

PROJECT FINANCE

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Cryptocurrency Mining for Power Suppliers

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Oversized profits from cryptocurrency mining are an enormous current opportunity for electric power suppliers. However, the length of time this opportunity will remain available is uncertain.

The profitability of bitcoin mining has increased rapidly along with the price of bitcoin, which has increased more than 75% year-to-date. Profit margins for bitcoin miners using state-of-the-art mining machines have climbed more than 80%.

In power market terms, bitcoin “mined” at a price of \$50,000 per bitcoin is equivalent to selling power at a price of more than \$400 per megawatt hour. This compares to wholesale electric prices that typically range from \$20 to \$60 per megawatt hour and that rarely exceed \$100 per megawatt hour absent super peak pricing.

Electricity demand from cryptocurrency miners has reached a scale that increasingly commands notice by all electric industry participants and is likely to become an increasingly integrated part of the United States electric grid.

If all bitcoin mining load was aggregated, it would represent the 32nd largest country in terms of total demand, and this is expected to increase meaningfully in the coming years. Regulated utilities report being inundated with inbounds for grid / *continued page 2*

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IN OTHER NEWS

LIBOR would be replaced automatically with SOFR in some loans and other contracts under a bill that passed the US House of Representatives in early December by a 415-to-9 vote.

The bill would also bar lawsuits arising out of the selection or use of any replacement benchmark rate based on SOFR.

It must still pass the Senate.

The measure is an effort to avoid a chaotic transition after the UK Financial Conduct Authority stops publishing LIBOR. Some LIBOR tenors will cease publication at the end of 2021, and the remaining tenors will cease publication after June 30, 2023. / *continued page 3*

Cryptocurrency Mining

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interconnection requests at a scale consistent with massive industrial complexes.

Power plant owners should view cryptocurrency not as something to be dealt with, but rather as a differentiated load source for their existing asset base that creates new avenues to sell electricity.

Depending on market dynamics, cryptocurrency mining has the potential to allow electric power producers to capture far more value for their electricity than otherwise available through traditional offtake agreements or by selling into wholesale markets.

High profits are attracting significant investment to cryptocurrency mining operations. As more miners are added to the cryptocurrency network, the share of revenues and profits for individual miners will decline all else equal.

In simple terms, cryptocurrency mining revenues are distributed based on an individual miner's pro rata share of the total computing power of all miners on the cryptocurrency network — known as the network hash rate.

Electric power is the largest operating cost for cryptocurrency miners. Therefore, miners with the lowest power costs will have the highest margins and be in the best position to capture profits whether network hash rates rise or fall.

Considerations for Power Suppliers

There are several important considerations for electric power suppliers while evaluating opportunities with cryptocurrency miners.

First, cryptocurrency mining operations have large, upfront capital costs for mining machines and infrastructure. Typical

large-scale cryptocurrency mining facilities have capital costs of approximately \$2,500 to \$3,500 per kilowatt.

Second, power suppliers will need to secure, or partner with someone who has, access to mining machines and the expertise to run a cryptocurrency mining facility. While state-of-the-art mining machines are currently available for order, that has not always been the case historically.

Third, setting up a cryptocurrency mining facility from scratch can take nine to 12 months or longer. Long-lead-time items can include the delivery of mining machines, transformer installation, electrical grid upgrades and interconnection approval.

Fourth, cryptocurrency miners can earn additional revenues from non-mining activities, such as providing demand response and ancillary services to the electric grid. Some cryptocurrency miners have indicated they are earning upward of 30% of their revenues from non-mining activities.

Electricity Demand

Demand from industrial-scale cryptocurrency miners can range from 25 megawatts to hundreds of megawatts of around-the-clock load. Unlike traditional data centers, cryptocurrency miners offer flexibility to shut off load, whether for forced outages or to sell power to the electric grid when it is more economic to do so during peak pricing periods. Furthermore, compared to traditional data centers, which must be located near backbone fiber networks, cryptocurrency mining facilities can be located anywhere there is sufficient power and internet connectivity.

Increasing electricity demand from cryptocurrency miners is driven by the rapid expansion of cryptocurrency mining operations in the United States in response to China's ban on most cryptocurrency activities, including mining. The United States is

now the leading location for cryptocurrency mining worldwide with a 35% share of global cryptocurrency mining activity.

Cryptocurrency mining in the United States is expected to continue expanding and attract more miners due to an attractive mix of low-cost generation, increasing renewable penetration, a favorable regulatory environment and a reliable legal system.

Using electricity to mine bitcoins worth \$50,000 each is equivalent to selling power for \$400 a MWh.

Expansion of cryptocurrency mining in the United States has created a shortage of power infrastructure suitable for cryptocurrency miners to procure power or access the electricity grid.

Historically, securing access to mining machines has been the primary restriction limiting expansion of cryptocurrency mining operations.

However, cryptocurrency miners generally report there is a sufficient supply of state-of-the-art mining machines and instead indicate that access to electric power infrastructure, whether behind-the-fence or to the electricity grid, has become the most difficult aspect for developing new cryptocurrency mining sites.

Transaction Structures

The primary decision for electric power producers is whether or not they want direct exposure to the upside potential and downside risks of cryptocurrency mining.

Under a traditional power purchase agreement with a cryptocurrency miner, power is sold at a set price and the electric power producer does not capture excess profits generated from mining bitcoin. However, depending on the strike price traditional power purchase agreements still provide value to certain electric power producers as a hedge against merchant power prices. Several power purchase agreements have been announced among merchant generators and cryptocurrency miners this year, with many more in discussions.

As an alternative to traditional power purchase agreements, certain electric power producers have entered into joint venture partnerships with cryptocurrency miners or have become vertically integrated cryptocurrency mining operations.

Joint venture partnerships have typically been structured such that the electric power producer contributes land and a favorable power supply agreement, which is further enhanced by potentially siting the mining assets behind-the-meter. Both the electric power producer and cryptocurrency miner contribute capital to fund development of the cryptocurrency mining facility and, as such, share in the mining proceeds and associated ancillary revenue streams.

The market for joint venture partnerships is still in the early stages, with nearly all options for structures and economic terms open for consideration and negotiation.

Additionally, cryptocurrency miners are increasingly interested in acquiring power-generating assets directly. With low-cost power purchase agreements difficult to find and joint venture partnerships complex to negotiate, cryptocurrency miners are actively looking at acquiring generation in / *continued page 4*

The UK Financial Conduct Authority plans to continue publishing “synthetic” LIBOR numbers for sterling-denominated contracts that will not require collecting interest-rate data directly from panel banks. It is considering publishing similar dollar LIBOR rates.

Under the House bill, LIBOR would be replaced automatically, in loans or other contracts that do not provide themselves for a replacement rate or make adequate provision to set such a rate, with a rate based on SOFR, plus a fixed spread adjustment that varies by tenor. The adjustment is .11448% for one-month LIBOR and .26161% for three-month LIBOR, the two most commonly-used tenors. The switch would take place on the first London banking day after June 30, 2023.

SOFR is a replacement rate for dollar-denominated instruments published by the Federal Reserve Bank of New York.

House action on the bill was delayed after the House banking committee included language to prevent the Internal Revenue Service from treating any shift in a benchmark rate as a taxable event. The House tax committee said the US Treasury has enough existing authority to sort out any tax issues in this area.

The IRS issued guidance in October 2020 to dispel fears that adjusting loan agreements and other contracts so that they still work after the UK stops publishing LIBOR will have adverse tax consequences. (For more detail, see “IRS Tries to Simplify LIBOR Transition” in the December 2020 *NewsWire*.)

Separate laws to avoid transition issues have passed in New York and Alabama.

The House bill overrides any state laws “insofar as they provide for use of a Benchmark Replacement,” meaning use of a new benchmark rate to replace LIBOR in loans or other contracts.

The parties to any loan or other contract can provide in the contract that it is not subject to the House bill. / *continued page 5*

Cryptocurrency Mining

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order to secure power and expand operations as quickly as possible.

How Bitcoin Is Mined

Bitcoin mining is the process through which the bitcoin blockchain is secured and transactions are completed.

Bitcoin miners perform this service by processing calculations to verify a batch of new transactions — called a block — and add the new block to the bitcoin blockchain, thereby maintaining a record of all verified transactions.

Miners are compensated for performing blockchain calculations through rewards distributed by the blockchain program — called block rewards — and transaction fees.

Large cryptocurrency mining facilities have capital costs of \$2.5 to \$3.5 million a megawatt.

Block rewards are distributed to the miner that successfully solves the blockchain calculation verifying the new block of transactions. The successful miner receives a block reward of 6.25 newly created bitcoins. Only one miner can successfully solve the calculations and receive the block reward.

Per the bitcoin program, a new block can be mined — and a block reward distributed — every 10 minutes, equal to 144 blocks per day or 52,560 blocks per year. The difficulty of the calculations required to mine a new block is automatically adjusted every 2,106 blocks, or approximately every two weeks, to maintain the average time between blocks at 10 minutes. Therefore, the total number of bitcoins distributed through block rewards is limited to 328,500 per year.

Since only one miner can receive the block reward, there is a high chance an individual miner could receive nothing for long periods of time. To get around this problem, miners join together in “mining pools” to split block rewards and increase the predictability of their revenue streams. Joining a mining pool typically incurs a cost of 1% to 2% of a miner’s block rewards.

Furthermore, the number of bitcoins distributed as block rewards will decline over time. Block rewards are programmed to cut in half every 210,000 blocks, or approximately every four years, in what is commonly referred to as a “halving.”

When bitcoin was first introduced in 2009, the block reward was 50 bitcoins per new block. The last halving occurred in May 2020 when block rewards were reduced from 12.5 bitcoins per block to the current reward rate of 6.25 bitcoins per block. The next halving is expected in 2024. Halving events will continue until the last bitcoin is mined, which is expected to occur in 2140.

In addition to block rewards, miners receive transaction fees paid by spenders of bitcoin when they submit new transactions. There is not enough data space in each new block to accommodate all transaction requests immediately. In order to incentivize miners to include their transaction in the newest block, and thereby complete the transaction faster, spenders can elect to pay zero or more bitcoins to the successful miner when submitting a transaction. Miners select

the transactions included in each new block and, absent an error, will select the combination of transactions with the highest total transaction fees first.

Transaction fees vary with the number of transactions and elections by spenders. Historically, transaction fees have made up 1% to 15% of revenue and recently have been observed at around 1.5% of block reward revenues. Transaction fees are expected to rise in the future to offset lost revenue from halving events, and transaction fees are expected over time to become the primary revenue source for mining. ©

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Current Challenges

The US renewable energy market is entering a period of potentially rapid growth, but with a great deal of short-term uncertainty. The sources of uncertainty include supply-chain difficulties, a potential rewrite of federal tax incentives for clean energy, inflation, import tariffs and domestic and international political tensions.

More than 3,400 people registered to attend the CLEANPOWER 2021 convention in Salt Lake City in early December. A panel of two tax equity investors and two lenders talked about the current state of the market. The panelists are Jordan Newman, managing director with Wells Fargo, Steve Schauer, managing director with KeyBanc Capital Markets, Mark Williams, managing director with PNC Bank, and Dave James, managing director with CoBank. The moderator is Keith Martin with Norton Rose Fulbright in Washington.

Supply Chain

MR. MARTIN: Mark Williams, how are supply-chain difficulties affecting transactions?

MR. WILLIAMS: They are introducing a large delay factor and some uncertainties. About 60% to 70% of the deals on which we are working and that were scheduled to close in the fourth quarter this year have slipped, at least partially, from 2021 to 2022. I could give you a better answer in three weeks as to how many have slipped, but that is how I would handicap it today.

Fortunately, all the deals for which we provided tax equity that were scheduled to close during the first half this year closed successfully with minimal delays. These earlier deals represented most of our volume for the year.

MR. MARTIN: Steve Schauer?

MR. SCHAUER: We like to have a buffer between when the tax equity funds to pay down the construction debt and the drop-dead dates for funding and for when the project is in danger of losing the power purchase agreement for failure to be completed in time. Those time periods are really contracting. This is a big concern.

MR. MARTIN: How common is it in deals today that projects are backing up against the deadline in the power contract to be in commercial operation or the tax equity investor's outside commitment date to fund?

MR. SCHAUER: It was happening before COVID. Supply-chain issues have been affecting deliveries of both solar panels and batteries. We are seeing a lot higher / *continued page 6*

TAX BASIS allocation issues are getting more attention in court.

The latest skirmish, in a Treasury cash grant case, suggests that the US government may regret insisting that the purchase price in M&A and tax equity transactions must be allocated among the assets purchased using the "section 1060 method."

It usually makes a difference in transactions that are treated as asset sales or sales of partnership interests for tax purposes how the purchase price is allocated among the various assets. For example, an investment tax credit cannot be claimed on the part of the purchase price allocated to a power purchase agreement. If the seller is an individual selling partnership interests and trying to treat any gain as long-term capital gain, it is better to allocate purchase price to goodwill and going concern value.

The section 1060 method must be used to allocate purchase price when someone is buying a business as opposed to a piece of equipment.

IRS regulations also require use of the section 1060 method in any sale involving assets with goodwill or going concern value.

The section 1060 method requires separating the assets that come with the business into seven asset classes from easiest to hardest to value. Classes I through IV are, in order, cash, things like commodities that are actively traded so that quotes are readily available, accounts receivable and inventory held out for sale. All other tangible assets go into class V. Class VI is intangible assets like power contracts, site leases and licenses. Any remaining purchase price goes into class VII and is considered a payment for customer goodwill or going concern value.

The government persuaded a US appeals court in 2018 that the section 1060 method should be used to allocate purchase price in sale-leasebacks of wind / *continued page 7*

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demand and a lot more projects. This would have been a challenge even before container ships started backing up at US ports.

MR. MARTIN: Mark Williams said 60% to 70% of the fourth-quarter deals on which PNC is working have slipped from this year to next. Do you have a percentage?

MR. SCHAUER: Right now we are laser-focused on getting closed. We have some 30 deals that we are trying to close between November 1 and year end. Are some of those going to slip? No one is telling me that. We are just working hard.

MR. MARTIN: You said 30 deals.

MR. SCHAUER: We are having a record year. We hope to have closed some 60 project finance deals this year and put something like \$3 billion in new capital to work.

Supply-chain issues are not a short-term problem that will disappear by next summer.

MR. MARTIN: Dave James, how have supply-chain difficulties affected your deals?

MR. JAMES: The schedules are getting pushed out and maybe up against PPA deadlines, and sponsors are having to approach oftakers in some cases to ask for more time. Whether equipment is arriving on time or getting stuck in port is definitely affecting closing schedules.

MR. MARTIN: What percentage of your deals have slipped into next year?

MR. JAMES: It is hard to say. Maybe 30%.

MR. MARTIN: Jordan Newman?

MR. NEWMAN: We certainly have had to extend

commitments a number of times for a number of different deals this year as projects were running up against PPA deadlines or up against construction debt deadlines. We are probably looking at 20% of the volume that we might have expected to do in 2021 slipping into 2022. It may be just luck of the draw. We saw a significant amount of volume slip from 2020 into 2021. We are also seeing deals on which we are working toward funding commitments in 2022 already being pushed into 2023 because of supply-chain issues.

MR. MARTIN: Slipping into 2023, not 2022?

MR. NEWMAN: Correct. They would have been 2022 deals, but it is already clear that delays will push them into 2023.

MR. MARTIN: So the supply-chain issues are not a short-term problem that will work itself out by next summer?

MR. NEWMAN: It certainly doesn't seem that way from where I sit.

Tax Changes

MR. MARTIN: Mark Williams, the "Build Back Better" plan that is being debated in Congress would increase the tax credits back at least to their full rates and, in some cases, push the ITC as high as 50% for projects placed in service in 2022 or later. Do you see developers delaying placing projects in service until next year in order to qualify potentially for higher tax credits?

MR. WILLIAMS: You would theoretically get higher tax equity investments if there are

higher tax credits, but I don't see a lot of negotiation and planning around that yet.

MR. MARTIN: The developer would be taking a chance in any event. The bill may not pass this year.

Jordan Newman, when a project ends up qualifying for higher tax credits than expected and the term sheet or deal papers have already been signed, do you increase the tax equity investment?

MR. NEWMAN: In short, yes. It is in everyone's interest for the tax credit to be of higher value. It allows us to put more capital to work, it increases the economic pie for the sponsor and, generally speaking, a deal that has more tax benefits allows us to take

less of the cash and still achieve our target return.

We have at least one example of a sponsor that was intending to place something in service this year and is going to hold out in hopes of higher tax credits next year for a PTC project. We have other examples where we structured our commitment to be flexible to allow for funding at the higher level should the tax credits increase.

Direct Pay

MR. MARTIN: Let me toggle back and forth between the two tax equity investors for a moment. Mark Williams, as you know, the Build Back Better bill would also let developers get cash payments in place of tax credits. What happens when developers say to the tax equity investor, “I would like to do tax equity, but if I have the option of getting cash, then I would rather dispense with the tax equity and convert the tax credits into cash directly.” Does that work?

MR. WILLIAMS: We have not encountered that issue. I don’t think it would work for a deal to which we are being asked to commit and negotiate fully.

The refundable tax credit is an interesting idea and will generally help the market, but there is a lot of uncertainty about how it will be administered. If you recall the Treasury cash grant days, a number of developers thought they had been shortchanged by the government. There is still a lot of detail that needs to develop around exactly how the new program will function and how reliable it will be.

MR. MARTIN: Steve Schauer, will the lenders lend on a back-levered basis where there is a cash payment and the government could, I assume, have a tax lien over the project in the event the government is owed some of the money back? Does that have to be sorted out before the banks will feel comfortable lending?

MR. SCHAUER: Absolutely. As you know, we like to be first priority during construction with a first lien over all the assets. Post-construction, we have an agreement with the tax equity investor that gives us an assurance that cash flow can be distributed to the sponsor to pay debt service. The priority of the government claim if some of the cash payment were to have to be paid back will definitely have to be worked out.

MR. MARTIN: During the Treasury cash grant era, the Treasury was willing to take a back seat in terms of lien priority in order to facilitate bank financings.

Jordan Newman, what role will there be for tax equity if there is a direct cash payment option?

MR. NEWMAN: There should continue to / *continued page 8*

farms. A lower court said that the method is required only in sales of the kind of business that has customer goodwill. There is no customer goodwill in a project that is not yet operating and has only a single utility as a customer under a long-term power purchase agreement, the lower court said.

The appeals court said that there can be customer goodwill by virtue of merely signing a contract with a customer — presumably even before the project is built — and directed the lower court to retry the case using the section 1060 method to allocate purchase price. (For more detail, see “Tax Basis Issues: Alta Wind” in the August 2018 *NewsWire*.)

The retrial is unlikely before 2023.

In the meantime, the government is showing signs of regretting the outcome in that case.

The government lost a series of motions in a separate case, called *Desert Sunlight v. United States*, involving two large solar power plants in a decision that was unsealed in early November. Under the section 1060 method, the parties assign purchase price to the equipment first and treat any remaining purchase price as basis in contracts and other intangibles like customer goodwill or going concern value.

If the entire purchase price is used up allocating to the hard assets, then there is nothing left to allocate to a power contract or goodwill.

The government argued that the power contract and interconnection agreement should be lumped in with the hard assets so that at least some of the purchase price would be allocated to them. The US Court of Federal Claims said no.

First Solar developed two large power plants — one with a capacity of 250 megawatts and the other 300 megawatts — in the California desert. It sold the development rights to NextEra and GE Energy Financial Services in 2011 before / *continued page 9*

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be a role for tax equity, especially for PTC deals. If you think about the value that tax equity adds, it is not just the tax credits, but also the depreciation.

There are two ends of the spectrum.

At one end, you might have a wind repowering deal where both PTCs and bonus depreciation will be claimed. We are putting in 70% or even 80% of the capital. The depreciation is on the full tax basis without the basis reduction that would happen for a deal with an investment tax credit. That is a lot of value to leave on the table for most sponsors if they cannot otherwise use the depreciation.

At the other end of the spectrum is a solar project that the parties will have to depreciate over 12 years using straight-line depreciation because of DRO issues. We are only putting in 33% of the capital, and our tax basis is reduced by half the ITC. The tax equity is giving hardly any value for the depreciation. Those are the deals where perhaps the direct pay compares more favorably to raising tax equity.

Then there is everything in between.

Projects delayed into 2022 may qualify for higher tax credits if the “Build Back Better” bill is enacted.

So perhaps the mix of projects that will seek tax equity will be different than it has been, but we certainly think there is a role for tax equity, and we continue to talk actively with customers about tax equity deals into 2022 and 2023.

MR. MARTIN: Let me understand that. You are suggesting that there will be a greater role for tax equity in wind where tax equity is about 65% of the capital stack on average, plus or minus 10%, as opposed to solar where tax equity is around 35% on average, plus or minus 5%. Wouldn't the depreciation be largely the same

in either case? It is a little higher in wind because there is no reduction in depreciable basis when PTCs are claimed.

MR. NEWMAN: Yes. It is about how much tax basis does the tax equity investor have that allows depreciation to be truly monetized rather than ending up as a suspended loss.

It is true that the amount of depreciation available to the partnership is roughly the same, but the outside basis of the tax equity investor in its partnership interest is lower in a solar deal. The investor is really only giving value in its discounted after-tax cash flow to the tax benefits that it has enough outside basis to absorb. We are providing more value beyond just the tax credits in a wind deal where we start with a higher outside basis and are in a position to absorb more depreciation.

MR. MARTIN: Mark Williams, do you agree with that? There may be less tax equity in the solar market if there is a direct cash payment than there will be in the wind market?

MR. WILLIAMS: The depreciation is still valuable whether the deal is solar or wind.

We are no longer in the very early innings of the industry. There are a lot of major sponsors that have deal papers in place with tax equity investors so that they can do repeat business easily and with little execution risk. Those players will continue to use third-party tax equity.

I agree that sponsors that have struggled to raise tax equity will avail themselves of the direct-pay option and forego the depreciation just to get a deal done.

MR. NEWMAN: I am not suggesting that there will not be tax equity ITC deals. I was just trying to draw the mathematical distinction between the two ends of the spectrum when it comes to monetization of depreciation.

There are other ways in which tax equity adds value for ITC projects. For example, the tax credits are higher if the project can be financed in a way that steps up the tax basis as happens when the project company is sold to a tax equity partnership.

Escalating Costs

MR. MARTIN: Dave James, some solar developers have told us that as many as 30% of PPAs for solar projects still in

development have been cancelled because the developers are no longer able to deliver the electricity for the original prices offered. Supply-chain difficulties and inflation are driving up project costs. Have you seen this?

MR. JAMES: I don't think so. If the deal is in financing, then the developer has already locked in a profitable spread between a fixed price in the PPA and construction costs.

MR. MARTIN: Steve Schauer, have you seen any distressed power contracts in the deals you considered financing?

MR. SCHAUER: What we see, particularly in solar, is that PPA prices have gotten so low that there is usually very little room for back leverage. Most of the back leverage and debt financing in general is in smaller-scale solar. We are lending to a lot more distributed solar projects under 20 megawatts.

MR. MARTIN: Mark Williams, inflation in November was running at a 6.2% annual rate. How, if at all, does that affect tax equity yields?

MR. WILLIAMS: It hasn't affected them yet. It is likely to affect them in the future. Both Janet Yellen and Jerome Powell said "transitory" is no longer an appropriate word to describe inflation. We see bond spreads and investment-grade bond deals getting wider. The bank market is typically lagging. If inflation persists, then bank spreads will widen, and tax equity yields and debt pricing will increase.

MR. MARTIN: Will they go up opportunistically? Or is it simply that a higher cost of funding will have to be passed through?

MR. WILLIAMS: The cost of funds will increase. As the Fed reins in bond purchases, interest rates will increase.

MR. MARTIN: Dave James, what other effects has inflation had on debt or tax equity?

MR. JAMES: Banks will be scrutinizing cost line items in the financial model with an eye to whether the project will generate enough free cash to cover debt service.

We have not seen any widening of the LIBOR spreads in our deals due to inflation, but it could be coming.

Financing Terms

MR. MARTIN: Steve Schauer, where are interest rate spreads currently in the debt market?

MR. SCHAUER: We are seeing interest rates on back-levered term debt in solar projects that are down the middle of the fairway in terms of risk at 125 or maybe 137.5 basis points.

MR. MARTIN: Above LIBOR?

MR. SCHAUER: Yes. For SOFR, you would add another 12.5 basis points. SOFR spreads have not been / continued page 10

construction started on either project. At the time, the development rights included long-term power contracts to sell the electricity from one power plant to Southern California Edison and from the other to Pacific Gas & Electric that had been signed in 2009 and 2010 as well as interconnection agreements to connect both projects to the California grid.

The parties signed five sets of contracts in 2011 when the project companies with the development rights were sold: an agreement to sell the project companies holding the development rights, three construction contracts for First Solar to build the projects and shared facilities, O&M contracts for it to operate them, a US Department of Energy loan guarantee and other financing agreements.

After completing the power plants, the owners applied for section 1603 payments from the US Treasury in lieu of investment tax credits.

First Solar had originally asked for a fixed price of \$2.36 billion to do all of the construction work, but the price was negotiated down to \$1.95 billion. The final figure included \$104 million in sales taxes.

NextEra and GE paid First Solar \$14.45 million in 2011 to buy the two project companies that owned the development rights. Immediately upon sale, the project companies borrowed \$1.46 billion that First Solar had arranged with several banks. DOE provided a loan guarantee for \$1.68 billion. NextEra and GE put in \$600 million in equity.

The two power plants were built in 20 blocks.

The owners submitted 15 separate applications to the US Treasury for section 1603 payments as blocks were placed in service. The power plants were completed in 2014.

The owners ended up spending \$2.13 billion to put the power plants in service, including \$87 million in / continued page 11

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worked out yet. SOFR is more trouble to swap because the full range of debt tenors is not available yet. For small-scale solar, we see LIBOR spreads in the 150- to 200-basis-point range.

MR. MARTIN: How do you define small-scale solar? Twenty megawatts?

MR. SCHAUER: Portfolios of solar projects that are under five megawatts each. We have probably closed seven of those transactions this year for various sponsors, both big and small.

MR. MARTIN: So interest rates basically have not moved this year. At the start of the year, if I had asked you what the LIBOR spread is on utility-scale solar debt, you would have said 125 to 137.5 basis points.

I was looking at a loan agreement yesterday. It will use a SOFR rate, and the spread is 100 basis points higher than the LIBOR spread. Why? You said it difficulty swapping. Is there more to it?

MR. SCHAUER: They should come talk to us. We are not charging anywhere near 100 basis points more.

MR. JAMES: Any new deals signed obviously have to be documented in SOFR. We have not really gotten into what the impact of that is on pricing.

MR. MARTIN: Why would the spread be higher? Is it because SOFR is a more volatile metric?

MR. WILLIAMS: It an inherently risk-free type rate. It does not build in a credit risk, so you have to build in a margin above SOFR, and the market has not really settled on what that is.

There have been suggestions for three-month SOFR that it is around 25 or 26 basis points, but my observations are — and these are my observations, not necessarily PNC Bank's opinion — that there are a lot of administrative, logistical and regulatory issues that need to be worked out before we have smooth sailing

in terms of the LIBOR transition.

MR. MARTIN: Steve Schauer, what is the current advance rate for construction debt on utility-scale projects? Eighty-five percent? 90%, 95%?

MR. SCHAUER: We see a wide range. On solar, you mentioned that tax equity accounts typically for 35% of the capital stack. We will advance 95% to 98% of the expected tax equity investment.

Term loans are all over the map. We will make a construction loan for 100% of what the project can support as a term loan. How much debt the project can support turns on the electricity price in the PPA. It would typically be 80%, but it could be as high as 90% or as low as 70%. We see a fairly wide range of construction loan advance rates.

MR. MARTIN: Mark Williams, do you see the same thing?

MR. WILLIAMS: We see around 90% for the construction loan and around 98% for the tax equity bridge loan in plain-vanilla transactions with top-tier sponsors, top-tier EPC contractors and an investment-grade tax equity investor.

MR. MARTIN: Jordan Newman, where are current flip yields for partnership flips?

MR. NEWMAN: Tax equity is always reticent about giving specific yield figures publicly. I will say that they have been remarkably stable this year after ticking up a notch at the beginning of the pandemic.

MR. MARTIN: I would put them in the 6% to 8% range, although we have seen some a little below six.

MR. NEWMAN: That is a fairly wide range, so I would describe that as accurate.

New Asset Classes

MR. MARTIN: The Build Back Better plan would create a new tax credit for standalone storage. It would create another new tax credit of up to \$3 a kilogram for making clean hydrogen. There would also be enhanced credits for carbon capture. Are all of you interested in financing these types of projects?

MR. JAMES: Most still have new technology risk. One type of storage — pumped-storage hydro — is pretty limited by geography. There are not very many of those deals. In anaerobic

As many as 30% of PPAs for development-stage solar projects have been cancelled because of escalating project costs.

digestion projects, it is hard to predict what P50 production will be and, therefore, what the cash flow is that you can reliably lend against. We are seeing more and more of these deals being proposed. Lots of people are interested in renewable natural gas. I think those projects can get done.

MR. MARTIN: So for hydrogen, some types of standalone storage and carbon capture, not yet?

MR. JAMES: Clean hydrogen is not really far enough along. Some types of projects may not qualify for construction debt and may have to be financed in portfolios of projects to spread the risk of a single bad project, again to reduce the risk.

MR. MARTIN: Renewable natural gas seems to be a fancy new name for what used to be called methane from cow manure. [Laughter] Jordan Newman?

MR. NEWMAN: We are very interested in all the new asset classes that either have potential new tax credits offered or, like offshore wind and carbon capture, have had recently enhanced tax credits, but the transactions are just starting to take form.

Each new asset class presents its own set of challenges. For carbon capture, for example, we have to wrap our heads around an entirely different type of technical analysis that is very different from renewable energy. We have to think about feed-stock risk in a way that we have not had to think about with renewable energy.

We are out in the market talking with sponsors of carbon capture projects now, and we will probably be doing our first commitments for carbon capture in 2022, with capital going out the door after that.

MR. MARTIN: Are you aware of any tax equity deals that have closed involving section 45Q tax credits?

MR. NEWMAN: I am not aware of any, certainly not any deal that has funded.

As you expand out to the other asset classes, we are definitely interested.

Lightning Round

MR. MARTIN: We are down to less than 10 minutes. Let me do a quick lightning round.

US Customs is blocking a lot of solar panels. One Chinese vendor told us as many as 80% of Chinese branded equipment is not getting into the US. How is this risk being handled in financings?

MR. JAMES: If the panels are not already in the United States, then the related construction funds will not be released. You might be mid-construction and US / continued page 12

construction-period interest and \$72 million for an early-completion bonus for First Solar.

They claimed \$2.05 billion, or 96.2%, as tax basis in assets qualifying for an investment tax credit. They applied for a Treasury cash grant of \$616.8 million, or 30% of the eligible basis. The Treasury paid \$59.3 million less than this amount. The owners sued for the shortfall.

The case is still in the early rounds, but the mental gymnastics by the government lawyers so far have earned them a poor score.

The government asked the court to award it summary judgment based on legal briefs without going to trial on grounds that the owners failed to file an IRS Form 8594. Both the seller and the buyer must file a Form 8594 with their tax returns for the year of sale showing how they allocated the purchase price in sales transactions to which section 1060 applies.

The court said no. The penalty for failure to file is \$250, not forfeiture of a claim. If the government truly thought the application for section 1603 payments was fatally deficient for failure to file a form with a later tax return, the court said, it is unfathomable that the government would have paid more than \$555 million in Treasury cash grants.

The government next found fault with a number of cost items that the project owners treated — or *failed* to treat — as basis in ITC assets.

The government said that the bank loans were non-ITC assets to which part of the purchase price should have been allocated in class III or V of the section 1060 waterfall. The court said no. Even if the loans are “assets,” the court said, purchase price must be allocated only to assets acquired in the acquisition. The bank loans were borrowed later. Moreover, even if they are assets, the court said, they are intangibles belonging in class VI.

Next the government argued that the court should ignore the price that two hard bargainers negotiated for the / continued page 13

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Customs holds up a shipment of panels, and you have a problem at that point. Lenders will take a hard look at whether to continue to fund. They will want a sponsor guarantee in some cases to ensure repayment.

MR. SCHAUER: I agree.

MR. MARTIN: The “pay fors” in the Build Back Better bill include a book minimum tax. Big companies with more than \$1 billion a year in average financial statement income over the past three years would pay 15% of the current-year financial statement income to the extent it exceeds the regular corporate income tax. How will this affect the tax equity market?

MR. WILLIAMS: The effect is unclear at this point.

MR. MARTIN: Jordan Newman, has Wells Fargo done any analysis?

MR. NEWMAN: Yes. The issue is the effect on monetization of depreciation. There is obviously some risk that there would be a loss in value from the depreciation. Tax depreciation is taken over five years on a front-loaded basis. Financial statement depreciation is straight-line over the useful life of the project.

Generally speaking, in the tax equity market, the ability of the tax equity investor to use the tax benefits has been borne by tax equity. It is one of the main risks that tax equity bears.

MR. MARTIN: Will that change?

MR. NEWMAN: I think when the BEAT tax was imposed in the tax bill at the end of 2017, a few investors tried to push that risk to sponsors. I think a few deals were done that way, but for the most part . . .

MR. MARTIN: Not many.

MR. NEWMAN: The book minimum tax feels to me like it is in the same bucket of the type of risk that tax equity has borne and will continue to bear.

MR. MARTIN: The Build Back Better bill would also require that the same “prevailing wages” that the federal government pays on its construction jobs be paid during construction, and also on alterations and repairs for five or 10 years after the project has been completed, to qualify for full tax credits. These wages do not have to be paid by the solar or wind company itself, but by the construction contractors and subcontractors who are hired to work on the project.

Is this starting to play a role in any deals on which you are working?

MR. WILLIAMS: I haven’t seen it come up yet. Tax equity

investors will ask for an indemnity from the sponsor to cover any recapture risk.

MR. MARTIN: How does 2022 look to you in terms of deal volume? We talked earlier about projects slipping, some into 2022, some even into 2023. How will the deal volume be affected by whether the Build Back Better bill is enacted?

MR. SCHAUER: I mentioned that 2021 was very strong. We expect 2022 will remain strong. You have a whole series of wind projects that were built in the 2009 through 2012 time frame that are ready for repowering. Solar kicked in two or three years later, so we see a lot of potential repowering in solar as well.

There should be lots of demand for tax equity, bank financing and even institutional debt. Institutional lenders and the project bond market will be looking to do more ESG investments that promote clean energy. We closed our first institutional loan earlier this year for a small solar developer as a refinancing and recapitalization, single-B credit. We are seeing a wave of that type of financing starting to come to market.

MR. MARTIN: These are refinancings?

MR. SCHAUER: This was actually triple leverage. There was tax equity, back-levered debt and then a further subordinated loan at the holding company level. I think there will be more of this type of capital available to sponsors to fund projects. It is a form of term lending rather than construction debt.

MR. MARTIN: Does it matter if the Build Back Better bill is enacted? How would it change the forecast?

MR. SCHAUER: It would be phenomenal for our business.

MR. MARTIN: The market will feel like a treadmill turned up to warp speed.

MR. SCHAUER: Yes. We are hiring.

MR. MARTIN: How has the “great resignation” affected the ability of the market to close deals? Working 22 or 23 months from home has given all of us a chance to reflect on life. Six percent of the US workforce quit in just August and September this year.

MR. SCHAUER: Most of our young people are back in the office. Some people are already traveling a lot. There is a mix. As a new junior banker, some of them decide they don’t really like the business and move on to something else, but for the people who like it, it is a really powerful business to be in and . . .

MR. MARTIN: This is your speech to KeyBanc employees, right? [Laughter]

MR. SCHAUER: Not only that, it is to all of you out there and your sons and daughters. Banking is awesome. [Laughter]

MR. MARTIN: Stephanie Ruhl of MSNBC said to the younger

people, “You need to come into the office because if you don’t establish relationships, you have a job, not a career.”

MR. SCHAUER: Totally true.

Climate Change

MR. MARTIN: Let me make sure we get in one more topic and that is casualty insurance premiums. They have gone up four and five times for solar projects. We have seen sponsors send notices to bankers and tax equity investors in deals that have already been financed that they cannot find casualty insurance at affordable premiums. What happens in that case?

MR. JAMES: You still need casualty insurance. It will cost more, so it will reduce the amount of debt the project can support.

MR. MARTIN: What if the project has already been financed?

MR. WILLIAMS: Most lenders and tax equity investors are loathe to go for an extended period without insurance. We have seen sponsors ask to have increased deductibles that go above and beyond what was in the documents. It has to fit within the budget. If it breaks the budget by more than 10%, then consent is required to spend the additional money. So far, things have been working out. Projects eventually find insurance.

MR. MARTIN: Are you seeing other effects from climate change? I know we have worked on projects that have been damaged by hailstorms, lightning strikes, flooding, hurricanes and wildfires.

MR. NEWMAN: Ice storms.

MR. MARTIN: Ice storms in Texas.

MR. NEWMAN: It certainly seems like one-in-500-year events are happening more than every 500 years. In addition to affecting insurance, it feels like there is more uncertainty around electricity output. For example, the wildfires in California put smoke in the air that reduced the output from solar modules.

MR. MARTIN: Output forecasts have been less reliable in certain parts of the country. What adjustments are financiers making to forecasts? Do you accept them? What do you do to them in the back room?

MR. SCHAUER: We are trying to hold the line on reducing coverage ratios.

MR. JAMES: I think that’s right. You want to sensitize a little more around production estimates, but I think the science of estimating solar resources is advancing, especially after we have seen industry wide that solar output has been maybe 6% on average below forecasts. Those types of revelations help the market become more efficient.

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construction job — First Solar on the one side and GE and NextEra on the other — because investment tax credits and, by extension, cash grants must be calculated on a price established in a *hypothetical* negotiation.

The government argued next that NextEra and GE paid *too little* for the development rights, since First Solar had spent \$35 million on the projects by the time they were sold in 2011. The court said this is a question of fact that requires a trial to settle.

Meanwhile, the court confirmed, at the request of NextEra and GE, that the power contracts and interconnection agreements are class VI rather than class V assets, the DOE loan guarantee is not a separate asset capable of soaking up purchase price, and if the entire value is used up by class V, then there is no need to continue down the waterfall to allocate anything to class VI or VII.

The case is headed for a trial in June 2022 — if the parties do not settle before then.

CALIFORNIA clarified that partnership flip transactions do not trigger property tax reassessments for solar projects.

The bill that did so still leaves some potential gaps that require attention to detail.

The California constitution limits property taxes on real property to 1% of the 1975 value or the value upon more recent new construction, plus an adjustment for inflation that is limited to 2% a year.

A change in ownership triggers a reassessment to the current value.

Section 73 of the California property tax statute effectively exempts active solar systems from assessment until there is a change in control after the initial construction.

Section 73 must be renewed from time to time. It applies currently to any active solar system put in service before 2025. Any such project remains exempted until a future change in control. / continued page 15

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Other New Risks

MR. MARTIN: This is my last question. Are there other, new risks that have shown up in the renewable energy market this past year that we have not discussed?

Banks are charging a higher interest-rate spread on SOFR loans than on LIBOR loans.

MR. SCHAUER: I see one other issue involving offtake contract structures. We are seeing a lot shorter power contracts, especially on the east coast. We don't see a lot of long-term contracts in PJM unless they are with corporate offtakers. The financing parties have to be nimble enough to deal with variations in offtake arrangements, from traditional utility PPAs all the way to New York feeder offtake agreements. Analyzing the different arrangements is taking a lot of time.

MR. NEWMAN: I echo that. It is not necessarily new, but the cash flows that we are being asked to underwrite have been substantially more volatile and less predictable.

This is especially true in markets like ERCOT and SPP, but really all over where you might have a project that has three different offtake arrangements that maybe only cover 80% of the capacity. All three of them are settled at a hub, so there is electricity basis risk and a merchant component, and there might be some kind of floor or upside sharing. There is a mix of different types of offtakers with different credit profiles. That puts a lot of stress on the downside scenarios.

MR. MARTIN: You must discount the cash flows in such cases when sizing the tax equity. How much of an adjustment do you make?

MR. NEWMAN: It is not so much a matter of adjusting the discounting as running downside scenarios and making sure that you are looking at a reasonable flip tenor, or even more fundamentally whether the project will have the liquidity to continue

to operate and generate production tax credits. We are layering on top of the production downside curtailment, availability and basis risk. Having a large, geographically dispersed portfolio helps to diversify the risk.

MR. MARTIN: It requires a lot more intellectual capital to pull off these deals. Any other new risks?

MR. WILLIAMS: The new risk is the cumulative impact of all the factors we discussed. We haven't had this level of uncertainty in terms of tax law, in terms of inflation, in terms of supply-chain difficulties and labor shortages, in terms of pricing, and all of that has contributed to a reluctance on the part of sponsors to lock in long-term offtake contracts because they think prices may be higher in a few months. That has contributed to more delay.

People are moving forward, but cautiously. There is an unusually large number of moving parts.

MR. MARTIN: That will be the last word. This may be a case of "May you live in interesting times." ☺

Hydrogen Funding and Tax Credits

by Jim Berger in Los Angeles, and Keith Martin in Washington

Developers are already circling money for hydrogen projects after a boost in funding in the infrastructure bill that President Biden signed in November. Such projects would get a further boost if the “Build Back Better” plan that passed the House just before Thanksgiving also passes the Senate.

Tax Credits

The “Build Back Better” bill would give anyone producing “clean hydrogen” the choice of production tax credits of up to \$3 a kilogram for 10 years on the hydrogen produced or an investment tax credit of up to 30% of the cost of the electrolyzer and other equipment.

The investment tax credit is claimed entirely in the year the electrolyzer or other equipment is put in service. The hydrogen producer must choose between the two credits on offer. It cannot claim both.

The credit amounts vary depending on the quantity of CO2 emitted to produce a kilogram of hydrogen.

To claim credits at the full rate, the production process must lead to less than 0.45 kilograms of CO2 emissions per kilogram of hydrogen.

The following table shows the tax credit amounts where the CO2 emissions exceed that amount.

CO2e kilograms to produce a kilogram of hydrogen	PTC per kilogram	ITC
At least 0.45 but less than 1.5	\$1.002	10%
At least 1.5 but less than 2.5	75¢	7.5%
At least 2.5 but less than 4	60¢	6.05%
At least 4 and not more than 6	45¢	4.5%

No credits could be claimed on hydrogen produced with more than six kilograms of CO2 emissions per kilogram of hydrogen.

The CO2 emissions are measured on a lifecycle basis, meaning taking into account all of the emissions from feedstock through the point the hydrogen is produced (rather than also through consumer use).

The production tax credit amount would be adjusted annually for inflation.

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Avoiding a change in control is a significant issue in any M&A transaction where California solar projects are involved.

A change of control is considered to occur when more than 50% of both the profits and capital interests in a partnership are transferred. The state focuses on whether someone is *gaining* control in a transaction rather than on someone is losing it.

The most common way to finance solar projects is for the developer to own the project in a partnership with a tax equity investor. The investor is allocated 99% of profits, losses and tax credits until a flip date, after which its interest drops usually to 5% and the developer has an option buy the remaining post-flip interest of the investor. Cash is usually be shared in a different ratio.

Thus, the tax equity investor starts with more than a 50% profits interest. Whether it also starts with more than a 50% capital interest depends on the share of total capital put in by the tax equity investor.

Partnership flip transactions had the potential to trigger reassessments until California Governor Gavin Newsom signed SB 267 on September 30.

The new law clarifies that neither the initial investment by the tax equity investor nor the flip will trigger a reassessment, but the bill leaves some potential gaps.

Until now, if a tax equity investor started with more than a 50% profits and capital interest, then the flip would trigger a reassessment, assuming the investor did not retain more than a 50% capital interest after the flip. A partner’s “capital interest” is the share of asset value the partner would be distributed if the partnership liquidates.

If the tax equity investor still had more than a 50% capital interest after the flip, then control would transfer when the capital interest dropped below 50% after the flip or, at the latest, when the

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Hydrogen producers would have the option to be paid the cash value of the credits under an IRS refund process with a one-year time lag.

Production tax credits could only be claimed on hydrogen produced after 2021 on facilities placed in service through 2026. The ITC could only be claimed on electrolyzers put in service between 2022 and 2026, but not on costs accrued before 2022 in cases where the electrolyzer was under construction before 2022.

The tax credits will be only a fifth of these rates unless contractors and subcontractors working on the project pay at least “prevailing wages” as determined by the US Department of Labor and use apprentices for at least 10% (increasing to 15%) of total labor hours, both during construction and when making any repairs or alterations during the full period production tax credits are claimed or, where an investment tax credit is claimed, during the five-year period the ITC is subject to recapture. Apprentices are supposed to be used to train more workers for jobs in the green economy.

New domestic content requirements that apply to other federal tax credits will not apply.

The House bill would also allow owners of wind, solar and other renewable energy power plants to use the electricity they generate to make clean hydrogen and still claim separate PTCs on the electricity output, thus doubling up on PTCs for generating

wind or solar electricity and then using the electricity to make green hydrogen. Normally, PTCs can only be claimed if the electricity is sold to an unrelated person.

The bill would also allow solar companies to claim PTCs instead of ITCs on solar projects. Solar projects have not had the option to claim PTCs since 2006.

There will be changes in the House bill, although not necessarily in the proposed hydrogen tax credit, when the bill is taken up in the Senate. Senator Schumer, the Senate Democratic leader, hopes to unveil the Senate bill before Christmas. The Democrats are still two votes short of the votes needed for the bill to pass the Senate. The Senate debate on the bill could slip into early next year.

Hydrogen Hubs

Turning to the infrastructure bill, project developers will be most interested in the \$8 billion the bill authorizes for grants to fund regional clean hydrogen hubs that are supposed to be networks of clean hydrogen producers, potential consumers and connective infrastructure located near each other.

The hubs are meant to show how clean hydrogen can be produced, delivered and used.

Congress hopes the hubs will eventually become the backbone of a national clean hydrogen network and facilitate a clean hydrogen economy.

The goal is to establish at least four regional hubs. The US Department of Energy is supposed to solicit proposals by May 14, 2022. At least four proposals are supposed to be selected within another year after that.

The regional clean hydrogen hubs will be selected using certain criteria in the legislation.

The bill requires the hubs to have feedstock diversity, with at least one hub producing clean hydrogen from fossil fuels, one hub producing clean hydrogen using renewable energy and one hub producing clean hydrogen using nuclear energy.

The second criteria is end-use diversity. One hub should use clean hydrogen for electricity generation, one hub

Developers are focusing on new federal money and tax credits for hydrogen projects.

should use clean hydrogen in the industrial sector, one hub should use hydrogen for heating and one hub should use hydrogen for transportation.

The hubs are to be located in different regions of the country, using resources that are abundant in that region.

At least two hubs are to be in regions that produce natural gas.

Finally, priority will be given to hubs likely to create employment for skilled training and long-term employment to the greatest number of residents of the region.

The grants are to accelerate commercialization, and demonstrate the production, processing, delivery, storage and end-use, of clean hydrogen.

With the various requirements for location, feedstock and end-use, the clean hydrogen hubs provisions are likely to incentivize various types of projects from electrolyzers to natural-gas fueled hydrogen production with carbon sequestration.

There is almost no detail in the bill beyond the general guidelines. DOE will add detail when it solicits proposals.

Electrolysis

The infrastructure bill also authorizes \$1 billion for research and pilot-scale demonstrations of ways to improve the efficiency, increase the durability and reduce the cost of producing clean hydrogen using electrolyzers.

Electrolysis is the process of using electricity to split water into hydrogen and oxygen.

The goal is to reduce the cost of hydrogen produced using electrolyzers to less than \$2 per kilogram of hydrogen by 2026. DOE estimates that the current cost is approximately \$5 to \$6 per kilogram.

The focus will be ways to improve electrolyzers by using new membranes or electrolytes, better component design, and coupling electrolyzers with clean hydrogen storage technology and integrated systems that combine hydrogen production with renewable or nuclear power generation.

Applications can be expected from various types of companies, from those involved in research and development to equipment manufacturers and renewable energy developers. The mention of integrated systems means there should be funding for companies that want to pair large renewable energy projects with an electrolyzer.

Manufacturing and Recycling

The final program with new funding is a clean manufacturing initiative that was allocated \$500 / *continued page 18*

developer exercises its option to buy the investor interest.

If the investor does not get control at any point during the flip transaction, then the flip and exercise of the purchase option by the developer are irrelevant.

The new law says that neither the initial transfer of an interest to a tax equity investor nor the flip in a partnership flip transaction will trigger a reassessment. It does not address what happens when the purchase option is exercised, but in many deals the developer should already be considered to have control as a consequence of the flip so that exercise of the purchase option does not transfer control.

The bill exempts the solar equipment, but not the underlying site on which the solar project sits from reassessment if there is a change in control of the site.

The bill can be used to shield only one partnership flip transaction on any project from reassessment. This should not be an issue unless the “Build Back Better” bill giving solar projects the option to claim production tax credits on the electricity output for 10 years is enacted. New tax equity investors sometimes replace the original investors in partnership flip deals before the full 10 years of production tax credits have run. Care would have to be taken to ensure that the new investor merely steps into the shoes of the original investor rather than enters into a new flip transaction.

There is more than one way to put a partnership flip transaction in place. One approach is for the tax equity investor to buy an interest in the project company from the developer. The new law defines partnership flip transactions that will not trigger reassessment as transactions in which the tax equity investor makes a capital contribution to the partnership in exchange for an interest. The state will have to decide whether the relief applies to “purchase model” flips where the investor buys and interest from the developer.

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million for grants, contracts and cooperative agreements for research and pilot-scale demonstrations to advance new clean hydrogen equipment manufacturing and clean hydrogen technology reuse and recycling.

Part of the focus will be on ways to improve the manufacturing process and use of resources. Priority will be given to the use of domestic supply chains and nonhazardous materials and location in economically distressed areas of major natural gas-producing regions.

The remaining focus will be on reuse and recycling, with priority given to applicants who can recover raw materials from clean hydrogen technology components, minimize environmental impacts, address barriers to commercialization and develop alternative materials.

Other Provisions

The infrastructure bill also includes a few other important hydrogen-related sections.

First, “clean hydrogen” will be defined differently for purposes of the spending provisions than for tax credits. For spending, the term means hydrogen produced with a carbon intensity of no more than two kilograms of carbon dioxide-equivalent per kilogram of hydrogen produced. This standard is to be reviewed, and possibly adjusted, in five years.

The bill also directs the 17 national energy laboratories under DOE to work together to carry out the hydrogen programs and coordinate with other institutions, such as colleges and universities, research institutes and industrial research units.

The bill directs DOE to develop a technologically and economically feasible national clean hydrogen strategy and roadmap, which is to be updated every three years.

The strategy and roadmap will set US goals by certain dates for hydrogen output, suggest a strategy for clean hydrogen production from various resources (including natural gas, coal, renewables, nuclear and biomass) and identify barriers to transitioning to a clean hydrogen economy.

While no funds are directly allocated to the development of the strategy and roadmap, the establishment of a roadmap could help determine how quickly the nation transitions to a hydrogen economy (if at all). ©

Buying American for Infrastructure

by Kenneth W. Hansen and Kevan Christensen, in Washington

“Buy America” provisions in the new \$1.2 trillion infrastructure plan enacted in November may require that any iron, steel, manufactured products and construction materials used in a domestic infrastructure project that receives federal government funding be produced in the United States.

Or they may not.

The scope of the new Buy America restrictions remains under review by the Office of Management and Budget and the affected agencies.

The Buy America requirement appears to apply both to infrastructure programs that previously had similar or less stringent Buy America requirements and to those that had no such requirements.

Consequently, the impact of the provisions varies across programs, from low or no impact in the case of programs that were already subject to similar requirements (such as federal funding for “public works”), to a potentially significant impact in the case of programs that had less restrictive Buy America requirements (such as TIFIA for transportation infrastructure and WIFIA for water infrastructure), to a substantial impact in the case of programs previously not subject to such requirements at all (such as the Department of Energy’s loan and loan guarantee programs).

Affected Projects

The crux of the Buy America requirement is in section 70914 of the new law. It reads as follows:

Not later than 180 days after the date of enactment of this Act, the head of each Federal agency shall ensure that none of the funds made available for a Federal financial assistance program for infrastructure, including each deficient program, may be obligated for a project unless *all of the iron, steel, manufactured products, and construction materials used in the project are produced in the United States.* (Emphasis added.)

A “deficient program” is any federal spending program that does not already impose the same Buy America requirement as

in the new infrastructure plan.

The Buy America requirement will be subject to common sense waivers and exceptions.

Substantial portions of the new infrastructure law are devoted to a process for reviewing existing federal financial assistance programs for their “domestic content procurement preferences” with the goal of bringing them up to the new requirement.

For instance, borrowers from the TIFIA program run by the Department of Transportation already are required to buy iron, steel and manufactured products from US suppliers. The new law expands that requirement to add construction materials (except for cement, which has been carved out). The WIFIA program run by the Environmental Protection Agency for financing water infrastructure projects already requires use of US-produced iron and steel, but it now appears that manufactured products and construction materials may also need to be domestically sourced.

The new requirement applies to all “infrastructure” projects that receive federal support. Infrastructure is broadly defined and means

at a minimum, the structures, facilities, and equipment for, *in the United States* — (A) roads, highways, and bridges; (B) public transportation; (C) dams, ports, harbors, and other maritime facilities; (D) intercity passenger and freight railroads; (E) freight and intermodal facilities; (F) airports; (G) water systems, including drinking water and wastewater systems; (H) *electrical transmission facilities and systems*; (I) *utilities*; (J) broadband infrastructure; and (K) buildings and real property. (Emphasis added.)

New transmission lines and other “utility” projects that receive federal support are covered. Thus, a utility project or transmission line that receives a federal grant is covered.

However, merely benefiting from federal tax credits will not cause a project to be covered, and it does not appear that a project whose owners receive a direct cash payment in place of tax credits will be covered, either, inasmuch as there are separate domestic content requirements that would apply in the build-back-better plan to projects receiving direct cash payments, but the Office and Management Budget will have to make this clear.

The reference to “in the United States” suggests that infrastructure projects located overseas that might be supported by the US development finance programs / *continued page 20*

The new law also defines a partnership flip transaction to which the relief applies as one in which the developer will obtain a majority profits and capital interest on the flip date. This may not always occur.

“PUBLIC UTILITY PROPERTY” questions continue to take up IRS time.

The issue is whether an investment tax credit and accelerated depreciation can be claimed on solar and solar-plus-storage projects in which regulated utilities have a direct or indirect ownership interest.

The IRS said in a private letter ruling made public in late November that a particular utility-scale solar project will not be “public utility property” despite being owned by a partnership in which a regulated electric and gas utility is a partner.

The utility signed a build-transfer agreement with an independent developer to buy the special-purpose project company that owns the project once the project reaches mechanical completion near the end of construction.

The utility plans to resell the project company immediately to a partnership in which it is a partner.

The partnership will sell the electricity generated to the utility under a power purchase agreement. The utility will then resell the electricity into the local grid and buy back from the grid what it needs to supply its ratepayers.

The utility plans to put the circled cash that it contributes to the partnership so that the partnership can buy the project company, and that the utility then receives back as purchase price for the project company, into its rate base, allowing it to earn a return on the amount. It may have been able to put the full purchase price under the build-transfer agreement into rate base had it retained the project directly.

A solar project is “public utility property” if the rates at which / *continued page 21*

Buy America

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(such as the United States International Development Finance Corporation or the Millennium Challenge Corporation) are not infrastructure for this purpose and, therefore, are not subject to its Buy America requirement — which makes sense since otherwise every overseas project would require a waiver.

Importantly for energy project developers, whether power plants are excluded from the definition of “infrastructure” turns on what was intended when Congress said structures, facilities and equipment for “utilities” are covered.

Federal financing for energy projects not falling under the headings transmission or utilities, such as energy efficiency projects and loans under the DOE advanced technology vehicle manufacturing program, would appear to be beyond the scope of the new requirement.

The intended scope of the Buy America requirement is further clarified with definitions of, among other terms, “domestic content procurement preference” and “Federal financial assistance” — but, again, not with perfect clarity.

“Federal financial assistance,” which brings the Buy America requirement into play for infrastructure projects, has the same meaning as in existing “Uniform Guidance” for federal awards that can be found on the OMB website.

The term includes assorted government transfers, such as grants, direct appropriations and non-cash contributions or donations of property.

Loans and Loan Guarantees

Whether the term covers federal loans or loan guarantees is unclear.

The definition of “Federal financial assistance” does not mention loans or loan guarantees, although it ends with “other financial assistance” — but that is qualified by an exception for “assistance listed in paragraph (2) of this definition.” That paragraph (2) lists both loans and loan guarantees (as well as insurance and interest subsidies), but qualifies that list by saying it is only for purposes of “§200.203 and subpart F of this part” which have to do with public notices and federal audits, respectively. If federal financial assistance includes loans and guarantees only for those purposes, then the term does not include loans or guarantees for other purposes. It is thus tempting to infer that

the Buy America provisions do not apply to federal loans or guarantees.

However, the definition has a further element labeled “Inclusion” that says:

The term “Federal financial assistance” includes all expenditures by a Federal agency to a non-Federal entity for an infrastructure project

(excluding federal expenditures related to disasters and emergency responses). This could be read to override the exclusion of loans and guarantees from federal financial assistance. Or possibly not.

The clause applies only to “expenditures” by Federal agencies. The OMB Uniform Guidance defines “expenditures” as “charges made by a non-Federal entity to a project or program for which a Federal award was received” — which is not particularly helpful one way or the other.

Disbursements of direct and guaranteed loans are not expenditures in the usual sense of spending money. Direct loan disbursements come with a repayment obligation. Disbursements by private lenders of federally-guaranteed loans involve no expenditure of federal funds. The logic that drove the Federal Credit Reform Act of 1990 was that both sorts of disbursements — of direct and guaranteed loans — ultimately impose the same cost to the government: the potential loss corresponding to the credit risk of the loan. That act requires all federal credit programs to prepay that projected loss by depositing the estimated amount (the so-called “credit subsidy cost”) into an account at the US Treasury.

It is difficult to see how that deposited amount, really a loan loss reserve, could be deemed to be a federal “expenditure.” If loans and guarantees are not federal expenditures, then the “Inclusion” clause in the definition of “Federal financial assistance” would not bring federal loan and guarantee programs within the scope of the Buy America provisions.

On the other hand, a broad exclusion of federal direct and guaranteed loan programs would be surprising since several such programs are explicitly mentioned in the new law as subject to a review to identify deficient programs, presumably with the goal of bolstering those programs’ Buy America requirements.

Whether the new Buy America requirement applies to existing federal loan and loan guarantee programs is currently under review at OMB.

Waivers

The beneficiaries of federal financing can seek waivers of the US sourcing requirement based on public interest, practicality (or impossibility) or cost. Specifically, the new law provides the following:

The head of a Federal agency that applies a domestic content procurement preference under this section may waive the application of that preference in any case in which the head of the Federal agency finds that —

- (1) applying the domestic content procurement preference would be inconsistent with the public interest;
- (2) types of iron, steel, manufactured products, or construction materials are not produced in the United States in sufficient and reasonably available quantities or of a satisfactory quality; or
- (3) the inclusion of iron, steel, manufactured products, or construction materials produced in the United States will increase the cost of the overall project by more than 25 percent.

The infrastructure bill requires projects receiving federal funding to use iron, steel, manufactured products and construction materials made in the United States.

The “public interest” grounds for a waiver mirror similar justifications found in other Buy America laws. The new law addresses potential uncertainties in determining when a Buy America provision is “inconsistent with the public interest” by requiring, in section 70921, that OMB produce guidelines to help federal agencies determine when purchasing

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electricity is sold are established or approved by a regulatory body on a rate-of-return or cost-of-service basis.

If a project is public utility property, then an investment tax credit and accelerated depreciation become harder in theory to claim. Such tax benefits cannot be claimed on any project where a public utility commission requires the benefits to be passed through to ratepayers more quickly than under a “normalization” method of accounting.

The IRS said the project in the ruling is not public utility property because the electricity will be sold by the partnership to the utility at a negotiated rate rather than a price set by a public utility commission based on a permitted rate of return or cost of service for the utility.

The IRS has confirmed in multiple private letter rulings to utilities over the last three years that projects owned indirectly by regulated utilities through partnerships are not public utility property if the electricity is sold for a negotiated rate. (For more details, see “Utility Tax Equity Partnerships” in the August 2021 *NewsWire*, “Public Utility Property: More IRS Rulings” in the December 2020 *NewsWire*, “Solar Projects and ‘Public Utility Property,’” in the October 2020 *NewsWire*, and “Utility Tax Equity Structures” in the December 2019 *NewsWire*.)

The latest ruling is Private Letter Ruling 202140014.

It is unclear why the IRS has not issued a general revenue ruling by now to the same effect on which all utilities can rely as a labor-saving measure.

None of the rulings addresses another key issue.

Partnerships that own solar projects normally run a net loss for tax purposes for the first three years due to accelerated depreciation on such projects. A partnership that sells electricity to a partner may not be able to claim any net loss

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Buy America

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American materials may be inconsistent with the public interest.

OMB has been directed to minimize waivers that result in a decrease in employment in the United States. Section 70937(c) requires any agency granting a waiver based on public interest now to provide a “detailed written statement” explaining why the waiver is in the public interest.

The second waiver justification — when the materials are not produced in adequate quantities or to satisfactory quality in the United States — also matches some existing Buy American provisions.

The regulations implementing the existing Buy American Act authorize an agency contracting officer to make an individual determination that an item is not available in adequate quantity or quality (per 48 CFR § 25.103(b)(2)). However, under section 70937(d) of the new law, an agency seeking to grant a non-availability waiver must now provide “an explanation of the procurement official’s efforts to procure a product from a domestic source” and the reasons why the product was not available, and post the explanation on a public website. Under the regulations implementing the existing Buy American Act, non-availability determinations that have been made for specific items are published at least once every five years in the Code of Federal Regulations.

The third waiver justification is for cost. An exception to the Buy American requirements is available if using materials produced in the United States will increase the project’s overall cost by more than 25%. Section 70937(c) of the new law requires that agencies providing a waiver based on cost publish “a comparison of the cost of the domestic product to the cost of the foreign product or a comparison of the overall cost of the project with domestic products to the overall cost of the project with foreign origin products or services.”

For each of these waiver types, the new law requires an agency seeking to waive an otherwise applicable Buy America requirement to submit a request to the General Services Administration, which must publish the request on a newly established BuyAmerican.gov website and keep the request open for public comment for at least 15 days. The focus is on increasing transparency around when and how waivers are granted as a means to

limit inappropriate waivers. However, there is an exception for an “an urgent contracting need in an unforeseen and exigent circumstance.”

The new law establishes a new position of Made in America director within OMB, with various reporting and compliance roles and the responsibility to implement procedures to review waiver requests from agencies.

An implied waiver also exists wherever imposition of the Buy America requirement would not be “consistent with United States obligations under international agreements.”

The new law directs the Commerce Department, United States Trade Representative and OMB, by April 14, 2022, and in a publicly available report, to assess “the impacts of all United States free trade agreements, the World Trade Organization Agreement on Government Procurement, and Federal permitting processes on the operation of Buy America laws, including their impacts on the implementation of domestic procurement preferences.”

A Work in Progress

The new Buy America requirement envisions being rolled out over time, with agency heads having until January 14, 2022 to notify OMB and Congress of “each Federal financial assistance program for infrastructure” administered by their agencies.

The Buy America obligation becomes effective on May 14, 2022.

OMB has until that same deadline to “define the term ‘all manufacturing processes’ in the case of construction materials.” OMB has until November 14, 2022 to “promulgate final regulations or other policy or management guidance, as appropriate, to standardize and simplify how Federal agencies comply with, report on, and enforce the Buy American Act.”

That leaves somewhat open what happens in the meantime.

Agencies may continue current practices until OMB provides implementing clarifications. Others may apply their best guesses given the statutory language. There may be a risk that processing of financing applications will slow until the new rules have been clarified. Among those pending clarifications is whether, or to what extent, the new Buy America enhancements will apply to federal loans and guarantees supporting the private development of energy infrastructure. In any event, sponsors with projects under consideration by affected federal financing programs should keep an eye out for developments. ©

Infrastructure Bill and Transmission

by Robert Shapiro, in Washington

The \$1.2 trillion infrastructure bill that President Biden signed into law in November moves the needle in favor of enhancing regional transmission construction, but it is not expected to have a material effect on the pressing or long-term need for additional transmission capacity to facilitate the transition from fossil fuel to renewable energy.

The bill makes it a little easier to override a state's opposition to permitting an interstate line within its borders.

It also permits the US Department of Energy to provide relatively low-dollar grants and to invest in, finance or contract for new interstate transmission capacity and the hardening of the transmission grid.

Meanwhile, the Federal Energy Regulatory Commission is moving separately to try to boost transmission capacity on a regional basis and address how the costs of new capacity additions are borne by interested parties, and the RTOs that run regional sections of the US electricity grid are taking steps to deal with bloated interconnection queues.

FERC Siting Authority

Unlike the Natural Gas Act, the Federal Power Act does not give FERC authority to issue a certificate to a utility that would allow it to use federal eminent domain power to push through a new transmission line.

The states retain the right to approve the siting of transmission lines. Therefore any state can stifle construction of a transmission line that would connect to the interstate grid and move electricity to customers in other states.

In 2005, Congress added a provision to the Federal Power Act that directed the Department of Energy, in consultation with the states, to identify certain "national interest corridors" with constrained transmission capacity. If a transmitting utility applied to a state commission for a certificate to construct a new transmission line and the state commission failed to act within one year, then FERC could issue a permit approving the line and allowing use of eminent domain if it determined that the new line would significantly reduce transmission congestion. This has become known as FERC's "backstop" authority.

This backstop authority has never / continued page 26

for tax purposes. Section 707(b) of the US tax code bars partnerships from claiming losses on sales of property to affiliates. Electricity is considered property for this purpose.

The IRS is studying section 707(b).

It put the issue on a priority guidance plan in October listing areas in which it hopes to issue guidance by next June 30. It is not unusual to see items on the priority guidance plan carried over from year to year until the IRS can get to them or even dropped without guidance having been issued in cases where the urgency wanes in relation to other subjects requiring guidance.

Many partnerships avoid the issue by structuring the contract with the affiliate as a swap or hedge or an agency arrangement where the affiliate places the power in the market for the partnership.

SOME SOLAR OUTPUT FORECASTS are too optimistic.

Projects greater than one megawatt in size generated 5% to 13% less output during the period 2011 through 2020 than predicted by P50 output forecasts, according to kWh Analytics in its latest "Solar Generation Index" report in late October.

The performance was worse in southern states than in northern states. Projects in the Pacific Northwest performed better than expected. Those in the southwest showed the biggest gaps.

The latest numbers are based on 350 operating solar projects with a total capacity or more than 10,000 megawatts and performance over the period 2011 through 2020. The calculations are weather adjusted.

Output has become noticeably worse compared to forecasts since 2016.

AN IOWA homeowners' association is a water utility and must collect a utility excise tax on water service, the state / continued page 25

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been used successfully. A federal appeals court in 2009 rejected FERC's view that a state's denial of a certificate within one year to build the new line equated to a "failure to act" under the new Federal Power Act provision. Thus, if a state formally rejected a new line proposal — as opposed to merely sitting on the request — FERC could not override the rejection.

The market interpreted this as a barrier to an effective federal eminent domain backstop authority. No transmitting utility has sought to use this authority, and the Department of Energy never identified any additional national-interest corridors beyond two that it had already designated.

The new Infrastructure bill amends the Federal Power Act to make clear that FERC has backstop authority to use federal eminent domain in national interest corridors even in cases where a state formally rejects a proposed new line as well as merely fails to act on the request, or where the state adds conditions to its approval that would not permit significant reduction in transmission capacity constraints.

DOE now has \$10 billion to lend to help with construction of new high-voltage interstate transmission lines.

The Department of Energy is to make national interest corridor determinations every three years.

The new law makes clear that a national-interest determination can include a finding that the designation would enhance the ability of facilities that generate or transmit firm or intermittent energy to connect to the electricity grid or would be in the interest of national energy policy.

It remains to be seen whether DOE will designate national interest corridors based on projected paths, for example, where there may be no current transmission but where there is

potential for substantial wind and solar capacity development and a likely demand for this potential energy in distant load centers.

While this modification to permit FERC's backstop siting and eminent domain authority is an improvement from the existing law, the path to permitting and eminent domain will still be a long and complicated process.

DOE still has to do a study in consultation with affected states and Indian tribes and make numerous findings before designating a national interest corridor. Then a transmitting utility has to ask for a permit from the affected state, which has a year to act. After a rejection or inaction by the state, the transmitting utility has to apply to FERC for a construction permit containing a right of federal eminent domain by, among other things, demonstrating to FERC that it has made a good faith, though unsuccessful, effort to engage with landholders and other stakeholder early in the permitting process.

Transmission Construction Facilitation

Perhaps the most significant transmission-related component of the infrastructure bill relates to a new "transmission facilitation program."

Under this program, "eligible projects" consisting of new high-voltage interstate transmission lines capable of transmitting at least 1,000 megawatts or upgrades to existing interstate transmission lines capable of transmitting at least 500 megawatts, and the related non-generating facilities, are eligible for a range of financing enhancements from the Department of Energy. The US Treasury is authorized to lend up to \$10 billion to DOE to be used to finance eligible projects, with no more than \$2.5 billion to be funded in outstanding repayable balances at any one time.

DOE can either enter into a transmission capacity contract with an eligible project in order to facilitate completion of the project, make a loan to an eligible project for the costs of carrying out the project, or participate in designing, developing, construction, operation, maintenance or ownership of the eligible project.

When deciding to enter into a transmission capacity contract, DOE can either make fair market value payments for the use for

the transmission capacity, with the amount to be paid on a scheduled basis or as a single payment. DOE cannot contract for more than 50% of the total transmission capacity of an eligible project. DOE is expected to become an “anchor” customer for new lines for which it contracts for capacity, thereby encouraging others to use the remaining capacity and facilitating private financing of the new line.

DOE has been directed to terminate the capacity contract as soon as practical after determining that enough other projects have signed up for transmission capacity to make the new line financeable. Accordingly, at some point DOE can be expected to sell its contracted capacity and recover its investment.

The other way DOE can serve as a catalyst for new transmission lines is to make loans. The amounts loaned are to be recovered from transmission owners through rates they charge for use of the new transmission capacity.

Given the time it will take for DOE to establish a “transmission facilitation program” and the time it has traditionally taken to complete the paperwork and authorization for DOE lending, even if successfully implemented, this program is unlikely to be effectively used in the very near term. It is a start. However, the dollar limitation on its use will not by itself meet the pressing need for new and upgraded high-voltage transmission, which many experts have projected in the hundreds of billion dollars over the next 10 to 20 years in order to approach the massive amounts of transmission needed to bring renewable power to the places that need the power to reduce or eliminate their carbon footprints.

Grid Resiliency Grants

DOE, after implementing the program by May 14, 2022, is authorized to issue up to \$5 billion in grants from 2022 through 2026 to “eligible entities” directly and to states and Indian tribes for the benefit of eligible entities in their respective jurisdictions for technologies and equipment to “harden” the transmission grid to avoid “disruptive events,” including wildfires.

The grants can be used for all of the following:

- (A) weatherization technologies and equipment;
 - (B) fire-resistant technologies and fire prevention systems;
 - (C) monitoring and control technologies;
 - (D) the undergrounding of electrical equipment;
 - (E) utility pole management;
 - (F) the relocation of power lines or the reconductoring of power lines with low-sag, advanced conductors;
 - (G) vegetation and
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tax department said.

The decision may have implications for micro-grids.

Iowa collects a 6% excise tax on water utilities on revenue from providing water service to customers. The tax only applies when water is “sold for a separately itemized price” or “when the price of the water service is identifiable from an invoice, bill, catalog, price list, rate card, receipt, agreement, or other similar document.”

A homeowners’ association owns wells and pipes and supplies water to the 58 houses in a housing subdivision. Homeowners pay fixed annual dues that cover road maintenance, snow removal, lawn care, maintenance of common areas and water service. The charges are not itemized. However, the association prepares an annual report that shows how the dues money it collected was used during the year.

The association asked for a declaratory order that it is not a water utility required to collect the tax.

The Iowa Department of Revenue said in the declaratory order that the association is a water utility and must collect the tax because the share of the homeowner dues that pay for water service is reported in the annual report. It said the fact that the water service charges are an incidental part of the annual dues is irrelevant.

The order is *In the Matter of Spring Valley Homeowners’ Association*. The association received the order in July, but the order was not made public until late summer.

THE UNITED STATES moved one step closer in December to requiring US companies to file reports with the US Treasury disclosing their beneficial owners.

Reports will also have to be filed by foreign companies authorized to do business in the United States.

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fuel-load management; (H) the use or construction of distributed energy resources for enhancing system adaptive capacity during disruptive events, like microgrids and underground cabling.

Eligible entities include grid operators, storage operators, generators and transmission owners, distribution companies and fuel suppliers.

DOE can act as a catalyst for new transmission lines by signing up as an anchor customer.

Grants to individual entities cannot exceed the amount spent by the entity in the past three years to reduce the consequences of disruptive events.

DOE is supposed to prioritize projects that it believes will produce the greatest community benefit.

At least 30% of the available grant money must go to small utilities that sell fewer than four million megawatt hours per year.

Each grant awarded to a state or Indian tribe – to make grants, in turn, to eligible entities within their jurisdictions — is subject to a 15% matching requirement.

The grants cannot be used to construct a new generating facility or large-scale battery storage facility unless it is used to enhance system adaptive capacity during disruptive events.

DOE is supposed to award 50% of the grants directly to eligible entities and 50% to states and Indian tribes. Except for small utilities, there is a 100% matching requirement for an eligible entity that receives the grant.

Research Funding

The legislation also authorizes up to \$5 billion during the period 2022 through 2026 to be given to state and local governments, Indian tribes and public utility commissions for research, development and demonstration projects to develop innovative approaches to transmission, storage and distribution infrastructure to harden and enhance resilience and reliability.

The bill also authorizes up to \$1 billion over the same period to improve reliability of the grid and electricity supply in rural areas and up to another \$1 billion to help with such things as siting of distribution lines, reducing greenhouse gas emissions

from generating facilities and developing microgrids in rural and remote areas.

Funding will be subject to a cost-sharing mechanism of about 20% of the total cost of the activity. The government will pay the remaining share of the cost.

FERC Efforts

Apart from the infrastructure legislation, FERC is moving independently to encourage faster construction of regional

transmission capacity over the longer term.

FERC has long recognized that the historic structure of the interstate transmission system was not conducive to regional planning in competitive markets. This was due mainly to the historic vertical integration of the utility industry and the construction of legacy plants with transmission facilities to match the delivery of their output to the utility's franchised load.

FERC made a major effort to stimulate regional construction of needed regional transmission capacity with Order 1000 in 2011, which required regional transmission planning for regional transmission organizations or RTOs and regional cooperation by utilities outside of RTOs. It also required stakeholder agreement for the needed regional transmission capacity increases, competitive solicitations to select the entities that would construct that capacity, and a general principle to allocate costs tied to the benefits received from the new transmission capacity.

Notwithstanding the goals of Order 1000, FERC recognized that very little regional transmission capacity was actually being built over the past 10 years.

While FERC recognized that it needed to rethink its decision and provide for methods that would accelerate construction of new regional transmission and also rethink generation interconnection procedures, including interconnection queues and network upgrade cost allocations, FERC indicated that it did not have a sufficient understanding of the obstacles or the solutions to propose a new rule to resolve the delays.

Therefore, in July 2021, FERC issued an “advanced notice of proposed rulemaking” or ANOPR that identified many of the problems and asked the market to comment on the problems and possible solutions. Since that time, FERC has received volumes of comments from the gamut of interested parties in the power markets, and it has held technical conferences on the issues as well.

This should lead to issuance of a “notice of proposed rulemaking” or NOPR containing the elements that the commission believes would provide a better approach to planning for new transmission capacity, selecting the entities to construct the capacity, streamline the completion of that construction as well as facilitate interconnection, and properly allocate the costs to those who are most likely to benefit from the new transmission capacity.

But even if FERC is able to issue a NOPR in the near term taking into account the results of the ANOPR proceeding, the NOPR will be subject to a period for comments by interested parties, followed by a final rule that could modify the NOPR proposals. And the various RTOs and independent utilities affected by a final rule would be given a period of time to modify their procedures before actually having to comply with the final rule.

Consequently, even if the new rule is issued and turns out to contain more appropriate mechanisms to facilitate construction of regional transmission capacity and interconnection construction, its impacts will not be felt in the near term.

RTO Interconnection

In the meantime, individual projects, whether renewable, storage or other technology, are having to wait in line for interconnection studies to determine whether their interconnections will require “network updates” to the transmission grid.

Neither the new infrastructure initiative plan nor the FERC re-evaluation of the regional planning process will do anything to speed interconnection for projects that are currently in line or planning to file for interconnection in the near future.

The existing policies of the various RTOs and individual utilities that are not members of RTOs will remain in place until they

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Existing entities must file reports within one year after an effective date that has still not been announced. FINCen, a bureau within the US Treasury that collects information about financial transactions in order to fight financial crimes, terrorist financing and money laundering, must finish building out a new computer system first to handle the data.

In the meantime, it issued 188 pages of proposed regulations and commentary in early December on the new reporting obligations.

New companies formed after the effective date will have to file reports within 14 days after formation.

An additional report will have to be filed within 30 days after any change in the information reported.

The reports must disclose the name, date of birth, residential address and a passport number, driver’s license or other unique identification number of every beneficial owner owning at least 25% of the company or having “substantial control.” Senior officers in the company are considered to have substantial control. Convertible debt instruments, options and warrants are considered ownership, as are debt instruments that allow the holder to exercise similar rights to an equity holder.

The same information must also be provided for the person who formed the company or directed that it be formed.

The company must also report all names under which it does business, its business address and a US taxpayer identification number or, if it does not have one, a Dun & Bradstreet DUNS number or LEI (legal entity identification number).

More than two million corporations and limited liability companies are formed every year in the United States.

There are 23 types of companies from whom reports will not be required. The exceptions include publicly-traded companies, large operating / *continued page 31*

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choose to amend their procedures and file them at FERC and FERC reviews them.

However, nearly all of the RTOS and utilities unaffiliated with RTOS are moving to modify their interconnection procedures to weed out from the avalanche of interconnection requests projects that are not viable and avoid restudying projects and clusters of projects to determine the network upgrade requirements on their systems and in the region for the foreseeable future. This will be an ever evolving process.

It remains to be seen whether the efforts by FERC to revise the regional transmission planning process will eventually work their way into or alongside these interconnection modification efforts to speed up the entry of more carbon neutral projects into the transmission grid. The new transmission component of the infrastructure bill will be only a minor step toward the major transmission expansion required over the next decade to meet the rapidly expanding needs for a cleaner world.

It should be noted that since ERCOT is not part of the interstate grid, the expansion of the backbone transmission system in Texas to accommodate more carbon-neutral projects would be a matter for the Public Utility Commission of Texas and ERCOT, not FERC, to address. However, the financial support from the federal government extends to Texas power sector assets as well. ©

New Money and Standards for EV Charging Stations

by Jake Falk and Deanne Barrow, in Washington

The \$1.2 trillion infrastructure bill that President Biden signed into law in November includes an unprecedented federal investment in electric vehicle charging infrastructure.

The law authorizes \$7.5 billion in federal spending on two new programs for such infrastructure.

The money will go to state and local governments, which are expected to contract, in turn, with private companies. The contracting structures may vary from state to state, but will create opportunities for project developers and equipment manufacturers.

The federal investment is supposed to serve as a down payment that will marshal additional state, local and private-sector capital behind a national EV charging network. Some industry sources estimate that the United States needs \$50 billion to develop an EV charging network fully.

The first program is a \$5 billion “national electric vehicle formula program” that will allocate funds to states using certain pre-determined formulas based on state plans for building out EV charging infrastructure in designated “alternative fuel corridors.”

The second program, the “grants for charging and fueling infrastructure program,” is a \$2.5 billion discretionary grant program to be run through the US Department of Transportation. Grants will be awarded to state and local governments not only for EV charging infrastructure but also for hydrogen, propane and natural gas fueling infrastructure.

The law also imposes federal standards on EV charging stations that are paid for partly with federal funds.

Some states, such as California and New York, are already developing or supporting EV charging infrastructure networks. These states may be in a position to move more quickly to tap into the new federal spending. However, the promise of federal funding should help spur investment in EV charging infrastructure and development of strategic plans for state-wide EV charging station networks in other states.

EV Charging Formula Grants

The \$5 billion under the first program will be distributed to states using pre-determined statutory formulas.

The money may be used to pay for acquisition, installation, operation and maintenance of EV charging infrastructure and data sharing. The federal share of the cost of projects funded under the program is 80%.

States may use money to contract with private companies, in which case the remaining 20% of the cost may come from the private sector.

States must submit plans to the US Department of Transportation describing how they will use the grant money. The plans will be made public together with a DOT assessment of how the plans will help build out a national EV charging network. Funded infrastructure must be in designated “alternative fuel corridors” and must be available for use by the general public. The designation of alternative fuel corridors and other federal standards for EV charging infrastructure are discussed below.

DOT has until February 13, 2022 to issue program guidance.

The guidance will help states develop plans that are aligned with federal objectives for EV charging infrastructure, and will take into account, among other things, the distance between publicly available EV charging infrastructure, the proximity of existing travel centers, fuel retailers and small businesses to the EV charging infrastructure, and the availability of EV charging infrastructure in rural corridors and under-served or disadvantaged communities.

The guidance will also take into account connections of the EV charging infrastructure to the electric grid, vehicle to grid integration, alignment with electric distribution interconnection processes and plans for use of renewable energy and storage.

The government will be looking for ways to encourage private and public-private investments and proper operation and maintenance of the infrastructure and to avoid creating stranded assets. It will take into account existing programs and incentives and will be focused on meeting current and anticipated market demand.

Refueling Infrastructure Grants

The law authorizes \$2.5 billion for a new discretionary grant program to deploy publicly accessible EV charging stations along designated alternative fuel corridors and in certain other locations.

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companies, utilities, insurance companies, banks, accounting firms, tax-exempt entities and registered broker-dealers.

Large operating companies are companies that have a real operating office and more than 20 full-time employees in the United States and that filed a federal income tax return the previous year reporting more than \$5 million in gross income.

— contributed by Keith Martin in Washington

EV Infrastructure

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The \$2.5 billion can also be used for the deployment of hydrogen, propane and natural gas fueling infrastructure along the same corridors.

The money will be awarded on a competitive basis, rather than by formula, unlike the \$5 billion awarded to states under the national electric vehicle formula program.

The grants will be made to state and local governments and certain other non-federal public entities. Funds may only be used to contract with private companies for acquisition and installation of publicly accessible charging or fueling infrastructure that is directly related to charging or fueling a motor vehicle.

Program funds may be used to help with operation and maintenance costs for the first five years after installation in cases where the charging or fueling stations are not expected to generate enough revenue to cover such costs.

For infrastructure that is forecasted to generate excess revenue once it is operational, the private company may be asked to enter into a revenue-sharing agreement with the state or local government that is the grant recipient. The state or local government may then use the shared revenue to fund other eligible projects.

State and local governments will be given \$5 billion to hire private companies to install electric vehicle charging stations.

The federal share of the cost of a project funded under the program is 80%, and the private company is required to pay the non-federal share.

The law directs DOT to have the \$2.5 billion discretionary grant program open for business by November 15, 2022.

A number of important factors will need to be addressed in applications submitted by state and local governments, and

public officials may look to private companies interested in partnering with them to provide some of this information for their applications.

Applicants will need to describe how the proposed investment considers public accessibility to the charging or fueling infrastructure, including with respect to the connector types, public information on real-time availability and payment methods that ensure secure, convenient, fair and equal access.

The state or local government's collaborative engagement with stakeholders will be an important factor, including engagement to foster public-private or private investment in EV charging or fueling infrastructure, to protect personal privacy and ensure cybersecurity, and to ensure that a properly trained workforce is available for such infrastructure.

The location of the EV charging or fueling infrastructure will be important as will availability of onsite amenities for vehicle operators, compliance with the Americans with Disabilities Act, height and fueling capacity requirements for facilities that charge or refuel tractor-trailer trucks and other large vehicles and geographic distribution to avoid redundancy and fill network gaps.

Applicants will have to describe how the proposed deployment of charging or fueling stations will be affected by future advances in technology and operated and maintained to avoid stranded assets and protect the investment of public funds.

Applications will also have to include an estimate of how much greenhouse gas emissions will be reduced using the "Alternative Fuel Life-Cycle Environmental and Economic Transportation (AFLEET)" tool developed by the Argonne National Laboratory.

DOT will be interested in whether proposals will provide redundancy to meet excess demand and reduce congestion in high-traffic locations. It will

also be interested in proximity to intermodal transfer stations for shipping freight.

Half the funds awarded each year are reserved for "community grants" that target projects in rural areas, low- and moderate-income neighborhoods and communities with a low ratio of private parking spaces to households or a high ratio of multi-unit dwellings to single-family homes.

Individual community grants may not exceed \$15 million and can be used for infrastructure located on public roads or in other publicly accessible locations, such as parking garages or lots in public buildings, schools and parks or in private parking garages that are publicly accessible.

Federal Standards for EV Charging

The infrastructure law imposes two standards that all EV charging infrastructure installed using funds provided under the federal programs must meet.

The first standard is that the infrastructure must provide non-proprietary charging connectors that meet applicable industry safety standards. There are different types of connection interfaces, or plugs, that run on direct current electricity. Three plugs are in widespread use today: combined charging system (CCS), CHAdeMO and Tesla. To access public funds, it appears that the CCS and CHAdeMO connectors would have to be installed at the site, given that Tesla's plug is proprietary and can only be used by Tesla vehicles.

Unlike refueling of internal combustion vehicles, which takes place at gas stations, today most EV charging takes place at home, but the goal of the federal EV programs is to increase the number of public chargers. Since the chargers will be available to the general public, they should be accessible by as large a swath of EV users as possible rather than limited to users of one make of vehicle. In addition, the requirement for non-proprietary chargers could boost competition in the marketplace for chargers.

The second standard is that the charging infrastructure must use payment methods that are available to all members of the public and are not limited by membership to a particular payment provider.

EV charging service providers use different business models. Some of them lock in subscribers to use chargers within a closed network and do not allow payment by debit or credit card, but rather require subscription to a service where the user pays a monthly fee or has a specific account associated with charging. Those sorts of arrangements would probably not meet the standard required for federal funding.

Alternative Fuel Corridor Designation

Another requirement is that any EV charging infrastructure installed with a grant under the \$5 billion formula program must be located along a designated "alternative fuel corridor".

An alternative fuel corridor is a section of the national highway

system that can sustain long-distance travel for electric vehicles and other alternative fuel vehicles such as hydrogen, propane and natural gas.

The US Federal Highway Administration, an agency within the US Department of Transportation, designates national alternative fuel corridors based on nominations from state and local officials. The alternative fuel corridor program was created by statute in 2015. To date, the FHWA has designated EV corridors on approximately 59,000 miles of the national highway system in 48 states plus the District of Columbia. South Dakota and Mississippi are the only states lacking an EV corridor designation.

Leading States For EV Charging

A number of states offer tax credits, rebates and grants to lower the cost of EV charging stations.

California is considered to have some of the most favorable policies in the nation to facilitate electrification of the transportation sector. California Governor Gavin Newsom issued an executive order in September 2020 setting a goal of 100% of in-state sales of new passenger cars and trucks to be zero emission by 2035. Other states have adopted more modest EV sales rules that require automakers to sell more EVs in state. For example, Colorado requires at least 5% of each automaker's new car sales in Colorado to be EVs by 2023.

The California electric vehicle infrastructure project — called CALeVIP — is a statewide initiative administered by the California Energy Commission that offers incentives for installing public EV charging stations. In some cases up to 75% of total project costs can be funded through grants and rebates under CALeVIP, depending on where the chargers are located. More funding is available for charging stations in rural counties and disadvantaged communities. CALeVIP currently has \$149 million in funding from the state and also receives funding from "partner" contributions.

The low-carbon fuel standard, or LCFS, program, which is administered by the California Air Resources Board, was amended in 2018 to allow LCFS credits to be awarded for in-state EV fueling stations. The program is supposed to reduce emissions in the transportation sector by promoting the use of low-carbon fuels like electricity. Owners and operators of EV charging stations can be awarded credits not just for EV charging activity but also for installing chargers, regardless of utilization.

LCFS credits are available for DC fast-charging infrastructure located in California and open to the / continued page 32

EV Infrastructure

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public for charging. Charging equipment at the site must support at least two of the three fast charging connector types: CHAdeMO, CCS and Tesla. “Open to the public” means no obstructions or obstacles exist to prevent drivers from entering the premises, no access cards or personal identification (PIN) codes are required to access the chargers, and no formal or registered equipment training is required for individuals to use the chargers.

Clean fuel programs that incentivize the use of electricity and other low-carbon fuels have also recently been enacted in Oregon and Washington state. Credits can be earned under both the Oregon and Washington programs for installing EV charging stations.

New York legislators have also been mulling enactment of an LCFS program. However, LCFS bills that were introduced in the New York state legislature last year stalled in part due to opposition from environmental groups who argue the program allows polluters to purchase credits instead of switching to cleaner fuels.

New York has several EV charging rebate programs that aim to lower the cost of publically-accessible fast charging stations. The largest program, called the “New York make-ready program,” awards incentives that offset a large portion or, in some cases, all of the infrastructure costs associated with preparing a site for EV charger installation. It was established in July 2020 and is currently funded with \$701 million and will run through 2025. New York has a zero-emission vehicle goal of having 850,000 electric vehicles in use in the state by 2025. ©

LCFS Credits for Renewable Natural Gas

by Chris Psihoules and Emely Toro in Washington, and Caileen Kateri Gamache in Houston

More renewable natural gas projects have come on line in 2021 than in the entire 30-year history of RNG.

The Wall Street Journal predicted that RNG may make up nearly 30% of the total natural gas supply by 2040 compared to less than 1% today. RNG is methane gas from decomposing garbage, cow and hog manure and other organic sources that is cleaned and put into pipelines as a substitute for conventional natural gas.

All signs point to the development of RNG projects picking up significant pace as we enter 2022.

The industry is taking notice. This article provides some of the nitty gritty of monetizing the RNG wave and responds to both lender and developer questions.

State Credits

States and localities are playing the leading role in creating opportunities to monetize RNG.

The Pacific Coast Collaborative — a first of its kind regional agreement among California, Oregon, Washington and British Columbia that aims to reduce greenhouse gas emissions — helped to facilitate state programs such as the California low-carbon fuel standard or “LCFS” and clean fuels programs in Oregon and Washington.

Low-carbon fuel standard programs offer incentives for greener fuels, such as RNG, by awarding tradable credits to suppliers of transportation fuels to encourage them to reduce the carbon intensity of the fuels they supply. Much like the federal government has done for conventional biofuels and advanced biofuels by instituting a renewable fuel standard that requires blending a certain percentage of ethanol or biodiesel into motor vehicle fuels, the development of state low-carbon fuel standards will help unlock the clean fuel market across the United States.

This article focuses on the California LCFS. Other states that have adopted or are considering clean fuel programs have modeled them on the California LCFS.

In 2009, the Oregon Department of Environmental Quality created a standard with the same structure as the California LCFS. The Oregon clean fuels program was fully implemented in 2016 and uses the life-cycle greenhouse gas intensity calculations created or approved for the California LCFS by the California Air Resources Board. Credit prices in Oregon have generally been lower than in California and are currently averaging \$124 per credit.

In May 2021, Washington state enacted HB 1091 enabling the implementation of an LCFS. The initial LCFS goal is to reduce greenhouse gas emissions from transportation fuels by 20% from the 2017 level by the year 2038.

The Washington state LCFS program must go into effect no later than January 1, 2023. The state is easing into it. By 2028, there cannot be more than a 10% carbon intensity reduction requirement unless there are both at least a 15% increase in biofuel production and approved plans for at least 60 million gallons of new biofuel production capacity in Washington state. This LCFS program, along with the California and Oregon programs, will work in conjunction with one another to cover the entire West Coast.

Various other states such as New York, Iowa, Minnesota, New Mexico and Colorado are still debating whether to adopt LCFS programs.

New York considered legislation in 2021 that did not make it to the governor's desk, but advocates plan to try again in 2022. A bill that would have established an LCFS program and set the initial carbon intensity reduction target of 20% for motor vehicle fuels by 2030 did not advance out of committee.

The Iowa governor proposed requiring diesel fuel sold in the state to contain at least 11% biodiesel beginning in 2022. The percentage would have increased to 20% in 2024. A 15% ethanol blending requirement for mixing ethanol in gasoline would have taken effect in 2026. The proposal did not pass in 2021, but may be considered again in 2022.

Minnesota has been considering the use of biofuels and implementation of an LCFS program for some time. The Great Plains Institute, a Minnesota non-profit focused on energy and climate change, helped create an outline for clean fuel standards intended for Midwestern states. A "Future Fuels Act" (HF 2083) was introduced this year in the Minnesota house, but did not pass. The bill would have required a 20% reduction in the carbon intensity of transportation fuels by 2035. Minnesota's largest source of greenhouse gas emissions is the transportation sector. The state set a target in 2007 of reducing transportation-sector

greenhouse gas emissions by 30% by 2025.

A New Mexico bill — SB 11 — that would have adopted an LCFS program similar to the California LCFS failed to pass the state legislature in 2021. The bill would have gone beyond the California program by awarding credits for actions that reduce the carbon intensity in a list of non-transportation sectors as well. The bill proposed a 10% reduction in carbon emissions by 2030 and 28% by 2040.

Colorado concluded a clean fuel standard feasibility study in September 2020 and made the decision not to implement an LCFS program at that time. The proposed program was similar to the California LCFS program. Colorado is focused on reducing greenhouse gas emissions in the transportation sector, including through adoption of lower carbon fuels. Several tools under discussion include advanced biofuels, RNG and hydrogen for aviation and some heavy trucks. Proponents of a clean fuel standard are expected to revisit use of LCFS credits in the near term.

Because the existing state programs and the new programs being contemplated in other states are largely modeled on the California LCFS program, what follows is an overview of how California LCFS credits work and how projects can effectively structure transactions to monetize such credits.

California Overview

California awards LCFS credits to producers of low-carbon fuels. RNG qualifies for credits as long as it is used to replace conventional transportation fuel in California. The RNG does not have to be produced in California or even land there physically. The credits are currently worth around \$150.00 per metric ton of CO₂ reduced.

Petroleum importers, refiners and wholesalers are "obligated parties" who must purchase California LCFS credits to meet carbon-intensity benchmarks set by the California Air Resources Board for the fuel they supply.

Obligated parties supplying transportation fuel in California must file compliance reports each year that verify the number of LCFS credits they purchased from low-carbon fuel producers through formal agreements, over-the-counter agreements (for forward-looking trades and transfers), brokers or in the credit clearance market, which is a CARB-administered market for credits in case of a market shortage.

Each obligated party must reach the carbon-intensity annual benchmark set by CARB. Alternatively, obligated parties can comply with the benchmarks by / continued page 32

LCFS Credits

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physically reducing the carbon intensity of their fuels. An obligated party would do so by blending a low-carbon or renewable fuel with the carbon-intensive fuel to bring the mixture below the annual carbon-intensity benchmark set by CARB.

Owners of RNG projects can earn revenue by being awarded credits and then selling them to obligated parties.

Project Qualification

RNG projects must register with CARB on its LCFS reporting, credit bank and transfer system. The system tracks a fuel pathway certification process as well as the creation and transfers of credits. Obligated parties register on the system.

Each registered entity records its fuel transactions on a quarterly basis and files annual compliance reports. The carbon-intensity value of the fuels that obligated parties supply is determined by the fuel pathway and can be estimated using the CARB life-cycle analysis model (which assesses the greenhouse gas emissions for fuel per unit of transportation energy delivered in the life cycle or pathway of the fuel). Obligated parties also report the energy economy ratio, which is a comparison of miles-per-gallon equivalent between two fuels.

The simplest way to ensure that RNG projects will qualify for LCFS credits in California is to produce RNG that fits in one of the fuel pathways listed in the “lookup table pathways” on the CARB website. The fuel pathways show acceptable ways of producing and then moving RNG to California for ultimate consumption in the California transportation fuel market.

However, other approaches are possible where the owner of an RNG project can demonstrate how its RNG will reduce the carbon intensity of transportation fuels over time. To register a fuel not found in the lookup table pathways, the RNG project may submit a tier 1 (LNG, L-CNG and most RNG pathways) or tier

2 (all other fuels not in the table or tier 1) fuel pathway application on the “alternative fuels portal,” also via the CARB website.

The location where the RNG will be processed to become a natural gas must be registered to determine the carbon intensity score for the pathway. The source, such as a cluster of anaerobic digesters near dairy farms or a landfill, must be registered as an intermediate facility.

Transacting for LCFS Credits

California LCFS credits can be earned by supplying RNG for use as a transportation fuel or by installing RNG refueling infrastructure. (For more detail on how the LCFS program works, see “Financing California Hydrogen Projects Using LCFS Credits” in the December 2020 *NewsWire* and “Virtual Supply Arrangements for Hydrogen” in the June 2021 *NewsWire*.)

In order for an RNG project to qualify for credits, the final offtaker of the RNG must use the fuel in California as transportation fuel. However, virtual arrangements are possible.

Three key contracts are used in RNG projects.

The first is a feedstock supply agreement. In most instances, because the dairy farm or landfill has no use for RNG as transportation fuel, there is a feedstock supply agreement under which a dairy farm, for example, supplies the raw material for making methane. The supplier is usually paid an amount per MMBtu of RNG produced or a fixed price per ton (or equivalent measurement) of the raw input.

The next contract is an interconnection agreement. The RNG project must connect to an interstate gas pipeline so that a pathway to the California transportation fuel market can be established.

The last contract is an offtake agreement for the RNG. The offtake agreement usually comes in one of two forms. It can be a marketing agreement between the RNG project and a middleman who delivers the RNG to a company producing vehicle fuels for the California market, registers the transaction and receives

Q1	Q2	Q3	Q4
“X” therms of RNG injected in the pipeline	“X” therms of RNG attributes can be matched with natural gas supplied and reported in the LCFS for Q1, Q2 or Q3		
Natural gas (therms) dispensed in Q1	Natural gas (therms) dispensed in Q2	Natural gas (therms) dispensed in Q3	
	Data reported for Q1	Data reported for Q2	Data reported for Q3

Source: CARB LCFS Guidance 19-05

LCFS credits. The credits and cash proceeds from sale of the RNG are then transferred back to the RNG project with a fee paid to the marketer.

Alternatively, the RNG project may enter into a fixed-price agreement where the RNG and associated environmental attributes are simply sold to the offtaker. The LCFS credits remain with the offtaker, but the value is factored into the price paid for the RNG.

Many RNG sales generating LCFS credits are virtual transactions.

In such cases, the RNG project sells RNG to an initial offtaker for distribution in the California transportation fuel market with an LCFS profit-sharing mechanism negotiated as part of the commercial agreement. The gas dispensed at the fueling station in California is not the same molecules produced at the RNG project. In fact, the RNG may never physically reach California. However, CARB certifies distribution of RNG via displacement.

How this works is simple: if RNG is produced by an RNG project outside California and injected into an interstate natural gas pipeline, the produced volume must match an amount of compressed natural gas withdrawn for use as a transportation fuel in California. This creates a pathway for California LCFS credits. The credits are then sold to an obligated party or to third parties who wish to purchase California LCFS credits.

At the same time the owner of the RNG project injects the gas into an interstate pipeline, it buys back the same quantity of “brown gas” (conventional natural gas) from the pipeline to resell. It may end up paying the same amount it was paid for the RNG to buy back the brown gas. It then resells the brown gas in the local market or consumes the brown gas onsite.

How to Verify California Transactions

Any RNG injected into a pipeline must maintain evidence of a chain-of-custody by CARB accredited LCFS third parties.

RNG projects can use book-and-claim accounting to keep track of the ownership and transfer of transportation fuel without tracking the physical fuel. Decoupled environmental attributes are used to represent the ownership and transfer of transportation fuel without regard to physical traceability.

The link between proving the energy economy ratio of the injected RNG and natural gas withdrawn at the other end of the pipeline for transportation purposes in California can be demonstrated by providing records of invoices and contracts. The records must show the quantities of RNG produced and injected at one end of the pipeline, the price per unit at which the environmental attributes were sold or purchased and proof that the entity has the exclusive right to claim the attributes.

Book-and-claim accounting is used to report transactions for up to three fiscal quarters for pipeline-injected RNG claimed as a transportation fuel in California. If a quantity of RNG is injected into an interstate pipeline in the first quarter of a given year, the quantity claimed for LCFS reporting must be matched to compressed natural gas dispensed in the California transportation fuel market no later than the end of the third calendar quarter of that year. Once quarter three ends, any unmatched RNG quantities expire for the purpose of LCFS reporting.

Once both the quantity of fuel and the associated LCFS credits are reported in the CARB LCFS data base as having been sold, the LCFS credits are treated as retired and can no longer be sold, transferred or claimed by any entity for any purpose.

Both the RNG project (or middleman acting as the pathway applicant) and fuel reporting entity must submit an attestation to CARB and keep records of attestations from upstream parties. The RNG project (or pathway applicant) must file an annual fuel pathway report and submit injection records that will remain subject to verification.

Current Market Conditions

As the *NewsWire* went to press, the California LCFS credits were trading for \$150 per credit on average. Each credit represents one metric ton of CO₂ reduced.

The most recent data posted shows the average credit price in the last quarter reached \$185. In November 2019, CARB amended the program to cap the price for credits. The price cap was imposed to ensure a stable market and limit compliance costs to avoid derailing program support. The cap was set at \$200 in 2016 to be adjusted for inflation, and it has increased year over year to a current cap of \$221.67 per credit. ☺

Sovereign Debt Crisis Disputes

by Alison FitzGerald in Ottawa, and Matthew Buckle and Madjie Hajjar in London

Some experts suggest that as many as 15 to 20 countries are candidates for sovereign debt defaults in the near term.

An additional issue is that China has become the world's largest official creditor, particularly for emerging-market countries. This has already caused some difficulties for debt restructurings.

This article explores lessons learned from the past crises and the role of international investment agreements and arbitration in resolving such disputes.

Foreign investors stand a better chance of weathering any debt crisis by understanding the available options.

Warning Signs

The COVID-19 pandemic has greatly lengthened the list of developing and emerging market economies in debt distress. Default rates are rising, and the need for debt restructuring is growing. For some, a crisis is imminent. For many more, only exceptionally low global interest rates may be delaying a reckoning.

The COVID-19 pandemic has exposed gaps in the sovereign debt restructuring architecture that could lead to a sovereign debt crisis unprecedented in size and complexity.

A debt restructuring legal framework for sovereign borrowers has yet to be found. The G20 countries committed earlier this year to extend their “debt service suspension initiative” to halt debt-service payments through the end of 2021. However, there have been problems with this initiative, in part because the private sector has not joined in.

A number of nations are facing potential defaults as a result of unprecedented amounts of borrowing driven by the COVID-19 pandemic. Many of these nations were arguably on the brink before onset of the pandemic. In February 2020, the IMF published a paper called *Evolution of Public Debt Vulnerabilities in Lower Income Economies* that found half of low income countries (36/70) were at high risk of debt distress or already in distress. Private international capital stopped flowing to emerging market countries after the COVID lockdowns started in March 2020.

A debt crisis is likely to be hard to avoid, especially among the

world's poorest countries and those with continuing high rates of COVID-19 infections.

In November 2020, Zambia defaulted on its external debt payments — the first African nation to default since the pandemic started. Zambia's bondholders refused to consider offering interim relief without full disclosure of the nation's agreements with its largest creditor, China. A study published in March 2021 by the Peterson Institute for International Economics noted that China's lending contracts contain confidentiality clauses that bar borrowers from revealing the terms or even existence of the debt and that “Chinese lenders seek advantage over other creditors, using collateral arrangements such as lender-controlled revenue accounts and promises to keep the debt out of collective restructuring.”

Investment Treaties

Foreign investors may be able to fall back on protections in international investment treaties or “IIAs”.

IIAs are agreements between states in which they mutually agree to certain minimum standards of protection for investments made in their territories by foreign investors from other states that are parties to IIAs. Among the thousands of IIAs currently in force worldwide, many are bilateral investment treaties between a developed and a developing state.

IIAs offer qualifying foreign investors — including creditors — a framework of protections against adverse state action, whether the action is inspired by a debt restructuring program or some other objective.

IIAs typically set out the criteria that must be satisfied in order for a claimant to benefit from such protections. For example, IIAs define who is an “investor” and what is a protected “investment”.

IIAs vary in the substantive and procedural protections that they offer. Investors who satisfy the criteria typically have access to protections in the form of prohibitions against direct and indirect expropriation absent certain minimum conduct standards, such as observing due process and the principle of non-discrimination, as well as rights to fair and equitable treatment or the minimum standard of treatment in customary international law, full protection and security, national treatment and most-favored-nation treatment, among other protections.

Some IIAs contain carveouts for taxation measures and particular industry sectors that may affect an investor's entitlements, as well as “umbrella” clauses that elevate contractual breaches to treaty breaches.

Critically, these substantive protections have teeth because IIAs afford qualifying foreign investors with standing to bring claims direct access to dispute resolution in a neutral forum, usually international arbitration, before impartial arbitrators and in accordance with neutral, transparent rules.

The fact that China has become the world's largest creditor is causing difficulties for debt restructurings.

Claims under IIAs tend to follow capital flows, and unsurprisingly claims most often arise between qualifying foreign investors from developed states as claimant and the developing state hosting the investment as respondent. However, increasingly IIA claims are also against and among investors and states from developed countries.

Past is Prologue?

Parallels with the looming sovereign debt crisis can be drawn with previous sovereign debt crises, such as the 1980 Latin American debt crisis, the 1998-to-2002 Argentina debt crisis, and the 2009 Eurozone crisis. Following each of these crises, investors brought IIA claims against defaulting states.

In the early 1990s, Argentina defaulted on US\$93 billion in sovereign debt. Argentina's subsequent debt restructuring process led to a number of IIA claims by Italian bondholders against Argentina under the Argentina-Italy bilateral investment treaty.

Three cases arose from Argentina's default: *Abaclat v. Argentina*, *Ambiente Ufficio S.p.A v. Argentina* and *Alemanni v. Argentina*. In each case, Argentina challenged the jurisdiction of the tribunal, asserting that its consent to ICSID arbitration in the bilateral investment treaty did not include consent to multiparty proceedings and that its bonds were not protected investments

under the ICSID convention. Argentina also challenged the admissibility of mass claims.

In all three cases, Argentina's jurisdictional objections were dismissed. The tribunal in *Abaclat* held that the claimants' purchase of security entitlements in Argentinean bonds constituted a contribution that qualified as an investment under article 25 of the ICSID convention. On the issue of admissibility, the tribunal determined that the ICSID procedural framework could be adapted to render the claims by the Italian bondholders admissible. The majority found that the only relevant question was whether there was sufficient homogeneity among the bondholders' claims, a question that the majority answered in the affirmative. The *Ambiente* and *Alemanni* arbitrations were discontinued before the issue of admissibility was adjudicated. All three cases settled before they progressed to a merits phase.

In the late 2000s, several European countries faced debt distress on the heels of the global financial crisis. Greece's default on its debt was followed by a restructuring process that gave rise to a claim under the Cyprus-Greece and Slovakia-Greece bilateral investment treaties in a case called *Postova Bank v. Greece*. The claimants, a Slovak bank and its former Cypriot shareholder, alleged that the Greek debt restructuring was a breach of the investors' rights under the bilateral investment treaties. In contrast to the Argentine cases, the tribunal refused jurisdiction over the claim, holding that the bank's Greek government bonds were not protected investments under the Slovakia-Greece treaty.

More recently, in the case of *Adamakopoulos v. Cyprus*, the tribunal held (by majority) that it had jurisdiction to hear a mass claim of a group of almost 1,000 claimants holding financial assets in Cypriot banks. The claimants alleged that the actions by two Cypriot banks to merge in response to suffering losses due to their exposure to the Greek financial crisis had caused significant devaluation to the assets held by them. Cyprus, like Argentina before it, argued that the mass claim arbitration was outside the tribunal's jurisdiction and was inadmissible. The majority followed the reasoning in *Alemanni* in determining that the claims were admissible and could / continued page 37

Sovereign Debt Crisis

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be considered together as a “single” dispute within the meaning of the Greek-Cyprus and Luxembourg-Cyprus bilateral investment treaties.

Implications for Today

This decade’s sovereign debt crisis threatens to unfold on a wider and deeper scale than we have seen in recent past.

Even if progress is made on an enhanced multilateral debt restructuring framework that includes the private sector, many foreign investors will probably fall outside the tent. They will therefore need to consider other alternatives.

IAs are an important potential tool. As past cases reveal, while some IAs expressly include debt instruments among protected investments, not all IAs are so clear. IA protections, where available, have real teeth because IAs allow investors to bring claims directly against the state through international arbitration. They can also add weight to settlement discussions and negotiations.

For more on this topic, including the experience of companies that have won foreign investment disputes when trying to collect on judgments, see “Experience with Foreign Investment Disputes” in the February 2003 *NewsWire* and “Tactics When Caught in an Expropriation” in the April 2007 *NewsWire*. ©

Battery Purchase Contracts

by Luke Edney, in Houston

The latest update in market trends from the Energy Information Administration predicts installed capacity for battery energy storage projects will contribute more than 10,000 megawatts to the grid between 2021 and 2023 – 10 times the capacity in 2019.

If the aggressive rush that the market has seen in 2021 for battery projects continues, this will turn out to be a conservative number.

However, the rapid growth in this sector has not been without considerable growing pains. While many look to contract in this space based on the concepts and approaches used in solar, wind or gas turbine power projects, the reality is that battery projects require a paradigm shift *backwards*. Battery energy storage systems have matured as the technology, quality, performance and reliability have also matured. The contract structure has not.

Two main issues should be considered when developing a battery energy storage system or “BESS” project.

The first is the general contracting structure. The second is key pitfalls when drafting and negotiating specific contracts. This article focuses on the contract structure.

Turnkey v. Separate Contracts

Legacy energy projects, such as the gas turbine power plants, have traditionally been built by a third-party contractor under a lump-sum, turnkey engineering procurement and construction contract. Both lenders and project developers prefer this approach because it shifts as much risk as possible from the developer to a single EPC contract.

Handing over of risk from the developer to a single point of responsibility greatly de-risks execution of a project for both the owner and its lenders. However, this transfer of risk to the EPC contractor has always come at a price, and with implications for the construction schedule. The more risk that is transferred, the more contingency in price and schedule will be added by the EPC contractor.

EPC contractors have historically been able to reduce the amount of contingency they include as technology and project risk have decreased. When an EPC contractor is building its fifth or tenth gas turbine project, the implementation risks are well

known and therefore much more manageable.

There has been a partial move away from this approach in the wind and solar sectors for two reasons.

In solar, there is little implementation risk, but the large cash flow requirements to procure solar panel modules can affect the competitiveness of a EPC contractor bid. As a result, owners are often more open to direct procurement of modules and perhaps inverters, with the owner supplying such items to the EPC contractor at the project site as owner-supplied equipment.

With the wind projects, the large capital cost, need for specialists to commission the wind turbines and the more generic nature of the large volume civil construction and assembly work has led to a split scope, with one contract covering the wind turbine manufacture and commissioning and the other covering the civil construction and assembly.

BESS projects have added complexity, involving the following core elements. The different elements may require as many as four separate contracts, with the BESS and battery management system in one contract, the power conversion system and inverters in another contract, the civil construction and electrical installation in another contract, and the energy management system in a separate contract.

There are four key issues to address in battery purchase contracts.

The most common procurement structure for BESS projects is to combine the first two elements — the BESS and inverters — in one contract and leave the rest separate.

A number of companies offer to provide a fully-wrapped lump-sum turnkey EPC that covers all elements of a BESS project. However, the cost of such a procurement strategy may be more than the developer wants to pay compared to the cost of a piecemeal approach.

Four Key Issues

While stepping away from lump-sum turnkey contracting lowers the cost, it exposes the project owner to a number of commercial and technical risks that must be managed throughout implementation. There are four key issues to consider.

The first is delay.

With multiple suppliers and contractors performing pieces of work, the contracts must work together as a “package” by addressing key points of interaction so that delays by one supplier do not then entitle the other suppliers and contractors to cost or schedule relief.

It is common to hear contractors complain they cannot agree to a schedule because they are not handling the full scope. This need not be the case. Instead of setting fixed delivery and performance requirements, consider aligning delivery dates to be X plus Y days, where X is a necessary performance milestone of another contractor that must be completed as a condition precedent. For example, electrical installation must be completed and tested before the BESS supplier commences commissioning of the BESS. The BESS contractor commissioning deadline should then be “Z days after notice of completion of cold commissioning.”

Another key contracting challenge is division of responsibility.

Care must be taken to ensure that all scoping documents require the same division of responsibility. A frequent complaint from project owners involves contractors claiming that certain work was not understood to be part of their scope, but rather included in the scope of one of the other contractors. Each contract should take into account the work scope being

undertaken by other contractors and ensure that each contractor makes representations and warranties about its work scope and performance obligations.

The third issue to address is commissioning.

The sequencing and process need to be worked out so that everything comes together at the same time to avoid not only cost and schedule issues, but also to avoid having each contractor blame

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Battery Procurement

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another for failure of the system. Each contract should include the full sequence of commissioning and require each contractor to coordinate with the other contractors. Each contract should require the contractor to provide reasonable assistance to each other contractor throughout the commissioning process. Such coordination should not entitle any contractor to cost or schedule relief.

The final issue is project risk.

A single point of responsibility with a lump-sum, turnkey approach gives the project owner a single point of recovery for delay liquidated damages, performance guarantees and any associated performance liquidated damages.

With the owner taking on a direct relationship with each key contractor, if something goes wrong, the owner will have smaller, separate claims based on the value of each individual contract.

A frequent concern is performance of the energy management system. The energy management system is a critical component of a BESS project, giving the project the ability effectively to discharge and charge to the grid in accordance with applicable grid requirements.

Unavailability of the energy management system can shut down the entire project. Inability of the energy management system to manage the project in accordance with grid requirements can expose the owner to penalties or even disconnection. However, the cost of the energy management system as a portion of the entire project is small, and it is not commercially practical for the company providing the energy management system to take on performance guarantees and potential damages that are sized to the value of the project compared to the value of the energy management system contract. ☺

Solar Tax Equity Structures

by Keith Martin, in Washington

The US government offers two tax benefits for renewable energy projects: an investment tax credit and depreciation. They amount to at least 44¢ per dollar of capital cost for the typical solar project.

Few developers can use them efficiently. Therefore, finding value for them is the core financing strategy for most solar companies.

Tax equity covers 35% of the cost of a typical solar project, plus or minus 5%. The solar company must cover the rest of the project cost with some combination of debt and equity.

Most debt is back-levered debt, meaning it sits behind the tax equity in terms of priority of repayment. Such debt is cheaper than tax equity. Competitive pressures mean back-levered lenders are not charging higher interest rates than they would charge for senior debt at the project level.

More than 40 tax equity investors invested in the solar market in the 18 months before COVID-19 hit. Roughly 50% of tax equity last year was supplied by just two large banks: JPMorgan and Bank of America. Renewable energy tax equity was a \$17 to \$18 billion market in 2020. It had been expected to hit \$20 billion in 2021 before supply-chain difficulties began causing projects to slip into 2022.

Tax equity yields this past year have been mainly in the 6% to 8% range. After this yield is reached, the investor's economic interest in the project drops usually to 5%. Tax equity investors charge structuring and unused commitment fees and price to a second all-in yield 50 to 100 basis points higher to be reached in many transactions around year 20 to 25.

Most tax equity investors are banks and insurance companies for whom a 6% to 8% yield is attractive compared to alternative uses of money, like making loans. A theory that internet retailers who have made huge profits since the start of the pandemic would be future sources of tax equity proved unfounded, as such companies can earn higher returns by reinvesting earnings in their own businesses.

Individuals, S corporations and closely-held C corporations, meaning corporations with five or fewer individuals owning more than half the stock, have a harder time than large companies acting as tax equity investors. They must thread passive loss

and at-risk rules that make it harder for them to use tax benefits from such investments.

There are three main solar tax equity structures with two significant variations. The three are partnership flips, inverted leases and sale-leasebacks.

Each of the tax equity structures raises a different amount of tax equity, allocates risk differently and imposes a deadline on when the tax equity investor must fund its investment.

About 80% of solar tax equity deals are structured currently as partnership flips.

Solar companies have been restricted since 2006 to claiming an investment tax credit that is a percentage of the amount the owner paid for the project and is claimed entirely in the year the project is first put in service. The “Build Back Better” plan being debated in Congress would allow production tax credits to be claimed instead. These are tax credits of at least \$25 a megawatt hour that are claimed over 10 years on the electricity output. Partnership flips are the only structure that works for projects on which production tax credits will be claimed.

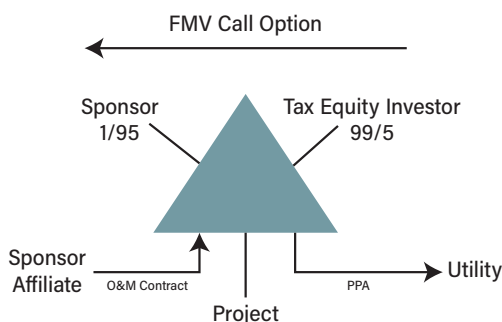
Partnership Flips

A partnership flip is a simple concept. A solar company brings in a tax equity investor as a partner to own a renewable energy project together. Partnerships do not pay income taxes; rather, any income earned, loss suffered and tax credits to which the partnership is entitled are reported by the partners.

The partnership allocates taxable income, loss and tax credits 99% to the tax equity investor until the investor reaches a target yield, after which its share of income and loss drops to 5% and the solar company has an option to buy the investor’s interest. Cash may be distributed in a different ratio before the flip.

Any purchase after the flip is usually for fair market value determined at time of purchase. The Internal Revenue Service allows fixed-price purchase options as long as the price is a good faith estimate of what the investor’s post-flip interest will be worth when the option can be exercised.

Basic Yield Flip



The IRS issued guidelines for partnership flip transactions in 2007. The guidelines provide a “safe harbor” for transactions that conform to them. Most do. The IRS said in 2015 that the guidelines were written with wind projects in mind and are not a safe harbor for solar transactions. (For more detail, see “The Partnership Flip Guidelines and Solar” in the July 2015 *NewsWire*.)

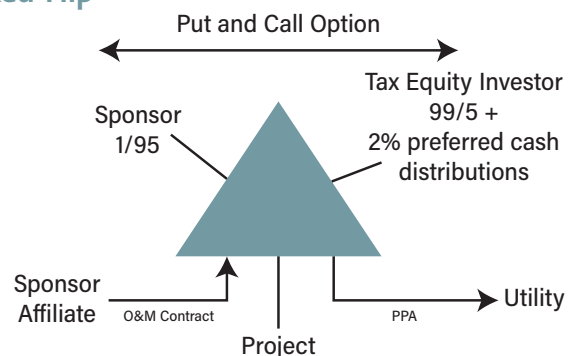
The central tension in flip deals is what label to put on the tax equity investor. The investor must be a real partner to be able to share in tax benefits at the partnership level as opposed to a lender earning a largely fixed return by an outside maturity date or a bare purchaser of tax benefits. Federal tax benefits may not be bought and sold.

There are two main variations in flip structures. In addition to the yield-based flip, there is also a fixed-flip structure that is offered by a small subset of tax equity investors and that leaves as much cash as possible for the solar company.

The tax equity investor in a fixed-flip transaction usually receives annual preferred cash distributions — ahead of any other distributions — equal to 2% of its tax equity investment. Almost all the remaining cash is retained by the solar company.

There are usually call and put options after the fixed-flip date. The solar company can buy the 5% post-flip interest of the investor for the fair market value at time of purchase. If it chooses not to do so, the investor can “put” its interest to the partnership usually six months later. It is important that there be a time lapse and a difference in exercise prices for the call and put.

Fixed-Flip



The solar company is responsible for day-to-day management of the project. Tax equity investor consent is required for a list of “major decisions.”

The tax equity investor may invest by buying an interest in the partnership from the company or by making capital contributions to the partnership. In most transactions, the solar company sells the special-purpose project / continued page 42

Solar Tax Equity

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company near the end of construction to the partnership as a way of stepping up the asset basis for calculating tax benefits to fair market value.

Almost all partnership flip transactions have “absorption” issues. Each partner has a “capital account” and “outside basis” that are two ways of measuring what the partner put into the deal and what it is allowed to take out in tax benefits. Most tax equity investors run out of capital account before they are able to absorb 99% of the depreciation. At that point, any remaining net tax losses shift to the solar company.

There are two ways to deal with the problem. One is by putting debt at the project or partnership level. This turns the losses into “nonrecourse deductions” that can be claimed even after the investor has run out of capital account, but at a cost to the investor of having to report an equivalent amount of “phantom” income later as the senior debt principal is repaid. (The income is “phantom” income because cash from electricity sales that the partnership might otherwise have to distributed to partners for use paying taxes on the income has gone to repay the debt principal.)

The other way to address absorption issues is for the investor to agree to make a capital contribution when the partnership liquidates to cover any deficit in its capital account. This is called a “deficit restoration obligation,” or “DRO.” Some tax equity investors have been willing to agree to DROs of as much as 50% to 70% of their initial tax equity investments. DRO percentages lately have been smaller. The IRS requires that certain steps be taken to show the DRO is real. (For more detail, see “Deficit Restoration Obligations” in the December 2019 *NewsWire*.)

In many solar deals, the income allocated to the tax equity investor drops to 67% after year 1 until the partnership turns tax positive. The sharing ratio is often restored to 99% once the partnership starts earning income.

Yield-based flips in the solar market price to reach yield in six to eight years. Fixed-flip deals flip at five to six years. Investors want at least a 2% pre-tax yield, but treat the tax credits as equivalent to cash for purposes of these calculations.

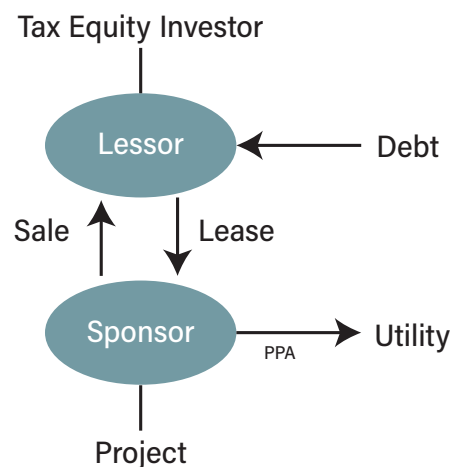
For more detail on partnership flips, see “Partnership Flips” in the February 2021 *NewsWire*.

Sale-Leasebacks

In a sale-leaseback, the solar company sells the project to a tax equity investor and leases it back.

Unlike a flip where the tax equity investor gets at most 99% of the tax benefits, all the tax benefits are transferred to the tax equity investor without complicated partnership accounting. The investor calculates them on the fair market value purchase price it pays for the project. The lessee has a gain on sale to the extent the project is worth more than it cost to build.

Sale-Leaseback



A flip raises 35% of the project value, plus or minus 5%. A sale-leaseback raises in theory the full fair market value, but in practice, the solar company is usually required to return 15% to 20% of the amount at inception as prepaid rent.

The prepaid rent is treated as a “section 467” loan by the solar company to the tax equity investor that is worked off over time. The solar company has to report interest on the loan as income and the tax equity investor has interest deductions to the extent it can use them under the current 30% cap on interest deductions. (For more detail, see “Cap on Interest Deductions Explained” in the August 2020 *NewsWire*.)

The IRS has guidelines for “leveraged” leases where the tax equity investor raises part of the purchase price by borrowing from a bank. These guidelines limit the term of the leaseback to 80% of the expected life and value of the project. If the solar company wants to keep the project at the end of the lease, the

solar company must repurchase it. Any lessee purchase option cannot be at a price that makes the option reasonably likely to be exercised. There also must not be any economic compulsion for the solar company to exercise.

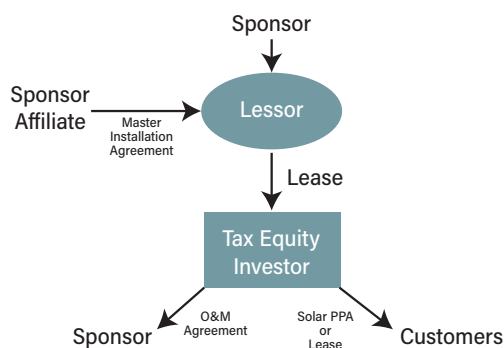
Sale-leasebacks remain common in the commercial and industrial and small utility-scale solar markets. They are uncommon in the rooftop market, where the deals are split currently between partnership flips and inverted leases. Rooftop companies dislike sale-leasebacks because they feel the tax equity investors pay too little at inception for the residual value after the lease ends. It frustrates them then to have to pay the full residual value to buy back the assets.

Inverted Leases

Inverted leases are used mainly in the rooftop market, although some utility-scale transactions have been done, including with debt that is effectively senior to the tax equity.

Think of a yo-yo. A solar rooftop company assigns customer agreements and leases rooftop solar systems in batches or “tranches” to a tax equity investor who collects the customer revenue and pays most of it to the solar company as rent. The solar company passes through the investment tax credit to the tax equity investor. It keeps the depreciation. The solar company takes the asset back at the end of the lease. The transactions work the same way in the utility-scale market, except that the tax equity investor is assigned a long-term power contract and then leased the solar project.

Inverted Lease



Solar companies like inverted leases because they get the asset back without having to pay for it, and the investment credit is calculated on the fair market value of the solar equipment rather

than its cost. Unlike a sale-leaseback, the step up in asset basis does not come at a cost to the solar company of a tax on a commensurate gain.

There are no IRS guidelines for inverted leases, unlike the other two structures. However, the structure is common in transactions involving tax credits for rehabilitating historic buildings, and the IRS acknowledged it in guidelines in early 2014 to unfreeze the historic tax credit market after a US appeals struck down an aggressive form of the structure in a case called *Historic Boardwalk*. (For more details, see “IRS Sheds Light on New Tax Equity Guidelines” in the January 2014 *NewsWire*.)

The tax equity investor must have upside potential and downside risk to be considered a real lessee. Some tax counsel like to see a “merchant tail,” meaning a period after the customer agreements or power contract ends when the lessee is exposed to market risk on electricity sales. Others focus on the amount of prepaid rent paid by the lessee and want to see at least a 20% rent prepayment on the theory that the more skin the tax equity investor has in the game, the more likely the lease will be respected.

Some big-four accounting firms treat the structure as a secured loan by the tax equity investor to the solar company, rather than a real lease, for book purposes.

Inverted leases raise the least amount of tax equity. The central challenge in inverted leases is how the capital raised by the structure moves from the tax equity investor to the solar company.

In the conservative form, the tax equity investor contributes the tax equity investment to a lessee partnership that is owned 1% by the solar company and 99% by the tax equity investor, and the capital contribution moves to the lessor (i.e., the solar company) as prepaid rent.

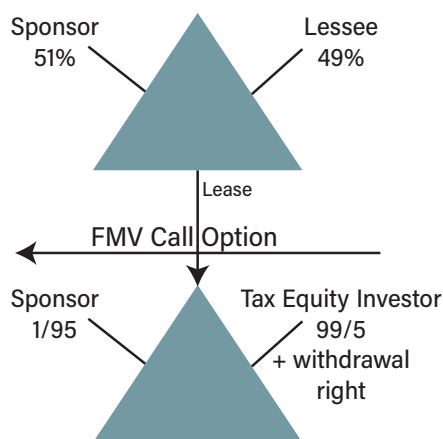
In an overlapping ownership structure, the tax equity investor makes a capital contribution to the lessee partnership, and the lessee partnership contributes it to a lessor partnership that is owned 51% by the solar company and 49% by the lessee partnership. This structure raises more tax equity because the tax equity investor claims not only the investment tax credit, but also 49% of the depreciation.

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Solar Tax Equity

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Overlapping-Ownership Inverted Lease



For more detail on inverted leases, see “Inverted Leases” in the June 2017 *NewsWire*.

Structures Compared

The three structures vary in terms of the amount of capital raised, risk allocation and the timing of when the tax equity investor must invest. The solar company must turn to other sources of capital (debt and equity) to raise the rest of the project cost.

Focusing on risks, in a sale-leaseback, the solar company has a hell-or-high-water obligation to pay rent and must indemnify the tax equity investor for loss of tax benefits and any acceleration of rental income due to a solar company breach of a representation or covenant. In a flip, the tax equity investor’s return turns on how well the project performs. The tax equity investor’s protection is it sits on the project at a 99% level until it reaches a target yield. The risk allocation in inverted leases is closer to the allocation in sale-leasebacks.

The principal business risks in any transaction are weather, technology, vacancy risk, curtailment risk, electricity basis risk and offtaker credit.

Turning to timing, the tax equity investor must be a partner in a flip deal before the project is placed in service.

In most solar transactions, the tax equity investor contributes 20% of its total investment after the project reaches mechanical

completion, but before it is placed in service, contributes the rest after construction has been completed. Inverted leases must be done before assets go into service. A sale-leaseback can be done up to three months after the asset is put in service.

In many deals, the tax equity investor has an unwind right to get back its 20% investment if the conditions to make the remaining 80% investment are not met: for example, because project completion is delayed beyond the outside commitment date for the tax equity investment. Such unwinds take various forms depending on the preference of the tax equity counsel.

Risks

A central challenge in all solar deals is how to get a step up in tax basis so that the tax benefits are calculated on the fair market value of the project rather than its cost. The market has been watching two key cases moving through the courts. A wind developer lost two key developer fee cases (*California Ridge* and *Bishop’s Hill*) in 2020 before a US court of appeals. (For more detail, see “California Ridge: Developer Fees Struck Down — Again” in the May 2020 *NewsWire*.) A basis allocation case (*Alta Wind*) is headed to retrial in late 2022 or 2023, and another case (*Desert Sunlight*) that may also shed light on basis issues is headed to trial in 2022.

Tax basis risk tends to be borne by the solar company, although this has been true only since 2010. Tax risks about which the solar company has special insight are borne by the solar company. An example is whether the project was under construction in time to qualify for tax benefits. Tax risks into which both the solar company and tax equity investor have equal insight are borne by the tax equity investor: for example, whether the structure works to transfer tax benefits to the investor. Risks over which neither has special insight are jump balls. An example is change-in-law risk.

Many tax equity investors are limiting the percentage markup they are willing to see in fair market value above cost. Some are requiring tax insurance to cover basis risk. Premiums on tax insurance run generally 2.5% to 3.5% of the maximum potential payout.

Cash sweeps are another source of tension in deals. Solar companies want to retain enough cash to cover debt service on back-levered debt. Many tax equity investors agree to limit sweeps to 50% to 75% of cash or, in some cases, to prevent the sweep from reaching cash to cover principal and interest on the debt.

In most deals, a section 6226 “push-out election” is made to

Tax equity covers 35% of the cost of a typical solar project, plus or minus 5%.

address the risk of a back tax assessment at the partnership level. The IRS audits partnerships, but has grown tired of chasing partners for their shares of any back tax assessment. Congress gave it the right starting in 2018 to collect back taxes from partnerships directly. A push-out election is an election to push out any back tax liability to persons who were partners in the year under audit. If such an election is made, the partners must pay 2% extra interest on the back tax liability.

Property taxes are an ever-present issue in transactions involving solar equipment in California. Any change in ownership of solar equipment after initial installation will trigger a property tax reassessment. A new bill signed at the end of September (SB 267) makes clear that the initial investment by the tax equity investor and later flip are not considered changes in ownership. (For more detail, see “Partnership Flips and California Property Taxes” in the December 2021 *NewsWire*.)

Higher Tax Credits

The “Build Back Better” plan that passed the US House of Representatives just before Thanksgiving would restore

renewable energy tax credits to the full level and extend deadlines to qualify. It would also provide a direct-pay option to receive cash payments from the IRS in place of tax credits.

Any project in a census tract where a coal mine has closed since 1999 or where a coal-fired generating “unit” has been retired since 2009, or in an adjacent census tract, qualifies potentially for an extra 10% investment tax credit or 1.1 times the production tax credits for which the project would otherwise qualify.

The restored tax credits will come with two bits of fine print.

The same Davis-Bacon wages that the US government pays on federal construction projects must be paid to mechanics and laborers during construction and for the five or 10 years after construction on alterations and repairs. Apprentices must be used on 10% to 15% of total labor hours.

The wage and apprentice requirements do not apply to any project on which construction starts no later than 59 days after the IRS issues guidance.

The other fine print is all steel, iron and manufactured products must be made in the United States.

The domestic content requirement is a carrot and a stick. The carrot is up to an extra 10% investment tax credit or 1.1 times the production tax credits for which the project would otherwise qualify. The stick is inability to receive a full direct cash payment for projects that start construction in 2024 or later. ©

US Offshore Wind Financing Update

The lead finance people at three large offshore wind projects planned off the US Atlantic coast talked about a range of finance-related topics at the annual American Clean Power Association offshore wind conference in Boston in October.

The topics included the recently concluded financing for Vineyard Wind, the financing plans for the other two projects and how the “Build Back Better” plan under debate in Congress will affect the projects.

The three panelists are Álvaro Ortega, chief financial officer of Vineyard Wind, an 800-megawatt project off Massachusetts, Joris Veldhoven, commercial and finance lead for Atlantic Shores, a 1,510-megawatt project off New Jersey, and Justin Johns, chief financial officer of Mayflower Wind, an 804-megawatt project off Massachusetts. The moderator is Keith Martin with Norton Rose Fulbright in Washington.

Vineyard

MR. MARTIN: Vineyard Wind is the first large offshore wind project in the United States to reach financial closing. Cape Wind came very close in 2014, but did not make it across the finish line. Block Island, a five-turbine project off Rhode Island, was financed in 2015, and Dominion Energy has two turbines operating in the water off Virginia.

Vineyard Wind said in a press release in September that it closed on a construction and term loan for \$2.3 billion. The press release said the financing was led by nine banks, and the trade press is reporting that the loan is already in syndication.

Álvaro Ortega, is there anything you can say publicly about the terms of the financing?

MR. ORTEGA: [Microphone not working].

MR. JOHNS: Maybe that is all he can disclose. [Laughter]

MR. ORTEGA: What can we say about the financing? It is a construction loan first, followed by a mini-perm term loan with principal amortization over the term of the PPA plus a short tail. We cannot disclose the terms, but the rate is similar to what we see for wind farms on land.

MR. MARTIN: Can you say the length of the term loan?

MR. ORTEGA: Seven years.

MR. MARTIN: Seven-year debt after construction. Nine banks. The interest rate spread is similar to what is available on land. Is there anything else you can say?

MR. ORTEGA: That is all I am able to say.

MR. MARTIN: The most interesting thing is how quickly the bank market has warmed to offshore wind. It is a new asset class in the US, but there is so much interest in financing such projects that the spreads have already moved immediately to roughly the same level as a more mature market.

Why did you end up with bank debt, given all of the other options available for projects of this kind? You could have borrowed from export credit agencies or in the project bond market, for example.

MR. ORTEGA: We explored all of the possibilities. We began the process in 2019 with probably 60 institutions. We narrowed down to a group of nine banks. The project had to be put on hold for a period while the federal government deliberated about whether to issue construction permits for any offshore wind projects off the Atlantic coast. We came back in 2021 with the same bank group. We wanted to close as promptly as possible this year after receiving the permits, so we decided to do this form of financing.

MR. MARTIN: Is the plan to refinance with longer-term debt — for example, project bonds?

MR. ORTEGA: At the end of the mini-perm, we will have to refinance. We have seven years to evaluate options.

Other Project Timetables

MR. MARTIN: Joris Veldhoven, how are you thinking about the financing options for the Atlantic Shores project? You have very big sponsors, as does Vineyard. Are you planning to use all equity? Or are you going into the debt markets?

MR. VELDHOVEN: Our sponsors are likely to look closely at a similar structure as Vineyard, but everything is on the table. Our current plan is to rely on project financing for as much of the capital stack as possible.

You mentioned export credit agencies. That is an avenue that we have not ruled out, but in all likelihood, we are going to talk a lot over the next two and a half years until our financial close with banks.

MR. MARTIN: That was going to be my next question. You are two and a half years away from closing on the financing. Álvaro Ortega, how long were you in discussions with the banks? When would you recommend that Atlantic Shores start negotiations?

MR. ORTEGA: As soon as possible. We started our debt discussions in 2019. They took more than two years, although we had to put them on hold in the middle because of the freeze on construction permits. We were able to build on the effort that

was done in 2019, so that is why we were able to close in a relatively short period of time once the negotiations resumed.

Most of these projects are owned by joint ventures. These are big, multi-party financings. There is a lot of back and forth among all of the parties involved to get to a loan commitment. The earlier you can start, the better. Engage early with the banks, but not too early because conditions can change over time in the financial markets.

MR. MARTIN: The Vineyard project has two owners.

MR. ORTEGA: Avangrid and Copenhagen Infrastructure Partners.

MR. MARTIN: The Atlantic Shores project also has two owners.

MR. VELDHOVEN: Shell and EDF Renewables.

MR. MARTIN: The Mayflower project is also owned by a joint venture.

MR. JOHNS: Mayflower is owned by Shell and Ocean Winds, which is a joint venture between EDP Renewables and Engie. Shell owns 50% and the EDPR-Engie joint venture owns 50%.

MR. MARTIN: Justin Johns, how are you thinking about financing, and when will the Mayflower project be in the market for financing?

MR. JOHNS: Mayflower is similar to Atlantic Shores in the sense that it has partners with strong balance sheets and existing banking relationships. The partners are funding the work themselves during development. Their balance sheets give us a lot of flexibility as to when and how we execute any financing.

We expect to use nonrecourse project financing ultimately, similar to what has been done in Europe. Our goal is to find the most competitive terms on offer in the market, building on what Vineyard has done and making it incrementally better.

MR. MARTIN: When will you be in the market?

MR. JOHNS: Sometime around 2024.

MR. MARTIN: Mayflower is slightly ahead of Atlantic Shores, but not by much.

Lawsuits

MR. MARTIN: Álvaro Ortega, a lawsuit challenging the permits in Vineyard was filed just days before the banks closed on the financing. That usually disrupts a closing, yet the banks closed over it. How did they get comfortable?

MR. ORTEGA: Any major infrastructure project always faces litigation. We hired law firm experts with experience in this kind of situation. They reviewed all of the documentation that was available to us, and then we shared both the documentation and the analyses with the banks. The banks felt comfortable closing.

MR. MARTIN: There was more than one lawsuit pending at the time, correct?

MR. ORTEGA: Yes, three.

MR. MARTIN: The Cape Wind project also faced one lawsuit after another. There was talk about getting the US Department of Energy loan guarantee program effectively to bear the litigation risk over permits. You did not have to go to that length. The banks looked at the lawsuits and decided they were comfortable enough to close over them.

MR. ORTEGA: The lawsuits were not against Vineyard. They were against the various federal agencies that were involved in granting a permit to Vineyard to build.

Capital Stacks

MR. MARTIN: What percentage of the Vineyard capital stack will be debt?

MR. ORTEGA: Around 50% to 60%. The rest will be a combination of sponsor equity and tax equity.

MR. MARTIN: The 50% to 60% seems to be not only the percentage of the capital stack after term conversion, but also the advance rate during construction.

Joris Veldhoven, do you have a sense yet of how the capital stack will look for Atlantic Shores?

MR. VELDHOVEN: We are not advanced enough yet to give detailed percentages, but our goal is to get to as high a percentage of nonrecourse debt as the market will allow and improve on the capital stack in Vineyard.

MR. MARTIN: “Improve on the capital stack” means get to higher leverage than Vineyard was able to achieve?

MR. VELDHOVEN: We should all try to stand on each other’s shoulders in this industry.

MR. MARTIN: The amount of debt that you can borrow is a function of the debt service coverage ratio and that, in turn, is a function of how certain the cash flows are. Coming back to Vineyard, what percentage of the offtake is contracted?

MR. ORTEGA: 100%.

MR. MARTIN: How long are the power contracts?

MR. ORTEGA: Twenty years.

MR. MARTIN: Joris Veldhoven, how long is the offtake contract for Atlantic Shores, and does it cover the entire output?

MR. VELDHOVEN: We have an OREC contract with New Jersey for 20 years. Atlantic Shores is a 1,510-megawatt project. The contract covers 100% of the output.

MR. MARTIN: Under the OREC program, electricity from an approved offshore wind project is sold / continued page 48

Offshore Wind

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into the PJM spot market. New Jersey then gives the project ORECs — offshore wind renewable energy certificates — that the New Jersey utilities are required to buy for pre-agreed prices. The utilities pass through the amount paid for ORECs to their ratepayers. The actual revenue the project receives from PJM spot sales is turned back to the ratepayers. Cutting through everything, the project exchanges revenue calculated at spot prices for revenue using a fixed contract price.

MR. VELDHOVEN: The value of the OREC credits starts in the mid-\$80-a-megawatt-hour range and escalates from there.

MR. MARTIN: Justin Johns, what do you think the Mayflower capital stack will look like?

MR. JOHNS: We plan to use as much nonrecourse debt as the project can support. Having sponsors with strong balance sheets means we have the luxury of waiting until the debt terms on offer are most opportune. Then it is just a question of how much tax equity we can raise or how large any direct cash payments will be in place of tax credits.

MR. MARTIN: Are you far enough along with banks to know whether they would be prepared to go above the 50% to 60% advance rate that we just saw in Vineyard?

MR. JOHNS: Not specifically, but we see a very strong interest among the banks in financing US offshore wind projects. Mayflower will probably be the second or third such project to hit the bank market. The market seems quite competitive as to the amount of leverage and other debt terms.

Tax Equity

MR. MARTIN: Álvaro Ortega, tax equity was not part of the Vineyard capital stack from the start. Why not?

MR. MARTIN: We expect the project to be in commercial operation by the end of 2023. We do not see tax equity committing that far in advance in the onshore wind market. Tax equity also requires high commitment fees that are a function of how long the commitment remains outstanding. We reached financial close on the debt without having tax equity committed, and we are confident that next year we can get there with tax equity.

MR. MARTIN: Did potential tax equity investors tell you how far in advance they would commit?

MR. ORTEGA: They could have probably committed this year if we had put a tax equity bridge loan in place and been prepared to pay the commitment fee.

MR. MARTIN: For how high a commitment fee were they asking?

MR. ORTEGA: That's confidential information.

MR. MARTIN: I see now why the advance rate during construction was only 50% to 60%. The banks were not willing to lend more without a tax equity takeout at the end of construction to repay the construction loan down to the level that the project can support as term debt.

Joris Veldhoven, is Atlantic Shores planning to have tax equity in from the start?

MR. VELDHOVEN: Our financial close will be in 2024, so anything I say today is not so valuable. Congress is considering a direct-pay alternative to tax credits. We will see how the world looks early next year and take it from there.

MR. MARTIN: Álvaro, do you have a sense for how much tax equity can be raised on your project?

MR. ORTEGA: Not yet. It depends partly on whether the export cable to bring the electricity to shore qualifies for the investment tax credit.

MR. MARTIN: The export cable can cost \$300 million or more. A 30% investment tax credit on it is a substantial number.

We are optimistic that the IRS will treat any export cable that is inside the perimeter of the offshore wind farm as part of the generating equipment and, therefore, as eligible for the tax credit.

The "Build Back Better" plan being debated currently in Congress would also allow a 30% investment tax credit on new transmission lines. However, any such line would have to be 275 KV or higher and have a capacity of at least 500 megawatts to qualify.

Some offshore wind farms plan to have more than one export cable to shore. The combined capacity is more than 500 megawatts, but each separate cable is not. Hopefully the IRS will allow the megawatts to be combined in such cases.

Álvaro, do you expect any complications from slotting in the tax equity after the debt has already closed?

MR. ORTEGA: Not at this point.

MR. MARTIN: Surely the lenders will have something to say, because you are going to insert tax equity ahead of them in the capital stack. It is like two farmers along a river. The tax equity farmer would have first claim on the water before it reaches the lender farmer downstream.

MR. ORTEGA: That is correct, but the lenders understand that this is going to be like any onshore deal. The debt will become back-levered. They feel comfortable with the typical terms in

Debt will cover 50% to 60% of the cost initially of the Vineyard offshore wind project.

such arrangements.

MR. MARTIN: There are a lot of other offshore wind projects in line hoping to tap into the debt and tax equity markets. These are behemoths; they are all multi-billion dollar projects. Is there any sense, starting with you, Justin Johns, that the market has limited capacity?

MR. MARTIN: Europe has a handful of projects that go to the financing market each and every year, and they are able to raise nonrecourse financing. The US market is still in its infancy. I understand there was strong demand for Vineyard. I expect that there will continue to be strong demand for Mayflower and Atlantic Shores, driven by quality PPAs, backstopped by quality revenue structures and managed risk.

Tax equity is an area where you have to look at market capacity for tax equity, but as long as we bring good projects, we are optimistic.

MR. MARTIN: Joris Veldhoven, what sense are you getting from the tax equity market about its interest in doing this type of project?

MR. VELDHOVEN: Our sponsors, EDF and Shell, have lots of experience raising tax equity for onshore wind projects. It is still early for us to have engaged fully with the tax equity market. The Atlantic Shores project is not expected to be in commercial operation until 2027. The initial interest is there, but tax equity investors are not able to forecast tax capacity six years in advance.

MR. MARTIN: Two banks, JPMorgan and Bank of America, have seemed recently to have endless tax capacity. Their main constraint is people. They are a little over 50% of the market.

Álvaro Ortega, remind us how many banks expressed an interest in financing Vineyard.

MR. ORTEGA: We started with probably 60, narrowed it to 20 and then ended up with nine. We had plenty of banks that wanted to participate, and now they will have a chance through the syndication.

MR. MARTIN: How many tax equity investors?

MR. ORTEGA: We are looking at two or three.

MR. MARTIN: The renewable energy tax equity market could be about \$20 billion this year.

Multiply \$3.5 billion for just one

offshore wind project by whatever percentage investment tax credit you think applies, and you can see that a string of offshore wind projects could have a big impact.

Practical Lessons

MR. MARTIN: Álvaro Ortega, what practical lessons did you take away from the financing negotiation?

MR. ORTEGA: The paperwork was huge for this deal. There were a lot of banks and two sponsors on our side. That made for a lot of back and forth. One lesson was the need to start early. Another was the importance of putting in place early hedges or derivatives. We have two sponsors. They have two different risk profiles and goals. The accounting implications of the derivatives take time to work through.

MR. MARTIN: What were you hedging?

MR. ORTEGA: We hedged the interest rate and some foreign exchange exposure for the components during construction.

MR. MARTIN: Your debt is in dollars. What percentage of the project cost is not in dollars?

MR. ORTEGA: Around 30%. We were able to lock in the exposure in some cases with the suppliers directly.

MR. MARTIN: What will you do differently the next time? I know that Vineyard has some other projects teed up.

MR. ORTEGA: The Vineyard Wind project will remain a 50-50 joint venture between the sponsors, but we are in the midst of reorganizing the remaining projects so that each will have only one sponsor. Each sponsor will decide on its own how to finance its projects.

MR. MARTIN: Is there nothing you would do differently the next time?

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Offshore Wind

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MR. ORTEGA: I think it went pretty well. We are very happy with the result.

MR. MARTIN: One of the lessons from Cape Wind, which came very close to securing financing in 2014, was that the politics of individual offshore wind projects can change rapidly if there is a change in governor in a state. It is important not to waste time arguing about small issues. Move rapidly through the financing process.

All three of you have been in the energy industry for a long time. What other lessons are there for people trying to develop offshore wind?

MR. VELDHOVEN: It is extremely important that we actually deliver and show real-life examples of where jobs are created. We talked about the local supply chain. This industry talks about local content. We need to show a lot of progress in the next 12 to 24 months to maintain momentum and political support.

MR. MARTIN: So build political support by creating jobs on shore to build parts of the project. The projects have also moved farther offshore so that they are not as visible from land, which helps dampen opposition from property owners along the coast. Justin Johns, any other lessons?

MR. JOHNS: I guess I would call it a reflection about how much more complex offshore wind development is in the US than in Europe. In the US, you have multiple levels of federal, state, county, city and community involvement, even down to the fisheries. You have so many stakeholder groups. You have a supply chain that is only beginning to develop. You have permitting issues with transmission. It is not so simple to apply skills learned in Europe to the US market.

MR. MARTIN: Another challenge for Cape Wind, which of course did not make it across the finish line, although it got very close, was the sheer number of contracts to build parts of the project. There was no one overall prime contractor who wrapped everything and guaranteed it would work once everything was assembled. How did you get past that in Vineyard?

MR. ORTEGA: We have multiple contracts, but we are doing the construction management in house. The banks felt comfortable with that approach. The due diligence went extremely well.

MR. MARTIN: Joris Veldhoven, Atlantic Shores has a 10-mega-watt hydrogen project tacked on the back end. The conventional wisdom is that hydrogen does not yet make economic sense. Why is this a benefit to Atlantic Shores?

MR. VELDHOVEN: It is a pilot project. We are not doing it for the return on capital. We are working with a local partner in New Jersey and plan to test different use cases. We have a primary use case, which is injecting green hydrogen into natural gas pipelines up to approximately 15% blending. That can be done without any additional infrastructure costs, either on the gas company or on the customers of the gas company.

This is our first project in New Jersey. Our partner is the local gas distribution company, South Jersey Industries. Congress is considering offering up to a \$3.00-per-kilogram tax credit for making green hydrogen, which would help with the economics.

MR. MARTIN: What are you projecting currently it will cost to make a kilogram of hydrogen?

MR. VELDHOVEN: I don't have those numbers.

MR. MARTIN: For those of you interested in hydrogen, there is a very good briefing in *The Economist* magazine this week at the start of the issue.

Changing Tax Laws

MR. MARTIN: Álvaro Ortega, your financing played out against the backdrop of a debate in Congress about changing the tax law, including possibly having the IRS make direct cash payments to owners of new renewable energy projects in place of tax credits. If that happens, will you still raise tax equity?

MR. ORTEGA: Let's see what Congress enacts, including any haircut, the timing and other details. At least for now, tax equity seems to make more economic sense for the project.

MR. MARTIN: There is no haircut in either the House or Senate bill. Of course, we don't know where this will land or whether the bill itself will be enacted, but if it is enacted with no haircut, how will you think about whether to do tax equity?

MR. ORTEGA: Tax credits are only part of the tax benefits on offshore wind projects. There is also accelerated depreciation. As long as there is no direct-pay option for depreciation, it will probably still make sense to raise tax equity.

MR. MARTIN: Justin Johns, if there is a direct-pay alternative to tax credits, will Mayflower raise tax equity?

MR. JOHNS: It depends on what the final bill says, whether there are any time limits on when direct payments are available and what other requirements will apply.

MR. MARTIN: We are down to the last five minutes.

The "Build Back Better" bill would restore federal tax incentives for renewable energy to the full level and extend deadlines, but it comes with fine print. One bit of fine print is the need to

pay the same Davis-Bacon wages that the government pays on federal construction projects and use qualified apprentices for 10% to 15% of total labor hours, both during construction and for five to 10 years after the project is completed on later alterations and repairs.

Is this already playing into your contract negotiations?

MR. VELDHOVEN: Yes. The supply chain in offshore wind is still emerging, but a lot of the suppliers that we are talking to are already paying prevailing wages. We will be interested in the eventual IRS guidance.

MR. MARTIN: Is there a prevailing wage for offshore projects? The US Department of Labor publishes them for the different locations onshore.

MR. VELDHOVEN: I am not sure. Another issue is how far down the supply chain the requirement applies. For lack of a better term, the jury is out. That said, I think overall, as an industry, we can pay good, living wages.

MR. MARTIN: Justin Johns, how are the wage and apprentice requirements playing out in your current planning?

MR. JOHNS: Mayflower certainly intends to pay a prevailing wage. I think the point was eloquently made.

MR. MARTIN: Álvaro Ortega, another bit of fine print is a domestic content requirement. You would have to use 100% US-made steel, iron and manufactured products. The domestic content requirement is both a carrot and a stick. The carrot is an additional tax credit if you comply. The stick is inability to qualify for a full direct cash payment in place of tax credits. The stick will not apply to Vineyard because the project is already under construction. There is a haircut in the potential direct payment for projects on which construction starts in 2024 or 2025 and no direct payment at all for projects on which construction starts in 2026 or later.

Is this starting to play into your planning for your future projects?

MR. ORTEGA: We are following it closely. The exact requirements are still taking shape in Congress.

MR. MARTIN: I gather at the moment offshore wind projects will have a hard time satisfying any requirement using 100% domestic content, but perhaps this will influence how the local supply chain develops over time?

MR. ORTEGA: That's correct.

MR. MARTIN: Has anybody looked enough to know whether his project can meet the requirement currently?

MR. VELDHOVEN: We are not constructing currently. As we proceed to construct in 2024, could we meet it as is? No.

However, I think we all are very bullish on what the US market can do given enough time to adjust.

You talked earlier about hedging. One of the benefits of a local supply chain is that there is less need to hedge. I think that is the goal. Atlantic Shores has committed major facilities on land in New Jersey as part of our project.

Offshore wind developers have been having meetings about how to get to the stage where we can confidently say the steel and iron come from the United States. I don't think anyone can really say today even with 2024, 2025 or 2026 construction you can make it.

MR. MARTIN: My last question is this: offshore wind projects already qualify for a 30% investment tax credit as long as construction starts for tax purposes by the end of 2025. The bill may end up with a corporate tax increase, and it has the fine print we just discussed in the form of wage, apprentice and domestic content requirements. Is the bill a net benefit or net detriment for offshore wind? [Editor's note: At the time of the panel discussion, the House bill increased the corporate tax rate to 25%, but the increase was later dropped from the bill before it passed the House in late November.]

MR. JOHNS: It depends on the particular facts of each project, but it should be a net benefit.

MR. MARTIN: What is the benefit?

MR. JOHNS: The benefits are a potentially higher tax credit and the possibility of being paid the amount in cash rather than having to go into the tax equity market.

MR. MARTIN: Only if you satisfy the domestic content requirement.

MR. JOHNS: It all depends on how the bill is implemented at the agency level. There is definitely potential, but it needs to be done right with recognition that US offshore wind is at a much earlier stage of development than other types of renewable energy. ☺

Environmental Update

The Bureau of Ocean Energy Management, or BOEM, part of the US Department of the Interior, formally designated California's Morro Bay Wind Energy Area for development of offshore wind power in November.

The Morro Bay WEA is approximately 20 miles off the central California coast and is a large expanse of about 376 square miles.

The Biden administration is expected to try to approve 3,000 megawatts of projects eventually in Morro Bay and another 1,600 megawatts off Humboldt County in northern California.

The Morro Bay designation triggered a 60-day public comment period and signaled the start of work on a formal environmental assessment of the project area. The public comment period ends January 11, 2022.

Once BOEM considers all public input, the agency will publish a draft environmental assessment for public review and comment. The analysis will inform BOEM's eventual decision whether to move forward with proposed lease sales in the WEA.

The US Department of the Interior outlined an "ambitious roadmap" to develop wind farms along almost the entire US

coastline. The plan suggests there will be as many as seven new offshore wind area lease sales in the United States over the next decade.

The roadmap includes a target of September 2022 for lease sales for the Morrow Bay and Humboldt WEAs.

The California environmental assessments and leases are likely to face technical hurdles. These include the need, because of deep ocean floors off the Pacific coast, to use floating turbines whose technology is not considered fully proven yet in the United States. The projects will also have to pass through a regulatory gauntlet before both federal and state agencies, particularly challenging in the current California regulatory climate. Opposition from fishermen is also expected.

In addition to the two California areas, the October BOEM roadmap also includes assessment of potential leases off the coast of Oregon, in the Gulf of Maine, in the Gulf of Mexico, and off the coasts of the mid-Atlantic states and North and South Carolina. Biden has set a goal of building 30,000 megawatts of US offshore wind capacity by 2030.

BOEM gave permission earlier this year for construction of the first large US offshore wind farm — the 800-megawatt Vineyard Wind project off Massachusetts — after a delay during which the Trump administration decided to prepare a supplemental environmental impact statement. The June 2021 supplement examined the cumulative impacts of several offshore wind projects proposed off the Atlantic coast, including

assessment of previously unavailable information on potential impacts to fishing and sea-going transit.

Migratory Birds

The US Fish and Wildlife Service revoked a Trump-era rule in October that limited liability for incidental "takes" of migratory birds.

The Migratory Bird Treaty Act of 1918, known as the MBTA, makes it unlawful to

BOEM will try to lease enough area off California for 4,600 MW of offshore wind projects.

Projects using best management practices may avoid prosecution for incidental “takes” of migratory birds.

pursue, hunt, take, capture or kill any migratory bird “by any means or in any manner.”

The MBTA covers practically every species of North American bird.

The now withdrawn Trump-era rule, only issued in early January after the election, took the position that the MBTA only prohibits intentional takes, such as by hunting or poaching, as opposed to incidental takes.

Before Trump, regulators had generally interpreted the MBTA to prohibit incidental takes, including takes that occur by accident in connection with otherwise lawful activities. However, the US Fish and Wildlife Service used discretion when incidental takes occurred to waive penalties.

Despite past practices, no formal rules codifying whether incidental takes are prohibited under the MBTA are currently in effect following the revocation of the Trump-era rule.

The US Fish and Wildlife Service has begun a rulemaking process to confirm its current position that the MBTA prohibits incidental takes, but the agency appears also ready to formalize the use of enforcement discretion in the case of incidental takes of migratory birds.

It also proposed new guidelines in October for handling

incidental takes to let project owners know what factors it will weigh in favor or against projects whose activities violate the strict letter of the law.

The USFWS guidance provides a measure of comfort for those seeking to avoid liability under the MBTA. A key factor to be considered is whether best management practices were used to assess, manage and lower the risk of harm to migratory birds. Anyone using best management practices would probably be classified as “not a priority for enforcement” by the USFWS.

USFWS’s “priority for enforcement” for incidental takes will now focus on two categories. First, the agency will use the MBTA against incidental takes that result from an otherwise illegal activity. Second, it will focus on incidental takes that result from activities by a public or private sector entity that are otherwise legal, but where the incidental takes were foreseeable and best practices were not being used to try to prevent them.

The USFWS has at long last begun consideration of a permitting regime to cover incidental takes. Permitting regimes have been in place to allow for limited incidental takes under both the Bald and Golden Eagle Protection Act and Endangered Species Act for some time, but never under the MBTA.

USFWS is considering allowing incidental takes under the MBTA in three situations.

First, the agency is considering exceptions to the general prohibition on incidental takes. These may include noncommercial activities, including most activities by homeowners and other individuals. They may also include certain activities where best management practices are being used to avoid harm to migratory birds.

Second, incidental takes may be allowed by those holding general permits for certain types of / continued page 54

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activities. A general permit is likely to be authorized through a registration system, where parties would pay a fee and agree to be subject to a set of conditions in the general permit, including reporting requirements. One permit condition may be to use best management practices to avoid incidental takes.

An MBTA general permit would be effective upon submission of the request. This is similar to how the nationwide permit program works for regulating impacts to wetlands and other regulated waters under the Clean Water Act.

The USFWS is considering general permit authorization regulations to cover renewable energy projects.

Third, the USFWS is likely to develop regulations that allow parties to apply for a project- or activity-specific permit authorizing incidental takes of migratory birds in cases where the project does not satisfy the eligibility criteria for a general permit.

The USFWS staff would review applications for project- or activity-specific permits and ask questions. The process to obtain such permits is likely to be somewhat time consuming and costly.

EPA may set drinking water limits for two “forever chemicals” in 2023.

COP26

China and the United States — the two largest emitters of greenhouse gases — issued a surprise joint statement at the end of the COP26 United Nations conference on climate change in Glasgow in early November.

The statement acknowledged the gap between current government policies not just in other countries, but also in the United States and China, and what needs to be done to meet the goal of limiting global warming to 1.5 degrees Celsius.

The two countries agreed to increase their efforts to cut emissions, including the extra potent methane gas. However, China declined to join the global pledge being urged by the United States and the European Union to cut methane emissions 30% by the end of the decade from 2020 levels. Instead, China said it will develop its own national plan.

The two nations pledged to establish a working group that will meet in the first half of 2022 to explore ways to step up global efforts.

Forever Chemicals

The US Environmental Protection Agency released draft reports in November suggesting that the safe levels of ingestion for two common “forever chemicals” — perfluorooctanoic acid (PFOA) and perfluorooctanesulfonic acid (PFOS) — are actually lower than suggested by prior assessments.

Both PFOA and PFOS belong to a class of chemicals called perfluoroalkyl and polyfluoroalkyl compounds, or PFAS (pronounced PeeFAS). The class of chemicals is sometimes referred to as “forever

chemicals” because they build up in the environment over time and are difficult to break down even with time.

PFAS are a broad group of fluorinated chemicals that are added to a wide variety of consumer products to make them non-stick, waterproof, stain-resistant and fire-resistant.

The new draft reports suggest that toxicity levels for both PFOA and PFOS may be lower than previously understood. However, the reports now suggest that PFOA is a “likely” carcinogenic to humans at certain levels, raising the carcinogenicity assessment from the prior finding of “suggestive” evidence that the substance can cause cancer.

EPA also recently found some evidence that another type of PFAS, known as GenX, may also be more toxic than previously understood.

PFAS have been found in drinking water in many areas of the country. Whatever the sources, the Centers for Disease Control and Prevention has found PFAS in the blood of nearly all people tested, with levels varying widely.

Consumer products containing PFAS include carpets and upholstery, waterproof apparel, floor waxes, non-stick cookware, camping gear, fast-food wrappers, cleaners, dental floss and firefighting foams for putting out intense fuel fires. PFOA have been used in non-stick cookware, flame repellants and cosmetics. PFOS have been used in water- and stain-resistant products.

The latest regulatory draft findings are part of an EPA effort to assess and potentially regulate the substances. They are not currently regulated as “hazardous substances” under standard federal environmental laws.

EPA may set drinking water limits for PFOA and PFOS in 2023.

While the science is developing and the draft reports have not yet been subject to standard peer review, some environmental activists suggest EPA’s newly proposed risk assessments for PFOA and PFOS could lead regulators to adopt an approach that assumes no level of exposure is safe for humans. They suggest that would lead to policies that mirror those regulating substances like lead and carcinogens like asbestos. That could lead EPA to regulate PFOA and PFOS more strictly

based on technical and economic feasibility, as well as the cancer risk range for PFOA.

There is some indication that EPA could tighten daily exposure limits for PFOA and PFOS by about four orders of magnitude compared to the non-binding advisory levels of 70 parts per trillion that EPA set for them in 2016. Some states have already set or are developing lower exposure limits, moving faster than federal regulators.

Regulation of PFAS both by EPA and by various states could have significant implications for cleanup decisions at PFAS-contaminated sites and for when and to what degree affected drinking water would require treatment.

At the federal level, regulations could result in listing the substances as “hazardous substances” under the US Comprehensive Environmental Response, Compensation and Liability Act, more commonly known as the Superfund law. The listing of certain PFAS as hazardous substances under the Superfund law could impose significant cleanup liability for responsible parties at sites across the country, including landfills. Even where regulators previously considered cleanups of other substances to be complete, a listing could reopen past settlements, requiring responsible parties to do additional remediation where regulated PFAS are found, but that were not addressed.

Subjecting the substances to regulation under the US Resource Conservation and Recovery Act could also open such contamination not only to federal enforcement, but also to citizen suits under RCRA.

The setting of nationwide drinking water standards, or even just state-level standards, could also have significant effects. Setting of drinking water standards could require water utilities to incur substantial ongoing costs to test and possibly treat water. Nationwide drinking water standards could force them to spend billions of dollars to comply with testing and treatment requirements over just the first five years.

Despite these findings, EPA has also signaled that it might use different regulatory models for different perfluorinated chemicals based on its work to divide the thousands of known PFAS into subgroups for testing and regulation.

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EPA has already identified 24 different classes of PFAS that may need to be studied before concluding how toxic these chemicals are. EPA is likely to regulate in piecemeal fashion. It will take time for studies to inform any new regulation, where needed.

— *contributed by Andrew Skroback in New York*

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