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Mexican CEL Ruling Roils Market

by Carlos Campuzano and Alejandro Aguirre, in Mexico City, and Raquel Bierzwinsky, in New York

More than 20 requests for injunctions have been filed by generators, industry associations and other interested parties in Mexico to challenge a government ruling that modifies who is entitled to receive clean energy certificates or "CELs" for generating renewable energy.

CELs were created as part of the 2014 energy reforms to give electricity generators an incentive to use clean energy sources to produce electricity. For each megawatt hour of clean energy generated, a generator is entitled to one CEL.

Suppliers of electricity to retail customers, including CFE Basic Supply — a subsidiary of CFE, the national utility — are legally required to supply a certain percentage of their electricity from clean energy sources. They comply by buying CELs.

The annual requirement for 2018 was 5%. For 2019, 2020, 2021 and 2022, it increases to 5.8%, 7.4%, 10.9% and 13.9%, respectively.

The administration and verification of CELs is managed by the Energy Regulatory Commission via an electronic system that records the CELs acquired or generated by each registered participant, their transfer to other participants, and the final cancellation upon use to comply with statutory obligations.

By statute, only generators producing energy from clean energy sources whose power plants started operations after August 11, 2014 are entitled to receive CELs.

However, the Ministry of Energy issued in late October a ruling that entitles all clean energy power plants owned by CFE to receive CELs for the energy produced, */ continued page 2*

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A TAX EQUITY PARTNERSHIP between a regulated utility and a tax equity investor received a partial blessing from the IRS.

Utilities are looking for ways to finance renewable energy projects in the tax equity market without turning the projects into "public utility property."

Investment tax credits and accelerated depreciation cannot be claimed on "public utility property" unless the state utility commission refrains from forcing the utility to pass through these tax benefits to ratepayers more rapidly than under a "normalization" method of accounting.

Tax equity investors would rather not deal with such complications.

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Mexican CELs

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regardless of whether the power plants commenced operation before or after August 11, 2014.

The ruling was a gift to CFE. It will increase the supply of CELs, thereby reducing the market price for CELs.

Fissures

The ruling is concerning and deeply flawed.

It provides that any CELs granted to post-energy reform and pre-reform clean energy projects will only be accredited as of October 29, 2019, the date that the ruling came into effect. The effect is to void any CELs validly issued — and even paid for — before that date.

An October ruling has shaken the CEL market in Mexico.

In response to the requests for injunctions, the Ministry of Energy amended the ruling to clarify that the October 29 accreditation date change is only relevant to pre-reform projects owned by CFE.

This change still leaves a ruling in place that violates various principles of Mexican law. They include a right to legal certainty, legitimate expectations in investments, and also possibly antitrust principles.

Several petitioners seeking injunctions were granted injunctions from a federal court in late November, provisionally suspending the application of the new ruling.

As the *NewsWire* went to press, courts had decided that at least two petitioners have enough merit to their cases to grant a "definitive" suspension that will last until final resolution of the request for a permanent injunction. More "definitive" suspensions are expected in December.

As long as implementation of the ruling remains suspended, the federal authorities must continue applying the rules for CELs before the October ruling.

A final resolution in the case is expected to take between six and nine months.

The main concern among renewable energy companies is that the ruling will flood the market with CELs, which will drive down their price to close to zero in the short term. This will affect any projects that sell CELs in the wholesale electricity market or through private contracts and that made pricing decisions based on earlier rules. It also creates a disincentive to build new renewable projects. That will reverse the momentum Mexico established after the 2014 energy reforms that has led to lower and more competitive energy prices.

Experts view the October ruling as a political move by the Mexican federal government to strengthen CFE. It allows pre-reform power plants owned by CFE to receive CELs, thereby not only adding to supply but also reducing the demand that CFE would otherwise have had for CELs from other generators. The Mexican government has been outspoken about the need to strengthen CFE and reduce any dependency that CFE may have on the private sector.

The CFE head has said that, given the presidential instruction to CFE to focus on energy generation, the company will promote clean energy, but "energy sovereignty will have priority" because the government considers that CFE is subsidizing private generating companies by buying energy and CELs from them.

The Mexican Business Council warned that the ruling puts more than US$9 billion in investments in new renewable energy projects at risk. ◎

Financing EV Charging Infrastructure

by Ben Grayson, in New York, and Deanne Barrow, in Washington

Bloomberg New Energy Finance predicts that 57% of passenger vehicle sales, and more than 30% of the global passenger vehicle fleet, will be electric by 2040.

More than two million electric vehicles were sold globally in 2018. BNEF predicts that annual passenger electric vehicle sales will hit 10 million globally in 2025, 28 million in 2030 and 56 million by 2040.

These electric vehicles will need places to charge and will collectively have an impact on the electric grid.

The promise of electric vehicle dominance is calling attention to ownership business models and strategies for financing charging infrastructure.

Utilities, oil and gas companies, automakers and charge-point operators are all active in this space. A number of oil and gas companies and auto manufacturers have recently acquired EV charging infrastructure developers and charge-point operators or formed joint ventures with them. Traditional project finance banks, infrastructure investors, private equity firms and others are showing interest in providing financing and investing in this new asset class.

The electric vehicle sector is nascent, but there is a consensus among industry executives and analysts that a tipping point is approaching where mass adoption will become unavoidable because of falling battery costs, pressure from regulators and government subsidies.

Charging Infrastructure

At the end of 2018, there were approximately 630,000 public charging points installed globally and 61,000 in the US. To achieve scale, developers and financiers need a common understanding of the development process and where the pressure points might be.

The first step in development of EV charging infrastructure is securing land and permits.

Because of the public or semi-public nature of where chargers are sited, sorting through easement and other real estate issues may be burdensome. Developers sometimes approach their utilities with several sites in mind to get one or a few sites approved, ultimately because of / continued page 4

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The IRS released a private letter ruling in late November describing a proposed transaction. The ruling is Private Letter Ruling 201946007.

A regulated utility agreed to buy a wind farm from an independent developer. The developer plans to build the project and then sell it to the utility under a build-transfer agreement. The utility is part of a group of regulated electric and gas utilities under a common holding company operating in multiple states.

The utility plans to form a partnership with a tax equity investor. The sale under the build-transfer agreement will be of the special-purpose project company that owns the wind farm. The developer will sell the project company to the tax equity partnership directly.

The project company has a long-term power purchase agreement to sell electricity from the wind farm to the utility that it won in a competitive bidding situation, presumably in response to the utility's request for proposals from private generators. The project company will have market-based rate authority from the Federal Energy Regulatory Commission to sell at the prices in the power contract.

The utility will resell the electricity to its ratepayers. The ruling is silent about whether the utility will put its investment as a partner in the tax equity partnership into rate base. Presumably the price it pays under the long-term PPA will simply be passed through to ratepayers as a purchased power expense.

The utility will have an option to buy the tax equity partner's interest in the partnership for fair market value after a future flip date.

The utility asked the IRS for two rulings.

The tax equity partnership will claim two tax benefits on the wind farm: production tax credits on the electricity output and accelerated depreciation. Production tax credits are not affected by whether a project is public utility property. Accelerated depreciation is affected.

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Charging Infrastructure

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permitting and real estate hurdles. Utilities often charge assessment fees on a site-by-site basis.

If the charging infrastructure is far away from the nearest electric distribution line, then new or additional lines will need to be installed, and this could require securing rights of way and easements to cross property owned by others. This process is similar to the land rights acquisition process that wind and solar project developers face when siting new interconnecting power lines— called "gen-tie lines"— for generation projects. A large number of easements can complicate financing the project later because lenders will often require estoppel certificates from each easement provider confirming that there are no defaults under the easement before they fund the loan.

Batteries may need to be sited near electric vehicle chargers to mitigate high demand charges.

Step two for a developer is to arrange for interconnection to the grid and adequate electric service from the local utility or community choice aggregator to support planned vehicle charging activities.

Costs will vary depending on whether the site already has a grid connection or a new connection needs to be established. Depending on the size and number of chargers sited in one location, the charging station's load has the potential to be equivalent to a small building. Equipping the site with adequate electric service to serve the new load could entail costly upgrades to distribution-level infrastructure such as distribution wires, conduits, substations and transformers, as well as involve trenching through dense urban areas.

Because the infrastructure upgrades will end up serving several businesses or homes, utilities are often mandated by state regulators to cover a portion of the capital cost. Often the utility will require the developer to pay the full costs of the capital outlay upfront and be refunded a portion later through a credit on the developer's electricity bill after the EV chargers become operational. The developer should consider engaging counsel to assist with utility negotiations and with documenting the terms and conditions relating to cost allocation and refunds.

There are predictions that installed EV charging capacity can grow to 250% of peak demand. According to BNEF, EVs will add 6.8% to total global energy consumption in 2040 and 11% in the US.

Step three for the developer is to install the charging station itself.

Charging infrastructure includes the charging unit and the make-ready equipment, meaning the electrical, wiring and mounting equipment that exists outside of the charger. Costs will vary based on voltage. Most chargers in retail or public spaces are level 2 (1.5 to 19.2 kilowatts) or DC fast chargers (fastest type of charging, currently delivering between 50 to 350 kilowatts of DC power).

Level 2 charging can take anywhere from 30 minutes to three hours. Because level 2 charging takes longer, the charger cannot accommodate as large a volume of customers per day as DC fast charging.

In terms of cost, deployment of one 75-kilowatt DC fast charger could range between $100,000 and $150,000. These figures are split relatively evenly between the charger itself and the make-ready equipment. Deploying one Level 2 charger costs between $2,000 and $10,000.

Public subsidies and rebates may be available to offset the costs of eligible charging equipment. Eligibility may be conditioned on using equipment from pre-approved vendors, so developers should pay attention to the terms and conditions of the rebates and incentive programs to make sure they qualify.

Throughout the development process, the EV charging station owner will often work with the local utility in determining a rate design. There are two transactions occurring if the charging station owner is not generating its own power: one between the utility and the charger for the supply of power and another between the charger and the end-use EV customer. Utilities have been willing to engage with the EV charging infrastructure community as they view EVs as a new area for load growth and one that could potentially provide ancillary grid benefits. Special EV rates are being designed to encourage off-peak charging and help grid stability.

Demand-charge management is consistently highlighted as a major challenge for EV charging station owners. Demand charges are utility fees charged to commercial and industrial customers based on the highest amount of power drawn during a defined time interval within a billing period.

Demand charges are not tied to the total volume of customers that visit a charging station or to the total amount of electricity consumed by an EV charger. This means that demand charges could be fatal to an EV charging station owner's economics if the owner does not earn enough revenue from charging services. Siting battery storage alongside chargers is one way to mitigate high demand charges.

Financing

The scale and timeline over which EV charging stations will be installed is not clear.

At a recent EV charging infrastructure conference in New York, many attendees recognized that there needs to be a large roll-out of EV charging infrastructure soon in order to mitigate the effects of climate change since the transportation sector accounts for a significant share of greenhouse gas emissions.

Some developers are currently using debt to finance their charging stations. However, it is not clear whether this is corporate-level debt or debt at the level of a special-purpose entity that owns the charging units.

Developers like project financing because lenders look only to the future earnings and assets of the project as the source of funds for repayment and security for the loan, with limited or no recourse to owners of the project.

Project financing for charging station development may be possible if developers can prove the revenue stream and customer volume are relatively predictable.

Lessons can be learned from toll road and telecommunications infrastructure projects, which have been successfully project financed despite the same inherent use / continued page 6

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The IRS said the project will not be "public utility property." A project is public utility property if the rates at which electricity from the project is sold are set on a rate-of-return basis. The IRS said no purpose would be served by requiring normalization accounting for the partnership to claim accelerated depreciation in this case since the project company selling the electricity will not be subject to rate-of-return regulation.

The IRS declined to give the utility the other ruling it wanted.

A partnership that owns a wind farm will usually have net losses due to depreciation for roughly the first three years after the project is first placed in service. Section 707(b) of the US tax code does not allow the partnership to claim a net loss to the extent the electricity is sold to an affiliate. A partner who owns more than a 50% profits or capital interest in the partnership is an affiliate.

The utility asked for a ruling that net losses can be claimed to the extent they are allocated to the tax equity investor rather than the utility partner. The IRS said it will not rule on "an issue that cannot be readily resolved before a regulation or any other published guidance is issued."

The latest IRS priority guidance plan does not show it working on any guidance in this area.

One way to avoid the problem is to convert the power contract to sell electricity into a "virtual" PPA or swap rather than a contract for physical delivery for the period the partnership will run net losses. Section 707(b) disallows losses only on sales to affiliates.

The ruling that the wind farm will not be public utility property is consistent with other private rulings the IRS has issued in the past.

For example, earlier this year, the IRS ruled that a Utah utility did not have to treat a solar project as public utility property. The utility planned to buy the solar project from a private developer in a similar / continued page 7

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and volume risk that EV charging infrastructure faces. Banks and other financiers require some minimum level of capital expenditure in order to justify a foray into the space. It is not clear whether individual developers are at a point where they can scale development and reach an amount of capital costs to match the level of expenditures that at least the large commercial banks would want to see.

One way to increase capital costs is for developers to site renewables and battery storage alongside EV chargers. Not only could this open a door to more creative financing, but it could also help charging operators manage their own power prices and mitigate the demand-charge concerns described earlier.

Automakers have become partners in joint ventures to develop EV charging stations. They may be willing to finance charging infrastructure on balance sheet in an effort to promote EV sales.

However, there is no consensus yet among automakers about whether EVs will have a positive impact on their business models; some have pledged to phase out the manufacturing of vehicles with internal combustion engines in the coming decade while others have recently joined the federal government in litigating against California, which is attempting to maintain its federal waiver that allows it to set its own auto emission standards. How automakers engage with the electric vehicle charging sector could have dramatic impacts on EV charging infrastructure financing given how deep their pockets run.

Depot Model

One model that could lend itself to project financing is the "depot model."

Large corporates with fleets of vehicles (for example, Federal Express) tend to have dedicated parking lots where their fleets park when the vehicles are not in use. These lots could be quality areas to site EV charging stations for four reasons.

First, there is a high degree of certainty in terms of offtake volume since the number of vehicles parked is relatively stable on a day-to-day basis. These chargers can be separately metered and data can be easily collected.

Second, there could be predictable charging times if routes are standardized, which can provide comfort to utilities in terms of rate design and how a developer prices its charging services to offtakers.

Third, the creditworthiness of the offtaker will be known. Instead of relying on individual EV drivers at retail or public charging locations as customers, EV charging owners can rely on a single known entity supported by strong financial data. Merchant risk is an issue that financiers are already familiar with in project financing of energy projects, and so the mitigants to merchant risk in the depot model could help with project financing.

Fourth, the lots are usually on private property, which can help in navigating real estate and permitting issues, and these lots may have space available to make co-siting of renewables and battery storage feasible.

Free Service Model

Among developers, the Volta Charging business model is unique because of its free service offerings.

Volta sites its chargers at retail locations, offering free charging to EV customers and free maintenance for its site hosts. Typically, charge point owner revenue streams are based on the sale of electricity from the charger to the EV customer, either on a $/kW or $/minute basis. Volta's revenue comes solely from advertising that runs along the physical charging asset. A digital platform allows for the advertisements to be changed frequently and remotely, helping Volta attract multiple advertisers and streamline its operations.

Volta targets premium parking spaces at its locations that are close in proximity to retail locations. These premium spaces justify the costs charged to Volta's advertisers. The idea is that the EV customers, along with all other retail customers passing by the chargers, are exposed to the advertising.

To date, Volta primarily installs level 2 chargers. This is because the time profiles of how long EV customers spend at the Volta charging sites (movie theaters, restaurants, etc.) matches the length of time level 2 charging typically takes. For example, a full level 2 charge may take two hours, but an EV customer may not care if he or she is charging a vehicle while attending a movie. (For more information on private EV charging business models, see "Opportunity: Electric Vehicle Charging Infrastructure" in the August 2018 *NewsWire*.)

Electric Buses

Another noteworthy sub-sector is electric buses.

Because of the size of EV bus batteries, developers and EV bus manufacturers are hopeful that there will be a market for vehicle-to-grid applications, discussed under the next subheading.

In early 2019, Proterra, an EV bus manufacturer, partnered with Mitsui by entering into a $200 million credit facility to support Proterra's battery lease program. By decoupling the batteries from the sale of the rest of the bus, Proterra can sell more buses. This is because the upfront cost of the entire bus, including the battery, which currently has a price tag of about $750,000, is higher than an internal combustion engine bus, which runs for roughly $500,000. There are significant operational cost savings on electric charging versus fueling a bus with diesel gasoline.

As part of the program, Proterra sells the bus and leases the battery over a 12-year life. Customers are able to use the operational savings to pay for the battery lease over time while also taking financial comfort in making the upfront purchase of the bus.

Over the life of the lease, Proterra owns and guarantees the performance of the batteries.

Lithium-ion battery pack prices have fallen significantly over the past decade, and EVs may soon reach cost parity with vehicles with internal combustion engines. According to BNEF, battery prices were just below $1,200 a kilowatt hour in 2010 and have recently dropped below the $100 a kilowatt hour. Further price decreases are expected. If battery prices drop enough, then the need for similar programs may not be warranted.

Municipal transit agencies tend to phase their bus purchases over relatively long time schedules, and there is a general consensus that EV bus adoption will happen over time unless municipalities receive more federal financial support.

The depot model described earlier could be used for municipal bus fleets.

Vehicle-To-Grid

The average personal vehicle is not used to drive more than 10% of the day.

EVs charge between 5% and 20% of the day, depending on the charger's voltage level. This means that EVs are idle about 70% of the time.

Companies across the EV value chain are actively exploring vehicle-to-grid— called V2G — technology to make EV batteries useful while the vehicles are idle by looking at the EV battery as a built-in energy storage system.

V2G benefits include ancillary grid services such as voltage and frequency regulation, spinning reserves, reactive power support, peak shaving and energy balance, akin to an energy storage system. These benefits could create new income streams for energy aggregators, fleet operators and EV drivers. As EVs and EV chargers proliferate, this / *continued page 8*

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build-transfer arrangement. The project came with a long-term power contract to sell the electricity to a corporate customer. The power sales were at the rates negotiated by the solar developer directly with the corporate customer rather than at regulated rates set on a rate-of-return basis. (See "Solar Projects and 'Public Utility Property'" in the June 2019 *NewsWire*.)

Separately, the IRS suggested in September that a regulated utility can pass through a form of accelerated depreciation called a "depreciation bonus" on a project to a tax equity investor by selling the project to the tax equity investor and leasing it back. A 100% depreciation bonus can be claimed on equipment put in service through 2022. The percentage bonus allowed phases down after that. A 100% bonus allows the owner to deduct the entire cost in the year the project is put in service.

A depreciation bonus cannot be claimed on "public utility property."

Under proposed IRS regulations in September, a project sold to a tax equity investor in a sale-leaseback transaction will not be public utility property for depreciation bonus purposes, even though the user of the asset — the lessee — is a regulated utility. (For more information, see "Depreciation Bonus Questions Answered" in the October 2019 *NewsWire*.) This makes sense. The lessor is not subject to utility regulation, so there is no possibility of the regulators requiring the bonus claimed by it to be passed through to ratepayers.

THE UNCERTAINTY AROUND TARIFFS makes trying to do business like negotiating deals on a trampoline with an overweight 73-year old bouncing up and down.

The US Department of Commerce recommended in early December that wind towers imported from Canada, Vietnam and Indonesia should be subject to countervailing duties to offset subsidies in the three countries. It recommended duties of / *continued page 9*

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intersection of EVs and energy markets could garner significant attention.

For more discussion about the consequences for the US power sector of electrification of the transportation sector, see "The Shift to Electric Vehicles" in the August 2019 *NewsWire*. ◎

US Offshore Wind: Current Financing Conditions

More than 1,300 people attended the annual offshore wind conference hosted by the American Wind Energy Association in late October in Boston. A panel talked about the current market for financing offshore wind projects in the United States. The following is an edited transcript. At the time of the panel, the 800-megawatt Vineyard project had been in the market seeking financing.

The panelists are Nuno Andrade, managing director and head of structured finance for North America for Santander, Yale Henderson, managing director and head of the tax equity desk at JPMorgan Capital Corporation, Martin Pasqualini, managing director with the CCA Group, one of top arrangers of tax equity, and Henrik Tordrup, formerly with offshore wind developer Ørsted and now a partner with Copenhagen Infrastructure Partners, a 50% owner of Vineyard. The moderator is Keith Martin with Norton Rose Fulbright in Washington.

Debt

MR. MARTIN: Nuno Andrade, you have been in the market this year trying to raise debt for the Vineyard offshore wind project. How much interest has there been among banks? Can you say how many banks are interested in lending?

MR. ANDRADE: We saw a tremendous response from the market. There is pent-up demand especially from European lenders who have been lending to such projects in Europe. The ability to raise debt will not constrain the US offshore wind sector.

MR. MARTIN: Can you say how many banks are interested in offshore wind?

MR. ANDRADE: Judging from the number of the unsolicited requests we got about Vineyard, more than 50 financing entities have a real interest in looking at offshore wind in the US.

MR. MARTIN: How much of a risk premium are banks requiring to lend to US offshore wind projects compared to projects on land?

MR. ANDRADE: It depends on the structure. Most deals on which we have been working have tax equity. The debt is back levered, meaning it is behind the tax equity in the capital stack. An inter-creditor or forbearance agreement has to be negotiated between the tax equity and the lenders. If the terms of this agreement are favorable to the lenders, then we would expect only a 25 basis-point premium to lend to an offshore wind project compared to a project on land.

MR. HENDERSON: Just to be clear, the inter-creditor discussion is about how much of a priority claim the tax equity will have over the cash flow from the projects. The discussions can become very nuanced depending on the transaction structure.

MR. MARTIN: Naturally the tax equity is willing to let the lenders take as much as much they want for scheduled principal and interest payments? [Laughter]

MR. HENDERSON: No. However, we are creative and open-minded.

MR. ANDRADE: These are bespoke agreements. The rating agencies focus on the terms. It is important to start the inter-creditor discussions early in the process.

MR. MARTIN: Besides a slight interest-rate premium, what other differences are there in debt terms between offshore and onshore wind projects? Let's start with tenor. How long are banks willing to lend?

MR. ANDRADE: The answer is different in Europe than in the US.

MR. MARTIN: Let's focus on the US.

MR. HENDERSON: It is a completely different dynamic, given the nature of the incentive being monetized by the tax equity and how much the tax equity represents as a percentage of the capital stack in an offshore wind deal compared to an onshore PTC deal.

MR. MARTIN: What will be the typical capital stack for offshore wind? What percent tax equity? What percent debt? What percent true equity?

MR. HENDERSON: I can only speak to the tax equity. It is definitely less than 30% of the capital stack.

MR. MARTIN: Sub-30% assuming what size tax credit? 80% of the full rate? 60%? 40%?

MR. HENDERSON: The most any of the new projects coming to market has been able to qualify for is 80%, and the percentages decline from there.

MR. MARTIN: So the tax equity is less than 30% of the capital stack in an offshore wind deal qualifying for tax credits at 80% of the full rate. Henrik Tordrup, what percent debt?

MR. TORDRUP: In round numbers, I think it will be 20% sponsor equity, 30% tax equity and 50% debt.

More than 50 banks are interested in financing US offshore wind projects.

MR. MARTIN: Nuno Andrade, I did not get an answer from you on the debt tenor.

MR. ANDRADE: In Europe, longer tenors are being done for this type of asset, while a seven-year mini-perm structure has been more typical of bank debt in the US market. There is a balancing act between cost and tenor. The refinancing risk is the key consideration that sponsors have in terms of the tenor. Even during the financial crisis in the US, the project finance market remained open, which is different from what people saw in Europe, so there is still a bit of back and forth about optimum tenor.

MR. MARTIN: I think I heard seven years from you for the US. Is that right?

MR. ANDRADE: That is the typical tenor today for onshore wind. The question is whether something can be structured in the middle between a seven-year deal in the US and the longer tenors for offshore wind that we have seen in Europe.

MR. MARTIN: Is the debt-service-coverage ratio relevant for back-levered debt?

MR. ANDRADE: Absolutely.

MR. MARTIN: What DSCR do you expect to see for US offshore wind? / *continued page 10*

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1.09%, 2.43% and 20.29% respectively.

It may recommend additional anti-dumping duties early next year.

US wind tower manufacturers have also complained about towers imported from South Korea. The Commerce duty calculations go next to the US International Trade Commission for confirmation that US manufacturers have been injured by the subsidies.

US Customs will collect cash deposits in the meantime from importers based on the preliminary duty rates.

Roughly $119 million in wind towers were imported from the three countries in 2018, but the first quarter 2019 number was 10 times as large as the first quarter 2018 if South Korea is included in the calculations.

Separately, the US International Trade Commission is expected to report to President Trump by February 7, 2020 on whether to leave in place US tariffs on imported solar panels at the current rates. A tariff of 25% is being collected currently. The rate is scheduled to drop to 20% on February 7, 2020, to 15% a year later in 2021 and then to disappear in 2022. The government is required to do a mid-term review after the tariffs have been in effect for two years. They started at a 30% rate in February 2018.

Some US developers have been importing panels into bonded warehouses. This defers collection of the tariff until the panels are removed from the warehouse for use in a project. The tariff rate is the rate that applies on the withdrawal date.

The US International Trade Commission held a hearing as part of its mid-term review on December 5. Chinese-owned US panel manufacturer Suniva has asked it to slow the annual 5% tariff reduction to 1%. The trade law under which the duties were imposed does not allow Trump to increase the tariff.

Meanwhile, the US Court of International Trade has temporarily blocked a move by the US Trade Representative ***/ continued page 11***

Offshore Wind

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MR. ANDRADE: I don't think there will be a big difference between offshore and onshore in terms of the debt-service-coverage ratio.

MR. MARTIN: What is the debt-service-coverage ratio currently for US onshore wind?

MR. ANDRADE: It is 1.0 for the P99 output and between 1.35 and 1.40 for the P50 output. What is interesting about offshore wind is that the wind tends to be more stable. In terms of net capacity and variability, the resource tends to be better. This is something that has to be taken into account when talking about sizing parameters.

Tax equity is expected to account for less than 30% of the capital stack.

MR. MARTIN: We established already that the typical offshore capital stack is expected to be 20% sponsor equity, 50% debt and 30% tax equity. Will lenders allow subordinated debt to count as sponsor equity for this purpose?

MR. ANDRADE: One thing that I learned in this country is that, with good lawyers, anything is possible in a structure. I would say that the key is how deeply subordinated the debt is. Keep in mind that a project goes through different stages. There is construction. There is the period between mechanical completion and when the project is put into commercial operation. The tax equity may fund when 90% of the turbines reach commercial operation, so there is a period where cash flow may be increasing. Returning to subordinated debt counting as equity, the key is how deeply subordinated it is. This is worked out in the inter-creditor agreement.

MR. MARTIN: The reason I ask is tax considerations push some European pension funds to put in money as debt rather than equity.

MR. ANDRADE: To the extent that the sponsors expect a takeout through project bonds and the debt capital markets, there is a discussion to be had with the rating agencies. They focus on the degree of subordination. The bank market is familiar with structures where deeply subordinated debt is treated for all purposes as equity.

MR. MARTIN: Before going to market for Vineyard, did you consider project bonds or were you focused solely on bank debt?

MR. ANDRADE: We considered all the options.

MR. MARTIN: Yet you settled on bank debt, I think. For what reason?

MR. ANDRADE: Banks probably are more flexible during the construction period. However, since, in Europe, institutional investors have shown considerable flexibility, what type of capital is more efficient for this type of project will remain a subject of ongoing discussion.

MR. HENDERSON: Another consideration beyond what is most efficient is execution risk and the speed at which parties can move. The original timeline was to sign documents next week, I think. That was an ambitious timeline, but could have been done had the US Department of Interior not thrown projects off the Atlantic coast into limbo in early August. Bank debt was preferred because it had the lowest execution risk given the timeline.

MR. MARTIN: What hot buttons are there for lenders looking at offshore wind?

MR. ANDRADE: Construction risk gets a lot of attention. The perception is there is more risk to put a big turbine in the middle of the ocean than to do so on land. Over time, people will better understand the real risks with this technology. The logistics, the interface risk, all of that is highly scrutinized, and we have to spend a lot of time educating the market.

MR. MARTIN: Are there any audience questions about debt before we move to tax equity? Dennis Meany with Oatfield LLC.

MR. MEANY: Keith asked about the tenor. What about the amortization periods for long-term contracts?

MR. ANDRADE: One interesting thing about offshore wind is the power purchase agreements are longer. In the onshore market, power purchase agreements are getting shorter, and people are doing sizing all the way to the end of the contract and even including merchant tails. The ultimate goal in offshore is to give credit for the contracted cash flows during the full term of the contract.

MR. MARTIN: Will the debt amortize over the full term? Will there be mini-perm features?

MR. ANDRADE: I am saying that is the goal. We will see how the market reacts. It also depends on the type of lenders. Banks are more prepared to see tails. Institutional investors are more familiar with giving credit to the full tenor of the PPA, but sometimes they require higher debt-service-coverage ratios for different P-values. An analysis must be done about what is more beneficial for the project sponsor.

MR. MARTIN: Say your name and affiliation and then your question.

MR. HARTSHORNE: Prescott Hartshorne, National Grid. LIBOR or SOFR spreads?

MR. MARTIN: What is the LIBOR spread on the debt? You said it is 25 basis points above where onshore would be. Onshore construction debt is 75 basis points over LIBOR and term debt is 125 basis points over for contracted cash flow. Does that sound right?

MR. ANDRADE: There is a big difference between construction risks for onshore and offshore. A straight comparison to onshore term debt is difficult because onshore PPAs are getting hairier and more difficult, but historically, we have seen term debt spreads on deals with good PPAs of between 150 and 175 basis points.

MR. MARTIN: That's for contracted revenue?

MR. ANDRADE: Correct.

MR. MARTIN: Presumably these are also the rates that would apply to front-levered debt at the project level since the banks are not charging any premium to lend on a back-levered basis. All debt at this point is back-levered debt.

MR. HENDERSON: Front-levered meaning what?

MR. MARTIN: Meaning that the debt is ahead of the tax equity in the capital stack.

MR. HENDERSON: From a collateral or from a cash-flow perspective?

MR. MARTIN: Both.

MR. HENDERSON: We have not seen / *continued page 12*

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to withdraw a tariff exemption for bi-facial solar panels that generate electricity on both sides of the panel.

Global bi-facial panel installations were 97 megawatts in 2016 compared to 2,600 megawatts in 2018. They are expected to reach 5,420 megawatts in 2019, according to Wood Mackenzie.

The US Trade Representative exempted bi-facial panels from the current 25% tariff on imported solar panels on June 26 at the request of three companies: Pine Gate Renewables, Sunpreme and SolarWorld Industries. Soon after, Suniva, First Solar and Hanwha Q Cells USA asked him to reconsider. He then revoked the exemption in October, but the US Court of International Trade blocked withdrawal of the exemption after Invenergy filed suit. Invenergy was later joined in the suit by the Solar Energy Industries Association (SEIA), Clearway Energy, EDF Renewables and AES Distributed Energy.

The court issued a preliminary injunction on December 5 to keep the exemption in place until the government can cure procedural defects in how it revoked the exemption.

The court said the government violated the Administrative Procedures Act by giving the public only 19 days' notice and without collecting public comments or compiling a public record on which to base a decision. The case is *Invenergy Renewables LLC v. United States*.

The injunction against removal may prove temporary until the government can go through the proper motions.

SEIA is seeking tariff exemptions for solar panels made in Canada and Singapore.

Jinko, a Chinese solar panel manufacturer that opened a factory in the United States, said it expects demand for its solar panels to surge nearly 45% in 2020 to four megawatts. Solar panels have been hard to find in the run up to the December 2019 deadline for starting construction of solar projects to qualify for federal tax credits. / *continued page 13*

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a front-levered deal since maybe 2014. Solar deals with investment tax credits are sometimes structured so that the debt is effectively senior to the tax equity on a cash-flow basis, but not on a collateral basis.

MR. MARTIN: I think you told me that you expect to see a return to some front leverage in the future. Is that true and, if so, why?

MR. HENDERSON: I don't think it will be "front leverage." It will be back leverage with some interesting features. An offshore wind deal with an investment tax credit has a very different risk profile from an onshore deal with production tax credits, and we are not looking to get as much cash out of the offshore deal.

If an ITC is claimed, the tax equity investors do not need as much cash as in a PTC deal.

Tax Equity

MR. MARTIN: If we have time at the end, we will drill down into the details. Let's switch to tax equity. Marty Pasqualini, you have been out in the market trying to raise tax equity for offshore wind. How many tax equity investors do you think have an interest in such projects?

MR. PASQUALINI: All of the tax equity investors that do deals with investment tax credits expressed interest in the Vineyard project. Some had constraints tied to timing and the longer construction period required for such projects.

There are two elements to timing. There is the cost of funds during the long commitment period. And for some smaller investors whose future tax capacity is not as certain as for a JPMorgan, Berkshire Hathaway or someone of that nature, asking them to commit to invest two years from now is difficult. Ask them much closer to the commercial operation date when their money would go in and the response is almost uniformly positive in terms of level of interest.

MR. MARTIN: How many tax equity investors is that? You said it is the ones who have an interest in investment tax credits. And how much capacity is that in a year? Is it $3 billion, $2 billion, less, more?

MR. PASQUALINI: Without giving out state secrets, I can tell you that we had more than two times the amount of tax equity available to this project than the project needed. And that was from folks who could commit to invest two years in the future. The plan was to close on November 1. The fact that we had more than twice the tax equity on offer than we needed from investors who would stand that long a commitment period gives you an idea of the level of interest.

MR. MARTIN: Wind projects must be under construction by a deadline to qualify for tax credits. How are you seeing offshore wind projects start construction?

MR. PASQUALINI: You cannot dig turbine foundations or put in roads on the site and, given how long it takes to manufacture offshore wind turbines, you have to get there on physical work by another means.

MR. MARTIN: These are expensive projects. It is hard to incur at least 5% of the cost of a $3+ billion project, so the sponsors are left with physical work.

MR. TORDRUP: The other thing worth noting about offshore wind is the turbines are improving at a very rapid pace. It is not a good idea to lock yourself into turbines too early in the process because, by the time you are ready to build, a completely different turbine may be available: say 12 megawatts instead of 8 1/2 megawatts.

You need to think carefully about how to start physical work because there are some dynamics that are more complicated than for onshore wind.

MR. MARTIN: So be careful. You want to do physical work, but not on things where the technology will change before you finish construction. Marty Pasqualini, coming back to you: will most projects claim PTCs or ITCs, and why?

MR. PASQUALINI: The choice is a function of a couple things. It used to be that the ITC made more sense for projects with high capital costs per installed megawatt, and PTCs made more sense for projects with high efficiency factors. ITCs are tied to cost. PTCs are tied to output.

Offshore wind has high capital costs, so you would think the ITC would make the most sense, but what we are seeing in real time is what Henrik just alluded to: the technology is evolving so quickly that PTC transactions actually can hold up. And there are reasons why it may be more attractive in a financing context to go the PTC route, if possible.

MR. MARTIN: But the investor takes operating risks in a PTC deal. The ITC is entirely up front.

MR. PASQUALINI: True. However, the pool of ready PTC investors is much deeper.

MR. MARTIN: Why? Yale Henderson, why are PTCs easier to digest than an ITC?

MR. HENDERSON: The simple answer is the ITC is recognized entirely in one year. For example, assuming a 12% ITC, that is $360 million on a $3 billion project. That is a lot of tax credits for someone to absorb on the balance sheet unless the investor is a large bank.

MR. MARTIN: That would be almost $1 billion of tax credits — $900 million — for a project on which a 30% investment tax credit can be claimed.

MR. HENDERSON:. . . if projects were actually qualifying for a 30% credit. Unless the law changes, they would have had to be under construction in 2016.

You can do a PTC deal, but it means you are probably going to have to draw a larger number of tax equity investors into the deal, and you will end up raising less money in relation to the dollar amount of tax credits. Investors may be willing to write a larger check in an ITC deal because the amount of PTCs that may ultimately be available is less certain. Sponsors have to balance check size against liquidity in the ITC versus PTC tax equity markets and the potential complications of trying to close a partnership with a larger number of PTC investors than for an ITC deal.

MR. MARTIN: Marty Pasqualini, will all of these projects be financed using partnership flip structures? Why not sale-lease-backs? They buy more time to complete the project.

PTC deals can only be done using partnership flips. That's the only structure the PTC statute permits. But you have a choice of three structures in an ITC deal. In an ITC partnership flip, the investor must be a partner before any / continued page 14

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President Trump tweeted on December 3 that he will impose tariffs on all steel and aluminum imports from Brazil and Argentina. Both countries agreed to quotas last year in exchange for a waiver from such duties. Trump accused both countries of "presiding over a massive devaluation of their currencies, which is not good for our farmers."

No formal proclamation has been issued yet by the White House or the US Department of Commerce.

The US is currently collecting a 25% tariff on imported steel and 10% on aluminum. The President used section 232 of the Trade Expansion Act of 1962 as the legal authority to impose them. That section allows tariffs to be imposed where imports threaten national security.

THE LATEST CFIUS REPORT to Congress in November shows a dramatic increase in the number of inbound US acquisitions that are being reported to the US government since Trump took office.

The odds of deals being pulled out for investigation or blocked have also increased.

Reviews have become a four- or five-month process.

CFIUS stands for the Committee on Foreign Investment in the United States, an interagency committee of 16 federal agencies, headed by the Treasury Department, that reviews potential foreign acquisitions for national security implications. It is supposed to report annually to Congress.

Filing of transactions with CFIUS used to be voluntary. Filings are made only in a fraction of acquisitions. The danger of not filing is that the government could force the transaction to be unwound later if it has national security concerns. However, some filings are now mandatory after a recent change in the statute. (For more detail, see "Scrutiny for Inbound US Investments" in the October 2019 *NewsWire*.)

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turbines go into service. In a sale-leaseback, the investor can wait up to three months after turbines go into service to fund.

MR. PASQUALINI: The problem is we are back into a front-leverage world, because I can't imagine a $3.5 billion single-investor lease transaction, so there will be debt at the lessor level, and you get all the inter-creditor issues we were discussing earlier. The change in lease accounting rules — the inability to use leveraged-lease accounting— has also made sale-leasebacks less appealing. I think the market is now very comfortable with partnership structures. If we need, for other reasons, to evolve to leveraged partnerships, this is a market that has always figured it out.

MR. MARTIN: Another reason sale-leasebacks do not appeal is they are longer-term financing. The term generally runs 80% of the expected life and value of the project. Investors want to be out of the deal sooner.

MR. HENDERSON: Yes, we don't like the long-term profile of a typical leveraged lease. We do not like the amount of residual risk we would have to take.

MR. MARTIN: Marty Pasqualini, offshore wind developers have been struggling to start construction of projects this year in order to qualify for federal tax credits at 40% of the full rate before the tax credits phase out entirely. A 12% investment credit on a $3.5 billion project requires something like $420 million tax equity investment.

There is an effort in Congress to allow a 30% investment tax credit to be claimed on wind projects that are under construction by the end of 2024 or until there are 3,000 megawatts of offshore projects in operation, whichever is later. Now you are talking about a $1 billion investment.

Is there enough capacity to cover the demand for tax equity for offshore wind if each project requires at least $1 billion in tax equity?

MR. PASQUALINI: I believe there is. I think that if we had been looking for the incrementally larger dollar amount for Vineyard, it would have been available. I can't speak for every single project and its particular dynamics, but I think there is depth in the market for these types of projects, especially with the high-quality sponsors behind them.

MR. MARTIN: Yale Henderson, JPMorgan is about 25% of the tax equity market at the moment. How many offshore wind projects have you been shown to date?

MR. HENDERSON: We are all in on offshore wind. We were there ready to go on Vineyard. We are talking to probably every major sponsor that has a leasehold position off the east coast about how it is qualifying for tax credits.

MR. MARTIN: How are you thinking about offshore wind? Why is it so attractive?

MR. HENDERSON: The risks are completely different than the risks we are running in the onshore wind space. With onshore wind, everything comes down to the revenue contract or lack thereof and uncertainty created by that. There is not a lot of uncertainty in the onshore market around construction: whether the project will get built, whether the turbines will work and how much the wind will blow. Those things are well understood in the onshore market.

With offshore, you have tax-credit-qualification issues, and you have turbine-risk issues. The turbine manufacturers are taking a lot of the turbine risk, so we feel pretty comfortable about it. Most importantly, you have a very good revenue contract. This gives offshore projects a different risk profile than onshore wind and solar projects and helps to balance our portfolio, allowing us to bid aggressively in big dollar amounts.

MR. MARTIN: Many offshore projects rely on physical work to get started. How comfortable are you with physical-work fact patterns?

MR. HENDERSON: We are comfortable with Vineyard's story, and we expect to be able to work with other developers. We are talking to them now about what they are trying to put together and making sure we are comfortable with their plans. We need ultimately to be comfortable not only with the construction-start facts, but also with the sponsor. Sponsors take construction-start risk. We need to be confident the sponsor has a strong enough balance sheet to cover the risk.

MR. MARTIN: One problem with starting construction based on physical work is that the developer must prove continuous construction if the project takes more than four years to complete. It is hard to do. How do you protect yourself at the back end of the construction period? I guess you don't invest. How does Nuno Andrade protect himself as the construction lender?

MR. ANDRADE: Whether or not the tax equity funds, the construction loan converts at the end of construction into a term loan that will be repaid over time out of project cash flows.

MR. HENDERSON: The lender is not bridging tax equity during construction.

MR. ANDRADE: . . . in this particular situation.

MR. MARTIN: Another big issue in the offshore wind market is these projects take time. The politics can change before a project is completed. How long a forward commitment are you willing to make as a tax equity investor?

MR. HENDERSON: The political risk is more of an opportunity cost for the tax equity investor. We will have spent time working on a project that ultimately has the rug pulled out from under it. We only fund at the end of construction. If the project does not satisfy all of the conditions precedent to funding, we will have lost a lot of time and effort, but we will be paid breakage costs and commitment fees to cover us for the time and expense of holding the capital for that two-year period.

MR. MARTIN: So you are prepared to commit two years in advance to fund the tax equity?

MR. HENDERSON: Yes.

MR. MARTIN: Henrik Tordrup, is that enough time to get from financial closing to mechanical completion?

MR. TORDRUP: Yes, with a proper plan.

MR. MARTIN: Yale Henderson, I asked Nuno Andrade how terms are expected to differ in the debt market for onshore versus offshore projects. What about tax equity?

MR. HENDERSON: The differences are dramatic. The terms and conditions around pricing, the inter-creditor issues between us and the back-leverage lender, and the sponsor claim on cash flows have a completely different dynamic.

MR. MARTIN: You have said that twice now. Give me some examples. What makes an offshore transaction a completely different dynamic?

MR. HENDERSON: One example is that if we are doing an ITC deal, 80% to 85% of our return comes from the ITC and depreciation. We do not need a large claim on cash. The biggest risk is around ITC qualification. If the ITC is disallowed, we will be looking to take all the cash flow. That is probably the biggest source of tension: our claim on cash for a very small risk, but very deep hole that happens if the project is found not to qualify for an ITC.

MR. MARTIN: There is currently a 100% depreciation bonus, meaning the entire cost of the project can be deducted in year one. The 100% bonus is available for projects that go into service through 2022. It phases out after that. Is it possible to raise tax equity on offshore wind projects that do not qualify for tax credits?

MR. HENDERSON: That goes back to your question to Marty Pasqualini about the appetite for leveraged-lease transactions. There is no appetite for leveraged-lease transactions in our institution at the moment.

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The committee makes recommendations. The president has ultimate authority to block a transaction. Presidential action to block a transaction is rare.

Most transactions that raise problems are voluntarily withdrawn. Many are later resubmitted on revised terms. In some cases, transactions are approved after the acquirer agrees to mitigation measures.

The latest report covers 2016 and 2017.

During 2016, notices were filed in 172 acquisitions. Of that number, 46% went into an investigation phase. Ten percent of the 172 acquirers had to agree to mitigation measures to address national security concerns. Another 16% ended up withdrawing their transactions. A little less than half (7%) of transactions that were withdrawn were ultimately abandoned and a little more than half (9%) were restructured and resubmitted to CFIUS in new filings.

One 2016 transaction was referred to President Obama. He blocked the sale by Aixtron SE, a German company, of its US businesses to Grand Chip Investment GmbH, another German company that is Chinese owned.

In 2017, the first year Trump was in office, 237 notices were filed, a 38% increase. The volume of US inbound M&A deals increased by only 9.79% over the same period. US inbound deal value fell from $506.04 billion in 2016 to $235.88 billion in 2017.

Of the 237 deals filed with CFIUS in 2017, 73% moved into an investigation phase. Twelve percent of acquirers had to agree to mitigation measures to address national security concerns. A sizable 31% of deals were withdrawn. Of that number, more than half (19%) were refiled after being restructured. Thirteen percent of acquisitions were abandoned.

One transaction was referred to President Trump. He blocked the acquisition of Lattice Semiconductor Corporation by Canyon Bridge Merger Sub, a Delaware subsidiary of China Venture Capital Fund Corporation.

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MR. MARTIN: Marty do you agree with that?

MR. PASQUALINI: In the bank market, yes. If an insurance company wanted to do an 18-year lease of a wind project with a 20-year offtake contract, I can be optimistic and say we could probably arrange that.

MR. HENDERSON: The leveraged leasing market has not really existed for 10 to 15 years. With interest rates where they are today, it is not worth the time and effort to do such a transaction, even for a $3.5 billion project.

MR. MARTIN: Marty Pasqualini, if Yale Henderson says tax equity accounts for about 30% of the capital stack for an 80% PTC or ITC deal, what if the only tax benefit is a 100% depreciation bonus. What percentage of the capital stack do you think would be tax equity?

MR. PASQUALINI: In a partnership?

MR. MARTIN: I guess you said it would not be a partnership. The transaction would be structured as a leveraged lease.

MR. PASQUALINI: So we are fully in the pretend world now. It would depend on what we can do on the debt side. The debt probably is going to be a significant component of the structure.

Wind projects off the Atlantic coast are currently in limbo while the Interior Department studies the environmental effects.

MR. MARTIN: Any tax equity questions form the audience? Gary Hecimovich from Deloitte.

MR. HECIMOVICH: Will tax equity investors be willing to invest in projects that take more than four years to construct if the developer can provide rigorous documentation proving continuous work? Has any tax equity investor had to cross that bridge yet?

MR. HENDERSON: We have not crossed that bridge. We know that question is being asked and we are working through that with our tax lawyers and with our management. I am hopeful that with the right facts and maybe some additional guidance from the IRS, we will be able to get there, but it will be a tough bridge to cross.

MR. MARTIN: Question from Tristan Grimbert, CEO of EDF Renewables.

MR. GRIMBERT: I did not hear a clear answer about what is an acceptable strategy for starting construction other than incurring at least 5% of the project cost and putting the risk on the sponsor.

MR. HENDERSON: I did say that we got comfortable with the physical work strategy used by the Vineyard project. We are in discussions with other sponsors about their particular facts and how they want to approach qualification.

MR. GRIMBERT: I heard what you said. You are putting the risk back on the sponsor.

MR. HENDERSON: True.

MR. GRIMBERT: If you require a sponsor guarantee, it is not really a risk with which you are comfortable. The first question should be whether it is a sponsor- or project-level risk. If you require a sponsor-level guarantee, you are not really comfortable with the risk.

MR. HENDERSON: Let me put this very clearly. The risk allocation is important to our analysis of the deal. However, we would not fund a deal unless we fundamentally believe that the qualification story works from a tax perspective and will survive IRS scrutiny. We would not do a transaction where we do not believe in the qualification story even if we had the US Treasury back stopping that risk.

Sponsors

MR. MARTIN: Let's move to the sponsor side of the equation, Henrik Tordrup with Copenhagen Infrastructure Partners, CIP owns offshore wind projects in Europe. It has also invested in Vineyard here in the United States. It is a 50% owner of that project. How is the cost of capital for offshore wind in the US compared to Europe? How much is the gap, if there is one?

MR. TORDRUP: It is difficult to say exactly what the gap is. I think there is a gap, but it is not significantly above the interest-rate differential between the two regions of the world. There are negative interest rates currently in Europe. There are positive interest rates in the US. Besides that difference, the capital cost varies from one project to the next. In terms of perceived riskiness of the sector, I think the US has caught up quickly.

MR. MARTIN: There were a number of lessons that people took away from the two US offshore wind projects that have sought financing to date: Block Island reached financing and Cape Wind fell a little short. One of those lessons is that it is important to move through the process as quickly as possible because the politics of the project can change in the midst of trying to finance it. Has this been an issue for Vineyard?

MR. TORDRUP: It is no secret that there is one specific permit that we did not get according to the timeline that had been put forward to us, but we are working through it and hopefully will get the permit soon so that we can move forward on the project. Apart from that one permit, things have moved expediently.

MR. MARTIN: Another lesson I think from Cape Wind is that the technology can change if you have to wait a long time to secure permits and then negotiate financing. It is too hard to go back and redo the permits. You reopen everything to opponents who want to challenge the project. Is it any different in Europe?

MR. TORDRUP: In Europe, there is more flexibility in what you can do. Many projects are put forward by the government, which has a plan for what it wants to see built. Permitting moves more objectively and is easier to plan for.

MR. MARTIN: Another lesson from Cape Wind was that a well-funded opponent — in its case, Bill Koch — can bleed the project to death by challenging it at every turn. Vineyard is 14 or 15 miles offshore. Is that far enough to insulate it from the sort of opposition that Cape Wind faced?

MR. TORDRUP: Our impression is that it has been a completely different exercise. We have worked diligently with the different stakeholders. We have had great support for the project both on Martha's Vineyard and Cape Cod. That is not what might hold the project back. We need to make sure the federal government gets comfortable with how it wants to build offshore wind. When it gets comfortable, the project will be built at some point in time in some shape or form.

MR. MARTIN: Yale Henderson said, while we were sitting at a table in the back waiting for this session to start, that a significant number of wind projects have run into issues this year with the Federal Aviation Administration. Is this an issue potentially for Vineyard?

MR. TORDRUP: That is less of an issue compared to onshore projects.

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The report lists deal elements that raise potential red flags in acquisitions of US companies. These include where the target company has access to classified or sensitive US government information or the foreign acquirer is controlled by a foreign government, especially where the foreign country has a poor record on nuclear non-proliferation or other national security matters or the country has a coordinated strategy of trying to acquire critical US technologies.

CFIUS is also more likely have issues with acquisitions of projects with offtake contracts with federal, state or local government agencies that have functions related to national security, and projects that "involve various aspects of energy production, including extraction, generation, transmission, and distribution" or that are near US military bases or other sensitive US government facilities.

In 2016, 10% of proposed acquisitions submitted to CFIUS for review were in the "mining, utilities and construction" sectors. The figure was 12% in 2017. The majority (13 of 18 in 2016 and 18 of 28 in 2017) involved the utility sector. Of those, 11 in 2016 and 15 in 2017 involved electricity.

Buyers from the following countries made the most filings in 2016: China (54), Canada (22), Japan (13), France (8), the United Kingdom (7), South Korea (6), Germany (6), British Virgin Islands (6) and Cayman Islands (5). There were few filings by buyers in the Middle East: Kuwait (1), Lebanon (1), Turkey (2) and the United Arab Emirates (1).

Filings in 2017 were concentrated among buyers from a similar, but not identical, list of countries: China (60), Canada (22), Japan (20), the United Kingdom (18), France (14), Cayman Islands (8), Switzerland (7), Germany (7), Holland (7), South Korea (6), Sweden (6) and Singapore (6). The few filings by buyers in the Middle East were from Kuwait (2), Saudi Arabia (1) and the United Arab Emirates (2).

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MR. MARTIN: Another thing that came out during Cape Wind was that US laws and inexperience with offshore wind add to the cost of projects. For example, the Jones Act and the Cargo Preference Act were adding as much as 50% to transportation costs in 2015 when Cape Wind was in the market. In 2015, the marine construction industry, ports, insurance and financial markets were all charging risk premiums for offshore wind. How much of an issue does this remain today?

MR. TORDRUP: It remains an issue. You have to price in the additional cost as a developer when you bid for a PPA. It makes projects more expensive and the electricity for the consumer more expensive.

The real issues with it as well as with the delays in securing permits are the technology is developing quickly and the four-year period the federal government allows to finish construction is too short for offshore wind. You end up in some situations with sub-optimal solutions. It means you will not always get state-of-the-art projects in this country.

MR. MARTIN: Another lesson from Cape Wind was that turbine vendors were unwilling to price turbines on a cost-plus basis. They insisted on value pricing. Is that still the case? And what is value pricing?

MR. TORDRUP: You should let the suppliers answer that question, but the markets are more competitive now than they were before. Just as for any other product, sellers try to do value-based pricing, but their ability to do it depends on the amount of competition.

MR. MARTIN: Value pricing means you do not look in a book for the price? There is no sticker like on the car in a dealer showroom?

MR. TORDRUP: I don't think any business that develops a product today looks at the price it cost to produce and then adds a margin. That might be an internal metric, but everyone wants to sell for the highest price the market will bear.

MR. MARTIN: How much competition are you seeing from vendors to supply 9.5-megawatt and 12-megawatt turbines?

MR. TORDRUP: The offshore wind market has never been more competitive from the turbine side than it is now.

MR. MARTIN: When do you lock in the price of the turbines? I assume you do not want to commit to turbines until you are about to start construction work in the ocean?

MR. TORDRUP: We did not want to choose the turbines upfront because there is value in avoiding an early-rush decision before you know it is the right decision to make. That is a problem with the ITC and PTC phasing down in amount. The carried interest rate cost to incur costs to start construction for tax purposes is high compared to the value of the tax credits, especially in cases where there are delays.

MR. MARTIN: Block Island is five six-megawatts turbines. It has a 48% capacity factor. Vineyard expects to use 9.5-megawatt turbines. What capacity factor do you expect?

MR. TORDRUP: It is not necessarily going to be different.

MR. MARTIN: You do not think it will be above 50%?

MR. TORDRUP: The turbines are much bigger at Vineyard, so it is not a relevant comparison.

Lessons to Date

MR. MARTIN: What other lessons have you drawn from your experience with offshore wind in the United States?

MR. PASQUALINI: I think there are misconceptions about what happened with Cape Wind. The major change has been in the size of the sponsors standing behind these projects. You have sponsors now coming to the table with deep balance sheets and vast amounts of experience building projects in Europe and elsewhere. They aren't looking for equity capital, and they aren't learning how to build an offshore wind project on the go. This is a different game now: from turbine technology, to siting, to sponsors who have the wherewithal to wait out anyone, no matter how entrenched the opposition.

MR. TORDRUP: And the cost of wind electricity is now a third of what it was before. There is not really a premium anymore.

MR. MARTIN: So offshore wind has become a real industry. It makes the financiers comfortable to see big balance sheets behind these projects. Yale Henderson, Nuno Andrade, what other lessons can be drawn from the experience with offshore wind in the US to date?

MR. ANDRADE: The strength of the sponsors is one reason why banks are so interested. Financing renewable energy in the US is hard compared to other places in the world. The incentives create huge distortions and more risk than is ideal. What banks like about offshore wind is you have strong sponsors, better contracts and the ability to create structures from scratch that are less risky.

MR. HENDERSON: This is the same evolution that we saw onshore wind, solar and other technologies go through. Everything is now coming together: the technology, the sponsors and, hopefully in the near future, the federal permitting process.

MR. ANDRADE: Another thing worth mentioning is risk perception. There is still a higher risk perception once the projects start running than is probably justified. That is the biggest lesson that the banks learned in Europe, and we are starting to see the risk perception shift here as well.

MR. TORDRUP: US offshore wind — when it is constructed — will probably have the best credit quality for renewable energy projects anywhere in the world. The contracts are longer here than they are in Europe, and when the projects move into the operating phase, output patterns will not look all that different.

MR. MARTIN: Project finance is an exercise in risk allocation. Nothing gets financed until all the risks are identified and each risk has been assigned to one of the participants. What is the biggest risk in offshore wind?

MR. TORDRUP: The risk is during development and construction. Construction on water can be challenging. When the project is up and running, it is not more risky than onshore wind. To the contrary, output is likely to be more consistent.

MR. MARTIN: Financiers, what's the biggest risk in these deals?

MR. ANDRADE: I agree with Henrik that the key really is construction, logistics, interface risk — getting comfortable with those — and obviously having all the permits ready to go.

MR. HENDERSON: For us, it is all about tax credit qualification and making sure that story can withstand IRS scrutiny.

MR. MARTIN: Last question: we have one operating wind farm in the United States — Block Island — five turbines, 30 megawatts. What do you think will be the next one and when?

MR. PASQUALINI: I am not going to offend Henrik; it will be Vineyard.

MR. TORDRUP: How soon is in the hands of the US Department of Interior, but I think it will be done relatively soon. ◎

IN OTHER NEWS

DEFICIT RESTORATION OBLIGATIONS and negative "tax basis capital accounts" are getting more attention from the IRS.

A deficit restoration obligation, or "DRO," is a promise by a partner to make a capital contribution to a partnership if the partner has a negative capital account when the partnership liquidates.

Each partner in a US partnership has a "capital account" and an "outside basis." These are two ways to track what the partner put into the partnership and is allowed to take out. If either metric turns negative, then it is a sign that the partner has taken out more than the partner is entitled.

In tax equity transactions in the US renewable energy market, the owner of a project usually brings in a bank or other tax equity investor as a partner to own the project. The partnership allocates tax benefits on the project disproportionately to the tax equity investor. The developer keeps a disproportionate share of cash.

The tax equity investor is likely to exhaust its capital account before it can absorb all the tax benefits. One way around this problem is for the investor to agree to put more money into the partnership in the event its capital account is still in deficit when the partnership liquidates. US tax rules allow the tax equity investor in such a situation to continue to be allocated tax losses (depreciation) by the partnership up to the amount of its DRO.

Many tax equity investors today are agreeing to deficit restoration obligations of up to 40+% of the original investment in order to absorb more of the depreciation on a project.

The IRS said in 2016 that it has concerns about "whether and to what extent it is appropriate to recognize DROs." The IRS proposed a list of factors at the time that it said may be a sign that the DRO is not real.

In October 2019, it incorporated them into final regulations. */ continued page 21*

Emerging Themes in Build-Own-Transfer Agreements

by Rick Susalka, in New York

Build-own-transfer agreements — also referred to as BOT or BTA contracts — are playing a bigger role in the renewable energy sector as utilities decide they would rather own projects than enter into long-term contracts to buy the electricity.

In a BOT contract, the developer usually retains the project and bears most construction-related risks until completion. The arrangement is an alternative to another common transaction in which the utility buys the rights to a project at notice to proceed with construction and thereafter bears construction risk.

BOT contracts are signed while the project is still in development and address what happens during three distinct phases: the later stages of development, the construction period and a post-completion period.

Negotiated BOT contracts tend to fall somewhere on the continuum between a purchase and sale agreement (PSA), on the one hand, and an engineering, procurement and construction (EPC) contract, on the other. The arrangement is PSA-like in that it is fundamentally an agreement for the sale of a project — albeit on a deferred basis — by the developer to the utility. At the same time, the parties usually want rights and protections that are more typically found in an EPC arrangement. For example, the utility wants extensive project approval rights and a broad covenant package, while the developer wants EPC-like protections, such as cost and schedule relief for changed circumstances.

BOT contracts vary widely, primarily due to the varied sensitivities and risk tolerances among individual developers and utilities. Project-specific differences can also require bespoke solutions. However, there are common themes.

Late Development Phase

BOT contracts usually have an initial, pre-construction phase that is a time-limited window for the parties to satisfy certain conditions to proceed to the construction phase. If the conditions are not satisfied within the agreed time, then the transaction may be terminated by either party.

Approval of the transaction by the utility's public service commission is the primary condition that must be satisfied during this stage. The developer will usually require, as an additional condition, that the utility has approved key elements of the project, such as the forms of construction contracts.

Where one of the parties has agreed to bear risks if the transaction moves into construction, it may seek relief if those risks materialize during this initial phase. For example, the utility typically bears change-in-tax-law risk under BOT arrangements, and it will usually want a right to terminate if such a change occurs during the pre-construction phase. The developer will wants similar relief if a circumstance outside of its control arises that would render it unable to satisfy milestone conditions during subsequent phases of the deal.

If the public service commission approves the contract, and the other conditions to move into construction are satisfied, before an outside date, then the transaction progresses into construction.

PSA v. EPC

BOT contracts are a hybrid of a PSA and an EPC contract. This becomes clear during the second phase. It is useful to lay out the two ends of the continuum before pointing out how a BOT contract falls in between.

In a simple PSA, a buyer (here, the utility) would agree to buy a project upon satisfaction by the seller (the developer) of certain closing conditions, primarily delivery of a completed project by an outside date. In a PSA, the developer bears the risk of most adverse developments before the sale, including developments that would render delivery of the project impossible. If the developer fails to satisfy the closing conditions, it receives no payment for its efforts but keeps the project.

In an EPC contract, the contractor (developer) builds the project at the direction of the owner (utility) to the owner's specifications. The developer is entitled to cost and schedule relief for many adverse developments outside of its control, and is entitled to periodic payments during construction as long as the developer fulfills — or is excused from — its obligations during construction. If the developer breaches the EPC contract, it is liable for damages that effectively reduce the contract price. Only in the most extreme cases would it not receive any payment.

In BOT negotiations, the utility prefers the best of both worlds, meaning it wants the risk allocation and payment terms of a buyer under a PSA but the control over construction of an EPC contract. The developer wants the flexibility and purchase-price premium of a PSA seller while benefitting from the protections typically afforded to EPC contractors. The negotiated BOT contract must land somewhere in between.

An example of how this tension plays out is how the BOT contract deals with schedule delays. In a typical EPC contract, the contractor must keep the construction on schedule. In a typical PSA, the seller is not held to any particular milestone schedule, although it risks losing the sale if it fails to deliver the completed project by an outside date.

A reasonable middle ground for a BOT contract might be for the parties to agree to generous cure periods for schedule delays, but only so long as the project is still expected to be completed on time. This is a compromise between the developer's desire for flexibility to address construction-period issues without losing the sale, on the one hand, and the utility's desire for certainty that the project will be delivered by an outside date, on the other.

Developers should be wary of other EPC-like covenants requested by utilities.

EPC contracts have covenants requiring the contractor to avoid doing things that will impose liability on the owner. An example is polluting the project site. Such covenants are arguably out of place in a BOT contract, where the developer remains the owner of the project and project site during construction.

Consideration should be given to the harsh consequences of breaching an EPC contract versus a BOT contract. In an EPC contract, the contractor is paid as it completes milestones, and the owner's remedies for contractor default are linked to the loss of value or damages suffered by the owner. In a BOT contract, the developer often earns nothing unless and until the conditions to transfer are satisfied, and a developer breach could lead to termination of the contract. In a case of partial performance, an EPC contractor would generally be permitted to retain the payments it has received, except as required to compensate the owner for the loss of value or damages suffered by the owner due to the contractor's failure to perform fully. In the same scenario, the developer under a BOT contract could be left with ownership of a substantially completed project, but without any arrangements to sell the project or the electricity it generates.

The risk to the developer might be mitigated by agreeing to EPC-like covenants in exchange for an extended cure period — perhaps up to the completion deadline itself — to cure defaults.

However, such a compromise would not address a scenario in which the developer has substantially performed under the BOT contract, but finds itself unable to / continued page 22

IN OTHER NEWS

IRS regulations now say that a DRO will be ignored in two situations. One is where the facts suggest "a plan to circumvent or avoid" the deficit restoration obligation. The other is where the DRO is a "bottom dollar payment obligation" or is not legally enforceable.

Facts that suggest a plan to circumvent or avoid the obligation are the DRO is "not subject to commercially reasonable provisions for enforcement and collection of the obligation," the partner is "not required to provide (either at the time the obligation is made or periodically) commercially reasonable documentation regarding the partner's financial condition to the partnership," or the DRO ends or can be terminated before the partnership liquidates or while the partner still has a negative capital account.

The practical effect is to impose a net worth test on the tax equity investor to make sure it can satisfy the DRO.

The other situation where a DRO will not be respected is where it is not legally enforceable or is a bottom dollar payment obligation. That is an obligation that is illusory because someone else has promised to reimburse the partner or the real burden is split among other parties by using tiered or upstream entities, legal subordination and other tools.

Separately, in early December, the IRS delayed for another year an effort to require partnerships to report "negative tax basis capital accounts" on partnership tax returns. The IRS announced the delay in Notice 2019-66.

The IRS first tried to require such reporting on 2018 tax returns, but tax advisers were confused about what it had in mind. It planned to try again on 2019 tax returns filed next year, but tax advisers remain confused. The requirement to report negative tax basis capital accounts will now not take effect until 2020 tax returns are filed in 2021.

The agency issued a list of frequently-asked questions and answers in November in an effort to clear up the confusion.

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BOT Contracts

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satisfy the closing conditions and thereby consummate the sale. One way to address this is for the parties to agree to close on the sale so long as the aggregate economic consequence of the breaches does not exceed a pre-agreed threshold, but the utility is permitted to withhold a commensurate portion of the purchase price unless and until the breaches are resolved. Such a mechanism provides the developer and its lenders greater certainty that the closing will occur, while reasonably protecting the interests of the utility via the holdback.

Timing of Transfer

Another area of focus in BOT negotiations is the timing of transfer.

The simplest structure — which is common in BOT contracts for wind projects — provides that the project is transferred, and the purchase price is paid in full, only when the project is satisfactorily completed. This usually happens at "substantial completion."

This does not work where the utility wants to claim an investment tax credit on the project. In that case, the utility must own the project at "mechanical completion." The utility pays a portion of the purchase price then and the rest when the project reaches substantial completion.

Some BOT contracts transfer the project at the start of construction, with an upfront milestone payment by the utility and subsequent payments during construction as milestones are met. These contracts are much closer to the EPC end of the EPC-to-PSA continuum and raise a set of unique issues that are beyond the scope of this article.

There are complications with any BOT arrangement that transfers the project before final consummation of the project sale.

One complication is that the developer — and, to the extent the developer finances construction, its lenders — may struggle with allowing the project to be conveyed before payment of the full purchase price. Lender concerns might be addressed if the amount paid at project transfer is enough to discharge the project debt or if the project is transferred subject to the lender's lien.

The unintended consequences of changing ownership while construction is ongoing present a second complication. The developer needs the ability to direct subcontractors, handle disputes, have access to the site, and so on, to complete its work. These developer rights can create tension with the utility's interest in protecting itself against exposure to third-party claims after it has acquired the project.

A third complication is: what happens if the sale is not fully consummated after the project has been transferred? To the extent a BOT contract contemplates an asset transfer rather than equity transfer, a simple unwind of the transaction is complicated, as it is easier to re-transfer equity in a project company than to transfer back all elements of a project (including the site, permit rights, project contracts, and so on).

Developer Risks

The conditions to closing — and receiving payment — are another key area of focus in BOT negotiations.

The developer is eager to avoid a scenario in which it constructs the project to the utility's specifications and is unable to close the sale — and thereby recoup payment for its efforts — due to a failure to satisfy all conditions. The concern is significant in all cases, but it is particularly acute if there are limited other uses for the project: for example, if the project is in a location that does not have a merchant energy market.

The developer can mitigate this risk by limiting ambiguity and subjectivity in the closing conditions. One common technique is to is to agree on baselines against which the satisfaction of conditions will be measured.

Another mitigant, discussed earlier, is for the parties to agree that closing can occur even while one or more conditions remain unsatisfied, so long as the aggregate economic consequence of the unsatisfied conditions falls below a dollar threshold and the utility is permitted to hold back a corresponding portion of the purchase price.

Developers should scour the list of closing conditions to ensure that they do not shift to the developer risks that it is unwilling to accept.

Developer Exposure

The developer's exposure to liability during the various phases of the transaction is a key area for commercial negotiation.

Both parties want to avoid liability if the project fails to move to construction.

Once the project is in construction, the developer's liability for failure to complete the project on time is heavily negotiated. The first challenge is arriving at a mutually agreeable evaluation of the actual harm that will be suffered by the utility if the transaction is not consummated, given that the harm is mostly intangible in nature.

The second challenge is reaching agreement on the circumstances in which the developer should have to compensate the utility for that harm.

The developer wants to avoid a scenario in which it has tailored a project to a utility's specifications, and used its own equity and potentially also borrowed money to fund construction of the project, only to run into an issue during construction that cannot be overcome and, as a result, faces the prospect of not only losing the BOT contract, but also paying a break fee. The developer's concern is particularly acute to the extent the closing conditions allocate to the developer risks that are beyond the developer's control.

BOT contracts with utilities are hybrids between a purchase and sale agreement and a construction contract.

The developer's liability to pay indemnities after the project has transferred is also heavily negotiated, with the developer usually seeking to limit its exposure to a percentage of the contract price it received, with that percentage reducing over time. The utility typically seeks certain exclusions from this cap, including for certain fundamental representations. Developers usually agree to limited exceptions, while still capping their aggregate liability at the purchase price received. Some developers buy representation and warranty insurance to protect against post-completion indemnification liability exposure.

Project Warranties

Another key topic related to the post-completion period is warranty coverage.

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IN OTHER NEWS

"Tax basis capital accounts" appear to be a hybrid between the two existing metrics — capital accounts and outside basis — that partners already track. They are basically the outside basis a partner has in its partnership interest, but just the remaining equity the partner has in the partnership. Normally a partner's outside basis also includes its share of any debt at the partnership level. This would be backed out of outside basis to calculate the "tax basis capital account." The frequently-asked questions and answers sometimes also call this the "tax capital account."

It is not clear why the IRS feels it needs a new metric in addition the two it already has.

A tax basis capital account can go negative either because a partner is allocated more losses or distributed more cash than it has equity in the partnership or because the partnership takes assets subject to a debt when the partner contributes assets, and the debt exceeds the tax basis the partner has in the assets.

The questions and answers suggest that someone buying a partnership interest inherits the tax basis capital account of the selling partner. This is how regular capital accounts rather than outside basis works. Some other suggestions in the questions and answers about how section 754 step ups affect the calculation of tax basis capital accounts in situations where a partnership interest is sold are contradicted by the instructions the IRS issued with the draft 2018 and 2019 partnership tax returns. The IRS still has some work to do to iron out the lingering confusion.

THE LIBOR TRANSITION became a little easier in October.

Most debt in project finance transactions and many swaps, hedges and other contracts are tied to LIBOR. For example, a loan might require payment of floating interest at a spread 137.5 basis points above LIBOR.

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The utility's right to project warranty coverage is not controversial. The source of the warranty coverage may be, particularly where the developer has engaged third parties to perform the work.

The utility will often seek a wrap warranty from the developer, as well as assignment of any warranties from the developer's vendors and construction contractors. A developer who engages third-party contractors to build the project wants to limit its warranty obligation to handing over the third-party warranties it receives, with warranty-related issues thereafter resolved directly between the utility and third-party providers.

In cases where the developer agrees to provide a wrap warranty, it should be careful to align its warranty with the corresponding third-party warranties it receives, and should ensure that it retains access to those third-party warranties after sale of the project.

In cases where the developer's warranty responsibility is limited to transferring third-party warranties to the utility, the developer should ensure that its representations, warranties and certifications do not create a backdoor to warranty-like exposure. For example, the developer should ensure that the project's satisfaction of construction milestones is certified by the third-party contractor that did the work and not also certified by the developer. ◎

Solar Finance Outlook

A panel of two sponsors, two lenders and one tax equity investor rolled quickly through a wide range of topics of current interest at the Solar Power International 2019 convention this fall in Salt Lake City. The following is an edited transcript.

The panelists are Meghan Schultz, senior vice president for finance and capital markets for Invenergy, David Shipley, chief financial officer of sPower, Andy Redinger, managing director and group head of utility and alternative energy for KeyBanc Capital Markets, Daniel Siegel, vice president for renewable energy business with US Bank, and Chris Diaz, co-CEO of Seminole Financial Services. The moderator is Keith Martin with Norton Rose Fulbright in Washington.

New Developments

MR. MARTIN: Meghan Schultz, what new developments have there been this year in how solar projects are financed?

MS. SCHULTZ: Banks are willing to take into account revenue beyond the term of the power purchase agreement when deciding how much to lend.

MR. MARTIN: How many years of such revenue?

MS. SCHULTZ: Several.

MR. MARTIN: What does "several" mean?

MS. SCHULTZ: Three to five.

MR. MARTIN: Andy Redinger, new trends?

MR. REDINGER: I'll name a few. Rapid growth in residential rooftop, PACE financing for C&I projects and deal-contingent swaps for utility-scale projects.

MR. MARTIN: We will come back to some of that. David Shipley, new trends?

MR. SHIPLEY: Same as what Meghan said. We do utility-scale solar, and we have seen both the banks and the institutional market not so much willing to lend beyond the term of the power contract, but the banks are doing mini-perm loans that mature typically in five or seven years, and the amortization period extends beyond the contract period.

Also, I think we have moved beyond the simple busbar, fixed-price, unit-contingent contracts. We have some level of merchant risk. We have capacity payments that may be contracted for a short period of time. The combination of merchant, capacity and post-PPA revenues are all being taken into account in debt sizing. That has been the biggest change because historically the banks have been at PPA term minus one or two years for the amortization period.

MR. MARTIN: What amortization period is used?

MR. SHIPLEY: It depends. Meghan touched on it. If you have a shorter-term contract in a very liquid market, you may be able to get the lenders to push to five years. An example is a 10-year contract in PJM where you may be able to get the lenders to take into account five years of merchant revenue.

If the project is in a not-so-liquid market and it already has a 20-year contract, the banks are not going to push the amortization period beyond the contract term to 25 years. It also depends on whether there are other factors. What is the credit risk? Is there a capacity market? If you have a super clean deal with a 10-year PPA, getting banks to go to 15 years for amortization is definitely possible.

MR. MARTIN: What percentage of the revenue needs to be contracted?

MR. SHIPLEY: We don't really think of it that way. It is more a matter of looking at the contract term. If the amortization period runs beyond the contract term, it will create a balloon payment, so there is some sensitivity to that.

MR. REDINGER: David is spot on. Financing for renewables projects seems to be moving in the direction of how banks have been financing merchant gas-fired power plants. If KeyBank is going to provide credit to merchant revenue when sizing debt, we think about the size of the balloon at the end of the contract term and the remaining useful life of the project and estimate the number of years it would take to repay our remaining debt balance.

MR. MARTIN: Himanshu Saxena, CEO of Starwood Energy, said at the REFF conference in New York in June that it is not unusual for the equity investor to get back only 30% of its investment by the end of a 10-year PPA term.

MR. REDINGER: That is good the investor is getting even that. It depends on the deal, but if the investor is getting its money back by the end of the contracted period, then the investor is doing well.

MR. MARTIN: Dan Siegel, new trends?

MR. SIEGEL: Not surprisingly, we are fielding a lot of safe-harbor questions currently around start of construction. We are active in all solar markets, but the most recent trend has been in community solar and in batteries tied to solar projects. In utility-scale solar, we are seeing more corporate PPAs and hedges.

MR. MARTIN: So it becoming a much more complicated market. Chris Diaz, new trends?

MR. DIAZ: Dan Siegel stole my thunder, but we focus on projects that are one megawatt to 40 megawatts in size. We are seeing a lot of community solar */ continued page 26*

IN OTHER NEWS

The UK Financial Conduct Authority has not committed to publishing LIBOR past 2021.

The Federal Reserve Bank of New York began publishing a secured overnight financing rate, or "SOFR," in April 2018 as a replacement for LIBOR for US-dollar denominated instruments. Other countries have chosen other reference rates for their currencies. For example, the UK will use a sterling overnight index average called SONIA, and Japan will use a Tokyo overnight average rate called TONAR. Separate reference rates have been selected for the Eurozone, Canada, Switzerland, Australia and Hong Kong.

Debt instruments and non-debt contracts that refer to LIBOR will have to be amended or replaced.

Under US tax rules, any debt instrument that undergoes a "significant modification" is considered to have been exchanged for a new debt instrument. This can trigger taxes. There is limited guidance about the tax consequences of amending non-debt contracts.

The IRS made the LIBOR transition easier in October.

It said in proposed regulations that it will not view a debt instrument or other contract as having changed if it is amended, or replaced with a new instrument, to substitute a new reference rate or provide a fallback to LIBOR.

However, three things must be true.

First, the amended instrument must be substantially equivalent in value. Second, there cannot be a change in currency. Third, the new reference rate chosen must be a "qualified rate," meaning a rate, like SOFR, selected or recommended by a central bank or similar authority.

As part of the LIBOR replacement, one party may have to make a one-time payment to the other party to keep the two instruments equivalent in value. The general principle that the instrument is considered unchanged extends to any such "associated alterations" related to the LIBOR replacement

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transactions. We are seeing a lot more storage as well. Also, it is not a new trend, but REAP loans from the US Department of Agriculture are becoming more prevalent.

You were talking earlier about merchants and longer amortization periods. USDA REAP loans are usually for $600,000 to $25 million in amount, and they can be made with 25-year amortization on a 20-year PPA, and then you have a merchant tail of five to 10 years after that.

Starting Construction

MR. MARTIN: One of the biggest challenges for solar companies this year has been how to start construction of as many projects as possible for tax purposes so that the projects will qualify for investment tax credits at the full 30% rate. Meghan Schultz, how are you seeing sponsors start construction?

MS. SCHULTZ: There are obviously two ways to start construction. You can acquire equipment and use the 5% test and you can do physical work of a significant nature. The physical work can be onsite at a project or on certain equipment offsite. From what we hear from different sponsors, companies are using a combination of those methods. That is similar to what has been done in the wind industry.

Wind developers were up against the same deadlines starting in 2016, so there is a well-worn path at this point for starting construction. It seems like there has been more noise around solar this year because the pure solar developers may not have had to go through the process of financing projects where the construction-start date is important.

MR. MARTIN: Are you stockpiling equipment to qualify under the 5% test?

MS. SCHULTZ: We are using a combination of strategies. They include buying modules for use in future projects.

MR. MARTIN: Are you also relying on physical work and, if so, what work?

MS. SCHULTZ: Yes. We are buying transformers for some projects and doing onsite work at other projects. In order of preference, if you could start work onsite at all your projects, you would probably do that because it is the lowest cost approach, but many projects lack permits to start work on site. Our approach varies from one project to the next.

MR. MARTIN: In cases where you rely on physical work on site, how much work do you try to do?

MS. SCHULTZ: There is no dollar requirement. There is no certain percentage requirement. In the wind industry, an example in the IRS notices suggested digging 10% of the turbine foundations was enough. That is what a lot of people did because you could point to a specific example. So, turning to solar, we are putting in a similar percentage of inverter piles.

MR. MARTIN: David Shipley, how is sPower starting construction?

MR. SHIPLEY: Same. The projects fall into two buckets for us. We have projects that are expected to be delivered in 2020 or 2021 where we expect to reach notice to proceed with construction on site this year. Those projects will be truly under construction before year end, although the percentage of work completed varies by project. For other near-term projects, we may rely on offsite physical work: something like 20% inverter skids in conjunction with main power transformers. For 2022 and 2023 projects, we are more focused on the 5% test. We are acquiring modules and taking physical delivery at the end of this year or paying for the modules at year end this year and taking physical delivery early next year.

Our reliance on the 5% test happened somewhat naturally. We have a significant pipeline of development assets. Last year, we were very concerned about the tariffs and uncertainty surrounding trade issues. In order to do some hedging, we found that doing three- and four-year purchase agreements gave us some front-end pricing benefit, and so we ended up being a little long on modules in 2019 and early 2020 which gave us safe-harbor equipment.

Banks are willing to credit three to five years of revenue after the power contract ends for sizing loans.

MR. MARTIN: Dan Siegel, how comfortable is US Bank with relying on physical work?

MR. SIEGEL: Obviously we work closely with our tax counsel. Most questions we are fielding currently are primarily around offsite physical work. Typically these are companies that are thinking long term about how to safe harbor, aren't necessarily comfortable with the the cost to write a 5% check on modules, so they want to figure out a way to have binding contracts with suppliers on things like transformers or centralized inverters. That is where we spend a lot of our time. We see many different fact patterns.

The utility-scale solar developers know what they are doing. We are more concerned about developers in the non-utility sectors, like residential and small C&I, where it is harder to find non-inventory equipment on which to start physical work and where developers may be less careful. We worry about having to analyze this retroactively after the fact.

MR. MARTIN: Do you have a rule of thumb for how much work you want to see done on transformers before year end?

MR. SIEGEL: No. We commonly see radiators being worked on with transformers. I think the real question is whether the contract to buy the transformer is binding. We spend a lot of time thinking about whether the contract is cancellable for a minimum fee. If so, it begins to look like an option rather than a binding contract to buy a transformer.

Tariffs

MR. MARTIN: Come back to tariffs. Are vendors absorbing the tariffs?

MS. SCHULTZ: I think it is a negotiation, but it is not an easy negotiation.

MR. SHIPLEY: Same. The tariffs are affecting not only the cost of solar modules, but also wind turbines and towers because of the tariffs on steel and other components. We try to negotiate protection. I don't think we are able to get direct tariff protection, but I think we have addressed this through other provisions in the documents.

MR. MARTIN: Like what?

MR. SHIPLEY: I'm going to rephrase that. Less contractual and I think more building really strong relationships with suppliers. Instead of spreading the wealth among suppliers, we create partnerships with particular suppliers where, if things do turn, they will work with you to help cover the costs.

MR. MARTIN: Are export credit agencies helping to reduce the cost of stockpiled equipment purchased / continued page 28

IN OTHER NEWS

Requiring that two instruments remain substantially equivalent in value to avoid triggering a tax creates risk.

The IRS provided two "safe harbors."

One is where the parties to the instrument are unrelated and determine through negotiation that the amended instrument or contract remains substantially equivalent in value.

The other requires mapping how the new rate compares historically to LIBOR. As long as the two rates have remained within 25 basis points of each other on average, then the values will be considered substantially equivalent. The lookback period for calculating averages cannot be more than 10 years or end more than three months before the rate is replaced.

Some debt instruments are exempted from changes in tax law that took effect after they were issued. They will not be considered to have been reissued for purposes of such grandfather provisions on account of replacing LIBOR.

Most lenders and borrowers have not updated their existing debt instruments yet. Anyone issuing a new loan or hedge must consider whether to punt for now or write the replacement rate into the instrument. Another option is a hybrid approach of hardwiring the changeover, but leaving the rate and spread to be filled in later.

TWO NEW TRUMP EXECUTIVE ORDERS may make it harder to get guidance from federal agencies in the future about what US law requires.

The orders direct federal agencies to cut back on the amount of "sub-regulatory" guidance they issue — notices, memos and letters — as opposed to more formal guidance requiring notice and comment periods. Formal guidance takes more time.

One of the new executive orders requires agencies to post all / continued page 29

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from foreign vendors?

MS. SCHULTZ: We have not been using export credit agencies for this.

MR. SHIPLEY: Same.

Inventory Loans

MR. MARTIN: There was talk earlier in the year about inventory loans to help developers stockpile equipment. Have you seen any such loans close? Why are they so hard to close?

MR. SIEGEL: We have seen a couple developers on the smaller end of the market close on equipment loans. Make sure that you are in close contact with your CPAs and attorneys to do the right things, and then document, document, document. Pictures say a lot especially if they are time stamped. You do not want to get into a situation where you think you did the right thing, but it turns out you did not.

MR. DIAZ: We are making such loans, and I think you will see several of them close in the next 60 days. They are complicated. They take longer to put together because all of the pieces you have to think about.

MR. MARTIN: Why are they so complicated?

MR. DIAZ: We have to believe the value in our collateral will be preserved if we have to foreclose. We want to see some additional collateral value beyond just the bare equipment being financed.

MR. MARTIN: How much additional collateral value?

MR. DIAZ: It depends on the situation and the relationship. Sometimes a little, sometimes a lot. Beyond that, it takes time to get your arms around managing the equipment, the logistics of working in the warehouse, transportation, insurance, tracking serial numbers . . . .

MR. MARTIN: All right, you have persuaded us there is a lot to cover.

MS. SCHULTZ: As a developer, you want to save this equipment to use as late as you can. That is in conflict with what the lenders want. They want as much certainty as possible on day one where the equipment will be used. The complication is how to bridge that gap.

MR. MARTIN: Invenergy is pretty well capitalized. Has it been interested in this sort of financing?

MS. SCHULTZ: Yes, we have. We used such a loan in our wind business. I think there were only two others that were done. We will take a similar approach for solar where I think you probably have a handful of such loans.

MR. MARTIN: Have you closed on such a loan yet?

MS. SCHULTZ: We don't normally comment on that.

MR. MARTIN: You said "normally." [Laughter]

MS. SCHULTZ: . . . .

Corporate PPAs and Hedges

MR. MARTIN: Andy Redinger, the market is moving to a corporate PPA and hedge market. How is it affecting financings?

MR. REDINGER: It puts some pressure on the banks, but lenders are finding ways to accommodate the shift.

MR. MARTIN: You said famously at a past conference that banks should be able to get comfortable with less predictable revenue streams. After all, they finance McDonald's based on hamburger sales.

MR. REDINGER: That's correct. Banks regularly provide loans to many corporate clients without requiring the product to have been pre-sold.

MR. MARTIN: So the answer is that the banks are rolling with this. They are getting less and less contracted revenue, but they are figuring out how to make it work.

MR. REDINGER: Correct.

MR. MARTIN: Do the financing terms change as you get to maybe 40% contracted revenue instead of 100%? You have cash sweeps, shorter tenors?

MR. DIAZ: Yes, all of that depending on the percentage of contracted revenue. We are trying to be constructive so we will come up with a structure with bells and whistles. We may size the loan differently. We may have cash sweeps.

Batteries

MR. MARTIN: Another new trend is developers are installing more and more batteries. SunPower told us that 25% of its projects at this point have batteries in them. Dan Siegel, how does adding a battery affect the financing? You are doing tax equity.

MR. SIEGEL: We have been going through a process of evaluating storage equipment for some time. Like anything else related to a solar plant, you want to make sure that you are using tier-one equipment. We have been watching things like the Arizona Public Service battery fire, for instance, and trying to learn as much as we can.

That said, transactions are less about the equipment and more about the revenue streams. There are different ways to monetize batteries. We need to understand the different potential revenue streams and which are reliable enough to take into account in sizing tax equity and which are still too speculative.

MR. MARTIN: Adding a battery adds to the capital cost of the project. Does the battery bring in enough additional revenue to cover the cost?

MR. SIEGEL: It depends on the market. We have been doing behind-the-meter batteries with our friends at residential solar companies for some time. The SMART program in Massachusetts has battery adders that provide an incentive to add batteries.

MR. MARTIN: David Shipley, does it feel like we are at a tipping point on batteries?

MR. SHIPLEY: It feels like the early days of solar. Our parent company, AES, has done a lot of storage. At sPower, we have not financed storage yet. It will be interesting to see where the independent engineers and appraisers come out on storage in terms of degradation, useful life and everything that feeds into the revenue forecast.

MR. REDINGER: Depending on whether the battery will be used in a bundled PPA with a fixed capacity payment or some form of arbitrage where you are shaping production to improve the pricing, more analysis will be needed into when you are charging and discharging and what prices you can earn from doing that.

MR. MARTIN: What percentage of projects are expected to have batteries this year?

MS. SCHULTZ: I don't have a number for you. Whether batteries will be part of our projects going forward depends on receiving a clear price signal from the market. We have not seen one yet. We are not planning to build merchant storage. We need some revenue stream associated with it.

MR. MARTIN: Invenergy has standalone storage facilities.

MS. SCHULTZ: That's true. We have about 60 megawatts of operating batteries that we put in place in PJM around five years ago. That made sense at the time based on the ancillary market revenue that was available in PJM.

The mechanism in PJM has changed, so we are not considering any other such projects at this time. However, it is public that we signed an agreement with Arizona Public Service to build storage for it more on a build-transfer-type basis.

Tax Equity Terms

MR. MARTIN: Switching gears again, what are current rates for tax equity? I know tax equity investors are reluctant to say them, so let me put something out and see if you disagree with this.

For utility-scale solar, we see 6.25% to 6.8% as the flip yield in partnership flip transactions. For / continued page 30

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guidance on a searchable website. Anything not posted is considered rescinded.

The other order is supposed to prevent federal agencies from holding companies to standards that are in a "guidance document" as opposed to a statute or regulation. A "guidance document" is a ruling or notice that answers a technical question or interprets a statute, as opposed to a regulation that is only issued after notice and a period for public comment. Agencies are now barred from imposing "new standards of conduct" in guidance documents "except as expressly authorized by law." The goal is to prevent the government from holding companies to standards that are "announced solely in a guidance document."

Both executive orders were issued on October 9. They are EO 13891 and EO 13892.

Independent agencies like the Federal Energy Regulatory Commission or US Securities and Exchange Commission are not affected.

It is unclear to what extent the executive orders will force the IRS to scale back on taxpayer guidance. The IRS historically has used lots of different tools to help taxpayers understand how it reads the law. Most are helpful because they fill in missing detail. Some put the market on notice about things that the agency finds troubling.

The US Treasury said in March that it will cut back on issuing notices, limit the use of temporary rules and focus on notice-and-comment rulemaking. This was in the midst of a rush of proposed and temporary regulations and other guidance to implement a bill that Congress passed at the end of 2017 to overhaul the US corporate income tax.

Each agency will have 120 days after the Office of Management and Budget issues a memo implementing the executive orders to review all guidance documents and rescind ones that no longer apply. This has the potential to take agency lawyers away from issuing any new guidance. / continued page 31

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inverted leases, which tend to price as dollars per tax credit, rates are between $1.09 and $1.14. Do those sound right?

MR. SIEGEL: You are in the ballpark. We see some utility-scale transactions where yields have been a little lower.

MR. MARTIN: In which direction are they moving?

MR. SIEGEL: I can only speak for us. We are holding our pricing going forward. It is an interesting market because it is driven by supply and demand.

I think there will be a rush of projects over the next several years as developers try to beat the cliff on expiration of tax credits. That suggests there will be more tax equity demand than supply.

USDA REAP loans can be made with 25-year amortization on a 20-year power contract.

The effects will not be evenly distributed. Developers who have relationships with particular tax equity investors should find the investors are still there for them. There may be challenges in the C&I market which has always been relatively inefficient. That is the market that is most likely to be affected by any scarcity.

MR. SHIPLEY: Tax equity yields turn on supply and demand, but let's not lose sight of the fact that power prices are going down. Project economics are going to be much tighter. Tax equity investors are motivated to get money out the door, so they are not arbitrarily setting yield.

As a sponsor, if I can't make my project work for the cost of capital on offer, the tax equity investors have to react to that. They have. I think that's why we have seen flip yields come down. The point is yields are not solely a function of supply and demand, but other factors also play a role.

MR. MARTIN: So it is a negotiation at the end of the day.

MR. SHIPLEY: Yes, it's a negotiation. When I did my first wind deal, we got the equivalent of LIBOR plus 600 basis points on a pre-tax basis. That is a really good investment given the risk.

MR. MARTIN: What percentage of the typical capital stack for utility-scale solar is tax equity today? 35%?

MS. SCHULTZ: Thirty to 40%.

MR. MARTIN: What percentage is back-levered debt?

MR. DIAZ: Forty to 50%

Debt

MR. MARTIN: Andy Redinger, you said at the REFF conference in June that 75 basis points over LIBOR was down the fairway for construction debt and you were seeing 125 over LIBOR for term debt. Still true?

MR. REDINGER: For down-the-middle-of-the-fairway deals, that is still unfortunately true. The frustrating part is that I am typically back-leveraged, have more operating risk, longer tenor with a negotiated standstill and still have a return that is 200 to 300 basis points lower than tax equity. That doesn't make any sense. I contend that tax equity needs to get cheaper.

MR. MARTIN: Dan Siegel, that's smack talk. [Laughter]

MR. SIEGEL: I can only speak for us. US Bank is a little unusual. So we will put out about $1.2 billion in tax equity this year. Half of that will be placed ultimately with syndication partners.

Most of the partners are not financial institutions. They are retail corporates, tech companies and insurance companies. When they look where to put their cash, they look not only at tax equity, but also at stock buybacks or at opening new stores and doing many other things with their money.

MR. MARTIN: So the yield has to be better than the alternatives.

MR. SIEGEL: I think our peak was in 2015. There was a ton of project pull-in from the anticipated expiration of the investment tax credit that year.

MR. MARTIN: Have any of you seen front-levered debt?

MR. REDINGER: Yes. The debt is effectively front-levered in an inverted lease. The tax equity investor is the lessee. The debt has project-level collateral at the lessor level. The lessor owns the project and is the borrower.

MR. MARTIN: The UK authorities will stop tracking LIBOR at the end of 2021. How is the market dealing with this?

MR. REDINGER: Just language about when we move to a new benchmark.

MR. MARTIN: What does the language say?

MR. REDINGER: It says we'll figure it out.

MR. SHIPLEY: He's right. There is language to the effect that we will adapt. It requires a leap of faith. We will probably get into the institutional market, which is not a LIBOR-based market, to refinance our bank deals.

MR. MARTIN: Institutional market meaning fixed rate?

MR. SHIPLEY: Yes, with insurance companies and pension funds as lenders. It is a fixed-rate market tied to treasury yields and locked in for a term.

Macroeconomic Effects

MR. MARTIN: Europe has $17 trillion in debt with negative interest rates. Trump would like our central bank to follow Europe's lead. How would negative interest rates affect the market?

MR. REDINGER: We rely on deposits to provide financing. If we go to negative interest rates, we are going to lose that deposit base. It will increase the cost of funding.

MR. MARTIN: Increase the cost, even though people are paying you to take their money?

MR. REDINGER: I don't think we will be paid by people to take their money. The deposit base will disappear.

MR. MARTIN: Where will the money go?

MR. REDINGER: It will not sit in our bank. It will go somewhere else. I am pretty certain of that.

MR. SHIPLEY: I can't say that I spend a lot of time thinking about negative interest rates, but my quick reaction is that it will help with equity sell downs. If we can offer a stable dividend, investors will put their money into that rather than a debt instrument paying a negative return.

The other point of view is that negative rates mean that we will devalue our currency. A lot of money that has come into the US has been attracted to the currency. A weakening dollar would make the US a less attractive place to invest.

MR. MARTIN: The inverted yield curve and the spike in overnight borrowing rates last week are giving the market jitters. What will happen to tax equity and debt if the US economy tips next year into a recession? What / continued page 32

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In the future, any "significant guidance document" will have to run a bureaucratic gauntlet before it can be issued. There must be a notice and comment period of at least 30 days, and an agency response to all major concerns raised in comments, before it can take effect, and it will have to be approved on a "non-delegable basis" by the agency head or subhead — for example, by the US Treasury secretary or the head of the IRS, which is an agency within the Treasury, and then sent for vetting to the office of information and regulatory affairs or "OIRA," an office within the Office of Management and Budget at the White House.

Meanwhile, the IRS issued a "priority guidance plan," or list of 203 issues on which it hopes to issue guidance by June 30, 2020. The IRS has been issuing such lists annually since 1992. The lists are usually released in August. This one was not released until October. The IRS is usually able to address only a fraction of the items on the list. Items not addressed are often carried over to the next year.

A number of issues on the current list are of interest to the project finance community.

The IRS is rewriting its regulations on when investment tax credits can be claimed on such things as solar facilities, geothermal power plants, fuel cells and batteries. The agency has been working on this project since 2015.

The market is eagerly awaiting guidance on when tax credits can be claimed for carbon sequestration, meaning trapping carbon dioxide emissions and disposing of them in a secure geological formation or using them for such things as enhanced oil recovery. A tax equity market may develop around carbon sequestration projects after the guidance is issued. (For more detail, see "Tax Equity and Carbon Sequestration Credits" in the April 2018 *NewsWire*.)

New regulations for investments in opportunity zones are under review at OIRA and should be out soon. / continued page 33

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happens in these markets during a recession?

MR. SHIPLEY: It may have a bigger effect on debt than tax equity. It was 2008 and 2009 when more investors started thinking about getting into tax equity. They were looking for ways to put their money to work in a market where other investments, like real estate, were not looking so good.

MR. MARTIN: People held on to cash in 2008 and 2009, so anyone with cash to offer was in a good position.

MS. SCHULTZ: I think it depends on what causes the recession. In 2009, you had big financial institutions that still had tax capacity. I don't know that that would necessarily be the case in the next recession. Overall, there will probably be less liquidity in the market, leading to a higher cost of capital.

Debt in an inverted lease is effectively front levered.

MR. MARTIN: Next question: tax changes are almost certain no matter who wins the national elections in November 2020. How is change-in-tax-law risk playing out in deals?

MR. SIEGEL: We went through this recently. Congress rewrote the corporate tax laws at the end of 2017. There was a lot of brain damage that went into addressing this risk during 2017 when it was clear tax changes were possible.

Frankly, most of the language used in 2017 remains in our tax equity documents.

MR. MARTIN: For how long are you protected?

MR. SIEGEL: That's a good question. We ask typically for protection for a session or two of Congress.

Electricity Basis Risk

MR. MARTIN: One of the big issues currently is electricity basis risk as the market moves from traditional utility PPAs to virtual PPAs with corporations and other forms of hedges. How are sponsors dealing with this risk? How do financiers view it?

MR. SHIPLEY: It is a component of most of our transactions. Now even the utilities that historically were buying electricity at the busbar under physical delivery contracts are now moving toward basis-type contracts where we are settling at the hub. Corporates are also settling at the hub. It has changed our company. It used to be easy for us to do solar. I did not really need to know a lot about the energy markets, just the fixed price as delivered. The dynamics of our team have changed. We now have a team of five or six people who are expert in strategic pricing in organized markets.

MR. MARTIN: You need a higher-than-average IQ in the pricing department.

MR. SHIPLEY: Definitely. They are all higher than mine. You need the team in-house to evaluate the risk. We are a developer at heart. A lot of times developers focus on what the tax equity and debt will accept, but I don't care as much about what they think as about whether it is good for us. We have to solve for our equity returns and our risk, so we need the in-house team to evaluate it. We need also to focus on markets where we are most comfortable and want to invest our capital. We do our own internal analysis. The banks may rely to a certain extent on us, but they will also have their own consultants. I will let Andy Redinger comment on that.

MR. REDINGER: We rely on consultants, but we are learning that they have been wrong in many instances. If this pattern persists, it will change the market. I think people will be watching carefully for this over the next couple years.

MR. MARTIN: How will it change in the market?

MR. REDINGER: Most likely less leverage, increased pricing and possibly fewer banks participating in the market.

MS. SCHULTZ: It is important to differentiate. Basis risk is not the same across all projects. It is important for lenders, investors and sponsors to evaluate the specific project and its location. All projects and all consultant reports are not the same. We have a lot of experience with merchant gas projects. We think that has put us ahead of the curve in terms of our ability to analyze basis risk. You have to have a strong understanding of how the particular market works.

MR. MARTIN: It has been hard to finance projects in the Texas panhandle because basis risk seems greatest there. Are there any other areas where financiers are reluctant to invest?

MR. SHIPLEY: What I tried to say earlier, but didn't get across, is we are starting to see it everywhere. Basis risk is the differential between where you are delivering and selling power, and where you may be settling under a contract. We are starting to see it creep into our power purchase agreements with utility offtakers while it has always been present in corporate PPAs.

You hear people say in Texas that PJM is a different market, and in Texas there are no barriers to entry. PJM is hard as heck. There are a lot of areas to build projects, but that is not a great thing. It means you might eventually have a level of congestion that you see in Texas where it is super easy to get into the market and build projects.

MR. MARTIN: Are any risk-shifting financial products getting significant traction in the market: for example, tax insurance, solar revenue puts, proxy revenue swaps, balance of hedges, deal contingent hedges, offtaker credit insurance?

MR. REDINGER: We have seen a lot of tax insurance, particularly around safe-harboring strategies. I imagine that it will remain popular with developers and financing parties. We have seen the solar revenue put used in a number of transactions. It makes the parties more confident about the output forecasts and allows lenders to justify a higher loan amount. Some lenders have basically sized their debt differently based on the knowledge that the revenue put provides protection against a worst-case scenario. Then there are some other specialty products. I know Energetic Insurance has a credit wrap for small C&I portfolios. We have not transacted on that. I know others have.

MR. SHIPLEY: We have not done a deal with a revenue put, which is the idea that you could reduce risk on production and the banks are willing to lend at a lower coverage ratio to get to a higher advance rate. As for hedges, I hear a lot about proxy revenue swaps. We are not as big a wind player. I am not sure a proxy revenue swap has been done yet in the solar market, but I think that as this market continues to evolve, you will see more use of structured financial products to address risk.

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Opportunity zones are designated low-income areas. The government is offering investors with capital gains the chance to defer taxes on the gains by reinvesting them in real estate projects or businesses in such zones. (For more detail, see "Opportunity Zones and Renewable Energy" in the June 2019 *NewsWire*.)

Taxes are not usually triggered when one asset is traded for a similar asset in a "like-kind exchange." The 2017 tax bill limited like-kind exchanges in the future to exchanges of "real property." The IRS hopes to define what qualifies as "real property."

The IRS is working on regulations explaining when income earned on partnership interests — called "carried interests" — that companies or individuals receive in exchange for services will have to be reported as ordinary income rather than capital gain. New rules on this subject were enacted in late 2017 and are in section 1061 of the US tax code.

Finally, the IRS is working on guidance relating to fees paid in connection with debt instruments and other securities.

AN INVESTMENT TAX CREDIT can be claimed on an increase in tax basis in an existing project, the IRS said.

The IRS also confirmed again that such tax credits can be claimed on renewable energy projects in Puerto Rico, Guam, the US Virgin Islands and other US possessions.

A utility holding company that owns wind and solar projects that are used to supply electricity to customers changed how it charges "mixed service costs" to basis in such projects. "Mixed service costs" are costs of departments that perform administrative, service or support activities that are necessary for overall operation of the company.

The change meant that more such costs were added to basis in solar assets that the company had already put in service.

The company made a "section 481 adjustment" to spread / continued page 35

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Deal Volume

MR. MARTIN: This has been a very busy year for new solar construction and financings. Do you think things will remain at this pace through 2023 when all projects need to be completed to qualify for a 30%, 26% or 22% investment tax credit?

MR. REDINGER: Yes. We see a big move to distributed solar. Roughly 80% of C&I installations today are not financeable because the customer is not investment grade. There are a couple products to help with this problem.

MR. MARTIN: Meghan Shultz, your company is generating projects. Do you see this pace continuing through 2023?

MS. SCHULTZ: I do. I think 2021 and 2022 are going to be two of the biggest years to new solar capacity additions. ◎

Joint Arrangements to Develop Renewable Energy Projects

by Becky Diffen and Josh Rocha, in Austin

There is no cookie-cutter joint venture or joint development arrangement.

Each party brings different industry expertise, capital and motivations going into the relationship.

A number of questions should be answered at the outset. What is the end goal? Why enter into a joint arrangement? What does each bring to the table? Do the parties plan jointly to develop a number of projects that one of the parties will own after development has been completed? Or is the goal for the parties to own projects jointly with a view to sell later to a third party? Each joint venture requires a different approach.

Joint Development Agreement

A joint development agreement allocates development responsibilities and explains how the project costs will be paid.

A common pattern is a developer with the experience to develop solar or wind projects, but without the means to post credit support for interconnection requests, safe-harbored equipment or offtake arrangements, enters into a joint development agreement with someone with money.

The first issue they face is how much control the money party should have over development decisions. The money party will certainly want information and access rights, but should consider to what extent it needs approval rights over decisions about how best to develop the project.

Most deals allow the developer to take responsibility for standard development activities with some level of oversight or approval from the money party. Standard activities may include determining the project location and layout, securing real estate and completing title work, obtaining interconnection studies and agreements, and securing local permitting and tax abatements. If both parties have significant development expertise, they may split the activities between them, or perhaps one party may have more financing expertise and take the lead on financing for the project. In scenarios where a utility or other participant in the power industry without significant renewable energy expertise is involved, it may take the lead on offtake arrangements, interconnection and community outreach, leaving the rest for the developer.

The next step is to focus on how project risks are shared. Risk generally should flow from responsibility.

The joint development agreement should also address the standard of care. Development is an inherently uncertain business, so the developer cannot guarantee success. A prudent-industry-practices standard is normally used.

Some collaborations are structured with only a joint development agreement between the parties. In these deals, only one party owns the project at any given time. Many such deals then contemplate the project will be transferred to the other party once a milestone is hit.

This type of arrangement is common in situations where a utility or private equity fund has money and wants to own projects, but lacks the skills to seed projects. In this situation, the parties can arrange a framework-type structure whereby the developer brings a project or portfolio of projects to the table, the parties participate jointly in development pursuant to the joint development agreement, and then the utility or private equity fund ultimately acquires the projects. In this scenario, the parties should consider attaching the form of purchase and sale agreement to the joint development agreement. The purchase and sale agreement will list "conditions precedent" to signing and closing of the acquisition, as well as standard M&A concepts such as timing, a milestone payment schedule, representations and warranties, and indemnities. The parties should also address any additional services that the developer should continue to provide after the project has been sold. These are sometimes put in a separate development services agreement.

A single owner model is simplest. However, in some cases, both parties need to remain as owners. For example, this may be required for tax reasons where one party has stockpiled equipment that can be used as a basis for claiming federal tax credits on a project and the other has the project. The party contributing the stockpiled equipment must retain at least a 21% interest in partnership capital or profits. Joint ownership will be required.

Joint Ownership

If joint ownership is desired, then the parties usually form a limited liability company to own the project. It may own the project directly or through another LLC subsidiary. It is generally best to use a Delaware limited liability company.

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the effect on its taxable income for the year of the accounting-method change over four years.

However, the IRS said an additional investment tax credit could be claimed in full on the basis bump up in the existing solar assets in the year of the accounting-method change.

The investment tax credit is normally claimed when an asset is put in service. However, if the final cost is not yet known, then an additional credit can be claimed in a later year when the remaining basis is established.

The ruling is Private Letter Ruling 201949002. The IRS made it public in early December.

Meanwhile, the IRS released another private letter ruling in October — the fifth since 2011 — confirming that renewable energy projects in US possessions qualify for investment tax credits, even if owned by a partnership like a US tax equity partnership. All the partners must be US corporations or citizens.

The latest ruling on this subject is Private Letter Ruling 201943021.

Equipment qualifies for an investment tax credit only if it is used in the United States. US possessions are considered outside the United States for this purpose.

However, the US tax code makes an exception for property used in possessions as long as the equipment is owned by a US corporation or citizen. US taxpayers keep asking the IRS what happens if the owner is a partnership since the tax code does not mention partnerships in this context. Partnerships and disregarded entities are transparent for US tax purposes. The IRS said it looks through them to any corporations or individuals in the ownership chain. Thus, a project can be owned by a project company formed in the possession as long as the project company is wholly owned by a tax equity partnership of two or more US corporations or US citizens. The

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JV Agreements

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The joint venture agreement allocates responsibilities and the obligation to fund project costs and addresses governance and how revenues will be shared. In some cases, there may also be a joint development agreement with more detail about the roles of the parties during development to avoid cluttering the joint venture operating agreement with this type of detail.

Governance will be crucial for the long-term health of the relationship. Some decisions require agreement by both parties. In many deals, a board of directors is created so that each party can have more than one individual involved in voting on key matters. Not all joint ventures are 50-50. In such cases, some decisions may require a super-majority vote to prevent the majority owner from making all the decisions.

Joint development agreements should address at least nine big issues.

At a minimum, a super majority is required for any change in the rights of the minority owner and for affiliate transactions between the joint venture and the majority owner. In some deals, the unaffiliated partner gets to make decisions on behalf of the joint venture about whether to enter into a contract with a partner or enforce rights or pursue remedies under such a contract.

The creation of a new class or category of member, and the issuance of additional equity interests in the joint venture, may also require minority protections if such a decision would unfairly dilute the minority member. The minority should also have a right to key information such as financial statements.

As the minority owner's interest gets closer to 50%, the number of decisions in which it has approval rights should increase. A list of "major decisions" that require minority consent is a focal point of negotiations. The list usually includes the budget, issuance of capital calls, borrowing, project and significant asset sales, entering into, amending or terminating material contracts, and declaring bankruptcy or insolvency.

If whole projects are being contributed by one of the parties to the joint venture, then a separate contribution agreement may be needed in order to address project-related representations and warranties and associated indemnities to be given by the party contributing the projects.

If the joint venture arrangement will cover multiple projects to be developed over time, then the joint venture agreement is more likely to take the form of a framework-type structure where additional projects may be added as certain predetermined development criteria are met. The parties should discuss the process by which one party presents a project for the other's review and approval and whether the economic sharing ratios remain fixed for all projects and, if not, how they will adjust as more projects are added. Will the money party contribute cash to match the contribution of the project, and how will the project be valued? Does the money party have the right to reject the project?

The parties will need to balance the desire to move quickly in order to lock up project opportunities, procure safe-harbored equipment or secure an interconnection queue position against the need to perform thorough due diligence. Once credit support is posted or significant capital is deployed, it may be difficult to unwind arrangements if a project turns out to be untenable.

The joint venture agreement should address how future capital requirements will be handled. Will the joint venture take on debt to finance the project? What obligations will the parties have to contribute cash initially and over time? If one party defaults on its contribution obligations, will the other party have the opportunity to dilute the defaulting party's interests? The answers to these questions may affect how cash flow is distributed once the project is in operation.

There are many options for sharing cash.

One approach is a simple fixed ratio based on the value of the contributions each party made to the joint venture. If one party then has to fund additional money, it may be entitled to preferred distributions. The parties will need to agree on how to value non-cash contributions.

Project Disposition

It is uncommon for a project to remain jointly owned after it has been built. The project is usually sold to a third party or to one of the joint venture partners.

The parties may want flexibility. They may not know exactly how the end game should look when the joint venture is being structured. In such cases, they may agree to a right of first refusal or a right of first offer for one of the parties to buy the other partner's interest in the project. A right of first offer may be preferable, as a right of first refusal can sometimes scare off other buyers who do not want to spend time negotiating a deal, only to have the ROFR entity come in at the last minute and match. If the joint venture plans a portfolio of projects, one project company could be purchased while the others stay under the joint venture.

Here again, it is a good idea to attach a form of membership interest purchase agreement, purchase and sale agreement or build-own-transfer agreement to the joint venture agreement as an exhibit. This may be a simple agreement assigning LLC interests or it may contain representations, warranties and indemnities. Any conditions precedent to closing should also be addressed.

When the sale is of a project company by the joint venture to one of the partners, a comprehensive package of development representations and warranties may not make sense. If one party was primarily responsible for development activities, should it be on the hook for all liabilities from breach of any development-related representations? A third party buying the project company will not want to get in the middle of a dispute between the two joint venture partners. It will want representations and indemnity from the joint venture. It may want the joint partners to have joint and several liability, meaning it can go after either for the full amount owed.

Joint venture partners do not always consider these issues when the joint venture is formed and instead wait until a sale is imminent. These types of negotiations between joint venture partners may slow down the sale process.

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local project company is not considered to exist for US tax purposes.

It is unclear how many more times the IRS will be willing to repeat this or why the market feels to the need to have it do so.

REITS can treat income related to some state tax credits and carbon allowances as good income, the IRS said.

REITs are corporations or trusts that do not have to pay income taxes on their earnings to the extent the earnings are distributed each year to shareholders.

However, they must be careful to ensure their assets are largely real estate and their income is largely passive income from the use of real estate.

There are both 95% and 75% income tests. At least 95% of the REIT's gross income each year must come from dividends, interest, rents from real property, or gain from the sale of stock, securities and real property. At least 75% of gross income must come from rents from real property, interest on mortgages secured by real property or gain from sales of real property.

"REIT" stands for real estate investment trust. Gas pipeline companies that had been organized as master limited partnerships — large partnerships whose units are traded on a stock exchange — have been looking lately at converting to REITs as interest in MLPs wanes.

Three REITs that own timberlands asked the IRS for private letter rulings this year that carbon allowances the REITs receive and then sell in state cap-and-trade programs as part of state-level efforts to limit carbon emissions are good income for REIT purposes. The IRS made the rulings public in December.

The REITs report the allowances as income upon receipt.

Each of the states where the timberlands are located places a limit on the greenhouse gas emissions that it permits each year. Companies must buy allowances to cover their emissions.

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Transfers and Competition

Joint venture agreements usually limit the ability of the partners to transfer their interests.

The restrictions may extend upstream to changes in control. There may be drag-along rights or tag-along rights. A drag-along provision may give a majority partner looking to sell its interest in the joint venture the right to drag minority partners into the transaction, thus making it easier to sell the entire joint venture without consent. A tag-along provision may give one partner the right to tag along and sell its own interest on the same terms and conditions as the other partner negotiating a sale.

It is uncommon for a project that is jointly owned during development to remain jointly owned after it is built.

These types of provisions work alongside rights of first refusal and rights of first offer. They provide more ways to exit the joint venture.

Another issue to address is to what extent the joint venture relationship should be exclusive within a certain geographic region or with respect to the development of certain projects.

It may be appropriate to restrict a developer partner from competing directly with a joint venture project. For example, a nearby project could cause transmission congestion. A nearby wind project could impede air flow and reduce output. Neighboring projects may also compete for offtake arrangements.

Larger developers with an active development pipeline may find a non-competition provision untenable. On the other hand, larger developers are less likely to enter into joint ventures because they lack neither development expertise nor capital.

Defaults and Disputes

The joint venture agreement should address what happens when something goes wrong.

In many contracts, when one party materially breaches the agreement, the other party has the right to terminate. However, a joint venture partner cannot be kicked out so easily because it paid for its ownership interest. Therefore, material defaults usually lead to voting rights being taken away. The defaulting partner retains its economic interest in the company, but no longer has a say in management.

Since a typical joint venture will have multiple agreements including a contribution agreement, a joint development agreement and an LLC agreement, the parties should consider to what extent an event of default under one agreement will cause a default under other agreements. For example, if a partner fails to make contributions under the contribution agreement, will this trigger remedies under the LLC agreement? Perhaps such a breach may lead to dilution of the defaulting partner's interest. Joint ventures usually only terminate when the parties are ready to wind up and dissolve the business.

There should be procedures for resolving disputes. The dispute may be inability to agree on something material to the business.

Joint venture agreements usually require senior executives of the partners to try to work out the disagreement first. The dispute moves up to more senior management as a first step. How many rounds of executive negotiations and the timeline for such negotiations should be considered based on the expected project timelines.

If the parties still remain deadlocked, then one partner may have a put to force the other to buy it out. Partner A could have a right to offer to sell A's interest to partner B for an offer price and then be required to buy out B's interest at that price if B does not buy A's interest. (This assumes both have equivalent interests.) Alternatively in the event of deadlock, both partners could be required to sell their interests to a third party.

Deadlock provisions should create a situation that would be quick and painful if exercised. If the parties agree to a worst case scenario that both parties would prefer to avoid, then they will have an incentive to resolve disputes quickly and avoid deadlock. ◎

Tracking Accounts in Hedges

by Christine Brozynski, in New York

Tracking accounts are used in many fixed-volume hedges to mitigate electricity basis risk.

Basis risk is the risk that the price at which electricity is sold at the grid node is less than the price at the hub.

Some wind and solar projects without long-term contracts to sell electricity enter into physical or financial fixed-volume hedges.

While the hedge settles at the hub, the project is still producing power that is sold into the grid at the node for the spot price. The project company uses these merchant revenues to cover amounts owed under the hedge.

For example, in fixed-volume hedges with physical settlement, the project company is required to purchase the required hourly volumes of power at the hub price and then immediately resell those volumes to the hedge provider at the fixed price. The purchase at the hub is funded by merchant revenues. In fixed-volume hedges with financial settlement, the merchant revenues would be used to pay the settlement owed to the hedge provider, if any, which is typically calculated on a monthly basis.

When the nodal price (meaning the spot price at the project's node) is less than the hub price, the merchant revenues might not be enough to cover the purchase requirement at the hub (in physical hedges) or the settlement amount owed to the hedge provider (in financial hedges). This delta between the hub price and the nodal price is called basis risk.

A tracking account is a way to mitigate basis risk.

Loan Balance

It is essentially a working capital loan provided by the hedge provider to the project company as part of the hedge.

The amount required to be borrowed or repaid monthly by the project is determined based on the difference between the "floating amount," which is the amount owed by the project company under the hedge (in both physical and financial hedges, the sum across all hours of the hub price multiplied by the fixed volume of power for that hour) and the "realized revenue" (the merchant revenue earned during the same period).

The realized revenue calculation includes all power sold by the project, even power in excess of the / continued page 40

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Trees absorb carbon dioxide. Anyone owning a forest is considered to be taking steps to reduce carbon emissions. The state enters into protocols with such persons requiring them to take certain steps, including to monitor and verify the amount of carbon sequestration occurring, in exchange for which the state awards one allowance for each metric ton of carbon dioxide sequestered. The allowances can then be sold for cash to other companies that need them to cover their emissions.

The IRS analogized the arrangements to granting the state an easement over use of the forest. The allowances are rent. The forest owner must agree to restrictions on how it can use the land. The land-use restrictions can be recorded as an easement under local law. Consequently, the income from the allowances is close enough to rent for use of real property to qualify as good income for a REIT.

The rulings are Private Letter Rulings 201949004, 201949005 and 201949007.

Another REIT asked about a state tax credit that it will receive for investing in a partnership that is developing a real estate project in a low-income area. The partnership was awarded a tax credit for a percentage of its capital investment in the project, up to a cap. The tax credit is transferable, but not refundable. The partnership plans to sell it and report the sales proceeds as income.

The IRS said the income from the tax credit sale is good income for purposes of both REIT income tests. The tax credit is part of the return the REIT will receive on a real estate investment. The ruling is Private Letter Ruling 201948006. The IRS made it public at the end of November.

CRYPTOCURRENCIES continue to receive high-level attention from the IRS.

The IRS shed more light on their tax treatment in November.

Cryptocurrencies are treated as property for US tax purposes. Therefore, anyone using a cryptocurrency to / continued page 41

Hedges

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volume of power required under the hedge.

The difference between the floating amount and realized revenue is called the "mismatch."

If during any settlement period the realized revenue is less than the floating amount, then the hedge provider is required to lend funds to the project in that amount.

If during any settlement period the realized revenue is greater than the floating amount, then the project company is required to pay down the loan balance in that amount.

Because the mismatch is calculated based on not only the difference between the price at the hub and node, but also the difference between the volume of power required under the hedge and the volume of power sold into the grid by the project, the tracking account ends up mitigating volume risk (the risk that the project produces less power overall than the amount required under the hedge) and shape risk (the risk that times of high production at the project do not align with the hours for which high-volume delivery is required under the hedge) in addition to basis risk.

However, because sponsors and financing parties tend to focus more on basis risk issues as opposed to volume risk and shape risk, the tracking account is thought of primarily as a way to mitigate basis risk.

The tracking account balance is usually documented as a negative number with a maximum "limit" that is also a negative number. For example, the tracking account limit might be negative $10 million, meaning that the hedge provider will not lend more than $10 million in the aggregate to the project company.

At the commencement of the hedge term, the tracking account balance is zero. If during the first settlement period the mismatch is $100,000, meaning the floating amount exceeded the realized revenue by $100,000, then the hedge provider lends that amount to the project company, and the tracking account balance then becomes negative $100,000. If, in the subsequent settlement period, the realized revenue exceeds the floating amount by $25,000, the project company is required to pay down the outstanding tracking account balance with that excess amount, resulting in a tracking account balance of negative $75,000. This simple example does not account for interest, which typically accrues on the outstanding balance at a pre-agreed margin over LIBOR. Accrued interest is added to the tracking account balance monthly.

If, in the example, the tracking account were to reach the limit of negative $10 million, then the project company would no longer be permitted to draw on the tracking account unless the project company pays down all or part of the tracking account balance. Furthermore, once the tracking account limit is reached, all interest on the outstanding balance must be paid currently going forward on a monthly basis, since there is no room left for the interest to be added to the outstanding balance. Financing parties may require cash sweeps once the tracking account balance reaches a certain level (before reaching the limit), as this is indicative of a basis risk problem at the project.

The tracking account cap is usually set at zero, meaning the balance cannot become positive. A positive balance would indicate a loan was made by the project company to the hedge provider.

The tracking account typically settles monthly. In a physical hedge where the hedge provider pays the project company for power daily, the tracking account settlement is determined separately from amounts owed for power. In financial hedges, which usually settle monthly, or in physical hedges for which the hedge provider pays for power monthly, the tracking account settlement is often netted out with the settlement for power.

The tracking account is only a temporary solution for basis risk. As the tracking account is a form of loan, a negative balance must be repaid at the end of the term of the hedge. Often the hedge provider will permit the project company to repay the balance either in one lump sum or in a structured repayment over the

Tracking accounts in hedges are a way to mitigate electricity basis risk.

course of two or three years. If the project company opts for a structured repayment, then the hedge provider will usually require that credit support remain in place until the tracking account balance has been repaid in full. A project company that has granted a lien on the project to the hedge provider as credit support might have the option to replace this lien with a letter of credit during the repayment period.

Four Options

Not all hedge providers offer tracking accounts as part of a fixed-volume hedge. Sponsors that find themselves across the table from a hedge provider that is unable to offer a tracking account have four options: provide for member loans in the project's capital structure, obtain a working capital facility, "sleeve" the hedge or go without a tracking account (or any similar facility).

Member loans are a common way for project owners to provide working capital to projects.

Typically, the owners agree among themselves that some or all of the owners can make loans to the project company for working capital needs. The loans typically are unsecured and are repaid to the extent of available cash, after payment of operating expenses but before distributions. Common points of negotiation include the interest rate, whether any of the members are obligated to provide member loans and the cap on aggregate outstanding member loans. In the context of a tracking account alternative, at a minimum the cap would need to be sized to accommodate reasonably anticipated liquidity shortfalls resulting from negative basis.

The second option — obtaining a working capital facility — involves the project company entering into a working capital facility arrangement with either an affiliate or a third-party financial institution.

These arrangements are uncommon; the price of such a facility can be prohibitive. Furthermore, if the working capital facility provider requires a lien on the project as credit support, then the sponsor will find itself in the middle of an inter-creditor negotiation among the back-levered lenders, tax equity investor and, if the hedge provider has a lien, the hedge provider. Another point to address is the priority of payments between principal and interest repayments under the working capital facility, on one hand, and settlement payments and termination payments owed under the hedge, on the other hand. Such negotiations can be time-consuming and expensive.

The third option is to "sleeve" the hedge.

This involves two simultaneous */ continued page 42*

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buy goods or services is treated as if the cryptocurrency had been exchanged for cash, thereby triggering a gain or loss equal to the difference between the amount originally paid for the cryptocurrency and the fair market value of the goods or services received in return. This makes it hard for cryptocurrencies to serve as a real currency. (For more detail, see "Bitcoins" in the April 2014 *NewsWire* and "Cryptocurrencies and Taxes" in the April 2018 *NewsWire*.)

The IRS addressed the tax consequences of "hard forks" and "air drops" in a revenue ruling in November.

Cryptocurrencies are basically entries on digital ledgers. A "hard fork" is when one cryptocurrency is split into two. The IRS said a hard fork without more does not trigger an income tax. The cryptocurrency owner is no wealthier than he or she was before the split.

An "air drop" is where new coins are widely distributed. For example, a company might give cryptocurrency holders free coins as a way to market a new offering and build awareness among potential customers. Recipients may not have asked for the coins.

Coins distributed in an airdrop must be reported as taxable income, the IRS said. The holder then takes a tax basis in the new coins equal to the income reported. There would be more income, or a loss, to report later when the coin is used if there has been a change in value.

However, anyone receiving new coins is not taxed on them until he or she has "dominion and control," meaning the ability to dispose of the coins.

The ruling on this subject is Revenue Ruling 2019-24.

The IRS is coordinating how it handles cryptocurrency issues. A notice distributed internally in late October said that all "novel issues or issues likely to attract national attention" should be brought back to the IRS national office in Washington.

Christopher Wrobel, an IRS special counsel, told a meeting of the American Institute of Certified Public ***/ continued page 43***

Hedges

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transactions: first, a different hedge provider that can provide a tracking account executes a hedge with the project company and second, this new hedge provider executes a back-to-back hedge with the original hedge provider that cannot provide the tracking account, passing through all of the economics except a premium. This route is more expensive because the amount the project will receive under the project-facing hedge will be lower to account for the hedge provider's premium.

It is rare for all of these elements to come together in a transaction such that a sleeve would be the best path forward or even a viable option. First, the project company would usually already be negotiating with at least two potential hedge providers concurrently, as it would be difficult to bring in another hedge provider at the last minute. Second, the potential hedge provider offering a tracking account would have to be willing to sleeve the hedge with the potential hedge provider that is not providing a tracking account. Third, the hedge provider that is not providing a tracking account would have to offer a high enough price such that even with the sleeving premium, a sleeve would be a better economic option for the project than executing a hedge directly with the hedge provider offering a tracking account.

The last option — forgoing the tracking account or similar facility — is usually only viable for sponsors that are building on balance sheet and do not require debt or tax equity financing. Financing parties usually prefer that the hedge have a tracking account because a tracking account offers relief on basis risk during the term of the financing. A sponsor might consider this route if the sponsor anticipates positive basis and is comfortable with contributing equity to the project in the event that basis is worse than expected. ◎

Revised Equator Principles May Make Projects More Costly to Finance

by Bob Comer, in Denver

The Equator Principles are perhaps the most widely used private international financing standards seeking to influence environmental and social "sustainability" in big project development.

Following recent revisions, they have become more probing and may now apply to more projects than before. The new version is version 4.

For example, it lowers the funding level necessary to apply from $100 million in aggregate project financing to $50 million on an individual lender basis. Thus, if a group of institutions is lending, each lender making a commitment of at least $50 million would be expected to make project compliance with the Equator Principles a condition to funding the loan.

Version 4 — called EP4 — expands the reach in other ways as well. The prior version of the Equator Principles applied through host country laws to projects in the Organization for Economic Co-operation and Development (OECD) list of "designated countries." This includes the United States, Canada, Iceland, Chile, Australia, New Zealand, Japan, Korea, Israel and most of Europe. However, EP4 creates some new compliance requirements for projects in these previously, largely unaffected countries.

Background

More than 100 financial institutions from 38 countries that provide advisory services and project financing subscribe to the Equator Principles. They are all members of an Equator Principles Association that exists to "encourage [developers] to address potential or adverse risks and impacts identified during the Project Development Lifecycle."

The financial institutions — called EPFI lenders — have all pledged their support for the objectives of a series of non-governmental organization programs.

These programs include the United Nations (UN) sustainable development goals, the UN Guiding Principles on Business and Human Rights, the UN Declaration for the Rights of Indigenous Peoples, the 2015 Paris climate accord, the recommendations of a task force on climate-related financial disclosures, the World Bank Group environmental, health and safety guidelines and the International Finance Corporation performance standards on environmental and social sustainability.

The individual financial institutions decide whether there is project compliance, at times in consultation with outside experts.

Project developers must commit to comply with the host country law and the EP4 process.

For transparency and accountability purposes, EPFI lenders must report at least annually on a variety of metrics. New information sharing expectations among financial institutions are included in EP4, as well.

Applicability

EP4 applies "globally and to all industry sectors."

It is applied by financial institutions when offering various types of services for new projects, project expansions and upgrades.

The types of services include advisory services or loan or other financing commitments to projects where total project capital costs are expected to exceed US$10 million. EP4 also comes into play where project-related corporate loans are being made with a tenor of at least two years, the lender has made an individual commitment of at least US$50 million and the borrower has direct or indirect control over project operation. It also applies to bridge loans of less than two years in duration.

EP4 also applies to project-related refinancing and acquisition financing where the underlying project was financed under the Equator Principles framework, there has been no material change in project scale or scope, and project completion has not occurred.

Financial institutions classify each project into three categories "based on the magnitude of potential environmental and social risks and impacts, including those related to human rights, climate change, and biodiversity."

Projects in category A have the most significant potential adverse environmental and social consequences: the potential consequences are diverse, irreversible or unprecedented.

Projects in category B have potential limited adverse environmental and social risks that are few in number, generally site-specific, largely reversible and readily addressed through mitigation.

Projects in category C have minimal or no adverse environmental and social consequences.

EP4 creates a middle category of higher risk category B projects that will be treated similarly to category / continued page 44

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Accountants in Washington in November that exchanges of one cryptocurrency for another may have qualified as tax-free like-kind exchanges before the 2017 tax reforms limited like-kind exchanges to exchanges of real property. He said it depends on the facts.

For now, IRS efforts appear focused mainly on education and compliance.

Michael Desmond, the IRS chief counsel, said in October that an estimated 8% of Americans hold some form of cryptocurrency.

The Form 1040 that individual taxpayers will have to file next year for 2019 will ask them to check a box on the tax form if they received, used or sold any cryptocurrencies during 2019. This is similar to the box used now to identify taxpayers with foreign bank accounts.

The IRS sent letters to more than 10,000 cryptocurrency holders over the summer whom it suspects may not have reported income.

A FINDER'S FEE is not deductible if paid by a target company on behalf of the company that acquired it, the US Tax Court said.

The point is to be careful who pays such a fee in an M&A transaction. Any such fee should be paid by the company that hired the investment banker or broker to whom the fee is paid.

The Ontario Teachers' Pension Plan Board (OTPP) bought Plano Molding Co., an Illinois plastic container manufacturer, for $240 million in 2012. Plano makes such things as plastic fishing tackle boxes, archery and gun cases, and ammunition boxes.

OTPP agreed to pay Robert W. Baird & Co., an investment bank, a finder's fee of $1.5 million for identifying Plano as a potential acquisition target.

However, Plano ended up paying the fee after the acquisition on behalf of OTPP.

The IRS said the fee could not be deducted and assessed a penalty. The US Tax Court agreed with the IRS.

Robert W. Baird & Co. / continued page 45

Equator Principles

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A projects and lower risk category B projects that "could be treated in a lighter regime."

Basic Requirements

Developers of category A and some category B projects must prepare an environmental and social impact assessment — called an ESIA — along with any necessary specialized studies, to the satisfaction of the EPFI lender. A more focused assessment not rising to the level of an ESIA may be prepared for category C and some category B projects.

Project finance and project-related corporate loans for category A and some category B projects require that an independent consultant review how the ESIA or other assessment is prepared. This includes vetting environmental and social management systems, environmental and social management plans and stakeholder engagement documentation to assist the bank or other lender with its due diligence.

Covenants about compliance must be included in the loan documentation.

Independent monitoring and reporting are required to assure compliance after closing on the financing.

Assessments must include human rights impacts based on the UN Guiding Principles on Business and Human Rights (paragraphs 17-21).

A climate change risk assessment is required for all category A projects, some category B projects and all projects with greenhouse gas emissions of 100,000 tons of CO_2 equivalent annually from direct emissions within the project boundary and from indirect emissions associated with off-site production of energy used by the project. The assessment also must consider climate transition risks and project alternatives with lower greenhouse gas emissions.

EP4 also calls for mitigation of residual effects, suggesting the potential for the bank or other lender to require a "no-impact" protocol. This could include compensatory mitigation, which could lead to a protracted negotiation process over the level of mitigation for both environmental and social issues.

The assessment must cover compliance with host country laws that pertain to environmental and social issues. For all category A and B projects globally, the bank or other lender must confirm that the project meets the EP4 principles. This review may require supporting advice from independent consultants. For projects in OECD non-designated countries, the assessment must also comply with IFC performance standards and the World Bank Group environmental, health and safety guidelines. For projects in OECD designated countries, there are new, potentially significant EP4 process and outcome requirements that now apply. One example is free, prior and informed consent for indigenous peoples over project funding authorization. In its review of the assessment, the EPFI lender may evaluate compliance and determine there is a justified deviation from the applicable standards or undertake additional due diligence in addition to host-country laws to address risks.

Other Obligations

For category A and B projects, EP4 requires the borrower to maintain an environmental and social management system and an "effective grievance mechanism." It also requires the borrower to demonstrate effective stakeholder engagement in a structured and culturally appropriate manner with affected communities, workers and other stakeholders.

Projects that affect indigenous peoples are subject to additional obligations. There must be a process of informed consultation and participation, compliance with host country law and host country obligations under international law. Where free, prior and informed consent to the project is required from the indigenous peoples, a qualified independent consultant or legal advisor must usually be retained to evaluate the consultation and consent processes with the indigenous peoples. In some cases, the stakeholder or indigenous peoples engagement may be the responsibility of the host government. In such cases, the developer must collaborate with the responsible government throughout the process.

In closing, EP4 contains a disclaimer. It provides that in the case of "a clear conflict" between host country law and the requirements of EP4, "host country [law] shall prevail."

EP4 is scheduled to take effect in July 2020. Implementation guidance is anticipated prior thereto. ◎

Environmental Update

The United Nations said in a report in late November that there is a significant gap between the world's current combined pledges to cut greenhouse gas emissions and the reductions that many scientists agree are required to avert the most disastrous effects of climate change.

Average global temperatures are currently between 0.8 to 1.2 degrees Celsius above pre-industrial levels, or between 1.4 to 2.2 degrees Fahrenheit higher on average.

Global greenhouse gas emissions continue to rise. The UN report said the global average temperature is projected to rise 3.9 degrees Celsius from pre-industrial levels.

The report warns that such increases would bring "widespread, catastrophic effects," such as extreme and longer lasting heat waves, extended drought and wildfire seasons, more frequent intense weather, and sea level rises that will threaten coastal cities.

The 2016 Paris Agreement on climate change set a goal of limiting the increase in global temperatures to no more than 2.0 degrees Celsius (3.6 degrees Fahrenheit).

Current country pledges to limit greenhouse gas emissions would need to triple to meet that goal.

The Paris Agreement is an accord within the United Nations Framework Convention on Climate Change relating to greenhouse gas emissions mitigation, adaptation and the financing of those efforts.

As of February 2019, 194 countries and the European Union had signed the agreement, with 186 of those countries and the EU having ratified it.

Each country signing committed to determine, plan and regularly report on its efforts to limit climate change. The agreement has no mechanism to force any country to set a specific reductions target by a specific date, but each target is supposed to go beyond previously pledged targets.

The UN held its annual climate meeting in Madrid from December 2 through 13 with a goal of completing detailed rules to govern international carbon markets. Once those rules are agreed to, the table would arguably be set for a 2020 meeting that would focus on getting participants to agree to more stringent emissions reductions targets.

While the four largest greenhouse gas emitters — China, the United States, the EU and India — have all ratified the agreement, President Trump announced his intention in June 2017 to withdraw the United States from the / *continued page 46*

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introduced OTPP to the opportunity and tried unsuccessfully to set up a lunch between the two companies. It was aware Plano was interested in a suitor because it had been retained by Plano two years earlier in an unsuccessful attempt to sell the company.

A taxpayer normally may not deduct a payment of someone else's expenses.

There is a narrow exception where two things are true: the payment would have to help advance of the business of the person paying it and be an "ordinary and necessary" business expense of that person.

The court said neither requirement was met in this case.

The primary benefit from the payment to Baird was to OTPP. Baird did little work for the fee. Plano had its own outside financial adviser. OTPP wanted to maintain a good relationship with Baird so that Baird would steer other business opportunities to it.

For the same reason, the payment was not an ordinary and necessary business expense of Plano. The court said it could see how it might be such an expense of OTPP had OTPP paid it.

The case is *Plano Holding LLC v. Commissioner*. The Tax Court released its decision in the case in October.

USEFUL DATA POINTS. US installed wind capacity stood at 100,125 megawatts at the end of the third quarter 2019, according to the American Wind Energy Association. AWEA reported another 21,651 megawatts of wind farms under construction and 23,844 megawatts in "advanced development," including 5,796 megawatts of offshore wind farms.

Wind and solar electricity are now cheaper — in terms of levelized cost of energy — than electricity from fossil and nuclear fuels, according to a report by Lazard in November. Lazard reported LCOE ranges for electricity from different kinds of projects: $11 to $45 a megawatt hour for subsidized / *continued page 47*

Environmental Update

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agreement. The earliest effective date of a US withdrawal is November 4, 2020, the day after the next US presidential election.

The EU disclosed at the Madrid conference that it will probably miss its target for reducing greenhouse gases by 2030. It had pledged a 40% reduction, but said it would still achieve a 30% reduction in the next decade compared with 1990 levels.

According to the UN, global emissions must decline by 7.6% every year between 2020 and 2030 to keep global warming within safe bounds.

Clean Air Act

The US Environmental Protection Agency has decided not to reconsider its current approach to when industrial facilities must calculate and report emissions from potential major modifications that might lead to higher air emissions. New Jersey asked EPA to scrap the exemption 10 years ago.

The state argued that the current approach makes it harder to determine which industrial facilities in the state should be subject to strict air pollution controls.

In general, the current EPA new source review program requires industrial facilities to install new pollution controls each time a company adds new generating capacity or expands existing operations.

Under current EPA rules, if planned modifications to an industrial facility are not expected by the owner to hit the major new source threshold, the owner is only subject to emissions recordkeeping and reporting requirements if there is a "reasonable possibility" that the predicted emissions from the modification will equal or exceed 50% of significant threshold levels for any pollutant under the Clean Air Act. EPA adopted this rule in December 2007.

EPA Administrator Andrew Wheeler said in a letter to the New Jersey attorney general in November that EPA will not reconsider the 2007 rule.

New Jersey filed suit over the rule in February 2008 and also formally petitioned EPA to get rid of it.

New Jersey complained that the rule leaves it to "plant operators to determine for themselves whether their emissions call for installation of new pollution controls."

The New Jersey lawsuit has been in limbo in federal court while waiting for EPA to decide whether it would reconsider the rule on its own.

Wheeler said in his November letter: "The EPA does not agree with New Jersey's assertion that the final rule is procedurally defective, and, therefore, the EPA is not required to convene a proceeding for reconsideration under the Act."

New Jersey could act on its own. If the state thinks additional reporting is required, Wheeler said, it has "discretion to adopt state regulations that would require sources in its jurisdiction to keep such records in circumstances not addressed in the 2007 EPA rule."

The lawsuit may now resume.

PFAS

EPA and federal lawmakers are currently considering separate efforts to regulate the two most common per- and polyfluoroalkyl substances, known as "PFAS."

PFAS (pronounced PeeFAS) are a group of fluorinated chemicals commonly added to a wide variety of consumer products to make them non-stick, waterproof and stain-resistant. Such products include carpets and upholstery, waterproof apparel, floor waxes, nonstick cookware, camping gear, fast-food wrappers, cleaners, dental floss and firefighting foams for putting out fuel fires.

PFAS have been found in drinking water in many areas of the country.

Global greenhouse gas emissions must decline by 7.6% a year between 2020 and 2030 to keep global warming within safe bounds.

Regulations could require listing the substances as "hazardous substances" under the Comprehensive Environmental Response, Compensation and Liability Act, more commonly known as the Superfund law, and the setting of nationwide drinking water standards.

The listing of certain PFAS as hazardous substances under the Superfund law could impose significant cleanup liability for responsible parties at sites across the country. Even where regulators considered cleanups of other substances to be complete, a listing could reopen past settlements, requiring responsible parties to do additional remediation where regulated PFAS are found, but were not addressed.

Setting of drinking water standards would require water utilities to incur substantial ongoing costs to test and possibly treat water. Nationwide drinking water standards could force them to spend billions of dollars to comply with testing and treatment requirements over just the first five years.

A proposed regulation addressing the two most common chemicals was sent to the Office of Management and Budget for review in early December. An EPA press release suggests that, in addition to perfluorooctanoic acid, or "PFOA", and perfluorooctane sulfonic acid, "PFOS," two other chemicals will be also included for evaluation, but it did not name them.

While this suggests that EPA may follow up its PFAS action plan to evaluate PFOA and PFOS and may ultimately set drinking water cleanup standards for the substances, the timing remains uncertain.

The Safe Drinking Water Act requires EPA to select chemicals from its contaminant candidate list and determine whether to regulate them via a national primary drinking water regulation, possibly by setting a maximum contaminant level.

EPA had said it would decide whether to regulate the two most common PFAS by the end of 2019. Any proposals are now not expected until sometime in the first half of 2020, with final action thereafter following public comment.

Several bills circulating in Congress would force EPA to move faster.

At issue is whether Congress should require EPA to set drinking water standards for the two PFAS by a date certain.

When a maximum contaminant level standard is set, all water systems are required to test for it twice a year. To date, EPA has only set a drinking water health advisory.

EPA Administrator Wheeler said in late September that EPA is strongly opposed to Congressional / continued page 48

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wind farms and $28 to $54 a megawatt hour without subsidies, $31 to $40 for subsidized utility-scale solar projects using crystalline silicon panels and $32 to $42 for such projects using thin film, compared to $44 to $68 for gas-fired power plants, $66 to $152 for coal and $118 to $192 for nuclear.

Lazard puts the unsubsidized cost of a 50-megawatt battery with 200 megawatt hours of storage capacity paired with a solar project at $102 to $139 a megawatt hour.

The Rocky Mountain Institute said in a report that it expects the cost of the battery to fall to $87 a megawatt hour by 2025.

NextEra said in its third-quarter earnings call that more than half of its solar projects in 2019 are being paired with storage.

SunPower reported that more than 20% of its residential solar installations in the third quarter this year included batteries. Sunrun had a 30% rate in the third quarter in California. However, the rate in the San Francisco Bay area in October spiked to 60% after Pacific Gas & Electric started blackouts during periods of high winds and dry conditions to reduce the risk of wildfires.

The global average installed cost in the United States is currently $1 a watt for solar and onshore wind and $2 a watt for offshore wind, according to Wood Mackenzie.

Replacing an incandescent light bulb with an LED bulb reduces electricity consumption by 80%, according to Lucas Davis, a Berkeley economist.

— contributed by Keith Martin in Washington

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efforts to impose federal cleanup standards for any class of chemicals.

Meanwhile, a case before the federal courts could set precedent on whether consideration of PFAS must be included in the mandatory five-year EPA review of Superfund sites that the regulators have been treating as fully remediated.

The US Air Force and Michigan regulators are fighting over whether a Superfund five-year review should address PFAS even though the chemicals were not a subject of the original cleanup plan. The resolution of the case could set precedent for similar cleanup reviews at other sites.

The Air Force is required to review how effective the cleanup was at a Superfund site every five years. However, it argues that it is only required to review the cleanup as it relates to the contaminants at issue in the original cleanup plan. ◎

— contributed by Andrew Skroback in New York

CHADBOURNE MERGER

Chadbourne & Parke merged into Norton Rose Fulbright on June 30, 2017. The combined firm has roughly 3,400 lawyers in 55 offices and four affiliated offices in 33 countries.

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