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Tariffs, Inflation and Other Challenges

A panel of veteran financiers at the annual ACORE finance forum in New York in early June was optimistic, but cautious about whether the Biden proclamation shielding solar panels imported from four Southeast Asian countries over the next 24 months from anti-circumvention duties will allow stalled solar financings to move forward. The panel also talked about how inflation and the current economic outlook are affecting the market. The conference is hosted by the American Council on Renewable Energy.

The panelists are Mit Buchanan, managing director on the tax equity desk at JPMorgan Capital Corporation, Gaurav Raniwala, global head of renewable energy for GE Energy Financial Services, Ted Brandt, CEO of Marathon Capital, Claus Hertel, a managing director at Rabobank, and Alain Halimi, an executive director at Nomura. The moderator is Keith Martin with Norton Rose Fulbright in Washington.

Anti-Circumvention Moratorium

MR. MARTIN: The Biden administration moved yesterday to ease solar industry fears that solar panels imported from Vietnam, Malaysia, Thailand and Cambodia will be subject to large anti-circumvention duties. It said there will be a 24-month moratorium on any such duties that the Commerce Department decides later this summer to impose.

Auxin, the US solar panel manufacturer that launched the Commerce investigation, is not happy. It could sue to block implementation. */ continued page 2*

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SOLAR COMPANIES are anxious about whether tougher enforcement of a US prohibition against importing products that benefited from Chinese forced labor will mean more blocked solar panels and batteries.

Solar panels and batteries imported on or after June 21 are at greater risk of being blocked at the US border under a Uyghur Forced Labor Prevention Act that took effect on June 21. (For more details, see "Customs Seizures of Solar Panels" in the March 2022 *NewsWire*.)

Two US government reports in mid-June describe what importers will have to do in the future to prevent such equipment from being detained. */ continued page 3*

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Will solar projects that are currently in limbo because they cannot tolerate the extra duties now move forward with financing?

MS. BUCHANAN: The Biden proclamation was welcome news. Whether it will ultimately succeed in its objective has to be worked through, but we are hopeful that some near-term projects that are in the pipeline will be able to close their financings as a result.

MR. MARTIN: Biden used authority under section 318 of the Tariff Act of 1930 to waive duties. That authority allows the president to waive tariffs on "food, clothing, and medical, surgical and other supplies for use in emergency relief work." The issue will be whether it allows tariffs to be waived on solar panels. Greg Wetstone mentioned immediately before this panel that Covington produced an analysis last night that suggested Biden was on firm ground to use this authority. I suspect financiers are going to want to see the analysis.

Ted Brandt, will this allow financings that have stalled over tariff fears to move forward?

MR. BRANDT: It was clearly a good day yesterday. The developers we talked to in the last 24 hours are optimistic that it will allow projects to advance. Everybody was waiting until late August for the preliminary Commerce decision and April 2023 for the final decision. This helps.

Unfortunately it may not have come in time to salvage 2022. We are hearing about a lot of 2022 solar projects that have shifted to 2023. Panel orders had slowed to a trickle. It is not as if there are a lot of shovel-ready projects. We are at a point where supply chain and labor issues and escalating costs are starting to affect even 2023 projects and cause them to slip into 2024.

MR. MARTIN: Bankers, any views?

MR. HERTEL: We have had to put five or six transactions with reputable developers on hold. It was pencils down earlier this year. With the news yesterday, I think folks are somewhat exuberant. Maybe not irrationally so, but they are excited that they can get to work again. I think we will see some extra closings this year. Some will slip into next year. Lawyers are back in action. Construction contractors may be able to get panels now.

MR. MARTIN: It seems like deals in the M&A market were closing anyway, but with sellers accepting a lower initial price with a possible earnout later depending on how the Commerce investigation comes out.

Alain Halimi, do you have a view?

MR. HALIMI: I agree with Claus. We have been busy since the Commerce investigation started helping developers structure around the tariff risk by providing bridge facilities that allow construction to get underway and that provide flexibility to shift the source of panels. We are working now on such a transaction that is supposed to close next week.

Obviously what happened yesterday is helpful. In terms of the pipeline of deals, with more people getting back on their horses, this could create more challenges with supply chains. It is a game of supply and demand.

MR. MARTIN: You were prepared to close bridge financings before the Biden proclamation. How have you structured around the tariff risk?

MR. HALIMI: We can do it non-recourse or partial recourse. Having a recourse loan is the lazy way to do it. The risk is present. It is a matter of shifting the risk to someone who can bear it. Everyone works together. By everyone, I mean the EPC contractor, the electricity offtaker, the developer and the lenders. For example, the offtaker says, "I need the power. I am happy to amend the PPA to have a price step up in the event there is a negative action on tariffs." That gives comfort to the lenders.

MR. MARTIN: So the offtaker is willing to take the risk. If it is a utility, it passes through the tariff increase to its millions of customers.

MR. HALIMI: A portion.

Between 25% and 40% of 2022 solar projects are at risk of slipping at least partly into 2023.

MR. MARTIN: What percentage?

MR. HALIMI: Up to 60% of any tariff increase.

There is also flexibility shown by the parties around the construction schedule in the event the developer needs to procure the panels from another source.

Tax Equity Volume

MR. MARTIN: Back to Mit Buchanan. Last year was about a $19 to $20 billion tax equity year. People were predicting at the start of this year that tax equity volume for 2022 will be about $20 billion, plus or minus 5%. We are now six months into the year. Where does it feel like the final figure will land?

MS. BUCHANAN: I think we are still on track for $20 billion for commitments in the form of an executed equity capital contribution agreement or letter of intent, but actual closings on some of that $20 billion will be delayed into 2023. We will be figuring out over the next month what really can close in 2022 versus 2023.

Going back to the Biden announcement yesterday, it is good news and it will allow some developers to move forward with their transactions in 2022, but this is June. Anyone hoping to close this year has to have the transaction well underway by now. It is not a matter solely of getting the documents done. You also have to have the construction contractor and the other technical resources lined up. Everyone is working flat out trying to get a few deals done.

MR. MARTIN: There are labor shortages across the spectrum.

MS. BUCHANAN: There are labor shortages.

MR. MARTIN: Tax equity desks, bankers, lawyers, appraisers, technical consultants, everybody.

MR. RANIWALA: We are seeing delays across the board. New solar capacity additions could be reduced by more than half this year. New wind construction could be down by a half this year compared to the past peak of 18,000 megawatts.

Without policy support for both solar and wind, while the short-term commitments might be keeping up, in reality the market is shrinking dramatically. Without a policy change, we are looking at a much smaller industry going forward.

Delays

MR. MARTIN: Ted Brandt and I were on a panel in January in New Orleans. The Lightsource BP US CEO said something surprising. I thought supply chain difficulties and labor shortages were accounting for the delays. He said it is inability to interconnect.

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Importers will have to produce a lot of paper. This will require a change in equipment procurement contracts to put a larger burden on suppliers.

All goods manufactured wholly or partly in Xinjiang or that include inputs from Xinjiang will be presumed to have been made with forced labor and be blocked from entry into the United States. Solar panels are particularly at risk because of the large percentage of polysilicon originating in western China. Roughly 80% of the cells that power lithium-ion batteries are also made in China.

The presumption that any product using any inputs from Xinjiang benefited from forced labor is rebuttable.

US Customs must decide within five days after goods are presented for entry whether to block them.

Customs may issue one of three types of notices: a detention, exclusion or seizure notice.

Anyone receiving a detention notice generally has 30 days to try to rebut the presumption.

An exclusion or seizure notice requires a more formal process to overcome.

Importers will either have to prove their supply chains are free of any inputs from Xinjiang or other forced labor or, if there is any link to Xinjiang, prove no forced labor was involved. The latter may prove very difficult.

The two papers the US government released in mid-June are a June 13 US Customs paper called "Operational Guidance for Importers" about how to comply with the new statute, and a June 17 report to Congress by the Department of Homeland Security, where Customs is housed, that reports on the steps it is taking to enforce the new law and that includes a section called "Guidance for Importers."

Anyone in a position of having to rebut the presumption will have to have done a lot of diligence.

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MR. BRANDT: I think you have both causes. Interconnections have slowed dramatically in PJM. That was a place where people were counting on significant new capacity additions in the next couple years. We are hearing in the onshore wind and solar markets of nightmares in terms of procuring panels, finding labor and all the other things required to build a project. General inflation is also taking a toll.

MR. RANIWALA: Five years ago, it used to take 1.5 years to interconnect a project. Now it takes an average of three years, according to a US Department of Energy study.

MR. MARTIN: Interconnection measured from what start date?

MR. RANIWALA: Measured from when the developer first applies to interconnect. There are something like 250,000 megawatts of wind projects and 400,000 to 500,000 megawatts of solar projects in line to interconnect. We have a massive backlog issue that is not getting resolved.

MR. MARTIN: PJM has now imposed a two-year moratorium on new interconnections. Bankers, coming back to you. What percentage of projects are you seeing pushed into 2023 or suffering some sort of delay?

MR. HERTEL: Around 50% of projects are moving into 2023.

MR. MARTIN: What is the average delay in months?

MR. HERTEL: We have three transactions in house that received credit approval last year that have still not closed because of all kinds of issues, from escalating financing costs to supply chain difficulties, inability to get panels, labor shortages and transportation snafus. It has been a perfect storm.

We have not seen anything like this in a long time where costs are increasing rather than going down.

We are doing more loans at the holding company level to help developers bridge a gap until they are in a position to build in 2023 and 2024.

MR. MARTIN: They are drawing money, but what are they spending it on if everything is delayed?

MR. HERTEL: It costs a lot of money to develop. If we are extending development capital at SOFR plus 350 basis points, that is cheaper than the equity that they have to get from a private equity fund at a cost of 15% or 20%.

MR. MARTIN: This helps explain a phenomenon we are starting to see where projects are worth less at the end of construction than they cost to construct. Alain Halimi, what delays are you seeing?

MR. HALIMI: Our experience is the same as what Claus described. We have been seeing opportunities to lend to acquire equipment, particularly in Europe where solar panel tariffs are not a threat. Another growth area is developers who want to recycle capital by borrowing against the equity value in projects.

MR. HERTEL: One more thing on the developer side. Projects that are ripe for construction were developed over the last few years. The developers have not been paid a developer margin or developer fee yet. Those margins are being squeezed with costs going up. The private equity owners are not happy. They need to renegotiate the EPC contracts or PPAs to get the margins back to something tolerable.

MR. BRANDT: For two decades, the way this industry worked is you sign a PPA at an aggressive price and then delay construction until the prices come down to a point where the project economics work. That was the game. The game no longer works.

MR. MARTIN: Power prices are up 20% to 30%. Developers have been caught flatfooted.

MR. RANIWALA: The same phenomenon applied to solar panels, wind turbines and other equipment. Costs fell over time, but they are no longer falling.

MR. BRANDT: The capital cost is now 20% higher. We are telling our clients not to lock in a power contract. We will help

Tax equity yields have been falling this year due to increased competition for scarce projects.

you raise money even if you do not plan to lock in the electricity price until close to the start of construction. We had one project in Oklahoma where the electricity price was $18 a MWh early in the development process. It is now $37 a MWh.

MR. MARTIN: Do you follow the same approach in your personal investing of betting when the stock market will turn?

MR. BRANDT: I was going to say, based on last month's statement, I am not sure that I am one to emulate. [Laughter]

MR. RANIWALA: It is a tale of two cities. Solar delays are driven by the anti-circumvention duty investigation, but wind projects, which don't have the same tariff issue, are also experiencing delays due to lack of long-term policy. There is uncertainty whether production tax credits for wind projects will be restored by Congress. Policy uncertainty is a big part of why we are seeing market stagnation.

MR. MARTIN: Mit Buchanan, that tees up the following question. Tax equity investors have been asking sponsors to covenant that they will complete their projects by a deadline. Listening to all this, it is hard to see how sponsors can do that. What do tax equity investors expect to happen if those covenants are breached?

MS. BUCHANAN: We need to plan on our side for all the fundings to which we commit. A lot of work goes into that in terms of having a line of sight into construction schedules. Sometimes coming up with an outside date requires consulting a crystal ball. We try to build in some cushion. We also need an independent engineer to vouch for what is realistic.

If a sponsor breaches the covenant, either we agree to extend the deadline or else we are entitled to get back the initial tax equity funding, if there was one.

Cost of Capital

MR. MARTIN: Let me ask you another question. Tax equity yields appear to have been dropping in the last few months, at least judging what we are seeing in recent term sheets. At the start of the year, they seemed to be headed up. What happened?

MS. BUCHANAN: A number of factors are affecting the bidding dynamics. For example, you probably had five sizable tax equity investors that did the majority of the business and then smaller ones, but this year there is an additional $4.5 to $5 billion of tax equity on top of that that is available from people who are re-entering the market and from several corporates that are big players.

MR. MARTIN: So it is competition?

MS. BUCHANAN: There is a bit more / continued page 6

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The importer must produce a supply chain map. All of the suppliers along the supply chain must have written codes of conduct barring forced labor and "addressing the risk of use of Chinese government labor schemes." The procurement staff must have had training on how to spot forced labor risks. It must monitor the suppliers for compliance with their codes of conduct. There must be an independent verification of "the implementation and effectiveness of the due diligence system."

The importer may also have to produce a list of every worker at any Xinjiang company in the supply chain, the worker's residency, the wages he or she is paid, proof that the factory output is consistent with the number of documented workers and proof that none of the workers was recruited with help from the Chinese government, the Xinjiang Production and Construction Corps (XPCC) or any company on the UFLPA entity list.

Anyone trying to prove the presumption does not apply in the first place because there are no links to Xinjiang or other forced labor must have affidavits from each company involved in the production process.

If Customs allows any goods in with ties to Xinjiang because the importer was able to prove no forced labor, then it must alert Congress in a report identifying the goods and the evidence considered. The reports will be made public. Proprietary information may be withheld from release under the same standards that protect confidential information from disclosure under the Freedom of Information Act.

The government has a UFLPA entity list with names of Chinese companies that use forced labor. The list includes four companies involved in supplying polysilicon and silica-based products: Hoshine Silicon Industry, Xinjiang Daqo New Energy, Co. Ltd., Xinjiang East Hope Nonferrous Metals Co. Ltd. and Xinjiang GCL New Energy Material / continued page 7

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competition, but there is not excess tax capacity. Yields overall are staying in a tight range.

MR. RANIWALA: Rising interest rates will eventually put pressure on yields. As a manufacturer, we like the cost of capital to be as low as possible so that developers can afford to buy more equipment. As a financier, we see our cost of funding going up.

MS. BUCHANAN: You also have internal metrics that you would like to meet, and you can't do that while continuing to ratchet down yields. Everyone has to share the pain.

MR. MARTIN: So you have to balance competition against the cost of funding.

Bankers, at the start of the year, there seemed to be more than 100 banks and grey market lenders chasing deals. There are not that many deals in the market this year, so that has kept downward pressure on interest rates. The spread above LIBOR for term debt had dropped to as low as 112.5 basis points over, but with most debt in the range of 125 to 137.5 basis points over. Are these margins still holding six months into the year?

MR. HERTEL: The banks are all still there. You are also right about the shortage of deals. We closed 25 and 30 deals a year on the project finance renewable energy side before this year. We have closed maybe six or seven so far this year, and it is the beginning of June.

MR. MARTIN: How many would you have normally done by this point in the year?

MR. HERTEL: Probably 10 to 12, but the deals we have done this year have been higher value-added deals, like holding company loan facilities.

MR. HALIMI: There has clearly been margin compression. It has been going on for several years now. Another factor is the number of banks looking to build their books of green exposure on top of lack of deal flow. It is creating some challenges.

The risk appetite among lenders has shifted as well. Lenders are now willing to take more risks by moving to deals that are more complex where there is more merchant exposure or more electricity basis exposure.

Five to seven years ago, for instance in Canada, you could borrow at a 200-basis-point spread against a government offtake contract. Now for 200 basis points, you can borrow to finance a project in Texas that has merchant risk.

MR. MARTIN: That is a clear indication of increased competition. Is it still the case that construction loans are available at 70 basis points over LIBOR?

MR. HERTEL: Maybe from some lenders, but not from us.

MR. MARTIN: What would you say is typical?

MR. HERTEL: Anywhere from 87.5 basis points to around 100 basis points for both the tax equity bridge loan and the construction loan.

MR. MARTIN: So bankers want complexity and more risk to justify the higher interest rates.

The market is switching from LIBOR to SOFR. SOFR is a risk-free rate. What should one assume will be the credit adjustment to get to SOFR? People were saying late last year it will settle at between 12.5 to 25 basis points.

MR. HERTEL: We've seen everywhere from 10 basis points to around 25 basis points for longer-term transactions in the five- to nine-year range. On the short-term side, construction or warehousing up to two years, perhaps 10 to 12.5, or even zero, basis points.

M&A

MR. MARTIN: Let's switch to M&A. Ted Brandt, I read in the Financial Times yesterday that there has been a 90% drop in the amount of capital raised in initial public offerings in Europe and North America this year compared to last year. We saw hugely inflated asset values coming into this year. There was $10.6 trillion in global fiscal stimulus the last two years. The money had to go somewhere. Have asset valuations started to cool?

MR. BRANDT: The public equity market is ugly. Traditional IPOs are largely on hold. The SPAC market has been virtually wiped out.

We are still seeing private equity funds and strategics putting more capital into the private markets, and so we have not seen any fall off in private market valuations. While valuations in the private market remain somewhat frothy, they were two and three times that in the public market before the collapse. I expect the public markets to recover at some point. What is driving M&A this year is the private market.

MR. MARTIN: It seemed coming into this year like almost every developer with a pipeline of projects under development had at least tested the market for them. Is that still happening?

MR. BRANDT: There is still a lot of inventory in the market. For the first time in six or seven years, we are seeing some sales that are not clearing.

MR. MARTIN: Two things seem important for anyone hoping to place the winning bid in an auction. One is the rate used to discount future cash flows. Even more important is the forecast used for out-year electricity prices — "out-year" meaning after the contracted revenue stream ends. I think you told me in January that it is not even worth bidding if you are more than 5% below the Ventyx electricity price curve. Ventyx tends to be the most optimistic forecast. Did I hear that correctly?

MR. BRANDT: Yes. The market has not turned yet. We are still seeing robust bids, but people are starting to look harder at pricing. The gas curves are showing gas at $8 an mcf for the next couple years and then coming down to $5. Some people are starting to take the view that we will see the same pattern for electricity. The power curve analysis is almost more important than the discount rate in terms of who is going to win any given deal.

MR. MARTIN: That's because the PPA contract term is just a fraction of the useful life of any project. There is a long merchant tail.

MR. RANIWALA: That's right.

MR. BRANDT: If you don't have a robust view of future power prices, you could probably use a discount rate that is as much as 250 basis points lower than the next bidder and come up short.

MR. MARTIN: At the start of the year, it seemed like winning bidders were discounting future cash flows at 7.5% to 8% for contracted onshore wind and 50 to 75 basis points lower for contracted utility-scale solar. Is that still true?

MR. BRANDT: My sense is the rates have creeped up a bit, but they are not crazy different for a contracted vanilla deal.

Common Questions

MR. MARTIN: Mit Buchanan, tax equity accounts for 35% of the capital stack for the average solar project and 65% for the average wind project. Why the difference?

MS. BUCHANAN: Production tax credits claimed over 10 years on wind projects are worth a lot more than an investment tax credit claimed in year one on a solar project. This is especially true after factoring in capacity factors on wind versus solar. Wind projects generate electricity at 40% to 45% of capacity while solar is around 30%.

MR. RANIWALA: Historically, solar cost more than wind per megawatt to build and solar capacity factors were lower, so when you combine those two things, the ITC made more sense for solar while PTCs were better for wind. The ITC is a function of cost. PTCs are a function of output. */ continued page 8*

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Technology, Co. Each of the companies operates under various aliases that are included on the entity list.

The New York Times suggested in a June 21 article that Xinjiang Nonferrous Metal Industry Group, which is involved in the supply chain behind batteries, uses some forced labor. The company is not on the entity list.

TARIFF MORATORIUM regulations are expected soon.

The US Department of Commerce must issue regulations to implement a 24-month moratorium on any anti-circumvention duties that Commerce decides later this summer to impose on solar cells and panels imported from Vietnam, Malaysia, Thailand and Cambodia.

Financiers reacted positively to news of a moratorium, but with some caution about whether they would be able to proceed with financing of stalled solar projects.

Auxin, a US solar panel manufacturer, could still file suit to block implementation. The Biden administration is using authority under section 318 of the Tariff Act of 1930 to waive tariffs on "food, clothing, and medical, surgical and other supplies for use in emergency relief work."

Projects that would be uneconomic if they had to bear the tariffs may still be delayed until after regulations are issued and the market has a chance to assess the merits of any lawsuit. (See "Tariffs, Inflation and Other Challenges" starting on page 1 of this issue.)

President Biden issued a proclamation on June 6 authorizing the US Secretary of Commerce to "consider" taking action to waive duties on solar cells and panels imported from the four Southeast Asian countries, "under such conditions as the Secretary may prescribe," until 24 months after June 6 or, if earlier, until US solar panel manufacturing can increase significantly enough to declare an end to the "emergency" requiring the tariff waver.

The Commerce Department issued two statements the same */ continued page 9*

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Over time, as solar capital costs fall and capacity factors increase, solar will be better off with PTCs. We will start to see such a shift if Congress allows solar developers the same choice of tax credits that wind developers have.

MR. MARTIN: We already see solar companies writing the option to move to PTCs into tax equity papers.

Another question people often ask is about cash flow. Tax equity investors said for the last few years that falling electricity prices were creating challenges. Tax equity investors have to expect a pre-tax yield. They cannot be in the deal solely for tax benefits.

Electricity prices are now increasing. There is more cash. How does that change the dynamics in deals? For example, does it mean that investors can agree to higher deficit restoration obligations? Does the cash sharing ratio tip more in favor of sponsors?

Private market valuations remain high as private equity firms and strategic investors look for places to put capital.

MR. RANIWALA: We were always able to structure around low cash flow by having the tax equity investor make more of its investment over time in the form of pay-go payments that are a function of the production tax credits allocated to the investor. If electricity prices increase, that probably means that construction costs are also increasing, so more capital is required. That may or may not affect DROs.

MS. BUCHANAN: I agree with that.

New Deal Types

MR. MARTIN: Bankers, there are a lot of new types of deals coming to market: carbon capture, standalone merchant storage, renewable natural gas, green hydrogen. How much deal flow are you seeing in these areas?

MR. HALIMI: We have seen increasing interest in all of them. We are working now on a green hydrogen transaction that will probably close in the next three to four weeks. The challenge for these types of deals, especially hydrogen, is they are either too small or too large and involve technologies that are not yet fully proven in the US market.

MR. MARTIN: The hydrogen is being put to what use?

MR. HALIMI: For making electricity.

Hydrogen technologies are key to support the energy transition. You basically convert some fuels to clean energy. From an energy standpoint, it is fantastic and we expect to see more of this type of transaction.

I would say that of the deals now crossing our desks, roughly 70% involve a link to batteries. There are also more merchant projects because you need more risk to make a return. Without that, returns are getting crushed.

MR. MARTIN: One banker told us that current debt service coverage ratios, which determine how much projects can borrow, are about 1.35 times debt service for onshore wind, 1.25 times for utility-scale solar and only 1.2 times for standalone storage. Do you agree?

MR. HALIMI: Those are for contracted revenue streams.

MR. HERTEL: We've actually seen as low as 1.15 times debt service for storage in projects with 20-year tolling agreements.

MR. MARTIN: How does a storage tolling agreement work compared to a standard PPA?

MR. HERTEL: Under a tolling agreement, the battery owner receives a fixed capacity payment each period as long as the battery is available and able to store electricity.

MR. MARTIN: The utility pays the battery owner essentially a reservation charge for the right to use the battery to store electricity. Is there an additional charge tied to the amount of electricity actually stored?

MR. HERTEL: No. There is some merchant exposure for the project on the back end after the tolling agreement ends. We take that into account in the debt sizing. For example, we credit the contracted revenue stream at 1.15 times debt service and size the debt against the merchant revenue on the back end at 1.75 to 2.0 times debt service.

The key in those long-term arrangements is really augmentation of the batteries because they get cycled pretty much on a daily basis and, within five to seven years, you need to replace a lot of the cells. It is paramount for us to have a creditworthy entity dedicated to augmenting the battery cells on a continuous basis.

MR. MARTIN: Do you also require a reserve account for cover the cost of replacing cells?

MR. HERTEL: In some cases, but mostly not if there is a creditworthy entity standing behind the obligation.

MR. MARTIN: Mit Buchanan, what new types of deals is the tax equity market seeing?

MS. BUCHANAN: The next big thing for us is offshore wind. We expect to close a significant transaction this year and a couple more will probably follow next year.

MR. MARTIN: Next year or 2024?

MS. BUCHANAN: 2024, thank you. The next big thing after that is carbon capture. We expect to close a transaction later this year or early next year, with some sizable ones to follow.

Next in terms of volume is hydrogen. And then if Congress passes the budget reconciliation bill with an investment credit for high-voltage transmission, we expect to see deal flow around that. We have been talking about transmission issues for 25 years. There could be a large investment opportunity for everyone.

MR. MARTIN: Are you seeing any renewable gas deals?

MR. BUCHANAN: That has not been an area of activity for us.

MR. RANIWALA: Natural gas is a force multiplier. We also see a lot of carbon capture deals heading to market.

MR. MARTIN: Are you aware of any carbon capture tax equity deals that have closed? We know of one with a large tax equity investor, but nothing beyond that.

MR. RANIWALA: There are a lot in the works, but I am not aware of any that has crossed the finish line. Many of them, especially in the power sector, need a higher tax credit to make the economics work.

MR. MARTIN: We have been involved with one where the tax credits over the 12-year period are $1.8 billion. These can be very large transactions.

Ted Brandt, what deal flow are you seeing in new areas?

MR. BRANDT: In terms of carbon capture, we are about to announce what we think will be the */ continued page 10*

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day indicating that it will implement the moratorium.

The implementing regulations will have to be vetted by the US Treasury and Department of Homeland Security before they are issued.

Commerce is investigating whether solar panels entering the United States from Vietnam, Malaysia, Thailand and Cambodia are essentially Chinese panels that would be subject to anti-dumping and countervailing duties if imported from China directly. If so, then they will be subject to the same such duties as Chinese panels.

Approximately 80% of solar panels imported during 2021 came from the four countries and fewer than 1% came from China directly. The US has been collecting anti-dumping and countervailing duties on Chinese panels since 2012.

The current China-wide rate for anti-dumping duties is 238.95% and for countervailing duties is 17.1%. Many manufacturers are subject to significantly lower anti-dumping duties after demonstrating to Commerce that their dumping margins are lower than the China-wide margin. Chinese-made panels are considered "dumped" if they are sold in the US for less than they are sold in China.

The countervailing duties on some Chinese manufacturers range a little above or below the China-wide rate. (For more detail, see "Solar Panel Import Duties" in the March 2022 *NewsWire*.)

Commerce has until August 29, 2022 to make a preliminary determination in the investigation and until April 3, 2023 to make a final decision.

The moratorium regulations will have to address whether any duties will apply retroactively to panels imported before June 6. Commerce has authority to impose them on solar panels imported as far back as November 4, 2021.

Most current solar panel supply contracts put the tariff risk on the US customer. However, presumably panel */ continued page 11*

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first closed deal. It is at an ethanol plant in Texas that will use the captured CO_2 emissions for enhanced oil recovery.

MR. MARTIN: Didn't you just announce it? [Laughter]

MR. BRANDT: Not yet. We have not announced a closing. It has been two weeks away for about two years. I should also mention that we have done a number of renewable natural gas deals, and we actually raised debt for a renewable natural gas project where we got Moody's to rate the bonds investment grade. The revenue stream was about 50% contracted. That is a maturing market segment. It was a landfill gas portfolio. We are very excited about growth in renewable natural gas.

MR. MARTIN: Are the renewable natural gas deals being driven by LCFS credits in California?

MR. BRANDT: Yes. Most such deals rely on LCFS credits in California plus RINs. It is possible to sign long-term contracts to lock in a revenue stream at a stated price, but we are finding developers using more equity and locking in only a portion of the revenue in order to keep the upside.

MR. MARTIN: Is there any concern about how long California will continue to make LCFS credits available to renewable natural gas projects outside California? I heard a story on NPR about a dairy farmer in the Midwest who was planning to add cows to produce more methane because more than half his income as a farmer is now coming from LCFS credits.

MR. BRANDT: It is amazing how microeconomic incentives work. I would just say if you have to ask that question, you are probably not going to do a deal where LCFS credits are a key to the project economics. You almost just have to grab your ankles and jump.

Washington Issues

MR. MARTIN: Here is my last question, starting with Alain Halimi. Are there any other issues in Washington that you are following besides the "Build Back Better" bill and the anti-circumvention duty investigation?

MR. HALIMI: I'll be very honest. I stopped following actually because . . .

MR. MARTIN: Nothing happens.

MR. HALIMI: Well, I think whatever happens, we find a way to structure around it.

MR. HERTEL: A storage ITC is one thing that we are following closely.

MR. MARTIN: That would be a big deal if it is enacted. Mit Buchanan mentioned a transmission ITC. Mit, you are on the board of at least one of the renewable energy trade associations. Is there any other issue you are following that rises to the level of the BBB bill and the anti-circumvention duty investigation?

MS. BUCHANAN: I would say not. We have been tracking the BBB bill discussion very closely. The deadline is approaching when that bill will have to come together if anything is going to happen this year. We remain optimistic.

MR. MARTIN: That has been your theme today.

MR. RANIWALA: Another thing we are following is an effort to get the Treasury to allow another year to finish construction of projects and claim tax credits in view of the continuing supply-chain difficulties, interconnection challenges and COVID-related shutdowns in China.

A related issue is the 5% test for starting construction. With inflation, the initial safe harbor purchases may not be sufficient so we need to modify the standard. The trade associations are starting to work on that issue as well.

MR. MARTIN: That is a very interesting point. Developers who thought their projects were under construction in time to qualify for tax credits because they incurred at least 5% of the total project cost are now coming up short. Inflation is driving up construction costs.

The Treasury extended the time period to finish projects after construction started to six years last summer, and it let developers buy even more time by proving they worked continuously on their projects. Does the tax equity market accept proof of continuous efforts?

MR. RANIWALA: I am aware of one deal that has been financed on that basis. We are looking at another transaction now with the same issue. However, even if the tax equity market accepts continuous efforts, it will not do so in the volume of projects needed to meet the administration's clean energy goals.

MR. BRANDT: When the richest man in the world and the top banker are both worried about the economic outlook, I am obviously glued to the inflation numbers and interest rates. This is an industry that benefited from falling interest rates. Increasing rates will have an effect. We have not yet seen an effect on the M&A market or project financings, but clearly that is one of the challenges with which we will have to deal in the months ahead. ◎

NORTON ROSE FULBRIGHT

Project Sales Still Closing Despite Circumvention Risk

by Sameer Ghaznavi in Chicago, Stefan Reisinger in Washington, Lee Gordon in New York, Lindsey Swiger in Houston and Lauryn Robinson in Austin

Sales of solar projects and solar development platforms are still closing, despite some risk that a court could still block implementation of a 24-month moratorium on anti-circumvention duties on solar panels imported from Vietnam, Malaysia, Thailand and Cambodia.

The four Southeast Asian countries accounted last year for roughly 80% of US solar panel imports.

While panel suppliers are getting creative with deferred milestone payments and tariff thresholds, most are unwilling or unable to take the tariff risk.

The result is that US solar developers end up in most cases with the risk and when they try selling projects or project pipelines with such risk, some developers are taking an immediate reduction in enterprise value, but most are taking a wait-and-see approach by introducing earnouts or other deferred payment structures into the purchase agreement.

The uncertainty created by the Commerce Department investigation into whether Chinese panel suppliers are circumventing duties that would apply to direct imports from China is creating unique legal issues for buyers and sellers to beware of when entering into purchase and sale agreements and solar panel procurement contracts.

The potential duties vary depending on the panel supplier. They are the same duties that would apply if the particular panels were imported directly from China. The US is currently collecting a China-wide anti-dumping duty of 238.95% and countervailing duty of 17.1% on Chinese solar panels imported, but many manufacturers qualify for lower rates after presenting evidence to Commerce of their actual dumping margins and government subsidies. (For more information, see "Solar Panel Import Duties" in the March 2022 *NewsWire*.)

Commerce has until August 29 to make a preliminary decision on circumvention and until April 3, 2023 to make a final decision.

President Biden authorized Commerce in a proclamation on June 6 not to collect any anti-circumvention / *continued page 12*

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suppliers will have to take the risk that their panels will make it past US Customs within the 24-month period. (For other market reaction, see "Project Sales Closing Despite Circumvention Risk" starting on page 11 of this issue.)

THE TAX EQUITY MARKET is wrestling with a series of issues tied to inflation and construction delays.

Developers form a separate special-purpose project company to own each project. Most renewable energy tax equity is raised in partnership flip transactions.

In the typical solar tax equity transaction, the developer sells the project company to the partnership once the project has reached mechanical completion, but before any part is placed in service, for the appraised value the project is expected to have at the end of construction. The partnership assumes any outstanding construction debt and the obligation to pay any remaining amounts owed to contractors.

Some projects are coming in at lower appraised values this year than the projects cost to construct. That's because inflation and construction delays are pushing up construction costs while the expected revenue under long-term offtake contracts remains unchanged.

In such situations, the developer may contribute the project company to the partnership — rather than sell it — in order to preserve the ability to use the construction cost as the tax basis for calculating tax benefits.

The partnership will have a "built-in loss," meaning it will have a higher tax basis than the project is worth.

US tax rules require that the tax depreciation on the built-in loss basis must remain with the developer.

The question is what happens to the investment tax credit.

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duties for the next 24 months to give solar developers and panel suppliers time to adjust supply chains. The Commerce Department is expected to issue regulations implementing the moratorium in June.

Before the Biden proclamation, there was a risk that duties would be imposed retroactively on panels entering the US as far back as last November 4. The proclamation talked about a bridge period with no duties for 24 months starting on June 6.

Earnouts

Sellers of projects and development platforms are having to balance the desire to get full value from the sale of their projects or companies against the desire to receive the consideration promptly after closing.

If Commerce finds circumvention, the final duties will not be known for years to come. April 3 next year is the deadline for a final decision on circumvention, but Commerce revisits the duty amounts over time. For example, in its most recent review, it reached conclusions about the preliminary subsidies from which various Chinese suppliers benefited on panels imported during the period December 2019 through November 2020 and preliminary dumping margins for calendar year 2019.

Importers post cash deposits. The deposit amounts are adjusted years later after the final duties are known and the deposits are liquidated.

We have seen anti-dumping and countervailing earnouts take various forms. Project or platform sellers who are able to get buyers to consider the overall impact of any potential duties on the value of the project or target company seem in the best position to maximize the sales price.

Parties should be aware that Commerce may find circumvention in one country and not another. It may also place lower duties on imports from one country versus another. Finally, individual suppliers may receive exemptions entitling them to lower duties than the country-wide rate.

The preliminary rates, if any, may differ from the final rates. Therefore, focusing too much on the preliminary rates or the anti-dumping and countervailing duties applied at the country-wide level may result in an earnout that is not representative of the overall impact to enterprise value.

Representations and Warranties

It is difficult, if not impossible, to make any representations and warranties about the current state of solar project schedules, accuracy of project budgets, and even defaults or threatened defaults related to supply or construction agreements. Sellers who agree to such representations risk providing an unintended insurance policy to buyers.

Sellers should not make representations about project schedules or costs. Industry data suggests a large percentage of projects are unable to maintain construction schedules due to tangled supply chains and labor shortages. Some projects lately are costing more to construct than they are worth at the end of construction, due to rising construction costs.

Solar panel suppliers from the affected countries have paused shipments. This created uncertainty about whether developers would be able to obtain panels in time to meet project deadlines. Because there is significant uncertainty about whether duties will be assessed, it is also difficult to give representations about whether current project budgets are accurate.

Some sellers try to exclude the impact of any changes to anti-dumping duties and countervailing duties from representations and warranties.

Some sellers give representations about the project schedule or budget, but qualify them by current knowledge. In such cases, the sellers should be careful to ensure that any conversations they had with their outside counsel about the Commerce investigation remain privileged. Even though these conversations and findings may be protected by attorney-client privilege when given, depending on the deal structure, the privilege may not belong to the seller and, following closing, the privilege rights may be transferred to the buyer.

Sellers should also carefully review governing law with counsel to limit the buyer's ability to "sandbag" the seller, or else include anti-sandbagging language in the purchase and sale agreement, which is uncommon in M&A transactions. "Sandbagging" is where a buyer has knowledge of a breach of a seller representation or warranty before closing, but closes on the transaction and brings a post-closing indemnity claim for the breach.

Material Adverse Effect

Sellers should also exclude the anti-circumvention investigation and any impact on the project or company from the definition of "material adverse effect." A buyer can usually walk away from the sale if some event has a material adverse effect on the economic prospects of the project or company.

Not only could a buyer argue that the investigation (or a potential or actual positive finding from the investigation) results in a material adverse effect, but it could also argue there was a breach of seller's representations and warranties in deals that already closed.

For the first time in six or seven years, some portfolio and platform sales are not clearing.

Some buyers may try to use an adverse determination by Commerce on circumvention as a reason to be excused from their obligations to close even in cases where the buyer was on notice of the investigation when the documents were signed.

While changes to general economic and political conditions are usually excluded from the definition from material adverse effect, they may be considered if the target company or project is disproportionately affected by the changes.

Because any potential duties could vary from supplier to supplier, it is possible for one company to be disproportionately affected compared to its competitors if its panels are subject to higher duties than panels from other suppliers or countries.

Interim Operating Covenants

Sellers should also consider the effect of the anti-circumvention duties on their contractual obligations to conduct the target business or project company "in the ordinary course in accordance with past practices" during the interim period between signing and closing.

Many solar companies are not operating their businesses in the ordinary course in accordance with past practices on account of the Commerce investigation. At minimum, they are having to pause construction work and

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Revenue Service says the built-in loss ITC must be allocated to partners in the same ratio as the investment credit on the rest of the project. Thus, 99% of the full ITC — including on the built-in loss — should be allocated to the tax equity investor.

The IRS declined in May to issue a private letter ruling to that effect on grounds that the law is clear. The IRS does not issue "comfort rulings" that repeat what is already clear, it said.

A related issue is what happens if the power contract is amended later to increase the electricity price.

In the typical solar tax equity deal, the investor funds 20% of its investment when the project reaches mechanical completion. The other 80% is funded when the project is completed.

Many developers are trying to renegotiate power contracts to increase the electricity price to reflect higher than expected costs.

In cases where this happens during funding, developers are asking for an adjustment to the purchase price the partnership paid for the project company. Tax equity investors are being asked to invest more to reflect the higher value.

Some tax equity investors cap the amount of "step up" in tax basis they are willing to accept above the actual cost to construct at 15% or 20%. A current issue in deals is whether the investor should allow a higher step up to reflect the additional value tied to the improved power contract.

Higher costs are also creating difficulties for developers who relied on the 5% test to start construction. The tax credits are phasing out. The amount of tax credit for which a project qualifies depends on when construction started.

One way to start construction is to "incur" at least 5% of the total project cost before the deadline. Some developers who incurred more than 5% of the

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Circumvention Risk

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renegotiate power purchase, build-transfer and equipment procurement contracts.

Although it is not directly related to development of solar facilities, buyers may attempt to rely upon case law related to the response to the COVID-19 pandemic. In *AB Stable VIII LLC v. Maps Hotels and Resorts One LLC*, a 2020 case in the Delaware chancery court, the parties disputed whether the seller's actions in response to the COVID-19 pandemic complied with its obligations under a purchase and sale agreement. The chancery court held that the seller was not operating in the ordinary course of business when the seller severely limited operations in light of COVID-19.

Buyers are addressing tariff risk by paying a base price at closing with a possible later earnout tied to the Commerce investigation.

Buyers may attempt to argue that changes made to the development plan, schedule or budget to accommodate the ongoing inquiries are not "in the ordinary course" and that seller's actions have harmed the project and, consequently, seller owes damages to the buyer.

On the other hand, sellers who are unable to meet contractual deadlines because they are unable to timely obtain panels (for example, because a court blocks implementation of the 24-month tariff moratorium, and manufacturers continue to pause shipments) may invoke the force majeure provisions of their agreements to defeat breach claims.

Equipment Procurement Agreements

Due to the limited supply of modules, suppliers who continued to ship were sometimes successful in shifting tariff risk to sponsors.

Whether as part of the diligence process in an M&A deal, or as part of equipment procurement negotiations, developers should ask for information from the equipment suppliers about their supply chains, any forced labor issues and the country where the modules will be manufactured. (For more detail on forced labor concerns, see "Xinjiang: Blocked Solar Panels" in the August 2021 *NewsWire*.)

Developers should limit risk by negotiating (or re-negotiating) for a termination or refund right for undelivered modules if tariffs exceed a certain threshold, either as a percentage of the purchase price or a certain dollar amount per kilowatt of affected module capacity.

Finally, developers should consider shipping and other importation costs beyond just tariffs, especially as these costs continue to rise and fluctuate. ◎

How Hedges Have Changed Since Uri

by Lee Taylor, with REsurety in Boston

The hedge market is offering the same menu of options a year and a half after a sudden cold snap in Texas left some power projects facing huge losses.

However, more attention is being paid to how to cap exposure in extreme scenarios.

Winter Storm Uri was an extreme cold event in late February 2021, centered in Texas but also affecting neighboring states, that was a one-in-10-year or one-in-50-year event, depending on which meteorologist you ask. It was not off the charts, but it involved an extreme level of sustained cold. There were deaths and significant property damage in Texas.

The storm led to a spike in electricity demand, especially for heating, and a shortfall in supply.

The shortfall in supply was driven by a number of factors, but the main driver was power plants froze physically and transmission infrastructure was shut down. These factors affected all types of power plants. The most pronounced effect was on gas-fired generation, but renewables, and wind in particular, were affected as well.

There was a pronounced financial impact in ERCOT because of the mechanism within ERCOT to reward generation during spikes in demand. There are administrative adders to the spot electricity price that force the price of power to go to a cap, incentivizing supply when demand spikes. At the time, the cap was $9,000 a megawatt hour. The result was that a spot market in which the price for electricity is often in the $20 to $40 range per MWh, was suddenly pricing power at $9,000 a MWh for three days.

It was an excruciatingly painful three days for anyone who was a net buyer of electricity and an exceedingly beneficial three days for anyone who was a net seller of electricity in ERCOT.

It is common for Texas power projects to be financed on a hedged merchant basis. The electricity is sold into the spot market in ERCOT and the revenues are then swapped or otherwise hedged for a fixed payment stream. The hedge is a way of reducing the volatility of electricity revenue so that the project can be financed.

Market participants have been working through the effects on hedging contracts ever since the / continued page 16

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expected project cost are finding, several years later, that escalating construction costs are making the incurred costs fall short of 5%.

An IRS notice explains what happens in such a case. If the project can be broken into separate parts — like individual turbines in a wind farm or separate circuits or blocks in a solar project — then the developer can multiply the costs incurred before the construction-start deadline by 20 and however many turbines, circuits or blocks it can fit inside such a 20-times circle qualify for the tax credit.

Some developers look for spare equipment whose costs were incurred in time to move to the project with the shortfall.

That said, tax equity investors report they are seeing few projects today start construction under the 5% test. Most projects claim to have been under construction based on limited physical work before the deadline on the main step-up transformer.

Another common problem is delays are pushing parts of projects into another tax year. For example, part of a wind or solar project may be completed in year 1 and the rest is not finished until year 2. The big tax equity investors report that anywhere from 25% to 40% of 2022 projects are at risk of slipping at least partly into 2023.

In some cases, the tax equity investor may be confident of its ability to use tax benefits in year 1 but not year 2. In such cases, a second tax equity investor may be found to claim the year 2 tax benefits. The challenge is the investment tax credit must be shared by partners in the same ratio they share in "general profits" or income. The investment credit claimed by the first tax equity investor in year 1 risks being recaptured if that investor's share of income drops by more than a third in year 2. Partnerships are dealing with this problem by treating the different parts of the project that were completed in year 1 versus year 2 as two separate businesses and keeping two sets of books, even though / continued page 17

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three-day storm. The storm continues to affect current and planned future hedges.

Three Hedge Types

There were basically three flavors of hedging before the storm, but they all had one thing in common: every hedge distills to a contract for differences in prices.

Most hedges are settled on an hourly basis. Most compare the spot market price for electricity that hour to an agreed-upon fixed price. One price is subtracted from the other, and the difference is multiplied by a volume of power for that hour.

That part of the math is generally identical across all three hedging structures. What differs is the volume used to multiply the price difference each hour.

The three flavors of hedge were as-generated contracts, proxy generation contracts and fixed volume contracts.

In an as-generated contract, also called a VPPA or virtual power purchase agreement, the price difference in an hour is multiplied by whatever power was actually generated in that hour. It uses the metered generation.

In a proxy generation contract, the price difference is multiplied by the amount of power the project could or should have produced in that hour given the fuel resource observed. For example, in the case of a solar project, solar irradiance is applied to a PVsyst model to convert solar irradiance into implied power. In the case of a wind project, per-turbine measured wind speeds and air density are translated into the amount of power that the project should have produced.

In a fixed volume contract, the output number is a fixed number that is set in advance. For example, if at noon on January 3, the average project of the same size and type would be expected to generate 20 megawatts of power and the sponsor decides to hedge 16 MW, then it would commit in advance to hedging 16 MW, regardless of how much power could have been or was produced by the project at that time.

A sponsor would choose one of the three hedge types based on what was available in the market and at what price. Before Uri, a sponsor might have called us to work with an insurer to write a proxy generation contract. It might have called any number of banks to source a fixed volume contract. It might have worked directly or through a broker to find a corporation willing to enter into a VPPA.

Different Risks

Each type of hedge comes with different risks and is priced differently.

There are different credit terms and term lengths. Terms vary from five to 15 years. Some hedges are bundled with renewable energy credits, and some are not.

The sponsor does not take operating risk with as generated, because payments are tied to actual output.

With a proxy generation contract, if the wind is blowing or the sun is shining and the project is not generating, the owner will owe the hedge counterparty the value of the power that could have been produced.

The highest risk during Uri would have been a fixed volume contract, because even if conditions were such that no electricity could be produced, the project owner still owes the hedge counterparty the value of the historical average output to which it committed.

Thus, the risk hierarchy is as generated at the low end, fixed volume at the high end and proxy generation in the middle.

Turning to what happened after Uri, not surprisingly, any fixed volume contracts that were settling in Texas during the storm had a very bad week. Solar irradiance and wind speeds were well below historical averages in most locations, and at many locations were below what was supposed to be the P99 number.

As a result, there were a lot of projects, even ones that were operating flawlessly during the storm, that came up short. They

Roughly a third of hedged Texas renewables projects suffered significant adverse effects during Winter Storm Uri.

ended up having to buy power at $9,000 a MWh because they were short the electricity that they had already sold under the contract due to inadequate wind speeds and solar irradiance. That type of contract was very painful for every project we are aware of that had one.

The proxy revenue contracts were the second most painful contract.

Wind projects with proxy generation contracts ran the gamut of outcomes. There were projects that produced at or above their proxy generation during that period because they maintained target availability during the storm. There were also projects that were shut down through the entire event and produced little to no electricity during the storm. For any project that was on the zero end of the spectrum, a proxy revenue contract was again very painful.

From the perspective of a power plant owner, the as-generated contracts were by far the most attractive. If the plant was down for whatever reason — no wind, no sun, no interconnection, the transmission line was down, or the plant shut down for plant safety reasons — there was really no penalty because the contract payments were tied to the electricity actually metered.

That is from the perspective of the power plant owner.

Things looked different to electricity purchasers. For example, take a data center with a large need for electricity. It has a virtual power purchase agreement with a solar project or wind farm to hedge its cost of electricity. If that plant was shut down during the storm, that energy purchaser ended up paying $9,000 a MWh for the electricity it needed, and it received $0 from the VPPA hedge it holds with a renewable plant.

Post-Uri

One thing that got less press after the storm than it should have was the impact of some as-generated contracts on grid resiliency.

The then-CEO of ERCOT said that it should not have to force people to winterize because that is what electricity market design is supposed to do. The idea is that the administrative adders that push the price as high as $9,000 a MWh during periods of high demand and short supply are a strong incentive to be able to generate during such periods.

However, generators who already committed the full output from their projects under long-term contracts get none of that $9,000 a MWh. The price spike provides no incentive for the large swathe of the market that has contracted its power via as-generated PPAs.

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everything is in a single partnership. IRS regulations allow such an approach.

A related challenge is that a tax equity investor who invests only 20% of its total investment in year 1 may not have enough capital account and outside basis — two metrics for tracking what the investor put into the partnership and can take out — to absorb the full year 1 tax benefits. This leads to an interim tax equity funding at the end of year 1 to push its capital account and outside basis high enough to absorb the year 1 tax benefits.

CLIMATE CHANGE DISCLOSURES that the US Securities and Exchange Commission is proposing to require of public companies could have two indirect effects on power companies.

They could increase demand for corporate power purchase agreements with physical delivery of renewable electricity.

They could also lead corporations to require power suppliers to quantify seven types of greenhouse gases emitted to generate the electricity.

The SEC proposed extensive new climate disclosures in late March that US and foreign companies that raise equity or debt in the US capital markets will have to make in annual reports and capital-raise registration statements in the future. The agency hopes to reissue them in final form by year end.

They do not apply to private companies whose only capital raises are Rule 144A or similar debt that does not require filing SEC registration statements.

The new disclosure requirements will phase in over a four-year period. Assuming the SEC gets the final regulations out as hoped by December 2022, very large companies will be required to start disclosing information on their 2023 annual reports filed in 2024..

Smaller companies whose publicly-traded shares have a market value of less than $250 million or that have annual revenues of less than $100 million and / *continued page 19*

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Projects with as-generated PPAs have little to no incentive to winterize or to put any of their plant infrastructure at risk to operate through extreme conditions when demand is highest.

Around the time of the storm, probably 20% to 25% of the hedges on renewable energy projects in Texas were fixed volume hedges.

Something like 10% were proxy-based hedges.

The same three types of pre-Uri hedges remain in use, but with caps on exposure in extreme scenarios.

That means that a third of projects had hedges that left them with significant adverse effects.

In the immediate aftermath of the storm, investment committees were not interested in signing new hedges.

Since then, the freeze has lifted, but with some conditions.

The main condition is no one is willing to hold or finance a project with an uncapped liability.

Thus, anyone planning to enter into a fixed volume contract must do something to ensure that if there is another week of spot market electricity prices at $9,000 a MWh, the project will remain solvent.

There are a number of ways a power plant owner might do this. People are looking at ways to unwind the hedge, layer in call options or physically hedge with storage, but the key is to be able to cut off the tail of extreme losses in the event of another Uri-like event.

To some extent, this just shifts the downside risk to the person who is buying the electricity or who is the financial counterparty on the hedge. Anyone approaching a hedge counterparty with a request to enter into a fixed volume swap with a settlement limit is likely to be told no. On the other hand, if the request is to enter into a hedge at electricity price $X and then work with the counterparty to dynamically manage the hedge going forward so the hedge buyer reduces or eliminates its risk of getting caught short in any hour, the answer is likely to be yes. Another way for a generator to manage risk is to enter into other contracts like call options around other projects in the generator's portfolio.

There are still new fixed volume hedges being written after the storm, but they are a very small minority of the market. Dynamically managing a hedge month to month to make sure the generator is never caught short is a very different proposition, and not everybody is eager to sign up for that as a sponsor or as a third-party source of capital.

As for proxy contracts, weather-linked or insurance-linked groups who offered that product before the storm have responded to market angst by inserting a cap. Instead of using proxy generation as the primary settlement index, the market has shifted to settling on metered generation, and using proxy generation as a damages calculator in the event of project non-performance.

If it is windy and sunny at the project location, the spot electricity price is high and the project is not operating, damages will be calculated for that period, but those damages are subject to a quarterly, annual or aggregate limit. The limit scales with the size of the project and is a negotiated term.

It is basically an as-generated swap with the damages calculated based on the proxy revenue rather than actual generation. In a sense, the result is just a hybrid of what was available in the market before Uri.

Impact on VPPAs

Corporations that signed VPPAs before the storm did not talk publicly about it, but some were not terribly excited about how their projects performed during the storm. On the other hand, there were some buyers of electricity whose projects operated flawlessly, and their PPAs proved very valuable to the electricity purchasers.

The corporate PPA market has responded with an interest in tightening definitions around availability and performance — including by pushing for proxy generation as a damages calculator in its procurement conditions with developers. However, today there are more VPPA buyers in the market than there are sellers. In this sellers' market, clean energy buyers are generally term takers rather than term setters, and we continue to see projects push for traditional as-generated contracts.

(For other assessments of the effects of Uri on the hedge market, see "Financing Merchant Projects After Texas" in the April 2021 *NewsWire* and "Diagnosing Weather-Driven Financial Risk in Hedges" in the June 2021 *NewsWire*.)

Why Texas?

The hedge market is not limited to Texas. The same types of hedges can be found in SPP, MISO and PJM, but the majority have been done in Texas for two reasons. One is Texas has punched above its weight in the number of wind farms that have been built there. The other reason is that the tradeable forward curve in Texas has been close to or in some cases even exceeded the VPPA market price.

In large parts of PJM, for example, projects have historically required an electricity price that is above what the financial markets are offering. Corporate clean energy and utility buyers have basically agreed to pay a premium to the spot market price for electricity in order to get more renewable energy projects built.

In Texas, generators have had more of a competitive menu of options. Depending on where the corporate appetite is relative to the gas curve in any given week, month or quarter, a corporate PPA may be more attractive or a financial hedge may look better. In PJM, if there is no corporate and utility offtake available, projects have pursued financial hedges, but typically at a lower price.

Summing up, the menu of hedge options is the same as it was before Uri, but there have been changes to avoid repeating some of the financial outcomes from Uri in the future. Proxy generation is still used, but as the damages calculator as opposed to the full settlement index, and you have a choice where you want to set the materiality threshold and the limit on those damages. These types of things affect the price for the hedge.

The other subject that is getting a lot of attention today in negotiations is the importance of a committed commercial operation date for the power project. Generators are facing lots of uncertainty about when projects can be delivered. They may have a target date of X, but then push for 18+ months of flexibility on that COD date. From a buyer's perspective, locking in a fixed price with that much uncertainty in start date is a real challenge. ◎

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either no publicly-traded shares or publicly-traded shares worth less than $700 million will have until 2026 to start disclosing the information. The first disclosures will be required in their 2025 annual reports.

Disclosures by other companies will start with 2024 annual reports.

Some of the more difficult greenhouse gas reporting — disclosure of so-called scope 3 emissions — by each category of company will take effect a year later.

Companies will be required to make detailed disclosures of not only their own greenhouse gas emissions, but also emissions associated with the electricity, steam, cooling and heating they purchase and, in some cases, for their full value chains.

Large public companies are adding multiple full-time positions to their finance staffs to work on climate change disclosures.

Many companies already make voluntary disclosures of emissions and reduction targets. Public companies are also already required to disclose material information to investors. However, the SEC said it is looking for "robust and company-specific disclosure" rather than boilerplate discussions about climate risks without any real analysis of the potential effects on their businesses.

The SEC wants a long list of future disclosures.

It wants companies to disclose how the board oversees climate risks, which management positions and board committees are responsible for identifying and managing risks, and how they do so.

Companies will be required to disclose all climate risks that have had or are likely to have a material effect on the business or financial statements. Risks are to be broken into short-, medium- and long-term risks, with the time periods of the company's own choosing. The disclosure must be accompanied by an analysis of how the risks have affected or are likely to affect the company's strategy, business model

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Carbon Capture Terms

by Deanne Barrow in San Francisco, and Keith Martin in Washington

Interest in carbon capture projects has soared over the past year. To document commercial terms, some parties are re-purposing concepts from gas and refined coal deals. Others are cutting brand new agreements from whole cloth. The market will eventually coalesce around a set of standard terms, but it is not there yet.

This article describes key terms we are seeing parties negotiate in carbon capture agreements.

Overview

There are as many as five roles in a carbon capture project. Multiple roles may be filled by the same entity depending on its technical capabilities, financial wherewithal and risk appetite.

There is the emitter of carbon dioxide (CO2), which is the owner of a plant at which CO2 is generated as a byproduct of an industrial or manufacturing process. It may take responsibility for capturing the CO2 because the equipment to do so will be on site and tied into its existing facility. It will install compressors, pipes and other equipment to pressurize, dehydrate and typically liquefy the CO2 for transport.

However, not every emitter takes on this role. There are companies in the business of installing and owning capture equipment. Emitters are more likely to capture the CO2 themselves if they have tax capacity to use the tax credits the federal government offers for capturing and disposing of CO2.

Next, there may be a separate entity responsible for disposing of and storing the CO2 underground. Only land with certain characteristics is suitable for CO2 storage. To be a good CO2 storage reservoir, the subsurface must contain permeable rock with millimeter-sized spaces called pores. The CO2 is injected through a well into the porous rock deep underground.

If the storage site is not immediately adjacent to the plant, then a pipeline will be built to transport the emissions. The sequestration company could sub-contract construction of the pipeline so that there is only one entity facing the emitter. Alternatively, the emitter could separately contract for the transportation and sequestration services. Splitting up the contracts this way will lead to greater finger-pointing risk if something goes wrong, but back-to-back indemnities can mitigate the risk.

The land on which the pipeline and storage facility are sited may be owned by one or more third parties, especially if the route is long distance or passes through multiple states. The landowners are typically paid a combination of a fixed lease or easement payment and a royalty tied to sequestration volumes. Real estate rights for the pore space can get complicated depending on whether the sequestration company's subsurface estate is severed from the landowner's surface rights. Real estate issues are governed by state law.

The fifth potential role is a tax equity investor. The federal government allows the owner of the carbon capture equipment tax credits for capturing carbon emissions and doing one of three things with the emissions. The emissions can be permanently stored underground, used for enhanced oil recovery or put to a permitted commercial use. The value of the tax credit is highest if the CO2 is sequestered permanently underground. (For more details, see "Tax Credits for Carbon Capture" in the February 2021 *Newswire* and "Stalled Carbon Capture Projects" in the August 2021 *NewsWire*.)

If the capture company does not have enough tax appetite to make use of the credits itself, it can monetize them in a tax equity transaction. Only one significant tax equity transaction has closed to date, but others are moving to market. The early deals are borrowing from a coal synfuel and refined coal transaction template as well as working with guidelines that the Internal Revenue Service issued in Revenue Procedure 2020-12.

Fees

Carbon capture projects turn concepts from power projects on their head.

In a power project, the a utility or corporate buyer of electricity pays the project company for the right to take delivery of the product, electricity.

In a carbon capture project, the project company may pay a sequestration company to take and dispose of the product, CO2.

The fee can be structured as a dollar per metric ton of CO2, analogous to a tipping fee in waste-to-power deals. Tax credits are based on the quantity of CO2 injected, so it makes sense for the tipping fee also to be based on injected CO2. In that case, the risk of line losses along the pipeline is borne by the pipeline or by the sequestration company if the latter also takes responsibility for moving the CO2 to the storage site. The sequestration company only gets paid based on whatever quantity makes it into the ground.

If the pipeline owner is a different entity from the sequestration company, the emitter may need to pay a transportation fee based on how much CO2 it puts into the pipeline and a separate sequestration fee based on how much CO2 is injected at the wellhead. In that scenario, the maximum allowable line loss should be capped. From what we see, 0.25% to 1% is reasonable, depending on the length of the pipeline and meter accuracy.

Another way to structure fees is as a percentage of the value of the projected tax credits for quantities sequestered in the previous month or quarter. A fee structured this way will have to remain subject to adjustment if tax credits are disallowed or recaptured later by the IRS.

A fundamental question that should be answered at the outset is who will keep the section 45Q tax credits because this will in turn affect how the economics flow.

The carbon capture market will eventually coalesce around a set of standard terms, but it is not there yet.

In practice, the federal government puts a lot of money on the table in the form of tax credits. The credits run for 12 years after the capture equipment is first put in service. Every party with a role in the transaction wants a share of the value. Thus, how a deal is structured and how money flows ultimately turn on who starts with the tax credits and how the parties decide to split the value.

The tax credits belong in the first instance to the entity that owns the capture equipment and physically or contractually ensures the disposal or use of the CO2.

The owner of the capture equipment can transfer some or all of the tax credits to another person that disposes of the CO2 permanently underground, uses it for enhanced oil recovery or puts it to a permitted commercial use. The election is made annually under section 45Q(f)(3)(B) of / continued page 22

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and outlook. Companies will be expected also to disclose what they are doing to mitigate the potential effects.

The risks fall into two categories: "climate-related events," meaning extreme weather, changing weather patterns and natural conditions that pose physical risks, and "transition activities," meaning risks tied to a change in the economy or business climate, such as the risk of new climate-related regulations, litigation, changing consumer tastes and investor preferences, reputational issues, demands from business partners or lenders, and long-term shifts in market prices. Physical risks need to identify affected locations and be divided between acute and chronic. The SEC wants to know the potential to affect particular line items in the financial statements.

It also wants to know the role that RECs and carbon offsets play for the company.

If the company has committed to a carbon reduction goal, the SEC wants it to report annually on progress.

It wants to know any carbon price that the company uses for internal planning, why the company selected the price and how the company expects the carbon price to change over time.

Companies are also free to disclose any climate-related opportunities to leaven what could otherwise be grim reading for investors. This could include cost savings from moving to renewable energy and opportunities to develop new products or services or to move into new markets related to the transition to a lower-carbon economy.

The SEC made this part optional to avoid forcing companies to disclose business opportunities.

Companies will have to disclose two, and possibly three, categories of greenhouse gas emissions. The SEC said such emissions could eventually affect a company's access to financing and its ability to reduce its carbon footprint enough to comply with / continued page 23

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the US tax code. The capture equipment owner can decide to pass through all or part of the tax credits in a single year or multiple years. If it does so, it should negotiate a reduction in the fees paid to the third party to take the CO2 emissions.

Congress is debating whether to increase the section 45Q tax credit amount. The parties should agree in advance how any such increase will be shared.

Volumes

The sequesterer will want the emitter to commit to delivering a minimum volume or mass of CO2 a year to ensure capital recovery within an acceptable time frame. The rate of return and time frame will be agreed in the term sheet.

The minimum volume can be expressed as a fixed volume or a percentage of base volume, so that if post-combustion emissions are captured, the minimum volume also increases.

The emitter will pay a deliver-or-pay fee for the volume by which CO2 delivered falls short of the minimum. The deliver-or-pay fee should be lower than the fee due the disposal company pays for volumes above the minimum volume requirement. The emitter should be excused from the minimum requirement if the plant is affected by force majeure and for periods when the plant is offline for maintenance or repairs. If the plant has a good year, it should be able to roll over the excess delivered volume to future years. The emitter should get credit for non-deliveries due to the sequesterer's inability or refusal to take delivery.

Some industrial processes emit a relatively pure native CO2 stream as well as a stream of CO2 resulting from combustion processes. At this time, post-combustion CO2 is too expensive to capture and purify to reach pipeline standards at the current tax credit rate of $50 a metric ton, but costs will come down as the technology matures.

It can be complicated to secure rights to deliver post-combustion gas because the pipeline and storage facility need to be overbuilt or at least there will need to be an agreement to expand existing capacity to accommodate the additional volume. In CO2 roll-up deals, where emissions from multiple sources are transported and disposed using the same pipeline and storage site, the emitter may be able to put additional volumes on the pipeline above the base quantity to use up spare capacity when another customer of the pipeline is experiencing an outage.

Schedule

In a carbon capture project, the emitter, pipeline company and sequestration company will be reluctant to make large capital outlays until they are sure the others will follow through on their commitments.

Construction of the capture equipment must start for tax purposes by the end of 2025 to claim tax credits. In addition, the 12 years of tax credits start to run once the capture equipment is placed in service. It may be in service once it is ready for use, even if the pipeline and wells are not ready to receive the captured CO2 emissions.

In an ideal world, the capture facility, pipeline and storage facility would all be completed at the same time. In practice, this is a difficult feat to accomplish.

The pipeline and storage facility are more likely to be late due to their relative complexity compared to the capture equipment.

There is usually a tug of war between an aspirational target, favored by the pipeline and sequestration company, and a hard deadline on final completion, favored by the emitter. A substantial completion deadline should be accompanied by penalties for delay. Delay liquidated damages are one option. There are others. Like in any large-scale civil work, each party should develop a detailed construction schedule outlining the sequence and duration of key milestones, which should be appended to the agreement as an exhibit.

Compliance

There are at least three compliance obligations on the part of the sequesterer that should be expressly spelled out in the agreement.

The first is annual filing of a Form 8933 with the IRS. The existence of each contract and the parties involved must be reported on Form 8933 annually. The entity that captures the CO2 and the entity that disposes of the CO2 must each file Form 8933 with a timely-filed federal income tax return. Among other information, the disposal site operator must certify metric tons captured and securely stored and metric tons the owner, operator or regulatory agency determined has leaked from the containment area of the reservoir during each previous year.

The second set of compliance obligations is owed to the Environmental Protection Agency (EPA). EPA's requirements under the underground injection control (UIC) program are focused on ensuring protection of underground sources of drinking water where CO2 is injected through an injection well for geologic sequestration. The requirements focus on the siting, permitting, operation, testing and monitoring, post-injection site care and site closure of a class VI well, which is one used for geologic sequestration of CO2.

In addition to the UIC program, EPA requires reporting under "subpart RR" regulations (40 CFR Part 98, Subpart RR), which are rules requiring reporting of greenhouse gases from facilities that inject CO2 underground for geologic sequestration. Subpart RR facilities are required to report basic information on the mass of CO2 received for injection, develop and implement an EPA-approved monitoring, reporting and verification plan, report the mass of carbon dioxide sequestered using a mass balance approach and report annual monitoring activities. Information gathered or developed and submitted for compliance with UIC class VI technical requirements can also be used to meet subpart RR requirements.

A third regime of compliance obligations arises if the project will claim credits under California's low-carbon fuel standard (LCFS) program. LCFS credit generation can be supersized as a result of carbon capture and storage. If the project is making vehicle fuel such as ethanol or hydrogen, then the addition of capture and sequestration can give the project access to sell the fuel for a premium price in California even if the capture and sequestration do not take place in California.

Direct air capture projects that store CO2 underground do not need to have a fuel component to be issued LCFS credits. For LCFS crediting purposes, carbon capture project operators are required to submit quarterly or annual (depending on how often the project elects to undergo verification) reports of greenhouse gas emissions reductions and ongoing monitoring results to the California Air Resources Board.

Local counsel should advise on state and local law compliance obligations.

Indemnity

An indemnity is a way to customize risk allocation. In a carbon capture contract, the sequesterer's indemnity for breach of contract is one of the most heavily-negotiated provisions in the contract.

There are several points of contention.

The first is the measure of recoverable damages. Recoverable damages may or may not equal the full value of the lost revenue associated with section 45Q tax credits, LCFS credits, carbon credits and other environmental attributes, depending on the reasons for the breach. There is a strong / continued page 24

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future regulatory, policy and market constraints.

The SEC wants both aggregate emissions and the emissions broken down into carbon dioxide equivalents for seven types of greenhouse gases: carbon dioxide, methane, nitrogen trifluoride, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride.

It wants them expressed as emissions per unit of product or revenue to make it easier to make comparisons across companies.

Scope 1 emissions are direct emissions from operations that are owned or controlled by the company.

Scope 2 emissions are emissions from generating the electricity, steam, heat and cooling that the company purchases for use in its operations.

Scope 3 are indirect emissions from the upstream and downstream value chain of the company. Upstream means emissions from goods and services the company buys, transportation of such goods and employee travel and commuting. Downstream means emissions from use of company products, transportation of company products to market, disposal of the products after use and investments by the company in other companies.

Scope 3 emissions would have to be disclosed only if they are material or if the company has set a greenhouse gas emissions reduction goal that includes scope 3 emissions. However, smaller companies would be exempted from scope 3 disclosure.

Scope 3 emissions are material if a reasonable investor would consider the information important when deciding whether to invest. The SEC said some companies treat scope 3 emissions as material if they are at least X% of total emissions. For example, Uber Technologies uses 40%, the SEC said. However, it said scope 3 emissions could be material even if they are small where they are a significant risk to the business model; for example where there is a material risk of regulatory action to require curtailment of such emissions. Scope 3 / continued page 25

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argument for full recovery if the breach was knowing or involved negligent conduct.

Liability to government agencies for environmental damage should always be covered by the indemnity because government agencies have the ability to come after any party associated with a leak, including the original source. There is room for argument over whether the source has a good defense that any release of materials from the underground reservoir falls within the federally permitted release exemption to liability under the Superfund law (officially the Comprehensive Environmental Response, Compensation, and Liability Act of 1980 or CERCLA).

Damages owed under the indemnity may be limited by incorporating liability caps or deductibles like thresholds and baskets. The indemnity could be paid on a pre-tax or after-tax basis. It is important to specify that the indemnity covers both direct and third-party claims so as to overcome a general presumption that an indemnity clause is meant to apply exclusively to third-party actions. (For more information, see a 1996 federal district court decision called *DRR, L.L.C. v. Sears, Roebuck and Co.*)

Carbon capture projects turn concepts from power projects on their head.

The indemnifying party typically asks the indemnified party to mitigate damages, but in a carbon capture project, the ability to mitigate is limited. If CO2 is not being sequestered, no tax credits or LCFS credits will accrue, and it is probably not going to be practical to find an alternative use for the CO2 in the short term.

Close attention should be paid to the indemnity trigger events. They should include failure to transport and leakage from the pipeline or storage facility, subject to specific excused events. The pipeline and storage facility will need to be offline for routine maintenance. Some pipeline and sequestration companies may be willing to provide an availability or uptime guarantee. Force majeure is not always an excused event. In cases where it is not, the pipeline and sequesterer can seek insurance to help cover the risk.

Change in Law

Change-in-law risk in carbon capture transactions is significant.

Pipeline and sequestration companies will size their fees based on the estimated cost to provide services under current law, which presents a problem because the regulatory framework is evolving. If new regulations are issued or agencies' interpretation of existing regulations changes, the pipeline and sequestration company will want to pass through some or all of their compliance costs to the emitter.

Congress is debating changes in section 45Q tax credits, including whether to increase the amount of the credits, reduce minimum capture thresholds for some types of industrial facilities and deny tax credits for emissions used for enhanced oil recovery. IRS interpretations could change. Changes in the tax credit regime could have significant effects on expected economic returns.

Parties sometimes resort to material-adverse-change thresholds to trigger relief for change in law. There are many ways to define material adverse effect. One way is a percentage change in net profits or in the expected economic return of one or more of the parties. Consider whether the party claiming tax credits should have the ability to walk away from the deal if there is an unfavorable change in tax law or action by the IRS that lowers the value of tax credits it has claimed.

No matter what the trigger, there should be a negotiation period during which the parties attempt to amend the documents or enter into a separate agreement to neutralize the effect of the change in law and restore the affected party to its initially anticipated economic position.

Credit Support

The pipeline and sequestration company is likely to be a special-purpose entity whose sole business and assets consist of the pipeline, wells and pore space leases and that has no prior business track record. Until the pipeline and storage facility are built, this entity will not have any assets other than permits and contract rights.

The emitter will be spending money to install capture facilities in reliance on the promise that the rest of the project will be built. The emitter is therefore likely to require performance security, in the form of a letter of credit, a performance bond or a guarantee from a creditworthy parent or affiliate, from the sequesterer at least until the pipeline and storage facility are built.

While bonds and guarantees are not as liquid as letters of credit, for larger and financially secure contractors with a history of executing similar projects, guarantees are probably acceptable.

There are drawbacks to a performance bond in that many common law protections have developed for sureties, and some surety bonds are written so as to require recourse first against the primary obligor before having recourse to the surety. (For more detail, see "Surety Bonds Compared to LCs" in the August 2020 *NewsWire*.)

A performance bond from a surety may be appropriate for a modestly-sized project, but for larger ones, a guarantee is preferable. The guarantee should require a parent or affiliate of the sequestration company that has the financial and technical resources to perform the company's obligations under the agreement no matter what circumstances arise.

A letter of credit is the most liquid form of credit support (besides a cash deposit), but will cost the sequestration party more than a bond or guarantee. Banks charge a letter of credit issuance fee as well as commitment fees. Like it or not, the cost of the letter of credit is a pass-through cost with markup to be reflected in the tipping fee.

Credit support cuts both ways. The sequesterer might ask for a payment guarantee from the emitter once deliveries start to backstop the minimum delivery and payment requirement. The emitter should try to negotiate a step-down in the amount since the counterparty's exposure will decrease over time. Financial assurances may be triggered if the credit support provider's financial condition deteriorates. ◎

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emissions account for 75% of electric utility emissions, according to IHS Markit.

Large companies would have to get an accounting or engineering firm or other consultancy with emissions expertise to attest to the accuracy of the emissions figures.

Audited financial statements would have to include notes addressing three metrics related to climate change: financial impacts, expenditures, and financial estimates and assumptions,

PRODUCTION TAX CREDITS for producing renewable electricity will be slightly lower this year than thought earlier after the Internal Revenue Service corrected an error.

Production tax credits for generating electricity from wind, geothermal steam or fluid or closed-loop biomass (plants grown to be used as fuel in power plants) will be 2.6¢ a kilowatt hour in 2022, 1¢ higher than the year before but not the 2¢ increase the IRS announced in April. The IRS corrected the error in May.

The tax credits will remain at 1.3¢ a kilowatt hour for generating electricity from open-loop biomass, landfill gas, incremental hydropower and ocean energy.

The credits are adjusted each year for inflation as measured by the GDP price deflator. They run for 10 years after a project is originally placed in service.

The credits phase out if contracted electricity prices from a particular resource reach a certain level. That level for wind in 2022 is 14.1¢ a KWh. The IRS said there will not be any phase out in 2022 because contracted wind electricity prices were 4.09¢ a KWh going into 2022. It said it lacks data on contracted prices for electricity from the other energy sources.

The tax credit amounts were published in the *Federal Register* on April 14, but then corrected in Internal Revenue Bulletin 2022-21 on May 23.

— contributed by Keith Martin in Washington

Private Activity Bonds for Carbon Capture

by Steve Watson, in Washington

A massive bipartisan infrastructure act that became law last November authorizes tax-exempt "private activity bonds" to be used to finance carbon capture projects.

Tax-exempt private activity bonds are bonds issued by state and local governments to finance projects that are privately owned or used. The interest payments on the bonds are excluded from taxable income of the bondholders. Therefore, bondholders are willing to accept a lower rate of interest than if the interest were taxable.

The new carbon capture bonds, like most tax-exempt private activity bonds, are subject to the alternative minimum tax if held by individuals. AMT bonds bear interest at a rate higher than other tax-exempt bonds but lower than taxable bonds.

Spreads between tax-exempt and taxable rates vary. Tax-exempt AMT rates are currently around 120 basis points lower than taxable rates for 10-year bonds.

Three types of carbon capture facilities are eligible for this new category of tax-exempt financing. It can be used for carbon capture, transportation and storage equipment installed in certain power plants and other industrial facilities. It can be used for gasification facilities. It can also be used for direct air capture (DAC) facilities.

For industrial or gasification facilities, this new financing is available only if the carbon dioxide (CO_2) captured from the facility is injected into geologic storage or used for enhanced oil or gas recovery (EOR) followed by geologic storage.

If at least 65% of a qualifying facility's CO_2 emissions are injected into geologic storage (or used for EOR followed by geologic storage), then tax-exempt financing is available for 100% of the eligible component costs. If less than 65% of the CO_2 emissions are so injected or used, then only that lesser percentage of the eligible component costs may be funded with tax-exempt debt.

The infrastructure act does not specify the permissible uses of CO_2 captured by DAC facilities, which capture CO_2 directly from the atmosphere. Additional guidance from the US Treasury will be needed to identify the permissible uses (though, at a minimum, geologic storage should qualify).

Tax-exempt financing is generally available only for schools, roads, municipal utility systems and other state or local government projects that benefit the general public. The new carbon capture bonds are one of a limited number of tax-exempt private activity bonds that the US government has authorized for the benefit of private entities.

Carbon capture bonds must be issued by a state or local government or an entity authorized to issue bonds on behalf of a state or local government. In a typical structure, the issuer of carbon capture bonds will make the bond proceeds available to the facility owner through a loan or similar agreement.

Like most tax-exempt private activity bonds, carbon capture bonds are subject to annual, per-state volume caps. For 2022, the volume cap for each state is $110 multiplied by the state population (or $335,115,000, if greater). An issuer of carbon capture bonds must receive a volume cap allocation equal to 25% of the bond issue amount. By contrast, most tax-exempt private activity bonds (including bonds for privately-owned solid waste disposal facilities) require volume cap for 100% of the issue.

Equipment financed with tax-exempt debt must be depreciated on a straight-line basis over a longer period. Thus, for carbon capture bonds to be economical, the interest savings must exceed the reduction in tax savings from slower depreciation. However, there is no trade-off to the extent the capture equipment qualifies as a pollution control facility eligible for 60- or 84-month amortization under section 169 of the US tax code.

If proceeds of carbon capture bonds are used to finance equipment for a project for which tax credits for carbon capture are available under section 45Q of the US tax code, the section 45Q credits will be reduced by the percentage of the project costs financed with carbon capture bonds, up to a maximum reduction of 50%. Given the value of section 45Q credits, it generally would not be economic to finance any costs of a section 45Q project with carbon capture bonds. The tradeoff is too great.

Treasury guidance will be needed to clarify the scope of a section 45Q project. For example, transportation and storage facilities might not be part of a section 45Q project if they are owned by persons other than the owner of the capture equipment and no election is made to transfer the tax credits to the party sequestering the CO_2 underground. If the transportation and storage facilities are not part of the section 45Q project, then the financing of those facilities with carbon capture bonds will not cause a reduction in section 45Q credits.

Tax-exempt bonds can now be used to finance privately-owned carbon capture projects.

Eligible Equipment

Carbon capture bonds are authorized to finance "eligible components" of "industrial carbon dioxide facilities."

Eligible components include equipment used to capture, treat and purify, compress, transport or store permanently underground CO2 produced by an industrial carbon dioxide facility.

An "industrial carbon dioxide facility" is a facility that emits CO2 (including from any fugitive emissions source) created as a result of any of five processes. The five are fuel combustion, gasification, bio-industrial production, fermentation or any process in eight types of manufacturing. The eight are chemicals, fertilizers, glass, steel, petroleum residues (consisting of the carbonized product of high-boiling hydrocarbon fractions obtained in petroleum processing), forest products, agriculture (including feedlots and dairy operations) and transportation-grade liquid fuels.

The first four processes (fuel combustion, gasification, bio-industrial and fermentation) are not limited to any specific industry. Thus, carbon capture bonds should be available not only for the above-listed industries (chemicals, fertilizers, glass, steel, petroleum residues, forest products, agriculture, and transportation grade liquid fuels) but also for any other industry using one of the four processes.

For example, fuel combustion should include the burning of fossil fuels or biomass at power plants or other industrial facilities. Accordingly, equipment (such as an absorber or regenerator) installed in such a facility to capture CO2 from the flue gas or other emissions stream should be an "eligible component."

Similarly, equipment installed in an ethanol plant to capture CO2 emitted from both the fermentation process and the burning of fossil fuels should be an eligible component. As another example, equipment that captures CO2 from blast furnace gas emitted in steel production should be eligible for this tax-exempt financing.

In addition to post-combustion capture, carbon capture bond financing is available for equipment that captures CO2 from a gasification process.

Gasification generally involves combining a carbon-based material with oxygen or air and steam in a gasifier. Gasification produces a synthesis gas consisting primarily of hydrogen and carbon monoxide. With the use of a shift reactor, the syngas can be converted into a gas consisting of hydrogen and CO2. If the gasification process meets certain requirements described below, the gasification facilities themselves (including, for example, the gasifier and an air separation unit) are eligible for financing with carbon capture bonds.

Carbon capture bonds are also available for equipment that captures CO2 from an emissions stream resulting from an oxy-fuel combustion process.

Oxy-fuel combustion is an emerging technology that uses nearly pure oxygen instead of air for fuel combustion and produces a flue gas consisting mostly of CO2 and water. This technology generally requires an air separation unit to produce oxygen for combustion. US Treasury guidance may be needed to clarify whether an air separation unit used for oxy-fuel combustion (as distinguished from downstream equipment used to capture and process CO2 emissions) is itself eligible for tax-exempt financing.

An air separation unit that is not a necessary component of an oxy-fuel combustion process (or does not qualify as gasification equipment) is not part of an "industrial carbon dioxide facility" in which eligible components can be installed using carbon capture bonds.

Three other types of property are also excluded from the definition of "industrial carbon dioxide facility" and thus cannot contain equipment financed with carbon capture bonds. They are property that produces a raw

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product consisting of gas or mixed gas and liquid from a geological formation, property that transports or removes impurities from the product, and property that separates the product into its constituent parts.

Accordingly, absent Treasury guidance to the contrary, facilities used to extract from a natural underground reservoir a raw gas comprised of CO2 and another gas (such as methane or helium) and to separate CO2 from the other gas would not qualify as industrial carbon dioxide facilities even if the extraction of the other gas were itself economically viable.

Similarly, properties used for oil or natural gas extraction, transportation and refining are not industrial carbon dioxide facilities.

Tax-exempt rates are currently around 120 basis points lower than taxable rates for 10-year bonds.

On the other hand, petroleum residues that are a byproduct of crude oil distillation can be used as a feedstock in a gasification facility financed with carbon capture bonds. Moreover, the injection of CO2 into an oil and gas reservoir for EOR (followed by geologic storage) is a permissible use of CO2 captured with bond-financed equipment.

Property eligible for financing with carbon capture bonds includes not only equipment used to capture, treat, purify and compress CO2, but also equipment used for transportation or on-site storage of CO2. The precise scope of transportation and storage facilities is not entirely clear, given that eligible components are required to be installed "in" the industrial carbon dioxide facility and storage facilities are required to be "on-site." US Treasury guidance will be needed to clarify these terms.

Carbon capture bond financing is available only if the captured CO2 is injected into geologic storage, or used for EOR followed by geologic storage. The statute does not define, or identify standards for, geologic storage or EOR. By contrast, section 45Q has detailed requirements for EOR and geologic storage, and the Treasury has issued extensive regulations implementing those provisions. The Treasury can be expected to follow similar principles for carbon capture bonds, taking into account differences in the two statutes. In any event, geologic storage generally should include permanent storage at deep saline formations, oil and gas reservoirs or unminable coal seams. EOR involves the injection of CO2 into oil and gas reservoirs to boost production.

In many cases, the owner of the carbon capture equipment may not also own the pipeline and wells needed to move the CO2 and bury it underground. In those situations, the capture equipment owner will need to contract with third parties to ensure that the captured CO2 is disposed of in a manner consistent with tax-exempt financing requirements.

Gasification Facilities

Certain gasification facilities are eligible for carbon capture bond financing.

Specifically, "eligible components" include equipment installed in an industrial carbon dioxide facility that is integral or functionally related and subordinate to a process that converts a solid or liquid product from coal, petroleum residue, biomass or other materials that are recovered for their energy or feedstock value into a syngas composed primarily of CO2 and hydrogen for direct use or subsequent chemical or physical conversion.

"Coal" for this purpose means anthracite, bituminous coal, subbituminous coal, lignite and peat.

"Biomass" means any agricultural or plant waste, byproduct of wood or paper mill operations, including lignin in spent pulping liquors (but not paper that is commonly recycled) and other products of forestry maintenance.

The statutory language regarding the use of carbon capture bonds for gasification facilities is nearly identical to language in section 48B of the US tax code, which authorized an investment tax credit for gasification facilities.

A key difference is that, for carbon capture bonds, the resulting syngas must be composed primarily of "carbon dioxide" and hydrogen, whereas the ITC requires that the syngas be composed primarily of "carbon monoxide" and hydrogen. The reference to "carbon dioxide" should permit the financing with carbon capture bonds of facilities (such as a shift reactor) that convert carbon monoxide in syngas into CO2. Facilities that capture and remove CO2 from the syngas also would be eligible for carbon capture bond financing. Once the CO2 is removed, the remaining hydrogen stream could be burned to generate electricity (for example, in an integrated gasification combined-cycle power plant) or used for another industrial or commercial purpose.

"Coal" that can be used as a feedstock in a qualifying gasification facility should include waste coal that is a byproduct of previous processing of anthracite, bituminous coal, subbituminous coal, lignite or peat.

Municipal solid waste also should be an eligible feedstock.

In addition to carbon capture bond financing, gasification facilities used to convert waste coal or municipal solid waste to syngas generally are already eligible for financing with tax-exempt solid waste disposal bonds. Solid waste bonds do not require capture or storage of CO2. However, a solid waste bond issue for privately-owned facilities requires volume cap for 100% of the issue as compared to 25% for a carbon capture bond issue.

The use of solid waste bonds to finance a gasification facility would not cause a loss of section 45Q credits even if the facility were considered to be part of the same project with the carbon capture equipment.

Direct Air Capture

A DAC facility that uses carbon capture equipment to capture CO2 directly from the ambient air is eligible for financing with carbon capture bonds.

A DAC facility does not include property that captures CO2 deliberately released from naturally occurring subsurface springs. It also does not include property (such as a tree) that captures CO2 using natural photosynthesis.

The statute does not specify the permissible uses of CO2 captured by DAC facilities. Additional guidance from the US Treasury will be needed to identify the permissible uses, although, at a minimum, geologic storage should qualify.

Absent Treasury guidance to the contrary, facilities used to transport or store CO2 captured from a DAC facility do not qualify for carbon capture bond financing.

Eligible Costs

The amount of costs of the eligible components that qualify for funding with carbon capture bonds depends on the facility's capture and storage percentage.

The "capture and storage percentage" is the total metric tons of CO2 designed to be captured, transported and injected into geologic storage (or used for EOR followed by geologic storage) each year, divided by the total metric tons of CO2 that otherwise would be released into the atmosphere each year if the eligible components were not installed.

If the capture and storage percentage is at least 65%, then 100% of the eligible component costs qualify for tax-exempt financing.

If the percentage is less than 65%, then only that lesser percentage of the eligible component costs qualifies.

If eligible components are designed to capture CO2 solely from specific emissions sources within a facility, then only those specific emissions sources are considered when calculating the capture and storage percentage. ◎

Challenges Facing Individuals as Tax Equity Investors

by Hilary Lefko, in Washington

Ever wonder why as an individual, you probably cannot claim the investment tax credit or production tax credits?

The passive activity loss rules prevent individuals from using tax credits and losses incurred from businesses in which they are not materially involved against active income from other sources. This means that most individuals cannot claim production tax credits or investment tax credits. The tax credits can only be used against income from other passive investments in the same activity.

This makes it hard to tap individuals as potential tax equity investors for solar and other renewable energy projects.

The passive activity loss rules have been around since 1986, enacted as a response to the tax shelters of the 1980s that taxpayers used to generate tax losses to shelter wages and investment portfolio income from taxes.

As a general matter, the passive activity loss rules bar individuals from using depreciation, tax credits and interest (other than home mortgage interest) to reduce taxes on salaries and investment income. Separate at-risk rules bar individuals from deducting interest on nonrecourse loans and claiming depreciation deductions funded with nonrecourse debt. Between the passive loss limitations and the at-risk rules, it is challenging for an individual to be able to claim energy tax credits, depreciation or interest expense from investing in renewable energy projects.

In addition to individuals, the passive activity rules also apply to estates, business trusts, personal service corporations and closely-held corporations. Even though the rules do not apply to grantor trusts, partnerships and S corporations directly, they do apply to the owners of those entities who are individuals.

Real estate developers, sports team owners, owners of limited partnership interests and family offices are all likely to have passive income that cannot be offset by losses and tax credits from investments in renewables.

What qualifies as passive income for this purpose against which passive losses can be offset?

Active losses can only be used to offset active income.

Passive losses can only be used to offset passive income, but not even all passive income. Passive losses cannot offset active income.

Passive losses can only offset passive income to the extent there is passive income from the same activity.

There are two kinds of passive activities. One is renting equipment or other property to others, including equipment leasing and real estate rentals. The other is businesses in which the taxpayer does not materially participate.

The following types of income are considered active income: salaries, wages, and independent contractor compensation, guaranteed payments, portfolio income (meaning interest, dividends, royalties, gains on stocks and bonds), sales of undeveloped land or other investment property, royalties and income from businesses in which the taxpayer materially participates.

Material Participation

What is "material participation," and why does it matter?

An individual investor in a power plant would have to participate materially in the business in order to take advantage of tax credits and depreciation.

Material participation requires the individual to be involved in the operations of an activity on a regular, continuous and substantial basis. It is narrowly defined and time sensitive. Material participation is based on time and not money. An investor can have a significant financial interest in a business, and yet not materially participate.

An investor must meet the narrow material participation definition in order to avoid the passive activity limitations on tax credits and depreciation. There are a number of ways an investor can prove he or she materially participates in a business.

The three most like to come into play are spend more than 500 hours working at the business, spend more time working at the business than any other individual (owner or employee), or spend more than 100 hours working at the business where no other individual (owner or employee) participates more.

Material participation is measured on an annual basis, so it is possible to meet one of these hurdles in one year, then fail the next. Participation by a spouse can be added to the individual's hours, but participation by children or a significant other cannot. A spouse's work counts even if the spouse is not a co-owner of the business.

Using a solar facility as an example, if an individual owner of the solar facility wanted to claim the investment tax, that individual would have to spend either more than 500 hours each year working in the solar business (and that's a lot!), work more at the solar facility than any other owner or employee (so you better learn how to replace those broken panels), or work more than 100 hours with no one — not even part-time employees — working more (again, better learn how to replace broken solar panels).

The IRS Audit Guide encourages agents to review W-2 forms and other non-passive activities to see if it even seems likely that an individual could spend 500 hours on an activity in light of other obligations. It also directs agents to determine the location of each of the individual's activities to determine if it is likely the individual could physically spend time at the site of the activity.

Individuals have a hard time acting as tax equity investors.

If you want to claim investment or production tax credits, get ready to do your own operation and maintenance and asset management. It does not count as material participation if the activity is supervised by another individual who is compensated for managing the business or if the paid manager spends more time managing the facility than you do.

The US Tax Court confirmed the difficulty of individuals proving material participation in a renewables business in a case called *Lum v. Commissioner* in 2012. A group of individuals purchased solar hot water heaters that were installed in the homes of third-party customers. The individuals hired a contractor to collect monthly payments from the customers. The Tax Court held that the individuals could not use the investment tax credits or depreciation from the solar hot water heaters to offset their other income.

The court was unpersuaded by the fact that one of the individuals solicited customers and managed collections. It said that the individuals did not materially participate because the hired contractor collected the majority of the payments, maintained the books and records, and made tax payments on behalf of the business.

The IRS listed factors that tend to show whether an individual has or has not materially participated. These can be reduced to a series of questions.

Was the individual compensated for services? Most people do not work significant hours for free.

How far does the individual live from the activity? If the person lives far away, the IRS questions how many hours can really be spent working in the business. Travel time does not count.

Does the individual has another full time job? Does the individual have numerous other investments, rentals, business activities or hobbies that absorb significant amounts of time?

Is there a paid on-site manager, foreman or supervisor or are there on-site employees who provide day-to-day oversight and care of the operations?

Is the individual elderly or does the person have health issues? Are a majority of the hours claimed for work that does not materially impact operations? Mere participation is not sufficient. Activities must be integral to operations.

Would the business operations continue uninterrupted if the individual did not perform the services claimed? Material participation is serious business, and the IRS will consider whether to discount portions of time that relate to investor-type hours or work not customarily done by an owner.

Indirect Ownership

Investors usually own a solar or other renewable energy project through a partnership or S corporation. Neither the partnership nor the S corporation itself can materially participate. Only the individual partner or shareholder can materially participate. Thus, material participation is tested at the partner or shareholder level.

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There is a look-through rule for tiered entities. An investor will be treated as holding an interest in the lowest tiered entity. This means that if an investor is a shareholder in an S corporation, and that S corporation owns an interest in a partnership, if the investor does not materially participate in the partnership's activities, he or she would also be treated as receiving passive income.

Limited partnership interests are presumed to be passive. Therefore, losses are not deductible by a limited partner unless the person has passive income from the same activity to offset.

However, limited partner taint can be overcome in one of three ways. One way is to show the limited partner works 500 hours or more in the same activity. Another is to show the limited partner materially participated in the activity in any five of the prior 10 years. Another for activities that involve personal services that the passive investor materially participated in the same activity in any three prior years.

Members in limited liability companies are treated like limited partners, even if the person is a member-manager.

In the case of a business trust, the material participation standard applies to the trustee. The trustee must satisfy the material participation standard. Another type of trust — a grantor trust — is ignored for purposes of these rules, and the tax owner of the trust must satisfy the material participation standard.

The passive loss limitations apply to all personal service corporations, meaning corporations whose core activities are performed by employee-owners.

Examples of personal service corporations include corporations through which people do business as doctors, attorneys, engineers, actors, consultants, accountants or financial planners. The rules apply to other closely-held C corporations to a more limited extent. The passive loss rules do not apply to C corporations that are not closely held and are not personal service corporations. A corporation is closely held if five or fewer individuals own more than half the stock during the last half of the year.

Thus, the level of shareholder participation determines whether a personal service corporation or closely-held corporation materially participates in its activities. Generally, one or more of the individuals holding more than 50% of the outstanding stock must materially participate in each of the corporation's activities to meet the material participation standard.

With respect to a personal service corporation, a loss is passive if the loss stems from renting real estate or equipment to others.

A loss is passive if it comes from a partnership or S corporation business in which shareholders holding more than 50% of the outstanding stock do not materially participate.

Similarly, if the personal service corporation owns interests in a lower tier S corporation or partnership, material participation means that shareholders owning more than 50% of the stock in the personal service corporation must materially participate in the business of the S corporation or partnership.

For a closely-held corporation that is not a personal service corporation, passive losses and credits can offset the corporation's net income, but not portfolio income. This means that passive losses can offset corporate earnings, but not investment earnings.

Separate Activities

What makes things separate activities, and why do separate activities matter? What if I own or invest in more than one business? Can I aggregate those activities for purposes of the material participation tests?

A person must materially participate an activity in order to be able to use tax credits and losses from that activity against active income. If the person does not, then the tax credits and losses are passive, but can still only be used against passive income from the same activity.

For purposes of the material participation standard, the term "activity" does not necessarily mean a single business or separate entity. Activities are not constrained by entity or organizational lines — IRS rules permit grouping activities and treating several businesses as one single activity if they form an "appropriate economic unit."

On the other hand, a single business entity could contain two separate activities.

Whether single activities can be grouped into an "appropriate economic unit" depends on a number of factors: similarities and differences in types of activities, the extent of common control, the extent of common ownership, geographic location of the activities and interdependence among activities. Factors that tend to show interdependence include the extent to which activities rely on each other for goods and services, involve products or services that are normally provided together, have the same customers, have the same employees, or are accounted for with a single set of books and records. An example of two activities that might be treated as a single economic unit is a retail store and a trucking company that transports goods for the retail business, if both are under common control.

Any reasonable method of grouping is permissible, and there may be more than one reasonable method for grouping activities. However, once activities are grouped together, they must remain grouped unless there has been a material change in facts and circumstances.

One thing to keep in mind is that grouping might not always be favorable. If one activity from a group is sold, prior unused losses from that activity will be suspended and cannot be used to offset taxes on gain from the sale until all of the grouped activities are sold. ◎

Taking Stock of Community Solar

A panel of five community solar experts talked in late February in Boston about new trends in the community solar market, including evolving contract terms, consolidated utility billing, customer attrition rates, state requirements for a certain percentage of low- and moderate-income customers, where to probe on diligence when buying community solar projects, potential inflection points that would affect the future trajectory of the market, and other topics. The community solar industry resumed its annual conference with a large audience after a two-year interruption due to COVID. The following is an edited transcript.

The panelists are Laura Stern, co-CEO of Nautilus Solar, Richard Keiser, founder and CEO of Common Energy, Taymaz Jahani, chief operating officer of OYA Solar, Tom Matzzie, CEO of Clean Choice Energy, and Myles Fish, vice president of business development for Perch Energy. The moderator is Keith Martin with Norton Rose Fulbright in Washington.

New Trends

MR. MARTIN: This is a challenging year with lots of headwinds. In addition to rising international political tensions with Russia invading Ukraine, we have tax law uncertainty, broken supply chains, inflation, Customs blockages of some solar panels due to forced labor concerns and a threat of anti-circumvention duties.

Laura Stern, are there any new trends this year that are unique to community solar?

MS. STERN: Most of the new trends are really a microcosm of what you see in utility and rooftop solar. One consequence of our success in community solar is that we are now facing many more interconnection issues that we have to address in order for the industry to reach the growth projections for which it is aiming.

MR. MARTIN: You can build the project. You can't get the electricity to market.

MS. STERN: Or you can't even build it because many community solar markets have regulatory cliff dates and deadlines. Everything from interconnection studies to actually tying into the grid at the end of construction has taken much longer than most developers anticipated.

MR. MARTIN: Richard Keiser, is interconnection the number one issue? Is there another new trend? */ continued page 32*

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MR. KEISER: We are a subscriber management organization. One of the most important trends that will emerge this year relates to collections from consumers.

The periodic payments that subscribers make and bill credits they receive are collected on the developer's behalf by subscriber management organizations. If you run a sensitivity analysis, the return of the developer is about 10 times more sensitive to the collection percentage than it is to the amount the developer pays a subscriber organization.

What is increasingly clear is that for most companies, the collection rates are in the 50% to 60% range, sometimes as high as 80%. And yet, when we are asked to bid on an RFP, we are never asked about our collection rates. We are only asked for customer acquisition costs and customer management costs, but those are irrelevant if you are unable to collect the money.

Residential subscribers in community solar projects usually sign one-year contracts with the right to cancel at any time.

We are very focused on the collection percentage. I think that will become an emerging trend as people figure out that their returns are highly dependent on collection efficiency.

MR. MARTIN: Did I hear correctly that the collection percentage is only 50% to 80%?

MR. KEISER: Yes. Let me explain why it is so difficult to track. You start a period, which would be generation period X, let's say January to February. Then the utility must calculate how much in bill credits to allocate to subscribers over the next period. That will take a few days. Then a few weeks later, the utility will tell you the number of bill credits that were distributed. Then you start collecting from subscribers. Three cycles end up being mixed together.

If Laura were to look at her bank account at the end of the 30- to 45-day bill cycle for customer payments and see a large pool of money, she might not know whether it means there was a 99% or only a 40% collections rate for the first cycle. When the auditor connects all of the dots, she may be disappointed with the results. We are very focused on trying to push collections rates into the 90% range.

MR. MARTIN: So there is potential for improvement, but any financier should discount the revenue stream?

MR. KEISER: Correct.

MR. MARTIN: TJ, what is a new trend for community solar?

MR. JAHANI: It is taking longer to develop projects.

MR. MARTIN: Because of supply chain difficulties?

MR. JAHANI: The design and engineering costs are going up. Developers are learning from earlier projects. The supply chain is also a challenge.

MR. MARTIN: Bankers have told us that 20% to 30% of projects that were supposed to fund at the end of last year flipped into 2022, and they are already seeing delays into 2023. Is that your experience as well?

MR. JAHANI: Yes, but we are also seeing manufacturers decide to ship their products to other markets. Solar installations are increasing in lots of other places besides North America. If prices are higher elsewhere, they will turn their ships around and send the panels to another country. That has been very challenging for us.

MR. MARTIN: Is this a US problem or do you have the same problem in Canada?

MR. JAHANI: It is more of a US problem. Manufacturers tend to have separate allocations for Canada. It may be easier to get panels in Canada.

MR. MARTIN: Tom Matzzie, what is a new trend for community solar?

MR. MATZZIE: State community solar programs are more likely than the last time we had this conference in 2019 to have a low- and moderate-income component. This has become a bigger part of our industry.

We are in the high 90% range in our collections. It would be unusual to see collections rate in the 50% to 80% range, in my view. However, the LMI component will introduce a collections challenge, and so the industry needs to innovate.

I think we are going to see more pre-pay models. If you walk into an Apple store, every consumer is qualified to buy an iPad and get a cellular subscription because it is an entirely prepaid product.

MR. MARTIN: Pre-pay over what time period? Five years? A year?

MR. MATZZIE: Pre-pay at the beginning of each month so that you remove the receivables risk. You still have a contract risk that the consumer could default.

Apple has democratized access to cellular service by having essentially an entirely pre-pay business model. I think you are going to see adoption of similar models. In the retail electricity sector in Texas, all the credit-disabled customers are on pre-pay products.

MR. MARTIN: Why is that considered an innovation? I remember living in London in the late 1970s, and to get hot water for a bath, you had to keep feeding five-pence coins into the gas meter. This is going backwards.

MR. MATZZIE: It is a way to allocate credit risk to the actual places where there is credit risk. It is a more data-driven approach to risk allocation rather than moving backwards, and what it will do is credit-enable more consumers. You will still have contract default risk, but you will address receivables risk.

MR. MARTIN: So it is a way to get around the need for FICO scores?

MR. MATZZIE: It depends on every counterparty's view of what risk the FICO score is addressing. Is it addressing default risk on the contract, or is it addressing receivables risk? There is evidence that people with lower FICO scores do not have the highest level of payment defaults, but you still have contract default risk.

MR. MARTIN: Myles Fish, you gave a compelling presentation immediately before this panel about the need for collective action to expand the market by getting more states to sign on to community solar programs. What new trend would you add to the list you just heard?

MR. FISH: I think that is part of the new trends. There is an opportunity to expand the potential addressable market.

More and more states are considering community solar, but what that also means for us as market participants is we have more states to monitor and to think about where to invest. It is encouraging to see new states considering this, but it is also then incumbent on us to weed through new opportunities to avoid speculative investments.

Business Model

MR. MARTIN: Laura Stern, going back to you. Talk to us about the basic business model. The community solar company builds a small solar facility and supplies the electricity to the local utility in exchange for bill credits that can be used against electricity bills. It basically sells those bill credits to local businesses and residents whom it signs up as subscribers. How does the money flow through that circle?

MS. STERN: It depends on the utility and the state, so different states have different programs. Consolidated billing is an important advance in terms of trying to facilitate not only the flow of payments, but also the level of understanding among our customers.

In places without consolidated billing, the customers receive two bills: one from the local utility for the electricity they use and one from the community solar company. The utility bill credits the bill credits.

With consolidated billing, there is one bill, and the subscriber payments on which the community solar company relies are collected in the first instance by the utility.

MR. MARTIN: So the customer makes a payment to the utility on a consolidated bill, and the utility splits it. What percentage does the community solar company receive? Tom Matzzie.

MR. MATZZIE: Our retail electricity business operates under utility consolidated billing in 34 markets, and there is a cash flow waterfall. Utility consolidated billing only works if there is also a purchase of receivables by the utility. The utility applies a discount rate of 1% or 2%. It owns the receivables risk. Then it just pays you.

If it does not purchase the receivables — and we operate in a few of those markets where there is utility consolidated billing with no purchase of receivables — there is a cash flow waterfall. It is a little bit of a nightmare to be honest with you. The utility always gets paid first, so if there is a shortfall in customer payments, the utility gets its share first and you get what is left. Then the next bill comes in and there is another customer shortfall. The utility pays itself first and pays you what is left of your prior month first and then your second / continued page 36

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month. The cash flow waterfall becomes a really important thing.

MR. MARTIN: So 34 states with consolidated billing?

MR. MATZZIE: Thirty-four markets.

MR. MARTIN: In 34 markets, the utility buys the right the solar company has to subscription payments.

MR. MATZZIE: It purchases the receivable.

MR. MARTIN: It discounts the revenue stream by 1% to 2%?

MR. MATZZIE: I have seen anywhere from 0% to 3.5%. In some markets, like in Pennsylvania, the utilities have claw-backs for some retailers that have really bad-performing receivables rates, but it is 0% in places like Maryland because the utilities there are actually collecting more in late fees than they were on defaults on receivables.

MR. MARTIN: If everything works as planned, what percentage of the revenue goes to the community solar company?

MR. MATZZIE: It should be the full revenue minus the discount, so if it is a 1% discount, then 99% of the revenue goes to the community solar company.

MR. MARTIN: Richard Keiser, do those numbers square with you?

MR. KEISER: Just to be clear, Tom is talking about something very different. He runs a retail electricity business. What percentage of your customers are retail electricity customers versus community solar companies?

MR. MATZZIE: Twenty times more.

MR. KEISER: I think the point that Laura was trying to make was community solar consolidated billing does not always function exactly that way, and the models vary by utility.

MR. MATZZIE: I was explaining what you should expect after utility consolidated billing gets rolled out. It can be a great tool, but you need to get the purchase of receivables in there. Otherwise, it becomes a cash-flow-waterfall nightmare.

MR. MARTIN: Myles, you touted consolidated billing in a presentation immediately before this panel. Has it worked as you hoped?

MR. FISH: I think the model for the community solar industry is New York. Focusing on the cash waterfall, the revenue comes from the utility directly to the owner of the solar project at a discount that is communicated to the customer ahead of time. The customer will be allowed bill credits equal to the amount it pays, less the discount.

The alternative, which you can still do in New York if you prefer, is the customer pays the owner of the project directly, and the full payments translate into bill credits for the customer. The customer receives a separate bill from the utility for the electricity usage, and it applies the bill credits toward that bill.

Consolidated billing is a lot more streamlined.

MR. MARTIN: Laura Stern, when you don't have consolidated billing, what is the split of revenue? The community solar company receives revenue solely from the subscriber?

MS. STERN: Yes.

MR. MARTIN: The utility has to receive some revenue for actually supplying the electricity. What is the split?

MR. KEISER: Let me break that down for you.

Let's assume that the customer is buying $200 worth of electricity currently before community solar comes into the picture. If we were partnering with Laura, we would formulate an allocation to that customer so that it would receive, let's say, a $180 credit on the bill. Now the net amount owed to the utility is $20. If the community solar company is offering customers a 10% discount from the retail electricity rate, the customer will keep $18 of that $180 credit, which would leave $162 for the community solar company. Our job in that scenario would be to make sure that Laura gets paid her $162.

What Myles was explaining was that if there is utility consolidated billing in the same format that New York has developed, then the utility just pays Laura $162 all the time with no question. She loves that model. But there are other models for retail electricity suppliers that Tom was explaining that work slightly differently, and that is why he is so focused on getting the purchase of receivables. Does that unify the responses?

MR. MARTIN: Yes, I think so. Thank you for that.

TJ, you heard in the example Richard Keiser just gave that a 10% discount was offered to the customer against the retail electricity rate to get the customer to subscribe. Is that where discounts are today generally in the market?

MR. JAHANI: That is in line with what we are seeing today. The discount that you could offer the subscriber depends on the economics of the project. As the cost of interconnection increases, as EPC costs increase, there is less ability to offer a 10% or higher discount.

MR. MARTIN: Myles, you are out soliciting business. Where do you see discounts currently?

MR. FISH: It depends on the market. In some states like Illinois, discounts tended to be a little higher in past years because of the way bill credits worked in that state. In most markets, 10% seems to be most common.

Contract Terms

MR. MARTIN: Our last conference was in July 2019 in Philadelphia before COVID hit. It was standing room only. At that point, it seemed like most community solar companies, with the exception of Nexamp here in Boston, were having to enter into 20-year contracts with commercial customers, and they were aspiring to get down to five to 10 years with residential customers.

Richard Keiser, you sent me an email last night that said this is no longer true. Where do you think contract terms are today, and how relevant are FICO scores for residential customers?

MR. KEISER: In the vast majority of markets where we work, residential subscribers are being offered a one-year, auto-renew contract, but the subscriber can cancel at any time or with notice. It is a perilous endeavor to try to collect money from consumers who do not want your service any more.

With commercial subscribers, the contract term varies based on the financing terms that the community solar company has behind it. If you have sophisticated financiers like Laura does, then they might be more comfortable with more flexible terms. If you have a bank or tax equity investor who is new to the market, it might insist on a 20-year contract at least for the anchor customer that has some teeth to it if the anchor wants to cancel. There is more variety around the commercial agreements.

MR. MARTIN: What contract length do you think is standard for commercial?

MR. KEISER: We typically do 20-year agreements. Really the most important thing is not the term length, but the termination provisions.

MR. MARTIN: How easy it is get out. How do the termination provisions work?

MR. KEISER: Some such contracts have significant penalties to terminate early. We try to be more flexible and ask for one year's notice, and then we ask for a termination fee for any period less than one year with the logic being that we will be able to replace the customer within that time period since the customer is being offered a significant discount from the price it would otherwise have to pay for electricity.

MR. MARTIN: So the commercial customer can walk at any time, but has to give you one year notice or pay a fee. Myles, where do you think contract terms are, and when are FICO scores required?

The first place to probe on diligence when buying development rights is whether the project has a feasible path to connect to the grid.

MR. FISH: It varies. It depends on risk tolerance of the financing party and the market. For example, Maine is offtake constrained and customers have to be offered larger discounts and more flexible terms to sign up. Illinois is less so.

We try to be flexible. Not every client prefers the same approach. We tend to be driven by any preferences the customer or financier has.

MR. MARTIN: What terms are required in the current market to be able to raise financing?

MR. FISH: We try not to get into a conversation where we are convincing customers to do one thing or another. We listen to what their preferences are and we can give advice on what the market might bear, but if their preferences are in line with what we think the market can bear, those are the terms that we will deliver.

MR. MARTIN: TJ, are financiers insisting on long contract terms and residential FICO scores?

MR. JAHANI: FICO scores were very / continued page 39

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important five years ago. They are less so today. We have managed to explain to our financiers that eliminating FICO scores lets us reduce our customer acquisition costs by going after bigger market segments. Over time, if a customer leaves, we are able more easily to replace that customer with a newer customer.

We are mostly active in New York, so with full consolidated billing, it is a no-brainer for us to dispense with FICO scores and go after bigger market segments.

MR. MARTIN: Laura Stern, Richard Keiser teed you up. You are dealing with sophisticated financiers. Are you able to have residential customers who can walk at any time and commercial customers who can walk with one year notice?

MS. STERN: Yes. The banks have come to accept consumer-friendly contract terms. This trend towards flexibility for the customer is not just something to which we have been driven by market forces; we are very comfortable with it as well. Flexible contract terms ultimately lead to reduced acquisition costs, increased customer engagement and higher retention. What we focus on more than FICO scores and contract length are the mechanisms that each state creates to mitigate the financial effects of churn, particularly features like the ability to bank bill credits and to flex up customers' allocations of electricity output of a given project.

These program structures can be equally or more important than the credit score of any customer. It is also important to distinguish between default and churn and to implement internal policies that prevent customers from lingering with an aging balance for several billing cycles. Customer acquisition is very expensive. Our goal is to minimize churn and defaults through active customer engagement, education and communication.

Customer Churn

MR. MARTIN: When you talk about policies, are you talking about the mix of residential and commercial customers, low and moderate income customers, or something else?

MS. STERN: No, I was referring to the mechanisms that the regulatory authorities have established to help mitigate the revenue impact of customer churn and defaults, such as consolidated billing. Some states allow the community solar generator to reallocate credits to other customers or to size one customer's share of the electricity output at a much lower percentage of the customer's overall usage so that when other customers terminate or default, the generator can reallocate the bill credits.

MR. MARTIN: These are state policies to help project developers mitigate the effects of customer credit problems and churn.

MS. STERN: Exactly.

MR. MATZZIE: It will be interesting to see what happens with churn once you have utility consolidated billing because the community solar provider will not have as much of a relationship with the customer as it does today. The churn rate in our retail electricity business, which is a utility consolidated billing business, is double or more what it is in our community solar business where we are billing customers directly and have a direct relationship with customers.

Why would the churn rate be so much higher with utility consolidated billing? You do not have as much of a relationship with the customer.

MR. MARTIN: Richard Keiser, how do you get comfortable in a market where customers are free to walk away from contracts that a new entrant will not come take your customers by offering a larger discount?

MR. KEISER: This is one of the misconceptions about community solar.

On the one hand, you need consumer-friendly, consumer-facing policies, starting with a website that is accessible to consumers. That is easy to build. Any high school student can build a web form that enables customers to click through and find a certain amount of information, so that is not the barrier to entry. The barrier to entry is where you have thousands of subscribers on 50 to 100 different projects. All of those subscribers have different usage, different credit rates, different discount rates, and all of that needs to be distributed into 50 different project bank accounts.

MR. MARTIN: Would you say that of the four solar market segments — residential rooftop, C&I, community solar and utility-scale solar — the barrier to entry is highest in community solar, or how would you rank the four segments?

MR. KEISER: It is a good question. There are different barriers in each segment, including ability to get access to sophisticated capital like tax equity. I don't think I would be able to rank them.

Low-Income Mandates

MR. MARTIN: TJ, many states are requiring a certain percentage of the output go to low and moderate income customers. What is the range of percentages, and what challenges does that pose in trying to finance projects?

MR. JAHANI: Contrary to what we feared, our financiers are actually excited about the low- to moderate-income customers. It helps their environmental sustainability goals. We see goals of around 20%.

MR. MARTIN: 20%? Myles, what are you seeing?

MR. FISCH: In Maryland, it is 30%. In Massachusetts, it is 50%. In New York, you can pick your own flavor and there is a range. I spoke about enabling more state policies to help our market grow. In general, I think we should expose ourselves to those higher percentages when we are given the option to choose.

MR. MARTIN: Tom Matzzie, is your idea of making people pay at the start of the month the way to finance LMI revenue streams?

MR. MATZZIE: It certainly could help deal with receivables risk. You would still have contract default risk.

We are seeing the same LMI percentages. One thing that is important to understand is not all LMI consumers are credit disabled. There are LMI consumers who have prime credit scores and are FICO qualified. Part of the opportunity is to connect with those consumers. They are people with stable jobs with health care. For example, if you work for a school district and drive a bus, you are probably credit enabled because you have good benefits, even though you might not have a lot of money. You may qualify for an LMI program.

MS. STERN: Tom is absolutely correct. The challenge is verifying customers and the state requirements to verify customers. It can be incredibly challenging. I think our collective job is to work with the regulators to come up with a smoother, easier, more efficient way to verify LMI customers.

MR. MARTIN: Is any state doing it right currently?

MS. STERN: It is a challenge everywhere, especially in states like New Jersey that are starting new programs.

MR. FISH: The best practice is geographic eligibility, which avoids requiring someone, as he or she is subscribing, to upload a document to verify income. Any time you must scan a document to include in some sort of enrollment process, it creates barriers to enrollment. Geographic eligibility allows us to collect the customer addresses as part of the enrollment process, run the addresses against a database and treat the person as LMI or not based on the neighborhood in which the person lives.

Attrition Rates

MR. MARTIN: Richard Keiser, early financial models assumed that customer attrition would be about 5% a year, probably highest in the first year when the first bills start to be received. What do you think is the right percentage now that the industry has more experience?

MR. KEISER: That's a great question. One way to think about it is US mobility is about one move every seven years, so you would expect natural housing churn of around 14%. Fortunately, the vast majority of people upgrade their houses when they move. If you assume that 70% of that churn is within a local area, and therefore 30% is true churn out of the system, 30% of 14% is 4.2%. That is not a bad natural model to assume.

This, like many of the other things that have been discussed on this panel, is sensitive to other factors. One factor is the developer's timeline for building the project. Say you have a project that has been advertised as expected to go live in the spring 2022. I will tell you a phrase that has never been said to me: "Hey Richard, great news. We finished the project three months early." [Laughter]

This has never happened, right? So if the completion date gets pushed out two years . . .

MR. MARTIN: The customers won't wait around.

MR. KEISER: Correct. It's like if you try for a second date after not contacting the person for two years. It's not going to work.

MR. MARTIN: TJ, suppose you are out in the market looking to buy community solar projects under development from other developers. Where do you probe first on diligence?

MR. JOHANI: I would probe first into whether the project has a feasible path to interconnect to the grid. We look at curtailment. We also look at the site control documents to make sure that we do in fact have site control, the proper easements and the tile is clean and financeable. We also check whether the project has a clear path to permitting.

We start with desktop diligence and, if we like the project, we dig deeper.

MR. MARTIN: Laura Stern, where would you probe?

MS. STERN: I agree with what TJ said. Physically, community solar is just like any other solar project. Our major gating milestone is the allocation for the state's community solar program. The allocation in the community solar program is equivalent to securing a PPA.

Audience Questions

MR. MARTIN: Are there any audience questions?

MR. WILLCHENE: Sean WillChene, CEO of Shared Solar Advisors. Illinois just adopted consolidated billing. When do you expect that to go live?

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MR. MARTIN: Anybody know the answer? [Pause] We may not have an answer.

MR. KEISER: I would expect two to three years.

MR. MICHELMAN: Tom Michelman, senior director, Sustainable Energy advantage. How do you see growth, outside of Texas, of community choice aggregation combined with community solar? We have been waiting a long time for it in Massachusetts. It looks like it is about to happen in New Hampshire.

MR. KEISER: We have only seen it in New York so far.

MR. FISH: It is only in New York today, and that is just a pilot program. New York has said it wants to be careful about the long-term implementation of opt-out CCA integration with community solar. In general, this is a positive thing for the industry because it is a streamlined way to get a lot of customers to participate in community solar. CCAs are municipalities. Residents in their areas are automatically enlisted unless they opt out.

MR. FELT: Justin Felt, director of policy analysis for Baltimore Gas & Electric. Do residential and commercial subscribers sign something that looks like a power purchase agreement where they pay a per KWh charge tied to a monthly meter reading?

MR. MATZZIE: Early on there were more esoteric contract structures. We have some customers who pre-pay each month on assets that we took over from other asset owners, and other customers have end-of-year reconciliation back to a credit rate. Nowadays, it is a discount to the bill credit rate. The esoteric kinds of contracts are mostly gone.

Inflection Points

MR. MARTIN: Here is my last question. Investors look for inflection points in any market: things that could change the market trajectory. What should we be looking for in the next two years in community solar as possible inflection points?

MS. STERN: Our inflection point needs to be a real breakout of the installed capacity of each state's program. We need more meaningful progress than establishing pilot programs in a few new states every year. We need to expand programs in the states that we are already in as well as promote larger programs in new markets. The programs are just too small. One gigawatt a year for all of us in this room is just not enough. An inflection point would be getting to 30 to 40 cumulative gigawatts of installed capacity.

MR. MARTIN: That is where the Coalition for Community Solar Access, the organizers of this conference, play an important role. Richard Keiser, inflection point?

MR. KEISER: I agree with that. The inflection point would be a lot more states with depth, like 400- to 500-megawatt programs.

MR. MARTIN: TJ, do you have another inflection point?

MR. JOHANI: I agree with the comments made. There needs to be a push from the federal government to streamline the processes, and perhaps to allow battery storage to be incorporated into projects to allow more penetration on the grid.

MR. MARTIN: Tom Matzzie?

MR. MATZZIE: An inflection point implies a much steeper rate of change. State programs tend to be incremental, and so I think what is required is a fundamental change in the business model to get to the type of scaling where the industry is adding tens of gigawatts. So what would that mean? It would probably be a more organized power market rather than one-off distributed energy resources.

MR. MARTIN: You are returning to your retail electricity supplier role.

MR. MATZZIE: Yes, but the thing about that model though is that there is no capacity limit. I can sell as much as I can find customers to buy. That is where you want to get eventually.

MR. MARTIN: Myles Fish, you get the last word. Inflection point?

MR. FISCH: I agree with what others have said. California would really change the addressable market in one fell swoop. ◎

Ex-Im Bank Financing for US Manufacturing

by Kenneth Hansen, in Washington

The Export-Import Bank of the United States is moving forward with plans to finance construction of new US factories and expansion of existing factories that, in each case, will produce some goods for export.

The program's parameters are still being worked out, but the bank has indicated financing availability will depend on two criteria: "export nexus" and jobs created.

The export nexus will be measured as the percentage of production projected to be exported. The qualifying percentage for small businesses, minority- or women-owned businesses, projects in "transformational export areas" and climate-related transactions is 15%. Other projects will require 25% of output to be destined for export.

The amount of Ex-Im financing to be made available for individual projects will be scaled based on the number of US jobs projected to be supported, both during construction and over the life of Ex-Im's financing. Each job year (where one job year equals one job for one year) allows for up to $189,242 in financing — an interesting criterion since it gives credit for more jobs the longer the term of the Ex-Im Bank loan, providing the borrower and lender an unusual shared interest in a longer maturity. This will presumably be subject to normal commercial leverage ratios for similar financings (similar except for the export dependency of projected revenues).

The statutory requirement of "a reasonable assurance of repayment" will also need to be met.

Some details of the new initiative are in an April news release by the bank on its "Make More in America Initiative." The initiative follows up on Executive Order 14017 that President Biden issued on February 24, 2021, about strengthening America's supply chains.

Political Flak

Senator Pat Toomey (R-Pennsylvania), the ranking member of the Senate Banking Committee (which is Ex-Im Bank's oversight committee), condemned the bank's announcement, declaring its decision is "worse than mission creep." That depends, of course, on what one considers to be the bank's mission. That mission has expanded over the years.

This is not Ex-Im Bank's first domestic financing program. The bank's motto — "Jobs Through Exports" — has already been interpreted more broadly than merely its traditional demand-side support through financing foreign purchases of US goods. Ex-Im Bank has also recognized and tried to address domestic financing constraints on the supply side of potential US exports.

As discussed below, borrowing against sales into emerging markets injects a degree of credit risk that is beyond the comfort zone of most banks. Ex-Im undertook to meet this challenge through its "working capital guarantee program," which provides short-term loans to domestic businesses to fund the cost of raw materials for products destined to be exported, with the loans repayable from the proceeds of overseas sales.

Ex-Im Bank also developed a "supply chain finance guarantee program," which guarantees banks against non-payment by foreign customers of accounts receivable purchased by the banks from US exporters. This program enables exporters to receive, at a discount, quick payment of their invoices.

In each of these programs, like the new manufacturing plant finance program, Ex-Im Bank's financing for US borrowers encourages exports, albeit indirectly.

Policy Drivers

Two distinct policy objectives have supported the idea of Ex-Im Bank in the decades since it was established in 1934 — market failure and leveling the playing field.

The market failure argument is that emerging market debt markets are imperfect. In particular, debt tends to be available only for relatively short terms. Short-term lending won't work for financing the acquisition of capital goods whose cost may need to be amortized over many years of operation. The loan maturity needs to extend through at least a substantial portion of the useful life of the equipment. Such debt is not available locally. Export credit agencies, like the US Ex-Im Bank, offer the long-term financing that the local debt markets cannot.

Senator Toomey's assertion of mission creep is tied to his observation that the US has as sophisticated a bank and capital market finance sector as any country on the planet, so there is no market failure here for Ex-Im Bank to address. But that fails to recognize the challenges faced by export-oriented manufacturing.

At least in cases in which projected revenues depend importantly on exports to lower-credit regions, domestic lenders will discount such revenues when considering financing such facilities and reduce the available leverage / *continued page 42*

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and perhaps decline to finance the sales or to support the project entirely.

An additional, and perhaps more dominant, defense of Ex-Im Bank's support of US businesses is to "level the playing field" — that is, to assure domestic suppliers that their potential offshore customers can benefit from financing terms as attractive as those available to their purchases of goods from competing foreign suppliers supported by their respective export credit agencies.

That leveling has been substantially achieved through widespread adoption by leading ECAs (specifically, Australia, Canada, the European Union, Japan, Korea, New Zealand, Norway, Switzerland, Turkey, the United Kingdom and the United States) of the OECD's "Arrangement on Officially Supported Export Credits." The arrangement was a collective response to the cutthroat competition among ECAs that characterized the first decades of Ex-Im Bank's operations.

The US Export-Import Bank is looking at financing US factories.

Some ECAs aggressively supported bids by their national producers with uneconomic terms such as principal amounts exceeding the cost of the goods being financed, minimal (if any) interest rates (regardless of the apparent risk), and maturities that exceeded the useful life of the goods being financed.

A competing bidder's ECA needed to match those terms or stand by while the business was lost to a competitor for reasons unrelated to the quality or price of the relevant product. Competition among ECAs worked less to achieve a level playing field than to contribute to a slippery slope of uneconomic financing terms. Among other issues, this competition was costly for the ECAs.

In 1971, leading ECAs from the largest OECD countries responded by establishing the arrangement, which is, in effect, a cartel that, as it has evolved, reflects agreement on three points.

The first is that ECA financing would not exceed 85% of the cost of the goods being financed, with an additional allowance for the local costs incurred in installing the exported equipment.

Second, interest rates had to be at least 100 basis points above the rates required for similar-maturity bonds issued by the government of the relevant country.

Third, the maturity of the loan would be restricted according to the nature of the financed goods, with shorter terms required for high-income countries. Permitted maturities are 8.5 years for most sales into high-income countries and 10 years for other countries, with longer terms permitted for specific industries, such as 12 years for new aircraft or coal-fired power plants and 14 years for project financings generally, but up to 18 years for renewable energy or nuclear projects.

While the OECD arrangement is non-binding, adherents agree to notify the other members if they are considering offering non-compliant financing terms, giving competing ECAs an opportunity to support their nation's bidders with matching terms. Such notices are infrequent, and adherence to the arrangement's terms is taken seriously by the world's ECAs, including by some that have not formally signed on to the arrangement.

Over the 50 years since its adoption, the arrangement has succeeded in generally providing a level playing field, encouraging winning business based on price and quality, and not via competing subsidies. But it has not succeeded in every respect.

When foreign manufacturers propose sales to prospective US customers supported with financing offered by their national ECAs, any US manufacturers competing for that business have no corresponding ECA support to offer. The customer may have access to the full field of US credit markets, but that plus better pricing or quality may still lose to the foreign bid. All else equal, the sale will go to the foreign supplier, and any potential employment that would have arisen from domestic manufacture of that equipment will be lost.

Arguably Ex-Im Bank's mission should include leveling the playing field at home as well as abroad, although so far the bank has declined to do so.

On one occasion, Ex-Im Bank was approached to support a domestic turbine manufacturer in competition with a European supplier supported by ECA terms sufficiently aggressive to require notification to the other arrangement participants. Ex-Im Bank issued a letter of interest asserting that there was "no policy impediment" to Ex-Im Bank matching the foreign ECA's financing terms. However, in due course Ex-Im Bank found an impediment and ultimately did not approve the requested financing.

Foreign investment into the United States has not been a particularly dominant activity, but it is growing. With that growth, US manufacturers are disadvantaged relative to foreign manufacturers in benefiting from that trend where the foreign manufacturers are supported by their respective ECAs. This is a good time for Ex-Im Bank to reconsider being open to supporting US jobs by leveling the playing field at home.

A related opportunity arises where a foreign company acquires goods in the US and contributes those goods as an equity investment in a US-based enterprise. From the perspective of national income accounting, such a transaction creates a claim on foreign currency and enhances overseas demand for US dollars, which has the same economic consequence as an export. From an economic perspective, the purchase is an export whether the goods acquired in the US are — or are not — ever transported out of the country. From this perspective, such purchases by foreign investors into the United States should qualify for Ex-Im Bank financing even absent direct competition from a foreign ECA.

When prospective investors are calculating the pros and cons of investing in the US, availability of Ex-Im Bank financing for equipment that could be procured from local manufacturers could sway their ranking of options in favor of the United States. To date, Ex-Im has not considered such transactions as qualifying for its support. US manufacturing would benefit if that practice were reconsidered.

Jobs Through Import Avoidance

The Biden administration's request to Ex-Im Bank goes further than just promoting exports.

It is aimed at kick-starting domestic manufacturing capacity in order to reduce dependency on certain imported critical goods, potentially raising further cries of mission creep.

Senator Toomey may be correct in calling this "mission creep" since it goes beyond promoting exports. But that creep may well serve the national interest.

Unlike many countries, the United States lacks a domestic development bank to support construction of infrastructure and other developmental facilities. The void has been partially filled with federal programs such as the Department of Transportation's TIFIA program to finance transportation infrastructure and the Environmental Protection Agency's WIFIA program to finance water infrastructure. No such program is available to support strategically important manufacturing.

The White House has recognized an important, possibly critical, national need and, after reviewing the tools in its arsenal, has identified Ex-Im Bank as well equipped, with the necessary legal capacity and staff expertise to fill that void.

The White House statement makes it clear enough that more than just jobs are involved when it states that Ex-Im Bank "is well positioned to address this issue, supporting jobs in America along the way" — that is, job creation is welcome, but subsidiary to other national objectives, such as kick-starting domestic manufacturing capacity in strategic industries, thereby reducing dependency on foreign sources.

Supporting jobs by encouraging exports is one thing. Doing so by discouraging imports is another. Economists tend to disfavor protectionism.

Import substitution strategies promote high cost, inefficient domestic production. Prior to its 1991 pro-market conversion, Albania imported as little as possible, but consumption was meager and the quality of domestic goods was reliably poor. The key argument for protecting domestic producers from competing imports, aside from serving special interests, has been to support an "infant industry" — arguing that, where a country is potentially an efficient producer of a good, but needs to achieve critical mass to achieve those efficiencies, blocking foreign competition for the period required for the industry / continued page 44

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to establish itself can lead to an overall economic improvement (for that country, at least).

That appears to be at least part of what the Biden administration has in mind. If only given a chance to catch up with foreign producers, US companies will be able to produce as efficiently as anyone. While there is no active barrier to imports in the program, there is a degree of subsidy, through financing on terms not otherwise available, to kick-start a domestic manufacturing capacity in a range of areas in which the US relies substantially on imported goods.

National security offers another motivation for protecting a domestic industry.

Currently electronic goods, including products on the cutting edge of a clean energy future, are overwhelmingly produced in Asia. China controls the refining of roughly 90% of the rare earths required in the production of computers, cell phones, wind turbines, batteries and electric vehicles. Taiwan dominates the production of semi-conductors.

Loss of reliable access to such materials and products could severely adversely affect the quality of American life. Some subsidy of a domestic capacity might be well invested. This is part of the administration's motivation and Ex-Im Bank's focus.

At least 25% of the factory output in most cases must be destined for export.

The bank's public announcement of the program notes that its new initiative will apply "especially in sectors critical to national security." That goal clearly goes well beyond "jobs through exports." But Ex-Im Bank's mission has already "crept" forward over the years in response to overseas challenges, as demonstrated by the introduction of the working capital and supply-chain-finance guarantee programs. The bank's goals are always subject to policy objectives arising from a changing global debt market, and so adjustments to its goals and, reflecting that, its programs, is warranted. Its mission may be creeping, but the more important issue may be whether it has crept far enough. ◎

Environmental Update

New York lawmakers passed a bill designed to slow the spread of cryptocurrency mining operations that burn fossil fuels for power in early June.

New York Governor Kathy Hochul subsequently suggested she may wait to decide whether to sign it into law until more information can be gathered about the effects.

If signed into law, the bill would impose a two-year moratorium on new and renewed air permits required to run fossil-fuel power plants used for cryptocurrency mining.

Environmentalists are urging Hochul to sign the moratorium in light of the energy-intensive nature of the mining operations and the environmental impacts from burning fossil fuels.

Bitcoin and Ethereum miners use high-powered computers to process transactions and collect rewards in crypto.

Bitcoin mining worldwide already currently uses more electricity annually than is used by the entire nation of Argentina. 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.

If enacted, the law would be the first of its kind in the United States.

There is speculation that Hochul may wait to sign or veto the bill until after the Democratic primary in late June in which she is running for re-election.

Clean Water

The US Environmental Protection Agency proposed in early June to reverse limits that the Trump administration placed on states' and Indian tribes' authority to review proposed new projects for effects on local water quality.

Section 401 of the Clean Water Act gives states the ability to review any proposed activity that requires a federal license or permit and that may involve discharges into federally regulated "waters of the United States" to ensure compliance with appropriate state water quality requirements.

States review impacts from proposed section 402 Clean Water Act discharge permits in states where EPA administers the permitting program and section 404 permits issued by the Army Corps of Engineers, as well as Rivers and Harbors Act sections 9 and 10 permits issued by the Army Corps and hydropower and pipeline licenses issued by the Federal Energy Regulatory Commission.

EPA says the new proposed rule would replace and update existing regulations to be more consistent with the Clean Water Act's statutory text and clarify elements of section 401 certification practice that has evolved since the regulation was first issued 50 years ago.

The Trump limits on state and tribal authority have been contested in the courts since they took effect on September 11, 2020, leaving regulated projects to proceed in the face of a repeatedly shifting regulatory landscape.

A US district court issued an order with nationwide effect vacating the Trump limits in 2021. The US Supreme Court stayed that order on April 6, 2022. EPA and the US Army Corps then laid out a policy giving states greater latitude, extending deadlines as much as possible and easing federal review of state rationales for rejecting certification.

Some states have used the water certification rules to oppose fossil-fuel projects, such as interstate gas pipelines in New York, New Jersey and Massachusetts and a coal export terminal in Washington. The Trump administration accused a number of states of obstructing development for reasons that go beyond impacts to water quality; namely, increased impacts on climate change.

The Trump administration objected to use of the certification process to delay or stop development. It moved in 2020 to prohibit states from blocking a permit for a project for any reason other than direct impacts to state waters.

Trump also limited the amount of time states and tribes can take to review a project and act on a request for water quality certification to one year. After one year, they will be considered to have waived the right to object.

The 2020 Trump approach remains in effect today as a proposed replacement winds through the regulatory process.

The Biden EPA identified concerns with the Trump approach that relate to cooperative federalism principles and the Clean Water Act's goal of ensuring that states, territories and tribes are empowered to protect their waters.

The new Biden policy is to require project developers to request a pre-filing meeting with state regulators to try to avoid potential issues. Once an / *continued page 46*

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application is filed, the states would have 30 days to work with the relevant federal permitting authority for the project to set a specific review period for the project, which can run up to a maximum one year. The period defaults to 60 days if no agreement is reached.

The new Biden policy would also restore the states' ability to evaluate an activity as a whole rather than limiting the review to a project's specific discharges.

In other words, EPA is proposing to "reaffirm the broader and more environmentally protective 'activity as a whole' scope of review that the Supreme Court affirmed in" a 1994 decision. In PUD No. 1 of Jefferson Cty. V. Washington DOE, a seven-member majority concluded that Clean Water Act section "401(d) is most reasonably read as authorizing additional conditions and limitations on the activity as a whole once the threshold condition, the existence of a discharge, is satisfied."

This significant change would allow states to object to any "activity" related to a project that affects water quality and not solely to direct pollution discharges.

Under the new approach, states would also have greater flexibility, including granting a certification subject to certain conditions.

Specifically, a state would have four options: it could grant a certificate, grant it with conditions, deny a certificate or expressly waive certification.

This flexibility would effectively limit federal override of state decisions on water quality to instances where there is a deficiency with the decision that is not fixed in time. It would limit the ability of federal regulators to hold a state certification "waived" if the state's action is deficient. The final action by state regulators must clearly state which of the four options was selected.

The proposed rule would also clarify when water quality certifications could be modified, the process for involving neighboring jurisdictions, and enforcement and inspection considerations. It also spells out mandatory pre-consultation meetings and a more standardized application and approval process.

The Biden proposals were published in the Federal Register on June 9, 2022. A virtual public hearing is set for July 18. The public comment period runs through August 8.

NEPA

The Biden administration, through its Council on Environmental Quality, is in the process of amending in two stages federal regulations for implementing the National Environmental Policy Act, or NEPA.

The first stage is complete. The headline is that federal agencies will again consider the climate change impacts from proposed new infrastructure projects and other activities that require federal action. NEPA review is required for projects on federal land or that require

The New York legislature voted in June to slow the spread of cryptocurrency mining operations that use electricity made from fossil fuels.

The US government will weigh climate change impacts from proposed new projects on federal land or that require federal permits.

federal action, like a hydroelectric license or permit.

NEPA requires federal agencies to conduct detailed environmental assessments of any major federal action that could significantly affect the environment, such as by increasing air or water pollution or threatening endangered species or their habitats. Federal actions include such things as federal agency approvals of non-federal actions (such as issuing permits), federal agency funding of projects and the development of federal agency regulations.

The second phase of the NEPA review is expected to lead to more comprehensive regulatory reforms later this year.

The Trump administration updated the NEPA regulations for the first time in more than 40 years when it acted in 2020 to facilitate "more efficient, effective, timely NEPA reviews."

Developers generally supported the 2020 update as a means of streamlining a lengthy and sometimes overly cumbersome NEPA process that often leads to significant project delay and increased costs.

Environmentalists opposed the changes as an attempt to weaken environmental protections, especially by prohibiting the use of the NEPA process to account for project impacts on climate change.

The first-phase updates to the NEPA regulations took effect on May 20, 2022.

They remove key 2020 limitations. Federal agencies have discretion again to consider a range of reasonable alternatives to address environmental concerns that may not be entirely consistent with the goals of the project developer. Thus, federal agencies may again consider alternatives that could minimize environmental and public health costs even if they extend beyond the scope of the agency's regulatory authority.

Federal agencies have been directed to consider the historic categories of "reasonably foreseeable" direct, indirect and cumulative effects when deciding whether to approve new projects.

Trump had wanted to require a "reasonably close causal relationship" between a proposed project and an environmental effect before the government could tag the project with the effect. The Trump regulations required federal agencies to consider only direct effects, despite giving agencies discretion to consider indirect effects. However, agencies were prohibited from considering cumulative effects during a NEPA review.

The latest changes direct federal agencies to evaluate all relevant environmental effects resulting from the agency decision. This includes consideration of climate change impacts in cases where a proposed new project will have a significant cumulative effect on climate change when considered alongside other projects.

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NEPA regulations are expected later this year and will change the NEPA rules on a more granular level. There is tension within the Biden administration over how to shape further changes. Any tightening of NEPA processes could conflict with the Biden goals to build out US infrastructure and advance renewable energy. ◎

— *contributed by Andrew Skroback in New York*

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