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PROJECT FINANCE

NewsWire

March 2023

Stimulus with Bottlenecks

The Inflation Reduction Act is stimulating demand at the same time that developers are running into multiple bottlenecks. Some of the bottlenecks are consequences of the war in Ukraine. Others are long-standing problems like grid congestion or issues that started with COVID and have not gone away.

Five veteran market observers talked at the Infocast projects & money conference in New Orleans in late January about how the market has changed in the past year and what opportunities they see in the Inflation Reduction Act.

The panelists are Gabriel Alonso, CEO of 547 Energy and former CEO of EDP Renewables North America, Laura Beane, president of Vestas North America and former CEO of Avangrid Renewables, Tom Buttgenbach, CEO of Avantus, formerly known as 8minute Solar, Justin DeAngelis, co-head of sustainable infrastructure investments for Denham Capital, and Himanshu Saxena, CEO of Lotus Infrastructure Partners, formerly known as Starwood Energy Group. The moderator is Keith Martin with Norton Rose Fulbright in Washington.

What Has Changed

MR. MARTIN: Gabriel Alonso, apart from the Inflation Reduction Act, what has changed since this same conference last year?

MR. ALONSO: There is more supply-chain and trade uncertainty than a year ago. Interest rates have also increased over the last 12 months. Natural gas prices increased significantly. Gas prices have collapsed lately, but high gas prices were a basic reality for most of 2022.

The interconnection queue process has worsened over the last 12 / continued page 2

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LMI BONUS TAX CREDITS will be hard to claim on 2023 projects the way the Internal Revenue Service plans to implement the program.

The Inflation Reduction Act authorized an additional 10% or 20% "bonus" investment tax credit to be claimed on small solar and wind projects that are less than 5 MWac in size.

This bonus credit is expected to be claimed mainly on community solar and rooftop solar installations. It can be claimed on batteries that are part of such projects.

It can only be claimed on up to 1,800 megawatts of projects a year. Project owners must apply to the IRS for an allocation. Congress gave the IRS 180 days to issue guidance explaining how the / continued page 3

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months, which is making it more difficult to bring projects across the finish line.

Projects cost more today to build. Electricity prices under wholesale power contracts have changed over the last 12 months.

MR. MARTIN: That is quite a list. I hope the Inflation Reduction Act offsets it.

MR. DEANGELIS: Add to that list a war in Ukraine and rising global tensions.

What hasn't changed is continuing strong investor appetite for sustainable infrastructure. That is a global phenomenon. The Inflation Reduction Act is drawing capital into the US. Even with the macroeconomic headwinds, this is still a fundamentally good market. We might not have said that 10 or 15 years ago when solar and wind were relatively expensive, but today, they compete with other sources of power on economic terms and not just for their environmental benefits.

MR. BUTTGENBACH: We saw last year a material change that is shifting attitudes in the market. There was a heat wave in California, but the lights did not go out. Four gigawatts of energy storage supported the grid in California. Without those four gigawatts, we would have had blackouts.

People have come to the realization that technology — energy storage in this case — is playing a fundamental role in grid stability. Renewables and energy storage are no longer merely a nice to have, a good thing for the environment, but they also play a fundamental role in supplying energy and grid stability.

MR. MARTIN: You made the point at a conference last June that energy storage in its current iteration is like a Model T Ford. You said you don't want to be locked into contracts requiring you to maintain the existing technology for 20 years. That is the other side of technology: it keeps evolving.

Himanshu Saxena, what has changed?

MR. SAXENA: Justin mentioned the war. I think we need to talk about how it has affected the energy transition. We can talk about ESG and reducing carbon emissions all day, but affordability and security of energy supply are growing concerns.

Before the war, there was not a lot of discussion about the risks that countries take when they rely on a single country for their energy supply. We see the equivalent in our own market where everybody was pushing to go 100% green 100% of the time. That conversation has shifted quite materially over the course of last year.

People are starting to be more realistic about how long it will take to go through the energy transition. We saw Germany build a regasification terminal in six months. Germany is signing 20-year contracts to buy LNG. The discussion about going off gas has slowed significantly.

The question we have to ask ourselves as investors is whether this is a near-term phenomenon or a change that will affect the next 20 years. We invest in gas, we invest in renewables, we have battery storage, we have RNG, we have R&D, we have transmission, we have hydrogen, we have ammonia. We have a little bit of everything.

We are seeing a lot more new opportunities in natural gas, sometimes paired with carbon capture and sequestration, than we ever did before. It has become clear that the US is now the energy superpower and the provider of the last resort for the world.

MR. MARTIN: Is the energy transition accelerating or will it take longer than expected?

MR. SAXENA: It is not going to happen as fast as people think. It takes 10 years to build a new transmission line. Coal and gas currently supply about 80% of our electricity. How do you move from 80% to 0% in the next 10 years?

MR. MARTIN: Laura Beane, what has changed?

MS. BEANE: All three of the major wind turbine manufacturers are reporting financial losses. GE just reported earnings before interest and taxes of minus 13%. Siemens Gamesa just announced a special provision that took its EBIT to more than minus 30%. Vestas is saying it will be in the 0% to minus 5% range. This is a fundamental shift that should be cause for concern.

MR. MARTIN: How is it possible with increasing demand for the things you make that the manufacturers are losing money?

MS. BEANE: It is counterintuitive. A lot of things led us to this point. The supply-chain crisis was the final push. We saw shipping costs skyrocket. All of us had firm commitments that we had to honor, and the costs were so much higher than what we had baked in. There is also an element of blame that belongs on the manufacturers. We all participated in a race to the bottom. We kept on delivering larger and larger turbines at lower prices. It reached an unsustainable point, both for the developers and then now clearly for us.

Supply Chains

MR. MARTIN: Gabriel Alonso, one item on your list is continuing supply-chain difficulties. The *Wall Street Journal* reported this week that it now takes 70 weeks to get high-voltage equipment, up from 30 weeks before. Do you see any relief ahead?

MR. ALONSO: We are starting to see some positive signals, but not yet a major improvement.

MR. MARTIN: What is causing the supply-chain problems? Is it labor shortages or something else? The ports have cleared on the West Coast.

MS. BEANE: Vessel availability and delays have been the largest contributing factors for us. We are starting to see an improvement. Part of that is due to lessons learned. We are fortunate to be a very large customer for the shipping companies. We have been able to leverage our global supply chain and our buying power to get more favorable contract terms.

MR. MARTIN: So not labor shortages, but lack of ships.

MR. DEANGELIS: I have a question for Gabriel and Laura. Has the market adjusted so that delays are now baked into project schedules or are projects coming in behind schedule due to unforeseen delays?

MS. BEANE: Total lead times have increased. The projects are not necessarily late because people are assuming longer construction schedules. There has been a general recalibration.

MR. MARTIN: Tom Buttgenbach, you order a lot of solar panels. How long does it take to get them today?

MR. BUTTGENBACH: Thirty days on the ocean.

It feels like it was long ago, but the threat of anti-circumvention duties just last year caused massive supply-chain disruptions and delayed projects. We started construction on some, but it was a nightmare contracting around logistics issues and dealing with cost overruns.

What we saw in the last year was a massive, massive disruption. Himanshu, you mentioned the topic. I think it will lead to an acceleration of the energy transition. The entire global economy has been disrupted and the energy markets have fundamentally changed in the last year. This is a huge opportunity. There is crazy stuff like increasing demand for LNG. Does that make sense long term? No. Does it make sense that Germany is restarting its coal plants? No. None of that makes any sense, but that is what happens when you have a massive disruption.

I would not want to have a 20-year LNG contract. That is a really bad idea. People are doing it because they are feeling the pinch to deal with energy shortages on a global scale. For the first time in a long time, the world has realized that energy is highly volatile.

Once my solar plant is built, I can guarantee you the price for 30 years. / continued page 4

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1,800 megawatts will be allocated.

The guidance, released in February, said the agency will not start accepting applications until the third quarter this year and then only for some types of projects. The applications window will remain open for 60 days. The US Department of Energy will then review the applications and make recommendations to the IRS.

Projects that are already in service for tax purposes when the allocations are made — as opposed to when the applications are filed — will not qualify for an allocation.

Developers have four years after receiving an allocation to complete a project. Developers counting on the bonus tax credit will have to view 2023 as a lost year and use any 2023 allocations for projects they install during the period late 2023 through late 2027. The IRS is trying to direct tax credits to projects that would not be built without them.

The IRS guidance is in Notice 2023-17. The IRS said it is "interim" guidance and more guidance will follow. The LMI bonus credits are in section 48(e) of the US tax code.

In particular, the Department of Energy is expected to announce additional criteria that projects must satisfy in order to qualify that go beyond the criteria in the Inflation Reduction Act. The IRS said the government may give priority to projects that are owned or developed by "community-based organizations and mission-driven entities" or new market participants and that provide substantial benefits to low-income communities and marginalized individuals, but with an eye on commercial readiness of the projects.

Projects must receive an allocation for the full DC capacity — rather than the net or AC capacity — to avoid a haircut in the bonus tax credit. For example, if a project has a nameplate capacity of 5.5 megawatts, but the net capacity is only 4.8 megawatts and it is allocated only 4.8 megawatts of tax credits, then it will only be able to claim 87% of the / continued page 5

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MR. MARTIN: You have a free fuel.

MR. BUTTGENBACH: It is a little rougher road building it, but I can guarantee the price for 30 years. Not a single fossil fuel plant can do that. That is a fundamental change.

MR. ALONSO: One fundamental change over the last 18 months is that we have moved from a global view of the supply chain of the different components to a much more domestic approach. The IRA has many features, but supporting domestic manufacturing is a key one. Europe is planning to follow soon.

Various countries have seen not only the constraints that can come from a global supply when there are disruptions like a war, but also the massive opportunity for local employment and growth. The shift will not be immediate, but supply chains will look very different in a few years.

MR. MARTIN: Laura Beane, if someone orders wind turbines today, how long does it take to get them?

All three major wind turbine manufacturers are reporting losses.

MS. BEANE: For us, it depends on where the components are being sourced because we have factories all across the globe. For a project in North America, the range is anywhere from eight to 15 months.

MR. MARTIN: How long does it take to get batteries today?

MR. BUTTGENBACH: Two to three years.

Grid Congestion

MR. MARTIN: Gabriel Alonso, another change, you said, is you can't connect new projects to the grid. The National Renewable Energy Laboratory reported a year ago that it takes 3.7 years on average to interconnect. There is a formal moratorium in place in PJM on new interconnections. Other RTOs have similar policies informally in place. What is the current wait time? Is it still 3.7 years or has it grown longer?

MR. ALONSO: I think it is longer than 3.7 years. It varies by ISO. If developers today are not planning on a period to go through the interconnection process of at least four or five years, then they are not being realistic. Another challenge is you have no visibility as to how long it will take to get through the entire study process and sign an interconnection agreement after getting into the queue.

MR. MARTIN: There were 8,100 projects lined up to connect to the grid at the end of 2021. The Federal Energy Regulatory Commission and PJM have offered proposals to try to clear the queue. One thought is to let people connect on a first-ready, first-served basis rather than first-in-line, first-served. How important a change is this?

MR. BUTTGENBACH: It should help. This is the same system that California uses. It is a bit more rational.

Another issue is the cost of interconnecting to the grid has increased quite substantially, not only in MISO but also in PJM and CAISO. The cost of deposits is increasing. A developer trying to build a 500-megawatt wind farm is now being asked to post a $40 million development security to secure the interconnection rights. It has become a game that the smaller developers will find hard to play.

MS. BEANE: The proposals are a good start, but we really need more focus on grid modernization and shortening the timelines. Is anyone else tired of talking about this? I have been in this industry since 1995. Transmission bottlenecks have been the root cause of all of the delays and challenges during most of that period, and yet here we are still talking about them.

MR. BUTTGENBACH: I hate to bring up technology again, but there are solutions.

First, you can't shut down a gas plant with a 65% capacity factor and replace it with a solar farm with a 25% to 30% capacity factor. That is not going to work, which is where technology comes in. With energy storage, we are well on our way to building solar power plants with 60%, 70% and 80% capacity factors. They are true substitutes, and that makes a huge difference to the customers as well as to the cost, because the interconnection cost per megawatt hour delivered goes down significantly.

Second, there are new technologies available. We did an analysis for the California market. We could add 75 gigawatts of capacity to the California grid for about $12 billion. That's the equivalent of 32 times Diablo Canyon's capacity.

How is that possible? The answer is modern conductors that can carry three times the energy at the same weight. That means you can replace the existing gas capacity using the existing transmission towers. You don't need any environmental impact studies. We can upgrade key existing lines for a third of the cost and in a tenth of the time. It is a simple solution that can be deployed nationwide.

MR. MARTIN: Himanshu Saxena, you started construction recently on a 3,200-megawatt Ten West Link transmission line from Southern California to central Arizona. How long did it take to get to the point where you could start construction? How much of the capacity is contracted? What percentage of the cost will be covered by lenders?

MR. SAXENA: I was in my 20s when we started this. [Laughter] Look, we won that award in 2014, and it is not a complicated project. It is 125-mile line. It doesn't affect anything environmentally sensitive, so it is pretty simple. It is a point-to-point connection of Arizona into California.

We have 8,000 megawatts of interconnection requests today in Arizona for a line with a capacity of 3,200 megawatts, so we are already starting to talk about a second circuit.

The thing that makes me concerned is we talk about all the renewables that need to be put on the grid for the energy transition, but if it takes eight years and $100 million in development-stage spending to develop a transmission line that is only 125 miles, how are we going to rebuild the grid across the whole country? How much time and money is that is going to take?

Seventy percent of our line goes over a BLM right of way. Delays to get a federal permit, to get past COVID and sort out supply-chain issues added to the challenges.

The line will be a regulated asset. The California ISO will have full access to it. At the groundbreaking last week, we had the vice president of the United States, the US energy secretary, the US interior secretary and the governor of Arizona. After the groundbreaking, we talked in the back room with / continued page 6

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bonus tax credit (4.8/5.5). This was in the Inflation Reduction Act.

The IRS said it will divide the 1,800 megawatts for 2023 among four sub-caps.

Four categories of projects qualify potentially for LMI bonus credits.

An extra 10% investment credit can be claimed on projects that are in low-income census tracts that qualify for new market tax credits or are on Indian land.

An extra 20% investment credit can be claimed on projects mounted on top of multi-tenant buildings whose tenants receive housing assistance or where "at least 50 percent of the financial benefits of the electricity produced" goes to households with incomes below 200% of the poverty line or below 80% of the area median gross income.

The IRS split the 1,800 megawatts for 2023 as follows: 700 megawatts to projects in low-income census tracts, 200 megawatts to projects on Indian land, 200 megawatts to projects on multi-tenant buildings and 700 megawatts to projects whose electricity benefits lower-income households.

The IRS said only the facility owner can apply for tax credits. It is unclear what happens if a project is owned by a developer through a special-purpose project company and that project company is contributed or sold to a tax equity partnership before the project is placed in service. Ownership of the project would be considered to change for tax purposes. Presumably the IRS will let the allocation travel with the project.

The IRS said it will start accepting 2023 applications for projects that qualify for a 20% bonus credit in the third quarter this year. The applications window will open later for projects that qualify for a 10% bonus credit, but it did not say when.

If there are more eligible projects in a category than there is volume cap to allocate, the IRS said the Department of Energy may use "a lottery or other / continued page 7

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the energy secretary and she said, "I understand that this is very painful for developers. It shouldn't take eight years." They are all trying to make it better.

Permitting reform is something that has been introduced several times in Congress and has been killed. When you have two states, the federal government, local communities and, in certain cases, Tribes of First Nation, it just becomes really difficult. Permitting took four years longer than it should have, but what can you do? This is the same experience we see across the board in developing transmission.

MR. MARTIN: Audience, if you are interested in this topic, Russell Gold, a *Wall Street Journal* reporter, wrote an excellent book called *Superpower* about the difficulties Michael Skelly had developing transmission. Another excellent book called *California Burning* by *Wall Street Journal* reporter Katherine Blunt explains how we got the utility regulatory regime in California that Tom Buttgenbach mentioned.

Gabriel Alonso, you look about to say something.

MR. ALONSO: We have two fundamental problems here. We have been talking about transmission bottlenecks, as Laura mentioned, for more than a decade. I first joined EDP Renewables 15 years ago, and this was already identified as a fundamental problem.

It takes two to four years to develop and build wind and solar projects, but it takes more than a decade to build the transmission infrastructure required to accommodate them.

Then there are the barriers to enter the interconnection queue. The grid operators are short staffed. They lack the staff to implement new reforms. PJM has already announced that it is six months behind the schedule it presented to FERC.

In Europe, they have approached this in two different ways. In some countries, a project must be fully permitted, and only then can it get into the queue. Examples are Germany and Greece. In other countries like Spain, the developer must post security of €40,000 to €50,000 per megawatt. If you do not build the project within five years, you lose the security.

Equipment Prices

MR. MARTIN: So the key in Europe is not letting people into the queue or pushing them out quickly.

Let me get two other points in here quickly, and then we will move to the Inflation Reduction Act.

Solar panel prices appear to be falling. Roth Capital Partners reported last week that they are about 23¢ a watt on average. It said prices will come down another 10% this month on top of a 10% to 20% drop last month. Is that consistent with what you are seeing?

MR. BUTTGENBACH: No.

MR. MARTIN: Where would you put current panel prices?

MR. BUTTGENBACH: We are looking for panels in the high 30¢ to low 40¢ range.

MR. MARTIN: Does anyone have a different experience?

MR. ALONSO: No. Polysilicon spot prices have gone from $35 to $21 a kilogram, and that will eventually trickle down into wafers, but panels that can clear US Customs are still scarce. The benefit of lower solar panel prices may surface in markets where you don't have this type of restriction, but the benefit is not being felt in the United States.

MR. MARTIN: *Axios,* a digital news source that is read by many policymakers in Washington, reported that new construction of solar projects has essentially ground to a halt because of Customs detentions of panels imports on forced-labor grounds. Customs told *Axios* it has detained 2,600 shipments of goods worth $806 million on forced-labor grounds since October. How significant are Customs detentions at this point?

Solar panels that can clear US Customs are still scarce.

MS. BEANE: We have had several customers tell us recently that they are pivoting resources that would have been allocated to solar to try to expedite wind development.

MR. ALONSO: I don't think Customs detentions are the most important metric. More important are the virtual detentions, meaning the deterrent for solar panel manufacturers to produce for the US market. They are diverting cargoes to other markets. What you need to look into is the number of projects that are not proceeding, or are stalled because they are not receiving panels, not because the panels have been detained, but because they are not even manufactured.

Inflation Reduction Act

MR. MARTIN: Let's move across the panel, short answers, broad question, where are you finding opportunities in the Inflation Reduction Act?

MR. DEANGELIS: The opportunities are in the medium term. The hydrogen tax credit has made green hydrogen more interesting than it was. We had been looking at Europe as the first spot for it, and the US has now leapfrogged Europe.

MR. SAXENA: We are seeing an uplift for many of our projects, from renewable natural gas to sustainable aviation fuel, carbon capture, all types of renewables. Our entire portfolio is benefiting from the IRA.

MR. MARTIN: Except for transmission.

MR. SAXENA: People talk about why transmission was left out of the bill, and it is because while cost matters, it is not the primary explanation for why more transmission is not being built. If a new transmission line makes sense, it makes sense with or without a 30% investment tax credit, at least that is my experience. The problem is you cannot get it permitted.

MS. BEANE: The IRA provides long-term certainty that should create a very robust market for wind. We are anticipating 125 gigawatts of new wind by 2030, which is significant for us. The new section 45X tax credits for manufacturing wind, solar and storage components are also important and helpful for the industry.

MR. BUTTGENBACH: We were closely involved with Congress working on some of these provisions, and we are eager to see how the IRS interprets them. Things like the bonus tax credit for projects in energy communities, more detail around when a coal-fired generating unit is considered to have been retired and the calculations for the domestic content bonus credit will all be important. We are excited about bringing the supply chain to the US, onshoring more jobs and working with suppliers to build factories in the US. */ continued page 8*

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processes" to decide who gets an allocation.

The House Ways and Means Committee staff does not expect the full 1,800 megawatts to be used in any of the first few years. It takes time for the market to learn about a new program.

Community solar advocates have been concerned that rooftop solar companies will use up the full volume cap. Not all residents in low-income census tracts are low income. Splitting the cap among the four categories may help to address that concern.

The IRS will allocate 1,800 megawatts a year through the year greenhouse gas emissions from the US fall at least 75% from 2022 levels. It will allocate them at least through 2032 even if greenhouse gas emissions reach this threshold more rapidly.

A SHOWDOWN over standards that must be met to count hydrogen as clean is pitting hydrogen producers against environmental groups and some renewable energy generators.

At issue is the ability to claim federal tax credits for producing clean hydrogen. The tax credits are in section 45V and 48 of the US tax code.

Environmental groups want the electricity used to make hydrogen to come from new renewable power plants — a concept referred to as "additionality" — in the same geographic area as the hydrogen plant and for hourly matching of the renewable power generation with the hydrogen production.

Hydrogen producers argue that the need for hydrogen plants to operate around the clock to be economic and the intermittent nature of renewable power generation make hourly matching untenable.

The European Union addressed the same issues in February. It will require monthly matching through 2029 and hourly matching starting in 2030, although individual countries are free to move to hourly matching as early as July 2027.

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MR. ALONSO: Solar manufacturing in the US is the area where we are seeing a lot of momentum based on the number of investment opportunities we are being shown. We have been hearing from lots of companies trying to manufacture different components here in the US.

MR. MARTIN: Tax credits for generating renewable electricity could reach as high as 70% of the cost of new projects, but they come with fine print. The fine print is that mechanics and laborers working on the projects not only during construction, but also on alterations and repairs for the next five to 10 years after projects are in operation, must be paid the same wages that are paid on federal construction jobs. How significant an issue is this?

MR. BUTTGENBACH: Most of our projects in the southwest are already under project labor agreements, so the cost delta is minimal.

MR. SAXENA: Monitoring is the bigger issue. The effect on cost is not material.

MR. MARTIN: Some developers say it is not additional costs during construction that are the issue, but rather having to pay such wages for the next 10 years on O&M-type work. Do you agree?

MS. BEANE: I think we really need further guidance to understand how large of an impact this will have.

MR. MARTIN: A bonus tax credit can be claimed for using domestic content if the steel and iron construction materials used in the project are 100% US-made, and the other components are at least 40% US-made initially, increasing to 55% over time. Do you see anybody able to qualify for this in the near term? If yes, on which types of projects?

MS. BEANE: Again, without guidance, it is impossible to give a definitive answer. Wind has strong a US manufacturing footprint relative to some of the other technologies.

MR. MARTIN: Is anyone expecting to qualify currently?

MR. D'ANGELIS: We do not see any qualified projects.

MR. BUTTGENBACH: Waiting for guidance.

US Manufacturing

MR. MARTIN: Many manufacturers are considering moving manufacturing to the United States because the US government is now offering a tax credit for making wind, solar and storage components and, not only that, it will also pay the tax credit value in cash for the first five years. Laura Beane, what percentage of the cost of a typical wind turbine do you expect the tax credits to cover?

MS. BEANE: The benefits are 5¢ a watt on the nacelle, 3¢ a watt on the tower and 2¢ a watt for making blades, so you can do your own math based on the prices that you are seeing for turbines. I see it largely as leveling the playing field with lower-cost imports. We were largely phasing out our US manufacturing footprint. Our larger, newest turbines have not been manufactured in the US simply because it is so much higher cost to manufacture here. These incentives are critical for keeping manufacturing in the United States.

MR. MARTIN: This could be an important source of cash flow for Vestas and other manufacturers to the extent they manufacture in the United States.

MS. BEANE: Definitely helpful, but remember a large upfront capital investment is required, and we need volume certainty to make such commitments. This is particularly relevant in offshore wind. The capital investments are very significant, and the way the industry is going about it, with each state wanting its own factories rather than talking about a regional approach, is very inefficient and will likely slow the growth of the industry.

MR. ALONSO: What about concrete towers for wind turbines? They allow developers to move away from exposure to steel, which is a volatile element. And concrete is manufactured locally, really locally. Moreover, such towers can be made by the wind turbine manufacturer or by the balance-of-plant construction contractor.

Will the IRA disincentivize or incentivize use of concrete towers, especially as people are thinking about using taller and taller towers? We have seen a shift to concrete in other markets like Brazil and parts of Europe.

MS. BEANE: We are definitely seeing concrete usage in Brazil. In North America, it has not penciled economically. In Germany, we are using concrete for the bottom tower sections as a way to allow taller towers. It is something that will continue to evolve as technology improves and costs fall.

Greater Volatility

MR. BUTTGENBACH: Tying all of the topics we have been discussing together, it is not just about cost, it is also about volatility.

We are planning projects today for four, five, six and seven years in the future. In order to get full capacity deliverability status in CAISO, I need to have a PPA. How do I commit to a PPA for a project five years out? I need to predict what I will pay in five years for solar panels. I don't know whether we will be importing panels from southeast Asia or buying domestically-made panels by then. The Auxin petition created volatility. It is good to encourage companies to manufacture in the US. Even if it ends up being a few percent higher in cost, the numbers work. I just need that certainty. I can't take the risk of the deal blowing up because of some new crazy import restriction.

MR. MARTIN: Isn't this a question of who bears the risk? Perhaps you can have a PPA in which you pass through some risks, like changing commodity prices.

MR. ALONSO: Three years ago, if you could sign a PPA at current prices for a project that would start delivering electricity five years in the future. Everybody would consider that PPA an asset. Solar panels or wind turbines will only get cheaper.

MR. MARTIN: Nobody wants to do that today.

MR. ALONSO: Correct. Now it's the opposite. The uncertainty around supply-chain cost and timetables mean that a PPA is no longer an asset. You cannot commit to the future electricity price for the reasons that Tom mentioned.

MR. MARTIN: That may explain why it seems easier than ever before to get a PPA today.

MR. SAXENA: That point is really critical. If we are developing a project five years out, I don't know what price PPA I can sign today. It used to be easier.

You don't have to look that far out in advance to find problems. Look at the offshore wind companies. Many of them are trying to renegotiate PPAs. The two off the Massachusetts coast cannot deliver electricity at the originally agreed price of $48 a megawatt hour escalating over time to $72.

The challenge for developers is how to get long-term price certainty or have PPAs that pass commodity price risk to the customers. Last year, 20 gigawatts of PPAs were signed by corporations. Are corporations willing to take on unlimited cost overrun risk? No. Maybe a little bit of cost increase can be passed through to them, but if there is a new administration in 2024, another trade war and a 25¢ tariff on the solar panels, how would you make that work? And 2024 is just next year.

There is a lot more volatility and uncertainty in the market for developers than I have seen in the last 15 years.

MR. BUTTGENBACH: That's right. For me, the most significant part of the IRA is the 10 years of stability. We have been completely dependent on southeast Asia for solar panels. Bringing manufacturing back to the US will help with supply-chain uncertainty and price stability.

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also addressed how to determine whether the renewable electricity comes from a new power plant and imposed complicated geographic restrictions.

The EU standards will apply to any hydrogen imported for use in EU countries.

The European Union has set a goal of producing 10 million tons a year of clean hydrogen domestically and importing another 10 million tons a year by 2030 to replace fossil fuels in hard-to-decarbonize industries and the transportation sector.

It also aims to reduce greenhouse gas emissions by at least 55% compared to 1990 levels by 2030. Such emissions were down 34% through the end of 2022.

The Inflation Reduction Act authorized tax credits for US hydrogen producers under a sliding scale depending on the carbon intensity of the hydrogen production process. The lifecycle greenhouse gas emissions must be less than four kilograms of carbon dioxide equivalent for each one kilogram of hydrogen produced to qualify for any tax credit, and they must be less than 0.45 kilograms per kilogram of hydrogen to claim the maximum tax credit of $3 per kilogram of hydrogen. The tax credits may be claimed for 10 years on the hydrogen sold or used. (For more details, see "Hydrogen Tax Credits" in the October 2022 *NewsWire*.)

Internal analyses by the US Department of Energy suggest that the electricity used to produce hydrogen made via electrolysis could come from nuclear, landfill gas, solar or wind power plants to claim tax credits at the full rate.

Release of the European standards was delayed by a debate about whether nuclear electricity should count as renewable electricity.

The EU said on February 13 when hydrogen made from sources other than biomass will count as made from renewable electricity. Hydrogen from biomass already qualifies as clean.

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Competing Incentives

MR. MARTIN: The Inflation Reduction Act has had a giant suction effect. It is drawing capital and manufacturing facilities into the US. What happens if Canada and Europe match these subsidies? Canada has already taken steps to do so.

MR. DEANGELIS: I don't think the IRA has as material an impact as implied by that statement. Fund managers with trillions of dollars in investment capital are looking for infrastructure projects around the globe. There is a lot of money that wants to come into the US because of an actual or perceived level of stability. Even though we just talked about instability, it is all relative.

MS. BEANE: The world has changed. There is an energy crisis whose duration is hard to predict that I have not seen before. The energy prices we have seen in Europe over the last 18 months are staggering. The more investment, the better. I would welcome mirror incentives across all the regions.

MR. MARTIN: Will they drive up the price of things like batteries and solar panels because they contribute to greater demand for these items?

MR. ALONSO: I think the disruption will be minimal. Panel manufacturers have the ability to increase manufacturing capacity. There are barriers to enter the wind industry. There could be periods when there is way too much demand for the supply. The reason we are seeing the collapse in polysilicon prices, for example, is because the amount of new polysilicon manufacturing capacity added in the last six to 10 months.

MR. D'ANGELIS: How about minerals? In the near term, there are shortages of key minerals like lithium, but in the medium to long term, the supply grows to meet demand.

We have another arm at Denham Capital that does minerals investments. It is astounding how much underinvestment there has been in exploration for rare-earth minerals that are needed for the energy transition. This is leading to short-term dislocation.

MR. MARTIN: Let's close out the IRA discussion with this. The IRA creates incentives to invest in a long list of new sectors. Tell me which single sector will receive the strongest push as a result of the IRA: hydrogen, standalone storage, biogas, sustainable aviation fuel, carbon capture, critical minerals, EV charging infrastructure or small, modular nuclear reactors? If you had to pick one, which will see the most new investment?

MR. ALONSO: Are you asking for absolute tailwind or incremental tailwind?

MR. MARTIN: They were all already advancing on their own. Incremental.

MR. ALONSO: If it is purely incremental, then green hydrogen.

MR. SAXENA: I think it depends on the guidance, honestly, because if the guidance comes out a certain way, the tailwinds that we are talking about for hydrogen will not exist. The biggest question is how closely in time purchased renewable electricity or renewable energy credits need to be matched with hydrogen production. If it is done on an hourly or daily basis, we are dead. If it is done on an annual basis, we are in play. The whole hydrogen thing is highly, highly dependent on how IRS comes out in the guidance.

If the guidance is favorable, then hydrogen. If not, it is carbon capture in my opinion.

MR. DEANGELIS: I agree.

MR. BUTTGENBACH: I agree, but it is all small stuff in the larger context.

MR. MARTIN: Small stuff compared to solar and storage?

MR. ALONSO: Yes, exactly. That's why on an absolute basis, it is solar, storage and wind.

Transferability

MR. MARTIN: The Inflation Reduction Act allows tax credits to be sold to other companies for cash instead of doing complicated tax equity transactions. Will you be sellers, have you received any offers and, if so, at what discount?

MR. SAXENA: There is a whole system in place for people to trade low-income housing tax credits. Our real estate business does that. Folks are telling us that there is unlimited demand for tax credits. We expect pricing in the 95¢ to 96¢ range per dollar of tax credit. If you sell a 10-year strip, that number is close to 90¢. Folks are setting up investment funds to buy tax credits. They are coming up with various structures. I expect a lot of financial innovation around how to trade tax credits.

MR. MARTIN: The price will probably increase toward the end of the year as companies have a better fix on their tax capacities.

MR. SAXENA: I think the fact that you can carry forward these tax credits 20 years and roll back three years is beneficial because it reduces the risk of tax credits being stranded. If you are a buyer and you don't know whether you will have enough tax capacity in 2024, there is the option of using the tax credits in a later year.

MS. BEANE: In the projects on which we are working currently, nobody is talking about transferability. Everybody is still laser focused on securing tax equity.

MR. BUTTGENBACH: That's because selling credits still leaves the tax depreciation unused.

MR. MARTIN: The depreciation is worth about 14¢ per dollar of capital cost.

MR. BUTTGENBACH: Right. I don't think people are willing to forego that much value, and from what we understand, the tax equity market is unlikely to be interested in depreciation-only transactions in the near term.

MR. SAXENA: If you look at these decisions as made around single projects, I agree. However, on a portfolio basis, the depreciation can be used to shelter gain from project sales and, in that sense, transferability is better than tax equity.

Inflation Effects

MR. MARTIN: Where else is inflation having an effect besides pushing up construction costs?

MR. ALONSO: Talent. Labor costs. Companies have budgets for how much they can afford to pay employees, and that has changed dramatically over the last 12 months.

MR. SAXENA: There is a valuation topic that hasn't quite sunk in yet. If you have a 20-year contracted asset and you built it to a 7.5% return and your cost of debt now, because of inflation and rising interest rates, is close to 7%, where is the margin for equity over debt? We have not had to deal with this yet because a lot of investors are still total-return investors.

If inflation persists, a lot of these bond-like cash flows that have been created from older assets will go down in value. When rates go up, bond values go down. There is a risk of a general resetting of valuations over time if interest rates remain high. That will affect portfolio values across the board for contracted assets with stable cash flows.

MR. BUTTGENBACH: I agree with that, but you have a countervailing effect, which is that the optimistic merchant assumptions that people have been using for post-contracted revenues are much more likely now to be realized. We used to laugh at Ventyx curves. They may end up being true.

MR. MARTIN: People are asking what discount rates are being used in appraisals. They used to be 6% to 6.5% to discount after-tax cash flows to arrive at a fair market value. What is the appropriate discount rate today? / continued page 12

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Member countries have four months to object before the standards take effect.

Under the EU standards, hydrogen will count as made from renewable electricity in four situations.

One is where the hydrogen plant generates its own renewable electricity or is connected directly to a renewable power plant. If the renewable power plant is also connected to the grid, then the hydrogen producer must show by use of a smart meter that it did not use any grid electricity. The renewable electricity must be from a new power plant that started operation no more than 36 months before the hydrogen plant started producing hydrogen.

Alternatively, a hydrogen producer using grid electricity may be able to show that the hydrogen plant is in the same "bidding zone" or equivalent concept in another country where renewable power accounted for more than 90% of the total electricity the previous calendar year. Once a bidding zone passes the 90% threshold, then it will be assumed to remain at this level for at least the next five years. Bidding zones in Europe are generally whole countries. The equivalent concept in the US may be a regional transmission organization or RTO.

The hydrogen producer would also have to show that the hydrogen plant does not run more than a maximum number of hours "in relation to the proportion of renewable electricity in the bidding zone." The proportion of renewable electricity in a zone is calculated by multiplying the total hours in a year by a fraction. The fraction is the share of renewable electricity as a percentage of total electricity load in the bidding zone where the hydrogen plant is located.

Alternatively, a hydrogen producer using grid electricity may be able to show the hydrogen plant is in a bidding zone where the emission intensity of the grid is below 18 grams of carbon dioxide equivalent per megajoule of hydrogen energy. There are 1,055 megajoules in one / continued page 13

Market

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MR. BUTTGENBACH: It depends on whether we are buying or selling.

MR. DEANGELIS: The equity markets don't seem to have directly reset the way the credit markets have. You would think with base rates up 200 basis points, logic and reason would tell you that discount rates for equity valuations should increase as well, but we are not seeing that.

MR. BUTTGENBACH: That's partly because you still have a lot of infrastructure funds for whom the only thing that matters is the hurdle rate.

MR. DEANGELIS: That is a rational economic behavior. It is also the issue. Financial models that used to be over 20 years are now over 40 years to make the numbers work.

MR. BUTTGENBACH: It is how the general partner makes money.

MR. ALONSO: You also have a supply-and-demand issue. There is so much capital trying to enter into a space that is full of bottlenecks. There is more uncertainty to develop and execute on projects, not just in the US, but also in other regions outside the US. We are also not seeing the same level of discipline on the equity front as we saw in the past.

MR. SAXENA: You could also argue the other way around, which is that the equity returns used to be way too high. When real interest rates were zero, why was the discount rate 6% to 6.5% for a solar plant with a 25-year PPA?

MR. DEANGELIS: Equity returns are never too high. Should equity returns be 50 basis points higher for somebody who just took a whole bunch of risks putting the project together? I didn't go to Harvard, but you know my second-grade MBA tells me that is not enough premium.

MR. MARTIN: Himanshu Saxena, you complained at past conferences that the equity has to wait 15 to 20 years just to get its capital back, let alone a return.

MR. SAXENA: I don't complain.

MR. DEANGELIS: That's not true. [Laughter]

MR. SAXENA: A little bit of complaining is good for the soul. If you sign a 20-year PPA, chances are that you will still not have gotten your capital back by the end of the PPA. You are still relying on the post-contract value of the assets to earn a return. That pattern has not changed.

MR. BUTTGENBACH: You are relying too much on debt.

MR. SAXENA: The capital structure has maybe 25% debt, 60% tax equity and 15% true equity. However, the tax equity in a partnership flip structure is a kind of mezzanine debt.

It takes two to four years to develop and build a wind or solar project, but it can take a decade to build the transmission infrastructure needed to accommodate it.

Audience Questions

MR. MARTIN: Let's try to fit in a few audience questions as we wrap up. Himanshu, what guidance are you looking for on hydrogen? You said one thing you are looking for is what is the measuring period for using renewable energy credits and VPPAs to offset dirty grid electricity so that the hydrogen qualifies as clean.

MR. SAXENA: Do you need to be directly connected to the wind or solar project that is the power source to run electrolyzers? That is question number one.

If you are not directly connected to it, can you buy grid electricity and use RECs from, or a VPPA with, the wind farm to offset the emissions from the grid electricity? If so, how closely do hydrogen output and the wind output have to match in time?

What happens if the wind farm is not operating? What if its capacity is only 40%? Do you have to shut your electrolyzers down? Do you have to do it in real time? How do you deal with the unpredictability of wind and solar versus the need for a downstream customer for the hydrogen to have a predictable supply?

The guidance is critical to sorting out these questions. Guidance that says you have to match in real time is not a practical outcome.

MR. MARTIN: Other issues are whether you have to match geographically and whether there an additionality concept. You can find all of these discussed in a paper on the web by searching for "hydrogen tax credits Norton Rose."

Another audience question: tax-exempt and state or local government entities, rural electric cooperatives, Indian tribes and the Tennessee Valley Authority can get direct cash payments in lieu of tax credits on projects they own. Are you seeing structures where people are trying to work such entities into their deals in order to convert the tax credits to 100¢ on the dollar?

MR. DEANGELIS: Working on it.

MR. MARTIN: Any details?

MR. DEANGELIS: Working on it. We have a lot of relationships with tax-exempt investors. We are trying to figure out a way to optimize the capital structure.

MR. MARTIN: This will be our last audience question. How much time should developers assume it will take to work out an investment from a private equity fund. How long does it take to work through the process?

MR. SAXENA: We have all the money for all of you in this room for good projects.

MR. DEANGELIS: I agree with the Himanshu's statement, except our money is better.

MR. MARTIN: Lower return? From whose perspective? [Laughter]

MR. SAXENA: Capital is a commodity at the end of the day. The challenges we talked about make it very important for developers to align themselves with the right partners. There will inevitably be delays and cost overruns. You don't want to be partnered with someone who at the first sign of trouble wonders what he or she is doing in the deal. Developers should focus less on 50 basis points more in yield and more on the track record of the potential partner in developing projects. Does the partner know what it is doing?

MR. DEANGELIS: One thousand percent agree with that. These are not M&A deals. They are long-term partnerships. ◎

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mmBtu. However, three other conditions must be met. A hydrogen producer using this method will also have to show it has power purchase agreements with renewable power generators for the electricity it uses and satisfy geographic and time-of-use limitations described below. Once the carbon intensity goal is satisfied, then it will be assumed to have been met in each of the next five calendar years.

Finally, renewable electricity is assumed to have been used to make hydrogen if the electricity complies with additionality, time-of-use and geographic restrictions.

The electricity must come from a renewable power plant that started operation within 36 months before the hydrogen plant. The power plant must not have received support in the form of operating aid or investment aid. Some types of aid are allowed, but this may create challenges for US hydrogen producers planning to supply hydrogen to the European market.

The hydrogen producer must show that the hydrogen was produced in the same calendar month as the renewable electricity (or that the renewable energy comes from a storage asset "located behind the same network connection point as the electrolyzer" charged — not discharged — during the same month as the hydrogen is produced). Monthly matching will apply through 2029. Starting in 2030, the EU will move to hourly matching. Individual countries are free to move to hourly matching as early as July 2027.

The hourly matching is considered satisfied if the spot price for electricity in the day-ahead market in the bidding zone is no higher than €20 per megawatt hour or less than 36% of the price for an allowance to emit one ton of CO2 equivalent.

The geographic requirement is satisfied if the hydrogen plant and electrolyzer are in the same bidding zone, or the power plant is offshore and interconnected with the bidding zone where the hydro- / continued page 15

Transferability: Selling Tax Credits

by Keith Martin, in Washington

The US Treasury is expected to issue guidance about direct sales of federal tax credits by the second quarter this year.

Sales are moving forward without waiting for the guidance.

Production and investment tax credits on solar and wind projects are trading for the most part at prices of between 90¢ and 92¢ per dollar of tax credit. A significant number of transactions are in the term sheet stage. Some have moved into documentation.

Prices should increase over time as more buyers come into the market, particularly as deadlines approach to file tax returns since companies that are potential buyers should have more insight into their tax liabilities closer to filing deadlines.

It takes time for new markets to develop. For example, it took four years after Congress fixed problems in early 2018 that were preventing a tax equity market from developing in section 45Q tax credits for capturing carbon emissions before the first tax equity transaction closed in early 2023.

Many people expect prices eventually to settle at 95¢ or 96¢, although some brokers expect them to reach as high as 98¢ and others expect a much wider range. Some recent offers in the 80¢ range have been rejected by sponsors.

IRA

The Inflation Reduction Act authorizes owners of new clean energy infrastructure to sell nine types of federal tax credits to other companies for cash. The tax credits must have arisen in 2023 or later to be sold. The rules for such sales can be found in section 6418 of the US tax code.

Many early buyers are existing tax equity investors and utilities that feel they understand the businesses to which the tax credits relate.

The deadline to sell tax credits is at least until year end for the year the seller becomes entitled to a tax credit and probably the due date for filing the tax return for the year. Thus, for example, 2023 tax credits could be sold up until the seller files its 2023 tax return in 2024. The buyer claims the tax credits in its tax year that ends on the same date as the seller's tax year (or that straddles the back end of the seller's tax year for buyers with different tax years). The buyer can carry them forward if not used immediately.

The seller must notify the Internal Revenue Service of the sale by filing an "election" with its tax return.

Sellers do not have to report the sales proceeds as income. The buyer cannot deduct its purchase price. Buyers pay less than 100¢ per dollar of tax credit because they need to profit from the transaction.

Tax Equity v. Sale

It is now standard practice in partnership-flip tax equity deals for the tax equity investor to insist on the right to direct the partnership to sell the tax credits. All tax equity transactions involving production tax credits, and 80% of tax equity financings involving investment tax credits, are structured as partnership flips. (For more details on structures, see "Solar Tax Equity Structures" in the December 2021 *NewsWire* and "Partnership Flips: Structures and Issues" in the February 2021 *NewsWire*.)

Many people wonder why a project developer would incur transaction costs to put a tax equity financing in place and then incur still more such costs to have the tax equity partnership sell the tax credits.

The tax equity investor demanding the right to force a sale sometimes pays the sale costs.

Combining both approaches allows the developer to "step up" the tax basis on which investment tax credits and accelerated depreciation are calculated by selling the project company to the tax equity partnership near the end of construction for the appraised value the project is expected to have when fully built. When the tax credits are later sold, they are calculated on the fair market value rather than the bare cost to construct.

Raising tax equity also allows the developer to get value for the tax depreciation on a project. Most renewable energy projects are depreciated on a front-loaded basis over five years. The tax credits are worth at least 30¢ per dollar of capital cost and could reach as high as 70¢ on some projects. The depreciation is worth another 14¢. (For more details, see "Bonus Tax Credits and the Inflation Reduction Act" in the October 2022 *NewsWire*.)

A tax equity market is not expected to develop in depreciation-only projects. The economics of such transactions are not sizable enough.

Tax credits on a project that is owned by a partnership can only be sold by the partnership. They cannot be allocated to partners who decide individually whether to sell.

Tax equity investors want the ability to direct the partnership to sell because it is a way to syndicate the tax equity by bringing in another investor later. Until now, any tax equity investor planning to share in the investment tax credit on a new renewable energy project had to be a partner in the partnership that owns the project before it is placed in service. This meant tight deadlines for developers to put tax equity in place. The ability to sell tax credits allows more time not only for investors to syndicate their positions, but also for developers who decide to forego tax equity to transact.

A later sale of tax credits by the partnership may also be an answer for how to treat tax credits on later improvements to a project, or allow later phases of a single project to be financed in a single tax equity vehicle, beyond the period the tax equity investor feels it can commit to have enough tax capacity.

Sales are also a way for some tax equity investors who lack current tax capacity to remain active in the market.

The market is still feeling its way on all of the potential uses of the direct-sale option.

Another reason to try to move a project into a tax equity vehicle is tax equity provides upfront funding for projects on which production tax credits will be claimed over 10 years on the electricity output. PTC sales are likely to draw annual or quarterly payments as tax credits are earned. Some banks are exploring lending bridge debt against the future payment streams in cases where there have been forward sales of all 10 years of tax credits. However, early offers from lenders have been at advance rates as low as 50% of the future payment streams.

Complications

Sales of tax credits by tax equity partnerships raise four issues.

If the partnership allocates the tax credits to partners, the tax credits are credited at 100¢ on the dollar against the target yield the investor must reach before its partnership interest flips down to 5%. What should happen when a partnership sells tax credits at a discount to credit value and distributes the discounted cash? Most tax equity investors to date have been willing to credit the full tax credit value as if the credits had been allocated in exchange for control over the terms of the tax credit sale.

The partnership will have to indemnify the tax credit buyer if the tax credits are recaptured or disallowed by the IRS. The parties negotiate a careful risk allocation in the partnership agreement. That risk allocation needs to be preserved so that the partner whose risk led to the loss must contribute capital to cover the indemnity payment.

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gen plant is located, or the power plant is in an interconnected bidding zone where the spot electricity prices for the relevant time period in the day-ahead market are equal to or higher than in the bidding zone where the hydrogen plant is located.

Meanwhile, guidance on the same issues in the United States is being worked on both by the hydrogen office in the US Department of Energy, which asked for comments on the issues last October as part of its clean hydrogen production standard, called CHPS, and by the US Treasury. Treasury officials have not said yet when to expect the guidance. The Treasury has received 204 comment letters to date on the subject.

A letter submitted on February 23 by a number of environmental groups, several renewable energy generators and M-RETS, EnergyTag, Electricity Maps and FlexiDAO — four entities that provide data that can be used for hourly matching — argued that "any regional or national registry who would like to can implement hourly matching tools at scale in less than 12 to 18 months, compared to the no less than 24 months scaling timelines for large-scale electrolyzer deployment."

A separate issue in play at DOE and the US Treasury is whether hydrogen tax credits can be claimed for producing hydrogen where hydrogen is an intermediate chemical step toward production of a different end product, such as ammonia, methanol or e-fuel. In some cases, hydrogen is produced as a discrete step before conversion to a different end product. In others, it is part of a gas stream that is converted directly to methanol. It can be removed from the gas stream and then converted, but this requires a more expensive process leading to the same end result.

Hydrogen producers argue that hydrogen needs to be converted into something else, such as ammonia or methanol, to transport it and, without such

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The developer will want control over any contest with the IRS over disallowed tax credits in cases where it will have to fund the indemnity. To that extent, the developer may not be able to cede all say over the terms of the tax credit sale to the investor.

In partnership flip transactions where the right for the investor to direct a tax credit sale is added after the parties are already far along in negotiations, the deal papers have to be reworked to distribute the sales proceeds 99% to the tax equity investor. In most flip deals, 99% of income, loss and tax credits are allocated to the investor, but cash is distributed largely to the developer.

A partnership selling tax credits reports the sales proceeds as tax-exempt income. This income pushes up the partners' capital accounts and outside bases, two metrics for tracking what each partner put into the partnership and is allowed to take out. The tax-exempt income must be allocated to partners in the same ratio the tax credits would have been allocated: thus, 99% to the tax equity investor. The allocation to the tax equity investor provides room for it to be distributed 99% of the cash sales proceeds but complicates any deal where the parties want to distribute the sales proceeds to the developer.

Nine Tax Credits

Nine types of tax credits can be sold. They are tax credits under the following US tax code sections: 45, 45Y, 48, 48E, 45Q, 45V, 45U, 45Z 45X, 48C and 30C. (Although there are 11 sections listed, there are only nine tax credits as two of them move after 2024 to new tax code sections.)

The nine credits are production tax credits for generating renewable or nuclear electricity, capturing carbon emissions or producing clean hydrogen and clean transportation fuels (like sustainable aviation fuel), tax credits for manufacturing wind, solar and storage components or processing, refining or recycling 50 types of critical minerals, tax credits for building new factories and re-equipping existing assembly lines to make or recycle products for the green economy and reduce greenhouse gas emissions at existing factories by at least 20%, and tax credits for installing electric vehicle and other clean fuel charging stations in low-income and rural areas.

Tax credits can only be sold once. Thus, a buyer cannot resell the tax credits it purchases. The buyer must pay cash.

Tax credits that are carried into a year from another year cannot be sold.

Developers building projects, like offshore wind farms, that have normal construction periods of at least two years, can claim investment tax credits on progress payments made to the construction contractor during construction rather than waiting, as in the normal case, until the project is placed in service to claim the full tax credit. These so-called QPE tax credits — QPE stands for qualified progress expenditures — cannot be sold. The Treasury will have to decide whether the full tax credit can be sold in the in-service year even though it was claimed earlier by the project owner.

The tax credit buyer cannot be related to the seller.

It is related if it has more than 50% overlapping ownership. A partner is related to a partnership if it has more than a 50% profits or capital interest in the partnership. Partnerships are already careful not to sell the electricity to such partners because such a sale will prevent the partnership from claiming net tax losses during the first few years from accelerated depreciation. (For more details on affiliate sale issues, see "Another Utility Tax Equity Structure" in the February 2022 *NewsWire* and "Section 707(b): Related-Party Electricity Sales" in the June 2021 *NewsWire*.)

A seller can transfer all of part of the tax credits. For example,

Most solar and wind tax credits are trading at 90¢ to 92¢ per dollar of tax credit, but prices are expected to increase over time.

the sale can be for a set dollar amount of tax credits. It can be for a percentage of the tax credits. Some tax equity investors want the ability to direct a partnership to sell only the tax credits that would otherwise be allocated to them. Whether that is permitted will have to wait for Treasury guidance.

Congress was concerned about inflated tax bases used to calculate tax credits. The Inflation Reduction Act authorizes the IRS to collect a penalty of 120% of any excessive tax credit claimed where part of the tax credit is later disallowed for any reason, and not just an inflated tax basis. Tax credit sale agreements should require the buyer to indemnify the seller in the event such a penalty is imposed that the IRS collects from the seller to the extent the buyer claims more tax credits than it paid the seller to purchase.

The option to sell tax credits was supposed to democratize tax equity. It is hard for developers below the top tier to raise tax equity.

Smaller sellers will have a hard time selling tax credits because buyers will expect creditworthy indemnities in the event the tax credits are later recaptured or disallowed.

Thus, smaller sellers may end up having to buy insurance to backstop indemnities. Tax insurance policies have generally required payment of a one-time premium of 2% to 3% of the maximum potential payout. The indemnity backstop insurance is too new for brokers to have established what is "market."

Some project developers have business metrics that put a premium on cash. Examples are yield cos. This may make them candidates for tax credit sales.

Open Issues

The market is looking to Treasury for guidance about a number of issues, but in many cases, the tax bar has already formed a view and the lack of guidance should not stop transactions from moving forward.

The market assumes that most individuals, S corporations and closely-held C corporations are not suitable buyers. A closely-held C corporation is a corporation in which five or fewer individuals own more than half the stock. The market assumes that passive-loss and at-risk rules will apply to such buyers making it hard for most of them to use any tax credits they purchase. (For more details on the passive loss restrictions, see "Challenges Facing Individuals as Tax Equity Investors" in the June 2022 *NewsWire*.)

Partnerships with "unblocked" pension funds, foundations, Indian tribes or other tax-exempt or government entities as direct or indirect investors lose the / continued page 18

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conversion, there is no such thing as a hydrogen economy.

MANUFACTURERS angling for some of the $10 billion in tax credits that the Inflation Reduction Act authorizes to encourage construction of new US factories to make products for the green economy must submit concept papers to the US Department of Energy by July 31.

After reading the concept papers, DOE will "encourage" or "discourage" applicants from submitting actual applications.

Of the $10 billion in available tax credits, $4 billion will be allocated in a first round. One or more other rounds to allocate the rest should follow soon after round one. DOE will rank the applications and make recommendations to the Internal Revenue Service. The IRS will make the actual allocations.

Projects must be completed within two years after receiving an allocation.

The IRS issued interim guidance in February about what qualifies for tax credits and how the process will work. The interim guidance is in Notice 2023-18.

More guidance is expected by the end of May, presumably including a timetable for the phase one allocations and for allocating the rest of the tax credits.

The tax credits are available under section 48C of the US tax code. Manufacturers can claim them for doing any of three things.

One is building a new factory or re-equipping an existing factory to make a long list of products for the green economy. Notice 2023-18 has a list of both eligible and ineligible products.

Tax credits can also be claimed for re-equipping an existing factory to reduce greenhouse gas emissions by at least 20%.

They can also be claimed for building a new facility or re-equipping an existing facility to process, refine or recycle any of 50 critical minerals.

The tax credit is 30% / continued page 19

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ability to claim a percentage of the investment tax credit and accelerated depreciation on their projects. The percentage is the high-water mark of the tax-exempt and government ownership. Thus, for example, if such investors start with a 1% interest, but this is expected to flip later to 95%, 95% of the ITC and accelerated depreciation are lost.

However, the Inflation Reduction Act allows such entities that own projects directly to apply to the IRS for cash payments for 100¢ per dollar of tax credit. Companies have been asking whether a partnership between a private developer and such investors qualifies for a cash payment for the share of tax credits that belongs indirectly to the tax-exempt or government entity. The market assumes the answer is no. The partners would have to own the project as "tenants in common," meaning each has an undivided interest in the project, rather than as a partnership, in order for this to work.

The market is waiting for the Treasury to say whether tax credits that company A transfers to company B under another tax code section or IRS regulation can be sold by B. An example is where tax credits are transferred to a tax equity investor by leasing the project to the investor and electing under IRS regulations to let the investor claim the investment tax credit. Another example is where section 45Q tax credits are transferred by the owner of the carbon capture equipment by electing under section 45Q to allow the company that will dispose of the captured carbon emissions to claim the tax credits.

Another significant issue is whether the tax credit buyer must report income equal to its profit when it uses the tax credit to extinguish a tax liability.

For example, must a buyer who pays 90¢ per dollar of tax credit pay 10¢ as taxable income when the tax credit is used. The IRS said in an internal legal memorandum in 2007, and repeated in a private letter ruling in 2009, that buyers of state tax credits must report such a profit. The IRS said state tax credits are "property" and when they are used to pay a tax bill, the taxpayer should be treated as if it converted the tax credit into cash equal to the full amount of the tax credit and used the cash to pay its tax bill. The conversion triggers a taxable gain. (For more details, see "Some Sales of State Tax Credits" in the April 2007 *NewsWire* and "Purchasers of State Tax Credits" in the February 2010 *NewsWire*.)

The Joint Committee on Taxation staff said any such result was not intended in this case. Congress intended that tax credit buyers would not have to report any income. It may make this clear in a "blue book" that is expected this spring. A blue book is a general explanation of the tax legislation that Congress enacted in the previous year.

Finally, the Inflation Reduction Act is unclear about who gets audited and has to pay any audit adjustment where tax credits have been sold.

The market assumes that the IRS will come after the seller for any taxes that have to be paid after a recapture or disallowance of sold tax credits. However, the Treasury must confirm this. It would make sense to pursue the buyer in cases where the buyer claims more than the tax credits it purchased. The Inflation Reduction Act requires the seller to notify the buyer of any disposition of the project that triggers ITC recapture and then for the buyer to notify the seller the amount of tax credits that were recaptured.

Rising Solar Insurance Premiums and Shrinking Coverage

by Tucker Compton, with Sterling Seacrest Pritchard in Savannah, Georgia

Property insurance premiums are up 15% to 45% across the solar industry and are becoming a major concern for developers, investors and construction contractors.

An increase in manufacturing defect claims is also causing underwriters to compile lists of module manufacturers that they will not insure.

Inflation, reinsurance market changes, a decrease in risk capacity and supply chain disruptions are among the top reasons for a hardened insurance market. While those with significant claims histories and in catastrophic areas will be affected most, a hard market means fewer coverage options and higher premiums for everyone.

Premiums

Policy holders should anticipate property premium increases to vary by renewal date — for example, January 2023 renewals saw an average 37% increase in catastrophic reinsurance rates.

General liability rates remain more closely aligned with inflation, seeing a 5% to 10% increase for ground-mounted solar projects and 10% to 15% for roof-mounted installations.

Umbrella premiums have increased by 10% to 15%, a smaller increase than those seen in recent years.

These figures reflect percentage increases compared to a year ago.

Directors and officers and professional liability coverages are softening across most sectors, meaning premiums are staying the same compared to last year. That being said, premiums are seeing a slight rise in solar due to increased mergers and acquisitions activity and the long tail risks associated with power purchase agreements.

The cost to insure against cyber risks is rising in all industries, but premiums are steadying as a result of increased underwriting measures and advances in cyber security.

Coverage Trends

The increased exposure paired with decreased risk capacity of insurance companies means the / continued page 20

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of the cost of the project. The manufacturer must ensure that mechanics and laborers working on the project during construction are paid at least the same wages that are paid on federal construction jobs. Qualified apprentices must also be used for 12.5% or 15% of total labor hours, depending on when construction starts.

Tax credits will not be allocated to any projects in census tracts that were allocated some of the $2.3 billion in similar tax credits that the federal government allocated in 2010 and 2013.

At least $4 billion of the $10 billion in tax credits must go to projects in census tracts (or adjoining tracts) where a coal mine closed after 1999 or a coal-fired generating “unit” was retired after 2009. The government will issue a map showing what areas qualify. Of the phase-one $4 billion, $1.6 billion has been tentatively earmarked for projects in such census tracts.

There is no benefit to rushing an application. All applications will be treated as submitted on the last day of the applications window.

A significant change in facts after an application is submitted will void the allocation for a project that has already received an award. If the government is informed before the allocations, the project will fall out of the phase one queue but can reapply in the next round. A change is significant if it might have affected the ranking that DOE assigns to the project. A change in location to a different census tract is considered significant.

An award cannot be transferred, even to a successor in interest to the original applicant, without IRS permission. Any request to transfer must be made to the IRS at least 30 days before the due date for the successor in interest’s tax return for the tax year the transfer occurs.

This creates a potential obstacle for tax equity financings where the project is moved into a tax equity vehicle. The application would have to be filed in the name of a special-purpose project company / continued page 21

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property limits being offered in catastrophic and high-hazard zones are shrinking. It will be difficult to find a $10 million or higher limit from a single carrier, as most are capping their aggregate limits at $5 million. This requires brokers to work harder to place risks among a pool of insurers.

High-hazard zones are anything with a greater-than-normal risk for flood, earthquake, windstorm, hail or wildfire damage. These zones are expanding as wind and hailstorms repeatedly cause significant and unforeseen damage in Texas, the Midwest and the forested areas of the west that are suffering from prolonged drought. The flood map continues to broaden, and wildfires are affecting areas beyond past footprints. Actuaries have expanded wildfire exposure areas from three to 18 states in recent years.

Deductibles for these high-hazard zones have risen accordingly. They are now set at 5% of the solar array's replacement cost value with a minimum of $50,000, up from a 2% cap and $10,000 minimum.

With limited insurance markets for solar coverage, there is only so much capacity in high-hazard areas. For example, one insurance company does not want to write $100 million in property in Florida. This would open it up to losing a lot of money from a single hurricane that could have a devastating effect on its financials. Insurance companies try to diversify risk in order to mitigate the risk of having a large hit to their loss ratios.

Liability limits are being compressed, with most insurance companies offering a maximum $10 million limit for umbrella coverage. To secure additional coverage, layered policies from multiple insurance carriers may be necessary to meet the developer's desired threshold. Spreading risk across a group of carriers in this manner typically leads to a higher premium because the premium ends up the level required to persuade the last underwriter to join the pool and to increased risk of a coverage gap.

The industry is seeing a growing number of high-hazard exclusions on liability policies, both midterm and at renewal. With the growing wildfire exposures, several insurance carriers are now excluding wildfire coverage on the liability side. A high-hazard exclusion means damages to others resulting from a wildfire caused by you or your solar array would not be covered. This is a significant exposure for developers and construction contractors. Other exclusions prevent coverage for work performed by a sub-contractor. With many prime contractors handling hybrid duties and offering developer-type services, this can mean more risk exposure when subcontracting the actual construction work on a solar array.

State	Average Electricity Price for All Sectors (¢ per kWh)	High Hazards by County
California	19.65	All counties (earthquake and wildfire)
Massachusetts	19.06	Barnstable, Bristol, Dukes, Essex, Nantucket, Norfolk, Plymouth, Suffolk (wind and hail)
Rhode Island	18.44	Bristol, Newport, Washington (wind and hail)
Connecticut	18.32	Fairfield, Middlesex, New Haven, New London (wind and hail)
New Hampshire	17.37	Rockingham (wind and hail)
Vermont	16.34	None
New York	16.11	Kings, Nassau, Queens, Richmond, Suffolk (wind and hail)
New Jersey	14.01	Atlantic, Burlington, Cape May, Cumberland, Monmouth, Ocean (wind and hail)
Maine	13.96	Cumberland, Hancock, Knox, Lincoln, Sagadahoc Waldo, Washington, York (wind and hail)
Michigan	12.93	None
Maryland	11.48	Calvert, Dorchester, Somerset, St. Mary's, Wicomico, Worchester Counties (wind and hail)
Minnesota	11.08	All counties (wind and hail)

D&O and professional liability policy coverage remains largely the same as prior years.

Cyber insurance carriers continue to see social engineering losses. This type of fraud involves hackers manipulating employees into providing confidential information or sending money to them. A common form of this type of attack is a hacker accessing your email, monitoring conversations between you and a third party, and then contacting your company with a request for money while posing as the third party with whom you have an established relationship.

If money is subsequently sent voluntarily by someone within the company without taking steps to verify the request, then coverage issues may arise. The sub-limits for social engineering coverage typically max out at $250,000. Cyber policy coverage forms vary widely across insurance carriers, so understanding what you are purchasing is essential. Securing a policy has become more involved as cyber carriers now require multi-factor authentication, end-point detection and many other firewall functions for placement.

Key Drivers

General inflation is the most obvious reason for the rise in premiums, and we can expect it to continue into the third quarter of 2023.

Inflation means a price increase in both materials and labor, leading to a higher cost to rebuild after a casualty. This effect was not generally unaccounted for in the prior year's underwriting, but is now being considered in the underwriting process.

Reinsurance markets will also be a considerable cost driver as prime insurers renegotiate their treaties with reinsurers this year. Insurance companies often reinsure all or part of their assumed risks with other carriers, called reinsurers, to hedge potentially catastrophic claims payouts that could bankrupt the primary insurer.

The primary insurer's risk is usually shared with a reinsurance carrier in the case of high-limit policies. Reinsurance market rate increases are passed along to the consumer, meaning your rates will rise if theirs do.

Many statisticians have reported this as the toughest reinsurance market since 9/11 or at the very least since the 1992 economy.

Solar developers tend to target states with the highest electricity prices as they offer better profit margins. Ten of the 12 states with the highest average electricity prices (not including Hawaii or Alaska) are considered to be / continued page 22

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that is then moved under a tax equity partnership.

The IRS will not approve a transfer if there has been a significant change in the information provided by the original applicant.

The IRS will publish the names of award recipients and how much they were awarded. Applicants can try to prevent any confidential or proprietary information from being released in response to Freedom of Information Act requests by marking such information in the application.

CHARITABLE CONTRIBUTIONS made in cryptocurrency cannot be deducted without an appraisal to establish how much the cryptocurrency is worth.

It does not matter that the particular cryptocurrency is traded on an exchange so that the parties can look up the value on the date the contribution was made, the IRS said in an internal memorandum.

This follows from an earlier IRS decision to treat cryptocurrency like property. (For more background, see "Cryptocurrency Tax Treatment" in the December 2019 *NewsWire*.)

In-kind contributions of property require an appraisal. Section 170(f)(11) of the US tax code makes exceptions for cash, publicly-traded securities and some other kinds of property where appraisals are not required. However, Congress has not updated the tax code to address cryptocurrencies, and the IRS declined to go beyond what the tax code says are publicly-traded securities.

The IRS analysis is in Chief Counsel Advice 202302012. The IRS made it public in mid-January. ◎

— contributed by Keith Martin in Washington

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in high-hazard areas for at least one hazard.

The latest catastrophic storms across the country offer actuaries new data on weather trends and will mean changes to policy forms as widespread losses extend the boundaries of high-hazard zones.

Recent history shows new areas being affected that have previously been spared catastrophic hazard losses. The middle of the country has been hit particularly hard by wind and hail. From Texas and Louisiana up to North Dakota and Minnesota, a drastic rise in claims will make it more difficult to secure coverage in the future.

Supply-chain and manufacturing delays also have a significant effect on the insurance industry.

Lengthier timelines for replacement part deliveries to jobsites and solar project outages mean larger business income losses. The industry is seeing six-month and longer lead times for parts necessary to complete repairs . Paired with manufacturing defects, claims are multiplying quickly.

With the majority of modules being manufactured overseas, insurance companies struggle to subrogate the losses to recoup money paid out to cover domestic policy claims. Expired and insufficient part warranties and unreliable manufacturer support mean manufacturing defect claims are often falling on the insurance carrier of the construction contractors or developers who bought them.

As manufacturing defect claims grow, underwriters are compiling lists of module manufacturers that they will not insure. We anticipate the selection of solar modules becoming a much larger part of the underwriting process in the near future.

Manufacturing Defect Claims

Weather-related events, such as lightning, that should normally cause damage only to a small section of an array are turning into mass failures. Investigation has determined a large portion of these scenarios were caused by a manufacturing error that prevented the blocking of the electrical surge throughout the rest of the solar system. This error is leading to larger, avoidable losses that insurance carriers are rarely able to recover from the manufacturers for the reasons already mentioned.

Another claims trend is due to property abandoned or exposed to the elements.

When modules are delivered to sites, they may sit unused, often for months at a time, leading to preventable claims. Substantial losses are reported due to packaging deterioration causing damage to modules, damaged packaging revealing module damage during unboxing, and theft from jobsites. Inventory management is an ongoing concern, with many construction contractors and developers purchasing extra panels to reap tax benefits, but not storing them properly once delivered.

An increase in module defect claims is causing insurers to compile lists of manufacturers whose solar panels they will not cover.

The continued rush to get to market is creating tight timelines for construction contractors, leading to careless behavior that leads, in turn, to claims. This is happening in both the construction and manufacturing segments. Poor grounding, recurring defects and defective installation are causing preventable claims that could have been avoided if protocol and processes were maintained.

Risk Mitigants

Despite all the things working against the solar industry in the insurance market right now, there is some good.

Technology is constantly improving, mitigating and minimizing risks and damage to solar arrays from weather-related events. Keeping up with these trends is something underwriters will be looking for when evaluating a risk.

Standardized safety and loss prevention protocols are also vital to this industry. Lighting, fencing, land maintenance, limited roof access and general solar maintenance are all crucial and required for most solar arrays. Insurance carriers also want to see ballasted arrays, which help to prevent roof leaks leading to large liability claims.

Insurance carriers will continue to require comprehensive equipment procurement and construction contracts from solar developers. Solar, much like any construction project, starts with the contractual risk transfer. These contracts should be state specific and transfer as much liability as possible to the equipment vendor or construction contractor. Strong insurance requirements allow the insurance carrier to subrogate against the liable party's insurance when applicable. In the event of a claim, the claims adjuster will always ask first for the power purchase contract and construction contract. Your lawyer, your insurance agent and your insurance carrier should all be involved in the contract creation and review process.

Vetting your sub-contractors is also critical to a successful project. Underwriters prefer established, lasting sub-contractor relationships. Repeat sub-contractor use across projects indicates reliability and stability in the construction industry. With the Inflation Reduction Act creating incentives for significant growth in solar, there will be more contractors entering the space with little to no experience. It is important to partner with experienced sub-contractors and not base the decision solely on cost.

Underwriters are also looking for inventory management policies with spare parts programs. The rising costs of business income losses due to sourcing replacement parts means underwriters want to know that you are proactively sourcing parts domestically that can be delivered quickly.

Maintaining an inventory of spare parts is quickly becoming the most effective mitigation technique used by larger solar developers. Managed inventory allows the efficient repair of damaged arrays and a quick return to operation. While inventory should ideally be stored in a temperature-controlled space, underwriters also understand the need to keep them on-hand locally at job sites. Use of a temporary shipping container can be a useful way to keep inventory out of the elements and secured from theft.

Cost Of Capital: 2023 Outlook

Around 5,000 people registered to listen to the outlook for the cost of capital in the tax equity and debt markets in mid-January this year.

Yields on 10-year and 30-year Treasuries are above 4% for the first time since 2007, up from only 1.9% a year ago. The futures markets show investors expect the federal funds rate to peak at 5.45% in September and then to dip to 5.33% by year end.

Meanwhile, inflation is moderating, but more slowly than the Federal Reserve hoped. The US inflation rate was 6.41% for the 12 months ending January 2023, down from 7.1% in November 2022, according to the latest data.

The Inflation Reduction Act has put major wind in the sails of the renewable energy market. The IRA has powerful incentives, not only to build new renewable energy projects, but also to do a host of other things, like produce clean hydrogen, sustainable aviation fuel and renewable natural gas, install large batteries and capture carbon emissions. Manufacturers of equipment like batteries and solar panels are making plans to move production to the United States. However, the US economy is still suffering from labor shortages.

The two largest tax equity investors and two veteran lenders talked about what to expect in the year ahead. The panelists are Jack Cargas, managing director and head of tax equity origination for Bank of America, Rubiao Song, managing director and head of energy investments for JPMorgan, Ralph Cho, co-head of power and infrastructure finance for the US, UK and EU for Investec, and Elizabeth Waters, managing director for project finance Americas at MUFG. The moderator is Keith Martin with Norton Rose Fulbright in Washington.

Tax Equity

MR. MARTIN: Rubiao Song, what was the tax equity volume in 2022?

MR. SONG: Total new commitments for tax equity in 2022 were about $18 billion, so roughly a 10% decrease from the 2021 level.

MR. MARTIN: The volume was $20 billion in 2021. Was the decrease due to labor shortages and supply-chain difficulties or to something else?

MR. SONG: Supply-chain and tariff issues continue to delay construction of new projects. Scarce */ continued page 24*

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battery supplies are also playing a role.

MR. MARTIN: How did the tax equity volume break down between wind and solar?

MR. SONG: It was about 60% wind and 40% solar. That is a reversal, for the reasons we just talked about, from what we saw in other recent years when the solar market share was increasing.

MR. MARTIN: Jack Cargas, what volume do you expect this year?

MR. CARGAS: We agree with Rubiao's view of about $18 billion for the year. The decrease was due not only to supply-chain and construction delays, but also to some sponsors who were looking forward to the new tax credits that became available in 2023. That may also have contributed to project delays.

We expect 2023 to be something of a swing year. We expect a 12- to 18-month gap between passage of the climate bill and the real impact on the market. There will also be a lot of backlog transactions from last year to work off this year. We expect to see $20 to $21 billion in 2023.

We are bullish in light of the climate bill, but the system is clogged. Calendars are already full. More sponsors are going to be hearing from their lawyers or bankers or third-party service providers that it will be difficult to get to their deals, unfortunately, for three, six or nine months. That will be a phenomenon in 2023.

MR. MARTIN: In the past, it seemed like as much as 85% of your tax capacity for the coming year had already been committed by mid-January. How does it look this year?

MR. CARGAS: At least 50% is already committed for the year.

MR. MARTIN: Rubiao Song, same number?

MR. SONG: We are probably a little below the 50% level. We have a lot of deals under negotiation right now. The 2023 pipeline looks pretty robust.

MR. MARTIN: The message is still the same as every year: Get in early to talk to tax equity investors.

Were there any new structures in 2022? A couple of years ago, the new structure was a mix of ITC and PTC assets, wind and solar, for example.

MR. CARGAS: We have mainly been seeing variations on the existing structures.

We have been seeing more mixing of projects, such as PTC wind with, now, PTC solar and ITC battery projects. During 2022, tax equity investors spent a lot of time converting solar transactions to PTCs. Such conversions are time consuming to sort out risk allocation and tax and accounting considerations. The market was not able to carry out every such conversion that was requested, for numerous reasons.

MR. MARTIN: People patch into this call hoping to learn what to assume tax equity will cost for their projects. What can you say about current pricing and where it is headed?

MR. SONG: Yields moved up during 2022. That reflected the underlying interest-rate movement as well as an imbalance between demand for, and the supply of, tax equity. That trend should continue into 2023. Wind and solar projects on land will have to compete with all of the new sectors, such as carbon capture, offshore wind, renewable natural gas, hydrogen and tax credits for manufacturing wind, solar and storage components.

Tax equity investors are being even more selective than before. Some projects will not be able to attract tax equity. Some sponsors will have to settle on electing ITC even if claiming PTCs looks better on paper in order to attract tax equity. They may also have to settle on doing tax credit transfer deals where tax credits are sold directly to another company for cash.

MR. MARTIN: The word on the street is that there are fewer PTC tax equity dollars. Is that correct?

MR. CARGAS: I would not say

Tax equity was an $18 billion market in 2022, but is expected to rebound to $20 to $21 billion in 2023.

that. We think that there are a number of tax equity investors who prefer PTCs to ITCs because PTCs do not place as large a claim on scarce tax capacity in a single year.

MR. MARTIN: Congress authorized straight sales of renewable energy tax credits starting this year. Rubiao just mentioned that. Will Bank of America be a direct purchaser of tax credits or will it stick solely to traditional tax equity?

MR. CARGAS: We expect to be a purchaser in some cases, and we expect to be a seller in other cases. Bank of America wants to be relevant in this evolving market. As the market as a whole is tax-equity constrained, these transferability trades are going to take center stage. This is probably the most talked-about provision in the climate bill, at least in our shop.

MR. MARTIN: Same answer for JP Morgan? Will you also buy and sell tax credits?

MR. SONG: Yes.

MR. MARTIN: How do you expect the tax-credit-sale market to develop? You heard Jack Cargas say that it will probably be 12 to 18 months before the Inflation Reduction Act is felt fully in the market. Do you think it will take that long for a tax-credit-sale market to develop fully?

MR. SONG: It will take some time. One should not underestimate what it takes to get corporate investors into this space. The education process can be long. It is also in the best interest of the industry to ensure that new investors understand the unique risks and rewards associated with tax credit investing.

MR. MARTIN: Do you have any sense for how broad the interest will be among corporations as tax-credit buyers?

MR. CARGAS: The 12 to 18 months was meant as the digestion period for all of the provisions of the climate bill. We think the transferability market will develop more quickly than that.

There is a lot of activity by banks, including Bank of America, in generating interest from potential tax-credit buyers. We are hearing some interest. It is not as robust as we would like, but we are going to keep working on it. Interest should grow once the Treasury issues implementing guidance.

MR. MARTIN: Tax credits are expected to trade at a discount to full value. Where do you think they are trading as the market opens? Do the discounts vary by type of tax credit?

MR. SONG: There have been price quotes, but you can't talk about the price without context. Using bonds as an analogy, you have to look at the asset backing the bond and the counterparty who is the credit. I believe the discount is going to be large for tax credit transfers because there will be enormous sponsor demand for long-term commitments while the ability of tax-credit buyers to make long-term commitments will be limited.

MR. MARTIN: Does that suggest there will be more appetite among tax-credit buyers for ITCs? Or will they buy PTCs year-by-year without committing to 10 years of them?

MR. SONG: The latter.

MR. MARTIN: I don't think I got an answer to my question about the discount. At what discount do you think tax credits are trading as the market opens?

MR. SONG: It depends on whether it is a current-year credit or it will require a long-term commitment. It depends on the projects themselves, the sponsors' creditworthiness and the demand-and-supply situation for a given year.

MR. MARTIN: Which suggests that the price should increase over time as more buyers come into the market.

MR. SONG: Not necessarily. Some of the new sectors — such as carbon capture, hydrogen and domestic manufacturing — will qualify for direct pay for the first five years and switch to tax credit sales, adding to the supply of tax credits available for sale five years from now.

MR. MARTIN: So no discount numbers. How easy will direct sales be to transact? Will the transactions rely on form documents that people can simply sign on the dotted line?

MR. CARGAS: They should be straightforward. These documents ought to be more easily produced and signed than complicated structured asset financings. A lot depends on whether the legal profession can resist the instinct always to "improve" or tweak the documents.

MR. MARTIN: What we have seen in the past is these markets start with just a couple forms of documents that everybody adopts, and then, over time, as more people come in, you get document proliferation.

How much interest do you foresee in newer kinds of tax credits? I am talking about not just direct purchases of tax credits, but also traditional tax-equity investment. You have section 48C tax credits for building new factories, section 45X credits for manufacturing wind, solar, and battery equipment, section 45V credits for making clean hydrogen, section 45Z credits for making sustainable aviation fuel, and then investment tax credits for standalone storage and renewable natural gas projects. Do you see interest in all of them?

MR. CARGAS: This is the 12- to 18-month period I was talking about earlier. Many of these will take time to understand, structure and deliver.

Banks like ours with their many constituents, both internal and external, who are focused on */ continued page 26*

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low-carbon initiatives will be all over these incentives as they crystalize over the next few years. We are interested in all of the above and in finding out how much value we can add for our clientele by making a market in these incentives.

MR. MARTIN: Tax equity has been about 35% of the capital stack, plus or minus 5%, for solar. It has been about 65%, plus or minus 10%, for wind. Are these percentages likely to change after the Inflation Reduction Act?

MR. SONG: Yes. Tax equity will be a larger percentage of the capital stack, depending on whether a project qualifies for bonus tax credits and whether solar developers choose to claim PTCs rather than ITCs. The ITCs on utility-scale projects could jump from 30% to 50%, depending on the project location and percentage of domestic content. There are not only bonus ITCs, but also bonus PTCs.

MR. MARTIN: So no numbers yet, but the percentage will increase.

MR. SONG: If a solar ITC project moves to PTCs, the 35% could go to 45%. The 35% could also go to 45% if a solar ITC project sticks with ITCs, but qualifies for a 10% bonus credit.

MR. MARTIN: We have time for just a few more tax equity questions. There are two principal bonus credits. One is for using domestic content, and the other is for putting a project in an energy community that is transitioning from oil, gas or coal employment. Are you seeing deals where it is clear the projects qualify so that the bonus credits can be taken into account in pricing?

MR. CARGAS: We are seeing deals that look like they qualify and we are prepared to take the bonus credits into account in pricing. We expect in such cases to receive legal representations from the sponsors that the projects qualify.

MR. MARTIN: I suppose you also have to do enough diligence to feel confident the projects qualify.

Some sponsors may end up selling tax credits, but they have depreciation that is worth about 14¢ per dollar of capital cost that they will be unable to monetize if they just sell tax credits. Do you foresee a tax equity market for just depreciation?

MR. SONG: I do not.

MR. MARTIN: Jack Cargas, same answer?

MR. CARGAS: We do not think it's terribly likely. Depreciation-only deals are too small.

MR. MARTIN: Many solar developers are talking about claiming PTCs on a solar power plant and an ITC on the co-located battery. Are you doing such transactions?

MR. SONG: We are. We are evaluating some of these opportunities. We are hopeful that Treasury will clarify some of the technical matters.

MR. MARTIN: Are you already doing such deals without waiting for Treasury guidance?

MR. SONG: We are already doing them. In some cases, you can make the case that the battery is a standalone project.

MR. MARTIN: In what types of transactions are you requiring tax insurance?

MR. CARGAS: We only require it in certain circumstances, such as to support the conclusion that projects were under construction in time or the tax basis has been properly calculated. However, it will not cause us to invest in a transaction that we would not have done without insurance. We will not close into deals expecting to claim the insurance in the base case. Insurance can be helpful. It is not a huge driver.

MR. MARTIN: On past calls, we have talked about inability to buy casualty insurance on economic terms. Is that still an issue for projects in parts of the country with high risk of hurricanes, tornados and hail, and what happens if the sponsor cannot renew casualty insurance after a deal has already funded?

MR. SONG: Sponsors can get risk insurance, but the premium will be higher. That's one of the key items to address early in discussions with potential investors. How sensitive is project performance to potential increases in insurance premiums?

MR. MARTIN: The answer is that insurance can always be purchased for a price, so you expect it to be purchased.

What other new developments are you seeing as we enter 2023?

MR. CARGAS: The big new development is that the transition to cleaner energy is about to accelerate. The passage of the climate bill is viewed by many observers as the single most positive development in the history of renewable energy finance in the United States. It will provide a strong tailwind for renewables for 10 years at least, and maybe even for another 20 years or more, depending on how quickly the US reduces its greenhouse gas emissions.

Direct sales of tax credits will help with the transition. We expect transferability to help the market expand to better match demand.

MR. MARTIN: Rubiao Song, new developments?

MR. SONG: A significant number of mega projects are expected to come to the market in 2023. They include some very

Calendars are clogged, leading to delays this year in processing and papering tax equity financings.

large onshore wind projects, major new transmission lines, carbon capture projects and large offshore wind farms. Each will require at least $1 billion in tax equity. Many will require several billion dollars of tax equity. This is going to take a lot of creative thinking to make it all happen.

Debt

MR. MARTIN: Let's move to debt. Next, we have Ralph Cho from Investec and Beth Waters from MUFG.

Ralph Cho, what was the volume of North American project finance bank debt in 2022 compared to 2021?

MR. CHO: It was up quite a bit from the year before. Refinitiv, which is my primary source, hasn't released its final year-end volumes, but we can extrapolate, based on its third-quarter numbers. The third-quarter North American project finance bank debt volumes totaled about $72 billion spread over 158 deals. At this run rate, I expect to see 2022 volumes of at least $96 billion over 211 deals. That would be a 43% increase, year over year, which would make it a record year.

That is on a smaller deal count of 211 deals in 2022 versus 224 deals in 2021.

MR. MARTIN: Why, if the tax equity volume was down, did the bank market set a record?

MR. CHO: There were a substantial number of large-scale, monster deals in the market in 2022. There was also a shift in focus to energy security. LNG deals made a comeback. There were a lot of large infrastructure deals. There was an airport deal. There was a really interesting semiconductor deal with Brookfield for Intel. These deals are not in the $500 million range but in the billions: very large deals.

MR. MARTIN: The war in Ukraine was a factor. It increased interest in LNG.

How many active lenders were there in 2022, and how many do you expect in 2023?

MR. CHO: I see around 90 lenders participating in project finance loans these days. Some folks may quote a higher number, but these are the ones I think are real. The number of consistent players in these types of loans was probably down in 2022. It was maybe 30 or 35 versus 45 to 50 the year before. Although bank appetite remains very solid — and I want to emphasize that — we have lost pockets of lender liquidity from, for example, South Korean institutions and grey-market lenders. They are not really lending actively today.

The divergence in pricing from the B-loan market to the A-loan market really didn't help the grey-market institutions that have better-yielding alternatives in other markets. We have also seen a significant number of lenders take a pause because they do not have the same pressure to put the capital out, and they are just waiting for a better deal to come along. The bank market is still relatively aggressive, especially when it comes to pricing and structure.

MR. MARTIN: Beth Waters, do all loans now use SOFR as the benchmark rate?

MS. WATERS: Pretty much. The regulators require everything be SOFR by July 1 this year, but they were telling our bank that we had to move to SOFR by the end of 2022, so all of our new deals are SOFR. Existing loans are still transitioning. They have until July 1 to do so.

MR. MARTIN: What is the current SOFR rate?

MS. WATERS: There used to be multiple SOFR rates, but the regulators have changed it to require really just one SOFR, which is daily SOFR, and right now that is 4.3%.

However, borrowers want term SOFR, because with daily SOFR, you get a rate change every day, and then you don't know what your payment is until the end of the period. So banks have created "term SOFR," with one, three and six-month rates. This morning, one-month SOFR is 4.48%. Three-month SOFR is 4.63%. Six-month is 4.79%.

Then there is a warehousing cost that / continued page 28

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the banks add to that. Every bank has a different calculation. It is a protection for the bank because it does not know what the daily SOFR rate will be over the period. The warehousing cost can range anywhere from 1.5 to eight or nine basis points on top of that. That is evolving as we go.

MR. MARTIN: What does that translate to as a coupon rate, say, for a wind or solar project for the back-levered term debt?

MS. WATERS: When you say the coupon, inclusive of the margin?

MR. MARTIN: Yes.

MS. WATERS: We always keep everything separate. The current margin for a construction loan could be anywhere from 125 to 150 basis points over the daily SOFR base rate. Add that to 4.3%.

Then there is a credit spread adjustment to adjust for the fact that SOFR is a risk-free rate. For term SOFRs, we add 10, 15 and 25 basis points respectively to the one, three and six-month quotes. It may be blended into the rate, so you might not even have that adder quoted. The market is continuing to evolve.

MR. CHO: I agree with Beth on that. The credit spread adjustment of 10 to 25 basis points was added when we were transitioning deals from LIBOR to SOFR because there was a point when LIBOR was a bit higher than SOFR. As we move away from LIBOR completely, the credit spread adjustment should eventually go away by being priced into the margin. Banks have already started doing that on some new deals this year.

MR. MARTIN: Is there a SOFR floor on bank loans?

MS. WATERS: Yes. Zero. We don't go below zero, just like we did not go below zero with LIBOR.

MR. MARTIN: What fees should borrowers expect to have to pay? Break it down for construction versus tax equity bridge versus term loans.

MR. CHO: The first is a structuring fee that the lead bank receives. The structuring fee can range — I am talking really high-level here — anywhere between $250,000 all the way up to $2 million per bank. It may be even higher for a monster deal. The fee depends on the size, complexity and amount of work and due diligence that are expected to be required.

Next, there is an up-front fee that can range between 100 to 200 basis points that varies based on whether the loan is sold into the wholesale market versus the general retail market.

Finally, if the credit facility is fully underwritten, you should expect to pay an additional underwriting fee of anywhere from 25 to 50 basis points. That is essentially an insurance premium that the borrower pays to feel comfortable it will be able to close the loan by a particular time. This is critical in M&A deals.

The total, all-in fees at the end of the day should range somewhere between 225 and 300 basis points. Please note that these are high-level numbers. The actual fees vary by the deal.

If a bank is underwriting a loan for you and writing a large check, you should expect to pay fees on the wider end of the range. If the lender is a retail bank, and an arranger is selling a small participation in a hot deal, expect to be paid fees at the tighter end of the range, or maybe even less.

For tax equity bridge loans, they have a shorter tenor so the fees will be lower.

MR. MARTIN: Does what you just said go for construction debt, as well?

MR. CHO: A lot of the construction debt we have done is debt that starts off as a construction loan and converts into a mini-perm term loan. Those are five- to seven-year deals. They would fall under the general framework I described.

MR. MARTIN: What are current debt-service-coverage ratios for wind, solar, storage and transmission?

MR. CHO: There has not been much change on the sizing methods, but of course every asset is different.

Contracted assets are really straightforward. Debt on wind projects size at 1.3 to 1.35 times debt service on a P50 forecast. Utility-scale solar will size at 1.2 to 1.25 times on a P50 forecast. Community solar is a little wider at 1.3 to 1.5 times on a P50 forecast. Residential solar, which is sized aggressively, sizes at up to 80% of the PV6. Battery storage coverage ratios are tighter, at like 1.2 times. These coverage ratios assume contracted — or hedged — cash flows. Lenders like those.

It is important to mention merchant cash flows. All borrowers want credit for merchant cash flows. I would, too. Merchant cash flow assumptions — whether the merchant revenue is from energy sales, ancillary services or a residual tail — have become more mainstream for commercial banks. Plain vanilla has evolved in the bank market to add a little bit of merchant exposure to contracted cash flows with basically no pricing premium.

This is how aggressive ESG lending has become, as banks have tried to differentiate themselves from other banks. Specifically banks are sizing loans on merchant energy revenue at around 2.0 to 2.5 times debt service coverage ratios. The million-dollar question is what is a comfortable balloon level to target at maturity. That varies by location, age and technology of the asset. It goes without saying that the more aggressive the credit profile, the wider the yield the arranger will have to offer to clear the market.

Holdco-consolidated coverage ratios go as tight as 1.1 times debt service. It would be tougher to get much tighter than that because the borrower has to put some equity into the deal.

Quasi-merchant gas deals are slightly more complicated. We have not seen too many of them, but if I had to size for capacity and revenue, those would probably end up around 1.0 to 1.15 times debt service coverage ratios. Swaps and call options size a little wider at 1.3 times. We like to use flat-line capacity forecasts, especially for markets like PJM and New England. We support that with some kind of cash sweep against a target to remain in balance.

Lastly, I will add something new that we have started lending lately. Late-stage developer loans are the latest rage with borrowers. Such loans are all structured slightly differently, based on the business model of the borrower. They are basically just giant letter-of-credit facilities that are being used to provide developers with more efficient capital to post as security for interconnection queue positions and PPAs. They are not really sized or structured on coverage ratios, but the bank analyzes what other assets and cash flows are available to support these facilities in a worst-case scenario where the LC is drawn.

We see more and more banks interested in these types of loans. By my count, we had about $3 billion of these facilities close last year, which is significant. I think this is going to be a very strong growth area for lenders and a critical source of capital for many renewable developers. It comes with premium pricing, at least until the supply of such debt increases after which we will see pricing come down.

MR. MARTIN: A lot to unpack there. Interesting data. What are current loan tenors for the renewable energy market?

MS. WATERS: They are usually construction plus five or plus seven. Occasionally there is a C+10, but the tenor has a lot to do with cost of funds for banks. That is a big issue today for banks, so tenors are coming in, and we can give better pricing on shorter tenors. The loan size is still a function of the amortization assumptions, even as we start pulling in on tenors.

MR. MARTIN: What are current advance rates on construction debt?

Spreads are widening across every part of the capital spectrum.

MS. WATERS: You have to do the normal debt sizing based on the term loan into which the construction loan will convert. If you do a construction loan without a term conversion on the theory that it is going to go to the capital markets, you would still want to size it for a potential bank takeout. The maximum draw is something like 85%, sometimes 90%.

MR. MARTIN: What is the spread above SOFR for construction debt? We heard on past calls that it had dipped as low as 75 basis points.

MS. WATERS: It is not that low now. Starting last spring, the market was extremely aggressive in pricing and what started happening is that bank costs of funds were going up. Some banks, maybe including MUFG, moved a little earlier to increase the cost of funds than others. Some banks, like MUFG, had a cost of fund increase a little earlier than others. Now I am seeing 125 basis points as the lowest spread on construction financing. We are not doing anything lower than that.

MR. MARTIN: That is a significant increase from even a year ago.

MR. CHO: If we are talking about short-term construction bridge loans, the spreads are definitely wider than a year ago. I would have put the range around 100 to 125 basis points over SOFR. That is almost double the range */ continued page 30*

Cost of Capital

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of 60 to 70 basis points discussed a year ago. These are very short-term loans, like one year or less.

MR. MARTIN: Is the reason why the spread has widened purely that cost of funding has increased?

MS. WATERS: Yes.

There is a lot of appetite from banks, but our cost of funds is affecting our decision-making, and my management is not going to approve a deal that does not give us our hurdle rate. What hurdled a year ago is not hurdling now. We have a revised cost of funds put into our models every week or so. The funding cost is coming back in a little bit, but we don't know where it is headed.

MR. CHO: This is definitely a new trend. We have been in an environment the last many years where spreads have remained extremely tight. Now for the first time in a long time, the spreads are widening across every part of the capital spectrum.

I attribute this to what Beth said. The funding costs are definitely moving up. It is also easier to increase spreads when borrower demand is strong. There has been a ton of deal flow. A backlog is building in the market, and you have a lot of deals that need to clear. We see the same thing in all of the other debt markets, like the B-loan market and the project bond market. Pricing has gone up across the board, and it does not help that we are losing liquidity. The grey-market lenders who had been playing in our A-loan market are gone.

The bank market, even as much as it has moved up, has not moved up as much on a relative basis as the institutional loan market.

MS. WATERS: The smaller the deal, the more aggressive terms you can get because you will be pitching to certain banks whose funding costs are lower. As the deal gets larger, you have to get the last guy in, so it will trend upward on pricing.

MR. MARTIN: Is it still the case that banks are not charging a premium to lend on a back-levered basis compared to lending closer to the project assets?

MS. WATERS: Yes.

MR. MARTIN: How much appetite do you foresee among banks for some of the new asset types in the Inflation Reduction Act, such as hydrogen, sustainable aviation fuel, electric vehicle charging infrastructure, standalone storage, renewable natural gas, CO2 and hydrogen pipelines and transmission lines?

MR. CHO: There is a very strong appetite for all of these types of deals from the lending community. At least at Investec, we have done some creative financing around EV charging infrastructure. We have also closed standalone storage and some renewable natural gas deals.

Some of these other ones that you mentioned could be interesting, like the hydrogen and sustainable aviation fuel assets. We just need to see more deal flow in these areas, and there has to be a structure that is financeable and does not make lenders take equity-like risk. I want to see proven technology and contracted revenues for the first few deals.

MR. MARTIN: Are you seeing any interest in lending bridge debt against future revenue from tax credit sales: for example, for production tax credits?

MS. WATERS: Yes. We are working on structures where we would have to discount a decent amount to make sure that we get repaid. I am working with at least two borrowers.

MR. MARTIN: The key phrase there is "discount a decent amount." Do you think the advance rate would be 50%? 75%? 80%?

MS. WATERS: We have not narrowed in on it yet. We are working on it currently.

MR. MARTIN: Are there any other noteworthy trends for debt as we enter 2023?

MR. CHO: Here are some trends that I think we will see in 2023.

ESG lending will remain hot. The IRA breathed another 10 years of life into this sector with all of the subsidies that are being thrown in. Digital infrastructure is going to continue to print a lot of deal flow: not just data warehouses, but also fiber to the home could pick up, as well. We have seen a lot of that in Europe. Core infrastructure deal flow will remain active, especially ports, roads and bridges.

Energy security will remain a strong theme in 2023. We expect to see $30 billion of LNG credit facilities come to market over the next quarter or two. Investment funds will continue to raise large amounts of capital; however, new or first-time funds may have a tougher time given how crowded this space is becoming. A fear of recession will make personnel more reluctant to change jobs. People may be less tempted to jump to a new fund.

Thermal power activity will remain tough. I expect to see both acquisition and refinancing opportunities, but relative to other mainstream sectors, I think liquidity and structure have to be addressed if you want to sell such deals successfully in the market.

MS. WATERS: I also have mega deals on my list of 2023 trends, not just power, but also basic infrastructure and LNG.

Expect to see capacity issues at project finance banks. The US is feeling labor shortages across all sectors, including on bank lending desks. This limits how many deals banks can do. There will be a tendency in such a market to pick the cleanest and most profitable deals. Supply-chain issues are still lingering. We are going to see a lot more standalone batteries, and more with merchant revenue streams.

Uncertainty around funding costs will remain an issue. What effect will recession fears have on the market? In 2008 when the world was falling apart, project finance loans were going gangbusters, and we are going gangbusters now. We just had a record year. We are expecting that to continue. The pendulum is now swinging toward giving lenders more negotiating leverage; it has not been that way in a long time. ◎

Washington Policy Outlook

Tom West, deputy assistant secretary of the Treasury for tax policy, told the 18th annual renewable energy law conference at the University of Texas in Austin in late January that the Treasury hopes to issue Inflation Reduction Act guidance on at least five topics as early this year as possible.

The five are bonus tax credits for projects located in "energy communities," bonus tax credits for using domestic content, the "transferability" rules for direct sales of tax credits, direct pay (meaning the procedures for tax-exempt and state and local government entities, rural electric cooperatives, Indian tribes and the Tennessee Valley Authority to be paid the cash value of tax credits on projects they own), and proposed regulations on new wage and apprentice requirements.

He said he could not commit that this guidance would be out during the first quarter. Some topics require input from other agencies. In general, he told the audience, the small Treasury tax policy staff feels like it has been pulled into the film "Everything Everywhere All at Once."

Immediately after West, JC Sandberg, chief advocacy officer for the American Clean Power Association, and Greg Wetstone, CEO of the American Council on Renewable Energy, talked about policy issues affecting the clean energy sector that they expect to be in play this year in Washington. The moderator is Keith Martin with Norton Rose Fulbright in Washington.

Inflation Reduction Act

MR. MARTIN: JC Sandberg, what are the two biggest issues on which your members want Inflation Reduction Act guidance quickly?

MR. SANDBERG: Domestic content and energy communities.

On domestic content, our members are making procurement decisions now for the next couple of years. They need greater clarity about how the calculations of US content work. We have expressed our views on how the calculations should work to both the White House and Treasury.

For energy communities, it is more a matter of assessing whether projects that have already been sited qualify. It is hard to change a site once a project is under development. Changing where a project is sited is such a long process with local regulators that no developer will want to undertake.

MR. MARTIN: Are you hearing from / continued page 32

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anybody who can meet the domestic content requirements currently?

MR. SANDBERG: Some wind turbine manufacturers feel they have enough US content currently in the pipeline that it may be possible for wind farms on land to qualify. A key issue is what is the end product since the steel and iron construction materials used to make the end product must be 100% US-made while the other components must be 40% US-made initially, increasing over time to 55%.

The Treasury is short staffed. The Department of Energy is lending Treasury a hand. DOE appears to feel more comfortable making the wind turbine the end product.

If they do define the "facility" as a wind turbine, then there are some turbine manufacturers currently who feel they can meet the domestic content requirement. The domestic supply chain is more built out on the wind side.

It is a little less clear what is likely to be the end product for solar projects. Is it the block? The array? What is the "facility" for solar?

MR. MARTIN: Greg Wetstone, what is the number one issue for your members?

MR. WETSTONE: What JC mentioned are the biggest issues for our members as well.

To pick something else, transferability. Project developers need a good sense of how the various elements of the capital stack will break down in order to determine the price at which they can afford to offer the electricity from their projects. They need to understand how the transferability rules work to sort this out fully.

Another issue is how the apprenticeship requirements work. What is the program going to be to certify new apprentices? What will the waiver look like if you can't find qualified apprentices?

Another area where there are plenty of questions is around the new hydrogen tax credit. That sector could boom or be a bust, depending on how they are answered.

We filed joint comments with the Treasury with the American Clean Power Association and other groups. The Treasury has gotten a ton of feedback. This is not an easy process, but if we are going to realize the immense potential growth for our sector under the IRA, we are going to need clarity on these issues.

MR. MARTIN: I thought it was interesting to hear Tom West say the Treasury hopes to issue proposed regulations soon on the wage and apprentice requirements that are the fine print behind many of the tax credits in the Inflation Reduction Act. The full tax credits cannot be claimed without complying with, or being exempted from, the wage and apprentice requirements.

I assumed the Treasury felt it had bought more time than that to write wage and apprentice regulations when it issued guidance about the requirements in late November.

Were you surprised the Treasury is already getting ready to release regulations to follow up the earlier guidance?

MR. SANDBERG: Yes. Seeing is believing.

We have had many substantive engagements with both the Wage and Hour Division and the Education and Training Administration within the US Department of Labor about prevailing wages and apprentices.

They keep defaulting to the frequently-asked-question part of their website. That makes us nervous. There are some very particular provisions requiring guidance because there are penalties for failure to comply, and it is not clear any law firm would be able to write the type of "will"-level opinions required by the tax equity market based on answers posted to a website to frequently-asked questions.

Treasury guidance on energy communities, domestic content, transferability and direct pay, and proposed regulations on the wage and apprentice requirements, are expected in the second quarter.

MR. MARTIN: Probably right. Answers to questions posted to a website are not binding on the government. The law firms will look for any legal authority elsewhere on which to base an opinion.

Markets generally figure out a way to function, with or without guidance. Sometimes that is not possible. There may be a few areas where there is too much risk and then an insurance market will develop to take that risk. You can put a price on it that way.

Here's another question for you. The Department of Labor has had a process for a long time where one can ask for a wage determination when no prevailing wage is listed for a particular job type or location on the department's website. For example, if you look for a wage for a geothermal rig operator in California, you won't find one. You could file a form. The department was already receiving more than a thousand forms a year before the IRA passed. It can take months to get a determination.

The IRS said in late November, presumably after consulting with the Labor Department, that all you have to do in the future is send an e-mail. One can imagine a flood of requests now that it is easier to submit them. What will that do to response times? Have you heard from anyone who has tried already to get a wage determination?

MR. SANDBERG: Not yet. This is a point of frustration because when we speak with the Department of Labor and organized labor, they tell us that every classification under the sun is done and there is no need to do much more. What our developer members are figuring out is that is in fact not the case, and that introduces risk.

I don't really feel like there is a process yet. We have not broken through to "Well, maybe we might need more classifications." It still seems to be "There is a classification for everything, and all you need to do is pay scale."

To your point, I think there will be a way to avoid penalties by showing you acted in good faith.

Energy Bill?

MR. MARTIN: Greg Wetstone you were on Capitol Hill where you worked on environmental issues, and you continued to work on them for a long time off the Hill. Will there be an energy bill this year? Will it have a permitting core? What else will be in it?

MR. WETSTONE: Good question. There are ambitious plans in the House. The committee chair, Cathy McMorris Rodgers, has introduced a bill. Others have introduced other bills in the House. These bills do what you would expect. For example, they authorize the Keystone pipeline and more oil and gas drilling and attempt to streamline permitting for mining of critical minerals. That formulation is not likely to resonate well with the Democratic Senate, much less get signed by President Biden.

The real question is how this evolves over the course of the year. Are we going to see the Republican majority in the House feel a need to reposition to appeal to independent voters and move a little toward the middle? You could see a compromise emerging that has some things that appeal to the renewable energy community, especially for transmission.

Joe Manchin proposed a package of permitting reforms that failed to get through Congress at the end of last year. It showed how polarized Washington is now. It was a bill that, if you were to remove all the labels in terms of who introduced what, you would say, "That's a Republican bill. Democrats are going to oppose it."

Manchin introduced it on the heels of the IRA. The overwhelming majority of Democrats supported it. The overwhelming majority of Republicans opposed it. Nevertheless, it is a possible road map for how to reach an eventual compromise. I don't expect to see an energy bill early in the current Congress, but you could see movement that way later on.

MR. MARTIN: "Later on" meaning this year?

MR. WETSTONE: Late in the year. Each Congress lasts two years, but you don't want to get too close to an election year when the politics get more complicated. On the other hand, sometimes an election year can force action. We saw that in the Gingrich Congress after he shut down the government. The Gingrich Republicans felt the need to get something done after the public backlash for the shutdown. I think what got done was the Safe Drinking Water Act. At the time, that was a big deal.

MR. MARTIN: JC, what else do you expect to be in an energy bill, if anything, besides permitting?

MR. SANDBERG: I really don't know despite your advance warning that this question would be coming. Frankly for us, it is a matter of keeping focused. Can we play offense on a few things and keep everybody together? Can we also prevent any backtracking? I am not worried about what might happen with the tax credits that the IRA has given us, but could there be efforts to set boundaries around those in some way, for example by restricting sourcing from China? Such proposals don't ever make it over the finish line, but the noise and disruption that would cause in the marketplace is concerning.

For us, I think it a question of whether we can play the transmission pieces right. Also, will the National / *continued page 32*

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Environmental Policy Act reforms that Republicans want to make happen in such a way that is good for offshore wind development. NEPA governs projects on federal lands and in federal waters. For us as an industry, that means offshore wind. All of those projects are in federal waters. Anything that happens to streamline federal permitting is good for developers and good for getting projects in the water.

MR. MARTIN: So it will fall to the trade associations to come up with an agenda of things they want to try to push in any energy bill. Will this be it for actions from this Congress that affect our industry? Just a potential energy bill?

MR. WETSTONE: We are going to see pretty aggressive oversight on implementation issues under the IRA and the bipartisan infrastructure law.

Before that, we will see an effort under the Congressional Review Act to overturn the Department of Labor's rules on ESG finance. The effort to bar pension funds from considering ESG factors when deciding where to invest is a form of direct government intervention in the free market. The idea that long-term investors should not consider the repercussions of climate change is asking them to put their heads in the sand.

MR. MARTIN: The House Republicans have two new catchphrases that they hope will give them traction in the next election: "woke capitalism" and the "climate cartel."

MR. WETSTONE: Being awake is not necessarily a bad thing in this area. Investors who want the ability to consider climate change impacts should be able to do so.

Anti-Circumvention Duties

MR. WETSTONE: There will be an effort to use the Congressional Review Act to overturn the moratorium that the Biden administration imposed on collection of anti-circumvention duties on solar panels imported from Southeast Asia. Both parties have pivoted in the last six or seven years from free trade to protectionism.

There is a global supply chain not just for renewables, but also for the whole economy. No one is saying that all cell phones, medical equipment and other items must be made in the US, and yet suddenly we are facing these questions in the renewables sector.

We are at a really critical pivot point in our climate response. We need to be able to continue to rely on a global supply chain while we build out domestic capacity. We can't walk away from the global supply chain overnight.

MR. MARTIN: Let's talk about the anti-circumvention effort. This is the idea that China-level duties will be collected on solar panels coming from Vietnam, Malaysia, Thailand and Cambodia. Biden said we will not collect those duties for two years. The two years expire on June 5, 2024. Panels have to be in by then and then actually installed by December 3.

JC, last week a bipartisan group of House members said it will try to overturn the moratorium by using something called the Congressional Review Act, which gives an incoming Congress the chance to override regulations that were issued at the tail end of the last Congress by a federal agency. This seems like a Hail Mary pass. It really can't work. It only works where the White House has changed parties. Biden would veto any rollback of the moratorium. His veto would take a two-thirds vote by both houses to override.

MR. SANDBERG: I agree it's a Hail Mary pass, but it creates noise in the market. We have to take that seriously; not to give it too much oxygen, but enough to make sure that in fact we build a firewall.

We spent a lot of last week focusing on what needs to happen to make sure that we have that firewall. If it gets to the president's desk, that is a very long time to have to deal with a noisy problem in the marketplace.

Transmission

MR. MARTIN: So the uncertainty is the killer. Switching gears, when you poll your members, they usually say lack of transmission is the biggest issue. They have been saying that for at least the last eight years.

The Federal Energy Regulatory Commission and PJM made proposals last fall to deal with this. One suggestion was to move from first-come, first served for letting projects in the queue interconnect to the grid to first-ready, first-served. There are something like 8,100 projects sitting in interconnection queues in this country. What are your members telling you about the effectiveness of what FERC and PJM are proposing?

MR. SANDBERG: The first thing they tell us is they need more transmission capacity. That sounds simplistic, but with more capacity, some of these interconnection problems solve themselves.

The second thing on which they focus is the rules around what it takes to get in the queue and the penalties for not being ready to deliver power when projects reach the front of the queue. It is a big problem to have the queues clogged with projects whose developers lack the capital to build them. That is where we are going to focus a lot of effort.

MR. MARTIN: What realistically can FERC do about building more transmission capacity? That seems like a states' rights question that it is Congress's responsibility to tackle. Nothing is going to happen at the administrative level.

House Republicans are starting to move a major energy bill.

MR. SANDBERG: Yes, but I think there are some green shoots in the new bipartisan infrastructure law that the last Congress enacted that could help. Also, the Manchin proposal had some things in it such as backstop siting authority.

I agree with Greg that there will have to be a compromise between the two political parties.

MR. MARTIN: Greg, one challenge FERC has is it has now lost its chairman. Then one of the other members, a Republican, has to step down in June. It will be down to three members. Have you heard any rumors that a Democratic nominee and a Republican nominee will be paired and brought to the Senate this year?

MR. WETSTONE: There is nothing definitive yet. There are various ways this could go. The administration could nominate a new chairman. It could wait. Obviously, pairing a Democrat with a Republican makes a certain amount of sense, but then you have to wait until June to get started.

We have some really important processes pending currently at FERC. If it is possible to find a candidate with whom Democrats are happy and whom the chair of the Senate Energy Committee, Joe Manchin, likes, things could move sooner. That would be helpful. The only way we unleash the full growth potential under the IRA is to enhance the ability to get projects on line.

We need FERC to do something to clear the bloated interconnection queues, potentially use backstop siting authority and encourage better long-term planning, and not merely tackle cost allocation and the other issues piece by piece. Early action is really important. The next FERC nominee cannot be someone who has to recuse himself or herself from the current FERC proposals.

Customs Detentions

MR. MARTIN: JC, US Customs told *Axios,* a digital news source read by many policymakers in Washington, that it seized 2,600 shipments from October to January worth $806 million on forced labor grounds. Are you hearing from your members that those seizures are a problem, particularly for the solar market?

MR. SANDBERG: This is a huge issue. Let me start by saying that the industry opposes forced labor in all of its forms and has taken vigorous steps to ensure that the supply chain is free of forced labor.

What it comes down to is the Customs and Border Patrol process. What is the process to let the good stuff in and, to the extent there is anything bad, keep the bad stuff out?

There was some progress late in the year around non-China sources of polysilicon. I am going to grossly oversimplify this, but there are three main polysilicon suppliers in the world. One is US and one is German, but those two represent about 30% to 40% of the US market. Sixty percent of polysilicon in US solar panels comes from a Chinese entity, Tongwei.

Solar panels that have been cleared for entry so far into the US use non-China sources of polysilicon. The issue is how to speed up entry of panels with no Chinese polysilicon and how to allow Tongwei to prove that forced labor has not been used to produce its polysilicon.

MR. MARTIN: Where does that effort stand?

MR. SANDBERG: Candidly, much better right now on the non-China side. Usually what happens is a small release followed by a larger batch release for similar paperwork essentially. Things are starting to speed up. We would like to see the process get to 45 days or less for clearance. There is going */ continued page 36*

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to be a lag on the China side. We are still waiting on the China side.

MR. MARTIN: Panels that have been subject to detention orders on suspicion of benefit from forced labor are not easy to free from Customs. I have been watching one case where the legal fees have hit $150,000 after just three months of effort.

MR. SANDBERG: At some point, the storage costs alone eat through the margin on the panels. At that point, the vendor will either reexport them or not even put the panels on the water to the US, other than small test cases because the panels cannot sit in a bonded warehouse at a port forever.

SEC Disclosures

MR. MARTIN: We have time for just two more questions. The Securities and Exchange Commission has proposed extensive disclosures that public companies would have to make about how climate change could affect their business models. The proposed disclosures are so extensive that big companies have been adding people who will work full-time year-round to collect the data required.

Are the trade associations engaging with the SEC on any aspect of this and, if so, what?

MR. WETSTONE: Yes. The existing voluntary framework for climate disclosure is uneven. There are inconsistencies. The existing framework does not necessarily reflect the reality of the greenhouse repercussions of corporate actions.

We favor a more consistent approach. We think that will lead to greater investment in our sector. The disclosures should allow companies to take credit for investments in renewable energy that are clearly part of the climate solution. We don't see that yet. We think the SEC has an important role to play, and we support many of the elements in the proposed rule.

MR. MARTIN: JC, are you engaged with the SEC on any aspect of this?

MR. SANDBERG: We are not. We have many publicly-traded members that are, but we as a trade association are not.

MR. MARTIN: My last question is whether there are other issues we haven't discussed that you think will be in play this year in Washington and that affect our industry?

MR. WETSTONE: I am tempted to say yes and leave it at that.

We are hoping to see from FERC a requirement for interregional transfer capacity between RTOs. We need to move in this country toward a macro grid that connects the parts of the country with the best renewable resources to the parts with the greatest electricity demand. Obviously, we don't have that.

We are in Austin today under threat of an ice storm barely two years after Winter Storm Uri. During Uri, people froze to death because the electricity went off. Electricity was available in neighboring states that could have been shifted to Texas, but the Texas grid is not interconnected with the rest of the country. We need better interconnection. I think it can be done in a way that does not subject the Texas grid to federal regulation. Tee that one up as an additional issue.

MR. MARTIN: Okay, JC?

MR. SANDBERG: We talked today about federal siting and permitting. The Department of Energy is thinking about issuing guidelines for developing solar projects on federal lands and adjacent sites. It is a potential issue we are watching because it could affect deployment. ◎

EPA Greenhouse Gas Reduction Fund

by Kenneth Hansen, in Washington

The Inflation Reduction Act establishes a $27 billion "greenhouse gas reduction fund" at the US Environmental Protection Agency.

The fund is to be used to provide grants to one or more non-profit organizations that are in turn to use the grant proceeds to provide downstream loans, grants and other financial assistance to a range of public and private sector recipients to support projects that will reduce greenhouse gas emissions and pollution, particularly in low-income communities.

The $27 billion fund is to be deployed by EPA in three tranches: $7 billion for deploying "zero-emission technologies," such as solar panels, in low-income and disadvantaged communities, $8 billion for projects that reduce greenhouse gas emissions and pollution in low-income and disadvantaged communities but without restriction to zero-emission technologies, and $11.97 billion for "general assistance" for projects that reduce greenhouse gas emissions and pollution but without restriction as to either the technology or the immediately benefitting community.

All three tranches are to be transferred as grants, with a recipient's permitted uses of the grant proceeds varying according to the tranche.

EPA said in mid-February that a "notice of funding opportunity" will be issued "by summer 2023." The applications window is expected to open then for two of the three tranches — the $8 billion and $11.97 billion tranches — which by the statute are available only for private non-profit organizations.

The announcement confirmed that the remaining $7 billion tranche will be available to non-profits as well as to state, local and tribal governments, notwithstanding speculation that it might be restricted to public-sector entities, just as the other two tranches are restricted to private-sector non-profit entities.

Legislation was subsequently introduced in the House that would eliminate the fund. It is unlikely to be passed by the Senate and would, in any event, not survive a veto.

General Assistance

The largest portion, $11.97 billion, provided under the rubric "general assistance," is for grants to "eligible recipients" for the purposes of providing financial and technical assistance both directly to "qualified projects" and to new or existing "public, quasi-public, not-for-profit, or non-profit entities that provide financial assistance to qualified projects at the State, local, territorial, or Tribal level or in the District of Columbia, including community- and low-income-focused lenders and capital providers."

Given the wide range of public and private organizations that might be well positioned to invest in reducing greenhouse gas emissions, it is surprising that "eligible recipients" of grants from this tranche are restricted to 501(c)(3) non-profit organizations. Such organizations must also satisfy four criteria to receive grants. They must: provide capital, including by leveraging private capital, and other forms of financial assistance for the rapid deployment of low- and zero-emission products, technologies, and services; not take deposits; be funded by public or charitable contributions; and invest in or finance projects alone or in conjunction with other investors.

The financial assistance the grants must be used to provide is not defined, but the statute describes it as "grants, loans, or other forms of financial assistance." It appears that such assistance could entail not only grants and loans, but also variations such as recoverable grants, subordinated debt, equity investments and co-financing arrangements, so long as the recipient benefits financially.

A "qualified project" is defined as any project, activity, or technology that "reduces or avoids greenhouse gas emissions and other forms of air pollution in partnership with, and by leveraging investment from, the private sector," or "assists communities in their efforts to reduce or avoid greenhouse gas emissions and other forms of air pollution."

That second prong suggests a broader program scope than just transferring funds. In-kind benefits should qualify.

Technical assistance, workforce development and community planning may all be qualified projects. Interested organizations are pressing for EPA funds to be used to educate communities how to take full advantage of other federal, state, local and private opportunities for grants, loans and tax incentives that encourage deployment of zero-emission technologies.

Disadvantaged Communities

The second-largest tranche, $8 billion, is also available only as grants to "eligible recipients."

The types of "qualified projects" are identical to those for the $11.97 billion in general assistance grants, except that these funds are to be used only for financial and technical assistance in "low-income and disadvantaged communities."

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EPA said in February that these grants are to be allocated consistently with the Biden administration's Justice40 Initiative, "which directs that 40% of the overall benefits of certain Federal investments flow to disadvantaged communities, including those facing disproportionately high and adverse health and environmental impacts." By combining the $11.97 and $8 billion tranches, slightly more than 40% of the total funds will support such communities.

Zero-Emission Technologies

The third tranche, $7 billion for zero-emission technologies, is also designated for low-income and disadvantaged communities, but with two differences from the $8 billion tranche designated for such communities.

One is that this tranche has a wider range of potentially qualified direct recipients from EPA. In addition to section 501(c)(3) non-profit organizations that satisfy the four criteria noted earlier, grants from this tranche can also go to states, municipalities and tribal governments.

The second difference is use of proceeds. This tranche is to support projects that "enable low-income and disadvantaged communities to deploy or benefit from zero-emission technologies, including distributed technologies on residential rooftops, and to carry out other greenhouse gas emission reduction activities, as determined appropriate" by EPA.

This appears to support a narrower group of "qualified projects" than the $11.97 billion and $8 billion tranches, except that EPA has discretion to determine permissible uses of these funds. Thus, the ultimately available scope is not entirely clear.

The remaining $30 million of the total $27 billion is appropriated to EPA to fund administrative costs of funding the program until September 30, 2031, which suggests that EPA will be expected to keep an eye on how grant proceeds are used and the results achieved.

Eligible Recipients

Grants in all three tranches are to be provided on a competitive basis.

All fund appropriations must be obligated by September 30, 2024, roughly a year and a half from now. Grants need not be funded by then, but the amounts need to have been "obligated,, which will require EPA to have made contractual commitments to designated recipients by then, or it will lose access to the funds.

Many of the public comments received by EPA went to the question of how widely grants should be distributed.

The statute provides that EPA can grant funds from any of the three tranches to qualifying private non-profit organizations and that the $11.73 billion and $8 billion tranches can only go to such non-profits. While the $7 billion appropriation can also go to such non-profits, it can also be used to make grants to states, municipalities and tribal governments. While some observers expected the $7 billion tranche to be limited to states, municipalities and tribal governments, there was no sign of that in EPA's February announcement.

The debate has focused on how broadly the $11.97 billion and $8 billion tranches should be shared. While all grants are to be competitively awarded, there is no requirement that there be more than one winner.

The idea of the fund arose in connection with a proposal to establish a national green bank, an idea promoted for more than a decade by the Coalition for Green Capital, a non-profit organization that has encouraged the establishment of regional and local green banks. It has lobbied aggressively to be awarded the full almost $20 billion, which is the full fund excluding the $7 billion tranche and the $30 million administrative budget.

The Inflation Reduction Act appeared to offer an opportunity to achieve that goal, but the technicalities of legislation passed through reconciliation precluded establishing a new federal entity — the hoped-for national green bank — so the work-around was to authorize funding for existing entities — the EPA and private sector recipients to be named later — to carry the mission forward.

EPA is now faced with the question of whether just to play its original part by concentrating all or most of the funding in a single, master entity that would in turn dole out funds to ultimate beneficiaries or to itself make multiple grants to assorted recipients and projects. Whether EPA is prepared to put all, or even a substantial portion, of its eggs in that one basket remains to be seen.

A partial answer was provided in recent EPA guidance, which indicates that EPA "expects to award up to 60 grants" in the competition for the $7 billion mixed public and private sector tranche. As to the roughly $20 billion-for-nonprofits competition, "EPA expects to make between 2 and 15 grants."

While the specific criteria for an "eligible recipient" may have been contoured with a particular target in mind, they also fit

EPA has a new $27 billion fund to support projects that reduce greenhouse gas emissions.

other organizations, such as the existing green banks in California, Connecticut, Colorado, Florida, Maryland, New York and Washington, DC. and community development finance institutions. All these have track records of serving low-income communities. Certain existing environmental organizations with a regional or national scope might also serve. Each of these already has in place on-going programs for investing in clean energy projects, while the Coalition for Green Capital has been a policy and lobbying shop.

EPA may also see some benefit to taking a portfolio approach in supporting multiple organizations.

This is not to argue that all-eggs-in-just-a-couple baskets) is necessarily the wrong approach, particularly given the tight time frame. But there are at least some issues to be confronted in concluding that it is the better way to go.

Grants v. Loans

An interesting aspect of the program is that, though the EPA will make grants, the recipients, whoever they are, are authorized to redeploy those funds in a number of ways by making "loans, grants or other financial assistance."

Federal funding programs are typically approved either as grant programs or as loan or loan guarantee programs. To contemplate both, with the allocation to be determined not by the agency but by the recipient of federal funds is not typical. EPA could make that choice for the recipient as it designs the program's parameters. However, the statute suggests that substantial discretion will be left to the grant recipients.

The recipients are encouraged to establish sustainable operations, as to which they are to "retain, manage, recycle, and monetize all repayments and other revenue received from fees, interest, repaid loans, and all other types of financial assistance provided using grant funds . . . to ensure continued operability."

This suggests that the recipient should not only, or perhaps not even substantially, simply pass grant proceeds downstream as further grants. If the EPA grants are to support sustainable operations, those proceeds will need to generate a revenue stream back to the source. That reflow could be interest on, and principal of, loans. It could also include recoverable grants, success-fee arrangements, and even equity investments in companies whose operations support reduced pollution or greenhouse gas emissions. But downstream grants will not serve.

A further complication arises from the conflict of interests that arises between EPA's direct grantees and their downstream beneficiaries. Offered the choice between a loan or a grant, the downstream beneficiary's choice is, all else equal, easy. All else should probably not be equal.

Borrowers and lenders have a shared interest in loan proceeds being used productively. If they are not, both face a business disappointment. A grant lacks the discipline imposed by an obligation to pay principal and interest. The incentive to use grant proceeds efficiently needs to come from something else. It may be the grantee's independent commitment to achieve an objective supported by the grant. It will likely be reinforced by the terms of the grant agreement.

More fundamental than the challenge of structuring appropriate incentives for EPA's grantees versus downstream beneficiaries is the question of whether the more efficient use of financial assistance is a grant versus a loan. Part of the answer is easy. Where the investment will generate revenue sufficient to repay a loan with interest as well as provide a reasonable return on any accompanying equity investment by the borrower, a loan will encourage the activity with less cost to / continued page 40

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the program and is the obvious way to go. If policy goals require incentivizing such investments that would not otherwise happen, then subsidized debt, with a less-than-commercial interest rate, may suffice.

Grants become the support of choice where policy desires to encourage an activity that will not, or will not without substantial risk, generate revenues for the recipient. The economists would look for circumstances where investments of grant proceeds would generate positive externalities that benefit society or a neighborhood, but that cannot be captured and monetized by the grantee.

That dichotomy may provide good guidance to EPA's grantees for allocating grant proceeds between loans and downstream grants. Loans should go to income-generating projects, but with such risks attached that commercial debt is not available. Financing revenue-generating projects that lack such risks would violate the statute's guidance to "prioritize investment in . . . projects that would otherwise lack access to financing." Grants should go to projects that generate public benefits but not revenue or not enough revenue. In the latter case, a combination of loan and grant might be called for.

Given the natural preference of project developers for grants rather than loans, the sensible program structure might be a presumption of loans, to be complemented by grants if and to the extent that a case can be made of substantial public benefit not reflected in the project's revenues.

Even where grants might make more policy sense than loans, another conflict of interest between EPA's direct recipients and their downstream beneficiaries could stand in the way of grants being available. The grants received from EPA, if deployed as loans, add to the lender's endowment. Grants made erode that endowment.

Rumors have it that the Coalition for Green Capital is already lining up prospective sub-recipients as borrowers rather than as sub-grantees. If the fund is to be an effective source of downstream grants, EPA will need to adopt program terms that assure that, where appropriate, grants will be available. ◎

New Hurdle for Some European Acquisitions and Tenders

by Jay Modrall, in Brussels

New European Union notification and approval requirements will hit public tenders valued over €250 million and acquisitions of EU businesses with more than €500 million in EU revenue beginning on October 12, 2023.

The European Commission will need to determine whether subsidies that the groups involved may have received from non-EU governments will distort competition in the EU internal market.

Current monitoring and reporting systems do not capture the information required to notify, and adapting those systems is likely to require many months of work.

Given the tight timelines for acquisitions and public tenders, parties who have not launched compliance efforts well in advance risk being excluded from EU markets as of October 2023.

Foreign Subsidies

The new notification and approval requirements arise under Regulation 2022/2560 on foreign subsidies distorting the internal market, known as the foreign subsidies regulation or FSR.

Under the FSR, the Commission will acquire new powers to launch ex officio investigations into potentially distortive foreign (meaning non-EU) subsidies starting July 12, 2023. The Commission is likely to open only a few investigations per year and to focus on subsidies to state-owned enterprises.

The notification obligations will have a much wider impact. The notification thresholds are based on a combination of target revenues (in the case of acquisitions) or transaction value (in the case of tenders) and a new concept, "financial contributions."

Financial contributions are defined very broadly and notably include a wide range of interactions with governments and affiliated entities, including investments, contracts and tax benefits, whether or not they involve a subsidy.

Notifications will require extensive information on the parties' group-wide financial contributions over the prior three years — for example, 2020 to 2022 for notifications in the fourth quarter of 2023 — as well as information on the notified transaction.

The Commission will review this information to determine whether any financial contributions qualify as "foreign subsidies" and, if so, whether those subsidies risk distorting the EU internal market.

The notification requirement for mergers, acquisitions and joint ventures will apply only where the target generates at least €500 million in EU revenues and is thus limited to relatively large transactions.

This briefing focuses on the notification requirements for public tenders, which are likely to affect a larger number of parties and transactions involved in project finance.

Public Tenders

Bidders in EU public tenders valued at €250 million or more (including lots of €125 million or more where such a tender is divided into lots) will trigger notification if the bidder's and its main sub-contractors' and suppliers' groups received more than €4 million in financial contributions in any non-EU jurisdiction.

New notices and vetting will be required for acquisitions of European companies starting in October.

If a notification is required, bidders and their main sub-contractors and suppliers will need to provide detailed information on their groups' financial contributions for their prior three financial years.

"Main" suppliers and sub-contractors are defined as those accounting for at least 20% of the tender value, or €50 million in a €250 million tender. When qualifying potential subcontractors and suppliers, bidders will need to assess their FSR-readiness as well as traditional credentials.

Where the thresholds are met, bidders will file an FSR notification to the contracting authority, which will transmit it to the Commission for review.

Since the €4 million financial contribution threshold is very low, all (or almost all) bidders in an in-scope tender will need to file FSR notifications.

The contracting authority may not award the contract to a bidder unless and until the Commission completes its review of the bidder's notification.

The Commission will have 20 working days after receiving a complete notification to conclude its preliminary review, subject to extension for an additional 10 working days.

If the Commission decides to open an in-depth investigation, that investigation must be completed within 110 working days after receipt of the complete notification, subject to an extension for an additional 20 working days.

In the course of its investigation, the Commission has extensive investigative powers, including issuing binding requests for information and conducting site visits and interviews.

The Commission also has powers to impose interim measures and fines: for example, if a notifying party provides materially incorrect information or refuses to cooperate. (Bidders will not be liable for incorrect information provided by subcontractors and suppliers.)

If the Commission finds that a bidder benefits from foreign subsidies distorting the internal market, then it must prohibit the contract award to that bidder, unless the Commission receives binding commitments that fully and effectively remedy the distortion.

Commitments may take a variety of forms, including a bidder granting competitors access to its infrastructure on "fair, reasonable and non-discriminatory" terms, reducing capacity or market presence, divesting assets or repaying the foreign subsidies in question with interest.

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The Commission may approve a tender in spite of a finding that a bidder benefits from distortive foreign subsidies based on a balancing of the negative effects of the distortion compared to its positive effects.

Forms and Compliance

The relevant notification forms will not be finalized until June 2023 at the earliest, but the Commission published draft forms in early February 2023. These forms — especially the procurement forms — raise many questions.

The final versions may be significantly revised, but the drafts confirm that notifications will require significant detail about individual financial contributions that multinationals do not currently collect.

The draft notification forms also require notifying parties to make legal judgments by identifying financial contributions that may meet the FSR criteria for "foreign subsidies" that are likely to be considered distortive.

Collecting three years of financial contribution information will require significant time and effort, but companies in sectors characterized by public tenders, such as energy, health care, infrastructure IT and transport, must make the investment or be excluded from EU markets.

Although no existing monitoring and reporting system currently captures financial contribution information in the form required, companies can leverage existing systems such as financial and tax reporting systems and supplier and customer databases.

Since the Commission has provided no guidance on ambiguous terminology in the FSR, companies will need to be creative and make judgment calls in consultation with experienced EU counsel.

For example, the Commission has extensive experience identifying entities "attributable to" non-EU governments in EU state aid law practice. To review hundreds or thousands of contract counterparties, however, companies will need to leverage existing know-your-client and anti-bribery and corruption compliance systems.

Similarly, to identify relevant "tax exemptions" and "fiscal incentives," as required by the FSR, companies may seek to rely on applicable international and US accounting standards. ◎

Make-Whole Provisions and Bankruptcy

by Mitchell Benson, in Houston

Make-whole provisions may be unenforceable where a bankrupt company is trying to restructure its debts and reemerge from bankruptcy.

A "make-whole provision" is an obligation for a borrower under a loan that is being repaid early to reimburse the lender for the interest payments the lender will lose because the loan will not run for the full term.

The ability to enforce make-whole provisions may depend on where the bankrupt company is located.

A Delaware bankruptcy judge ruled in November 2022 that a make-whole premium owed by Hertz Global could not be enforced because the premium represented unmatured interest, which is statutorily disallowed under the US bankruptcy code.

The *Hertz* decision follows a string of decisions in other jurisdictions disallowing make-whole provisions.

For example, a US appeals court for the fifth circuit held in *In re Ultra Petroleum Corporation* in mid-October 2022 that claims rooted in make-whole provisions can be disallowed. The fifth circuit covers Mississippi, Louisiana, Texas and the Canal Zone. The bankruptcy courts are increasingly hostile toward make-whole provisions, particularly in the context of insolvent debtors.

Significance

Make-whole clauses are pervasive in high-yield financings and project bonds. They require payment by the borrower of a lump-sum premium to the lender upon an early redemption or prepayment of a loan. The premium is typically a sum calculated to provide the net present value of the interest payments that lenders forego because of an early redemption or prepayment.

The sums protected by make-whole clauses are not trivial. In the *Hertz* and *Ultra Petroleum* cases, the make-whole premiums were approximately $223 million and $203 million, respectively.

Arguments over the propriety of make-whole provisions are nothing new. US appeals courts in the second and third circuits have issued conflicting decisions concerning the validity of make-whole provisions in chapter 11 (bankruptcy restructuring) cases, Make-whole provisions in loans may be unenforceable against companies that are trying to restructure their debts in bankruptcy.

but the decisions focused on the specific loan terms and not the US bankruptcy code aspects.

The fifth circuit court is the first US appeals court to assert the invalidity of make-whole provisions in insolvent-debtor bankruptcy proceedings on grounds that the premium is unmatured interest that is not allowed under the US bankruptcy code.

There will be significant consequences if other appeals courts adopt the same reasoning.

It could lead to forum shopping by distressed enterprises. Well-advised insolvent-debtors will choose to file for bankruptcy in jurisdictions that disallow make-whole provisions. Concentrating bankruptcy proceedings in jurisdictions that disallow make-whole provisions will lead to smaller recoveries for high-yield lenders and project bondholders when the debtors they lend to become insolvent. Lenders may price in the probability of a borrower filing for bankruptcy in a jurisdiction that disallows make-whole provisions, raising the cost of credit for high-yield and project bond capital users.

It is important to note that make-whole provisions continue to be enforceable and valuable tools when bonds with call options or similar features are called before maturity. Thus, make-whole provisions are unlikely to see diminished use any time soon. The issue becomes how to protect lenders and fixed-rate investors from potential denial in bankruptcy proceedings.

Two Solutions

Lenders and fixed-rate investors need to begin preparing now for the impact of the disallowance of make-whole provisions.

There are two ways for lenders and fixed-rate investors to protect themselves from make-whole disallowance risk.

Lenders could take make-whole disallowance risk into account in pricing. Lenders might use probability of insolvency to calculate precise interest rate adjustments for each borrower, but a more likely outcome is across-the-board increases in rates for high-yield borrowers.

Alternatively, an insurance-like product might be a more attractive solution if the market can be coaxed into offering it. The borrower would pay a premium upfront to cover the cost of insurance, and the lender would be protected in the event of an insolvent-debtor bankruptcy in a jurisdiction that disallows make-whole provisions.

Insurance offers two distinct advantages to raising rates across the board to compensate for make-whole disallowance risk.

First, an insurer could tailor the cost of its product to the unique risk profile that each debtor presents. This would allow for more competitive pricing of loans. Second, insurance would limit the impact of bankruptcy courts on high yield financing. Lenders and fixed-rate investors would no longer be subject to as much uncertainty with respect to bankruptcy courts and make-whole provisions.

The question is whether the financial markets will provide a product like this. ◎

Environmental Update

The White House Council on Environmental Quality, or CEQ, released interim guidance for how federal agencies should assess climate change effects of federal agency actions in their environmental assessments under the National Environmental Policy Act, or NEPA.

The guidance requires NEPA assessments to include reviews of the direct and indirect greenhouse gas emissions from proposed projects.

The interim guidance took effect when it was published in the *Federal Register* on January 9, but CEQ is still collecting comments through March 10.

Agencies do not have to apply the new guidance to NEPA reviews that have already been completed. They are asked to consider using it in reviews that are still underway.

The guidance does not set a specific threshold for when a project will have a "significant" amount of greenhouse gas emissions that would require a more rigorous review under NEPA because of the potential effect on "the quality of the human environment."

Instead, the guidance requires "quantifying a proposed action's reasonably foreseeable GHG emissions whenever possible, and placing those emissions in appropriate context."

The lack of significance thresholds could rekindle a long-stalled debate at the Federal Energy Regulatory Commission over how to conduct NEPA reviews for natural gas pipelines and other energy infrastructure.

The guidance says that it is not enough for agencies to state that GHGs from a proposed project "represent only a small fraction of global or domestic emissions." CEQ said such a statement "merely notes the nature of the climate change challenge, and is not a useful basis for deciding whether or to what extent to consider climate change effects under NEPA."

Agencies should calculate both direct and indirect GHGs. In the case of pipelines, for instance, that could include consideration of both downstream emissions when the gas is used as a fuel and upstream emissions tied to additional production.

Federal agencies have been told to use a "rule of reason" to conduct their greenhouse gas analyses "commensurate with the quantity of projected GHG emissions." In other words, in-depth analysis is not required for projects that "involve net GHG emission reductions or no net GHG increase." Obviously, this will aid renewable energy projects over those that use fossil fuels.

New York

New York Governor Kathy Hochul signed a bill on the last day of 2022 amending the State Environmental Quality Review Act to require consideration of potential environmental justice impacts from agency actions as part of the normal review process, including permit approvals.

The review process will now consider both long- and short-term effects of any proposed action "on disadvantaged communities, including whether the action may cause or increase a disproportionate or inequitable or both disproportionate and ineq-

The Biden administration is moving to extend federal regulation to more wetlands and streams.

uitable pollution burden on a disadvantaged community."

Like the federal National Environmental Policy Act, SEQRA's basic purpose is to force consideration of environmental factors in government agency planning early enough to inform, but not direct, agency decisions.

SEQRA does not establish a permitting process. Instead, it requires state agencies to make comprehensive assessments of environmental impacts from proposed government actions so that the effects, once identified, can be mitigated.

Going forward, New York agencies will now also be required to consider the cumulative impacts of their actions on disadvantaged communities.

New York is now only the second state, after New Jersey, to require that environmental justice considerations be assessed as agencies make environmental permitting decisions.

The new regime is likely to become effective in June 2023 and will be implemented over a two-year period.

Phase I Assessments

The US Environmental Protection Agency approved an updated industry standard for conducting most phase I environmental site assessments of industrial and commercial properties, following consideration of public comments on the proposal last year.

The new standard for conducting phase I environmental site assessments is ASTM E1527-21. EPA released it in late 2021 to replace an earlier standard that has been widely used since 2013, ASTM E1527-13. The previous standard remains valid for use but only until February 13, 2024, after which ASTM E1527-21 will be the only EPA-approved standard.

Phase I site assessments are almost always required before closing financings, commercial and industrial real estate purchases, and mergers and acquisitions involving real property.

The new ASTM E1527-21 standard defines what are good commercial and customary practices for conducting environmental site assessments of property to identify both hazardous substances under the Comprehensive Environmental Response, Compensation & Liability Act, or CERCLA, and petroleum products.

A phase I site assessment requires a qualified environmental professional to assess potential environmental risks from hazardous substances and petroleum products by physically inspecting sites, observing adjacent properties, interviewing knowledgeable persons, reviewing government regulatory data bases and considering certain historical information that may yield information relevant to site conditions. Although a phase I assessment requires inspection of a property to look for visual evidence of actual or potential contamination, invasive sampling is not usually performed.

The goal of a phase I site assessment is to identify and disclose what are referred to as recognized environmental conditions, or "RECs." A REC is not only the presence of a hazardous substance or petroleum product on a site, but also the "the likely presence" of such items "due to a release or likely release."

The new standard broadens what consultants should consider "likely" release of contamination when assessing a potential REC. "Likely" contamination is now "neither certain nor proved," but something that "a reasonable observer" would expect or believe "based on the logic and/or experience and/or available evidence."

Site assessments must also now explain why consultants believe there is or is not a "likely presence" of contamination. Proof of an actual release is not required for a REC, and the consultant cannot dismiss common sense.

Under the new standard, consultants must classify site conditions as current RECs where the applicable regulatory standards have tightened over time, even if past phase I reviews did not.

If a site previously reached approved regulatory closure by meeting the unrestricted use standards in effect at the time of the release or subsequent cleanup, the condition may nevertheless still be classified as having a current REC in a new phase I assessment if the available data show that site conditions do not meet applicable new, stricter regulatory standards. In other words, consultants must check whether the available cleanup data satisfy the standards that are currently in effect even if a site previously achieved regulatory sign-off.

The new standard also clarifies when a phase I site assessment is too stale. Instead, each */ continued page 46*

Environmental Update

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specific diligence inquiry required by the standard — the site visit and visual inspection of adjoining properties, interviews with occupants, owners and operators, searches for environmental cleanup liens and governmental records searches — must have been completed within 180 days before closing the transaction for the report to meet the standard.

All phase I site assessments will have to comply with a new EPA standard starting in February 2024.

Parties follow the EPA-approved standard not only to assess risk and meet best practices, but also to preserve the ability to claim a defense to CERCLA liability as an innocent landowner, contiguous property owner or *bona fide* prospective purchaser by having conducted what EPA considers "all appropriate inquiry." A report whose required assessments are older than 180 days may still provide valuable diligence information, but the report is considered too stale to meet EPA's standards.

It is important for parties relying on phase I site assessments to do diligence of environmental risks to realize that, even under the new standard, the site assessment does not have to assess environmental risks associated with certain emerging chemicals of concern that are very likely to be sources of increasing liability risk in the future.

While the scope of hazardous substances regulated under the Superfund statute overlaps broadly with most other environmental laws, the overlap is not 100%. Emerging contaminants are substances that are not currently defined as hazardous under CERCLA, but that may already be regulated as hazardous substances under state law, or that may later become regulated as hazardous under CERCLA. These substances are called "emerging" because regulation of them is evolving quickly, such as in the case of per- and polyfluoroalkyl substances, also known as "PFAS."

Because even the new ASTM standard only requires assessment of hazardous substances already regulated under CERCLA, plus petroleum products, phase I assessments are not required to consider known or suspected releases of contaminants that do not currently fall within that scope. This is true even if a particular contaminant found on a property is already regulated under state law, potentially imposing non-federal cleanup liability or establishing a basis for tort exposure.

An environmental counsel should assess the potential limitations of any reports on which a lender, tax equity investor or acquiror is asked to rely for environmental diligence.

Conducting an optional PFAS assessment — or making sure the phase I assessment includes one — is particularly important for sites where specific current or historical site uses may have resulted in PFAS releases.

Finally, it is important to remember that all RECs are not necessarily disqualifying to a transaction or acquisition.

Environmental site assessments are tools to enable parties to assess risk and then consider whether or how to proceed.

The Inflation Reduction Act established new financial incentives to reuse certain brownfield sites still burdened by the presence of hazardous substances or other pollutants for renewable energy development.

Water

The scope of federal Clean Water Act regulation of waters of the United States has been the subject of regulation, litigation, re-regulation and general uncertainty and tumult since the 1970s.

It has shifted back and forth over decades from narrow limits of just waters that are actually navigable to tributaries of such waters, to interstate waters and their tributaries, to non-navigable intrastate waters whose use or misuse might affect interstate commerce, and to freshwater wetlands adjacent to other jurisdictional waters.

The stakes are significant, both for development and for the environment.

The US EPA and Army Corps of Engineers issued final rules on January 18, 2023, revising the definition of "waters of the United States," often shortened to WOTUS — again. The term determines what gets regulated.

The new WOTUS rule is the latest regulatory attempt to define the geographic reach of federal agency authority to regulate streams, wetlands and other water bodies under the Clean Water Act.

It supplants a Trump administration navigable waters protection rule, itself a controversial revision to prior regulatory authority that significantly narrowed clean water protections. In 2021, the navigable waters protection rule was set aside by the courts.

The new 2023 WOTUS rule expands federal jurisdiction significantly by allowing federal agencies, and state agencies acting under powers delegated under the Clean Water Act, to regulate most wetlands or streams.

The new rule also establishes a complex analysis for whether an area is a regulated water. The analysis could cause some landowners simply to concede federal jurisdiction.

The new WOTUS rule relies on two standards to establish federal Clean Water Act jurisdiction that were at issue in a split decision by the US Supreme Court in a 2006 case called *Rapanos v. United States*. The new WOTUS rule regulates based on both the "significant nexus" standard advanced in Justice Anthony Kennedy's concurring opinion in *Rapanos* and the "relatively permanent" standard in court's plurality opinion.

The long-running 30,000-foot issue can be simplified to the question of "when does a federal agency have authority to regulate a wetland or other non-navigable water body under the Clean Water Act?" The Rapanos opinion was a split decision that did not clearly resolve that issue.

A water body is considered to have a "significant nexus" if it "either alone or in combination with similarly situated waters in the region, significantly affects the chemical, physical, or biological integrity of traditional navigable waters, the territorial seas, or interstate water . . . ."

The "relatively permanent" test requires a permanent hydrologic connection to traditionally navigable waters, thereby excluding channels through which water flows intermittently or ephemerally, or channels that periodically provide drainage for rainfall. Under that test, a wetland must have a continuous surface connection with the navigable water to be considered jurisdictional. Under this narrower standard, only relatively permanent, standing or continuously flowing bodies of water that in everyday English are "streams, oceans, rivers and lakes" qualify as regulated waters of the United States. ◎

— contributed by Andrew Skroback in New York

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