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Trump Bulk-Power System Order: Market Reaction

by Keith Martin, in Washington

Market reaction to the Trump bulk-power system order has been mixed.

Some tax equity investors and lenders moved quickly to require sponsors to fund any future costs to replace foreign adversary equipment that the government decides poses a threat to the US electricity grid. Not every tax equity investor or lender has done so.

Some construction lenders are requiring sponsors to do special cyber-security audits to help show that the project is following best practices in case of government scrutiny.

The question has been showing up on diligence lists in both financings and M&A transactions whether any equipment that is manufactured or designed by Chinese suppliers will be used in projects.

Companies that were on the verge of signing equipment supply agreements with Chinese suppliers have been thinking carefully about whether to move forward with such arrangements. It is too early to tell how much, but some level of pullback in the short term from Chinese equipment seems inevitable, especially for equipment like transformers or batteries that is closer to the grid than other equipment like solar panels.

US Department of Energy officials seemed to feel that the reaction among renewable energy developers was overblown and went out of their way in calls to industry trade associations and interviews soon after the order was issued to downplay */ continued page 2*

IN THIS ISSUE

IN OTHER NEWS

UTILITIES continue to get private rulings from the IRS about different ways to engage in the renewable energy sector.

The two latest rulings address a tax equity transaction that a utility entered into to finance a wind farm and a program that another utility is using to supply solar electricity to its commercial customers.

The wind tax equity transaction is a slight variation on a strategy other utilities have used to raise tax equity to finance renewable energy projects that the utilities will own. (For earlier coverage, see "Utility tax equity structures" in the December 2019 *NewsWire*.)

A utility signed a build-transfer agreement with a project developer to buy a wind farm at the end of construction. The utility */ continued page 3*

Grid Order

continued from page 1

concerns that equipment might have to be ripped out and replaced. A list of frequently-asked questions put out by the department said, "As of today, no equipment is prohibited . . . . As such, any immediate steps by owners or operators would not only be premature, but may be unnecessary."

Trump Order

President Trump issued an executive order on May 1 that imposes an immediate ban on the purchase, use or transfer of as-yet unidentified foreign adversary equipment that might be used to harm the US power grid.

The order bans the "acquisition, importation, transfer, or installation" of transmission and electric generating equipment designed, manufactured or supplied by any company that is "subject to the jurisdiction" of a country that the US considers a "foreign adversary."

The order leaves more questions than it answers.

There are four broad questions.

One is who are the foreign adversaries. The order seems directed at China. Russia, North Korea and Iran are not large suppliers of equipment for the US power sector.

Mark Menezes, the deputy energy secretary-designate, confirmed the list of adversaries in comments on May 21.

Another question is which power projects are affected. The order applies only to equipment used in the "bulk-power system," defined as not only "facilities and control systems necessary for operating" the transmission grid, but also "generation facilities that are necessary for system reliability."

The order does not apply to distributed energy or distribution system equipment.

Key phrases appear to have been drawn from section 215 of the Federal Power Act, including the phrases "generation facilities needed to maintain transmission reliability" and "facility used in the local distribution of electric energy."

The Federal Energy Regulatory Commission, which administers the Federal Power Act, draws the line on the bulk-power system at 100 KV. The Trump executive order draws it at 69 KV.

DOE officials say it is too early to know to what extent the department will follow FERC precedent to decide what equipment is considered used in the bulk-power system.

President Trump has said repeatedly at rallies that intermittent renewable energy is an unreliable source of electricity. However, any possibility that the order does not cover wind and solar facilities was dispelled by comments by the White House trade adviser, Peter Navarro, who had a hand in writing the order. "To those who have concerns," Navarro said on May 5, "I would simply say work in good faith with the process. And unless you intend to use foreign components that may pose a risk for the bulk-power system, including flawed batteries or inferior solar or wind turbine systems, you have nothing to worry about."

A third broad question is how the ban is supposed to work in practice. The Department of Energy must determine one of three things about a transaction before the prohibition applies. The transaction must either pose an "undue risk" of "sabotage or subversion of" the US bulk-power system or of "catastrophic effects" to critical US infrastructure or the US economy or pose simply an "unacceptable risk" to US national security. Given how broadly the Trump administration has invoked national security concerns in other contexts, this does not draw a very clear line for the market.

Finally, the effective date of the ban is confusing. The order says in one place that the order applies "where the transaction is initiated after the effective date of this order." It says in another place that the prohibitions in the order apply "notwithstanding any contract entered into or any license or permit granted prior to the date of this order."

The Trump grid order immediately bans the purchase of as-yet unidentified equipment.

Context

US intelligence agencies have warned in the past that the US electric system is vulnerable to attack. The executive order says that "foreign adversaries are increasingly creating and exploiting vulnerabilities" in it, including through cyber activities.

A DOE intelligence official said that although the main focus is Chinese equipment, the timing had nothing to do with current tensions with China over the coronavirus. The order has been in the works for a year. It just happened to get through the process on May 1. It is possible there may be some ripping and replacing of equipment in the future, but it will not happen quickly.

The order reads like a similar order that President Trump signed on May 15, 2019 dealing with the US telecom network. The US Department of Commerce is charged with administering the telecom order. Commerce took six months, until November 27, 2019, to issue proposed implementing regulations.

The order applies not only to projects in the United States, but apparently also to projects outside the United States undertaken by US persons. It applies to a transaction "by any person . . . subject to the jurisdiction of the United States."

The Department of Energy can propose measures that would mitigate the national security concerns in order to let a transaction move forward.

Sales of projects into tax equity vehicles are potentially affected to the extent the order covers renewable energy. The order bans any "transfer . . . of any [proscribed] bulk-power system electric equipment (transaction)." Read literally, it applies to purchases of development rights to projects where a foreign adversary company has signed a contract to supply equipment.

The Department of Energy is supposed to identify equipment that is potentially a problem "as soon as practicable" and make recommendations for how to "identify, isolate, monitor, or replace" such equipment in the US power system. This creates risk that the government might require replacing any equipment in the future that it identifies as a potential threat.

Mark Menezes said FERC is working on a plan to compensate utilities that must remove equipment considered a security risk.

The order also directs the Department of Energy to set up an inter-agency task force that will report within a year on model procurement policies for federal agencies to follow in the broader US energy sector to address national security concerns. The task force will also focus, among other things, on the potential for attacks on the electricity supply to originate through the distribution system and will engage distribution system industry groups in that effort.

Bruce Walker, the assistant energy secretary responsible for administering the order, said in a briefing on May 7 that DOE plans to establish a pre-qualification / continued page 4

IN OTHER NEWS

will form a partnership with a tax equity investor and assign the build-transfer agreement to the partnership.

The partnership will own the wind farm and sell the electricity generated to the utility under a long-term power purchase agreement.

The utility will resell the electricity into an organized market at the grid node and then buy back at a hub the electricity it needs to supply power to its ratepayers.

The IRS said the project will not be "public utility property." Utilities must clear an extra hurdle to claim investment tax credits and accelerated depreciation on any assets considered public utility property by showing that their regulators do not require them to pass along to their ratepayers the value of the tax benefits more quickly than under a "normalization" method of accounting.

A project is public utility property if the rates at which electricity from the project is sold are established or approved by a utility regulator on a rate-of-return basis.

The IRS focused on the electricity sales by the partnership to the utility and said they will be at market-based rates. However, the electricity reaching the ratepayers will not be sold at regulated rates, either. The amount the utility pays to buy electricity at the hub for resale to ratepayers will be passed through as a purchased-power expense.

The ruling does not say whether the utility will put its investment in the partnership into its rate base.

The ruling is Private Letter Ruling 202020011. The IRS made it public in May.

One problem with utility partnership flip transactions where the utility buys the electricity from the partnership is section 707(b) of the US tax code. That section does not allow the partnership to claim losses from selling "property" to a partner that owns more than a 50% profits or capital interest in the partnership. Electricity is considered property for this purpose. Most wind and / continued page 5

Grid Order

continued from page 3

system for suppliers of bulk-power system equipment. DOE will issue a request for information first to vendors and other stakeholders for input that it will then use to put out instructions for companies that want to be considered for pre-qualification. He said it will take five months for DOE to work out a pre-qualification process.

DOE will be working separately with the US intelligence agencies, FERC and the North American Electric Reliability Corporation, NERC, to identify existing equipment that may pose security risks. Where risks are identified, DOE will come up with strategies to monitor and mitigate risks and work with asset owners to replace equipment, if necessary.

The Wall Street Journal reported in late May that federal officials commandeered a large Chinese transformer made by Jiangsu Huapeng Transformer Company when it arrived by ship in Houston last summer and took it by truck under federal escort to the Sandia National Laboratories in New Mexico. The transformer was purchased for use in a substation owned by the Western Area Power Administration. ◎

California Split-Roll Initiative Upsets Solar Developers

by Keith Martin and Sol Kwon, in Washington

A California "split-roll" ballot initiative would change the way commercial property is taxed in California and lead potentially to significantly higher property taxes on solar projects.

Property taxes would be assessed on commercial property at fair market value rather than on the historic cost as is the case under current law.

If the ballot initiative is successful, it is expected to increase annual property taxes by as much as $12 billion a year beginning in 2022. The change would be particularly troublesome for solar projects, effectively eliminating a long-standing property tax exclusion for solar systems.

The measure will be put to a vote this November.

Existing Law

Under Proposition 13, real property in California is generally taxed at 1% of its 1975 value plus an adjustment for inflation, which is limited to 2% each year.

Real property is assessed at its current fair market value only when it undergoes a change in ownership or is newly constructed.

When improvements are made to an existing property, the fair market value of such "new construction" is added to the property's assessed value.

Certain types of construction activity are excluded from assessment as "new construction." In such cases, while improvements may increase the value of an existing property, the additional value is not subject to the property tax.

Proposition 7, approved by California voters in 1980, authorized an exclusion for active solar energy systems. The term "newly constructed" is defined in section 73 of the property tax statute to exclude "the construction or addition of any active solar energy system."

The effect is to exclude new active solar energy systems from property tax assessment in California until a change in ownership occurs.

The solar exclusion applies to active solar energy systems placed in service before January 1, 2025. Any active solar energy system that was completed before 2025 will remain excluded until there is a subsequent change in ownership.

The solar exclusion has helped to drive the explosive growth of solar in California. California is the nation's leader in solar power generation with more than 27,400 megawatts of generation.

Split-Roll Initiative

California Secretary of State Alex Padilla said on May 29 that the split-roll initiative became eligible for the November ballot with more than 1.09 million signatures.

If passed, the initiative will "split" how real property is taxed in California.

Residential property will continue to be taxed under the existing Proposition 13 rules.

A ballot initiative in California could significantly increase property taxes for solar projects.

Commercial and industrial property with a fair market value of more than $3 million will be assessed at its current fair market value and be reassessed at least once every three years. The new regime will generally not apply to commercial and industrial property with a fair market value of $3 million or less. However, if any of the direct or indirect owners of such property also owns an interest in other commercial or industrial property in California, the new regime will apply if all such property in the aggregate has a fair market value greater than $3 million. The $3 million threshold will be adjusted for inflation every two years starting on January 1, 2025.

If passed, the measure would take effect on January 1, 2022.

This change will essentially render the solar exclusion meaningless, since the concept of "new construction" will generally no longer be relevant when determining the assessed value of commercial property. Thus, most / continued page 6

IN OTHER NEWS

solar partnerships report tax losses for the first three years after a project is placed in service due to accelerated depreciation on the project. These losses are part of what a project owner barters in the tax equity market to raise capital to pay for a project.

The IRS declined to rule on whether the partnership may claim losses in this case.

The simple fix is for the partnership to sell the electricity directly to the grid and to enter into a swap or hedge with the utility to put a floor under the electricity price. Any such arrangement could not be a PPA with the utility in substance.

In the separate solar ruling, a utility launched a voluntary solar energy services program and got approval for it from its regulatory commission.

The utility will put solar systems on customer roofs and retain ownership of the systems. Each customer will receive a percentage of the electricity generated by its system for a fixed monthly fee. The fee amount will be negotiated with each customer. It may be subject to a fixed percentage price escalator.

Participation in the program is limited to certain commercial customers, probably large customers who are candidates to enter into corporate power purchase agreements with independent generators. The cost of the solar systems will not be put into rate base.

The IRS said the systems will not be public utility property. The fees charged customers under the program will not be set on a rate-of-return basis.

The ruling is Private Letter Ruling 202017027. The IRS made it public in late April.

CHANGES IN US IMPORT TARIFFS remain a constant risk in the Trump era.

US companies paid more than twice the import duties last year that they paid in 2017. The figures are for the US government's fiscal year that runs through September 30. Most of the increase comes from / continued page 7

Split-Roll Initiative

continued from page 5

commercial, industrial and utility-scale solar power plants could become fully taxable on their current fair market values, despite the fact that many such projects are locked into long-term power purchase agreements under which the developers committed to supply electricity at prices that assumed no property taxes would have to be paid on the projects.

Advocates of the split-roll initiative say they did not intend to disturb the solar property tax exclusion, and they have offered to cooperate with the industry in an effort to remedy the situation. However, short of pulling the initiative from the November ballot and rewriting it in a manner that preserves the effects of the section 73 solar exclusion, there may be little that can be done to fix the problem.

Loss of Exclusion

The impact to the industry of losing the section 73 property tax exclusion could be significant, particularly for operating plants and for unconstructed plants with signed power purchase agreements.

Virtually all operating solar power plants in California have long-term PPAs under which the projects have close to fixed revenue streams. These projects have limited ability to absorb unanticipated property taxes. In the worst case, some project companies could default on their debt and go bankrupt, while in the best case the equity value of the project would drop commensurately with the erosion in project cash flows.

An annual tax of 1% of the full value of a project after a 20-year life could mean that 20% of the project value would have to be paid in property taxes. This is on top of that revenue share that must go to pay income taxes.

Developers usually need a signed long-term power contract with fixed pricing to finance any new California project. They will have a hard time financing any project that is locked into a contract that was already signed and committed to sell electricity at prices that will be no longer economic.

Electricity prices will have to rise in order to absorb the higher property taxes for solar projects that no longer qualify for the exclusion. ◎

Corporate VPPAs: Risks and Sensitivities

by Ben Grayson, in New York

Eighty-two percent of power purchase agreements signed with US corporate offtakers in 2019 were "virtual" PPAs that do not involve physical delivery of electricity.

Price spikes in ERCOT during the summer months, the COVID-19 pandemic and economic downturns have exposed how critical certain contract provisions are in these types of contracts.

The contract provisions primarily affected are the ones dealing with risks and sensitivities around price, electricity basis risk, credit and construction delay.

Negotiations are sometimes challenging because of information asymmetries between experienced developers and corporate buyers that may have never entered into a power purchase agreement before.

In 2019, 13,600 megawatts of corporate power purchase agreements were signed in the United States, more than all global activity in 2018, according to Bloomberg New Energy Finance. Traditional busbar utility PPAs covering the output of an entire project are being signed less frequently.

As a more diverse cast of corporate offtakers participates in energy markets, there is a need for buyers and sellers to come to the negotiating table with an understanding of each other's risk appetites and constraints.

VPPAs

At its core, a virtual power purchase agreement, or VPPA, is a purely financial contract that exchanges a fixed-price cash flow for a variable cash flow and often renewable energy credits.

An independent power project sells its electricity into an organized spot market, like ERCOT, the name for the power grid in Texas.

The project owner enters into a VPPA with a corporate offtaker. It pays the corporate offtaker the floating revenues it receives from the electricity sales in exchange for fixed payments back from the corporate offtaker.

The VPPA typically settles monthly. If the project's revenues from selling power to the grid are greater than the corporate offtaker's fixed-price payments, the VPPA is considered profitable or "in the money" by the project owner. In some cases, the VPPA will be a "contract for differences" where the project company and corporate offtaker split the wholesale revenues to the extent they exceed the fixed price payments. In contract-for-differences VPPAs, the fixed price will be lower than in a VPPA where this upside share feature is not used.

For a developer or sponsor, entering into a VPPA helps to put a floor under the electricity price for a project, which is a key step toward project financing. For a corporate buyer, entering into a VPPA means supporting sustainability goals while providing a hedge against market price volatility for the electricity it buys from its local utility. The contract is not affected by the buyer's actual electricity usage or the geographic location of its actual offtake.

Basis Risk

Electricity basis risk is the risk that the project owner takes by using the electricity prices at a "hub" for settling a VPPA while selling electricity from the project into the spot market at "node" prices. VPPAs are frequently hub-settled. Hubs are aggregations of nodes. Because hubs cover a broader geographical range than a single node, hub prices are less volatile than node prices and so settling VPPAs at hub prices is perceived to carry less risk. Basis risk is the risk that there will be a difference in electricity prices at the two locations.

Take an example: if a lot of wind projects with similar generation profiles are built close together in northwest Texas, there are likely to be congestion issues along the transmission lines during periods of heavy wind, driving node prices down. Tying the floating VPPA price to a broader geographical range with different levels of demand and generation will help smooth out volatility and ideally keep floating prices up relative to the node where the project sells its physical power.

However, settling at the hub introduces risk to the project. Hub settlement requires the project to purchase the same volume of energy at the hub as it sells at the node in order to manage settlements. If hub prices are greater than the node price, then the project suffers losses.

When raising capital for a project financing, a sponsor will need to walk the lenders and tax equity investors through the locational analysis and forward curve projections for the project to get them comfortable with the basis risk the project wears.

When hub prices are higher than node prices, a project could be incentivized to curtail, or scale back, its electricity output in order to avoid loss or seek out contractual mechanisms in the VPPA to mitigate basis risk. If a / continued page 8

IN OTHER NEWS

tariffs imposed on imported goods from China.

Bi-facial solar panels remain exempted from the 20% "safeguard" tariff that the United States is collecting on most imported solar panels, but possibly not for much longer. A hearing is scheduled for June 17 in the US Court of International Trade.

The US Trade Representative exempted bi-facial panels from the safeguard tariff in June 2019 and then tried in October 2019 to walk back the exemption.

The US Court of International Trade granted a preliminary injunction on December 5 blocking removal of the exemption on grounds that the US Trade Representative did not follow proper procedures to withdraw it. (For earlier coverage, see "Solar and wind tariffs" in the December 2019 *NewsWire*.)

The government tried to cure the defects by issuing another notice in April.

On May 27, the trade court said there were still problems and declined to remove the injunction. The court said it takes no position on whether the exemption is warranted, but "merely continues to require the government to follow its own laws when it acts."

The US Trade Representative tried again to cure the procedural defects with another notice on June 12.

Even if the preliminary injunction is lifted, it may not be the last word. Courts grant preliminary injunctions as a way of freezing the status quo until they can hear the case on the merits. The court said in its latest ruling on May 27 that the government "has not met its burden of showing sufficiently changed circumstances" to warrant lifting the preliminary injunction.

Bi-facial solar panels are more expensive than regular panels, but generate roughly 30% more electricity.

Meanwhile, the US Department of Commerce launched an investigation on May 19 that may lead to tariffs on imported electrical transformers and their / continued page 9

VPPAs

continued from page 7

project curtails, then the corporate offtaker will receive fewer renewable energy credits or RECs. The project owner earns less revenue, but this is the tradeoff for not having to operate at a loss.

Curtailment could be critical to maintaining steady project economics. In August 2019, the ERCOT North hub saw prices spike up to $9,000 per megawatt hour of electricity, while node prices were only $1,000 per megawatt hour.

A 300-megawatt project using a hub-settled VPPA would have experienced a $2.4 million loss in a single hour.

Parties to a VPPA negotiate over how often and under what circumstances the seller can curtail energy. Developers and sponsors are also beginning to negotiate for other creative contractual tools to manage basis risk.

Related to curtailment is the availability guarantee. Often in VPPAs, the project owner promises that the project will remain on line and available to supply power for a minimum amount of time during each contract year, expressed as a percentage. If the availability guarantee is not met, then the project must pay the corporate offtaker some amount of liquidated damages.

The slow economy and summer price spikes create issues for virtual power contracts.

A VPPA will often carve out certain periods of time that are considered "excused" for purposes of calculating the availability percentage. These excused periods of time are excluded from the availability calculation. Parties to a VPPA negotiate whether periods of curtailment should be treated as "excused." The parties will also negotiate whether to cap the amount of time or volume of electricity that a project can curtail.

Battery storage can help mitigate basis risk. If a project can store electricity during times of high congestion and shift its electricity sales to times of lower congestion (i.e., times of higher node prices), the likelihood that the node price will be less than the hub price can be reduced.

Buyer Sensitivities

During periods of low demand, it is possible for wholesale power prices to dip into negative values.

Similar to how project owners are concerned about basis risk, corporate offtakers are concerned about settling a VPPA at negative floating prices. When such a settlement occurs, the corporate offtaker ends up paying the full fixed price with no offset; the floating price is treated as zero. As a way to protect against negative prices, a VPPA can feature floating price floors. For solar projects, the price floor is typically set at $0 and for wind projects where tax equity is contemplated, a negative amount equal to the value of the production tax credits. (Production tax credits were $25 a megawatt hour in 2019. The 2020 amount has not been announced yet.)

Since VPPAs are typically signed ahead of or in the middle of construction and construction is where most project risk lies, corporate offtakers will want to make sure that enough protections are in place in case of delays.

Over the VPPA term, the project owner will post security in the form of a parent guarantee, letter of credit, surety bond or cash. The corporate offtaker and project owner negotiate how much security is required, whether the amount of security required to be posted can decrease over time, and whether security needs to be replenished after it is drawn upon. Project owners prefer that the amount of security required decreases once the construction period is over and the project is in commercial operation. VPPAs typically set a guaranteed commercial operation date and if that milestone is not met on time, then the project pays delay damages on a dollar-per-megawatt basis for each day of delay. Because the project is not generating revenue at this time, the corporate offtaker will look to draw on the security as protection against delay risk.

If a project is using a letter of credit or surety bond, the project owner should see whether its relationship banks have forms and share those forms with corporate offtakers to level set expectations. The drawing conditions in those forms should align with the terms of the VPPA.

There are significant information asymmetries between project developers and corporate offtakers in terms of how development and construction work, an understanding of energy markets and similar issues. This is especially the case if a company is entering into a VPPA for the first time. While many companies hire outside consultants with institutional knowledge, the corporate offtaker will want to collect as much information as possible. Corporate buyers and project developers negotiate over the extent to which the developer provides progress reports, construction milestone updates, notices and similar information, their frequency and their form. It is important for developers to coordinate with their asset management teams to make sure what they are promising to provide is feasible and is something that is monitored.

Corporate buyers are also sensitive to assignment provisions. Many corporate offtakers try to specify competitors in their sector and exclude developers from assigning the VPPA to them.

Developer Sensitivities

Developers are sensitive to assignment and change-of-control provisions.

VPPAs will typically state that no assignment or transfer is allowed without the other party's consent, except for an enumerated list of certain types of assignments. Because lenders will probably be needed to finance the project, developers want to make sure their corporate offtakers are comfortable if the developer makes a collateral assignment of the VPPA to secure the financing. It can be helpful to negotiate a form of consent to collateral assignment and attach it to the VPPA as an exhibit. Negotiating the form of consent at the VPPA stage can help avoid problems for sponsors later when they are trying to sign financing commitments.

The same logic follows for agreeing to forms of estoppel certificates for tax equity providers. Since VPPAs represent project revenues, financing parties will critically review consents and estoppel certificates. Creating a foundation for what these documents look like early can reduce heartburn later, especially since companies may not be familiar with signing these types of documents. / continued page 10

IN OTHER NEWS

components. The affected components are laminated steel used to make cores, wound cores and transformer regulators.

The US has been collecting a 25% tariff on imported steel and a 10% tariff on imported aluminum since March 23, 2018 on grounds that the metal imports are a threat to US national security.

The investigation comes at the request of US steel manufacturer Cleveland-Cliffs Inc., which makes electrical steel. The company accuses other countries of evading the existing steel tariffs by sending electrical steel through Canada and Mexico, where it is incorporated into downstream products like transformer cores that are shipped to the United States.

The US removed tariffs on steel and aluminum imports from Canada and Mexico in part to secure Congressional support for the new US-Mexico-Canada trade agreement.

The Commerce Department has until February 13, 2021 to complete the investigation. If a national security threat is found, the president will have another 90 days after that to take action. (For more detail, see "Possible transformer tariffs under review" on www.projectfinance.law.)

Separately, the Trump administration launched a so-called section 301 investigation on June 2 that may lead to tariffs on nine countries and the European Union in retaliation for taxes those counties plan to collect from digital services providers like Amazon and Google.

The potentially affected countries are the United Kingdom, Spain, Italy, Turkey, India, Brazil, Indonesia, Austria and the Czech Republic, plus the European Union.

The tariffs would apply only to specific goods to be identified in the future.

The US has already decided to impose tariffs of up to 100% on French goods like make up and wine, but has delayed launching them while negotiations are ongoing through the Organization for / continued page 11

VPPAs

continued from page 9

Developers often negotiate for an ability to assign the VPPAs to affiliates or other types of permitted transferees. The "permitted transferee" definition is typically used to allow the developer to assign the VPPA to other sponsors. The definition often has two elements — an experience requirement (years operating projects of a similar type and the number of megawatts operated) and a net worth requirement.

As is the case for corporate buyers, credit support is also a sensitivity for developers.

The legal entity used to represent the corporate buyer could be a less well capitalized subsidiary of a corporate parent. Developers scrutinize the credit of the VPPA counterparty. The project owner is usually obligated to post security for the life of the VPPA. In contrast, the corporate offtaker may only be required to post credit support if its credit falls below some creditworthiness threshold. The parties negotiate the threshold that triggers an obligation on the part of the corporate buyer to post credit support and the terms around when such support is no longer necessary after it has been posted.

More scrutiny may be placed on corporate buyers' credit support in light of unforeseen economic difficulties caused by the COVID-19 pandemic that have affected corporate credit across the country.

Developers try to limit the amount of influence a corporate offtaker has over upstream activity.

Similar to assignments, a VPPA will typically say that, with respect to a project, a "change of control" is not permitted without the corporate buyer's consent. Developers should evaluate their ownership structures and try to negotiate for certain carve outs to the definition, allowing them to take certain actions that are reasonably foreseeable without the corporate buyer's consent. For example, these carve-outs may include transfers of interests of the project company in connection with a tax equity financing or a transfer of interests of a direct or indirect owner of the project company.

As the COVID-19 pandemic has played out across the energy project value chain, there has been increased scrutiny of force majeure provisions in VPPAs.

Just like in a traditional PPA, the project will be granted relief from termination if a force majeure event lasts up to a certain amount of time and granted relief from paying delay damages if the reason for delay is due to force majeure. The COVID-19 pandemic has caused supply-chain issues, permitting and construction delays, issues in obtaining financing, as well as other problems. Because pandemics like COVID-19 have effects that are less visible and obvious than a storm or hurricane, for example, developers should try to bake broad force majeure definitions and favorable relief provisions into their contracts. At the very least, developers should make sure pandemics are included in the non-exhaustive list of events that are treated as force majeure if the other elements of the definition are met.

Another risk developers try to manage is imbalance-charge risk. This is the risk associated with settling VPPAs in the real-time market versus the day-ahead market. Physical power is sold in real-time markets. However, VPPAs may settle at day-ahead market prices by scheduling sales on an hourly basis in advance. Corporate buyers generally perceive day-ahead prices to be higher and prefer their predictability. Developers want to avoid managing the mismatch between real-time prices and day-ahead prices and will try to have the VPPA settle at real-time prices.

For large projects, it may not be feasible to contract the entire output to one corporate offtaker. Instead, there might be multiple VPPAs. In such cases, it is important for developers to try to achieve consistent terms across the VPPAs. There will be reporting requirements that last over the life of each contract and the project owner's asset management team will want to make sure those are relatively similar so that the team is not overburdened and can easily reproduce reports. Often, the first VPPA signed will act as a foundation for the next slate of VPPAs signed for the same project. ◎

Financing Storage

by Deanne Barrow, in Washington

Although the coronavirus pandemic is expected to trim global storage installations by almost 20% according to some analysts, 2020 should still be a record-breaking year for new storage projects in the United States.

Seven states now have dedicated storage procurement targets. They are California, Massachusetts, Nevada, New Jersey, New York, Oregon and Virginia.

Procurement targets, improving economics and increasing levels of renewables on the grid are leading to record procurement activity this year. Some utilities are releasing requests for storage proposals in the megawatt and even gigawatt range.

The procurement ramp-up has led a flood of developers to go to market in search of debt, cash equity and tax equity financing to get projects they have been awarded off the ground. Discount rates tend to be higher, and interest rate margins wider, reflecting the perceived riskier nature of storage compared to wind, solar and gas.

Financing storage is different than financing other kinds of projects.

Revenues

We see five kinds of offtake structures currently for standalone storage facilities. Storage projects provide a number of services and, for each service, receive a different revenue stream. The developer tries to lock in a long-term offtake agreement for each service.

The first offtake structure is a capacity sales agreement with a utility.

The project company receives a capacity payment that is a fixed dollar amount per megawatt in exchange for an obligation to be ready to run (charge or discharge energy to the grid) when called on by the grid operator. The utility purchases only capacity, so the project company may be able to earn additional revenue from selling energy or ancillary services in the wholesale market. This structure is common in California where the investor-owned utilities and community choice aggregators need to procure capacity to meet resource adequacy obligations set by the California Public Utilities Commission.

The second structure is a twist on the basic capacity sales agreement.

The project company may negotiate a put option that gives it the right to sell to the utility on an / continued page 12

IN OTHER NEWS

Economic Cooperation and Development over a possible multilateral approach to digital services taxes. The OECD hopes that an agreement can be reached on the taxes by October 2020.

A number of other countries are also considering such taxes, including Hungary and The Philippines.

Section 301 is the same trade statute that President Trump invoked to impose blanket tariffs on most Chinese goods as he ramped up pressure in 2019 on China. Tariffs may be imposed where another country violates US trade agreements or engages in acts that are “unjustifiable” or “unreasonable” and burden US commerce.

The Commerce Department is investigating whether tariffs should be imposed on national security grounds on imported mobile cranes after the Manitowoc Company in Wisconsin complained that it is being harmed by increased competition from crane manufacturers in Japan, Germany and Austria.

Finally, there is still no word from the administration about the results of a mid-term review of the 20% “safeguard” tariff being collected on most imported solar panels. The tariff, which has been in place since early February 2018, is supposed to remain in place for four years. Suniva urged the administration as part of a required mid-course review after two years to slow down the rate at which the tariffs are decreasing from 5% to 1% a year. (For more detail, see “Solar and wind tariffs” in the December 2019 *NewsWire*.)

PARTNERSHIPS will have to track another metric called partner “tax capital” starting next year.

The IRS explained what additional calculations will be required in a notice in early June. The notice is Notice 2020-43.

It is the third attempt the IRS has made to explain the new metric. Earlier attempts left the market confused. (For past coverage, see / continued page 13

Storage

continued from page 11

annual basis all of the stored energy and ancillary services at a fixed price. Although the project company loses the flexibility to earn additional revenues in the market, it may assign greater value to the certainty of a fixed revenue stream. The agreement is typically structured as a tolling arrangement, where the utility provides and pays for all charging energy during the put period. In return, the utility has the right to charge or discharge the facility as it sees fit.

The third offtake structure is an ancillary services financial hedge.

Five types of offtake arrangements are being used currently for standalone storage.

Ancillary services are used by the grid operator to balance the frequency of the grid and ensure there is enough reserve capacity to meet unexpected stress events. The project company sells ancillary services to the market at the spot price. It swaps floating payments for a fixed-dollar-per-megawatt-hour price calculated on a fixed volume of capacity for each settlement period. The swap uses as the floating price the market clearing price for the specific ancillary service product sold. The project company can mitigate volume risk by self-scheduling rather than taking the risk of not being dispatched by the independent system operator under economic-merit-order rules.

The fourth offtake structure is a demand response grid services agreement.

It involves aggregation of distributed storage facilities to form a virtual power plant that provides demand-response service to the utility in exchange for fixed payments. Demand response means shedding behind-the-meter load in response to a signal from the utility. The battery or other storage device may be used by customers for other applications when not providing demand-response services.

The fifth offtake structure is a demand-charge management agreement.

Unlike the other structures, this agreement is with a commercial and industrial solar customer rather than a utility. Power from the storage facility is used to meet peak demand at the customer premises, thereby reducing expensive fees the utility would otherwise charge the customer for peak electricity consumption. Demand-charge savings are split between the customer and project company under a shared-savings model. Alternatively, the customer pays a fixed monthly subscription fee in return for guaranteed savings. This provides revenue certainty for the project company, but it eliminates upside potential.

Merchant Storage

Storage developers are relying on merchant revenues for an increasing part of their overall cash flows. Contracted revenues as a percentage of total project revenues are expected to continue shrinking as banks remain eager to lend and sponsors continue to pressure debt and equity providers to assume more risk.

In 2017 when we closed the first-ever non-recourse financing of standalone storage assets, banks were unwilling to lend against anything other than a fixed capacity payment locked in for a specific contract term. We have seen the market shift toward giving credit for uncontracted revenues from sales of energy and ancillary services in the spot market. However, when sizing the debt, banks are likely to lower the advance rate.

Merchant exposure for storage is fundamentally different from gas, solar and wind in two ways.

The first is variable fuel costs. Fuel costs for merchant gas are usually fixed under a gas supply contract. For wind and solar, fuel is essentially free. Fuel for storage is the electricity used to charge the battery and, in a merchant project, it is purchased on the spot market. This opens storage to double merchant exposure on both the input and the output sides. The project might mitigate exposure on the output side with a hedge that sets a floor under the electricity price.

The second difference has to do with the potential for overlap between the term of an offtake agreement and the time period during which the project makes merchant sales. When calculating advance rates, lenders will credit a certain number of years of revenue beyond the term of the power purchase agreement. Because of the unique ability of storage to provide different services to different customers at the same time, storage can realize contracted and uncontracted revenues during overlapping periods, rather than waiting for a merchant tail.

Tax Credits

Batteries that are combined with wind or solar projects on which investment tax credits are claimed potentially qualify for such an investment tax credit at the federal level.

The amount of ITC for which a battery linked to a solar or wind project qualifies potentially depends on whether the battery is installed as part of the original construction or as a later improvement, when construction started and when installation is completed.

There are two important eligibility rules. The first is that the battery must be considered part of the generating equipment as opposed to a transmission asset. To accomplish this, the battery should be on the low-voltage side of the step-up transformer. It should be physically adjacent to the generating equipment and owned by the same legal entity. Care should be taken about giving the utility dispatch rights, since they can tend to make the battery look like a transmission asset unless dispatch is solely for the purpose of regulating the ramp rate at which electricity from the wind or solar project is fed into the grid.

The second eligibility concept is that at least 75% of the energy stored by the battery should come from the renewable energy project to which it is coupled. Standalone storage does not qualify for tax credits at this time. (For more information, see "Batteries and tax credits" in the October 2016 *NewsWire*.)

Lenders and tax equity investors will want a covenant in the loan agreement and tax equity documents requiring the sponsor to ensure exclusive charging from the linked solar or wind facility during the first five years of operation during which any tax credit claimed remains exposed to recapture. To the extent the offtaker has a right to control charging, the owner may want to build in a right to recover any ITC-related recapture or losses in the PPA.

/ *continued page 14*

IN OTHER NEWS

"Deficit restoration obligations" in the December 2019 *NewsWire*.)

Part of the confusion is the name given to the new metric since it sounds like the capital accounts that partnerships are already required to use to distribute assets among partners when the partnership liquidates, but it is calculated differently.

Partnerships will still be required to maintain capital accounts, but the Form K-1s that are sent each year to partners will no longer tell partners their capital account balances at year end and will report their tax capital amounts instead starting with K-1s delivered in 2022 for payment of 2021 taxes.

The new metric — "tax capital" — is basically a way for the IRS to identify partners who perhaps should report taxable gains to the IRS. Negative tax capital is a sign of a potential gain.

Tax capital must be calculated using one of two methods. Partnerships can change back and forth between methods, but must tell partners the reason for the change and how their beginning and ending tax capital for the year differs as a result when sending partners their K-1s.

One method for calculating tax capital is the "modified outside basis method." Under this method, a partner's tax capital is the "outside basis" the partner has in its partnership interest, but with its share of partnership-level debt backed out of the calculation.

Partnerships do not always have the information needed to calculate partner outside bases. Notice 2020-43 requires partners to notify the partnership within 30 days or, if later, by the last day of the partnership tax year of any changes in a partner's outside basis, other than changes due to capital contributions or distributions and allocations of which the partnership will already be aware.

An example of something the partnership would have to be told is if a partner paid an adviser a fee to buy a / *continued page 15*

Storage

continued from page 13

Split-Obligation EPC Contracts

Project lenders and tax equity investors have historically preferred a fixed-price, turnkey EPC contract that aggressively shifts as much risk as possible from the owner to a single EPC contractor. In contrast, a split structure may have multiple equipment supply, construction and installation contracts. Split EPC contracts are more common in storage projects than in gas or solar.

There is more risk for the project owner under a split arrangement than a full-wrap structure where a single contractor takes responsibility for ensuring that all the different parts of the project will work together once the project has been fully assembled.

Splitting creates interface risk with lost time and finger-pointing to sort our responsibility for any defects. Construction lenders and tax equity investors will assess the "bankability" of split EPC contracts by assessing whether the additional risk exposure is sufficiently mitigated.

There are various ways that a project owner can mitigate risk.

To begin with, the owner should mitigate against the risk of construction delays by ensuring that all supply, installation and construction schedules match so that the project will meet target milestone dates.

The construction contractor will usually be excused from its obligation to pay delay liquidated damages if delays are attributable to other contractors hired by the project owner. When this happens, whichever contractor is on the hook for an unexcused delay should be liable for liquidated damages that are large enough to meet any penalties under the offtake agreement stemming from a failure to start delivering power on time. The project owner would also be well-advised to negotiate a common dispute resolution mechanism that applies in the event of a dispute as to which contractor is to blame for a construction issue.

Performance Guarantees and Warranties

Storage projects have a shorter operating track record than gas, wind and solar because the technology is newer. Poor operational performance can jeopardize offtake contracts and subject developers to heavy non-performance penalties in certain wholesale markets.

Project finance lenders and tax equity investors do not like technology risk.

For storage, the key technology risk is capacity degradation. Financiers will look for a performance guarantee or capacity maintenance agreement under which the service provider refreshes the battery with new cells to maintain capacity at minimum, albeit decreasing, levels over time.

The cost of disposal and recycling of the old cells should be factored into the model if the service provider has not assumed responsibility.

Debt service coverage ratios for storage projects are typically more conservative than for other assets to reflect the risk of the project realizing lower revenues if degradation occurs at a faster rate than what is warranted in the performance guarantee. Lenders may also want to build a reserve account into the financing documents.

Creditworthiness of the performance guarantor is a major issue. Insurance products are available to bolster warranty and performance guarantee providers with weak balance sheets.

Regulatory Issues

Regulatory regimes for storage are in a state of flux.

The Federal Energy Regulatory Commission and regional transmission organizations or RTOS are struggling with whether to classify storage as generation, transmission or a hybrid.

Projects are more likely to get financed the clearer the regulatory framework. ISO and RTO market rules for storage participation vary widely. It is crucial to have a deep understanding of the particular market in which the project is located.

The recent resolution of a long-standing dispute over the PJM regulation service market may offer some welcome regulatory certainty for storage developers.

The dispute began in 2017 when a group of prominent storage developers sued PJM over what they alleged were unfair changes to PJM's regulation service market rules. PJM had revised its energy neutrality automatic signal for storage and other fast-responding resources participating in the regulation D market, adjusted its algorithms for determining which resources clear the market, and placed an overall cap on the amount of fast-responding resources that could be procured during peak-demand morning and evening hours. PJM said the changes were necessary after experiencing operational challenges (area control error) due to an influx of storage participating in the regulation market.

Owners of battery and flywheel storage projects in PJM (including AES, Convergent, EDF Renewables, Invenergy, NextEra and RES) complained to FERC that the changes were unfair, unduly discriminatory and would result in losses of up to 75% of their investments in some cases.

The project owners acknowledged the inherent risk of being early market entrants, but raised concerns that the re-designed market signal reduced compensation and increased the energy throughput of their storage assets, thereby decreasing life expectancy and compromising performance and warranty contracts with battery and other storage equipment manufacturers.

The case settled in March 2020. Starting on July 1, 2020 until January 1, 2024, PJM will treat all price-taking offers from participating storage resources as having cleared the market as long as they abide by the ISO's conditional neutrality signal and meet certain minimum performance criteria. The settlement order identifies a list of storage projects to which it applies, but any storage project in PJM can sign up for the deal by filing a two-page "opt-in" form with the ISO.

Trump Executive Order

Tariffs and other trade and national security policies can affect procurement of storage system components.

On May 1, 2020, President Trump issued an executive order banning the use of certain foreign-manufactured equipment in the nation's bulk-power system, meaning the interconnected electric grid.

There are three key questions for storage developers.

The first question is whether battery cells, modules and packs are covered by the order. The order defines the bulk-power system to include "facilities and control systems necessary for operating an interconnected electric energy transmission network" as well as "electric energy from generation facilities needed to maintain transmission system reliability."

It appears a standalone battery connected to the transmission grid and injecting energy to provide voltage support would be covered by the order because it ensures transmission system reliability. The order does not apply to batteries that are sited behind the customer meter or interconnect to the distribution system.

The second issue is whether balance-of-system components are covered by the order. The inclusion of "control systems" could potentially cover inverters, power conversion systems and battery management system (BMS) hardware. The order says that it is intended to guard against "malicious cyber activities," among other threats to the grid. This could signal an increased level of scrutiny for BMS hardware given its vulnerability to remote attacks and the crucial role it */ continued page 16*

IN OTHER NEWS

partnership interest. The fee must be added to the basis the partner has in its partnership interest since it is a cost of acquiring the partnership interest.

Partnership agreements should require partners to provide partnerships such information.

The other way to calculate partner tax capital is the "modified previously taxed capital method." The calculation is as follows.

First calculate the amount the partner would be distributed if the partnership sold all of its assets for fair market value and liquidated, using the cash raised in the asset sale to pay all partnership liabilities first before distributing the remaining cash to partners.

Next add back any tax loss the partner would be allocated for the liquidation year.

Alternatively, subtract any tax gain the partner would allocated.

For example, suppose a partnership with two equal partners has assets in which the partnership has an "inside basis" of $3,000. The partnership owes $5,000 to a third party.

Partnerships are assumed for this purpose to be able to sell their assets for at least the amount of debt secured by the assets.

Assuming a sale for $5,000 in this case, the partnership would have no cash to distribute to partners since the cash would all go to repay the debt.

The partnership would have a gain of $2,000 on the sale, or the difference between $5,000 and its tax basis of $3,000 in the assets. Each equal partner would be allocated half this gain. The gain is subtracted from the $0 in cash they would be distributed. Thus, each partner has tax capital of negative $1,000.

In this simple case, each partner has tax capital of negative $1,000 under both methods for calculating tax capital.

However, the two methods produce different numbers in cases where there is no partnership-level debt exceeding the gross asset value.

/ continued page 17

Storage

continued from page 15

plays in maintaining the battery system in a non-hazardous state.

The third question is whether Chinese battery vendors and US companies that have manufacturing facilities in China are covered by the order.

The order covers bulk-power system equipment "designed, developed, manufactured, or supplied by persons owned by, controlled by, or subject to the jurisdiction or direction of a foreign adversary." The foreign adversary countries have not been identified yet, but it appears the order is aimed at China.

If batteries are covered equipment, then the order could have significant ramifications for supply chains. According to Bloomberg New Energy Finance, China accounted for 73% of global lithium-ion cell manufacturing capacity in 2019. The US was a distant runner up with 12% of global capacity.

It is unclear whether US companies that have established manufacturing plants in China would be considered "subject to the jurisdiction or direction of a foreign adversary." Tesla, for example, recently opened a "gigafactory" in Shanghai, although production appears to be geared towards the electric vehicle market.

Looking ahead, the order directs the US Secretary of Energy to publish regulations explaining how the order will be implemented in practice no later than September 28. The implementing regulations are expected to identify the particular countries and persons that will be considered foreign adversaries and establish a process under which vendors can apply to the Department of Energy to clear their products.

In the meantime, storage developers may want to consider using alternative suppliers to Chinese companies and other companies who do their manufacturing in China.

There could also be an opportunity for individual developers to obtain clarification from the DOE. In an interview in late May with Politico, the press, Bruce Walker, the DOE assistant secretary charged with implementing the order, suggested developers who are nervous about the order could "work with the Department of Energy . . . with regard to understanding places on the system that we're more concerned about or not." ◎

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State of the Tax Equity Market

Many renewable energy developers are having a hard time raising tax equity this year. A number of mainstream investors are no longer writing term sheets. Even investors who are still doing deals are turning down new business.

Four mainstream tax equity investors talked on a widely-heard conference call in late May about the state of the market. They are Peter Cross, a managing director with Credit Suisse Securities, Jorge Iragorri, head of the alternative financing group at Morgan Stanley, George Revock, head of alternative energy and project finance for Capital One, and Darren Van't Hof, managing director of environmental and community capital at US Bank. The following is an edited transcript. The moderator is Keith Martin with Norton Rose Fulbright in Washington.

Tax Equity Supply

MR. MARTIN: Darren Van't Hof, more developers than usual appear to be having trouble this year finding tax equity. Is that because there are more deals in the market or because there are fewer tax equity investors?

MR. VAN'T HOF: Developers are more anxious about getting commitments. The number of tax equity players has probably remained the same. There are roughly 12 to 15 traditional tax equity providers. Of those that we have been in contact with, they are fully intending to close on their commitments. Some are writing new term sheets at varying degrees of pace.

Separately, we have just over 20 investors that we bring into our transactions as co-investors. We have added a couple this spring that we had on hold. We have not had any investor say it is out of the market. There is some delay in getting commitments, but by and large, we think that commitments can still be had. Lastly to your point, there are more deals in the market. There has been an acceleration of activity, as was to be expected because of the four-year window to complete projects and the step down in tax credit amounts.

MR. MARTIN: Let me ask the same question of the others, starting with Peter Cross: are more developers than usual seeking tax equity or are there fewer tax equity investors?

MR. CROSS: Both. We have heard of a couple of investors tapping the brakes slightly, but I think concern about liquidity in the tax equity market has driven sponsors to line up, particularly in light of grandfathering issues, so there has been a little bit of a run on tax equity desks.

MR. MARTIN: Do you expect to do less, more or the same volume as last year?

MR. CROSS: About the same. Our business is really all solar, primarily in the commercial and industrial and residential sectors.

MR. MARTIN: Darren Van't Hof, do you expect to do less, the same, or more volume this year than last year?

MR. VAN'T HOF: Our current forecast is to do the same, but our hope is that we will be able, in the second half of the year, to increase our commitments over the plan. We have a few things to sort out before we can get there.

MR. MARTIN: Like what?

MR. VAN'T HOF: First and foremost, whether the additional opportunities fit within our risk framework. Second, the additional opportunities require more work. In a normal year, we are stretched from a human-resource capacity and this would simply exacerbate that.

MR. MARTIN: I think you are doing more syndication rather than direct investment this year. Is that correct?

MR. VAN'T HOF: We do about 50-50, so we hold about half of what we originate. We do full-on commitments to our developer partners, so when they get a US Bank commitment, it is from us. It is not contingent on being able to syndicate part of the investment. Between when we give the commitment and when the project is placed in service, we either sell down the entire position or a portion of it, with the assumption that if we are unable sell down, we will close the deal and hold the investment.

MR. MARTIN: Jorge Iragorri, what volume do you expect this year compared to last?

MR. IRAGORRI: Around the same. Given the uncertainty around COVID-19, we are still re-running numbers, but as of this moment, around the same.

MR. MARTIN: Is it your sense that there are fewer tax equity investors this year overall? Are there more deals pressing for attention? Peter Cross said that there seemed to have been a rush by sponsors to get in line so as not to be caught flat-footed later in the year.

MR. IRAGORRI: There was some slowness in March and April, for obvious reasons, but not due to lack of appetite. One thing that is different this year is deal quality. There are probably more deals generally, but there has been some deterioration in quality. The deals of poorer quality are still sputtering, and I think that may account for some of the indigestion that you hear about.

MR. MARTIN: When you say deals are of poorer quality, what do you mean?

MR. IRAGORRI: Some it is too much / continued page 18

IN OTHER NEWS

Partnerships are not required to have appraisals done each year for the calculations. The IRS said to use the fair market values of assets "if readily available." Otherwise, partnerships can guess at the numbers by using numbers they already track for tax or book purposes or by using some other method spelled out in the partnership agreement for "determining what each partner would receive if the partnership were to liquidate."

It is still not entirely clear why the IRS feels it needs partnerships to track tax capital. The figures may confuse IRS agents on audit since the actual gain or loss on sale of a partnership interest may be a different number.

A MASSACHUSETTS property tax exemption for wind and solar projects does not apply to the extent net metering credits earned by the project are sold to entities, like schools and local governments, that do not pay property taxes.

United Salvage Corp. installed an 800-kilowatt solar system in 2012 on the roof of a building it owns in Framingham, Massachusetts. It supplies the electricity from the system to the local utility, Eversource, in exchange for net metering credits that can be used to pay for electricity purchased from Eversource. The solar system was assessed for property tax purposes at a little over $1.2 million in 2016 and a little less than that amount in 2017.

United Salvage Corp. signed a contract in 2013 to sell all of its net metering credits to the city for five years. The city used them to pay the electricity utility bills at three city facilities: the police station, the public library and the public sports arena.

The Massachusetts property tax statute exempts wind and solar facilities that are used to supply energy to "property taxable under this chapter." The exemption is in clause 45th.

United Salvage Corp. argued that because the electricity goes into the Eversource grid, it

/ continued page 19

Tax Equity

continued from page 17

geographic concentration. Some markets are being massively overbuilt. Some of it is more offtake risk. Some of the offtakes, as everyone knows, have more embedded risks that we did not have to deal with in the past. Underwriting those risks is more challenging, particularly at a time when investors are being careful where they deploy capital.

MR. VAN'T HOF: A lack of quality deals does not necessarily translate to a lack of tax equity.

Tax equity has become hard to find this year.

MR. MARTIN: George Revock, will Capital One do less, the same or more volume this year than last?

MR. REVOCK: There is plenty of deal flow to be had. However, we do not expect to have much tax capacity in 2020. That is primarily because we are already flush with tax credits from existing investments in low-income housing, new markets and renewable energy projects. We are bumping up against the 75% cap on how much tax liability can be reduced by claiming tax credits.

MR. MARTIN: Has your tax capacity been affected by coronavirus and the economic slowdown?

MR. REVOCK: Yes. We expect to remain profitable in 2020, but tax capacity for the year will be down. The question to which we still do not have an answer is how much 2020 pre-tax income will be generated and what does it translate into in terms of tax capacity.

MR. MARTIN: Do you expect to do any deals at all this year?

MR. REVOCK: We are expecting to do deals that commit this year and fund in 2021, unless there are changes in the tax code.

MR. MARTIN: Renewable energy tax equity was a $12 to $13 billion market last year. It had been expected to hit $15 billion this year. Given where things stand, does anybody have a sense where the figure will land ultimately? [Pause, no response.]

I take that as a no. It is a very concentrated market. Last year, two tax equity investors, JPMorgan and Bank of America, together accounted for about 50% of the market. Each did $3 billion. We have heard from one of them that it expects to do about $4.5 billion this year, and the other is also saying it is business as usual. That, plus the fact that three of the four tax equity investors on this call are still in the market doing a normal volume, suggest that we should do at least the same volume as last year and maybe a little higher.

MR. VAN'T HOF: The one thing to mention is that deals will slip. I think that the volume is there, but some of it might translate into 2021 volume.

Window Closing?

MR. MARTIN: Good point. My numbers are commitments made during the year even though the funding may not be the same year. If someone comes in now with a new deal that he or she wants to close this year, what would be a realistic closing date?

MR. CROSS: The answer depends in part on whether it is a new client. If it is a repeat client and we have documents we can pull off the shelf, the deal will move faster.

We are getting to the stage where we are at risk of bumping up against the year-end deadline, and we are starting to look ahead to 2021. I think we could still get off a deal this year, particularly for an existing sponsor, but it is tough. We are getting kind of close to the end of the 2020 season.

MR. MARTIN: Jorge Iragorri, does it feel like we are at the end of what can be done in 2020?

MR. IRAGORRI: Yes, it does feel that way. We are closing on a variety of deals that we originated either last year or the beginning of this year. Any new mandates at this point are really for funding in 2021.

MR. MARTIN: Darren Van't Hof, same answer?

MR. VAN'T HOF: I would say we are getting pretty close, like Peter said. If it is an existing customer, we can move a little faster, but new customers will take longer.

MR. MARTIN: How have the tax equity terms have been affected by coronavirus, if at all?

MR. VAN'T HOF: Tax equity yields have gone up a bit. The sponsors are having to pay a bit of a premium in exchange for certainty and an ability to execute.

MR. MARTIN: Can you give us a sense how much yields have gone up?

MR. VAN'T HOF: People look at yields differently. Some people focus on the net present value and others look at internal rates of return. It may be a function of what metric you use, but let's say maybe 50 basis points.

MR. MARTIN: We heard last week on a lender call that debt spreads had widened by 50 basis points, but that many borrowers are waiting for the market to normalize before pulling the trigger on new borrowing. Jorge Iragorri, has there been any other change in tax equity terms as a consequence of economic conditions?

MR. IRAGORRI: Not many. Credit spreads to tax equity have a significantly delayed effect. We heard on one of these calls a couple months ago about yields widening in the bank term loan B and project bond markets. That generally does not translate immediately to the tax equity market. We have just been in a period where the spread had narrowed significantly. Net net, I am seeing roughly similar terms, probably slightly higher yields in exchange for execution certainty, but not a lot of changes elsewhere.

MR. MARTIN: Peter Cross, same answer?

MR. CROSS: Same answer. Maybe 25 to 50 basis points higher.

MR. MARTIN: Has any of you run into any force majeure or supply chain issues in deals on which you are working?

MR. REVOCK: We have a couple deals where suppliers have had issues that will push them into 2021. We have also had contractors warn that they may have to invoke force majeure, but none has done so yet.

MR. MARTIN: How has the pace of deals been affected by having to work from home?

MR. REVOCK: Aside from missing out on a three-hour round trip to commute to New York City, we have not missed a beat. The bank's management did a nice job preparing our systems for something like this. Obviously we miss the camaraderie of seeing our teams and our clients and other / *continued page 20*

IN OTHER NEWS

ends up being supplied to all Eversource customers.

However, the policy of the Massachusetts property tax board is to treat electricity as used where the net metering credits are used. On appeal, the Appellate Tax Board declined to overrule that policy.

The case is *United Salvage Corp. of America v. Board of Assessors of the City of Framingham*. The appeals board released its decision in May.

The case is a warning to factor in property taxes on Massachusetts projects where the net metering credits will be used by a government or tax-exempt entity.

A STRUCTURED FINANCE TRANSACTION was partly rejected by a US appeals court.

Three other banks that engaged in similar transactions have gone to court to defend the hoped-for tax results in the transactions. All three lost when the cases reached US courts of appeal.

The transaction is called STARS, for structured trust advantaged repackaged securities. It was promoted by KPMG starting in 2001.

Wells Fargo engaged in the transaction with Barclays in 2002. The district court judge who heard the case said the transaction was so complicated that "it almost defies comprehension."

It had two parts.

Wells Fargo contributed $6.7 billion in income-earning assets to a Delaware trust and appointed a Wells Fargo affiliate that was a UK tax resident as the trustee. This subjected the income earned on the income-producing assets to tax in the United Kingdom. Wells Fargo claimed the UK taxes paid as a foreign tax credit in the United States.

Barclays bought an interest in the trust from Wells Fargo for $1.25 billion. In substance, the purchase was a loan to Wells Fargo. Wells Fargo made payments to Barclays that were essentially interest on the loan. Wells Fargo was / *continued page 21*

Tax Equity

continued from page 19

industry professionals, and my family is sick of seeing me every day, but it could be worse.

MR. MARTIN: Has anyone else on the call seen the pace of deals affected by having to work from home?

MR. VAN'T HOF: No effect. To echo George, I think our institution did an exceptional job of preparing folks to work from home.

MR. CROSS: We are firing on all cylinders.

We also canvassed all of our existing sponsors to assess their preparedness. This was in the early days when we were concerned about their ability to continue operating and maintaining projects for existing funds and deployment for funds that are currently in tranching mode. We have been impressed with the level of preparedness that all of our sponsors have. They were all working remotely. In many instances, they still had boots on the roofs.

Developers rushed to line up commitments early.

It is not surprising that the big financial institutions have this in hand, but so do the sponsors.

MR. MARTIN: Do any of you have concerns about offtaker liquidity?

MR. IRAGORRI: We are re-evaluating every offtaker in a COVID world. We are looking at every offtaker, credit quality, liquidity, etc. So far, the offtakers that are in our pipeline all remain strong.

Five-Year Carryback

MR. MARTIN: The CARES Act authorized companies to carry back losses up to five years and get back taxes paid in the past. Will this make tax equity investors more interested in claiming a 100% depreciation bonus?

MR. REVOCK: The five-year carryback is helpful, but it really does not help us because tax credits cannot be carried back. If a company remains even slightly profitable in 2020, the carryback does not help at all. The tax credits we earn this year could be carried forward and might actually reduce our tax capacity in future years.

What would really help would be to allow a five-year tax credit carryback as opposed to a five-year carryback just for net operating losses. That would help us make full use of all the tax credits from our existing investments and also open up capacity to fund transactions this year and increase our tax capacity in future years.

MR. VAN'T HOF: We look at this quite a bit on the syndication side. If there were to be another round of stimulus bills, something that would be extremely beneficial not just to this industry, but also to other capital-intensive industries would be to allow tax credits to be carried back in time.

The ability to carry back net operating losses is marginally beneficial because they can be carried back to a period with higher tax rates. But the ability to carry back tax credits and allowing them to offset more than 75% of tax liability would have a much greater impact. These are ways Congress could support the market without having to initiate a big new program.

MR. MARTIN: There has been some discussion on Capitol Hill about these suggestions, but it is hard in the current climate to know what might ultimately be in the next bill.

Let's switch topics. President Trump issued an executive order on May 1 that immediately bans purchases, use or transfers of as-yet-unidentified equipment supplied by foreign adversary companies that could harm the US power grid. Darren Van't Hof, how are you dealing with that order?

MR. VAN'T HOF: We are looking at it closely. There has been a ton of discussion about which equipment, which countries and what parts of the grid are affected. The Solar Energy Industries

Association and the American Council on Renewable Energy have been on top of this. We are just riding their coattails. There are no clear answers yet.

MR. MARTIN: Has anyone on the call formed a view about how to deal with the executive order? The Department of Energy is assuring the industry that the order will not prove disruptive.

MR. CROSS: The guidance we have gotten is that it does not apply to distributed generation, so we are of the view and hope that it does not affect our business.

MR. MARTIN: The order itself says that it does not apply to distributed generation. You are in an unusual position because of your focus on distributed generation. Jorge Iragorri, how has Morgan Stanley reacted to the order?

MR. IRAGORRI: Wait and see. We are waiting for other organizations to sort things out.

Continuous Efforts

MR. MARTIN: George Revock, wind projects that were under construction for tax purposes in 2016 must be completed by the end of this year to qualify for tax credits.

The developer can buy more time by proving that continuous efforts have been made to advance the project since construction started, and an IRS notice is expected to allow five years instead of four to finish.

What happens when a project takes longer than the allowed time? Suppose a developer is prepared to offer proof of continuous efforts. Is he out of luck or will you finance projects that take longer than the four- or five-year period to construct?

MR. REVOCK: That's a tough question. We have been talking to some clients who are looking to go that route potentially. Unless the developer can get a private letter ruling from the IRS confirming the project still qualifies, it will end up being a supply-and-demand issue. We will focus first on projects that do not have this complication. We would probably look to avoid the scenario if we could.

MR. MARTIN: The IRS is not issuing private letter rulings on construction-start issues. There are developers who have kept very good logs showing what was done from one week or month to the next and who have tables showing significant costs being incurred steadily over time. Jorge Iragorri, how does Morgan Stanley look at this?

MR. IRAGORRI: We are more focused on solar than wind, so this has not really been an issue for us.

MR. MARTIN: Tax equity deals done between 2008 and 2015 are reaching flip points when sponsors */ continued page 22*

IN OTHER NEWS

required to buy back the trust interest — in effect, repay the loan principal — after five years.

The interest that Barclays held in the trust in theory entitled it to cash distributions of income the trust earned on the income-producing assets. However, in practice, the distributions were paid into a blocked account at Wells Fargo in Barclays' name. The money was then reinvested in the trust.

This allowed Barclays to deduct the money retained by the trust from its UK taxes as a trading loss. It also received credit against the UK taxes it had to pay on its distributions from the trust for the UK taxes already paid by the trust on the trust's income.

It made fixed "Bx" payments of roughly $32 million a year to Wells Fargo that were around 47.5% of the UK tax credits received by Barclays, thereby effectively reducing the interest that Wells Fargo had to pay on the loan. Barclays was then able to take further tax deductions in the UK for the Bx payments.

At the end of the day, the transaction was a complicated $1.25 billion loan by Barclays to Wells Fargo structured to produce tax benefits for Barclays that the UK bank shared partly with Wells Fargo to reduce the interest Wells Fargo had to pay on the loan.

British tax authorities alerted the IRS in 2005 that STARS may be an abusive tax shelter.

The IRS put a halt to the transactions in 2007 by issuing regulations, but the regulations did not apply retroactively.

The federal district court that heard the case said that the trust part of the transaction was a sham, but allowed Wells Fargo to deduct the interest it paid on the loan. It disallowed the foreign tax credits claimed by Wells Fargo for the UK taxes paid on the trust income.

The appeals court agreed. It said Wells Fargo had voluntarily subjected itself to taxes in the UK on the trust income. This was not a transaction for which Congress intended to give foreign tax credits, it said. "Wells Fargo artificially generated */ continued page 23*

Tax Equity

continued from page 21

can buy out the tax equity investors. Discount rates in the M&A market have gone up reflecting a perception of greater risk. One would think this should reduce sponsor call option prices. George Revock, has it?

MR. REVOCK: We are a relatively new player that started in 2014, so we have not really had any buy-out discussions yet. We expect to have the first couple ones within the next 12 months. Usually, our sponsor call options are priced at the greater of two or three amounts. Fair market value is just one of the amounts.

The higher discount rate would certainly reduce the fair market value, but the other prongs are an amount that protects our full-term yield and an amount that is at least the GAAP book balance.

MR. MARTIN: Darren Van't Hof, have you seen any change in sponsor call option prices?

MR. VAN'T HOF: A bit, but we are also seeing ones that are indexed to fair market value in our residential portfolio where candidly the prices are coming in higher than we projected. We have a sizeable portfolio of residential solar that tends to offset transactions on the C&I side or the utility side where discount rates have gone up.

Project Mix

MR. MARTIN: Has coronavirus affected the type of deals that you are prepared to do? For example, has it affected your interest in doing projects with corporate PPAs, hedged projects, rooftop solar, projects with community choice aggregators in California or community solar? Peter Cross, you are focused on C&I solar. You are dealing with a lot of corporate credits. Has coronavirus changed anything?

MR. CROSS: As Jorge Iragorri said, we are looking closely at all of our existing investments. We have a big residential solar exposure as well. I think there is clearly going to be hardship in that market.

We have always taken the view that we should be in a relatively good position since the alternative to paying the solar bill is to pay the local retail price for electricity, and it is higher. Logically you would think that the solar bill would be the last thing people will stop paying.

We have not seen, either on the corporate side or the residential side, a dramatic impact at all. It is still early days. We all need to keep watching. We are aware that some sponsors have implemented deferral plans in one-off situations where people are in economic distress. Any effect will be felt after a time lag.

MR. MARTIN: When you say there will be hardship in the residential market, are you referring just to these deferral plans where some homeowners may be out of work and do not have the cash to make payments in the short term?

MR. CROSS: Exactly.

MR. MARTIN: Jorge Iragorri, has there been any change in the types of deals you are prepared to do as a consequence of coronavirus?

MR. IRAGORRI: No. Our pipeline remains C&I, mostly focused on high-quality offtakes, and utility-scale again with high-quality offtakes. We have done some deals with CCAs as offtakers. We are not doing residential rooftop deals. Everywhere else we continue to do business as usual on a credit-by-credit basis.

MR. MARTIN: Has there been any change in appetite for merchant solar projects in ERCOT?

MR. IRAGORRI: No change. We would need an offtake.

MR. MARTIN: Does that mean you would not do them because there is no offtake contract? In the past, Morgan Stanley has been the tax equity investor and also provided a hedge.

MR. IRAGORRI: There has to be a hedge or a PPA.

MR. MARTIN: Darren Van't Hof, has there been any change in types of deals you are prepared to do as a result of coronavirus?

MR. VAN'T HOF: No, not wholesale. We are just like other institutions. We are doing a much deeper dive than maybe we would have done two years ago when we might have relied on a credit rating for the offtaker. The mix of project types is the same as in prior years.

DROs

MR. MARTIN: Electricity prices are falling. This leaves less cash flow and reduces the amount of tax equity raised, making it harder to absorb all of the depreciation on a project. Investors sometimes deal with this problem by agreeing to a deficit restoration obligation or DRO. How high are you seeing these go?

MR. VAN'T HOF: We have seen on the top end as high as 50%, but that is the extreme. Retail electricity prices have not been falling. On the utility-scale side, there are pockets of falling prices, but that has not been a driver for whether we need to accept a DRO.

MR. MARTIN: So falling electricity prices do not affect whether you need to post a DRO. Has anyone seen DROs go above 50%? I know we saw a term sheet yesterday at 70%.

MR. REVOCK: We have gone north of 50%, but in deals where we are taking a 100% depreciation bonus rather than five-year MACRS depreciation. At the end of five or six years, you are still in the same place, but your initial DRO might be very high because of expensing.

MR. MARTIN: Has there been any change in the percentage of the capital stack that is tax equity in the typical solar or wind deal, and what is the percentage?

MR. CROSS: Our product is different than the common tax equity structure. We are more of a hybrid of debt, cash equity and tax equity in that we will advance against as much as 99% of contracted cash flow. As a result, our flips are much farther out than the typical six- or seven-year structure. We could be advancing 80% of the capital stack.

The clock has largely run out on signing up new deals to close by year end.

MR. MARTIN: I think you are doing leveraged inverted leases where you are both the tax equity investor and lender. Is that correct?

MR. CROSS: We have moved to partnership flips of late.

MR. MARTIN: Jorge Iragorri, has there been any change in the percentage of the capital stack that is tax equity?

MR. IRAGORRI: No. We are doing solar partnership flip deals with a flip in seven or so years. The tax equity is between 30% and 40% of the capital stack. We are flexible on cash flow allocations, but we prefer more cash than normal.

MR. MARTIN: George Revock, where do you think tax equity is as a percentage of capital in wind deals?

MR. REVOCK: It has come down a little as pay-go structures become more common. We usually see it at 50% to 60% of the capital stack.

/ continued page 24

IN OTHER NEWS

this tax by engaging in an economically meaningless activity which was specifically designed to create foreign-tax liability."

Three other banks that went to court to defend their STARS transactions — Bank of New York Mellon, BB&T and Sovereign — also lost in appeals courts for the 1st, 2nd and federal circuits. (For earlier coverage, see "A transaction lacked economic substance" about the BB&T case in the July 2015 *NewsWire* and "Economic substance" about the Bank of New York Mellon case in the November 2015 *NewsWire*.)

The latest case is *Wells Fargo v. United States*. The 8th circuit court of appeals released its decision in late April.

PRODUCTION TAX CREDITS for wind and geothermal projects will remain at the same level as in 2019.

They will increase slightly for landfill gas, biomass and other renewable energy projects.

Credits for producing refined coal are also increasing.

Production tax credits for generating electricity from wind, geothermal steam or fluid or closed-loop biomass (plants grown to be used as fuel in power plants) will remain 2.5¢ a kilowatt hour in 2020, the same amount as in 2019. They will increase to 1.3¢ a kilowatt hour for generating electricity from open-loop biomass, landfill gas, incremental hydropower and ocean energy.

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

The credits phase out if contracted electricity prices from a particular resource reach a certain level. That level for wind in 2020 is 13.3496¢ a KWh. The IRS said there will not be any phase out in 2020 because contracted wind electricity prices are 4.16¢ a KWh going into 2020. It said it lacks

/ continued page 25

Tax Equity

continued from page 23

All of these percentages will drop as the tax credits start to step down. You might see the amount of cash that we get start to increase as we move more toward a lending type-proposition where the tax credits plus the depreciation become less of the tax equity return. Maybe at that point we start taking more cash, not only with the help of a DRO, but also to get to a more efficient structure.

MR. MARTIN: Why is the market moving to more pay-go structures? How does taking more cash get you to a more efficient structure?

MR. REVOCK: There are a couple of primary reasons for pay-go. For tax equity, it is a risk mitigant in downside wind scenarios. For the sponsors, there is less tax equity on day one, and this could create a more efficient structure. Pay-go is also expected to increase future cash distributions to the sponsor. If a structure is constrained by a DRO, one solution is to increase the tax equity investment, which may require additional cash to hit the flip. That said, such an approach could require a trade-off between an increase in the tax equity pre-tax cash return with a corresponding reduction to after-tax return to create a more efficient structure.

Audience Questions

MR. MARTIN: Let's move to audience questions. Several questions come down to the same thing: how small a deal will you look at? One person framed it this way: would you invest in a series of $10 million deals from the same developer that add up to $100 million over time? Peter Cross, I assume that works if you set up a master financing facility for a series of C&I projects, correct?

MR. CROSS: Yes, if we put them into a single partnership. Our bite size is probably $100 million total.

MR. MARTIN: Darren Van't Hof, US Bank has traditionally looked at smaller projects. Where are you drawing the line at this point on how much tax equity is required for a deal to be of interest?

MR. VAN'T HOF: We are probably at $30 to $40 million on the small end. We see a lot of portfolios that have anywhere from five to 15 different projects. If they are all under one master PPA with one offtaker but happen to be at different sites, that is a lot different than if there are 10 sites and 10 different offtakers. The latter is inefficient to do from a legal and due diligence standpoint.

MR. MARTIN: We have a ton of audience questions and only about six minutes remaining. I will ask a question, and mention a name. Give me short answer that so we can fit in as many as possible.

Jorge Iragorri, are you putting out more or fewer term sheets now than you did pre-COVID-19?

MR. IRAGORRI: About the same. We slowed down a bit in March and April as we were trying to navigate the situation, but that did not stop us from putting out term sheets.

MR. MARTIN: George Revock, how strong is the appetite in the tax equity market for more deals in west Texas?

MR. REVOCK: I am probably the wrong guy to choose on that one. We have a lot of west Texas exposure in our portfolio. We are looking outside ERCOT because more than 50% of our portfolio is in Texas currently.

MR. MARTIN: Darren Van't Hof, are you seeing renewed interest in inverted leases since they do not make capital accounts go negative?

MR. VAN'T HOF: We still do a fair number of them. They are helpful particularly if you have a sponsor that can absorb some of the depreciation. On the syndication side, we have some investors that much prefer them. We are probably split 50-50 currently between inverted leases and partnership flips.

Waiving a 75% limit on use of tax credits to reduce tax liability would help.

MR. MARTIN: Is the 50-50 split between inverted leases and partnership flips a consequence of the times or were you headed there anyway?

MR. VAN'T HOF: We were probably headed there anyway. We have not seen coronavirus or the economic shutdowns affecting choice of deal structure, at least not yet.

MR. MARTIN: What percentage of projects are taking bonus depreciation today? Is it more or less than in the past?

MR. VAN'T HOF: About the same. Bonus depreciation really is not that exciting for investors. If we need to take it for the benefit of a sponsor, we will, but the ability to absorb it is a challenge, and whether we will do it is a decision we make on a deal-by-deal basis.

MR. MARTIN: Has the inclusion of energy storage in more plain-vanilla solar and wind deals created any obvious hurdles or underwriting issues?

MR. VAN'T HOF: We are seeing a lot of storage. From an underwriting perspective, it comes down to an independent engineer review and technology review and the strength of the warranty. If the manufacturer does not have strong financials or the warranty falls short of what we need, there are insurance products around that. We are looking at a raft of ways to mitigate storage as it is still evolving as a technology.

MR. MARTIN: Peter Cross, there has been a lot of talk about C&I solar on this call. Are there any particular metrics that you are watching to determine whether there may be short-term problems?

MR. CROSS: We are always watching our accounts receivable, time outstanding, first customer payment dates and the like. They are nothing new or different, but we are keeping a sharp eye on them.

MR. MARTIN: Are any of you interested investing in carbon capture projects with section 45Q tax credits?

MR. VAN'T HOF: Not at this time.

MR. MARTIN: George Revock, once you have tax capacity, will they be of interest?

MR. REVOCK: We have looked at them. We will probably look at them a little more deeply in association with enhanced oil recovery, but it may turn out to be a tough market for us to wrap our hands around. ◎

IN OTHER NEWS

data on contracted prices for electricity from the other energy sources.

Production tax credits for producing refined coal are $7.301 a ton in 2020. Refined coal is coal that has been treated with chemicals to make it less polluting than regular coal. The IRS said there will not be any phase out of refined coal credits in 2020. The refined coal credit phases out as the reference price for raw coal moves above 1.7 times the 2002 price of raw coal. The 2020 reference price is $48.58 a ton. A phase out would have started at $90.49 a ton.

The tax credit amounts are in IRS Notice 2020-38. The notice appeared in the IRS Cumulative Bulletin on June 1.

A NEW YORK electricity generator qualified for a $350,000 cap on part of the annual franchise taxes it had to pay in the state.

The decision turned in part on whether generating electricity is "manufacturing." A tax tribunal said that it is. Manufacturers are given tax breaks in many states, including New York.

TransCanada owned two large gas-fired power plants in the United States during the period 2010 through 2012. One was the 2,480-megawatt Ravenswood generating station on Long Island in New York. The other was a 575-megawatt power plant in Coolidge, Arizona.

It owned both through a common US holding corporation. More than 50% of the annual gross income from the two power plants came from the Ravenswood power sales in New York.

New York collects annual franchise taxes from companies doing business in the state. The tax is calculated mainly on a company's capital base.

The tax on capital base is capped at $350,000 for "New York manufacturers."

The state audited the company in 2015 and sent a bill for back tax liability for the period 2010 through 2012 of $3.3 million, plus interest of $1.2 million / continued page 27

Rights to Block Bankruptcy Filings in Doubt

by Eric Daucher and Christy Rivera, in New York

A federal bankruptcy court decision in May has called into question the validity of certain "bankruptcy-remote" structures frequently used by businesses, particularly in project financing.

The court rejected the right a shareholder held to block a bankruptcy filing by the company in which it owned shares. The shareholder had negotiated for the right when it made an investment in the company.

The case is *In re Pace Industries*.

The court also said that such blocking rights impose full fiduciary duties on minority equity holders holding such rights to consider the interests of the company itself (and, by extension, those of other equity holders and creditors) before exercising them.

There are key distinguishing features between the facts in the *Pace Industries* case and those likely to be found in project finance transactions.

First, in particular, the *Pace Industries* case involved a corporation, rather than a limited liability company, which is what would normally be used in a project financing. This distinction may be critical, because the bankruptcy court's negative decision depended, in part, on the fiduciary duties of the shareholder. Such fiduciary duties usually are much more limited in the context of an LLC.

Second, the rejected blocking right was held by a shareholder, rather than by a professional independent director with no economic interest in the result. When the right to block a bankruptcy filing is requested by a lender, the structure may involve the appointment of a disinterested independent director.

Tax equity and true equity investors should not rely heavily on blocking rights given directly to them as equity owners.

Finally, the corporation in this case was in real financial distress. This was not a case of a parent company trying to bring its otherwise healthy subsidiaries into bankruptcy with it. As a result, while the decision creates additional risk for bankruptcy-remote structures and will need to be closely monitored, it should not be seen as the end of bankruptcy remoteness for the structures most commonly used in the project finance market.

The Arguments

Pace Industries, Inc. and 10 affiliates filed for bankruptcy protection in Delaware.

As part of their first-day filing package, they proposed a so-called "prepackaged" plan of reorganization that would restructure the company's more than $300 million of debt, largely by swapping debt for equity. A preferred shareholder in Pace asked the bankruptcy court to dismiss the bankruptcy filing entirely, claiming that it possessed a negotiated-for blocking right over any bankruptcy filing by the company and that it had not given its consent.

Pace opposed dismissal of the case, arguing that allowing a shareholder to block a "last-resort" decision such as a bankruptcy would represent an extraordinary and impermissible level of control over the company.

Although counsel for Pace acknowledged that there was no case precedent for overriding such a contractual provision, he argued that "[w]hile the Delaware General Corporation law is flexible, we do think Delaware's Supreme Court would put limits on this kind of blocking right, in this context."

TCW Asset Management, a secured creditor that supported the proposed prepackaged plan, also argued against dismissing the case. Taking a practical angle, TCW argued that even if the case were dismissed, the creditor would simply commence an involuntary bankruptcy case, against which there would be no defense given that Pace was not paying, and was unable to pay, its debts as they came due.

The shareholder responded that the bankruptcy court should not deprive it of its bargained-for protection, which was a critical element of its agreement to purchase more than $37 million of equity in Pace.

The shareholder also said that a blocking right, without more, could not mean it has improper control over the business, and that any suggestion that it controls the business is particularly unsupportable given that the board had, without its consent, decided to file for bankruptcy. Responding to TCW, the preferred shareholder noted that there was no involuntary bankruptcy petition before the court, and that any involuntary petition would face obstacles.

The Ruling

The bankruptcy court declined to dismiss the bankruptcy filing.

Although it acknowledged that there was no Delaware authority on point, and that no bankruptcy court had previously overridden a shareholder's veto right over bankruptcy filings, the judge said that "based on the facts of the case, I am prepared to be the first court to do so."

The judge focused less on the negotiation of the contractual veto right and more on the financial condition of the company.

She said it was "no contest that the debtor needs a bankruptcy" given that it was in "financial straits even before COVID-19." She said the company, in order to survive, would need the special protections and liquidity measures only available in bankruptcy.

Critically, and in contrast with a recent decision by the US court of appeals for the fifth circuit, the bankruptcy court found that "under Delaware state law . . . [bankruptcy] blocking rights, such as exercise in the circumstances of this case would create a fiduciary duty on the part of the shareholder." That fiduciary duty, the court found, would compel the preferred shareholder to approve a bankruptcy filing in light of the company's economic circumstances.

Implications

The court's analysis, if carried to a logical conclusion, could adversely affect the bankruptcy-remote structures relied on by numerous businesses.

Bankruptcy block rights, and so-called "golden-share" provisions in which a particular shareholder's consent is required for a bankruptcy filing, are fundamental to bankruptcy remoteness.

However, there are several reasons to question whether the risk caused by the decision may be contained. Most important, the decision was made about a Delaware corporation. Most bankruptcy-remote arrangements use limited liability companies. While Delaware law provides some flexibility for managing or disclaiming fiduciary duties owed to a corporation, it provides almost unlimited flexibility for duties owed to limited liability companies. Accordingly, the conclusion that a blocking right creates fiduciary duties that would have compelled the shareholder to authorize the bankruptcy filing would not necessarily translate to an LLC.

That said, courts outside Delaware considering the laws of other states have not necessarily distinguished between a corporation and an LLC.

For example, a bankruptcy court in Illinois rejected a blocking provision held by a "special member" of a Michigan LLC. However, the special member was also a lender to the LLC. The LLC agreement provided that the lender was specifically excused from all fiduciary duties. It only needed to / *continued page 27*

IN OTHER NEWS

and another $328,165 in penalties. Any company that substantially understates its tax liability is subject to a 10% penalty.

An administrative law judge said the company is a manufacturer, but not a "New York manufacturer" as defined in the tax statute.

On appeal, the Tax Appeals Tribunal said it is also a New York manufacturer.

To qualify for the cap, a company must show three things: it is a manufacturer, it has property in New York described in a state investment tax credit statute, and either that property has an adjusted tax basis for federal income tax purposes of at least $1 million or else all of the company's tangible property is in New York.

The state treats electricity generation as a form of manufacturing, and the Ravenswood power plant that TransCanada owned in the state had an adjusted tax basis well above $1 million.

The issue came down to how to read the requirement that TransCanada must have property in the state of a type described in the state investment tax credit statute. Power plants to do not qualify for the investment tax credit.

The appeals tribunal read an exclusion for power plants in the investment tax credit statute to apply just for the investment tax credit and not also for the franchise tax cap.

It was swayed in part by the fact that the governor proposed in 2008 and 2009 — just before the tax years at issue — to exclude electricity generators, among others, from the cap. The legislature failed to act on the proposal.

The case is *TransCanada Facility USA, Inc.* The appeals tribunal released its decision in May.

LIKE-KIND EXCHANGES are largely limited to swaps of land, buildings, transmission lines, gas pipelines and other "real property."

Proposed regulations that the IRS issued in June dashed any hope that power plants would be considered "real / *continued page 29*

Bankruptcy

continued from page 27

consider its own interests when deciding whether to authorize a bankruptcy filing. The court rejected the blocking provision. It said blocking provisions are only acceptable where the party possessing the blocking right is obligated to exercise "normal director fiduciary duties" when deciding whether to file. In other words, any provision that purports to give a lender (or, presumably, an equity holder) free rein to reject a company's bankruptcy filing without considering the interests of the company itself is unacceptable and unenforceable.

Some bankruptcy-remote structures are in doubt after a court ruling

Combining the court decisions in both Delaware and Illinois, the conclusion may be that any effort to impose a meaningful contractual barrier to a bankruptcy filing is simply unenforceable.

While that result may be what the Delaware bankruptcy court has in mind going forward, not all courts have taken that view, even when considering Delaware law.

In a relatively recent decision, the fifth circuit US court of appeals (which includes Texas, Mississippi and Louisiana) enforced similar bankruptcy blocking rights. In that case, the court held that "federal bankruptcy law does not prevent a bona fide equity holder from exercising its voting right to prevent the corporation from filing a voluntary bankruptcy petition just because it also holds a debt owed by the corporation and owes no fiduciary duty to the corporation or its fellow shareholders."

After resolving that threshold question, the appeals court considered "whether Delaware law allows parties to provide in the certificate of incorporation that the consent of both classes of shareholders is required to file a voluntary petition." After noting the general flexibility provided by Delaware corporate law, the court concluded that it would not prohibit corporate provisions that condition bankruptcy filing on shareholder consent.

Finally, the court found that potential control of a company is not enough to create fiduciary duties; actual control is required. Unlike in the Pace Industries case, the appeals court found that the company's willingness to file for bankruptcy without obtaining the required consent undercut any suggestion of actual control. In closing, it said that even if such a blocking provision did create fiduciary duties, the proper remedy for any breach of a fiduciary duty would not be to deny an otherwise valid motion to dismiss the bankruptcy case, but rather for the company to see remedies against the breaching party under state law.

Market reaction to the Pace Industries decision has been muted, perhaps in part because the particular facts of the case — the company's acute financial distress — may limit its broader application.

The decision also may not necessarily be seen as a large shift in the law given that at least one other bankruptcy decision in Delaware held earlier that a minority equity holder may not use a bankruptcy blocking right for its own purposes where its primary relationship with the company was as a creditor.

While the latest decision appears to dispense with that second element, it does little to disrupt the general market understanding that any provisions that attempt to impose a firm bar to bankruptcy — whether expressly or implicitly — are unlikely to be upheld in Delaware courts. ◎

The Virus, the Bear and the Cost of Capital

Three lenders and the managing partner of a private equity fund talked in late May about how coronavirus and the economic downturn are affecting the cost of capital for the US power sector, especially for renewable energy projects. They also talked about how project valuations are being affected.

The lenders are Michael Pantelogianis, co-head of power for North America for Investec, Steve Cheng, a partner within the credit business of Global Infrastructure Partners, and Manish Taneja, managing director and deputy global head of infrastructure credit for The Carlyle Group. Scott Harlan is managing partner of Rockland Capital. The conversation took place on Zoom and was organized by Solar Media UK. The following is an edited transcript. The moderator is Keith Martin with Norton Rose Fulbright in Washington.

Current Deal Flow

MR. MARTIN: Mike Pantelogianis, how would you characterize current deal flow in the US market?

MR. PANTELOGIANIS: Deal flow varies by sub-sector. Conventional power is somewhat slow. There was a lot of activity in that area in the last year or two.

Renewables seem to be strong in terms of volume. Obviously getting the projects done by the end of the year is a focus, so this area is very active both on the equity and the credit sides.

For midstream oil and gas, which we focus on as well, we see more attention being given to trying to address the liquidity needs as a result of the crash in oil prices.

MR. MARTIN: Scott Harlan?

MR. HARLAN: We are busy. I agree with Mike. The busy-ness is there are more renewable energy deals getting done while the bid-ask spread on the non-renewable investments has widened. Sellers of fossil generation are cautious about going to market right now. We see a lot of opportunities in development-stage renewables projects and less opportunity to invest in deals at the start of construction, and there are not a lot of transactions involving operating projects.

MR. MARTIN: Are the renewables deals solely project sales or also financings?

MR: HARLAN: We participate on the M&A side of the market, so I cannot comment as much on financings. We are building out solar projects for which we safe / continued page 30

IN OTHER NEWS

property" for this purpose.

Any swap of one property for another normally triggers an income tax on gain. The gain is the difference between the value of the property received in the exchange and the "tax basis" that the owner had in the original property.

However, no tax is triggered if the swap qualifies as a "like-kind exchange."

Congress limited the ability to claim a like-kind exchange to trades of "real property" in the Tax Cuts and Jobs Act in late 2017. The change applies to exchanges after 2017.

New proposed IRS regulations to implement the change define "real property" as "land and improvements to land, unsevered crops and other natural products of land, and water and air space superjacent to land." Two pieces of real property are considered of like kind. Thus, timberland can be swapped for a mine without triggering a tax. The two properties do not have to be identical in use or value, but any cash received by one of the parties is taxed to the extent of gain.

Each distinct asset involved in the exchange must be separately analyzed for whether it is real property.

Improvements to land are real property if they are considered "inherently permanent" structures like buildings.

However, machinery is not real property, unless it is something like a heating or air conditioning system that is a structural component of a building. Even then it must heat or cool the building as opposed to serving as the power source to run machinery inside the building that is used to produce goods for sale.

The taxpayer cannot own just the machinery and not also have a legal interest in the physical space in the building served by the machinery, like ownership, a lease or other right to use the space.

The IRS chose to define "real property" for purposes of like-kind exchanges close to how it uses the term for / continued page 31

Cost of Capital

continued from page 29

harbored equipment in 2019. We are still looking for more projects in which to invest equity.

MR. MARTIN: Steve Cheng, how do you see the market?

MR. CHENG: We see the same thing that Scott and Mike see. The traditional thermal generation market is slow. Pretty much the only activity we see in that sector is refinancing of debt with upcoming maturities or potential restructurings.

Most recent activity for us is in the renewables space and oil and gas. The oil and gas activity is pretty much liquidity plays. Companies are dealing with the decline in oil prices and are looking for liquidity to ride out this trough in the market.

On the renewables side, it is a lot more development stuff rather than opportunities to pick up operating projects. The more traditional lenders, like commercial banks and insurance companies, are more focused on construction and term debt. As an alternative lender, we have to focus on the higher value-add parts of the capital structure. This includes more development and pre-construction types of opportunities.

MR. MARTIN: Manish Taneja, how do you see the market?

MR. TANEJA: I agree with what has just been said.

The only thing to add is that sponsors and borrowers that can wait and do not need capital immediately are choosing to wait for a number of reasons. The availability and cost of capital both come into play. Despite that, deals are getting done. It is all about relative value. As an investor, we are seeing opportunities, but when we look at opportunities, we have to think about how they compare to what is on offer in the secondary market.

Trump Grid Order

MR. MARTIN: President Trump issued an executive order on May 1 that bans the purchase, transfer or use of as-yet-unidentified equipment from foreign adversary companies that might be used to harm the US power grid. Is the order having any effect on financings of projects with Chinese equipment?

MR. PANTELOGIANIS: We have a couple projects under construction in our portfolio that will use Chinese equipment. They are conventional power projects. In each case, there have been a couple months of delays due to equipment coming from China, but there is still room in the construction schedule to accommodate the delays.

MR. MARTIN: So you are still moving forward with the equipment despite the order. Does anyone else have any experience with the order?

MR. HARLAN: We are following it fairly closely. We are not currently in financings of any of our projects, but we purchase equipment from countries like China. We are concerned about it and will be reluctant to order more equipment from China. We also have Chinese equipment in some of our existing projects. We are in a wait-and-see mode to see how the regulations are promulgated.

Availability of Debt

MR. MARTIN: Regulations are not expected until the fall. Mike Pantelogianis, how is coronavirus affecting the availability of debt?

MR. PANTELOGIANIS: It depends on the sector. There is less liquidity for the midstream space. There is still debt capital for renewable energy and conventional power. Smaller deals can get done. The larger deals have struggled. The marginal dollar to clear a transaction is expensive. Sponsors with deep relationships in the banking sector are able to close their deals and fund them, but COVID has definitely had an effect on pricing and the overall appetite for credit.

It is still a competitive landscape for banks.

We are open for business. We are deploying capital and closing transactions, but we are being selective.

We want to deliver to clients, but the uncertain economic outlook leads to a level of conservatism that all banks are practicing. We are able to get deals done, but there is a higher marginal cost of funding and liquidity today. The guy without existing relationships is probably having a little tougher time finding capital.

MR. MARTIN: Have you written any new term sheets or letters of intent in the last month?

MR. PANTELOGIANIS: Yes.

MR. MARTIN: For what types of deals?

MR. PANTELOGIANIS: Renewables, refinancings of existing debt facilities and bridge financings. There are quite a few bridge opportunities that are smaller in size for which we are competing. It is still a competitive landscape for lenders. We have been surprised by the reasons why we have not won particular mandates. There is capital out there.

MR. MARTIN: We closed construction loans without tax equity take-outs recently. This may be a sign of difficulty raising tax equity. Are you seeing that as well?

MR. PANTELOGIANIS: We do not do a lot of construction financing around renewable energy because the cost of capital is very, very inexpensive. The economics do not work for us.

Our expectation is that if earnings are dampened, it will affect the tax capacities of banks that are the principal source of tax equity in the US market. If they start sustaining losses through other areas of their businesses that are affected by COVID, it will mean lower earnings which means less investment

MR. MARTIN: Let me go to one of our two private equity fund lenders, Steve Cheng. Have you written any letters of intent or term sheets in the last month?

MR. CHENG: Yes.

MR. MARTIN: For what types of deals?

MR. CHENG: We have written term sheets for all different types of assets and all different places in the capital structure: senior debt, traditional mezzanine debt, holdco debt and preferred equity transactions. A lot of it is in the midstream oil and gas space.

We have had discussions and put out some term sheets on the renewables side, and we even did one traditional power generation transaction. As Mike said, there is competition to be the lender in all of these transactions, so clearly there is still a fair amount of liquidity in the market.

There are fewer people who are open to doing midstream oil and gas transactions than before the downturn. More people are doing renewables, although anecdotally we have seen some institutions not exit the market, but / continued page 33

IN OTHER NEWS

REIT and FIRPTA purposes. REITs, or real estate investment trusts, must own at least 75% real property. FIRPTA, or the "Foreign Investment in Real Property Tax Act," subjects foreign investors to US tax on their capital gains from investments in US real property.

Gas pipelines qualify as real property. Each part of the pipeline must be analyzed separately. Isolation valves, vents and pressure-control and relief valves qualify as structural components of the pipeline because they are specially designed for the pipeline and are embedded enough that they would cause damage and be time consuming and expensive to remove. For the same reason, meters that measure the gas carried by the pipeline are not real property. However, they may qualify as part of the like-kind exchange if they are considered incidental. Otherwise, any gain on them must be reported in the exchange.

The like-kind exchange rules are in section 1031 of the US tax code.

The taxpayer must recognize gain to the extent of any cash or non-like-kind property received in the exchange.

Like kind refers to the nature or character of the property and not its grade or quality. Thus, if two pieces of land are exchanged, it does not matter whether one of the sites is unimproved and the other is improved. However, the improvements must be analyzed separately for whether they are real property.

A taxpayer may count any number of properties as the replacement real property as long as they do not have an aggregate fair market value more than 200% of the value of the relinquished property. If they are more valuable than this, then the limit on number of replacement properties is three.

Personal property, like equipment or furniture, that is incidental to the real property is ignored if such items are typically transferred with the larger item of real property in standard commercial transactions. The equipment must not be worth more / continued page 33

Cost of Capital

continued from page 31

certainly pull back. They are being more selective.

The issue is the opportunity cost of capital for lenders. You have to weigh in terms of portfolio construction whether to have more oil and gas, where there are relatively higher returns for higher-risk opportunities, or to focus on lower-risk types of opportunities: renewables, for example, where there might be more competition.

MR. MARTIN: Mike Pantelogianis, your colleague Ralph Cho said in January that there were 80 to 100 banks and grey market lenders chasing deals. Do you have any sense what the number is today?

MR. PANTELOGIANIS: Not much has changed. Our treasury guys tell us that the cost of funding for banks is starting to normalize and come back.

We saw a big spike in the cost of funding early on, call it mid- to late March. The cost jumped by 25 to more than 100 basis points for a bank to borrow. Since then, our cost of funding has come back in by almost 50%. A sense of normalcy is returning, but people are still being choosy.

Debt Terms

MR. MARTIN: Manish Taneja, how are debt terms being affected by coronavirus?

MR. TANEJA: We are going to be a bit more conservative in our terms today than we were three months ago. It is all about supply and demand. Demand has come down, but so has supply. We have seen a lot of banks that were active in this space on an opportunistic basis drop out. That has led to a smaller number of banks providing capital.

From a terms perspective, obviously we are putting in more protections to address the uncertainties around how much longer the economic downturn will continue. For example, for projects under construction, there may be disruptions in the supply chain where material cannot get from Asia to the US, but such disruptions can be addressed by having additional reserves to mitigate construction delays. Broadly speaking, terms are definitely more conservative today.

We are being more conservative on leverage as well. We are very active and have been putting out new term sheets.

Renewables are a sector that is very attractive for obvious reasons even though there is a lot of competition among lenders.

We are seeing more opportunities in the transportation sector, and we have put out a few term sheets on transactions in this sector recently. There are also opportunities in the telecom sector. With all of us working remotely, we are seeing opportunities to strengthen some of the infrastructure behind the scenes that supports our ability to work from home.

MR. MARTIN: Sponsors who can wait will do so to see whether the terms improve. Those who need the cash now of course are in the market now.

Mike Pantelogianis, how are bank debt terms changing: maturity dates, LIBOR floors, spreads, sweeps, commitment fees? If bank term debt for renewables was pricing at 125 to 137.5 basis points over LIBOR in January, where do you think it is today?

MR. PANTELOGIANIS: We see that market in the 175-over-LIBOR range.

MR. MARTIN: And maturity date? Is it seven years? Longer? Shorter?

MR. PANTELOGIANIS: Seven years is fine. Is there a marginal benefit to keeping it at five? It helps bankers achieve returns, but generally speaking seven is fine.

MR. MARTIN: Spreads have widened by about 50 basis points we heard earlier. We have heard that banks are pricing off a 1% LIBOR floor.

MR. PANTELOGIANIS: We personally do not require a LIBOR floor. We are comfortable about our ability to fund through LIBOR markets. We are not dependent on asset managers to help clear a deal. I think larger transactions might require such a floor where the incremental dollar needs to be facilitated from a nonbank player.

MR. MARTIN: As far as cash sweeps and commitment fees, has there been any change?

MR. PANTELOGIANIS: Not really.

MR. MARTIN: Steve Cheng, how do you think spreads have been affected in your market segment?

MR. CHENG: It a question of relative value and where the best return is for the risk. When you look at where deals are pricing in the midstream space, they are pricing much higher than before the oil price downturn.

On the power side, if you look at spreads in the secondary market, other than some special situations, the market as a whole has more or less traded back almost to where it was, and so you are not seeing spreads that are much wider than what they were pre-COVID.

For renewables that are in construction or operation, spreads have widened by 25 to 50 basis points.

There has been a bigger increase in pricing for projects that are still in the development stage or for so-called pre-NTP capital, which is why it is a bigger focus for us right now.

Liquidity Concerns?

MR. MARTIN: Let's drill down a bit more into power since a large part of our audience is focused on renewables. Focusing on power, are there concerns about liquidity of utility and corporate offtakers or of independent generators and, if so, in which situations?

MR. HARLAN: Probably not for utility offtakers. I would think there will be a greater focus on the liquidity and credit quality of some of the corporate offtakers.

As for the independent power sector, the balance sheets are slightly stronger this time around than they were during the last shock in 2008 and 2009. That said, power prices are down. Energy margins are down. We are holding our breath, but we are in a much better position from a liquidity perspective this time around.

MR. PANTELOGIANIS: We have been doing a lot of analysis for our credit committee to understand what is going on in the US power markets. The most recent findings for April show the biggest drops in load demand ever. We saw drops in the 8% to 9% range. Scott, I don't know whether you have seen load demand decrease by that much, but do you think the utilities will be in front of the regulators soon asking for relief?

MR. HARLAN: Yes, I do. What we have seen across the country is that demand is off between 5% and 15% depending on the location. I think the regulatory commissions are going to be loathe to allow their utilities to be dragged down by liquidity problems in a situation like this. Certainly utility revenues are down. That is unmistakable.

MR. MARTIN: Some utilities have rates that automatically adjust without the need for a rate case.

MR. HARLAN: Some do, and others don't. It varies by state.

MR. MARTIN: That's right.

A lot of the activity in the renewables market in the US recently has been quasi-merchant deals in places like Texas. The projects sell into the spot market, but they have a hedge that could be a virtual power purchase agreement with a corporation to put a floor under the electricity price. Has there been any change in the willingness of lenders to finance that sort of project?

MR. CHENG: We are putting out term sheets on deals like that. A hedge delivers a lot of value in the form of certainty of cash flow. Obviously you need a good */ continued page 34*

IN OTHER NEWS

than 15% of the value of the larger item of real property.

ANNUAL RITE.

Every summer, the IRS collects suggestions about tax issues on which it should issue guidance and then comes up with a priority guidance list. Suggestions are due by July 22. Instructions for sending in suggestions are in Notice 2020-47. The IRS will try to complete the items it puts on the list by June 30, 2021.

— contributed by Keith Martin in Washington

Cost of Capital

continued from page 33

balance sheet behind the hedge from somebody of investment grade quality or else it may need some credit support.

MR. MARTIN: A number of new business models were gaining traction before coronavirus struck: community solar, standalone storage, electric vehicle charging infrastructure. Has there been any change in the willingness of the financial community to finance these types of projects?

MR. PANTELOGIANIS: We have been very comfortable with the CCA model for quite a few years now. We have done CCA financings. We believe that California has a good framework to protect the credit of CCA offtakers.

The experience with community solar over the past two or three years has shown that the financing markets are pricing it in a very aggressive fashion at least from a senior lender perspective.

The residential rooftop model was moving to a very attractive cost of capital. Because the ABS markets have shut down since COVID, we have seen residential companies looking for more expensive capital compared to what they had pre-COVID. Pre-COVID, they were getting deals done with banks at about LIBOR plus 200 basis point. Today they are negotiating term sheets at LIBOR plus 325 basis points.

Inflation

MR. MARTIN: The federal government is printing a staggering amount of money through Federal Reserve purchases and fiscal stimulus measures. Are there growing inflation concerns? Think about the aftermath as we try to climb out of this. How will it play out in deals?

MR. HARLAN: It is a loaded question. You are right. There is a tremendous amount of stimulus going on and right now. It is fine because consumer demand is off. A headline this morning said consumer demand had the biggest one-month reduction ever in history.

We are setting a lot of records now. It remains to be seen how consumer demand will be affected by the stimulus. Once we start to get into the recovery, I am very concerned. Rockland is concerned about inflation and that has an impact on how we look at possible exits from investments in contracted renewables deals.

Obviously if you have fixed cash flows and you have inflation, then those equity positions are going to be harmed, and our exit in five to seven years could be affected.

The concern is causing us to underwrite investments in development-stage and construction-stage contracted projects to slightly higher levels.

MR. PANTELOGIANIS: Interest rates in the high-yield bond market are up 32% year over year. The ability of the leveraged debt players to get paper done in the 6% to 8% range has led to a lot of activity in the high-yield space in the midst of a crisis. It is very strange.

MR. MARTIN: Does it change anything you do?

MR. PANTELOGIANIS: Yes, I think so.

MR. MARTIN: How?

MR. PANTELOGIANIS: We are a bank, so we are primarily relationship focused. So Scott Harlan calls up and needs capital. We have finite resources. We are probably looking at a very aggressive transaction being priced by a bunch of banks. The risk may be the same as other deals where the competition is not as fierce. It is a difficult thing for us to argue to our credit counterparts within our bank who want to give us capital, but only at a reasonable price.

That relative value discussion has been probably the hardest element associated with going to credit today because they are seeing what lenders are able to get in the leveraged debt market. Our business, generally speaking, is a BB-type business, so our credit desk asks, "Why would I give you the capital at 4%, when I could go give it to somebody

Smaller deals are easier to close than larger deals that require more than one lender.

else at 6%?" We are having to deal with a lot more of those discussions.

Institutional Debt

MR. MARTIN: Let's move to the term loan B market. It was essentially shut down to new issuances in April. That's an institutional debt market. It is for single B and BB credits. It is sub-investment grade. The average B loan instrument for independent power producers was trading at about 80¢ to 84¢ on the dollar in face amount. That was for secondary trades in April. Has that market come back to life for new issuances?

MR. PANTELOGIANIS: The market is back, but it has been slow. I think issuers are finding the high-yield bond market to be more attractive.

MR. CHENG: We have seen the secondaries trade back up. Most of the names are back to the mid-90¢ range on the dollar.

There are a few specific issuances with some amount of distress surrounding them or else they are by borrowers with some link to coal that have not traded back to anywhere close to where they were.

I don't think a new power deal has been done in the term loan B market since the downturn. At least a couple such deals are in the wings. Everyone is waiting to see what happens to them.

MR. MARTIN: Those numbers suggest a spread perhaps in the 400 to 500 basis-point range.

MR. CHENG: Correct.

Central Bank Support

MR. MARTIN: The Federal Reserve has been propping up the investment grade market by offering to do direct lending to private borrowers. It extended the offer recently to borrowers a little below investment grade. Are private lenders feeling any effects from the competition from the Federal Reserve? It is shorter-term money.

MR. TANEJA: The support being provided by the Federal Reserve is not geared to the types of borrowers that this panel supports. We are not seeing it have any impact. As you mentioned, the tenors are much shorter in duration than are needed for project finance transactions.

MR. MARTIN: A core financing tool in the US renewables market is tax equity. The two largest tax equity investors said on a call in late March that they are operating at close to business as usual. At the same time, many developers report that it feels harder to raise tax equity.

Scott Harlan, you are a consumer of both tax equity and debt. How does the tax equity market feel to you?

MR. HARLAN: It feels shaky. I hear the same thing from the tax equity investors that it is business as usual. Our dealings have been on smaller projects. Our tax equity providers are not the traditional players for large projects. They are all saying that they are still in business and giving us a lot of comfort.

Everything depends what happens to the balance sheets and income statements of these tax equity providers over the next six months. If the recession lingers and it is not a V-shaped recovery, then that is bound to affect the supply of tax equity. So far there has been no effect, but I am concerned for the future.

MR. MARTIN: What about the availability of debt, Scott? You heard from all three lenders that debt is available, but possibly on slightly worse terms.

MR. HARLAN: We are not in the capital markets right now trying to raise debt. We refinanced pretty much all of our fossil-fuel projects in 2019. We are financing some pretty small solar construction projects currently, but not with the big banks or private equity funds.

We are working with very small lenders. It is business as usual. We have not even seen a change in pricing from those guys.

I think what Mike Pantelogianis said is right. If you had relationships with banks going into this, lenders for the most part are trying to stay true to those relationships. On larger deals, obviously the markets have moved and there will be repricing.

Equity Appetite

MR. MARTIN: People talked in the last few years about a wall of money chasing deals in the US. Three of the four of you work for investment funds. What are you hearing from your existing investors about their liquidity and desire to put capital commitments to use?

MR. TANEJA: I think the view is that infrastructure as an asset class remains pretty resilient in times of difficulty for a number of reasons, including the fact that these are real asset-based financings.

This asset class performed relatively well during the 2008-to-2009 financial crisis.

If you look at how the bonds performed at the time, there were very few defaults and when there were defaults, the recovery rates were pretty high. That is something that the investors or LPs understand. They appreciate the fact that not only does this asset class provide diversification, but it also gives them resiliency in their overall investments. */ continued page 36*

Cost of Capital

continued from page 35

So the investors are not shying away from this asset class. If anything, they are recognizing the value that it presents.

MR. MARTIN: Is there still a wall of money?

MR. TANEJA: It depends on your definition of the height of the wall. For the right strategies and for the right projects, there is money available.

MR. CHENG: Our investors understand that our strategy is a relatively illiquid one. It is different than if you are focused on either public-sector equities or public-sector fixed income where liquidity is important.

They understand that we plan to hold investments until maturity or until we are refinanced out and that we are not looking to trade any of the paper or deals that we do. They take a much longer-term view for what we are doing relative to some of the more liquid strategies.

When this crisis started, our investors began asking whether this would create new opportunities to invest because, until the dislocation happened, we thought the market as a whole was mispricing risk. We lost a lot of deals before COVID because someone else was willing to do them for less. Now the investors expect us to deploy capital at a faster pace.

MR. MARTIN: The market was mispricing risk. Now it is pricing it more appropriately, meaning the potential returns are higher.

MR. CHENG: Correct, for the risk.

Another thing we are starting to see is deals are starting to come to us that would have, absent this dislocation, gone into the private placement or capital markets because there is a lot more caution among those particular institutions. Borrowers are coming to us with deals that they cannot get done in a regular way in the capital markets. These are generally higher-grade quality deals so high BB, low BBB- type of stuff. We are starting to see more of those where, a couple months ago, they would not have come to us.

MR. HARLAN: I agree with Steve Cheng whole-heartedly.

We have been very frustrated over the last year and a half with the market being overly aggressive and mispricing risk on the equity side. We lost out on a lot of deals. We have not made a significant investment for 12 months, and it is not for a lack of trying.

The difference today is not that you can get outsized returns, but that you can get fair returns. It is a more rational market today.

MR. PANTELOGIANIS: We have seen Korean investors on the debt side run for the hills. For the past four years pre-COVID, they were extremely reliable. They were coming in with big, chunky dollars helping to clear transactions at attractive prices, and that has just stopped. Is anyone also seeing that on the fundraising side?

MR. MARTIN: Scott Harlan?

MR. HARLAN: We are not fundraising right now, thankfully.

Maybe some of those investors were part of the mispricing problem. Their disappearance may be part of a return to normalcy.

Our LPs want us to invest the money. They want to make sure that the investments that we are making are down the fairway for the kinds of investments that Rockland makes. They are asking the same questions about whether the current downturn will mean more opportunities than before. We have a few things that are teed up right now. We are getting ready to make some capital calls. I made a few calls to LPs just to make sure that people are not experiencing liquidity problems. They are all in business. They like the power business.

A lot of the LPs are managing investments more broadly in the energy sector, including oil and gas, metals and mining. They are reeling from those investments. It is a breath of fresh air frankly when I call to talk about what is going on in the power sector because that sector has been fairly resilient. They are encouraging us to continue to invest.

Lightning Round

MR. MARTIN: We are down to our last six minutes. Let's make this a lightning round. Rapid questions and short answers.

Has there been any change in the sources of inbound capital either geographically or by type of investor? We heard the Koreans have backed off. We know Chinese investment is way down. What about others?

MR. TANEJA: We are not seeing a material change.

The conversations may be taking a little bit longer because everybody wants to understand the impact of the current situation, but we are not seeing foreign investors pull away from the asset class.

MR. MARTIN: How have investors return expectations changed in the power sector, particularly in renewables. Scott Harlan?

MR. HARLAN: I think on contracted deals, investor returns are maybe 100 basis points higher on the equity side because of fears about inflation and the takeout, but there has not been a dramatic effect. Inflation may not be as big of an issue if you do not have a contracted deal. If you have a merchant project, then inflation may be your friend. An uncontracted or merchant plant may be a good inflation hedge.

MR. PANTELOGIANIS: We are currently in an equity placement process for a Texas-based wind project that is under construction. The equity will get a high single-digit return. This may be marginally higher than it would have gotten pre-COVID, but nothing significant.

MR. MARTIN: Ted Brandt with Marathon Capital said in late March the shutdown of the term loan B market tells you all you need to know about the M&A market. He said, "What we're hearing from the financials is why the hell would someone buy a 7% or 8% after-tax return when BBB bonds are on offer at something close to that. And they're completely liquid."

Interest rates on debt have increased by at least 50 basis points.

There are a lot of assets for sale. Scott Harlan, you said something at the outset about the bid-ask spread widening. Has it gotten too wide for deals to transact?

MR. HARLAN: Yes. I think it has widened to the point that closing transactions has become difficult. There is a lot of motion, but honestly in the last couple of months I have not seen a lot of equity deals close.

MR. CHENG: That quote is spot on. We already talked about it in terms of the need to figure out how to deploy capital into the best opportunities. Whether it is renewables or conventional power or oil and gas or Manish mentioned transport, you have to look at the choices on a relative-value basis. To the extent that something is mispriced relative to the risk, then you are probably going to have a hard time getting the buyer and seller to meet on a price. You are not going to get anything done.

MR. MARTIN: Two more questions. Steve Cheng, sticking with you, I last visited your company just before the stay-at-home orders took effect. One of your partners showed me a chart comparing how out-year electricity price forecasts varied by consultant. Are out-year electricity price forecasts viewed as riskier today so that people are using higher discount rates to bid assets?

MR. CHENG: Absolutely. I was just on a call before this one where somebody was presenting his macroeconomic view over the next couple of years. The variability in projections is pretty large. I don't think anybody can tell with any certainty what the future holds. Nobody could before, but now the uncertainty is even greater. To make any investment decision in this type of environment, you have to increase the discount rate to take into account that uncertainty.

MR. MARTIN: What do you think is an appropriate discount rate today for bidding on renewable energy assets? I realize this is a very general question. The assets may be at different stages, but give me a range for solar assets.

MR. PANTELOGIANIS: It is difficult to give an absolute number, but I am going to stick with my previous answer of roughly 100 basis points higher than it used to be. For operating assets, when we do a valuation on the assets that are in our portfolio, we use a range of discount rates and we have increased the high end of that range by about 100 basis points, maybe a little bit more, for doing our internal values.

MR. CHENG: I think it is at least 100 and maybe 200 basis points, something in that range. ◎

Evolving Middle Eastern Power Market

by Charles Whitney, in London

The Middle East power market, particularly in the Gulf Cooperation Council, is currently undergoing a transformation as the region shifts to more renewable energy.

The region has been attracting some of the lowest tariffs for electricity globally.

The GCC countries are Bahrain, Kuwait, Oman, Qatar, Saudi Arabia and the United Arab Emirates.

Advances in the procurement process for independent power projects have led to increased efficiencies throughout each stage of project development.

Rising electricity demand and the ongoing energy transition suggests that IPPs will continue to be at the forefront of government strategy. There are also indications that certain states are looking ahead to an even more liberalized future through the adoption of spot markets.

The Procurement Model

The development model for IPPs has largely been similar across the Middle East. The government procuring authority prepares a list of pre-qualified bidders to whom draft project documents (such as the power purchase agreement, natural gas supply agreement and land lease agreement) are issued, together with terms for the technical specifications and parameters for the financing.

Bidders then hire a contractor (typically on a lump-sum turnkey basis) and arrange financing before submitting a bid to the government. Often, but not always, the lowest bidder wins.

Of course not all countries in the region are the same. The countries comprising the Gulf Cooperation Council are generally viewed as having efficient, transparent and reliable IPP procurement programs.

The process in one of the Emirates, Abu Dhabi, is a good example, as demonstrated by the Shuweihat S2 IWPP project. The EPC contract was signed, and the project was successfully financed, in the midst of the global financial crisis in 2008 and 2009.

Part of Abu Dhabi's continued success comes from seeking efficiencies in the bidding process in response to the move toward renewable technologies in the region. With abundant oil and gas reserves, natural gas has historically been used to meet the significant power generation requirements for both space cooling and water desalination in the Middle East. However, as states look to decarbonise, investment in renewable generation has risen significantly.

In developing its renewable energy program, Abu Dhabi has tried to accommodate smaller renewable players. It recognized that bidders for gas-fired power projects were largely European or Asian utilities or other large energy companies, with big balance sheets and large, experienced business development teams. These teams could afford to incur larger development costs.

Developers in the renewables sector are not necessarily able to do this. Abu Dhabi has therefore looked to reduce development costs in a number of ways, such as by issuing a financing term sheet and EPC term sheet with the bid package. This ensures that bidders themselves will not need to spend time and money preparing these documents. It also has the added benefit of ensuring that bids are more consistent in their terms and risk allocation, which ultimately saves time in post-bid negotiations and facilitates efficient closing of the transaction.

The procurement models adopted in the region have, in part, helped to create significant reductions in the levelized cost of energy for solar photovoltaic in particular. This has meant that the Middle East has been able to capture some of the lowest tariffs for renewables recorded to date. For example, in April 2020 a consortium of EDF Renewables and JinkoSolar was named the preferred bidder for the 1,500-megawatt Al Dhafra PV project in Abu Dhabi, bidding US$13.50 a megawatt hour: a tariff reported to be the world's lowest for solar power by Abu Dhabi Power Corporation.

Regional Goals

Underpinning the development of renewables in the region is the "Pan-Arab Strategy for the Development of Renewable Energy, 2010–2030." Adopted at the third Arab economic and social development summit by the League of Arab States in 2013, it includes commitments to increase the region's installed renewable power generation capacity from 12,000 megawatts in 2013 to 80,000 megawatts in 2030.

The scale of development anticipated in the region will mean investment, research and development into other technologies needed to integrate renewables into the local energy system, such as storage and green hydrogen.

In relation to storage, the Middle East Solar Industry

Association (known as MESIA) in its "Solar Outlook Report 2020," notes that storage using lithium batteries and molten salt are beginning to be used in conjunction with solar projects. For example, the Al Dhafra PV project included an optional bid for the provision of battery storage, with this being said to attract substantial market interest.

The development of concentrated solar power has been limited in the region due to dust and humidity affecting system efficiency, but MESIA notes that hybrid CSP and PV systems may unlock intermittency issues in future. MESIA also sees potential for floating solar PV in the region, particularly because of its positive impact by reducing water evaporation.

Market reforms in the Middle East are leading to adoption of electricity spot markets.

Green hydrogen may become an important export from the region. The first proton exchange membrane electrolyzer is expected to be installed in Mohammed bin Rashid Al Maktoum solar park in Dubai by DEWA and Siemens in 2020.

Another first-of-its-kind project in the region that demonstrates the commitment to the energy transition is the upcoming subsea cable project being developed by The Abu Dhabi National Oil Company and Abu Dhabi Power Corporation. The project will reportedly allow ADNOC to reduce the carbon footprint of its offshore facilities by up to 30% by replacing offshore gas-fired electricity generation with more efficient electricity supply from Abu Dhabi Power's onshore operations. The intention is to use project financing for the project under a long-term concession contract based on the capacity of the cables.

Market Liberalizations

Oman has been an early adopter of private investment in the power generation sector, beginning the privatization process in 2004. Since then, the country has achieved complete liberalization of the generating sector and has continued toward further privatization of the transmission and distribution sectors.

Oman Electricity Holding Company (known as NAMA) raised US$1 billion of capital in 2019 by selling 49% of its shares in the Oman Electricity Transmission Company (known as OETC) to State Grid Corporation of China. This forms part of the plans for the privatization of OETC, which NAMA says it has implemented in order to "support the government's objectives of attracting foreign direct investment into the country and promoting private sector participation as part of the wider nation-building process."

NAMA also intends to divest up to 70% of government shareholding in each of Oman's Muscat Electricity Company, Majan Electricity Company, Mazoon Electricity Company and Dhofar Power Company. Before the COVID-19 pandemic, the speculation was that NAMA was in the process of discussing government subsidization with potential bidders and that it expected bids to be entered for the Muscat Electricity Company by the third quarter of 2020. In the case of the other three distribution companies, the understanding is that once the initial 70% has been divested, NAMA plans to sell the remaining 30% of government-owned shares of these companies through an initial public offering.

The energy procurement-and-supply model in Oman is also subject to a considerable overhaul through the intended introduction of a spot market for the commercial trading of power in Oman. The spot-market initiative aims to improve the efficiency and transparency of the operation of the electricity sector and to provide opportunities for diverse generation sources that do not compete in the Oman Power and Water Procurement's normal tender process for water and power supply. OPWP would play the role of market operator and purchaser, purchasing energy from generators who supply to a pool and managing that pool.

Once the Omani spot market goes live, existing power purchase agreements will remain valid and the obligations under them will be honored through the end of their respective terms. Current generators will not be forced to / continued page 40

Middle East

continued from page 39

operate as merchant generators immediately upon the activation of the spot market.

However, current generators have been obliged to enter into a consultation process as a result of an amendment to generation licenses. Generators are being required to provide structural, technical and other data to OPWP. Naturally, generators will want to understand better how OPWP will administer the new rules, dispatch generators and handle the transition to a more market-based model.

Despite having launched a consultative process in 2017, the Omani spot market appears to be some way off from being implemented, and there remain many unanswered questions about how it will work.

As of early June 2020, it also remains to be seen how the market will react to recent reports that OPWP threatened to hold back certain payments due to generators under existing contracts. Certain generators have issued notices to the Capital Markets Authority in Oman indicating that certain payments under power purchase agreements may not be honored. The state-owned power purchasers in the GCC have a strong reputation for honoring their payment obligations and any move by OPWP to default on its payment obligations to generators would of course affect sentiment and the ability to attract foreign investment in the future.

Financing Structures

The financial crisis shifted the way most bidders in the GCC fund their projects.

Before the crisis, most bidders for GCC projects would fund through a combination of equity bridge loans (to reduce the electricity tariff) and senior facilities provided by commercial banks, perhaps with export credit agency support. Financings typically provided tenors falling just short of the term of the power purchase agreement.

After the financial crisis, bidders in the region started turning slowly to mini-perm structures, where the senior debt must be refinanced a short time after completion of construction. This brought more liquidity to the market, as, in the aftermath of the financial crisis, not all banks were prepared to lend on a 15- or 20-year basis to a single-asset project company.

There are generally two types of mini-perm structures: "soft" and "hard." A soft mini-perm is generally one where, from the target refinancing date, the senior debt is prepaid under a mandatory-prepayment or cash-sweep mechanism, with a margin ratchet applying. A hard mini-perm is less complicated, from a documentation perspective. It provides for a balloon repayment on the target refinancing debt, thereby putting the project into a non-payment event of default if that balloon payment is not made.

The more competitive pricing that may be offered for a hard mini-perm must be balanced against the different consequences between a hard and soft mini-perm, as the lenders would not typically have a right to enforce security if a soft mini-perm is not refinanced by the target refinancing date. That said, sponsors will be no less motivated to refinance as, under both structures, the dividends would cease to be payable in the event of a failed refinancing.

Governments were generally open to these new financing arrangements and have become more and more comfortable with the passage of time. This may be driven, in part, by a degree of confidence that the projects are well structured and well operated, and therefore well placed to refinance successfully in either the bond or bank debt market.

Certain jurisdictions such as Saudi Arabia and Abu Dhabi also benefit from strong sovereign credit ratings, which facilitates refinancing in the bond market. Refinancing risk largely remains with the foreign investors. ◎

Financing Subsea Cables in Latin America

by Marissa Leigh Alcala, Rachel Rosenfeld and Pablo Calderon, in Washington

Subsea cables that are key to economic growth in Latin America are expected to require more than $1 billion in new investment over the next five years.

The move to 5G wireless will require a significant increase in new subsea cable construction.

Cable developers whose cables will be open to market use — as opposed to dedicated to a single tech company — enter into long-term contracts with companies that want to use the capacity in exchange for large upfront payments and smaller payments over time that can be used to pay construction and operating costs.

Several new subsea cable projects are under development this year in Latin America. The impetus is coming not only from 5G, but also the ongoing Latin America tech boom and steady growth in the use of data, bandwidth, telecom subscriptions and internet connections.

Subsea cables are built between locations that have significant communications traffic. Chile and Brazil, who are already home to significant data center and other investments from global tech giants, are becoming major hubs for Latin America.

Growth

The global subsea cable market is expected to be valued at $22 billion by 2025, more than doubling from 2019, and $30.4 billion by 2027.

A significant portion of this growth is in cables connecting Latin America to the rest of the world.

Subsea cable development within the Americas has been increasing steadily, with four cable systems going into service in 2017, five cable systems put in service in 2019 and eight more new cable systems expected to be in service by the end of 2020. During this period, new Americas cable systems included connections in Latin America.

A new trans-Atlantic cable has been built every year for the last five years. Three more new cables are planned in the next two years between South America and Europe.

At least one new trans-Pacific cable was built each year from 2016 through 2019. Eight new trans-Pacific cables are planned through 2022. Trans-Pacific development is of particular global interest after the US government blocked a proposed trans-Pacific cable by Google and Facebook connecting Los Angeles and Hong Kong on the basis of national security concerns in 2019.

Latin American Tech Boom

Latin America has had an influx of investment in digital and other high technology businesses. This tech boom is being driven by young and tech-savvy citizens with high rates of mobile and internet usage, paired with investors interested in fintech and data startups and services in the region. Data centers and telecom, fintech, agtech, and e-commerce companies are growing and attracting substantial investment, particularly in Brazil, Chile, Colombia and Mexico. Governments in the region have taken steps to attract investment in tech startups.

Chile, in particular, has been an attractive base for such enterprises due to a reputation for long-term stability and economic performance and international and government support for incubators and technology innovation. Chile is home to numerous data centers belonging to big names like Google, CenturyLink and HP.

Brazil, the largest country in Latin America and the world's eighth largest economy, has benefited from venture capital support in this area and investments from major players, including Amazon, Google and Oracle. Scala Data Centers recently announced plans for construction of its third data center project in the State of São Paulo. The State of São Paulo has seen tech investment volumes in recent periods greater than the combined tech investments in all of Chile, Colombia, Argentina and Mexico combined.

Colombia has also emerged as a leading destination for new tech investments. Colombian tech start-up Rappi secured, when it was made, the largest-ever investment in a Latin American tech startup with a total of $1.2 billion raised. This year HostDime, a global leader in data center infrastructure, announced the construction of the largest data center in Latin America in the Bogota suburbs, hosting data processing, comprehensive IT solutions and advanced technological infrastructure in security, stability and implementation of smart data and big data. The Colombian government has been actively promoting investments in technology and tech startups for more than a decade.

Mexico has seen recent investments from Microsoft, which announced in February 2020 that it will build its first set of cloud data centers in Mexico as part of a $1.1 billion investment in the country over the next five years. */ continued page 42*

Subsea Cables

continued from page 41

HostDime also has co-located cloud servers and dedicated servers in Mexico.

More than half of Latin American GDP is expected to be based on the digital economy by 2022. About $380 billion is expected to be invested across the region in digital technologies over the period 2019 through 2022, with almost three quarters of that investment dedicated to mobility, cloud services, data and social media.

About 99% of international communication is by cable, and mostly subsea cable, making subsea cable projects critical to GDP growth.

Subsea cables in Latin America will require more than $1 billion in new investment.

5G Proliferation

Many Latin American countries are moving forward with 5G wireless. If 5G is the vehicle for driving faster, subsea cables are the roads. As 5G becomes available on land, more efficient subsea cables will be needed in support.

The Chilean telecom agency, Subtel, was expected to launch a 4-part request for proposals for 5G networks in April 2020. The COVID-19 pandemic has delayed the launch. No new date has been set.

The Brazilian telecom regulator Anatel may postpone a 5G spectrum auction from 2020 until early 2021 due to COVID-19.

Telefónica Telecom in Colombia is expected to launch 5G services this year. Telecom Argentina is expected to launch 5G services by 2022.

The spread of 5G to Latin America follows 5G network announcements in 2018 by the United States and South Korea and in 2019 by the United Kingdom, Australia, Switzerland, Finland and Spain.

Latin America is expected to have 3.5 million 5G connections by 2021, 17 million in 2022 and as many as 75 million by 2025.

Bandwidth in Latin America is expected to grow 63% by 2022, reaching 1,430+ terabytes per second, or more than 10% of interconnection bandwidth globally. As much as 31% of this growth will be driven by the content and digital media industry.

In recent years, emerging technologies such as containers, big data, the "internet of things" and artificial intelligence have taken on greater relevance for companies in Latin America. COVID-19 is helping to accelerate this trend. Stay-at-home orders have highlighted the importance of efficient digital infrastructure to keep services running.

Chile

Subtel, the Chilean telecom agency, is leading development of the Asia-South America Digital Gateway, a proposed subsea cable expected to be between 15,000 and 22,000 kilometers in length with landing points in the Juan Fernandez Islands and Easter Island in Chile and at two locations to be determined in Asia.

Feasibility studies for the project were funded by the Development Bank of Latin America, CAF.

Subtel expects to create a public-private consortium to develop the project. The timeline for launching the RFP process has not been set yet.

Chile is also exploring potential engagement on this project with other countries in South America who would benefit from connectivity with the Gateway cable.

The project would complement a number of other recently built subsea cables serving Chile. Google built a private cable called Curie that connects Los Angeles with Valparaíso and has a spur to Panama. Google built the Curie cable to improve resilience for its data center in Santiago. The Curie cable was successfully installed and tested in November 2019 and is expected to go on line in the second quarter of this year. The Curie cable is reserved for Gmail, YouTube, Search and Google Cloud data transmission.

América Móvil and Telxius are building a 7,300-kilometer Pacific submarine cable along the west coast of South America to connect Puerto San José, Guatemala with Valparaíso, Chile and with additional landing points in Salinas, Ecuador, Lurín, Peru and Arica, Chile. The Pacific cable is expected to be ready for service at the end of 2020.

Chilean telecommunications company Grupo Gtd is building the 3,500-kilometer Prat cable with 12 landing points along the Chilean coast. It will go on line this year.

Brazil

The Malbec subsea cable, a 2,500-kilometer subsea cable linking Rio de Janeiro and São Paulo with Buenos Aires, is currently in the final stages of construction and is expected to open for use in the third quarter of 2020. Malbec is being developed by Facebook and GlobeNet.

The South Atlantic Express, SAEx1, subsea cable will run from Cape Town, South Africa to Fortaleza in Brazil and then will connect to Virginia Beach in the United States. The project is expected to be ready for service in March 2021. A second phase, SAEx2, is also planned to connect South Africa to Asia. The route from South Africa to Virginia is 14,720 kilometers.

Seaborn Networks has a portfolio of submarine cable systems that includes the 10,500-kilometer Seabras-1 cable between São Paulo and New York that delivers the lowest latency route between Nasdaq and the Brazil Stock Exchange. Seaborn Networks plans to add the SABR cable, a 6,200-kilometer subsea cable that will be the first southern Atlantic route between South Africa and Brazil and the ARBR subsea cable that will link Brazil to Argentina. It is expected to start construction this year.

The ARBR cable will be the newest and most direct route between Argentina and the United States due to its interconnection with Seabras-1. Notwithstanding chapter 11 bankruptcy filings by Seabras 1 Bermuda and Seabras 1 USA, these expansion plans are continuing to move forward.

The EllaLink project, a 10,119-kilometer subsea cable connecting Brazil and Portugal, is currently under development and is scheduled to be in service in 2020. The European Commission committed €25 million to support the project via the "Building Europe Link to Latin America" program. An older cable, Atlantis 2, commissioned in 2000 that connects Brazil and Argentina to Portugal and Spain, currently also runs this route, but its capacity and speed are significantly lower than the newer cable. Atlantis 2 is nearing its end of life, based on the typical 25-year useful life for a subsea cable.

Another cable that connects Brazil to other countries is the GuyaLink cable, planned to run from Kourou in French Guiana on the northeastern coast of South America to Fortaleza, Brazil. This project remains subject to diligence and investment approval.

Improvements to existing cables are also underway. The 2,000-kilometer Tannat cable, operational since mid-2018 and connecting Santos, Brazil to Maldonado, Uruguay, is being extended to the nearby coastal city of Las Toninas in the Buenos Aires province.

All of these submarine cable projects are privately sponsored.

Financing Challenges

Historically, roughly 90% of subsea cables have been developed and financed by consortia with multiple owners. In some consortia, each owner brings its own financing, whether from the owner's balance sheet, from an equity raise or from corporate debt. In other consortia, the financing is at the level of the joint venture company.

The number of subsea cables being developed and financed by a single private owner has increased. Single private owners accounted for roughly 5% of subsea cables historically. However, from 2019 through 2021, single private ownership of new cables is projected to be on par with consortia ownership of new cables. Increasingly, tech majors have started developing subsea cables for their own exclusive use.

Subsea cables that will be available for market use typically contract for long-term capacity commitments called "IRUs" or "indefeasible rights of use." The holder of the IRU makes a lump-sum up-front payment for a right to use part of the capacity on the cable. Smaller periodic payments are then made over time for operation and maintenance.

Large up-front IRU payments can reduce the need for long-term financing. However, it would not be unusual for a sponsor to delay contracting for the full cable capacity until the project is far along in development. Most cables available for market use also reserve a portion of capacity for the spot market or short-term contracts.

Subsea cables have been financed by commercial banks, multilateral development banks, export credit agencies linked to key equipment suppliers, private equity funds and other sources of equity. Project financing for subsea cables comes with challenges, including complex / continued page 44

Subsea Cables

continued from page 43

rights to the cable's path across multiple jurisdictions and the risks inherent in a partially-merchant project.

Older subsea cable operators may face challenges competing for business in an over-saturated market or against superior technology. To the extent that an existing cable is not fully contracted with long-term capacity commitments, the market value of its service may decrease below the levels originally projected when that cable was first installed. The average life of a subsea cable is around 25 years, but with improvements, an existing cable can be upgraded and its useful life potentially extended.

COVID-19 and Financings in Emerging Markets

Development finance institutions and export credit agencies are called to step into the breach during economic downturns. How are they responding to COVID-19? Are they still open for business in emerging markets? How have financing terms changed? Representatives of six such institutions talked about these and other questions during a call in early May. The following is an edited transcript.

The panelists are Tony Bakels, director of credit, legal and special operations at Dutch development bank FMO, Georgina Baker, vice president for Latin America and the Caribbean, and Europe and Central Asia at the International Finance Corporation, Koffi Klousseh, managing director and head of project development at Africa50, Luke Lindberg, senior vice president of external engagement at The Export-Import Bank of the United States, and Tracey Webb, vice president for structured finance and insurance at the US International Development Finance Corporation. The panel was introduced by Sarah Devine and moderated by Ken Hansen with Norton Rose Fulbright in Washington.

COVID Responses

MR. HANSEN: Tracey Webb, has COVID-19 prompted the US International Development Finance Corporation to offer any new products or programs or to make interesting changes to normal procedures?

MS. WEBB: With respect to new products or programs, technically "no." We are prioritizing the hardest hit regions. We are also trying to think beyond the immediate and medium term by shoring up supply chains. One thing that COVID-19 has exposed is the vulnerability of world global supply chains.

MR. HANSEN: Luke Lindberg, what is happening at the US Export-Import Bank as far as new products and programs?

MR. LINDBERG: ExIm is viewing this mostly as a short-term liquidity problem. We do not see what is happening as creating any longer-term structural issues. Our objective, as always, has been to focus on US workers and on figuring out how we can support them when the private sector is unable to do so.

Here are a couple key things that ExIm has done in response to COVID-19.

On March 12, we provided some program waivers and deadline extensions as well as additional flexibility in our working capital program and our multi-buyer and single-buyer short-term insurance programs.

On March 25, the ExIm board adopted four temporary relief measures. First, we implemented a new bridge financing program for foreign purchasers that provides bridge loans to get them through this time. Second, we outlined a program to offer progress delivery payment financing where ExIm is supporting pre-export payments to manufacturers. Third, there is a real need in the supply chain for short-term liquidity, and we have responded with supply chain finance guarantees. We are working with our lending community and banks to purchase receivables and provide liquidity to the supply chain and have the buyer purchase or transfer the credit to the bank at a discounted rate.

The last item, which we finalized in April, is a temporary expansion of our working capital guarantee to simplify and reduce our fees, expand the definition of inventory from export-related inventory to any inventory that could potentially be exported, and increase our guarantee from the traditional 90% to 95%. This should help make private lenders better able to keep lending. The word of the day for us is flexibility.

MR. HANSEN: Staying in Washington, Georgina Baker, what is the International Finance Corporation doing differently in response to COVID-19?

MS. BAKER: The IFC board has approved an $8 billion COVID-19 response program that allows us to move very fast into four areas.

Of that $8 billion, $2 billion is going to financing in two- to seven-year buckets for clients that either face significant disruption of labor force, disrupted supply chain, or even on the positive side, significantly higher demand for their goods and services because they are online retail, pharmaceutical, clinics or hospitals.

Another $2 billion is directed to financial institutions and supports our trade finance program where we are extending credit lines, extending tenors and increasing credit lines.

An additional $2 billion is dedicated to portfolio programs on supply finance, critical commodities and trade finance.

The final $2 billion is for our working capital solutions and supply chain finance.

That is all shorter term. It is really to work with our existing clients to say, "How can we support you? How can we help you in this economic downturn?" Cash is king. You may have a sustainable long-term business, but if you do not have cash today, the business can dry up. We are ready, and we have $8 billion already approved.

We are looking at ways to be counter-cyclical because that is the huge benefit that development finance institutions can bring to crises like these. We are looking at many different initiatives, and we will make a second approach to our board. As of today, we are focused on short-to-medium-term capital and getting cash out for existing clients.

MR. HANSEN: Moving overseas, Tony Bakels, how is FMO responding to COVID-19?

MR. BAKELS: We are seeing similar trends. Our traditional products are loans and equity investments, typically with a tenor of five years for financial institutions and up to 18 years for project finance. The objective of this long-term finance is really to create value by helping clients expand their activities.

With this crisis, our focus is shifting. Instead of creating value, we look more at the preservation of value and making sure that our clients get through this crisis. Instead of long-term finance, we are now also looking at short-term finance with liquidity support to help clients weather the next six to 12 months. It might be with additional loans. Another simple way to do it is to re-structure existing loans and defer the payments. We have streamlined our procedures, including by delegating the authority to approve such restructurings to our front-office staff.

MR. HANSEN: Koffi Klousseh, has COVID-19 prompted Africa50 to offer any new products or programs or make adjustments to its procedures?

MR. KLOUSSEH: We are an infrastructure platform owned by African states. Generally, our work is long term in nature because it is infrastructure. However, the first thing we have done in the short term is to donate cash to a number of initiatives on the ground in Africa. It might not be obvious to people in the US or in Europe, but staying in business when you are in Africa right now is not easy. We have done a lot to make sure people have internet access and can communicate remotely.

We are also continuing to fund our equity commitments. We have projects under construction, and it is important to us to continue funding as much as possible.

Third, it is important to us to signal that we are open for new business. A lot of stakeholders in the business community are looking to Africa50 for a signal that business can continue in Africa.

In the short-to-medium term, we are looking at a shift in our investment policy toward a greater share in social infrastructure like hospitals and education. We have fast */ continued page 46*

DFIs

continued from page 45

tracked a number of investment initiatives in order to provide services to the African population in terms of health and sanitation.

We also have views about how to help in the long term. One is related to what we call asset recycling, which is to help countries that have a lot of infrastructure on the balance sheet to sell and monetize it, thereby freeing resources for governments to tackle the very important issues and problems of COVID-19.

Market Reaction

MR. HANSEN: I understand from friends who do sovereign lending that the phones are ringing off the hook from finance ministries looking for financing or re-schedulings. What are you hearing from existing borrowers? Are they asking for help or are they staying quiet until you call them?

The development finance institutions have set up special liquidity facilities to help in emerging markets.

MS. WEBB: The phones are ringing off the hook. Even business models that have been working well are facing short-term liquidity needs. The demand has been tremendous, and we are working on trying to meet client needs.

MR. HANSEN: Tony Bakels, how about at FMO?

MR. BAKELS: Our story is similar. So far we have mainly received requests for restructuring. That seems to ease the immediate pain. So far between 10% and 20% of our clients have approached us or are expected to approach us in the next few months. We have received fewer requests for new money, but that is of course also because the crisis has only just started and most companies have buffers to get through the first one or two months. There will be requests for new financing. This may just be a period of silence before the storm.

MR. HANSEN: Can you say anything that can be shared with a small group of friends about how you are responding to those requests?

MR. BAKELS: I think we all realize that the need is there. These are not requests out of luxury, but out of need. We have been working closely with other DFIs to respond quickly to these requests.

MR. HANSEN: Georgina Baker, rounding out the DFIs in the room, what is IFC hearing from its existing customers?

MS. BAKER: Most clients are in evaluation mode, but the crisis is just beginning. They are looking at how long they think this will last and, if it lasts six months to two years, what will happen to their businesses. They are trying to deal with the day-to-day stresses. Now is not a great time to be borrowing because the markets are so uncertain and pricing is fluid. We are looking shoring up the finances of clients that have businesses with long-term potential.

As I mentioned, we have $8 billion delegated authority from the board to move quickly, but that is not all we are doing. For any existing client whose needs fall outside that program, we are working on an expedited basis. Brand new financings are hard because of an inability to travel and appraise businesses. But clients that were in good standing and are no longer clients because their equity was recently sold or the loan was recently paid off are ones that we are also reaching out to and saying, "How can we help, and what can we do to support you?"

MR. HANSEN: Georgina has flagged some of the challenges in dealing with new projects and new customers. Among other things, it is hard to do a site visit. It is hard to get to know a new team.

Koffi Klousseh, you said Africa50 is moving more into social infrastructure. That means new projects. How are you managing to do that given the obvious challenges?

MR. KLOUSSEH: New pipeline is very difficult. We have to deal with our present pipeline and make sure that projects that we have started reviewing move forward as much as they can.

Let me shift the question a little bit from pipeline to portfolio, which is where things are uncertain and difficult. Evaluation of where things are with our existing projects will dictate our openness to new business.

For example, we have important investments in power plants with offtakers that are not being paid regularly by the customers, and that is affecting the business seriously. We have to devise good plans to reschedule payment of debt, making sure that we allow breathing room to weather the storm. The question is how to do that with our partners, other DFIs and sponsors around the table and not in a silo.

MR. HANSEN: How about at ExIm? Are you seeing much new business? You clearly have a lot of new programs.

MR. LINDBERG: Because of our four-and-a-half-year hiatus from the marketplace, our portfolio is a bit older than perhaps some of our counterparts around the world. We have been engaged with some clients on restructurings.

With respect to new interest, we have seen a dramatic uptick in letters of interest. Part of that is due to the new relief measures we rolled out and part is that we have significant overall capital that we can still lend. We have a $135 billion exposure cap, and we are still sitting on about $48 billion of that.

We are countercyclical. If there is ever a time to need ExIm, now is a perfect example. We have seen an increase in pipeline opportunities.

Deteriorating Market Conditions

MR. HANSEN: What impact has all of this had on underwriting standards? On the one hand, maybe they are a little tighter because everyone is a little gun shy. On the other hand, maybe they are a little more flexible when you are looking at the creditworthiness you would like to see in a project sponsor or an offtaker.

MR. BAKELS: Our risk appetite is not changing, so as much as possible we are maintaining our existing standards. For existing clients, we want to preserve the investment and to be a reliable partner at moments like these. We may do things differently for short-term lending to existing clients even if our overall risk appetite has not changed.

Going forward, it is indeed a big dilemma because the environment is becoming more risky. We may have to adjust. The adjustments might include requesting additional collateral or requiring higher equity levels, better pricing or more government support for projects. How exactly that will work is still on the drawing board, but I do not think our conclusion will be to relax our overall underwriting criteria.

MR. HANSEN: Georgina Baker, how about at IFC?

MS. BAKER: I completely endorse what Tony said. There is a constant tension between the two sides of the shop, between risk and operations, to be as responsive as possible to clients. Risk argues, completely legitimately, that now is not the time to lower standards and then find in a year or two that our portfolio is severely affected. As of now, we are not reducing credit standards because we have so much business with clients of good standing.

Where that will stand in six to nine months remains to be determined. We will try to respond to clients that have needs that are not being met by our current facilities, and where necessary we will adapt and adjust.

MR. HANSEN: IFC has been a leader in its B loan program. How has COVID-19 affected the availability of commercial partners and co-lenders?

MS. BAKER: There has been a big impact. When you compare the first quarter of 2020 to 2019, global lending is down 15%. Part of that is because borrowers are drawing on revolvers or working capital facilities and are shelving fundraising for acquisitions and capital expenditure plans. Banks are also refocusing on their core clients with strong fundamentals. I think we are going to see second- and third-tier clients losing out because banks will focus on their best clients.

Funding costs seem to be settling at least 50 basis points higher than pre-pandemic levels. There has been an increase in bilateral loans or club deals instead of general syndications. Banks are not interested in pursuing new clients or expanding their client bases.

On the positive side, we have 10 to 15 financings that are expected to close by the end of the year. These are deals that were in process before the crisis hit, everybody received credit approval, and banks are sticking by those transactions even though market conditions have deteriorated.

MR. HANSEN: Luke Lindberg, commercial bank partnerships are fundamental to ExIm as well. What are you seeing in the availability of your traditional commercial-bank guaranteed lenders, co-lenders and insured lenders?

MR. LINDBERG: I will break it into two buckets. A lot of people had been waiting for ExIm to resume full operations, so there are some deals in the pipeline that / continued page 48

DFIs

continued from page 47

people have been excited about. So far, on the medium-to-long-term side, we have not had a problem finding co-finance opportunities or folks willing to lend alongside us or take our guarantees.

On the shorter-term side, ExIm Chairman Kimberly Reed just completed a listening tour of all of our delegated lenders. I have been moderating those calls alongside her and listening to what is happening with them. The issue that was raised most frequently was increasing our working capital guarantee above the 90% level to 100%. We just increased it to 95%. It is not surprising that financial institutions want a full guarantee, but we think a 95% guarantee is a useful move to help weather this short-term liquidity crisis.

MR. HANSEN: During the 2009 crisis, there were large financings fully guaranteed by ExIm that could not close because, notwithstanding the US government guarantee, the lenders could not find the liquidity to fund. This prompted ExIm to open the spigots for direct lending. You have not seen that kind of constraint in availability so far I take it?

MR. LINDBERG: We have not.

MR. HANSEN: That is a piece of good news. Koffi Klousseh, Africa50 focuses on the equity side of deals, but presumably those deals all want to see debt. Are you making adjustments?

MR. KLOUSSEH: We have not seen any change. This is due in my view to the fact that there have been special envelopes that are dedicated for Africa that allow the deals being discussed to be completed.

As a matter of fact, we are in discussions with some of the DFIs around the table, namely IFC, and we are executing mandate letters, so there is still a transaction mindset. For existing commitments, we do not see any difficulty. What might be a bit more challenging is meeting the conditions to disbursement when these commitments have to disburse.

Many of our projects rely on some type of sovereign or government guarantees, and the standing of these governments and the appreciation commercial lenders will have of these governments being able to make good on their guarantees will have a strong bearing on whether financing is obtained. So we will see.

Renewable Energy

MR. HANSEN: Every institution with us here today has been an important source of capital for renewable energy projects. The dramatically depressed oil price has led to concern about the ability of renewable energy projects to compete effectively in the near and medium term. How has the depressed price of oil affected your portfolio and your prospective pipeline? Tony Bakels, could we start with FMO?

MR. BAKELS: The oil price is only one of the considerations we are faced with at the moment. The immediate concern is the drop in demand for electricity, which is up to 30% in some markets. When that happens, curtailment starts with the most expensive electricity sources. It then becomes important to distinguish between old renewable projects and new ones.

Projects that were built three or more years ago tend to have high power purchase agreement prices. For this portfolio, we have some concern that at some point governments, as offtakers, will be under pressure to start renegotiating tariffs. We think these portfolios may be at risk even though we have legally binding offtake agreements. However, it is only a small percentage of the total electricity supply, so overall we expect that this part of the portfolio will remain performing.

If you look at new projects, then we think that renewable energy is highly competitive, even with a low oil price. Storage is more of a challenge than oil prices for solar projects because obviously solar can only be used during the day. If you find a good solution to store electricity so that it can be available 24 hours a day, we think it allow solar to thrive even with low oil prices.

MR. HANSEN: Tracey Webb, what is the view on renewables at DFC?

MS. WEBB: Let me revisit underwriting standards first. I think the real differentiator right now is whether lenders are disbursing into existing deals. At DFC, we are disbursing into transactions, and we are accessing the capital markets. One of the projects we are disbursing into is an oil transaction. While we did not lower our standards, we looked closely at material adverse effect clauses, and we ran the model with new short-term oil projections. We are not changing our standards, but we are continuing to be a reliable partner to our investors.

Decreased oil prices have affected projects that were in process. We have already lost major projects as oil companies cut back on their capital expenditures.

The impact on renewables will be an issue, particularly with the weaker government credit support. We continue to disburse into that sector by looking at where we think the tariff is compared to the best projections we can get for medium-term oil prices in the same geographic region.

MR. HANSEN: Georgina Baker, what impact are low oil prices having on IFC's operations?

MS. BAKER: Our support for renewable energy projects will continue. We require that at least 35% of our projects must be climate related.

We are supporting projects that are very competitive to oil. The last solar project we financed in my area of coverage was in Uzbekistan where we got a price of 2.67¢ per kilowatt hour, which is very competitive. To the points that were made earlier, when there is a government agreement to pay a fixed capacity payment, governments have a serious fiscal issue when there is low demand for electricity. We are seeing that in Africa, Pakistan and other parts of Asia where there are huge offtake payments that must be made. This is a very big risk for our portfolio. Whether this lasts for six months or two years will dictate how big of a problem it is.

Demand for political risk insurance may increase if COVID-19 leads to social upheaval.

We are continuing to develop projects in markets that are more mature. For example in Mexico, where it is a merchant market and there is no reliance on government guarantees, we are engaging with a solar project because renewables can be competitive. The pipeline is continuing, but only in more mature markets.

Although renewable energy can be competitive, many of the power purchase agreements that have been signed with governments will face difficulties that we will have to work through. We have seen governments in Europe and Latin America say, "We cannot afford to take this hit and you, the electricity suppliers, must reduce the tariffs."

Potential Upsides

MR. HANSEN: A few years ago there was an ExIm chairman for whom I worked, Jim Harmon, who was fond of saying that anybody could make money in a bull market, but it was in a bear market where you could show your clients that you could make a difference. He said that during the Asian economic crisis. The question for this crowd is: what opportunities does COVID-19 give your agencies to stand out? Is there any upside to all this?

MR. KLOUSSEH: That is a tough question to be frank. It is hard at this stage to see the opportunities clearly. The market is changing right before our eyes. We are in an observation mode as to what might or might not work.

What I would say is that the crisis has shown the frailty of certain sectors within Africa, including the health sector, education, and information and communications technology in terms of last mile collection. Everything that relates to decentralized power generation has become a priority. In order to test people for coronavirus, you need to have refrigeration, you need power to operate testing centers, and you need power to operate small medical units. Governments have asked us to try to develop public-private partnerships to implement these projects quickly.

MR. HANSEN: Tracey Webb, is there any upside to COVID-19 for DFC?

MS. WEBB: There are obviously no good options here, and I think this situation is going to have a larger impact than we realize. Social upheaval will often accompany a time like this, so we may see more demand for political risk insurance.

I hope that we can demonstrate that we will be a reliable partner. Historically, our portfolios have performed well during periods of low demand, crumbling */ continued page 50*

DFIs

continued from page 49

supply chains and high prices, but I think this is really going to test everybody.

MS. BAKER: At IFC, we are seeing opportunities because we are being so proactive and pushing things through at a very fast rate. We hope this will change the way that IFC operates.

I think many DFIs, and IFC is no exception, are seen as being relatively slow moving compared to commercial banks. Our staff are really invigorated to move fast under crisis-response conditions and asking why we cannot do this all the time. This provides a glimmer of hope internally. We love being quick. Let's always do this.

It is also testing our ingenuity. We are looking at programs to support manufacturers of personal protective equipment because we see that there will be high demand in many emerging markets that do not have enough today. Hopefully, they will not need as many as have been needed in some of the developed countries because of the difference in demographics, but let's be ready.

The biggest struggle that we have is in responding to the informal, unregulated sectors where the needs are huge. Remittances have dropped by something like $3 billion globally. These are cash flows that many people in the informal sector depended on, and we are struggling to come up with something that helps in that area. At a minimum, we are hoping to work with governments that were not passing the right legislation to support digital finance so that it is easier for people to send remittances in the future, even if that will not solve the problem today.

The informal sector is front and center in my mind in terms of what multilaterals can do. The informal sector can be 50% of some countries' economies and much of what governments and banks are doing is helping the formal sector. This may not be such a positive ending to my comment, but I hope that we come up with something that can respond. This is where the need is great.

MR. HANSEN: Tracey Webb, has COVID-19 changed DFC's equity and debt allocations for the fiscal year 2021?

MS. WEBB: We are hoping for a tremendous increase in 2021. I do not think we will see a difference in how we allocate between debt and equity.

MR. HANSEN: Tony Bakels, how is FMO streamlining risk due diligence for the sake of speed and given the realities that in-person diligence is not possible?

MR. BAKELS: We are really improving our digital due diligence skills. For most existing clients, we accept that if you have only done the digital due diligence, that can be sufficient. We are also looking at solutions working with local partners. There may be co-lenders that have offices in the country or we may work with consultancy firms or accounting firms that could do at least part of the due diligence on our behalf. The most innovative thing I have heard is to work with drones, but how that exactly will work still remains to be seen.

MR HANSEN: Koffi Klousseh, there has been a big push to get more institutional investors to invest in African infrastructure, directly and through private equity. What have you been hearing from the institutional investor community?

MR. KLOUSSEH: We are seeing institutional investors globally exercise more caution. We are going through a crisis, as we said. We do not know what the risks are going to be. We do not know the prices and returns that investors will require. It is harder to assess, especially for infrastructure, governments' ability to support infrastructure properly. We are fundraising right now, so this is something we are experiencing in real time. ◎

Solar Securitizations and the Federal Reserve

by Patrick Dolan, in New York, and Ryan Graham, in Houston

The New York Federal Reserve Bank confirmed informally by email in late May that it is not prepared to use one of its new lending windows to maintain liquidity in private debt markets to finance asset-backed bonds backed by consumer solar loans and leases, despite extensive lobbying efforts by industry trade groups.

Nevertheless, the New York Federal Reserve at the same time confirmed that commercial solar loans and leases will be considered eligible collateral for borrowing directly.

The particular Federal Reserve window is called the TALF program. TALF stands for the "term asset-backed loan facility."

Fed lending through this window will be available for terms of up to three years at rates that are 125 basis points over the overnight swap rate. The window will open for borrowing in mid-June.

Eligible Borrowers

Anyone borrowing through TALF will have to be able to check off a number of boxes.

Each eligible borrower must certify that it is unable to secure adequate credit accommodations from other banking institutions and that it is not insolvent.

In making this certification, an eligible borrower may rely on unusual economic conditions in the asset-backed securities market or markets intended to be addressed by TALF. Adequate credit does not mean that no credit is available, but instead means that credit may be available, but inadequate in amount, price or other terms because, for example, asset-backed securities spreads are elevated compared to normal market conditions.

The debt or lease obligations or other customer receivables being borrowed against must fall into one of nine categories: auto loans and leases, student loans, credit card receivables (both consumer and corporate), equipment loans and leases, floorplan loans, premium finance loans for property and casualty insurance, certain small business loans that are guaranteed by the US Small Business Administration, leveraged loans or commercial mortgages.

Loan sizing will turn on the amount of eligible collateral pledged. The Fed will only accept AAA-rated US dollar-denominated asset-backed securities issued on or after March 23, 2020.

The Fed will apply a haircut to the full value. The haircut varies by economic sector, the weighted average life of the pledged customer paper and historical volatility. The government has provided a schedule of haircut percentages. Collateral substitutions during the term of a loan will generally not be allowed.

Any company attempting to borrow at the TALF window must be formed under US law. It must have significant operations in the US or have a majority of its employees in the US. It must also have an account relationship with a primary dealer. US businesses that have a foreign government owning 10% or more of any outstanding class of securities are ineligible to borrow. Both equity and debt instruments are considered "securities" for this purpose.

Any investment fund — or a portfolio company of such a fund — attempting to borrow must show that no foreign government holds 10% or more of the securities of the management company.

Over the last few months, the Federal Reserve has expanded the classes of eligible collateral to include static collateralized loan obligations, meaning CLOs with reinvestment features, and legacy commercial mortgage-backed securities issued before March 23, 2020.

The legacy commercial mortgage backed securities must be related to real property located in the United States or a US territory.

The Federal Reserve said that it may consider adding new asset classes as eligible collateral in the future.

Loan Terms

All loans extended under TALF will be non-recourse, be generally pre-payable, and have terms of three years.

With some exceptions, the interest rate to borrow at the TALF window against asset-backed securities — like securitized solar commercial asset borrowing — with underlying credit exposures that do not have a government guarantee will be 125 basis points over the two-year overnight swap index rate for securities with a weighted average life less than two years or 125 basis points over the three-year overnight swap index rate for securities with a weighted average life of two years or greater.

The three-year overnight swap index rate is currently 0.29%. The spread would put the interest rate on borrowing at 1.54%. That compares to 3.35% rate that was on offer in the asset-backed securities market for / continued page 52

Securitizations

continued from page 51

commercial solar securitizations before COVID-19 shut the market down.

The Federal Reserve will assess a one-time administrative fee of 10 basis points of the loan amount on the settlement date.

The minimum amount a TALF borrower can borrow is $5 million. There is no maximum loan amount.

The Fed will accept commercial solar loans and leases as collateral for direct borrowing through its TALF window.

The Federal Reserve will not lend directly through the TALF window. Rather, the New York Federal Reserve Bank will make loans to a special-purpose vehicle that will lend, in turn, to private-sector borrowers, essentially the future revenue streams they offer as collateral into current cash. The Federal Reserve is prepared to lend up to $100 billion through the TALF window. The US Treasury will make a $10 billion equity investment in the special-purpose vehicle as a form of political buy-in by the government in case the special-purpose vehicle incurs losses on the loans.

The purpose of TALF is ensure there is enough liquidity in the asset-backed securities markets.

Clarifications

The Federal Reserve put out a term sheet to provide potential borrowers with details. In the first few versions of the term sheet, the Federal Reserve made no reference to renewable energy financial assets. Industry advocacy groups pressed to include consumer renewable energy financial assets in the list of eligible collateral, but have been unsuccessful. However, in a significant development, a Federal Reserve official confirmed by email in late May that the category of "equipment loans and leases" includes commercial solar loans and leases.

Asset-backed securities pledged as collateral to borrow through the TALF window must have been issued on or after March 23, 2020. Commercial mortgage-backed securities issued on or after March 23, 2020 will not be eligible

The securitization markets slowed in March due to the COVID-19 pandemic, but prime auto and equipment lease securitizations were becoming more common by late May with the expectation that the TALF program will be launched this summer, and the related spreads have tightened.

The Federal Reserve has said there will be approximately two TALF loan subscription dates per month, and each will be open to all eligible asset classes. The first loan subscription date for the TALF program will be June 17, 2020, and the first loan closing date will be June 25, 2020. The TALF window is set to close on September 30, 2020, meaning no further loans will be made after that date, unless the program is extended.

Environmental Update

A new Trump executive order in early June directs federal agencies to waive required reviews of environmental impacts from proposed infrastructure projects to be built during the COVID-19 pandemic.

The order invokes "emergency authorities" to waive parts of the National Environmental Policy Act, or NEPA, to speed development and construction.

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

The order calls on the heads of the Army Corps of Engineers and the Departments of the Interior, Defense, Transportation and Agriculture to each "use all relevant emergency and other authorities" to expedite infrastructure projects.

The emergency authorities are usually reserved for response to natural disasters.

The agencies must report back to the White House within 30 days with a list of projects that have been fast-tracked.

The order is headed to court. Environmental groups are questioning the legality of waiving federal laws by presidential dictate and are accusing the Trump administration of using the coronavirus pandemic to speed up long-sought regulatory changes already moving through standard regulatory channels.

NEPA already allows federal agencies to consult with the White House on whether emergency circumstances make waiver of certain requirements necessary: here because of the pandemic. It is unclear whether a president can waive the law's obligatory review of environmental impacts by federal agencies on such a broad basis.

Project developers again find themselves in a situation more prevalent under this administration than perhaps any other in recent memory, facing the prospect of proceeding with development and commerce in the face of the uncertainty that they may be proceeding under regulatory processes vulnerable to legal challenge or possibly to quick legislative or executive reversal following the next election.

While any federal approval of projects under the diminished review allowed by the order could be challenged in the courts, the order itself could be undone with the stroke of a new president's pen.

The order follows closely on the heels of a pre-pandemic effort by the Trump administration to diminish NEPA. In January, it proposed new rules to limit the law's review process and prevent federal agencies from the taking climate change impacts into account when weighing the environmental consequences of infrastructure projects under NEPA. The January proposals would narrow the range of projects that require NEPA review and set more accelerated timetables for completion of federal review. The January proposals are set to go into effect later in June, but are also expected to end up in court.

New York

New York moved in April to accelerate permitting and construction of new renewable energy projects.

Seventy percent of electricity generation in New York is supposed to come from renewable energy by 2030.

The "Accelerated Renewable Energy Growth and Community Benefit Act," enacted in April, creates an office of renewable energy siting that will consolidate environmental reviews and permitting of major renewable energy projects under one roof.

It is expected to set uniform standards for siting, design, construction and operation of wind and solar projects.

Applicants seeking a permit for large renewable energy projects will now undergo a streamlined review under section 94-c of the NY Executive Law, rather than having to seek a permit under the more time-consuming process in article 10 of the Public Service Law. Large-scale renewable energy projects currently in the article 10 process can elect to participate in the new process.

The new office will provide draft permits for public comment and consult with local municipalities about proposed projects.

Proposed projects must still comply with local regulations, though the new office may determine whether such regulations are unduly burdensome.

Final decisions on permit applications are expected within a year or less under the new accelerated process.

The new statute also encourages the New York State Energy Research and Development */ continued page 54*

Environmental Update

continued from page 553

Authority to identify what the statute calls "build-ready" sites, such as brownfields, landfills and former industrial properties, and then actively to secure permits, property interests and other authorizations for renewable energy projects. These sites will then be auctioned to developers.

The new law can be found online within section JJJ at https://nyassembly.gov/2020budget/2020budget/A9508b.pdf

Trump ordered federal agencies to identify infrastructure projects that will be put on a fast track.

Regulated Waters

The US Environmental Protection Agency and Army Corps of Engineers have significantly narrowed the scope of waters that are subject to regulation under the US Clean Water Act.

A new "navigable waters protection rule," published in the Federal Register in late April, follows from a Trump executive order directing EPA and the Army Corps to "review" a clean water rule put in place by the Obama administration in 2015 and to consider reinterpreting the scope of statutory terms to narrow the reach of federal regulation of water.

The new rule limits the scope of the term "waters of the United States," often referred to as "WOTUS," the meaning of which sets the outer bounds of regulation under the Clean Water Act.

The new rule lists four categories of waters that are considered WOTUS and, therefore, subject to regulation under the Clean Water Act. They are the territorial seas and traditional navigable waters, tributaries of such waters, certain lakes, ponds, and impoundments of covered waters, and wetlands adjacent to other covered waters (other than waters that are themselves wetlands).

All water bodies not falling within these four categories are now excluded from the definition of WOTUS by the rule and fall outside EPA and Army Corps of Engineers regulatory jurisdiction.

Notably, the new rule eliminates the "significant nexus test" that was described by Justice Anthony Kennedy in a landmark Supreme Court ruling in Rapanos v. United States in 2006. The 2015 Obama rule relied on the significant nexus test to justify making the WOTUS definition cover various non-navigable waters that affect WOTUS. The new rule observes that the Supreme Court in Rapanos said that the test was necessary only in the absence of clear regulations.

The new rule lists 11 types of water bodies that will be specifically excluded from federal regulation in the future. The 11 include such things as groundwater, including groundwater drained through subsurface drainage systems (such as drains in agricultural lands), ditches that are not traditional navigable waters, tributaries artificially irrigated areas that would revert to upland if artificial irrigation ceases, and artificial lakes and ponds that are not impoundments of water from a covered water body.

The new rule will take effect on June 22, 2020 unless blocked by a court.

Developers should expect uncertainty in the short- and possibly long-term as challenges to the new rule move through various federal courts. While challenges may be met by varied court rulings across the country that are limited in their application, it is possible that a federal district court could issue a nationwide injunction.

Prior jurisdictional determinations will remain valid after the new rule goes into effect, but anyone holding a valid jurisdictional ruling or a preliminary jurisdictional ruling may seek a reassessment based on the new rule.

States remain free to exercise jurisdiction over a wider range of waters or impose more stringent regulations under state law.

Water Quality Certifications

EPA in early June limited the role that states and Indian tribes play under the federal Clean Water Act in determining how proposed energy and other construction projects will affect water quality.

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

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

The Trump administration believe that some states use the certification process to delay or stop development.

EPA announced on June 1 that it had changed its Clean Water Act rules to limit the amount of time states and tribes can take to review a project and act on a request for 401 certification to one year. After one year, they will be considered to have waived the right to object.

The Clean Water Act rule changes also now prohibit states from blocking a permit for a project for any reason other than direct impacts to state waters. The Trump administration has accused a number of states of obstructing development for reasons that go beyond impacts to water quality: namely broader impacts on climate change.

A number of states have used the water certification rules to oppose fossil-fuel based energy infrastructure projects, such as an interstate gas pipelines in New York, New Jersey and Massachusetts and a coal export terminal in Washington.

In making the announcement, EPA Administrator Andrew Wheeler said the agency was acting to "curb abuses of the Clean Water Act that have held our nation's energy infrastructure projects hostage, and to put in place clear guidelines that finally give these projects a path forward." He said states would no longer be allowed to use the section 401 certification process to object to projects "under the auspices of climate change."

A legal fight is expected with Democratic governors whose state agencies have used the Clean Water Act to block fossil fuel-based projects. Developers may still have difficulty overriding permit denials in cases where both water quality and climate change concerns are cited as reasons for denying a certification.

The new rule also clarifies the definition of "water quality requirements" and adds more items to address in applications for certification.

The new rule also requires applicants to request a pre-filing meeting with state officials to promote early coordination, though there does not appear to be any obligation that a state grant one.

Federal agency review of a state or tribal section 401 decision finding will be focused on whether the procedural requirements of both section 401 and the federal rule were met, rather than substantive issues in the document. EPA acknowledges that federal agencies may not possess

/ *continued page 56*

New York is trying to streamline permitting of renewable energy projects.

Environmental Update

continued from page 55

the expertise or detailed knowledge concerning water quality and state law matters that would be needed to make substantive determinations.

If applicants have concerns about substantive issues discussed in the certification decision document, the courts are the proper forum.

The new rules say that "if a certification, condition or denial meets the procedural requirements of section 401 and this final rule, the federal agency must implement the certifying authority's action, irrespective of whether the federal agency may disagree with aspects of the certifying authority's substantive determination."

— contributed by Andrew Skroback in New York