen in water and then the hydrogen is used to run a gas turbine to generate electricity. Such a process makes sense only if it uses electricity during periods when the wind or solar project that is the power source would have otherwise been curtailed.

The weighted-average battery duration in 2019 was 1.5 hours. The weighted average duration for pumped-storage hydro was much longer. The duration refers to how long the energy remains stored before it is retrieved from storage.

**SOLAR, WIND AND STORAGE** are expected together to account for 83.1% of new capacity additions this year in the United States, according to most recent monthly forecast by the US Energy Information Administration.

Storage accounts for 9.3% of that amount. Solar is 37.7%, and wind is 36.1%. Natural gas at 14% and nuclear at 2.4% account for most of the rest. Unit 3 of the massive Vogtle nuclear power plant in Georgia is expected to come on line in November 2021. It is 1,117 megawatts.

Forty-four coal-fired power plants with a total capacity of 13,223 megawatts are expected to retire in 2021 and 2022. Four nuclear plants with a total capacity of 5,902 megawatts are expected to retire during the same period. Total US generating capacity is 1,119,187 megawatts. In a market where electricity demand has remained basically stagnant for the last two decades, coal and nuclear power plant retirements are what has given solar and wind developers the opportunity to grow.

US solar companies set a record last year, installing 19,200 megawatts of new capacity, according to the *US Solar Market Insight 2020* report released in March by the Solar Energy Industries Association and Wood Mackenzie. The EIA forecast is for 16,929 megawatts in 2021. Installations in 2020 were 43% higher than the year before.

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# Financing Merchant Projects After Texas

Many developers are wondering whether the appetite among banks and tax equity investors to finance hedged merchant power and storage projects has changed as a result of the February cold snap in Texas and, if so, how. What lessons did lenders and tax equity investors take away about how to do future projects? Are the effects limited to projects in ERCOT?

Close to 3,000 people registered to hear answers to these questions from four senior financiers who have been significant participants in past financings of Texas merchant projects. The four are Sven Wellock, managing director and co-lead of energy – renewables and power for ING Capital, Dan Miller, a managing director of CIT's power and energy group, James Wright, managing director and head of renewables, clean energy and sustainability in the United States for CIBC Capital Markets, and Rubiao Song, head of energy investments for JPMorgan Capital Corporation. The moderator is Keith Martin with Norton Rose Fulbright in Washington.

## General Pullback?

MR. MARTIN: Sven Wellock, many power projects in Texas sell electricity to the grid at spot prices and enter into hedges to put a floor under the electricity price. In your view, is it still possible to finance new greenfield projects with this profile?

MR. WELLOCK: The short answer is yes. I think the recent polar vortex exposed some loopholes in the financing structure that include unmitigated, asymmetric risks for the lenders and the equity. Some banks are still licking their wounds and may shun these types of financings, but I think other banks are going to continue to look at such financings and will be laser focused on these risks. There are tools to fix some of these loopholes. We can talk about those tools. I think that there is still a future for these types of financings in ERCOT.

MR. MARTIN: Give an example of an asymmetric risk that you consider a loophole.

MR. WELLOCK: An example is where the project is exposed to a settlement under the hedge when it is unable to produce electricity and generate any revenue to offset that settlement payment under the hedge. There is no cap on that risk. The required uncovered payment could be huge, as we saw happen to many projects in ERCOT.

MR. MARTIN: Dan Miller with CIT, is it still possible to finance greenfield projects with hedges?

MR. MILLER: I agree with Sven. I think for the right sponsor, the right credit structure and the right pricing, it is still possible. The sponsor needs to demonstrate that the borrower's credit profile can withstand a similar event and is doing that in a variety of ways. The lenders understand the sponsors' view that this was a highly unusual event, but there still needs to be a well thought-out answer for what is an obvious question.

Some sponsors are putting together back-casts, some are restructuring the hedge entirely with lower volumes and larger tracking accounts, and some are providing further support themselves to stand behind the deal. So there are ways to get these deals done. It just might be a little different than in the past.

MR. MARTIN: The bottom line is the sponsor has to show the project can survive this sort of event were it happen again in the future.

MR. MILLER: Yes.

MR. MARTIN: James Wright, will it still be possible to finance merchant projects with hedges?

MR. WRIGHT: Yes. What comes to my mind is that wonderful line, I think from Jurassic Park, when they said "life finds a way." The financing markets will find a way through this.

The asymmetric risks that Sven mentioned have people thinking more about covariance risk and how we deal with that in renewables. I think we will see far fewer fixed-volume hedges in the future. To deal with some of those risks that Dan and Sven talked about, we need to think more broadly about possible technical solutions in ERCOT to help fix this.

One thing that could help is to combine wind with more storage. Could batteries help mitigate some of that covariance risk? I am always optimistic that life will find a way.

MR. MARTIN: Explain covariance risk.

MR. WRIGHT: It is a renewables phenomenon that is often thought about as being somewhat theoretical, but we saw it in action a couple of weeks ago.

When there is little wind, prices tend to spike in ERCOT, and then prices fall when there is more wind. That means there is a negative relationship: the more you hedge, the more covariance risk you get, and the more renewables you build on the grid, the more the covariance risk as well. We have to be more thoughtful about these hedge structures and some of the possible technical solutions.

(For more detail about covariance risk, see "Covariance Risk: What is it and how to manage it" in the June 2019 *NewsWire*.)

MR. MARTIN: We will dig into that more deeply. Rubiao Song, JPMorgan accounts for about 25% of the tax equity market in renewables. Will merchant projects with hedges still be able to raise tax equity?

MR. SONG: Yes, but it will be more difficult. It has been increasingly difficult to finance hedged projects in ERCOT precisely because of the covariance risks. And not only that, the hedges also expose projects to large locational basis risk that we can explore in more detail later.

## Hedged merchant power and storage projects in ERCOT can still be financed.

We have to remember that the hedge serves a specific purpose for the wind projects, which is to provide a long-term general power price protection. There are projects with hedges that were entered into five or more years ago that provide a fixed price of $30 or more a megawatt hour. Those hedges are providing real benefits to the projects.

The sponsors need to understand that these hedges are not just a contract: you cannot sign one and put it on the shelf and forget about it. It requires continuous monitoring and risk mitigation at a project level precisely because of the covariance risks.

We saw this in the summer with heat waves. Power prices spike when the wind is not blowing as strongly and electricity output is low. The winter storm exponentially exposed that risk. Now we see that sponsors are actively managing this risk by selectively unwinding the near-term hedges with banks. That gives them long-term power price protection, but without suffering the near-term volatility. The / continued page 20

## IN OTHER NEWS

**CALIFORNIA** will need to triple the capacity of its power grid and may have to add 6,000 megawatts of new renewable and storage facilities a year to meet state targets of 60% renewables by 2030 and 100% by 2045, according to a joint report in March by the California Energy Commission, California Public Utilities Commission and the California Air Resources Board.

Over the last decade, the state has installed an average of 1,000 megawatts a year of new utility-scale solar and 300 megawatts of wind. Regulated utilities in the state are expected to install another 8,000 megawatts of renewable energy generating capacity over the next three years.

**DATA POINTS.** Half the US renewables M&A deals in 2020 were with foreign buyers.

Green hydrogen currently costs between $3 and $6.55 a kilogram to make, according to a July 2020 report by the European Commission. Morgan Stanley estimates that even if the cost fell to $1 a kilogram, the price would still be $8 an mmBtu, or about three times the current price of natural gas that it would have to displace in order to have a significant market.

Utility-scale solar panels are expected to cost 28¢ to 29¢ a watt for H2 2022 deliveries, an increase of 2¢ to 3¢ a watt over earlier forecasts, assuming no US import tariff. Solar panels for residential solar systems generally cost 2¢ to 4¢ more than for utility-scale applications, according to Phil Shen with Roth Capital Partners.

China supplied nearly half of US lithium-ion battery imports in the last quarter of 2020.

**NOT *THAT* TAX EQUITY.** An April 7 headline in *Tax Notes Today* read, "Congressional Democrats United on Need for Tax Equity." The article was about support among Democrats in Congress for increasing the corporate tax rate.

*— contributed by Keith Martin in Washington*

## Texas

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winter storm taught everyone that these covariance risks are real. The market is still thinking about it and also thinking about other risks associated with these types of contracts.

There are always means to manage risk. We need to be actively pursuing these strategies in a programmatic way and not on an ad hoc basis, and not trying to time the market. That is the main takeaway.

MR. MARTIN: Your predecessor as head of energy investments, Yale Henderson, said on a past call that JPMorgan was pulling back from the Texas panhandle because the electricity basis risk had widened to as much as $12 to $14 a megawatt hour. Electricity basis risk is the risk that a project will sell its electricity to the grid at a node for one price and have to pay $12 to $14 more per megawatt hour at a hub to buy back electricity to supply under a fixed-volume hedge.

Were there parts of Texas in which you were not investing tax equity before the cold snap?

MR. SONG: I would not say that there were parts where we would not invest, but we certainly were always very selective about project locations. It was tougher to finance projects in parts of Texas that have local congestion issues and curtailment risk. There are structural features that we can deploy to mitigate that risk. For example, for wind projects, we have been doing almost exclusively pay-go deals where the amount of tax equity invested is tied partly to the output.

### Pause?

MR. MARTIN: Are you working currently on financing any new greenfield merchant projects and, if so, when do you expect the next one to close? What I am really getting at is whether the market will pause for a while before closing another such deal.

MR. SONG: I do not expect a pause, but things will slow down. We know that a lot of sponsors and investors are still actively working through the situation. It will take time to work through how best to mitigate the risks we saw in evidence due to the winter storm. A risk mitigation strategy needs to be put in place.

MR. MARTIN: That says pause to me. Lenders, do you expect a pause on lending to hedged merchant projects and, if so, for how long?

MR. WRIGHT: I expect a pause. I agree with Rubiao. Part of that is a natural visceral reaction to what just happened. It is worth noting that there are a lot of other routes to the market right now for banks and tax equity. If you think about the broader renewables market around the US, the other regional grids are all booming, so it is not like there is a shortage of supply so far as deals.

The current regulatory uncertainty in Texas is also causing folks some indigestion right now. There is a lot in flux with the PUCT and ERCOT plus the governor and Senate weighing in. The state Senate voted earlier this week to adjust some of the power charges retroactively. It is hard to lend into a market with so much political turmoil. I do think there will be a pause or slow down.

MR. MARTIN: One of my colleagues, Sam Porter, pointed out that Texas has finally fully deregulated. The governor fired the sole remaining public utility commissioner yesterday. Dan Miller, Sven Wellock, will there be a pause and, if so, for how long?

MR. WELLOCK: I think it will be a slowdown. I don't know that we can call it a pause. There are some deals in the market right now. ING is in a few of those. They will require more scrutiny to make sure that the asymmetric risk allocation is mitigated and the impact of the events we saw in February will not happen again. How much time it takes to sort this out will probably vary by project.

The case may be easier to make for a solar project that does not have as many moving parts as a wind project, but even wind projects can mitigate the risk by winterizing. We do this all the time in other parts of the US. For example, we have financed wind projects in PJM in harsher climates, and they work fine.

Some banks may take a break, but I think other banks will merely take more time to ensure that they are comfortable with the risk.

MR. MILLER: If there are good answers to the most obvious question what would happen after another extreme weather event, then deals can get done. There are a few ways that sponsors can address these problems. This is not a "one size fits all." Every deal takes on a life of its own, and a sound credit structure will prevail to the extent that one can be agreed to with the sponsor.

MR. MARTIN: But it does seem that people should assume that things will take a little longer. How much longer?

MR. MILLER: Yes. It is like any new interesting risk, whether it was the fire risks in California or the construction-supply risks during the heat of COVID, there will just be a longer diligence process and more questions from banks. To the extent there are good answers just as in any deal, transactions will get done.

## Unhedged Better?

MR. MARTIN: The tax equity market has been requiring hedges of 10 to 12 years. Some developers would rather do without hedges because they introduce two risks: electricity basis risk and the price spikes like the ones in February. Rubiao Song, do you think tax equity investors will decide they are better off without hedges?

MR. SONG: I am not sure that I agree with that statement. I do not believe every tax equity investor requires a hedge. We always understood the limited value of hedges and the problems they introduce. Tax equity investors require very little cash to reach their returns. They are mostly concerned with the project generating enough cash flow to cover the operating expenses and to keep production up. For the reasons we were just discussing, hedges are not necessarily the best offtake strategy to ensure such cash flow.

We are open to other arrangements that will ensure a minimum level of cash flow. Looking forward, different types of contracts like contracts for differences, unit-contingency hedges and affiliate PPAs could all be solutions.

MR. MARTIN: But not selling in the spot market without any price protection?

MR. SONG: I think we will expect a certain level of price support. We are not looking to hedge to the P99 level of production. This is going to depend on the project specifics, but we will need certainly a very small level of price support to ensure that operating costs can be covered.

We have seen the corporate offtake market evolving. We have seen some CfDs with price floors and upside sharing with the sponsor; we like that feature. Some CfD contracts would offer the sponsor the ability to pick node or hub settlement. That has been a welcome development.

MR. MARTIN: Sven Wellock, you heard Rubiao say he will need price protection on the down side and there are various forms that could take. How do lenders feel about hedges? Are they required and, if so, at what level?

MR. WELLOCK: I still think hedges will be required to demonstrate resilience in the cash flows. I think that the key question is how much hedging is necessary to get the banks comfortable with some minimum floor of cash flows. The answers will require understanding the availability risk and basis risk in hedges and what the risk mitigants are.

I do not see the hedges going away. I expect to see an increase in the premium for projects that have these risks. I do not see banks going to a full merchant model.

MR. MARTIN: How much of a premium do you think will be required? Most debt in the renewables market is back-levered debt that sits behind the tax equity investor in the capital structure.

MR. WELLOCK: I don't know, but recent events have exposed some loopholes in the financing structure. I don't think back-levered lenders realize they could be completely wiped out if the hedge goes upside down. That was not priced into their margins. How much the premium will be for these types of hedges remains to be seen. I can't answer that question.

MR. MARTIN: Dan Miller, what percentage of the revenue must be hedged if you agree that there will have to be a hedge of some sort? And what happens if the hedge covers only a fraction of the revenue stream? Is the debt sized solely on the basis of the fixed revenue?

MR. MILLER: Taking a step back, we have been working with clients on some fully merchant options. These structures would obviously be much lower leverage and higher priced, but the sponsors are willing to take that tradeoff to gain access to higher electricity prices.

Not every lender will be doing that, but there will be a sub-segment of the debt market that is open to it and thinks that it makes sense to be paid earlier to avoid having merchant risk later in the useful life of the asset on hedged assets with merchant tails.

We have seen a couple broadly syndicated deals get done where 60% to 70% of the revenue is contracted. We are willing to give credit in debt sizing to that 30% to 40% merchant, but clearly at a discount. If it is below that level — say 50% or fully merchant — then you need to start adding a greater discount to the merchant revenue and probably use a higher debt-service coverage ratio as well.

We think that there are some solutions that we can work for the debt to the extent that we can come up with a practical approach that also works for the tax equity.

MR. MARTIN: Let's say the debt-service coverage ratio is 1.25 times P50 for solar and 1.35 times for wind currently for contracted revenue, meaning hedged revenue. What DSCR would have to be used for the merchant part?

MR. MILLER: If the revenue is fully merchant, then the DSCR would be in the two-times range. Maybe the ratio is lower initially. For example, maybe in years one through seven, you hit 1.75 or 1.6 times, stepping up as you get later in the useful life to 2.0 but not going out further than 15 years on an amortization profile. This is not priced anywhere near some of the other bank market products. It is much higher. */ continued page 22*

## Texas

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### Contract Mix

MR. MARTIN: What percentage of projects you are seeing in ERCOT with hedges versus standard bus-bar PPAs?

MR. WRIGHT: I think the vast majority have been heavily contracted up until now.

I was going to add to what Dan said. I agree with the way he is approaching this. I think about this in terms of buckets of capital. In a significant portion of contracted revenue deals, those margins start with a one handle, which is where the market has been up until now. They have robust investment-grade constructs. That is one bucket of capital.

Then you have the partially contracted deals that Dan was talking about, which I think of as another bucket of capital, which might have margins of 200 basis points and higher above the base rate, which is matching the risk-weighting of how lenders look at that risk.

And then there is a very small bucket of capital that is going to be doing fully merchant, to Dan's point. There are lenders who will do fully merchant deals, but obviously at a much higher cost of capital.

MR. MARTIN: Rubiao Song, what percentage of projects does JPMorgan see currently in Texas with hedges versus traditional bus-bar PPAs?

MR. SONG: Fixed-rate bank hedges are a small percentage, say less than 20% to 25%. But bus-bar PPAs are also a very small percentage. It is rare these days to have bus-bar PPAs. The most common contracts we see are CfD contracts that require payments on a unit-contingent generated basis. They do not have the price-spike risk about which we have been talking, but they do introduce the locational basis risk, which could be significant in congested areas.

MR. MARTIN: CfDs or contracts for differences are hedges that are financially settled. The project owner swaps floating payments tied to spot electricity prices for fixed payments, correct?

MR. SONG: Right. The difference is whether the settlement quantity is a fixed or pre-agreed amount or it is based on actual output from the project. The latter is better suited to mitigate the risk that happened last month in Texas.

MR. MARTIN: How common are hedged merchant projects in other markets besides ERCOT?

MR. SONG: In any liquid power market, you could use hedges. We have certainly been financing them in California, MISO and PJM. They are not a big percentage.

### Hedge Hierarchy

MR. MARTIN: Hedges take multiple forms. There are fixed-volume swaps that can be physically or financially settled. There are proxy-revenue swaps. There are proxy-generation PPAs. There are contracts for differences that Rubiao Song was just describing. From your perspective, are all hedges the same? JPMorgan's preference is a contract for differences tied to actual generation and not to a notional amount.

MR. WELLOCK: We have a preference for contracts for differences. We have looked at a few proxy-generation hedges, but didn't really get comfortable from a debt perspective with these because they have both basis risk and availability risk.

The more difficult risk to mitigate and get comfortable with is the availability risk. Your hedge might be in the money, but if you are not producing energy, you have no revenue to offset your potential settlement under the hedge.

Electricity basis risk depends on location. If you are in a congested area, the basis risk might be significant. We try to make sure that we are looking at a project that has minimal basis risk.

There are certainly differences in the types of hedges. People need to understand what they are and what risks they are taking with different hedge products. (For more detail, see "Hedges for wind projects: evaluating the options" in the June 2017 *NewsWire* and "Lending to hedges wind and solar projects" in the February 2020 *NewsWire*.)

MR. MARTIN: Are there some of type of hedges that you will do and some you will not do?

MR. MILLER: Our preference clearly, after this event, is the hub-settled as-generated contracts for the reasons that were just discussed. The market depth will be much wider for the same reasons, and the pricing would be better on this type of deal.

When we first started doing ERCOT projects, they were mainly fixed-shape hedge deals. We have seen a lot of corporate buyers come in. The projects are being sited closer to the hub to which they are tied. That is alleviating a lot of the basis risk, which is the primary risk in the as-generated hub-settled contracts.

MR. MARTIN: James Wright, are there some forms of hedges that you will do and some you will not do?

MR. WRIGHT: I don't want to generalize. We will look at everything and be thoughtful about what we execute on. The challenge, when you move beyond traditional power purchase agreements with utilities, is the variety of contracts we see nowadays in renewables in the US. Each of the contract types that you just ran through — corporate PPAs, proxy revenue, proxy generation, CfDs — has unique benefits and challenges.

The counterparty credit risk on those can be very different depending on who is on the other side of the contracts. Some of them come with tracking accounts to deal with basis risk. Some will have a lien on the project. When you get into the corporate PPA world, there is a deeper dive on what is the alternative route to market for the project if the corporate defaults on the PPA, particularly with some of those more sub-investment-grade or crossover investment-grade buyers that we are now seeing in the market. All of these contracts require a much more nuanced credit analysis than you would typically see with a utility offtake contract.

## Changing Terms

MR. MARTIN: How will other terms for hedged merchant financings in ERCOT change, besides what we have just discussed about hedges?

MR. SONG: We have been accustomed to thinking the tax equity is in the first position in the capital stack. Going forward, we are going to be very focused on whether these offtake arrangements have introduced a senior creditor to the project that could cause liquidity or other problems.

Going forward, if you do not have a bus-bar PPA or other well-structured offtake contract, sponsors should expect to have to provide more support for the project through working capital loans or project reserves or entering into affiliate contracts to provide cash-flow protection.

We are already seeing this happening. We are already seeing more deals on a portfolio basis, combining wind and solar, combining projects in different regions and with different offtake strategies. That could be a good way to get the deals done.

MR. MARTIN: So perhaps put one ERCOT project into a portfolio of three projects, with the other two having bus-bar PPAs and being located in other parts of the country. Let me pose the same question to the rest of the bankers: how will other terms for ERCOT merchant financings change?

MR. WRIGHT: The cost of capital will certainly increase, at least in the short term. Lenders will be less bullish on some of those merchant tails that we have been seeing in quasi-contracted deals. There will be a bit of a step change or rethink needed on how tracking accounts work.

MR. MILLER: I think that there will probably be less market depth for some of the fixed-shape hedges. There were probably around 15 lenders who were willing to do the fixed-shape deals before February. That is obviously going to change, and especially if you do not have a good answer to the obvious question how the project survives another extreme weather event.

We are in the market now with several as-generated deals. The merchant plus an as-generated hub-settled hedge is a good combination to marry together, because you could obviously take advantage when there are price spikes and the sun is shining and not get hurt on the downside.

We are seeing a lot of those opportunities come across our desk, and we are seeing a lot of interest from lenders in that profile, at least on projects with top sponsors. I think it all comes down to who is the sponsor, what is the proposed structure, and what is the price relative to the other three or four deals that come across your desk in a given week or two.

MR. MARTIN: Let me mention one more thing, and then we will go to a few audience questions.

Some people have been asking about "default uplift allocations." ERCOT has to break even, and so if it is ordered to return billions of dollars — the ERCOT market monitor said initially that $16 billion was overpaid — all market participants would be required to contribute. There is a cap on how much ERCOT can collect each month.

One question being asked is whether new greenfield projects will end up having to bear a share of these default uplifts. The amounts would be an offset against the future revenue such projects earn from spot sales of electricity. ERCOT is already more than $2 billion in the red before any adjustments for overcharges.

The answer is new projects that were not connected to the grid when the default occurred would not be affected.

CPS Energy — the municipal utility in San Antonio — filed suit on Friday to block the burden from being shared across all market participants.

## Audience Questions

MR. MARTIN: We are going to audience questions. I will read each question quickly. Just one person answer. Let's see how many we can get in during the short time remaining.

"How do you think about your preference for merchant versus fixed shape if sponsors were conservatively to haircut the fixed shape in lieu of moving to a unit-contingent contract?"

MR. MILLER: We were already there before the winter storm. Lenders were more than willing to trade */ continued page 24*

## Texas

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more merchant risk for less shape risk on the deals that we were getting done. That is one tool that sponsors are using to get through this period.

MR. MARTIN: Another question.

"Is anyone hearing how long it may take market consultants to recalibrate merchant price forecasts in Texas? There were large retirements forecasted in the coming years, and perhaps those units forecasted to retire are the very units operating that saved the ERCOT grid from total collapse. Does anyone have any insight into this?"

MR. MILLER: I have talked to several market consultants about that. Fewer projects may retire in the near term. There were not many retirements expected earlier, maybe two or three gigawatts in the next five. However, other plants may have to weatherize, which could offset the impact. It is a fluid situation. The market consultants are trying to gather as much information as possible for their next quarterly forecasts.

Lenders are focused after the February cold snap on unmitigated asymmetric risks.

MR. MARTIN: Next question.

"Will tax equity be available for a contract for differences that is for 80% of the output? How low could you go on contracted output to attract tax equity?"

MR. SONG: A contract for 80% is a pretty high level. The real answer to this question is it depends. In regions where there is a very liquid market, and the electricity basis issue is not a big concern, having a CfD contract that covers at least 50% of the output could make the project viable from a tax equity standpoint.

MR. MARTIN: Next question.

"What percent of debt sizing would you be comfortable linking against purely merchant cash flows?"

MR. WELLOCK: Around 50% or less is an amount of merchant risk that we would be prepared to take.

MR. MARTIN: Next question.

"Is there a greater preference for solar given less availability risk?"

MR. WELLOCK: Yes. I think you can make the case of mitigated risk for a solar project more easily than you can for gas or a wind project.

MR. MARTIN: Apologies to those waiting to have questions answered. We are out of time, so this will have to be our last question.

"Unlike wind and gas facilities, batteries in Texas are already winterized. HVAC containers keep them warm when it is cold. They have no problem operating during a cold snap. Do any of the panelists believe that financing batteries on a purely merchant basis in Texas could be less risky than hedged storage?"

MR. MILLER: We will take the same approach that we do on solar. We will work with a market consultant and understand all the assumptions going in, apply a discount to that, and work on some downside sensitivities. If that leads to a five-year repayment profile for a battery deal, then it is something that we can entertain. We are open to merchant, but with less leverage to ensure debt repayment occurs well within the useful life of the asset. ◎

# Climate-Change Risks for Company Leaders

*by Tom McCormack in New York, and Robin Ball in Los Angeles*

Climate change is making it more risky to serve as a director or officer of some energy companies.

The fund set up to pay victims of California wildfires is suing 22 former executives and board members of PG&E Corporation, the parent company of the electric and gas utility that serves northern California, for their failure to take actions that could have prevented the wildfires. The suit had been on hold while PG&E was in bankruptcy, but resumed moving forward in late February.

Lawsuits are proliferating after a cold snap in Texas in February left millions without electricity and water and caused a number of deaths.

Companies buy directors and officers insurance, and corporate articles and by-laws typically contain indemnification provisions. But these protections are not bullet-proof.

Directors and officers have a fiduciary duty to the company to exercise adequate oversight of company affairs.

They also have a duty of loyalty to the company.

If directors or officers breach these fiduciary duties, they can be sued for the resulting losses by the company. However, in practice, it is more common that the company itself does not sue and that instead a shareholder seeks to sue derivatively on the company's behalf, particularly where a company suffers heavy losses.

Of course, claims for damages are not the only sort of liability company leaders may face for misconduct. For example, two executives of a South Carolina utility company pled guilty to criminal charges in 2020 for their roles in misleading investors about the status of a nuclear power plant that was facing major cost overruns and construction delays. (For more details, see "Charges against corporate officers" in the April 2020 *NewsWire*.)

## California

The lawsuit against 22 former PG&E directors and executives claims they breached their fiduciary duties to PG&E and should be held liable for subjecting it to billions of dollars of damages and loss of market capitalization resulting from the 2017 North Bay Fires and the 2018 Camp Fire. The suit was originally filed as a shareholder derivative suit in 2018, but was put on hold by the courts to allow time to sort out conflicting creditor claims after the company filed for bankruptcy.

As part of the bankruptcy plan approved last year, PG&E assigned its claims against the former board members and officers to the Fire Victim Trust, the entity created to administer and distribute funds set aside to pay fire victims on their claims against PG&E. The bankruptcy stay has been lifted and the trustee, who has taken over as the plaintiff, filed an amended complaint and is proceeding with the action.

The core theory in the lawsuit is that the former directors and officers prioritized short-term profits (and lining their own pockets with lavish compensation and bonuses) over incurring the costs of safety and regulatory compliance. The complaint provides a detailed account of PG&E's repeated risk-management failures and safety violations that the complaint claims led to the 2017 North Bay Fires and the 2018 Camp Fire.

The California Public Utilities Commission found that the 2018 Camp Fire was caused when a 100-year-old, outdated and worn "C-hook" broke, causing a pole, wires and other equipment to fall to the ground and ignite the fire. PG&E was found to have violated 12 public utility regulations and codes, pled guilty to multiple felonies, and was fined more than $2 billion.

The lawsuit against the directors and officers claims they breached a duty to exercise reasonable care by failing to ensure inspection and maintenance of PG&E's equipment such as the aged C hook. The suit also says that PG&E knew that one of its transmission lines involved in sparking the fire was a hazard and had determined that the line needed maintenance. However, PG&E cancelled maintenance on the line in 2014 and there were no subsequent climbing inspections of the line.

As to the 2017 North Bay Fires, the suit claims the officers and directors failed to ensure that PG&E complied with California Public Utilities Commission regulations for keeping power lines cleared of vegetation. They allegedly compounded that failure by failing to ensure that PG&E installed a power shut-off system for use during high-wind periods. Such power shut-off systems are critical during high winds because of the risk that trees will make contact with power lines and start fires. The complaint alleges that PG&E should have installed a power shut-off system in 2017 because it was six years behind at the time on its vegetation management program.

PG&E's directors and officers also allegedly failed to ensure that the company took other critical risk-management measures, such as reprogramming circuit breakers so that they would not automatically re-energize power lines in / continued page 26

## Climate Risks

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order to avoid fires caused when trees or limbs contact power lines and cause outages. The complaint claims that the directors and officers knew these conditions posed an unacceptable risk and that a de-energization program was needed during extreme fire danger conditions, but failed to ensure implementation of the necessary programs in compliance with applicable regulations and standard.

The suit charges that this was all a product of the directors' and officers' fostering an environment in which safety and regulatory compliance were sacrificed to improve corporate profitability (and their own incomes), resulting in corporate liabilities that exceeded the entire market capitalization of the company by billions of dollars.

### Texas

The recent events in Texas, where blackouts left millions of customers without power for days amid bitterly cold temperatures, have not yet given rise to similar actions against directors and officers. But they have already spawned a raft of other lawsuits and investigations and, by all accounts, there will be many more.

Climate change is making it riskier to serve as a director or officer of some energy companies.

To date, the actions filed include wrongful death claims and class actions filed against the Electric Reliability Council of Texas and against a number of power companies alleging failure to prepare properly, despite prior warnings, for cold weather.

Another electricity provider accused of price gouging was hit with both a class action seeking over $1 billion in damages and a suit by the Texas attorney general. The largest power cooperative in Texas filed for bankruptcy protection. Prosecutors have announced criminal investigations into the power outages.

If the companies involved suffer significant losses as a result of the fallout from the blackouts, derivative suits alleging oversight failures against directors and officers, particularly of public companies, appear likely to follow.

### D&O Insurance

D&O insurance policies generally cover damages and legal fees if the director or officer is sued personally for alleged wrongful acts related to their company roles. The policies also usually also provide coverage to the company itself.

Policies also cover both current and former directors and officers. D&O policies are usually "claims made" policies, which means they provide coverage only if the claim is made while the policy (including any extended coverage period the company purchases) is in effect.

While D&O policies are not uniform, there are important limitations on coverage that may affect whether or to what extent a policy covers any particular claim.

First, depending on the size of the claims and the number of persons sued, the policy's dollar limits may or may not be adequate to cover all of the liability and defense costs. This is particularly apt to be an issue where the losses are catastrophic and the lawsuit targets a large number of directors and officers.

Second, there are typically coverage exclusions that may eliminate coverage, depending on the specific policy language and the precise claim.

For example, policies generally exclude coverage for intentional, willful or deliberate misconduct or criminal acts. This might eliminate coverage, for example, for intentionally implementing a program of regulatory non-compliance. This exclusion may be subject to a "final adjudication" requirement, so that it is not triggered until there is a final court decision finding such misconduct, and the insurer has to fund defense costs until there is such a determination. However, if there is ultimately a final adjudication of such misconduct, then the insurer may be entitled to recover amounts it paid to defend the director or officer.

The policy may also exclude coverage for claims by one insured against another insured; unless there is an appropriate exception to the exclusion, it could eliminate coverage for shareholder derivative actions.

Further, the policy could exclude bodily injury and death which, depending on the specific language, could eliminate coverage where the company losses at issue arose from wrongful death or bodily injury claims.

Third, an insurer may be able to restrict or eliminate coverage where information about the activities and risks was known before the policy was purchased, but was not disclosed to the insurer during the insurance application process.

Fourth, the insurance may not include coverage for punitive damages and, depending on the state, may be prohibited from offering such coverage.

Applying these and other coverage exclusions and limitations will depend heavily on the exact language of the D&O policy and the factual details of the claim.

## Corporate Indemnification

Directors and officers may also be protected by corporate articles and by-laws indemnifying them against claims concerning their corporate roles, or, for directors, exculpating them from liability. But these provisions also have significant limitations.

State corporation laws typically authorize, but do not require, corporations to indemnify directors and officers for damages and legal expenses related to claims concerning their corporate roles.

However, state law generally bars indemnifying intentional misconduct. For example, Delaware's statutes permit indemnification only if the director or officer acted in good faith, reasonably believed his or her actions were not opposed to the best interests of the company and had no reasonable cause to believe his or her conduct was unlawful. Further, corporate indemnification may be of little value if the corporation is bankrupt, leaving the directors and officers with unsecured claims against the bankrupt estate.

State laws generally permit exculpation — the elimination of monetary liability — of directors, but not officers, for breaches of their fiduciary duty of care (for example, for simple negligence).

The advantages of this over indemnification are that it potentially permits a motion to dismiss such claims at an early stage, before expensive discovery, and that it is unaffected by the corporation's bankruptcy since it is not a claim for payment by the corporation. But states typically bar exculpating directors for breaches of the duty of loyalty, bad faith, intentional misconduct, violations of law or transactions in which the director derived an improper personal benefit.

## Board Members

Anyone who serves or is asked to serve on the board of a company that could be charged with contributing to climate-related disasters should take steps to insulate himself or herself from liability for fiduciary-duty claims.

Most importantly, he or she should closely examine the pertinent company policies and programs — including regulatory-compliance policies and programs for identifying and addressing climate-related operational risks — and the company's implementation of those policies and programs.

Directors should actively engage with management to assure that risks are minimized and that compliance programs are real, robust and effective. It may be appropriate to increase the frequency of meetings where these issues are addressed. Further, directors should assure that their oversight activities, including discussions, analyses and plans, are appropriately documented.

Further, directors and officers should make sure that the D&O coverage that the company has in place is adequate, both as to the amount of coverage and as to the policy's terms. They may consult with the company's internal insurance professionals or its broker to understand the relevant terms of coverage and assess whether more favorable terms are available in the market and at what cost.

Finally, directors and officers should also examine the corporation's indemnification and exculpation provisions. To the extent those provisions do not afford the maximum protection permitted by state law, they may want shareholder approval for amended provisions that do so.

These steps may not guarantee immunity to future fiduciary-duty claims, but they will aid in defending against any such claims and in maximizing the protection afforded by D&O insurance and corporate indemnification and exculpation provisions. ◎

# Hydrogen: The Next Frontier

Despite widespread excitement at the prospect of green hydrogen being the next multi-trillion dollar commodity, the reality is that a number of challenges will have to be overcome before the gas can reach its full potential.

Hydrogen from renewable sources costs two to four times more than fossil fuel-based hydrogen. The United States lacks a comprehensive hydrogen strategy as has been adopted by many European countries. New pipelines will have to be developed or existing infrastructure retrofitted to transport hydrogen. Law and policy will have to adapt to accommodate advances in technology and business structures.

Despite these challenges, the Biden administration has hinted that hydrogen will play a key role in achieving the federal government's decarbonization goals. At the state level, California and New York have stepped into the vanguard with generous incentives and favorable policies.

Three experts discussed the prospects for hydrogen in the US during a livestream panel discussion in early March. The panelists are Sheldon Kimber, CEO of Intersect Power, Karen Lee, senior counsel at Southern California Gas Company, and Sanjay Shrestha, chief strategy officer at Plug Power. The moderators are James Berger and Deanne Barrow with Norton Rose Fulbright.

## Entry Points

MR. BERGER: Sheldon Kimber, Intersect Power is a solar developer. What is it doing with hydrogen?

MR. KIMBER: Intersect Power is a utility-scale solar and storage developer moving into ownership of its own assets. Our development portfolio is about 2.5 gigawatt-hours of solar PV and 1.5 gigawatt-hours of batteries. After construction, we will become an independent power producer and own our own assets.

We see hydrogen as the next step in our evolution from being a developer of solar to being an owner of solar and then eventually being an owner and operator of clean infrastructure assets. That means hydrogen, carbon-capture-and-sequestration and desalination projects.

Our view is that clean, cost-effective electricity is the nexus for decarbonization. A series of technologies, hydrogen being one of them, will bridge into other segments of the economy that are much harder to decarbonize, such as transportation, fuels, aviation and industrial uses.

Intersect will be a developer and owner not only of the solar and renewable plants that power hydrogen production, but also of hydrogen production.

MR. BERGER: Karen Lee, SoCalGas is the largest natural gas distribution utility in the country, serving more than 20 million consumers. What is it doing with hydrogen?

MS. LEE: We believe that gas distribution companies will be required to provide cost-effective transmission and distribution of hydrogen. We have the gas pipelines and related infrastructure. We think we are well-positioned to help with this energy transition.

We have also been a long-term supporter of research and development on the clean energy front, including research into hydrogen. We are actively working on opportunities for the transportation of hydrogen and for the base-load and resiliency components of hydrogen, including use at our data centers and other locations with high demand for hydrogen fuel cells. We are supporting the protonic exchange membrane – PEM — fuel cell development for transportation and stationary use. We are also looking at the ability of our natural gas pipeline infrastructure to play a role in hydrogen storage.

We have already moved forward with modernization projects at many of our key stations, including our Moreno compressor station, to create opportunities for advanced renewable energy. At Moreno, for example, we added an electrolyzer that can convert curtailed renewable energy into green hydrogen that is then put into on-site hydrogen storage tanks or used to run PEM fuel cells and hydrogen vehicle fueling stations.

We are in the midst of a hydrogen blending demonstration program and are working with our regulators to establish a safe target for blending hydrogen into the natural gas pipelines.

We are working on a demonstration of an "H2 hydrogen home" that will showcase various opportunities for consumers to use hydrogen in their day-to-day lives. We are also field testing various other technologies on the research and development front.

MR. BERGER: Sanjay Shrestha, Plug Power is clearly in the hydrogen business. Tell us what it is doing.

MR. SHRESTHA: We have been at it now for two decades. The real inflection point for the company happened sometime between 2014 and 2015. We believe we have created the first viable commercial market for hydrogen fuel cells. From 2014 to 2020, we experienced a 40% growth rate. We have the highest number of fuel cell systems out in the field: more than 40,000 systems. We have run our systems more than 600 million hours, which, if you assume five miles an hour even from a fork lift, is three billion hours of operating data.

We are taking costs out of the system. We have improved the reliability. We have done all of that with customers like Walmart and Amazon. On top of that, we have built more hydrogen fueling infrastructure than anybody to support material-handling and distributions operations at Amazon, Walmart and other large customer sites we are serving. We are the largest user of liquid hydrogen in the world today. We consume about 40 tons per day.

In 2020, we took important strategic steps to expand our presence and role in the green hydrogen ecosystem. We acquired a company that is in the PEM electrolyzer business called Giner ELX. We also acquired the only private company that has successfully built a large-scale liquefier. With those two acquisitions, we have become a vertically integrated green hydrogen generation company.

We are planning to build a first-of-its-kind force-majeure-resistant hydrogen network here in the United States. We are looking to build multiple green hydrogen generation plants throughout the US.

We have also been very busy establishing a global presence. We announced a partnership with Renault that will be our European platform and take us further into the fuel cell vehicle business. There will be a co-branded Renault and Plug Power light commercial vehicle. We have a partnership with the SK Group, one of the largest conglomerates in South Korea, that gives us an Asian platform. We also recently announced a partnership with Acciona that fully expands our hydrogen generation business into the European market.

## Use Cases

MR. BERGER: There are three main use cases with a lot of sub-use cases for hydrogen. They are transportation fuel, fuel for heating and cooking, and energy storage. Sanjay Shrestha, talk more about the opportunities for using hydrogen for transportation.

MR. SHRESTHA: In terms of the decarbonization of the transportation industry through electrification, one issue is the kind of electrification that will take place. Is it battery electric vehicles or is it fuel electric vehicles? That answer may depend on whether the need is short- or long-distance transportation.

For example, the reason we have had the kind of success and growth we have had in our distribution center and material-handling business is that there are sustainability, environmental and decarbonization benefits. The use case has also been successful because our customers are saving money. They get labor sayings, better productivity and better asset utilization.

We have also addressed one other critical piece of the puzzle in the material-handling market, which is the infrastructure. We have built fueling infrastructure for the likes of Amazon and Walmart. They can drive across the country by leveraging the network that we built and now manage for them.

If you are back at the depot, if you are looking to do less than 100 kilometers a day, or if you are driving a passenger car and charging is not an issue, then a battery electric vehicle makes all the sense in the world. This should continue at least until we get to a certain level of penetration of battery electric vehicles and charging infrastructure becomes a challenge.

When you start to think about payload, fast fueling and range, that is where hydrogen fuel cell electrification becomes meaningful. Owners of light commercial to class 8, middle-mile to long-haul trucking vehicles that carry cargo have a choice to make. They have to decide whether they want to drive around with a lot of batteries to meet the range or whether they want payload benefit and fast fueling benefit similar to traditional vehicles. It is in these areas that we believe the fuel-cell electric-vehicle value proposition becomes very powerful.

We are building a green hydrogen generation network in the US. We will have at least two plants running by the end of 2022. We believe that we will be able to provide green hydrogen fuel at diesel price parity when you take into consideration the efficiency benefit of a fuel cell system. We think transportation will be a very important market.

We also see a lot of applications in other areas, such as long-duration energy storage. We even see the benefit for some of the industrial market, even though that is not our core focus today.

MR. BERGER: Karen Lee, I am a SoCalGas customer. When will I be burning a little hydrogen along with the natural gas in my home?

MS. LEE: Hopefully fairly soon. We are working with our regulators to determine what is a safe level of hydrogen blending. We began hydrogen blending on a pilot scale recently. The target blend is up to 20%. This is well supported by applications in Europe and globally. In California, safety is our first concern. The application to the regulators, for anyone interested in regulatory issues, is Application A2011004.

We are working separately on a demonstration "hydrogen home" that will use solar panels to / continued page 30

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generate electricity that can be used to produce green hydrogen via electrolysis.

On the commercial customer side, we have projects focused on steam methane reformation. We are working with many of the large transit agencies to enable on-site conversion of natural gas into hydrogen to power hydrogen fleet vehicles.

MR. BERGER: Sheldon Kimber, talk about the opportunities for use of hydrogen to store energy.

MR. KIMBER: Power-to-gas-to-power is the thing about which we are least bullish. We think that putting hydrogen in gas turbines will happen, but almost all of that value will accrue to the existing asset owners because most of the value will be capacity value and not energy value. Those turbines are not going to run for many hours until you try to solve intra-seasonal issues, and then there might be a higher capacity factor for the hydrogen turbines.

At least in the near term, a very small amount of hydrogen will be burned for a few hours. As the resource develops, there will be green capacity payments from community choice aggregators and others that need to go fully green and require a firm commitment through the night. But these types of deals are going to accrue to people like Calpine who will not need to buy a lot of hydrogen from Sanjay or me.

We see the market breaking down into four areas.

One is decarbonization of the existing market. For example, steam methane reformers that make hydrogen produce something like 3% of all global emissions of carbon dioxide. Ammonia production and de-sulfuring in refining are niche applications, but they have large volumes. They present a huge opportunity for using hydrogen to decarbonize.

Moving to energy storage, that will not happen quickly.

On use of hydrogen for transportation, I agree with Sanjay. Fuel cell vehicles that people wrote off a long time ago are potentially a big market, but they are a thermal play.

I said in a speech at the University of California Haas School of Business years ago that we cannot assume every single hot spinning thing on earth will be replaced by some solid-state electronic device or a chemical battery.

We have to be able to put fuel into existing equipment. I think you are going to start seeing people try to burn hydrogen in the aviation and marine sectors. You are going to start seeing people try to make e-fuels, whether you put it in a pipeline as a gas substitute, or you add carbon and go to some sort of longer-chain hydrocarbon or even into ammonia. There was an announcement about an ammonia-burning turbine a couple of days ago.

In the thermal area, we think hydrogen is not only going to go into gas pipelines, but we are also going to see it transferred into e-fuels that can be used as drop-in replacements in existing infrastructure. Those are the markets on which we are focused.

We are spending an enormous amount of time trying to figure out where to put the facilities because the timeline and ultimate end-use market are unclear.

MR. BERGER: Karen Lee, you are doing some work with microgrids and reliability.

MS. LEE: Microgrids are an exciting development, particularly here in California where we have periods of high power interruptability due to wildfires. We are looking to learn, particularly from Japan.

We have a partnership with a Japanese manufacturer as well to explore the opportunities for fuel cells. We have also worked with Bloom Energy on fuel cell use for our high-demand important areas such as data centers. Fuel cells are effectively a form of microgrid. They build resiliency as a back-up source, particularly in instances where the larger electrical grid is subject to periodic interruption.

Fuel cells are well established and have an excellent safety record over the past 10 years in Japan. We think this is an area that, although new to California, has strong potential for relatively immediate application to improve the reliability and resiliency of the power grid.

### Overcoming Obstacles

MR. BERGER: Let's talk about some of the obstacles that each of you are seeing in moving to a more hydrogen-based economy. I think of hydrogen as an energy carrier and not really a new source of energy. We do not mine it. We do not drill for it. You have to use energy to get hydrogen out of water or natural gas.

I see a couple big obstacles: cost and transportation. Sanjay, talk about the cost of hydrogen from fossil fuel sources compared to hydrogen produced from renewable energy?

MR. SHRESTHA: I was hoping I would get that question because I think there is an interesting dynamic in the market.

The cost varies from liquid hydrogen, gaseous hydrogen, merchant hydrogen to captive hydrogen.

Some people believe green hydrogen cost parity is 10 years away and that many things have to happen for green hydrogen to be economical. We are thinking about it in a very simple way, which is we know what it costs us today to pick up liquid grey hydrogen from our key suppliers, and we know what our customers are paying for it. Our biggest input cost for green hydrogen is 24/7 renewable electricity. We are the ones making the electrolyzer ourselves. We have a view on the cost-reduction roadmap for that. We have built the liquefier system ourselves. We have a view on how to think about efficiency and how to think about kilowatt-hours per kilogram for liquefaction.

## The market for hydrogen breaks down into four areas.

By offering our end customer the same price that it is paying for grey hydrogen today, we can see 30% improvement in our gross margin for our hydrogen-fuel business. That is something that I think is important for everyone to note. The future of green hydrogen is largely dependent on the cost of renewable electricity. The cost will continue to come down. In some of the key markets that we serve today, we can provide green hydrogen at the same price that our customers are paying today for grey hydrogen, so the use case actually makes sense.

The United States will have to add a lot more renewables to decarbonize the grid. Solar can compete today with gas-fired peakers in terms of the levelized cost of electricity. The cost curve will continue to decline. Therefore, the cost of green hydrogen will continue to go down.

It takes 55 kilowatt-hours of electricity to produce one kilogram of hydrogen with Plug Power's PEM electrolyzer that we are building in our giga-factory in Rochester, New York. We will have 500 megawatts a year of production capacity, 400 megawatts of which will be for our own internal use. With this capacity, we are building a network that can deliver green hydrogen at cost parity with grey hydrogen in certain applications today. By the time our network is complete, we will be able to deliver green hydrogen at cost parity with diesel for freight transportation.

We believe the green hydrogen opportunity is here today and only growing and getting bigger.

MR. BERGER: Sheldon Kimber, talk to us about obstacles to use of green hydrogen for transportation.

MR. KIMBER: We believe that building toy projects, if you will, smaller-scale demonstrations, will happen, but that is not where we are focused.

As a smaller developer, with a smaller team, we are focused on projects at scale in the near future, rather than losing time with smaller, early-stage projects. We look for markets where we can rely on policy changes and technical changes that we think will open up very large-scale markets. By large-scale markets, we are talking about thousands of megawatts of renewables generating hydrogen either through electrolysis or through pyrolysis, which we have not talked much about.

I see at least three regulatory changes that need to happen to open up these large markets. The first is pipeline access. The second is harmonization of the different green gas credits. There are credits for renewable natural gas, and there are LCFS credits. The third is we need market structures that allow us to inject hydrogen into the transmission gas grid, and have a different entity pull out different molecules, just like they pull out different electrons on the transmission grid for electricity. We need to create this kind of pathway, not just physically, but also commercially through market structures.

Establishing a physical and a commercial transportation structure that allows the end use to be in a different place from production would blow this market wide open. We need to move from it being customized pathways to being broadly accepted, direct-style pathways.

The exciting long-term outcome of these regulatory changes is that developers will put hydrogen in the best, cheapest renewable spots in the country and change the concentration of hydrogen in the gas system. / continued page 32

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### California

MR. BERGER: Karen Lee, SoCalGas owns pipelines. Sheldon is talking about the ability to pump more and more hydrogen into these pipelines. Does that work for you?

MS. LEE: We will need buy-in from the state legislature and other policymakers in California. We are interested in how our existing pipelines and infrastructure be used to maximize customer value in the form of hydrogen blending and storage. We are also interested in how we can help develop new markets, like use of hydrogen for transportation.

The federal and state governments need to help develop a regulatory roadmap. I think 85% of the hydrogen roadmaps in development are being done in Europe, Asia and Australia. We need the US, with California having very aggressive energy policy, to lead the way. It is similar to how wind and solar moved forward due to government guidance and policy.

Some of the challenges we face today are that the rate structures are not in place to incentivize use of hydrogen for storage. California has more renewable electricity than it needs at times. It has to pay neighboring states today to take the excess power.

We see a real opportunity for hydrogen as energy storage and for our pipelines to store that hydrogen. However, the current rate structures do not support that. For example, there is no retail wheeling rate for energy, retail wheeling being the transmission and distribution of power for another entity.

There are no rates that address the different components of the value that hydrogen could offer as a storage vehicle for the excess renewable electricity. We see a lot of development in Europe in particular with respect to the EU hydrogen commitment, where regulatory and the governmental infrastructure exists to facilitate development in this area. SoCalGas hopes to support similar initiatives in the US. We are doing research and development in this area.

We recently partnered with the California Energy Commission on a hydrogen fuel cell demonstration project in the rail and marine application areas known as the H2RAM grant program. There are four projects that have been selected for funding through the CEC. The CEC has provided more than $10 million in funding, and SoCalGas has provided more than $1.3 million, to test various technologies that can provide clean energy in ports, such as fuel-cell marine vessels, hydrogen refueling stations and fuel-cell locomotives.

We also have some promising, recent legislation here in California that I think can be the framework for progress. We have SB 18 by Senator Skinner that makes hydrogen an eligible resource under SB 100. It directs state agencies to develop a plan for big hydrogen. We also have Governor Newsom's recent executive order that included support for hydrogen-fuel-cell vehicles, and sets a target for 200 hydrogen fueling stations by 2025.

We need strong policy signals from the state to move forward. We need a strong California hydrogen roadmap, paired with a strong national roadmap. We are making inroads with existing state legislation, support from the government and partnerships between the utilities and regulatory agencies.

### Federal Policy

MS. BARROW: Let's talk in more detail about regulatory and policy developments not just at the state level, but also at the federal level.

At the federal level, there is optimism that the Biden administration will be a champion for hydrogen. The president has already laid out a goal of decarbonizing the power sector by 2035. The US has rejoined the Paris climate accord. Last week, we heard the US secretary of energy say that the DOE is revitalizing its loan program and that one of its areas of focus will be hydrogen.

The question for the panel is what would be the most effective policy or regulatory change that could come from the federal government to support hydrogen? Sanjay, you start.

MR. SHRESTHA: The fact that hydrogen reduces greenhouse gas emissions compared to traditional fossil fuels needs to be recognized. Any policy should take a long-term view so that the industry can plan accordingly from that long-term perspective.

One area is re-thinking the DOE loan guarantee program. That program played such a big role in helping to accelerate the adoption of solar energy. Bankability went up, and returns improved to equity investors in new technologies. When the cost of capital started to decline, we saw the levelized cost of solar energy also come down. The DOE loan guarantee program is an important tool that can help with capital formation.

Another useful tool is the investment tax credit, which has been helpful for the broader fuel cell industry. If an investment tax credit were available for the green hydrogen generation

Plug Power expects to use 55 KWh of electricity to make one kilogram of green hydrogen.

facility or a production tax credit were offered for the green hydrogen output, that would help.

The reason we are in the green hydrogen business is because of feedback from our key customers. We see the potential to make green hydrogen economical versus grey hydrogen. From Plug Power's perspective, fortunately we are not cannibalizing our existing customer base to move to green hydrogen, a classic innovator's dilemma. We do not have an existing asset that will become a lot less valuable as more and more of the green hydrogen infrastructure gets built. Others may have that concern, but we do not.

MS. BARROW: Sheldon Kimber, same question. What is on your federal government wish list?

MR. KIMBER: I agree with Sanjay. I definitely want the government to look at tax credits. We are currently looking for $1 billion in tax equity financing. I think the right move is a technology-neutral tax credit along the lines that Senator Ron Wyden is expected to propose and that we are hoping will be part of the "Build Back Better" infrastructure plan the federal government is planning to roll out this summer. It would be an absolute game changer.

In addition to a tax credit, the industry would be helped by interstate and intrastate pipeline access and some sort of structure that allows companies to take advantage more easily of the low-carbon fuel standard or LCFS in California.

Another issue is grid charging. The federal government should allow hydrogen electrolyzers to be considered industrial loads. It is not as though the load is being used for making widgets. Something close to the non-generator resource rules that the California Independent System Operator has established for batteries could be appropriate. Those rules allow batteries to charge at wholesale rather than retail electricity rates. Grid energy consumption by the facility could be limited to certain days, and the utility could have the right to direct the electrolyzer to reduce its electricity consumption or turn off completely if necessary. We could do those sorts of things to make charging at wholesale rates more amenable to the utilities.

## LCFS

MS. BARROW: Sheldon, to stay with you, you mentioned easing the path for hydrogen companies to take advantage of the LCFS. California's LCFS is one of the most progressive clean energy programs in the world. LCFS credits are generated when hydrogen is used in vehicles in California.

However, you identified a pitfall that developers might run into in terms of chain of custody. What is the issue and what do you think regulators should do to ease the path to using LCFS for hydrogen that is transported in pipelines?

MR. KIMBER: LCFS is the renewable portfolio standard of the future. California passed an aggressive RPS, and the rest of the nation followed. I believe that a number of climate-conscious states will adopt LCFS programs similar to California's because federal lawmakers cannot seem to do anything but argue with each other on CNN.

We have heard that there is a chain-of-custody issue under the LCFS when an independent power generator puts renewable power on the grid and sells the renewable energy credits or RECs associated with the power to a refinery, for example, that uses the electricity to make clean fuels. The issue is that the refinery cannot show physical ownership of the same electrons that were generated by the renewable power plant.

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The same chain-of-custody issue potentially applies to hydrogen injected into pipelines. If I inject hydrogen gas into a pipeline somewhere and a refinery elsewhere takes the hydrogen out and uses it to make fuel, it is not straightforward to claim LCFS credits. To do so, the refinery must file what is called a "tier 2 pathway" application for the California Air Resources Board to bless the pathway. If we can establish a standardized pathway, it would make claiming LCFS credits much more efficient.

### New York

MS. BARROW: We have talked about law and policy at the federal level and in California. Let us move to New York, which is Plug Power's home state.

New York has a keen and growing interest in supporting green hydrogen. In your introductory remarks, Sanjay, you said that Plug Power plans to construct multiple green hydrogen facilities, including in New York. Plug Power also has plans for the first giga-factory for PEM also in New York. Why choose New York?

MR. SHRESTHA: Plug Power has been a New York company since its founding more than 20 years ago. We have had a very big supporter in Senator Chuck Schumer. He has been an advocate of Plug Power, of hydrogen, and of fuel cell industry. He played a very big role in terms of us deciding to build our giga-factory in Rochester.

We received a lot of support from the county where we are building the plant and from the New York Power Authority. The site is strategically located in NYPA's low-cost hydropower zone.

The decision to site the project came down simply to the cost of the renewable electricity, which will allow us to produce green hydrogen at a price point that is economical. It will let us provide the hydrogen to our end customers at a similar price to what they were paying for grey hydrogen.

New York also makes sense because of the "Climate Leadership and Community Protection Act," which is the law that establishes an aggressive target of 70% renewable energy by 2030 and 100% emissions-free energy by 2040. New York's goals are more aggressive than even the Paris accord. ◎

# Aggregated PPAs

*by Kat Gamache in Houston and Washington, and Bob Shapiro in Washington*

A number of project developers in the last few years have signed multiple PPAs for a single project. These are referred to as "aggregated PPAs."

There are benefits to having multiple offtakers for a single wind or solar project.

It expands the market for renewable energy by aggregating smaller companies that do not need as much electricity individually as would be required to support a 100- or 200-megawatt power project. Outside of certain state mandates that require utilities to sign power contracts to meet specified state goals, investor-owned utilities increasingly prefer to build their own renewable power plants or buy such power plants from developers at the end of construction under build-transfer agreements. Developers have been able to fill the gap caused by loss of utility PPAs with long-term PPAs with corporate buyers. However, many of the large corporate buyers have already filled much of their procurement quotas. Aggregated PPAs are a way of reaching deeper into the corporate market.

Lenders will finance a project with multiple buyers if each buyer has an adequate credit rating or credit support or if the developer is prepared to have some of the revenue serve as a cushion to support a financing without being taken into account fully in debt sizing.

Corporations sign PPAs to help meet environmental or sustainability goals. They also do it to lock in electricity prices for an extended period. Solar and wind power prices are now competitive, and sometimes lower, than electricity from comparable fossil fuel-powered power plants. Aggregated PPAs not only allow corporate buyers with relatively small load requirements to secure these benefits, but they also let larger buyers diversify supply risk by procuring electricity from multiple projects.

The most significant barrier to aggregated PPAs is negotiations with each buyer can be labor intensive since each has unique demands. Some developers have determined that small offtakers are just not worth it. Financing also becomes more difficult and costly because each unique PPA requires diligence.

### Two Models

Nevertheless, there has been an uptick in interest in such arrangements. We see two models emerging.

The first involves multiple buyers signing essentially identical PPAs for shares of the output from one project. This is a multi-PPA model. Some brokers specialize in combining like-minded offtakers and matching them with a developer and then leading negotiations on behalf of the group of buyers. Some developers do their own aggregation by offering a form PPA on essentially a "take it or leave it" — or a "take it for the most part" — basis to smaller corporate buyers.

Another common model is where a single buyer signs a single PPA on behalf of multiple buyers who all have separate back-to-back PPAs with the principal buyer. This is called the consortium model. It is less common with corporate buyers, but more common for municipal or cooperative aggregators. For example, municipal utilities or other state entities may join together to buy the output from a single project and allocate the output among themselves. Utilities sometimes also play this role where utility customers ask a utility to procure renewable energy on their behalves in exchange for paying an increased retail rate.

It is more common to see multiple PPAs for a single project. Two business models are emerging.

The key for successful PPA aggregation is to reach consensus on the principal PPA terms and method of output allocation. There is an atypical level of transparency in these transactions. The buyers usually know the identities of the other buyers. All buyers must accept the same terms, including contract price and collateral provisions. There is no room to negotiate a competitive advantage in pricing or terms absent collective action.

### Common Questions

The following are answers to common questions about aggregated PPAs.

Q: Are there limits to how many corporate buyers can be combined in this manner?

A: No more than 100% of the project capacity may be contracted, so the size of the project is a natural limit. The more offtakers, the more difficult it may be to build the necessary consensus as to PPA terms.

Q: Are these physical-delivery contracts or virtual PPAs that are financially settled?

A: A typical corporate PPA is a financially-settled contract for differences, or "virtual" PPA. The corporate buyer pays a fixed price for the electricity physically delivered by the project into a competitive market and receives in return the market price the project receives from selling the output to the grid. Consortium-model contracts are more likely to be physically settled. The aggregator offtaker takes physical delivery at an interconnection point and then allocates transmission responsibilities among the consortium members from that interconnection point to the point of delivery for each member.

Q: Do the offtakers all have to be in the same state or ISO?

A: The location of the offtaker is irrelevant for virtual PPAs. However, individual offtakers may have internal corporate requirements that the project must be located in the same region as the corporate load.

Q: Does each offtaker have to take a fixed percentage of the actual output or is there a notional output to which offtakers commit?

A: Corporate offtakers often have a fixed capacity procurement goal. Anyone with such a goal usually prefers to contract for a notional amount of electricity, and it takes all the energy and other products attributable to the contracted capacity. Issues arise when the project ends up being smaller than anticipated. Each offtaker's share may be decreased pro rata, or certain offtakers may have priority rights. This issue is mitigated if the buyer agrees to a percentage share of the total installed capacity, which is another popular model.

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## Aggregated PPAs

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Q: What happens to renewable energy credits under state renewable portfolio standards and ancillary services payments?

A: A corporate buyer is normally entitled to all RECs associated with the share of actual output electricity the buyer takes (1 REC = 1 MWh of electricity). If ancillary services are part of the "product" that is sold, they are also allocated based on the share of electricity taken by the buyer. Buyers may also request "bridge RECs" or RECs purchased from the market in a set quantity before the project goes into commercial operation to satisfy internal corporate goals, particularly if the commercial operation date is delayed.

Q: How does storage fit into the picture?

A: The PPA may be identical unless the buyer has dispatch rights, in which case things get more complicated and the developer may not find it advantageous to have multiple offtakers. In simple terms, a single large project with multiple buyers having dispatch rights must be configured and metered in a manner that essentially breaks it into multiple small projects that can be operated separately from one another. Dispatch rights do not apply to VPPAs.

Q: What happens if one or more offtakers fail to pay on time?

A: Buyers will rarely agree to assume liability for the actions or inactions of other buyers. The good news for project owners and lenders is that the other buyers continue paying even when one defaults; thus, only a percentage of the project revenue is affected.

Under the consortium model, the project-facing single buyer is responsible for the full cost of the electricity, even if some of the secondary buyers with whom it has back-to-back PPAs default.

Q: How do lenders and tax equity investors view aggregated PPAs?

A: Lenders are likely to accept multiple buyers and may actually like the diversification of credit risk, provided that none or only a small portion of the revenue is tied to entities with weak credit outlooks. Lenders lending against a consortium-model contract will be keen to understand how liability is spread among the consortium members for debts of the aggregator.

Q: Is there a danger of the project company being considered a utility because it is making multiple sales?

A: No. The project owner will not be regulated any differently based on the number of wholesale buyers that it has.

Q: Are there other differences in key terms compared to single-offtaker arrangements?

A: Not generally. Curtailment, electricity output and other matters affecting the project as a whole will normally be allocated to each buyer on a pro rata basis.

Some buyers ask for priority rights: for example, a right to the first capacity that comes on line or the right to be curtailed last. This is difficult to administer and is rarely accepted by developers. Sometimes a single large project will be "chunked" into separate metered portions, with each buyer having rights to its separately-metered portion of the project to address this type of issue.

Aggregated PPAs occasionally limit the types of other buyers with whom the developer can sign PPAs for the same project. For example, a buyer may prohibit a developer from selling to its competitors. This may limit the lenders' foreclosure options for transfer of the equity interests after an event of default under the financing agreements. Preferably, the broker presenting a group of buyers will have vetted this issue before approaching a project developer.

The aggregator under a consortium model may offer shorter terms to its members if it has the ability to substitute new members relatively easily.

Q: Under the broker model, brokers find the corporate offtakers. Is this like a double auction where the broker narrows down potential developers for a pool of corporate buyers and the corporate buyers then press for even more concessions?

A: Yes, this is often the case. There are a few brokers that use algorithms to help match buyers and projects.

Q: How else do aggregated PPAs differ from traditional corporate PPAs or utility bus-bar contracts?

A: The most significant difference is that an aggregated PPA is usually "middle of the road" on all terms to reduce negotiations. It is important to leverage experience on all sides — developers, lenders and corporate buyers — to determine what "must haves" the PPA requires. From there, the person drafting the PPA strives to make the terms as fair and balanced as possible so that buyers can feel comfortable signing without significant negotiation. ◎

# New Life for Distributed Wind

*by Christine Brozynski, in New York*

While distributed wind has not had much success in the United States, new technology from Alpha 311 could potentially revitalize this sector.

The Alpha 311 turbine is a small, vertical-axis wind turbine, about six feet tall. It was originally designed primarily for roadside use. It relies on the breeze created by passing cars to cause the turbine to spin and produce electricity. It spins like a merry-go-round around a pole.

The roadside application opens the door to wind power in areas that might not otherwise be hospitable to wind turbines due to a lack of wind or space for more traditional turbines. One such area is the northeastern United States, where solar has thrived but wind turbines on land are less common. Traffic along the interstate highways could drive small turbines embedded in light poles to produce electricity during the day. Wind tends to be more active at night, so the turbines could take advantage of the higher wind levels at night when there is less traffic.

While roadside installations are arguably the most innovative use for the turbines, they can be installed anywhere. They can also be mounted on top of poles to pick up real breezes. These turbines are a different design from the roadside units, but they still follow the same basic principles. They are a little over two feet tall. The O2 Arena in London announced a deal with Alpha 311 in March 2021 to install 10 such turbines around the arena.

Alpha 311 says that one turbine can generate as much power in a day as 215 square feet of solar panels. Each turbine costs around $26,000 to make, according to published reports. The company says the cost will fall once the turbines are able to be mass produced. Many components of the turbines are made with recycled plastic that is in turn recyclable.

The technology has not been certified yet in the United States by the American Clean Power Association (formerly the American Wind Energy Association) or the ICC-Small Wind Certification Council.

A number of other companies make competing models of vertical-axis turbines.

**A new wind turbine that can be mounted on light poles along interstate highways has potential.**

## Cost Curve

Distributed wind has failed to take off on a large scale in the United States. The US Department of Energy Pacific Northwest National Laboratory (PNNL) reported that only 18 megawatts of distributed wind came on line in the United States in 2019, the most recent year for which there is published data. Only 1.4 megawatts of the 18 megawatts were small wind turbines of 100 kilowatts or less in size.

Based on PNNL data, the levelized cost of energy for large turbines was approximately 7¢ a kilowatt hour in 2019, compared to 24¢ a kilowatt hour for small turbines using a conventional design. PNNL estimated that vertical-axis turbines had an LCOE of 11¢ a kilowatt hour in 2018.

The attractiveness of distributed wind depends on government policies. The technology is not yet cost effective to build without state and federal incentives.

Like distributed solar, it also relies on "net metering" policies, which differ from state to state, to help the economics. Net metering is a means of crediting customers for excess energy produced by a distributed solar or wind project. If the project produces more electricity than the customer uses, then the customer is permitted to sell that excess electricity to the local utility and receive a credit on its electricity bill. The customer meter essentially runs backwards. Utilities complain that this forces them to buy electricity at the retail rate for which they could pay less in the wholesale market.

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## Distributed Wind

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While many states permit net metering, the programs often focus specifically on distributed solar rather than distributed wind. Solar costs have plummeted in the last decade, whereas the cost of small wind turbines has remained fairly stagnant. The lower cost of solar has encouraged states to focus even more on solar, which in turn results in incentive programs that reduce solar costs even further. Historically, distributed wind has not been able to compete with distributed solar from a cost perspective.

According to US Department of Energy data from 2018, the most recent year available, Texas, Iowa and Minnesota are the top three states for distributed wind. Distributed wind, in this case, includes large turbines located on an individual's or company's property for use by that individual or company. For small wind specifically, the top states are Iowa, Nevada and Alaska.

### Financing Equipment

If the Alpha 311 turbines revitalize the distributed wind sector in the United States, then some users will inevitably want to finance large-scale deployments with third-party debt and tax equity.

They can look to residential rooftop, C&I and community solar projects for guidance.

Developers of these types of projects in the United States rely on master tax equity facilities and back-levered debt. A tax equity investor agrees to fund monthly tranches of projects that satisfy a checklist of items, up to a maximum dollar amount for the entire portfolio or through an outside funding date, whichever is reached first. The back-levered debt then funds after the tax equity portfolio is put in place. The debt may take the form of securitized debt in the private placement market.

C&I projects are generally located on the property of the electricity customer. "C&I" refers to the commercial and industrial customers for such projects. The O2 Arena in London is a good example of how the model could work for distributed wind. If the O2 Arena were located in the United States, then the arena could qualify for an investment tax credit and accelerated depreciation taken on a front-loaded basis over five years if it owned the turbines. These two tax benefits could be worth as much as 44¢ per dollar of capital cost. Alternatively, a third party developer might retain title to the turbines and enter into a long-term power contract to supply electricity from them to the arena. The developer in that case would raise funding.

Community wind projects are potentially more complicated due to state policies. Under the community wind model, a developer would own turbines to which local businesses or residents would subscribe. The electricity would go to the local utility. It would grant the subscribers bill credits for their shares of the electricity generated and the customers can use to offset the cost of electricity they buy from the local utility. Such projects are highly dependent on state law, as they must be located in a state that permits "virtual net metering" or otherwise has a program specific to community wind or community renewables projects. "Virtual net metering" is the method by which subscribers receive a credit for a portion of electricity produced by a wind turbine that is not on their property.

Community solar, by way of comparison, has thrived in states with virtual net metering policies that also offer incentives. (For more details about community solar programs, see "Community solar: current issues" in the October 2019 *NewsWire*.) For example, Massachusetts has a Solar Massachusetts Renewable

The wind from passing vehicles causes the turbines to spin.

Target (SMART) program under which utilities make direct payments to solar projects meeting certain criteria that are accepted into the program. There is an adder for features like storage. Massachusetts also has a permissive net metering and virtual net metering policy.

The Massachusetts net metering policies apply to both wind and solar, but the SMART program applies only to solar. As a result, even though community wind is feasible in Massachusetts, it may be difficult for it to compete with community solar.

Anyone looking to finance distributed wind projects should be aware that financiers tend to be uncomfortable with new technology risk. The technology must be thoroughly vetted, and even then the financiers may try to shift some of the technology risk back to the sponsor by adding extra protections in the financing documents.

Wind studies are a prerequisite for financing utility-scale wind projects. Anyone seeking financing usually needs at least two to three years of wind data. If Alpha 311 turbines are used for a roadside project, then financiers will almost certainly want a credible traffic study and data on adjacent wind speeds. The study would have to take in account increasing congestion on US highways, leading to slower traffic speeds, and the potential impacts of driverless cars and trucks.

Government entities that own the light poles have other sources of financing not available to the private sector. The cost of such financing would have to be compared to financing run through the private sector. Usually the ability to claim large tax benefits if the equipment is privately rather than publicly owned is enough to tip the scale. ◎

# Hydrogen and Japan

*by Julien Bocobza and Claire Tuch, in London*

The Middle East could be key to realizing Japan's hydrogen ambitions.

Japan has committed not only to decarbonization by 2050, but also to the use of hydrogen and the development of a "hydrogen society" in order to achieve this goal.

Japan is unable in the near term to produce green hydrogen at scale. Thus, green hydrogen supply is likely to be treated in a similar fashion to hydrocarbon supply, which means that, at least for the foreseeable future, Japan may have to rely on clean hydrogen imported from abroad.

The Middle East is a potential powerhouse for green and blue hydrogen production. It has abundant natural resources and well established trade routes. Japan would bring to any strategic partnership a commitment to increase demand for hydrogen and a willingness to make a significant investment in carrier vessels for imports and to use its public financial institutions to provide financing for all elements of the supply chain.

## A "Hydrogen Society"

Japan has recently announced its intention to build the world's first full-scale hydrogen supply chain by around 2030. This future, free from fossil-fuel dependence, is referred to as the "hydrogen society."

Had the 2020 Tokyo Olympics and Paralympics gone ahead as planned, the first flames of this society would have been visible in the Olympic cauldron and relay torches lit by hydrogen fuel.

Japan's Suiso Frontier, the first ship in the world designed to carry hydrogen, is set to start carrying hydrogen from Australia to Japan later this year.

Additional transportation capacity is in the pipeline, with Kawasaki aiming to build 80 more hydrogen carriers to import nine million tons of hydrogen a year by 2050, after building two commercial-scale ships to import 225,000 tonnes by 2030.

Japan is already a leading player in hydrogen technology. The Fukushima Hydrogen Energy Research Field — the world's largest facility for producing hydrogen derived from renewable energy — went into operation on March 7, 2020.

The project is supported by the Ministry of Economy, Trade and Industry (METI) and the New Energy and Industrial Technology Development Organization / *continued page 40*

## Japan

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(NEDO). It sits on a 180,000-square-meter site and uses 20 megawatts of electricity from solar and the grid to conduct electrolysis of water in a renewable energy-powered 10-megawatt hydrogen production unit. It has the capacity to produce and store up to 1,200 Nm3 (normal meter cubed) of hydrogen per hour, a measure of gas flow. The output is transported currently mainly to users in the Fukushima prefecture and the Tokyo metropolitan area in hydrogen tube trailers and hydrogen bundles to be used to power stationary hydrogen fuel-cell systems and to provide for fuel-cell cars and buses.

In order to maintain its global lead in hydrogen technology, and to truly leverage the benefits of the hydrogen application, Japan will need to overcome its geographic limitations and its current limited ability to produce green hydrogen on a large scale. This will be done through investment in and development of an international hydrogen supply chain. According to 'the Strategic Road Map for Hydrogen and Fuel Cells' published in March 2019 by METI, the government's efforts to establish the global hydrogen supply chain include enhancing government-level relationships with countries with rich renewable resources, such as countries in the Middle East.

Japan wants to become a "hydrogen society" by 2030.

Japan is currently heavily dependent on hydrocarbons shipped mainly from the Middle East and Australia to meet its energy demand. Mountains occupy approximately 80% of the Japanese land mass, making sites suited to onshore solar and wind installations rare. The deep waters surrounding Japan's islands are unsuitable for fixed foundation offshore wind and the technology for floating offshore wind, which would be ideal for Japan, is still at an early stage.

While the Japanese government had hoped that nuclear power would lead the energy transition, the 2011 great east Japan earthquake and resulting tsunami and the Fukushima nuclear disaster led to the widespread suspension of operating nuclear power plants which — for the most part — have yet to be restarted.

### Ideal Strategic Partner?

Japan already depends on the Middle East for a large proportion of its crude oil imports, and core sea trading routes linking Japan and Europe pass through the region. The wide open spaces in the Middle East and location astride international trade routes make it an ideal green and blue hydrogen producer.

A number of pilot projects and memoranda of understanding have been signed in the past few months, demonstrating the appetite among private parties and governments for developing a clean hydrogen supply chain in the region. Other countries outside the Middle East who are competing for similar roles include Australia and Chile.

The MENA Hydrogen Alliance launched recently to accelerate the development of value chains for green molecules in the region and bring together private- and public-sector players with those in academia. The Alliance includes Dii Desert Energy, ACWA Power, Neom, Thyssenkrupp, Masdar, MAN Energy Solutions, MASEN and Fraunhofer among its members.

Beyond small pilot projects and MOUs, a number of large-scale projects are also being developed. The most ambitious is in Saudi Arabia, where a consortium of ACWA Power, Air Products & Chemicals and Neom plans to build the world's largest green hydrogen-based ammonia plant to be powered by wind and solar electricity, which should produce 650 tons of green hydrogen daily for export to global markets.

METI signed a memorandum of cooperation in January 2021 with the Abu Dhabi National Oil Company (ADNOC) to encourage bilateral cooperation in the fields of fuel ammonia and carbon recycling, focusing on the demonstration of technology and expansion of the market.

While the green hydrogen supply chain is being developed, blue hydrogen will be key to Japan's energy transition.

Masakazu Toyoda, chairman and CEO of the Institute of Energy Economics, Japan (IEEJ), says that 10% of power in Japan can be generated by 30 million tons of blue ammonia, and he expressed an intention to move from co-firing blue ammonia in existing power stations to single firing with 100% blue ammonia by 2050.

Japan received the world's first shipment of blue ammonia in 2020 from Saudi Arabia. The pilot project undertaken by Saudi Aramco, the IEEJ, partnered by SABIC and supported by METI, involved a full value chain, spanning the conversion of hydrocarbons into hydrogen and then to ammonia, and capture of the carbon dioxide by-product. After transport to Japan, ammonia was burned in thermal power stations without releasing carbon emissions.

Saudi Aramco said in February 2021 that its hydrogen business will be world scale by 2030 and that Japan and South Korea will likely be where the first hydrogen trading markets will begin at the end of the 2020s or early 2030s.

Japan's largest refiner, ENEOS Corporation, said on March 25, 2021 that it signed an MOU with Saudi Aramco to consider development of a CO2-free hydrogen and ammonia supply chain as it accelerates efforts to develop hydrogen production, transport and sales businesses. Under the MOU, the two companies will conduct a feasibility study looking at means of hydrogen production and transport options. Upon completion of the feasibility study, ENEOS will review the possibility of establishing hydrogen networks that will entail importing the product to Japan and supplying hydrogen to power stations and other industries from its refineries.

The Middle East will be an essential source of blue hydrogen for Japan. The United Arab Emirates aims to become one of the lowest-cost and largest producers of blue hydrogen created from natural gas, according to Sultan Al Jaber, chief executive officer of ADNOC. ADNOC intends to capitalize on the emerging global market for hydrogen by leveraging its existing infrastructure and partnership base as well as Abu Dhabi's vast reserves of natural gas.

While supply-chain development is currently limited to pilot projects and MOUs, the success of the Saudi Aramco ammonia initiative demonstrates that a full value chain is achievable, and the commitments made by both private and public players in Japan and the Middle East are a strong indication that both regions view this partnership as a mutually beneficial endeavor that will create real opportunities for a viable hydrogen economy.

## Japanese Financial Support

Financing electrolyzers, ships and other equipment needed for green hydrogen and for blue hydrogen carbon-capture technology will remain challenging in the near term.

Technology risks associated with the limited track records of electrolyzers at scale and hydrogen carriers, combined with the fact that green hydrogen costs too much to make currently compared to the gas with which it competes, and evolving but potentially unpredictable regulatory regimes, pose challenges to accessing finance.

Financing from public finance institutions such as Japan Bank for International Cooperation (JBIC) and Nippon Export and Investment Insurance (NEXI) will be crucial to attract private capital.

JBIC has expressed its intention to support the development of Japan's hydrogen society by providing long-term funding to supplement private-sector funds. Under a January 2020 cabinet order, the sectors eligible for funding from JBIC were expanded to include support through export loans and overseas investment loans in projects involving the production, transportation, supply and use of hydrogen in developed countries.

JBIC has recently added hydrogen as an "important resource," which allows it to finance the acquisition of interests in, and the development and importing of, hydrogen.

The European Bank for Reconstruction and Development and NEXI have signed an MOU to combine their expertise in green financing. NEXI has also launched a loan insurance product for green innovation that can be applied by Japanese companies for financing projects in the field of environmental protection and climate-change prevention. ◎

# India Wants More Mines

*by Aditya Rebbapragada, in Singapore*

India took steps in late March to encourage more private investment in mines.

A new "Mines and Minerals (Development and Regulation) Amendment Act, 2021" took effect March 28 that amends the existing regulatory framework for mining in India to make the sector more attractive to investors.

Mining in India currently contributes only about 2.2% to 2.5% of the national gross domestic product. The country imports natural resources such as coal and gold in large quantities, although assessments by the Geological Survey of India indicate substantial domestic reserves are untapped.

Mining law reform in India is a critical component of the Modi government's target of making India a US$5 trillion economy by the 2024-25 budget year.

The *NewsWire* reviewed the amended legislation and also spoke with Anjan Dasgupta, senior partner in the Mumbai office of DSK Legal, on the implications of the amendments on mining projects in India.

## Concessions and Licenses

The amendments simplify the permitting and lease process under the mining regulations.

The separate permitting regimes for conducting reconnaissance operations (for preliminary prospecting of minerals), prospecting operations (for exploration, locating or proving of mineral deposits) and for grant of mining leases (for conducting actual mining operations) are now replaced by a single concept of "mineral concessions." However, the central and state governments retain flexibility on the approvals that may be included in a single mineral concession granted to a concessionaire.

The "prospecting-licence-cum-mining-lease" regime under the previous legislation — which was relevant where there was inadequate evidence to show the existence of mineral contents of minerals in a certain area — has now been replaced with a "composite license" regime. This is a two-stage concession for undertaking prospecting operations followed by mining operations in a seamless manner.

Under this new regime, a composite license holder must submit a geological report specifying the area required for the mineral concession after it completes prospecting operations. Once the conditions of the composite license are met, then the state government must grant a mineral concession to the composite license holder.

A composite license will be granted though an auction process.

The state governments require the central government's approval before granting composite licenses for mining atomic minerals, a category that includes uranium, lithium-bearing minerals and minerals in the "rare earth" category.

## Starting Over

According to the Ministry of Mines of the central government, the central government exploration agencies have handed over geological reports for 143 mineral blocks to various state governments since 2015. However, of these, only seven blocks have actually been auctioned by the relevant state governments.

To facilitate efficient auctioning of the available mineral blocks, the amended legislation provides that all applications for prospecting licenses or mining leases that were awaiting approval will now lapse.

The applicants under these applications will be reimbursed by the central government for the expenditure incurred by them toward conducting reconnaissance or prospecting operations.

The relevant areas will then be re-auctioned under the terms of the amended legislation.

The government expenditure for the reimbursement will be drawn from the National Mineral Exploration Trust and will be recouped from royalties received from successful bidders of the mineral concessions in that area.

In the case of atomic minerals of a certain minimum grade that are relevant from a national security perspective, the auction will be conducted under central — rather than state — government rules.

## Auction Process

The amended legislation allows for a uniform process for auctioning mines. Prospective concessionaires would now not have to deal with the array of processes that vary from one state to the next.

One of the more contentious amendments made to the legislation is to empower the central government to take over the auction process or identify mining areas to be auctioned if the state governments to which those areas belong are facing difficulty in conducting auctions or have failed to identify mining areas to be auctioned.

The goal is to ensure that more mineral concessions are auctioned on a regular basis for continuous supply of minerals in the country.

However, the affected state governments may see this as a way for the central government to usurp their authority and possibly undervalue mineral concessions in order to encourage private participation.

India is taking steps to encourage more private investment in mines.

Government-owned concessionaires will be granted mining leases for terms "as prescribed by the Central Government."

Previously, the term of a mining lease granted before 2015 was at least 20 years and not more than 30 years. Mining leases granted after 2015 were for a 50-year period, with some exceptions.

The flexibility for concessions granted to government-owned entities is useful in cases where the government has been unable to auction a particular mine and requires a government-owned company to commence work at the site before it can be auctioned to the private sector as a brownfield asset.

The amended legislation also requires payment by government-owned mining companies of additional amounts to the state governments when mining leases are granted to such companies or extended. This is expected to create a level playing field between mines auctioned to the private sector and the mines operated by government-owned companies.

## Transfers and End Uses

If a holder of a mining lease fails to undertake mining operations within two years or discontinues mining operations for two years, then the mining lease will expire at the end of the two-year period.

The amended legislation makes the rules more specific on this point by referring to "production and dispatch" in place of "mining operations." This would give concessionaries more certainty around what would trigger loss of a mineral concession.

The amended legislation provides that in the case of a mineral concession that has been granted by auction, all approvals, clearances and licenses in relation to the mineral concession will remain valid even after expiration or termination of mineral concession (other than in the case of atomic minerals).

Previously, the new transferee lessee had to reapply for everything within two years after transfer of the mining lease.

A new transferee concessionaire will therefore be permitted to continue mining operations without having to reapply for approvals, clearances and licenses and can avoid the repetitive and redundant process of obtaining clearances for the same mine.

The amended legislation removes the distinction between captive mines — where the concessionaire must apply all of the extracted minerals toward a dedicated purpose — and merchant mines.

Where mining concessions are being auctioned, no mine can now be reserved for captive purposes.

Previously, where mining concessions were being auctioned, the state governments could require that the offtake from a mining concession only be used for a particular end use. This meant that only certain end users were eligible to participate in the auction of those mining concessions. This also discouraged mining concessionaires from producing more than what they required for the particular end use. */ continued page 44*

## India

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The amended legislation also allows existing captive mines (including captive coal mines) to sell up to 50% of the minerals produced to third parties after meeting the requirements of the concessionaire. An additional charge will be levied on such sales.

DSK Legal said that the amended legislation will leave concessionaires free to determine the end use of the mine output, thereby increasing the domestic supply of minerals.

This is particularly relevant to minerals such as manganese, which is a by-product of iron ore mining. Previously, manganese could not be sold by captive mines or refined if that was not a permitted end use. At the same time, India imported manganese from South Africa and Australia to support its steel mills.

### Government Funding

The amended legislation clarifies that holders of mining concessions will be eligible to receive funding from the National Mineral Exploration Trust.

The National Mineral Exploration Trust was set up by the central government and is funded through royalties received from mining concessionaries. The funds in the trust are to be used for exploration activities.

DSK Legal said that this change should address some of the financing concerns faced by mining projects by providing an alternative funding option.

The more contentious change is in relation to the District Mineral Foundation.

Under the mining legislation, state governments are required to establish a district mineral foundation for each district that is affected by mining related operations. This is intended to operate as a not-for-profit trust and is funded by royalties received from holders of mining concessions.

The earlier legislation provided that use of funds in a district mineral foundation was left to the direction of state governments.

The amended legislation lets the central government now give directions about the composition and use of funds by a district mineral foundation.

As with the change to the auction rules, this change is also likely to be seen as an attempt by the central government to take some authority away from the state governments. ◎

# Environmental Update

Deadlines for federal and state governments to limit methane emissions from municipal landfills are back in place after a US appeals court rejected a Trump-era US Environmental Protection Agency effort to delay the deadlines on April 5.

The Obama EPA issued a rule strengthening methane standards for both new and existing landfills in 2016. States had to submit plans by August 2019. The federal government would impose a plan on any state that failed to come up with its own plan.

After Trump took office, the EPA said it would delay imposition by two years or more of federal plans in states that do not act on their own.

EPA concluded in 2020 that 42 states failed to submit landfill methane reductions plans.

A federal plan is now expected from EPA in May. States that do not have their own plans in place will probably have to adopt that plan.

## Stationary Sources

The same US appeals court also set aside a new rule issued in the waning days of the Trump administration that would have prevented the agency from regulating greenhouse gas emissions from stationary sources other than power plants.

The court said EPA failed to follow a normal notice-and-comment process before issuing the rule.

The vacated rule said EPA could not regulate greenhouse gas emissions for any category of stationary sources whose emissions are less than 3% of total US emissions. While that threshold would have allowed EPA to regulate power plant emissions, it basically prohibited it from regulating greenhouse gas emissions from the oil and gas industry, manufacturers of steel, iron, chemicals and cement, and other industries.

## State GHG Regulation

The Biden administration is moving to reverse the Trump-era effort to override state vehicle greenhouse gas programs that are more stringent than federal law.

The National Highway Traffic Safety Administration, or "NHTSA," sent a proposal to reverse course to the White House Office of Management and Budget on March 24. OMB generally takes about 90 days to review such proposals, but this one could be put on a fast track.

The Trump administration argued that federal law on vehicle emissions and fuel economy preempts any state regulations absent "compelling and extraordinary conditions" justifying separate state rules.

The Trump EPA withdrew a long-standing waiver granted to California under the Clean Air Act to regulate vehicle emissions. Meanwhile, NHTSA asserted that state regulation is preempted by a prohibition against separate state programs "related to" fuel economy.

Since the Trump attacks against state vehicle greenhouse gas programs were the product of rulemakings by both EPA and NHTSA, both agencies will probably have to take action before states can proceed. EPA will probably have to re-grant permission for individual states to act.

State regulators will be watching what legal basis the Biden administration uses to decide the issue. For example, will it decide narrowly that NHTSA lacked authority to issue its rule blocking state programs or will it affirm states' rights more broadly by suggesting such state programs do not conflict with federal law? In other words, it remains to be seen whether the Biden administration will try to take the preemption issue off the table temporarily or permanently by affirming the right of California and other states under Clean Air Act section 177 to implement programs more stringent than the federal government standards.

The Trump rollback of federal standards and the gutting of stricter state standards through preemption claims are being litigated in court.

A coalition of states led by California, environmental groups and some industry stakeholders are in one court with an assertion that some state regulations that are more stringent than required under federal law are specifically authorized by the Clean Air Act.

The Biden Department of Justice asked the US appeals court that has the case to suspend work on it while the federal government reassesses its position. The court granted the request on April 2.

The case is *Competitive Enterprise Institute v. National Highway Traffic Safety Administration*.

The new EPA Administrator, Michael Regan, has pledged "aggressive" vehicle regulations that are expected to encourage widespread electrification of the US / *continued page 46*

## Environmental Update

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vehicle fleet. The new infrastructure plan that Biden unveiled in late March includes numerous incentives to spur deployment of zero-emissions vehicles.

### Climate Disclosure

The US Securities and Exchange Commission is moving forward with an array of initiatives related to climate and other environmental, social and governance matters.

The new rules are expected to require public companies to disclose risks related to climate change and other environmental, social and governance issues.

The SEC in March asked for input from business leaders and investors on what the SEC should require. The SEC has also formed a task force focused on ESG issues and climate-related disclosures and hired the commission's first senior policy adviser for climate and ESG.

Acting SEC Chair Allison Herren Lee, who was appointed as a commissioner by President Trump in 2019, announced that the SEC would take a closer look at its climate-related disclosure requirements and said the commission should also require new disclosures of political spending. Lee said, "Investors are demanding more and better information on climate and ESG, and that demand is not being met by the current voluntary framework." She added, "Not all companies do or will disclose without a mandatory framework . . . ."

Gary Gensler, President Biden's nominee to lead the SEC, has signaled support for climate and other disclosure requirements. His nomination is set for Senate debate in mid-April.

Senator Pat Toomey (R-PA), the senior Republican on the Senate Banking Committee, asked in a March 24 letter to the SEC for a briefing on its plans for a new task force and enforcement priorities regarding climate-related financial risks. The banking committee oversees the SEC.

Toomey wrote, "These announcements appear to presage major changes in longstanding practices on disclosure and enforcement matters at the SEC. Such changes would be premature." He urged the SEC not to "use enforcement actions as a backdoor for imposing new regulations on ESG and climate change issues."

### Bitcoin

Bitcoin mining requires more electricity annually than is used by the entire nation of Argentina.

A recent analysis by Cambridge University researchers suggests that Bitcoin consumes around 121.36 terawatt-hours (TWh) per year of power.

As a virtual cryptocurrency, Bitcoin is run by a massive peer-to-peer computer network that uses a ledger system called blockchain to keep track of Bitcoin accounting and to keep the network safe. Blockchain records all transactions, and everyone in the network gets a copy. Each copy is linked to other copies. Anyone with a high-powered, purpose-built computer can become a part of the network and perform "mining" operations that can yield new Bitcoin to miners, but that also require significant energy use.

In order to "mine" Bitcoin, computers are connected to the cryptocurrency network to verify transactions made by people who send or receive Bitcoin and to prevent fraudulent edits to the global record of those transactions. The "mining" of cryptocurrencies uses

> Bitcoin mining consumes more electricity than Argentina uses and could soon surpass Norway.

complicated computer calculations to verify transactions and solve increasingly difficult math problems, or puzzles, to keep the blockchain secure and functioning. Miners occasionally receive small amounts of Bitcoin in a sort of lottery, thus making the venture profitable if the price is high enough.

To increase profits, more and more miners connect more and more power-hungry computers to the network that are constantly at work. To avoid overheating, the machines that are performing these complex puzzles must be powered to do the work and must be kept cool, which draws significant power.

As the price of Bitcoin has increased, so has the energy consumption as more miners deploy. According to Michel Rauchs, the researcher at the Cambridge Centre for Alternative Finance who co-created an online tool to estimate Bitcoin-related electricity consumption, the annual consumption has surpassed Argentina (121 TWh) and could soon exceed the electricity load in Norway (122.20 TWh). If Bitcoin itself were a country, it would be in the top 30 in terms of electricity consumption.

All of this electricity demand has implications for greenhouse gas emissions. Unless new renewable energy capacity additions keep pace, the electricity will come partly from dirty sources. Governments have not endorsed cryptocurrencies and regulatory risks remain not only from its use to shield currency exchanges from regulators, but also from possible emissions regulation, such as through a carbon tax.

This is also a potential opportunity for renewable energy companies that want to supply power. However, the challenge will be finding creditworthy offtakers so that projects with such offtake contracts can be financed.

## New York Renewables

New York is moving to make siting and permitting of new renewable energy projects in the state easier.

The state Office of Renewable Energy Siting issued final regulations on March 3 to implement the "Accelerated Renewable Energy Growth and Community Benefit Act" the state legislature passed last year to streamline the state's cumbersome "article 10 process" for siting renewable energy projects. The new statute created a new state agency called ORES for short dedicated exclusively to the siting of renewable energy projects.

The final regulations should improve the siting process for renewable projects that are 25 megawatts and larger.

New York law now requires the state to generate at least 70% of its electricity from renewable sources by 2030.

The article 10 siting process has been overly complex and burdensome. ORES was ordered to establish a uniform set of standards and conditions for the siting, design, construction and operation of each type of major renewable energy facility. The new regulations are an attempt to do that.

Applicants for permits must now do five things as part of the pre-application process.

First, an applicant must meet with the chief executive officer of the municipality within which the project will be sited, along with any local agencies identified by the CEO, at least 60 days before filing the application. The applicant must share certain information with the municipality, including a summary of local laws that apply to the project and the plans for complying with them. In a change from the draft regulations, the final version clarifies that applicants must include summaries of substantive provisions of local laws on decommissioning, as well as on construction, operation and maintenance.

Second, the applicant must also meet with community members that may be adversely affected by the project at least 60 days before the application is filed. The applicant must provide copies of transcripts, presentation materials and a must of questions asked during the meeting.

Third, the applicant must submit a wetlands study for ORES review identifying any wetlands on the project site and within 100 feet of areas to be disturbed by construction.

Fourth, it must also identify all federal, state and local waters present on site and within 100 feet of areas to be disturbed by construction, as well as 100 feet beyond the limit of disturbance that may be hydrologically or ecologically influenced by site development.

Finally, the applicant must submit a report on any species listed as threatened, endangered, or of special concern to ORES that will be affected by the project. The report must document species and suitable habitat for protected species at the project site and within five miles of it. ORES is supposed to identify any mitigation measures it will require within 30 days after receiving the report. */ continued page 48*

## Enviornmental Update

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The regulations also establish uniform setback requirements for wind turbines and solar arrays from residences, property lines and centerlines of public roads.

The new regulations also establish clearer regulatory requirements to minimize project impacts, including to viewsheds, wetlands and aquatic resources, protected species and cultural resources and from noise.

The article 10 process allowed various state agencies to impose requirements on applicants that were sometimes in conflict and were not nearly as clear as the new single set of rules. ORES was created to function as the regulatory nucleus in the siting of large-scale renewables, avoiding multiple regulatory masters each with potentially divergent demands.

ORES must make a "completeness determination" within 60 days after receiving a complete application. ORES must then issue a permit within another year. Permits must be issued within six months for projects proposed for a "repurposed site." A repurposed site is an existing or abandoned commercial or industrial use property, such as brownfields, landfills, dormant electric generating facilities or other previously disturbed locations.

The new rules aimed at reducing effects on threatened and endangered species are more stringent than those that applied previously.

Applicants must now identify any migratory bird and bat routes over the project site and adjust the scope of disturbance or construction schedule in certain circumstances. The mitigation-requirement calculations have changed in certain situations.

For example, if an active nest of a bird species considered threatened or endangered under New York law is discovered on a project site, the applicant will have to engage further with ORES. To the extent an applicant proposes a bird habitat conservation plan in lieu of paying a mitigation fee, the regulations establish the basis for the required mitigation.

Public review and comment are still required, as are adjudicatory hearings when substantive issues are identified.

With respect to geological studies of a project site, the applicant must now provide results of borings or test pits and representative mapped soil and bedrock formations. Wind developers must also provide a final geotechnical engineering report that includes results of boring or test pits at each turbine location.

Finally, projects currently in the article 10 process may seek a transfer to the new ORES process.

*— contributed by Andrew Skroback in New York*