NORTON ROSE FULBRIGHT

PROJECT FINANCE
NewsWire
March 2022

Effects of the Russian Invasion

by Keith Martin, in Washington

Leading project finance market participants were split as the *NewsWire* went to press about the effect the Russian invasion of Ukraine will have on renewable energy and the broader project finance market.

Some said they see little lasting impact.

Others saw potentially wide-ranging second-order effects, with the effects growing more pronounced the longer hostilities and sanctions last and if the fighting spreads beyond Ukraine.

Debt and Equity

Interest rates for bank project finance debt have not yet been affected.

Ralph Cho, global co-head of power and infrastructure at Investec, said that the bank market remains "business as usual aside from the shock of the invasion happening."

The institutional debt market tends to react more quickly than the bank market to events. Spreads have widened for term loan B debt with institutional lenders either pausing or pricing at the wider end of the range, Cho said. "I can only imagine it is a matter of time" before the effects are felt in the bank market.

Andy Redinger, group head of utilities, power and renewable energy at KeyBanc, said he has not seen any widening of spreads in the bank market and does not expect any currently, assuming tensions do not escalate beyond Ukraine.

Russian banks do not appear to have been involved in project finance / continued page 2

IN OTHER NEWS

US IMPORT TARIFFS on solar cells and panels could remain a battleground into the summer.

Opinions differ about whether the US Department of Commerce is likely to proceed to an investigation phase after Auxin Solar Inc. asked Commerce to impose anti-circumvention duties on solar panels assembled in Malaysia, Thailand, Vietnam and Cambodia using Chinese components. The agency has in theory until March 25 to decide, but may take more time.

Any duties could apply retroactively to panels imported from February 8 forward, which is the date Auxin filed the petition. / continued page 3

IN THIS ISSUE

Ukraine

continued from page 1

transactions in North America, but have been in some transactions in Europe. "That will be directly problematic for obvious reasons," the head of infrastructure and energy finance at a global private equity fund said.

The invasion has added to volatility in the equity markets. It could delay launches of initial public offerings of a few renewable energy development companies, Redinger said.

Stock prices have been falling for weeks. The decline has been small when compared to recent gains. The S&P 500 index was in correction territory after a 12% drop so far this year, but that compares to a 114.4% increase in the period from March 2020, when the market hit bottom, through January 3 this year.

Ted Brandt, CEO of Marathon Capital, said Marathon has not noticed any slowdown in the private equity markets, "although a drop in public equity prices will have a negative effect on private firms who are always compared against public trading multiples."

European capital could eventually be diverted to fund a more rapid transition to renewable energy in Europe. The heavy dependence of Europe on Russian oil and gas has limited Europe's room for maneuver in the current crisis. Europe relies on Russia for nearly 40% of its natural gas supply. Roughly 8% of Russian gas supplied to Europe passes directly through Ukraine.

Gas prices shot up to $40 per mmBtu versus about $5 per mmBtu in the US. Prolonged higher prices would make a recession more likely in Europe as consumers struggle to pay bills and factories have to curtail production.

Michael Kumar, global head of project, commodity and infrastructure finance for Morgan Stanley, said he sees a "boom for US LNG and I expect numerous projects to be commissioned, the clear winner in this tragedy."

Kumar said he will be interested to see to what extent global policy shifts to "drill baby, drill" to try to replace Russian oil and gas supplies. Russia supplies 12% of global oil demand and 10% of petroleum products. About 60% of Russian oil goes to Europe and 30% to China. The prices for Brent crude surged briefly after the invasion to above $100 a barrel for the first time since 2014, before settling back into the $90 range. The US imports little Russian oil. However, the oil price is set in global markets.

There were indications as the *NewsWire* went to press that Russian oil was starting to trade at a discount, indicating buyers are trying to avoid Russian cargoes.

It is unclear to what extent oil and gas producers will be interested in making new investments to increase production. The oil majors have started transitioning to renewable energy. Many lenders and equity investors are no longer willing to finance fossil fuel projects. US regulatory policies have made building new pipelines more difficult.

Any substantial increase in US exports of natural gas to Europe would have to be accompanied by increasing US production to mitigate the potential to increase the price of gas supplied to the domestic market.

Tax Equity

The potential for escalating political tensions with uncertain economic effects could lead to more price indexing in the tax equity market. Tax equity investors may be more likely to want to index the tax equity yield during the period between signing the letter of intent and document signing, one tax equity investor said.

More broadly, tax equity investors are worried that upward pressure on interest rates, raw materials and international shipping costs will increase project costs.

Costs have already been increasing due to tangled supply chains and general inflation. Russia accounted for 6% of the global aluminum supply and 5% of nickel in 2021. Aluminum prices are at an all-time high of $3,450 a ton after increasing 3% immediately after the invasion. Nickel is at a 10-year high of $25,000 a ton. Russia also accounts for more than 4% of the global copper supply.

The Russian invasion of Ukraine could have wide-ranging second-order effects on the project finance market.

Russia and Ukraine supply almost all of the neon that is used by lasers to etch features on computer chips.

"Increased fuel prices will drive up costs all along the supply chain and especially in the already-stressed logistics sector," Michael Alvarez, president of Longroad Energy, said. If defense procurement is ramped up in Europe and the US to supply or stockpile arms and equipment, more commodity demand could put further stress on the supply chain.

Escalating project costs have led to cancellation of as much as 30% of solar power purchase agreements for projects still under development as the projects are no longer able to supply electricity for the prices originally promised, according to some solar CEOs.

The higher costs are also leading to other challenges. Many developers of renewable energy projects stockpiled equipment in order to treat their projects as under construction before deadlines to qualify for federal tax credits. The stockpiled equipment had to amount to at least 5% of the total project cost. With escalating costs, the equipment is falling short.

Another consequence of escalating costs is appraisals for some projects are suggesting the projects are worth less at the end of construction than they cost to build. The construction costs have gone up, but the revenue expected under long-term power purchase agreements has not changed.

One tax equity investor said we may see "decreasing appetite for long-dated low-price PPAs on the part of sponsors not wanting to fix the revenue side when the price-indexed cost side remains unfixed." This could have a significant effect on how tax equity transactions are structured, he said, "such as more merchant risk, increased reserves, collateral requirements and more robust sponsor support." At the same time, it would eliminate electricity basis risk.

US Economy

The invasion increases the challenge facing the Federal Reserve as it increases interest rates and pares the $8.9 trillion in assets on its balance sheet in an effort to tame demand.

The Fed is expected to start increasing rates at its next meeting on March 15 to 16. Higher rates should lead eventually to higher rates in the project finance debt market. Tax equity yields are less directly correlated to interest rates.

The Russian supply shock will make it harder to bring the US economy in for a soft landing.

The US economy suffered both supply and demand shocks during COVID. Labor shortages and shipping / continued page 4

IN OTHER NEWS

The US has been collecting countervailing and anti-dumping duties on solar panels imported directly from China since December 2012 to offset the effects of Chinese export subsidies and of Chinese manufacturers dumping product on the US market at lower prices than the panels are sold for in China.

US duties vary depending on the panel supplier. The China-wide rates are 238.95% in anti-dumping duties and 17.10% in countervailing duties. Some companies qualify for lower rates after presenting evidence to Commerce.

JA Solar and Risen panels are subject to countervailing duties of 18.49% and 15.71%, respectively.

Jinko and Risen solar panels are subject to anti-dumping duties of 32.69% (although Jinko panels appear to be being blocked by US Customs due to forced labor concerns). Anti-dumping duties of 23.17% are being collected on panels from JA Solar, Suntech, LONGi and six other Chinese manufacturers.

These are the preliminary subsidies that Commerce found various Chinese suppliers benefited from on panels imported during the period December 2019 through November 2020 and preliminary dumping margins for calendar year 2019, the most recent years under review. The final figures are not expected to vary significantly.

Importers must post cash deposits when the panels pass US Customs.

Adjustments are made to the cash deposits as Commerce revisits the dumping margins and export subsidies over time. In such cases, importers may be required to pay more or receive refunds.

Auxin said in its petition that the four southeast Asian countries accounted for more than 79% of US solar panel imports in 2021. US government figures are 81%, not including Cambodia. / continued page 5

Ukraine

continued from page 3

difficulties were constraining supply at the same time that a $10.6 trillion global fiscal stimulus was adding to demand. However, some types of demand dropped precipitously, like for dining out and travel. The challenge for the Fed is how to tame demand just enough for it to match the constrained supply without stifling the post-COVID recovery. Some economists expect the invasion to lead to an increase in the US inflation rate to just below 9% rather than just shy of 8% as currently forecasted.

Many market participants worry about the effect the invasion could have on efforts to tame climate change.

A shift in focus to energy security is not as good for renewable energy development, one said.

Some worry that the invasion could sink whatever remnants remain of the "Build Back Better" bill as not only the invasion, but also the new Supreme Court nominee and the ongoing negotiations between Republicans and Democrats over funding for the federal government use up whatever available time there is on the Senate calendar this spring. The US government is still operating under budget priorities set during the Trump administration. It faces a March 11 funding deadline to fund federal agencies after having kicked the can down the road several times.

Catalyst?

Others see the reminder of European vulnerability to unstable fossil fuel supplies as a catalyst.

Andrew Waranch, CEO of Spearmint Energy and a former commodity fund manager and trader, predicted the "switch to alternative energy is emboldened to remove dependence on foreign energy." Jam Attari, former CEO of BayWa r.e. Solar said "uncertainty is a killer for long-term planning in any market," but "on balance, I think we come out ahead relative to other markets" because renewables remain a good bet for long-term growth.

Gabriel Alonso, CEO of 547 Energy and former CEO of the North American development arm of Energias de Portugal, said the invasion will force Europe to focus seriously on energy independence and a more stable energy partnership.

He thinks Europe will have to streamline its licensing approval process for use of both onshore and offshore resources before it can shift more quickly to renewable energy. It will also have to debate whether it wants to continue to rely on Russia for energy supplies to northern Europe and Algeria, Egypt and Libya for supplies to southern Europe, or shift possibly to the United States as supplier.

He does not foresee any major changes in financing for renewable energy projects in the near term. "If anything, the appetite to finance merchant projects or provide financing for longer merchant tails may increase if the supply of gas is viewed as more than an interim issue," he said.

Himanshu Saxena, CEO of Starwood Energy, said he sees a mixed bag. The invasion will "worsen inflation and supply-chain issues, thus keeping costs to build new projects high, but at the same time, it will keep commodity prices high, thus helping renewable projects get new PPAs."

The effect on US-China relations could prove very important. China is a major supplier of polysilicon, solar cells and modules, batteries and lithium. The US tried for weeks to get China to pressure Russia not to invade. China criticized the US in the immediate aftermath of the invasion, but then abstained from voting on a UN security council resolution condemning Russia and moved to a somewhat more neutral tone in its public comments.

Samir Verstyn, chief investment officer of Origis Energy, said, "China has appeared not to have actively sided with the West or Russia." Any shift in US-China relations could have "much larger global repercussions and implications for our business."

Verstyn said US power companies are having to increase cybersecurity materially, especially

The invasion will make it more challenging for the Federal Reserve to tame inflation in a manner that brings the US economy in for a soft landing.

after Russia threatened retaliation if the US keeps supplying Ukraine with defensive weapons. Origis not only develops its own solar projects, but also operates large projects for other companies.

Emerging Markets

Political risk insurance will be harder to find for projects in former Warsaw Pact countries, affecting the ability to do projects in such countries.

The insurance markets do not cover war risks of the type that could lead to a loss in the current circumstances, one insurance underwriter said. Russia coverage has been difficult to find for the past several years because of sanctions, she said. Ukraine coverage had been virtually impossible without participation by multilateral lending or export credit agencies.

However, if there are non-war losses — for example, from political violence or forced abandonment, as happened after Russia annexed Crimea — this could affect premiums on future policies as underwriters look to recoup losses through higher prices.

John Schuster, former head of project finance at the US Export-Import Bank and currently president of JLS Capital Strategies, said he sees a negative effect on financing projects in emerging markets, "maybe even a very large negative effect." He said a large number of factors will outweigh the potentially positive effect of higher commodity prices that benefit many emerging market countries and the increased need and even urgency for renewable energy.

Those factors include the "generally higher risk profile of projects and the peril of doing business" in undemocratic countries, the threat of political violence and cyberattacks, and a "global slowdown in the economy and a tightening of financial markets that will follow a market correction," Schuster said.

Jeremy Hushon, a project finance partner who focuses on emerging markets with Norton Rose in Washington, said he expects the US government and European development finance institutions to shift emphasis to countries that represent the next line of defense — Poland, Romania, Hungary, Moldova and the Baltic countries. "Turkey will be particularly interesting to watch," he said. "Despite the recent history of tension with the West, I expect we may see a rapprochement and renewed investment in an attempt to keep the country away from Russian influence."

The issue for all of these countries will be whether private developers have any appetite for the risk. ◎

IN OTHER NEWS

Less than 1% of US solar panels came directly from China in 2021.

Meanwhile, the US House of Representatives voted in early February to require Commerce to look into circumvention concerns whenever an interested party files a petition and to make a decision on an accelerated timetable. The language is part of a sweeping America COMPETES Act aimed at boosting American competitiveness with China. The bill the House passed must now be reconciled with a different measure the Senate passed in June last year and that lacks the anti-circumvention language.

Separately, President Biden decided in early February to extend existing "safeguard" tariffs on imported solar panels for another four years at an initial rate of 14.75% for the period February 7, 2022 through February 6, 2023, falling to 14%, at the rate of 0.25% a year, by the last year of the four-year period.

However, he exempted bi-facial solar panels, which make up a growing share of US panel imports, from the duties.

He also increased the volume of crystalline silicon solar cells not yet assembled into panels that can enter duty-free from 2,500 megawatts to 5,000 megawatts a year.

The safeguard tariff does not apply to panels imported from a list of 99 developing countries, including Brazil, Cambodia and Indonesia. President Trump withdrew developing country status from India in May 2019.

The US Trade Representative can withdraw the exemption for a developing country if its share of total panel imports exceeds 3%. Auxin asserted in its anti-circumvention petition that Cambodia supplied more than 3% of US solar panels in 2021. The trade representative can also suspend the exemption for all developing countries if the share of total imports from countries with less than a 3% import share exceeds 9% of total imports.

Biden directed the US Trade Representative to enter into negotiations with Mexico and

/ continued page 7

Cost of Capital: 2022 Outlook

A record number of banks and grey market lenders are chasing projects at the start of 2022, keeping downward pressure on interest rates despite rising inflation. The tax equity market did a record volume in 2021. However, there are concerns about its ability to handle demand as giant offshore wind farms and carbon capture projects start coming to market. Supply-chain difficulties that are delaying projects helped to mitigate demand in 2021. A direct-pay alternative and an option for solar projects to claim production tax credits will be needed to take pressure off the market longer term.

Developers are facing an unusual number of headwinds at the start of 2022, including broken supply chains, inflation, Customs seizures of solar panels, skyrocketing casualty insurance premiums, tax law uncertainty and rising domestic and international political tensions.

More than 3,300 people registered to hear a panel of veteran financiers talk in mid-January about what to expect in the year ahead. The panelists are Jack Cargas, head of origination on the tax equity desk at Bank of America, Rubiao Song, managing director and head of energy investments for JPMorgan, Ralph Cho, global co-head of power and infrastructure finance for Investec, Max Lipkind, managing director and head of Americas leveraged finance origination for Credit Suisse, and John C.S. Anderson, global head of corporate finance and infrastructure for Manulife. The moderator is Keith Martin with Norton Rose Fulbright in Washington.

Tax Equity

MR. MARTIN: Rubiao Song, what was the tax equity volume in 2021, and how did it break down between wind and solar?

MR. SONG: The total volume in 2021 was $19 to $20 billion, roughly split 50-50 between wind and solar. If we compare that to 2020, it represents a small decrease in wind and a large increase in solar.

MR. MARTIN: To put these numbers into perspective, renewable energy tax equity volume was $17 to $18 billion in 2020 and $12 to $13 billion in 2019, so the volume continues to grow, but the rate of increase slowed. Jack Cargas, do you agree with those numbers?

MR. CARGAS: Yes. Our estimate for 2021 was $19.5 to $20 billion. We also see the market leaning more heavily toward solar. Our investments at Bank of America were roughly 60-40 wind and solar, but we believe the overall market was roughly 50-50.

We are expecting another $20 billion in 2022, plus or minus 5%.

MR: MARTIN: Rubiao, what is your expectation for 2022?

MR: SONG: I agree with Jack. Demand for tax equity remains exceptionally strong, particularly in the utility-scale solar and solar-plus-storage sectors. However, the volume for the year ahead is harder than usual to predict because of the many challenges, such as tax law uncertainty, COVID, trade tensions and supply-chain issues. It could be the first down year for tax equity in many years.

MR. CARGAS: We don't expect a down year. The market size has roughly doubled over the last five years. It was about $10 billion as recently as 2017. It has been growing steadily.

MR. MARTIN: How much tax equity did Bank of America invest last year?

MR. CARGAS: I can't give a figure, but it is not an exaggeration to say that 45% to 50% of the 2021 tax equity is represented on this panel.

MR. SONG: I think we did about the same volume as in 2020, so that is $5+ billion in new commitments executed in 2021. We would have done more if not for supply-chain delays.

MR. MARTIN: One message from past calls is that most tax capacity is already spoken for by the summer. It is only January, but can you say what percentage of the tax equity you will invest this year has already been committed?

MR. CARGAS: Our message to sponsors last year about 2022 projects was to come to market early. Many sponsors were in a position to comply, and so we have been able to fill out a significant portion of our book for wind, solar and storage. Roughly 80% of our 2022 tax equity is already allocated. That is not necessarily committed through executed term sheets or documents, but circled.

MR. SONG: It is hard to state a percentage. Many deals were delayed into the first quarter of 2022, so that is a significant claim on 2022 capacity. I think 2022 tax capacity is going to be a very scarce commodity given the demand from the solar market.

In general, $10 billion in solar tax equity would require about $10 billion in current year tax capacity, but $10 billion in wind tax equity only requires about $1 billion in current year tax capacity because the tax credits on a wind project are spread over time. That is a huge difference.

How much of the market the scarce 2022 tax capacity will be able to cover will be influenced by the fate of the "Build Back Better" bill in Congress. If solar developers can claim production tax credits and there is a direct-pay alternative to tax credits, it will allow tax capacity to be spread over a larger number of deals.

MR. MARTIN: Last year, you both said that tax equity is roughly 35% of the capital stack for the typical solar project, plus or minus 5%, and it is 65% for the typical wind project, plus or minus 10%. Have those percentages changed since last year?

MR. CARGAS: No. The capital stack percentages could change if some of the "Build Back Better" provisions are enacted.

MR. MARTIN: Let's talk about factors that affect the cost of tax equity. I know you are reluctant to talk about flip yields. Flip yields seemed to us to have fallen in 2020 into the low-to-mid 6% range for the best projects and a few sponsors even saw tax equity yields below 6%. In 2021, they seemed to be moving up and were more likely to be in the high 6% to mid-7% range.

The cost of tax equity is a function of demand and supply. It does not move closely with interest rates.

Do either of you expect supply to be a constraint at your banks? You both have seemed to have unlimited tax capacity. The constraint has been people to do the deals.

MR. SONG: The traditional tax equity base will not be able to absorb the many billions of tax credits on renewable energy projects in 2022 and beyond. A big portion of the tax capacity is already spoken for before the year even begins, and there is competition for the same tax capacity from the low-income housing market.

It is more critical than ever for the industry to attract more untraditional investors, especially if the Build Back Better bill is not enacted. A serious supply-demand imbalance will remain, and there are other headwinds this year like rising interest rates and more stringent regulatory capital requirements for banks.

MR. MARTIN: On the demand side, a potential future issue is the number of giant offshore wind and carbon capture projects that will also need tax equity.

Jack Cargas, do you expect more than one offshore wind tax equity deal to close this year?

MR. CARGAS: We do not. We see numerous offshore transactions on the horizon, but most of those deals are two to five years away. We expect to see one offshore wind tax equity transaction close in 2022.

Supply-chain issues and Customs seizures of solar panels helped to moderate demand in 2021.

MR. MARTIN: Are you aware of any carbon capture tax equity deals that have closed?

MR. CARGAS: We are aware of one or two small carbon-capture-and-storage transactions, but the */ continued page 8*

IN OTHER NEWS

Canada to exempt imported solar panels from those two countries from the safeguard tariff.

A dispute settlement panel operating under the US-Mexico-Canada trade agreement found in early February that President Trump violated the agreement by collecting import duties on solar panels imported from Canada after the US International Trade Commission concluded that Canadian solar panel imports were not harming US panel manufacturers.

The US has until March 18 to drop the tariffs on Canadian panels or Canada can impose retaliatory tariffs on American goods of comparable value.

Canada said its solar panel exports to the United States have declined by 82% since the tariffs were originally imposed in 2018. The decision by the dispute settlement panel does not apply to Mexico because the US International Trade Commission found that Mexican panel exports to the US could harm US manufacturers.

The US collected close to $2.8 billion in duties on imported solar panels over the four years of the Trump administration.

US CUSTOMS is starting to release some blocked Chinese solar panels.

A federal task force is collecting suggestions by March 10 for how best to prevent Chinese products that use polysilicon or other components made with forced labor from entering the United States.

US Customs released nearly 100 megawatts of detained LONGi solar panels in February and the vast majority of Trina solar panels after initially blocking entry over concerns that the panels may have benefited from forced labor in Xinjiang in western China.

US Customs detained 1,469 shipments of goods that were suspected of being made with forced labor in fiscal year 2021.

Meanwhile, the US government is moving toward a deadline of June 21 to implement a new Uyghur Forced */ continued page 9*

Cost of Capital

continued from page 7

larger deals look like they are still a couple years away.

MR. SONG: We expect several large carbon capture projects to get done in 2022 that are already trapping CO_2 emissions and have existing pipelines and storage sites.

MR. MARTIN: Are you aware of any that have closed?

MR. SONG: No.

MR. MARTIN: Inflation hit 7% in the latest consumer price index report last week. The Fed could start increasing rates as early as March. Is this affecting the tax equity market?

MR. CARGAS: Not a lot. Inflation may have more of an effect on project costs than on financing costs. If inflation leads to higher equipment and construction costs, the already thin developer margins may be that much more squeezed, and developers will need relief on the revenue side or there will be some really nettlesome project economic issues.

As for tax equity, there could be some internal spread compression due to rising costs of funds, but I think tax equity investors will live up to the commitments they have made as priced.

Renewable energy tax equity was a $19 to $20 billion market in 2021.

MR. MARTIN: There were a lot of challenges last year. How are you addressing supply-chain delays and Customs seizures of Chinese solar panels in deal papers?

MR. SONG: We have seen both affect construction timelines. Some sponsors are better equipped to deal with these issues than others because of their market presence and their relationships with suppliers. It is more important than ever for developers to be realistic about project timelines. They need to build in an additional cushion, plan for delays and cost increases, and be sensible about when to approach tax equity because a tax equity commitment carries significant cost.

MR. MARTIN: Jack Cargas, are there any special provisions that are put into documents to address these risks?

MR. CARGAS: We are focused on quality assurance and quality control standards for equipment supply and delivery, especially in light of the forced-labor concerns. We want a clear line of sight into the supply and delivery of solar panels and other equipment, including into the country, through Customs and to the project site. We need to have absolute certainty about those things before the first funding.

MR. MARTIN: Another challenge is tax law uncertainty. The Build Back Better bill is stalled currently in Congress. Biden could make another push before his State of the Union address to Congress on March 1. Suppose it passes and projects end up with higher tax credits than were expected when the deal papers were signed. What should happen in such situations? Does the tax equity fund more?

MR. SONG: The devil is in the details. We start to analyze the potential economic impact on deal terms with sponsors before the commitment is signed.

MR. MARTIN: I imagine you are not letting people walk away from the tax equity deal if direct pay suddenly becomes an option after the deal has been fully negotiated?

MR. SONG: That's right. We think tax equity can be efficient even in a scenario where a direct payment is chosen in place of tax credits.

MR. MARTIN: Jack Cargas, if the tax benefits turn out to be larger than expected, of course the extra tax benefits will be taken into account for tracking when the flip yield is reached, but is there also some adjustment in the amount of tax equity invested?

MR. CARGAS: That is how the tax equity market has responded to such changes in the past, and we expect that is how it will respond again. I think the tax equity market has generally dealt very well with change-in-tax-law provisions in the past. This has become a core competency.

The problem with the Build Back Better bill is that it is so complex and nuanced. It is not particularly susceptible to contingency planning. You cannot document comprehensive treatment for the many, many scenarios possibly emanating from the bill. There are too many issues in play, and the outlook for the bill itself is uncertain.

That said, as a general matter, if there is more value in the tax credits, then you would expect to see an increased funding amount.

MR. MARTIN: Last question, and then we will move on to bank debt. Are there any other noteworthy developments as we start the year?

MR. CARGAS: People listening to this call may be struck by the number of challenging headwinds, but there may be another way to look at it.

When Bank of America started its renewable energy tax equity business 15 years ago, there were only a handful of individuals in our shop and across the entire US corporate landscape interested in renewable energy finance. Capital for renewable energy projects was scarce. If you fast forward to today, there are scores of people inside our firm and thousands across the corporate landscape working in the sector, bringing with them massive amounts of technical expertise and hundreds of billions of dollars through many types of capital.

Despite the headwinds — and we haven't even touched on the winter storm in Texas and things like the continuing legislative quagmire in Washington — there is still plenty of room for optimism in this sector.

MR. MARTIN: Well put.

MR. SONG: I certainly echo that. Two other trends to add: one is there are more utilities now owning renewable energy projects and tapping the tax equity market. Another is electricity prices are enjoying a small rebound. More cash flow makes the tax equity financings work better.

Bank Debt

MR. MARTIN: Let's move to the bank market. Ralph Cho, has the bank market settled back into its pre-COVID pattern? If not, what are the lingering effects?

MR. CHO: It definitely looks that way. The bank market last year was super busy. / *continued page 10*

IN OTHER NEWS

Labor Prevention Act that Congress enacted in late December to block products made with forced labor in Xinjiang from entering the United States.

The new law requires the government to collect suggestions on implementation, then hold a public hearing and then publish a strategy by June 21 by when comprehensive enforcement measures are supposed to be in place.

The Forced Labor Enforcement Task Force kicked off the process by asking for suggestions in a January 24 *Federal Register* notice. The task force, which was created under the US-Mexico-Canada free trade agreement, is looking for ideas on potential measures that can be taken to trace the origin of goods, offer greater supply chain transparency and identify third-country supply chain routes that lead back to forced labor and the People's Republic of China.

The comments and a public hearing this spring are supposed to lead to a strategy that includes publication of various lists, including Xinjiang entities that use forced labor to produce goods, Chinese products that are made with forced labor, entities that export such products and factories and companies that "source materials from" Xinjiang.

The new law identified three high-priority sectors for enforcement: cotton, tomatoes and polysilicon.

The strategy is supposed to include an enforcement plan for each high-priority sector.

It is also supposed to inform importers what due diligence and supply-chain tracing they are expected to do and the type of evidence that can be used to prove no connection to Chinese forced labor.

US companies trying to purge supply chains of forced labor are running into resistance from Chinese suppliers who bristle at western claims of genocide in Xinjiang and fear violating Chinese laws against enabling western trade sanctions.

The task force is / *continued page 11*

Cost of Capital

continued from page 9

It just seems like everyone keeps grinding it out in the face of less travel and too many video calls and without an end in sight.

The market is still awash in liquidity. There are more banks chasing deals than there are deals to finance. You really see this as the margins continue to tighten. Even a pandemic has not slowed all of this lending appetite. Omicron shut our offices at the end of the year, but no one really missed a beat. Demand for deal documents is still sky high, even going into this year.

We see investment interest coming in not just from the traditional players, but also from a lot of small regional banks and from credit funds acting as direct lenders. The South Korean investors that have had a big impact in recent years are selectively crawling their way back into the market as well.

MR. MARTIN: How many active banks were there in 2021, and how many do you expect this year?

MR. CHO: Unlike last year when we saw a number of players pause because of the pandemic, it is now a little bit of the reverse. I think I said there were between 50 and 70 lenders last year chasing deals. I put that estimate at closer to 100 this year, if not more.

Smaller commercial retail banks account for a lot of the increase. They are interested in ESG deals. The grey market lenders also continue to expand. A lot of new capital is being raised not just by existing fund managers, but we also see a lot of new fund managers.

Some of the limited partner investors in funds are choosing to become direct lenders themselves. They are looking to hire their own teams to evaluate deals. There was a lot of sideline capital last year. That is also coming back into the market.

MR. MARTIN: You said 80 to 100 banks and grey market lenders in 2018 and 2019, and then the number dipped significantly in 2020. What was the volume of North American project finance transactions in 2021 compared to 2020?

MR. CHO: Definitely down. The numbers are still preliminary, but North American banks came in around $61 billion across 183 deals. We were down in North America about 9% compared to last year. We did not see a lot of super large LNG deals in the bank market. The market remained busy with a lot of renewables deals, but renewables deals tend to be smaller in size.

MR. MARTIN: In 2020, the volume was $69.5 billion and 213 deals. Will all loans this year use SOFR as the benchmark rate?

MR. CHO: Yes and no. New floating-rate issues will have to move to SOFR as the benchmark rate. No bank can issue a new loan that is LIBOR based. Existing LIBOR loans can stay with LIBOR until June 2023, so call it 18 months left. People are expected to adjust their loans before then because LIBOR will be discontinued.

Here's something interesting I can share with you: we have been running new amendments and upsizings for our borrowers, and so we have had to be creative to make everybody happy. One thing we are doing is keeping the existing loan at LIBOR, while basing the upsizing on SOFR. Eventually, everything has to go to SOFR.

MR. MARTIN: What is the current spread above the benchmark for bank debt?

MR. CHO: It varies. The market is still tightening. Every year, I say that spreads cannot go lower, and here we are with plain-vanilla loans pricing as tight as LIBOR plus 112.5 basis points. The low end of the range was 125 basis points at this time last year.

Short-term construction bridge loans are now as tight as LIBOR plus 60 to 70 basis points for one-year paper. These rates are really for tier-one clients. If you are a borrower and you are not getting that rate, I suggest

Offshore wind and carbon capture projects may cause demand for tax equity to increase faster than the supply.

you talk to your banker, because that yield definitely seems to work for a lot of banks.

The range for quasi-merchant gas deals is a little wider. It is LIBOR plus 250 to 500 basis points. It is a wider band because it is harder to move thermal paper or quasi-merchant gas paper. Banks don't want to do it or they at least seem more resistant. We have moved paper that I would say is safer, on the merchant end of the spectrum, to the tighter end of that spread. We have also done more aggressive paper that we have had to move into the grey market on the wider end of the range, and we have a lot of deals that fall in between.

For HoldCo paper, if you are offering LIBOR plus 400 basis points and some upfront fees, you are probably getting momentum with some lenders – not all, but some. Hopefully, it is enough to clear the market. The sweet spot for these types of investors is really around 7% all-in. That is what everybody wants.

There is a potential, if your credit profile is very clean, to find commercial banks willing take HoldCo paper at an even tighter spread, in the area of LIBOR plus 200 basis points. Commercial banks don't need a floor, and they don't need call protection. They are your cheapest source of capital. We have lost hybrid HoldCo deals to aggressive commercial banks this way.

The delta between between OpCo and HoldCo loans is typically around 200 basis points. It is probably around 125 to 200 basis points now because of competition. The reason is the banks are not pricing it to risk. They are pricing it to a spread over their return models. I would take that paper every day if you can get it.

MR. MARTIN: What are current debt-service-coverage ratios? Last year, they were 1.35 times P50 cash flow for contracted wind and 1.25 times P50 cash flow for contracted solar. Has there been any change?

MR. CHO: Not really. I would even now throw in batteries. Batteries are even tighter at 1.2 times P50. However, it is not really solely about contracted cash flows. Borrowers want credit for merchant cash flows after the PPAs end, and they are getting maybe five years of such credit. Such structures are now considered plain vanilla. Lenders cannot get enough of these types of deals, either.

Everything else is still the same. Thermal deals were sizing around 1.3 times contracted revenue. They are now getting merchant credit.

Portfolio debt is still tested on a consolidated basis. We are going down to 1.1 times P50.

Capacity payments and revenue puts are still getting 1.15 times P50. Heat rate call options are still / continued page 12

IN OTHER NEWS

supposed to send its first report to Congress by June 21, 2022 laying out the strategy and then to update Congress annually.

The new law directs Customs to presume that any goods produced or exported by entities on the entity lists should be blocked from entry. The presumption can be overcome in theory by showing that the importer of record fully complied with all of the guidance for diligence and supply-chain tracing and answered all questions from Customs.

Any exceptions granted must be reported to Congress within 30 days.

The task force must also report twice a year to Congress on the number of times goods are denied entry and provide descriptions of the blocked goods.

These measures will remain in effect for eight years through the end of 2029, unless the US president tells Congress sooner that China has ended mass internments, forced labor and any other gross violations of human rights of ethnic minorities.

CRYPTOCURRENCY MINERS are becoming a potentially lucrative outlet for some power suppliers.

Electricity is a large percentage of the cost of mining bitcoin and ether, two currencies that rely on "proof of work" using power-hungry banks of computer servers to solve complicated equations to earn coins and validate transactions. Bitcoin mined at a price of $50,000 per bitcoin is equivalent to selling electricity for more than $400 a megawatt hour. (For more detail, see "Cryptocurrency Mining for Power Suppliers" in the December 2021 *NewsWire*.)

There are three main business models. The simplest is a power contract by a renewable energy generator to supply electricity. The typical power purchase agreement is for five years of electricity at the local spot price, plus an adder. The miner enters into a hedge to cap the amount it will have / continued page 13

Cost of Capital

continued from page 11

around 1.3 times. We use flat-line capacity payment assumptions for projects in places like PJM and New England. The PJM capacity auctions are really testing the line that we are using with our capacity assumptions. If PJM could get them back on a normal cycle, we could see some good numbers. They even have the potential to reset our assumptions and appetite for new merchant gas financings this year.

MR. MARTIN: Bank loan tenors have generally been five to seven years with mini-perm structures and two-plus-five years if the debt includes a construction loan. Has there been any change in that?

MR. CHO: No change on tenor. Lenders can go up to 15 years, but it costs a little more. The Canadian banks are able to go up to 19 years. I think that is because of local market dynamics.

MR. MARTIN: Have you seen any change in appetite among banks for any of the following: quasi-merchant projects, corporate PPAs, CCA contracts in California, community solar, standalone storage, hydrogen?

MR. CHO: Banks have super-high appetite for anything connected to ESG deals. What really is driving that is the large number of banks that have committed publicly to sustainable finance goals. We have been seeing such banks focus on buying renewable exposure, which continues to add to the liquidity in the market.

Every level of the capital stack that wants ESG exposure has to be willing to accept lower returns and higher risk compared to other asset classes. Some banks are even acknowledging that they are offering lower rates to borrowers for ESG-type exposures.

Exciting areas that lenders are trying to look at now include carbon capture and sequestration, fuel cells and hydrogen. The deal volume in those areas is well short of the available capital.

Thermal assets and quasi-merchant gas assets are harder to place in the market. We have seen banks turn down thermal activity to pursue ESG projects. The dismal capacity prices in the last PJM auction have made banks rethink how much overall merchant gas exposure they should have in their portfolios. They are considering cutting back. Capacity prices have to move up in the next auction before banks will be interested in making new loans.

MR. MARTIN: Last question, brief answer. Are there any other noteworthy trends as we enter 2022?

MR. CHO: Trends. We talked about ESG, liquidity and limited partners in credit funds doing direct lending. I will throw one thing out there that nobody really talks about. That is a banker shortage, Keith. People are becoming more mobile and changing lifestyles. It is hard to find people to fill open positions. We see a large number of people moving from junior levels all the way up to the senior levels at banks. Lots of teams at banks are hurting for staff. The market is going to have to pay up to obtain and retain talent. It is a great time to be a recruiter. Everyone is busier than ever before.

Term Loan B

MR. MARTIN: We are all suffering from exhaustion. The "Great Resignation" is affecting everybody working in this sector.

Thank you for that, Ralph. Let's move to Max Lipkind with Credit Suisse and talk about the term loan B part of the institutional debt market.

To set the stage, the term loan B market is institutional lenders using bank-like loan documents. The institutional debt market responds more quickly to changing market conditions. The term loan B market was pretty severely dislocated after the COVID lockdowns started in 2020. The average B loan debt instrument was trading in the spring 2020 at 76¢ on the dollar compared to the face amount, which implied a spread of 625 basis points over LIBOR and a yield of about 11%.

The market had fully recovered last year. Where is it as we enter 2022?

MR. LIPKIND: The institutional loan market remains in excellent shape. Many of the themes that you heard from Ralph about the bank market are also true of the institutional debt market. The key theme to start the year is the momentum in rates. The 10-year Treasury bond is now trading north of 1.9%. That dynamic obviously hurts the high-yield and investment-grade bond markets, and they have been reeling a little bit to start the year. Conversely, it is a dynamic that is very helpful to the floating-rate instruments like term loan B debt.

The index you mentioned is currently at 98, implying an average spread on loans of 415 basis points over the benchmark rate for a coupon of about 5.46%. That is roughly half of the peak when the market was trading at 76¢ on the dollar a couple years ago.

New term loan B issuances last year were about $611 billion for the overall market. To put that in context, that is more than double the new issuances in either 2019 or 2020. The term loan B market has had a ton of tailwind.

MR. MARTIN: Break it down, though. What was the term loan B volume in the North American power sector in 2021?

MR. LIPKIND: It was fairly subdued. To put that into context, the power sector volume in 2019 was $14 billion across 19 deals. It was about $10 billion in 2020 across seven deals. Last year, there was a total volume of $9.4 billion across 10 deals.

The volume was subdued compared to what we saw in the period from 2016 through 2019.

MR. MARTIN: What volume are you expecting this year?

MR. LIPKIND: Hard to predict. Ralph touched on some of the ESG themes that are also affecting the institutional market. If I had to guess, I would say comparable volume with some upside.

There are some deals from the 2016 and 2017 time frame that need to be refinanced and may not trade all that well. There might be more refinancings this year compared to last year, as some loans are getting closer to maturity and interest rates are rising.

A lot will depend on the volume of leveraged buyout activity. About 30% to 40% of overall volume in 2020 and 2021 was leveraged buyout activity. It is hard to tell how much such activity there will be in 2022.

MR. MARTIN: The 415-basis-point spread is for the market as a whole. Last year on this call, we said pricing for strong BB credits was about 325 to 350 basis points over LIBOR. Single B credits were 375 to 425. Have those numbers changed as we start this year?

MR. LIPKIND: On average, they have not.

To give you a couple data points, the index we keep of power leveraged loans stands at 96.57 as of last night. That reflects an average spread of 468 basis points. The basket of power loans trades a couple points below the overall market. On a spread basis, that is about 50 basis points wide of the overall market, for a coupon of 5.82%.

The reality is there is a ton of bifurcation within that. I think Ralph touched on some of that in his market, as well. Some of the best-in-class BB paper, particularly from some of the independent power producers, is pricing at 200 to 250 over the benchmark. Conversely, some of the fossils and thermal power generation may be a little less in favor. We saw those deals price at 475 to 500 basis points over the course of much of the second half of last year.

While the average index is in the high 90s with a spread in the mid-400s, the reality is not every credit is created equal. The market is bifurcating a lot more than it has in the past five or six years. You can see the divergence. A new issuance will come in with some of the best-in-class pricing, say 200 basis points over the benchmark, while some more / continued page 14

IN OTHER NEWS

to pay for electricity. A more complicated model is a joint venture between the renewable energy generator and the crypto company to own the data centers and split the profit. In some cases, the crypto company owns its own solar array inside the fence in an effort to find cheap power.

Cryptocurrency companies are being wooed by some states, while other states are concerned about the amount of electricity consumed.

China cracked down on cryptocurrency transactions and mining in September 2021, citing national security and economic policy concerns. This has led to a large migration of crypto operations to the US, increasing electricity demand in places where crypto data centers are relocating and, in some cases, contributing to delayed retirements of some fossil-fuel power plants.

The US share of bitcoin mining increased from 4% in August 2019 to 35% in July 2021.

Bitcoin electricity consumption increased threefold from early 2019 through May 2021 and is now equivalent to the electricity usage of a country like Sweden with 10 million people.

One of the states wooing data centers, Kentucky, exempted electricity purchased for crypto mining from the 6% state sales and use tax and 3% utility gross receipts tax in March 2021. There is also a sales and use tax exemption for material and equipment purchased to retrofit existing industrial facilities, including for crypto mining.

Texas exempts electricity, servers and software purchased for use in data centers from its 6.25% sales tax for 15 years.

In all, 17 US states enacted laws in 2021 that help cryptocurrency infrastructure. Examples are Arkansas, which amended its Uniform Commercial Code to address cryptocurrency, and Nebraska, which created a regulatory framework / continued page 15

Cost of Capital

continued from page 13

levered LBOs are now closer to 500 basis points over, versus the 375 level that you quoted.

MR. MARTIN: B loans tend to be used for acquisition financing and also for refinancing debt on operating projects. Is it still the case that the last new-build issuance in the B loan market was in 2015?

More than 100 banks and grey market lenders are chasing deals, keeping downward pressure on interest rates.

MR. LIPKIND: Truly new build, yes. We did see in 2019 and 2020 a couple of refinancings for single-asset combined-cycle gas turbine projects that were not quite new builds, but that were refinanced not long after COD. For truly greenfield projects, you are right. The last one was a Panda issuance in 2014 or 2015. New builds are being financed in the A loan commercial bank mini-perm market.

MR. MARTIN: Just a few other metrics. Let me know if any of these has changed. Advance rates have tended to be in the mid-60% range, and the tenors have been seven years. B loans have been sized historically at six to six and a half times projected EBITDA, with at least 50% repayment of the loan required over seven years and a loan-to-value ratio of 75%. Are all of those metrics still holding?

MR. LIPKIND: There are a bunch there.

Advance rates and loan-to-value are pretty comparable concepts. Sixty percent debt and 40% equity is probably the right zip code. In some instances, we can stretch leverage closer to the 75% you referenced. In other instances, for older assets or assets with more noise and color to them, it is probably closer to 50-50. That said, 40% is where I would peg the typical equity check.

In terms of sizing, it is six to six and a half times EBITDA. However, the actual figure will be very asset specific. When asset valuations fall back to historically normal levels, I think we will see deals closer to three, three and a half to four times EBITDA, certainly for older thermal assets. Some of the renewables should also be able to pierce through the six and half times EBITDA.

All of this is asset specific. Again, the theme I touched on is there is differentiation in terms of asset quality and asset types. There is strong interest in lending to ESG projects. I would not say that for traditional power projects, six and a half times is where we see financings.

In terms of repayment, that one depends on the credit quality and asset type, as well. In a couple of recent deals we did at the end of the year, we saw 75+% repayment over the life of the loan. Investors in older thermal assets are looking for closer to full repayment. For traditional power, we see 50+% and really closer to 100% repayment in recent deals.

Project Bonds

MR. MARTIN: Max, thank you for that. Let's move to John Anderson at Manulife and project bonds.

Project bonds are long-term fixed-rate loans. The loan tenor may be as long as 30+ years. The rates are fixed for the full duration. The loans are made at a spread above current 10-year Treasury bond yields. That rate is 1.9% as of this morning.

John Anderson, a year ago you said contracted projects were clearing at spreads of about 175 to 190 basis points over Treasuries. That translated into a coupon rate of around 3%. Where are rates today?

MR. ANDERSON: The change since last year is the increase in the Treasury yield. The spread above that yield has remained unchanged and is still 175 to 190 basis points for long-term, long-tenor, investment-grade financing. That translates into an overall coupon of 3.65% to 3.80%.

MR. MARTIN: We heard figures for bank and term loan B debt in the power sectors, including the transaction volumes last year. Do you have any sense of the size of the project bond market in the US power sector?

MR. ANDERSON: What Ralph Cho described as down by 10% for bank loans sounds right for project bonds. I triangulate in that the broad project bond market had another record year this past year. Our volumes were up over 2020. There is a ton of investor demand. You put on top of that the energy transition is accelerating, so that helps supply.

More investors care about renewable energy because they made public commitments to move their portfolios to net-zero carbon by 2040. Adding zero carbon wind, solar and hydroelectric is a great way to do that.

There is keen interest from across the debt spectrum. Borrowers have good options in the bank market, the leveraged loan market and the bond market. Which way do they want to go? What duration of loan are they looking for? We tend to do our best work when people want to lock in long, cheap money. That is where we end up being the best answer.

MR. MARTIN: I was going to say with inflation looking likely to increase, you would think there would be increased interest among borrowers in long-term, fixed-rate debt. Is there any evidence of that as we head into the new year?

MR. ANDERSON: We are not seeing treasurers say that is the reason. We are talking about civil construction projects that are on the drawing board where local authorities are seeing a 20% increase in total cost based on what has happened with supply chains, labor shortages and everything else.

Getting your cost to capital locked in for a long period of time might be really attractive for a lot of people this year.

MR. MARTIN: Let's talk about how large a loan one needs to make it worthwhile to look at project bonds. You are a direct lender. You don't do syndicated deals in the public market. I think you have said in the past that direct loans can be as small as $25 to $50 million. Syndicated project bonds really need to be at least $250 million to make it worth the effort. I know we have heard in the past that B loans can be as small as $225 to $250 million.

Have any of these metrics changed?

MR. ANDERSON: Those remain good numbers. As you say, we lend from our own book. We don't / continued page 16

IN OTHER NEWS

for digital depositary institutions.

Wyoming is studying whether to allow use of bitcoin to pay sales and use taxes. The main backer of the proposal in the state legislature withdrew the proposal for now, but said he plans to reintroduce an updated proposal next year.

A strong Trump and "stop the steal" backer in the Arizona Senate is promoting a bill to make bitcoin legal tender in Arizona. The proposal raises issues under article 1, section 10 of the US constitution, which restricts states from issuing their own currencies.

Senator Elizabeth Warren (D-Massachusetts) and seven other Democrats sent letters to six cryptocurrency mining companies in late January asking for information about their electricity usage. The six are Riot Blockchain, Inc., Marathon Digital Holdings, Stronghold Digital Mining, Bitdeer, Bitfury Group and Bit Digita. Warren sent a similar letter in December to Greenidge Generation Holdings.

The letters ask for information on the effect of digital mining on climate change, the local environment and the cost of electricity for retail customers.

A US House subcommittee held a hearing on January 20 about the same issues. A Democratic staff memo prepared for subcommittee members in advance of the hearing called the competition to be the first to solve increasingly complicated math puzzles over time to win the 6.25 new bitcoins that are issued every 10 minutes a "vicious circle" that encourages mining companies continuously to increase the computing power of their facilities to compete.

It said the estimated annual energy usage of the bitcoin network grew from 77.78 terawatt hours on January 2, 2021 to more than 198 terawatt hours by November 26, 2021. Electricity usage by the Ethereum network grew from 14.81 terawatt hours to more than 92 / continued page 17

Cost of Capital

continued from page 15

arrange syndicated financings, although we will participate. We will work on something as small as $50 million. A lot of people will do something like $25 to $50 million if they think it will lead to repeat business.

To get a good syndication, you are going to need to do at least $250 million. You can get together two, three or four direct lenders if you want to do something in that range and don't want to take the time to do a broadly syndicated loan.

You have a lot of options depending on project size. You can see projects easily clear more than $1 billion with a good roster of lenders ready to support them.

MR. MARTIN: Can you give us a sense for the types of deals in the power sector you saw project bonds being used last year?

MR. ANDERSON: It is where people want to go long. We have worked on loans that were as long as 40 years, depending on revenue visibility. An example is hydroelectric projects. Those assets can frequently have 100-year performance lives with proper maintenance.

The 20-year utility PPA is a less common part of the market. There is a lot more competition for them from banks. As Ralph said, lenders are now very constructive about pricing in some merchant cash flows.

The advantage renewable energy projects like solar enjoy is the fuel is free. They are not like merchant gas plants that might prove too inefficient and might not get called to run. A solar plant is going to run, so lenders can give credit for the merchant cash flows.

MR. MARTIN: Last question. There are a lot of tailwinds in this sector. You and I exchanged emails about the two main ones, which are the flood of capital from investors looking for ESG investments and the growing demand from borrowers as the transition to renewable energy gathers steam.

What are the principal headwinds?

MR. ANDERSON: I would highlight two. One is as we start 2022, a lot of investment committees are asking whether the broad markets are getting ahead of themselves. Are asset valuations trading too high? Are we headed for a correction?

Another headwind is this is a tough environment for midstream oil and gas issuers. Investors are being tracked on the carbon profiles of their portfolios. They are worried about stranded-asset risk on natural gas assets, even though those assets are critical in the transition to move the world off coal. There is uncertainty about how long can we lend to them prudently.

There is a dearth of capital going into oil and gas exploration and production. As you heard from the previous speakers — and it is true in the project bond market as well — lenders are more careful about how long do they want to go on natural gas assets, whether it is a power plant or an LNG export facility.

It will be interesting to watch this year whether we see a systematic premium that gas-fired generation, gas liquefaction and pipeline projects have to pay relative to renewable generation, which I think we all expect could more consistently price tighter because of growing investor demand.

Audience Questions

MR. MARTIN: John Anderson, thank you. Let's see if we can get in some audience questions in the few minutes remaining.

The first question is for our tax equity investors. Where would you put the current tax equity yield on section 45Q carbon capture projects?

MR. CARGAS: We think that those projects are still a little far off. Maybe there will be one this year, but they are more likely next year or the year after, so it is too early to predict. The inflation you mentioned earlier, the potential significant demand for tax equity and the cost associated with basically developing a new product would all have to factor into the return.

MR. MARTIN: What about tax equity for natural gas fuel cells, another audience member asks? Is there much interest in fuel cells from the tax equity market?

MR. SONG: We are not active in that market.

Going back to the carbon capture question, most of the CCUS projects at which we have looked are done on a basis of a 50% upfront contribution and 50% contingent contributions over time. They follow the IRS guidelines that were published a couple years ago for carbon capture transactions.

The yield is not the right metric in my opinion. We don't look at those deals from a yield perspective.

MR. MARTIN: How do you look at them?

MR. SONG: The IRR is not a good return metric when you have significant deferred capital contributions since that makes the IRR more volatile. We look at carbon capture investments from a net after-tax cash flow perspective and generally require a higher net after-tax cash flow from such an investment than from the typical wind investment.

MR. MARTIN: Ralph Cho, an audience member asks what debt-service-coverage ratio are you applying to merchant cash flows. Is there a different ratio for merchant revenue or do you use a blended ratio for the entire revenue stream?

MR. CHO: Merchant cash flows are much more volatile. Banks would probably size the debt against the merchant cash flow using a 2.0 times to 2.5 times P50 coverage ratio.

MR. MARTIN: Is that for the merchant tail after the power contract ends? What if a project has a power contract covering 80% of the electricity output and the other 20% of electricity revenue from day one is merchant?

MR. CHO: The merchant tail is different. For merchant cash flows during the power contract term, the debt-service-coverage ratio is 2.0 times to 2.5 times P50 cash flow. For the merchant tail, we generally look at what balloon payment will be required on the loan at the end of the loan term and try to come up with a view, based on the technology, the age, the location and the type of asset how large a balloon payment we are comfortable with heading into a sea of merchant cash flows.

It varies. A brand new combined-cycle gas turbine is going to have a much higher value than a 30- to 40-year-old peaker power plant.

MR. MARTIN: Another audience question: What bank appetite is there for transmission infrastructure and what metrics do you apply to it?

MR. CHO: There is very strong appetite at the level of the operating company and sometimes even at the holding company level. Such projects are usually investment grade. They generate regulated cash flows. Such projects should attract a low cost of capital. Lenders will be all over transmission.

MR. ANDERSON: You should definitely take that to the project bond market. The banks can go long, too.

MR. CHO: Roger that. ◎

IN OTHER NEWS

terawatt hours during the same period.

The economics of increasing electricity usage do not work unless the price of the cryptocurrencies increases in tandem. Bitcoin increased in value by 60% and ether by 200% over the same period.

The memo said the annual CO2 emissions of the mining operations for the two currencies are equivalent to the tailpipe emissions of 15.5 million gasoline-powered cars.

The computer servers used for mining last three to five years before becoming obsolete. Mining operations produce about 30,000 tons a year of electronic waste that cannot be repurposed and that create a disposal problem at landfills, according to the staff memo.

One witness at the hearing suggested that energy usage for crypto mining should be compared to other stores of value like gold mining, which is not only energy intensive but also dirtier. Another said that bitcoin mining still accounts for only 0.1% of global electricity use and, in the US, uses 58% clean energy compared to 31% for the US energy grid as a whole.

Spikes in electricity use are creating challenges for some communities. Plattburgh, New York saw crypto mining spike to 20% of total electricity consumption in the winter 2018, forcing the city to buy more expensive power on the market beyond its allotment of more affordable hydroelectricity.

Ethereum is moving to a "proof of stake" process for validating transactions that may use 99.99% less energy than the current "proof of work" process.

REPLACING LIBOR with SOFR will not trigger US tax consequences, as long as the change does not cross one of four tripwires, the IRS said in January.

"Associated modifications" can also be made at the same time without triggering US taxes.

The UK Financial / continued page 19

Policy Outlook for US Renewable Energy

Law firms are fielding constant questions about the outlook for the "Build Back Better" bill, whether certain provisions risk being left behind and what is likely to happen with Customs seizures of some Chinese solar panels. The Federal Energy Regulatory Commission is moving to tackle bloated interconnection queues and grid congestion that are making it hard to connect needed projects in some parts of the country to the electricity grid.

Three long-time Washington observers talked about these and other policy issues currently in play in Washington at the annual renewable energy law conference hosted by the University of Texas in Austin. The panelists are Richard Glick, chairman of the Federal Energy Regulatory Commission, Abigail Hopper, CEO of the Solar Energy Industries Association, and JC Sandberg, chief advocacy officer for the American Clean Power Association. The moderator is Keith Martin with Norton Rose Fulbright in Washington.

Build Back Better

MR. MARTIN: Abby Hopper, what is likely to happen with the "Build Back Better" bill, and on what timetable?

MS. HOPPER: Gosh, if I knew the answer to that question, I would probably be playing Powerball to capitalize on my fortune-telling and future-prediction skills.

Here is what I know. We have been continuing to talk to members of Congress since that reset moment at the end of December when Senator Machin went on Fox News to say he will not vote for the bill. What we hear consistently from the Democratic caucus is that they believe they will get something done.

The energy provisions in the bill have a lot of support. We are focused on reminding everyone about the huge impact those provisions would have on solar and other domestic manufacturing for the global energy transition.

The clean energy provisions would serve as a catalyst for major transmission investments, major storage investments and workforce development. They are groundbreaking. They will change the way that our economy is fueled for decades to come, so I remain optimistic.

MR. MARTIN: Are you giving odds?

MS. HOPPER: I am not giving odds. I am optimistic. I think the politics tell us that something needs to happen. One of the things we talk about a lot, which really has resonance in Washington, is that if this bill passes, it would add $234 billion to our economy and 450,000 more people working in solar and storage over the next few years. Those numbers have resonance regardless of your party affiliation.

MR. MARTIN: JC Sandberg, are you giving odds?

MR. SANDBERG: No, and the inertia right now is frustrating, but this game has more innings to play. A lot will have to happen to get it going again.

I believe the clean energy provisions enjoy support not just from Democrats. While they will never vote for it, there are Republicans that would support it because, as Abby said, it really is transformative to the industry. It means maintaining and sustaining US jobs and building the supply chain here. There is political expediency to it. There is also a real economic expediency to acting now.

MR. MARTIN: This is an election year, and the conventional wisdom is things don't get done once the elections come into clearer view. By when do you think this must pass to have any chance?

MR. SANDBERG: I have stopped giving guesses on time, but I think you have some runway through the spring and maybe early into the summer. The election calendar may also be a benefit because this needs to have passed with enough time for the benefits from some of the social programs in the bill to be felt before the election.

MR. MARTIN: Abby Hopper, one of the big mysteries is why Biden has not engaged with Manchin. It has been more than a month since Senator Manchin said on Fox News that he will not vote for the bill. There do not seem to have been any negotiations since then. Why not? When will they restart?

MS. HOPPER: I feel like President Biden might be in a better position to answer that question.

What I do know is that we have reminded members from key states, including West Virginia and Arizona, about the investments that will be made in those states if the bill passes. It feels to me like some of the opposition is for reasons that have nothing to do with the clean energy provisions.

Controversial Provisions

MR. MARTIN: Many of the questions coming into law firms are whether there is a danger of X or Y falling out of the final package. Let me ask you two some of those questions. You are both in Washington.

Abby Hopper, starting with you: what about restoration of the wind and solar credits to the full rates for an extended period? Is there any danger that will fall out of any bill that passes?

MS. HOPPER: We are hearing consistently, across the board, that there will be long-term extensions of the clean energy tax credits. Whether that means seven years, eight years, nine years, 10 years, I would not opine about the exact number. I think that may be up for negotiation.

I think there is also consensus and a general understanding about the importance of the direct-pay provisions. I think that the standalone storage credit, the transmission credit and the manufacturing pieces all seem to be areas of consensus. While there may be some massaging around the edges, I am less concerned about those falling out.

MR. MARTIN: JC Sandberg, you have the Energy Storage Association now under your umbrella. What about the standalone storage credit? Is there any danger that it will be left on the cutting-room floor?

MR. SANDBERG: No. Never say never, but I think, as Abby said, most of these things are probably seen as part of a whole package. These items have not been controversial. The controversy has been more on the social side. There are certain things that are still kind of percolating. There is still some uncertainty around what direct pay will look like. We continue to work with interested parties on it.

There are certain issues around the tax credit for standalone storage that could still imperil it.

MR. MARTIN: What is such an issue?

MR. SANDBERG: Normalization.

MR. MARTIN: The regulated utilities do not want to have to prove, in order to claim the tax credit, that it will not be shared more rapidly with ratepayers than permitted.

MR. SANDBERG: Normalization has had a long history and may or may not have been the reason the storage credit failed to make it before now, but I think that everybody wants to see such a tax credit in the final package. I am confident that the parties will find a resolution.

MR. MARTIN: Are utilities focused solely on normalization of the storage credit or of investment tax credits more broadly?

MR. SANDBERG: I think their interest is broader, but that happens to be the one issue that is still unresolved with the storage credit.

MR. MARTIN: Is there an issue that potentially could hold up direct pay?

MR. SANDBERG: I don't think so, but it remains on lists of things that need to be resolved. There are other constituencies that need direct pay that are helping to keep it in the mix. The carbon capture people want it.

/ continued page 20

IN OTHER NEWS

Conduct Authority stopped publishing one-week and two-month LIBOR rates after 2021, but it is continuing to publish "synthetic" sterling and yen LIBOR rates using a methodology that does not require collecting information from panel banks. It is also publishing the remaining LIBOR tenors — including the most commonly used one-, three- and six-month rates — through June 2023.

It may require publication of one-, three- and six-month dollar LIBOR past June 2023 using a similar synthetic methodology. However, any such synthetic rates are expected to be published only for a limited time.

US regulators have been discouraging US banks from entering into new LIBOR contracts and encouraging them to add ARRC hardwired fallback language to LIBOR-based instruments so that the instruments will automatically adjust to a new benchmark rate once LIBOR stops being published.

The US expectation is that most of the market will shift to SOFR, a replacement rate for dollar-denominated instruments.

ARRC stands for the Alternative Reference Rates Committee. It is a group of private-market and government participants convened by the Federal Reserve Board and Federal Reserve Bank of New York to advise on LIBOR transition issues.

The ARRC fallback language describes when and how references to a current benchmark rate will be replaced with a new benchmark rate. It includes mechanisms for determining the replacement benchmark rate and a spread adjustment that will be added to the replacement benchmark to account for any differences between the new and old benchmark rates.

Under US tax rules, any debt instrument that undergoes a "significant modification" is considered to have been exchanged for a new debt instrument. This can trigger taxes.

There is limited guidance about the tax

/ continued page 21

Policy Outlook

continued from page 19

There is an education effort underway about what direct pay is, who benefits and why it is important. I think the message is resonating. It is just that we are not at a point yet where the final deals are being cut in Congress.

MR. MARTIN: Abby Hopper, what about production tax credits for solar? Is there a risk that proposal will be left on the cutting-room floor?

MS. HOPPER: As JC said, the final deal has not been cut yet. That is not something about which we have heard a lot of concerns expressed on Capitol Hill.

Going back to direct pay, the version that passed the House has been extended to both utility-scale and distributed energy projects. I think that brings a constituency with it and some political capital that is important for ensuring the provision stays in the bill.

MR. MARTIN: What about the tax credit for new transmission lines that are 275 KV or higher and have at least 500 megawatts in capacity. Is there any danger of it falling away?

MS. HOPPER: That one is critical for many of our members. If there is a hierarchy of things folks can agree on, high-voltage transmission as a critical element of the infrastructure buildout would be high on the consensus list. I think that is less likely than other things to fall out.

MR. MARTIN: JC, it seems like the Democrats are locked into the wage, apprentice and domestic content requirements in the bill because of campaign promises that the energy transition will bring good-paying jobs. Is there any possibility those will not be in any final bill?

MR. SANDBERG: If they fall out, it would be because of procedural issues. Any final bill will have to go through a "Byrd bath" in the Senate where extraneous items that are not strictly tax or spending provisions are cut from the bill. The parliamentarian decides what is extraneous.

We have worked hard with labor and the tax committee staffs to get those provisions to a place where they can be workable in the market and not slow down project deployment. I think we are in a reasonably good spot.

MR. MARTIN: Abby Hopper, nothing seems to pass in Congress without a forcing date. Christmas was a forcing date; that didn't work. What is the forcing date this year for action?

MS. HOPPER: I wish I knew. I concur with JC that there is definitely a political need to pass something and then campaign on it. Smart minds could differ on whether that means March 1, April 1 or May 1. Late winter or early spring is a critical marker to receive any political benefit that might come from passing it.

MR. SANDBERG: It was really pencils down into early December, thinking this was going to be done. There are some things on the margins that remain in play. It is not the top-line content, but really down-in-the-weeds kinds of things that will help the law firms write opinions. That is where we are focused in a handful of instances.

MS. HOPPER: We glossed over the issues around the wage and apprentice requirements. I am not suggesting that those details remain to be worked out — I think they are pretty set — but that is going to be a pretty transformational aspect of this bill. We remain focused on the details of how to implement them.

MR. MARTIN: I have always thought Washington is like a dinner party with a tablecloth that is too small to fit the entire table, and everyone is tugging it in his direction. People finally sat down to dinner in early December, and then found that dinner is not ready. So they are tugging again on the tablecloth.

Tariffs and Customs Seizures

MR. MARTIN: Let's move to tariffs. Biden has seemed more protectionist than project developers had hoped. He has to make a decision by Sunday about whether to extend the current US safeguard tariff on imported solar panels.

Trump exempted bi-facial solar panels from the tariff and then tried unsuccessfully ever since to impose the tariff on them. He was blocked by the courts. Biden has been defending the Trump effort to collect duties on bi-facial panels.

Is it your understanding Biden could extend the tariff, but do an about face by exempting bi-facial solar panels?

MS. HOPPER: We have been advocating for the tariff to go away in its entirety for a variety of reasons, but we are also of the opinion that if he chooses to extend the tariff, he can do so while exempting bi-facial panels.

We have argued that the issue whether to revoke the current bi-facial exemption is before the courts and outside of Biden's jurisdiction, but that he has the ability to restore the exemption since that would be consistent with the court decisions to date.

MR. MARTIN: Are there other trade issues besides the safeguard tariff and the bi-facial exemption that are at the top of the SEIA agenda?

MS. HOPPER: One that comes to mind quickly is the enforcement and unpredictability of the withhold-release order that the Customs and Border Patrol issued in June. We could have a very long conversation around that.

That has had a pretty significant impact on the availability of solar modules. Both we and ACP have been deeply engaged in trying to make Customs actions in this area more predictable because that is important to being able to finance projects.

As you know, we advocated successfully against the initiation of an anti-circumvention tariff on Chinese-branded panels coming to the US from southeast Asia. That was a very good outcome.

There is obviously a longer list of trade issues that affect project development and domestic manufacturing. Those are the next level down of trade conversations to have.

MR. MARTIN: How widespread are solar panel seizures by US Customs on account of forced labor concerns?

MS. HOPPER: We are aware of some.

The more chilling effect is the uncertainty is making some panel manufacturers decide either not to ship to the United States or even, in some cases, to shut down factories overseas and not manufacture at all until there is more clarity here. That makes it hard to get modules. That makes it hard to plan for projects in 2022 and 2023.

We have carried that message to the administration to say, "You have these incredible climate goals that enjoy wide support and, yet, you have this trade policy that is pushing in the opposite direction." It is not the concerns around forced labor that are the problem. It is the uncertainty around / continued page 22

Renewable energy advocates remain optimistic that some form of clean energy tax bill will get through Congress, but they are no longer giving odds.

IN OTHER NEWS

consequences of amending non-debt contracts.

The IRS said in proposed regulations in 2019 that it will not view a debt instrument or other contract as having changed if it is amended, or replaced with a new instrument, to substitute a new reference rate or provide a fallback to LIBOR. However, three things had to be true about the amended instrument. (For more detail, see "The LIBOR Transition" in the August 2019 *NewsWire*.)

The IRS issued a separate revenue procedure in October 2020 that said anyone adding the ARRC hardwired fallback language to a debt instrument or hedge will not trigger taxes. (For more detail, see "IRS Tries to Simplify LIBOR Transition" in the December 2020 *NewsWire*.)

The IRS issued final regulations in January 2022 in an attempt to make the rules in this area simpler, but they are in the form of abstract guidance that will leave unanswered questions.

They add a new section 1.1001-6 to existing IRS regulations for calculating gain or loss when property is exchanged for cash or another property.

A "covered modification" does not trigger taxes.

A change in the base rate from LIBOR to SOFR is such a modification, as long as it does not cross one of four tripwires.

"Associated modifications" can be made at the same time. These are modifications that are reasonably necessary to adopt the rate change.

An example of an associated modification is an "incidental" cash payment intended to compensate the counterparty for small valuation differences resulting from a change in administrative terms of the contract, like a change in the interest period or in the timing and frequency of determining rates and making interest payments.

Another example is a single cash payment intended to compensate the other party for the basis point difference / continued page 23

Policy Outlook

continued from page 21

the enforcement and around what kind of information companies have to provide to prove that their products are not made with forced labor. The forced labor requirement is an important step. It is the execution that has caused havoc in the marketplace.

MR. MARTIN: SEIA issued a protocol for companies to follow to determine whether forced labor was used to manufacture products. Is there any further work being done on that protocol?

MS. HOPPER: Yes, absolutely! Two things. One of the ways in which Customs and Border Patrol can be confident that there is no forced labor in a supply chain is through a third-party independent audit and using the traceability protocols. We are in the process of transforming the protocols into an accepted standard. That kind of outside validation is what an enforcement agency like Customs needs.

We are also working with Customs and Border Patrol directly. A notice went around for comment after Congress enacted a forced labor bill late last year. We are working on that as well.

Crypto Mining

MR. MARTIN: JC Sandberg, the House Energy and Commerce Committee held a hearing in January about large electricity usage by cryptocurrency miners. Senator Warren and seven other Democrats sent letters last week to six cryptocurrency mining companies. What, if anything, do you see coming out of this effort?

MR. SANDBERG: It is true that mining cryptocurrency is an incredibly energy-intensive exercise. The process of creating bitcoin consumes 91 terawatt hours of electricity annually. That is more energy than is used by Finland, which has five million people.

Senator Warren has expressed concern about the amount of fossil fuel generation being used to power these operations. Some of the crypto miners have been moving to clean energy for their sources of power. We are committed to helping that.

MR. MARTIN: Rich Glick, is cryptocurrency energy usage on the Federal Energy Regulatory Commission's radar screen?

MR. GLICK: It is an interesting topic. Many of the issues associated with cryptocurrency mining involve use of electricity supplied at the retail level, which is not subject to our jurisdiction. However, we are talking about a significant amount of increased demand on the grid, so it affects how we make decisions about transmission, how we keep the grid reliable and how we organize and design markets. We are definitely following this issue very closely.

MR. MARTIN: Is any proceeding planned or is this just the staff taking growing electricity usage for cryptocurrency mining into account while it does transmission planning?

MR. GLICK: More of the latter.

MR. MARTIN: Abby Hopper, what other Washington-type issues are getting the most attention currently from your members?

MS. HOPPER: Another area that we are really focused on is workforce. We talked a lot about solar panels and other types of assets, but this really is a human capital transition as well. It is important that the transition happen justly, not just for the end users but also for the people who work in our industry.

We are focused on ensuring that people from all parts of the country and every community have an opportunity not only to work in solar and storage, but also to have careers in solar and storage and to be business owners and entrepreneurs in solar and storage. It is one of the most exciting parts of what we are doing. The infrastructure bill has lots of workforce development money in it. Congress identified this as a critical need.

MR. MARTIN: JC Sandberg, is there another issue that ACP is following?

MR. SANDBERG: The implementation of the parts of the infrastructure bill around transmission. We are getting heavily involved with the US Department of Energy and the other federal agencies that will have a hand in implementation of the infrastructure bill.

Transmission

MR. MARTIN: Rich Glick, this is a good bridge to you.

I shared with you, before this call, some interesting data that came out of an Iowa State University study in November about the amount of high-voltage interregional transmission capacity built since 2014 in various countries. China has built, or is close to having built, 260 gigawatts since 2014, the EU 44 gigawatts, Latin America 22 gigawatts, Canada four gigawatts and the US just three gigawatts.

The bipartisan infrastructure bill that President Biden signed in November gives FERC stronger backstop authority to push through transmission lines, but it can only do so in national interest corridors. So far, the Department of Energy has only designated two such corridors. Do you see any more national interest corridors being designated and, if so, on what timetable?

MR. GLICK: The answer is yes. The Department of Energy recently announced plans for implementing a number of authorities that it was given by the bipartisan infrastructure bill that passed last year. It announced that it will designate more corridors and ask for comments.

In the past, the focus was on broad corridors. It is looking more now at project-by-project functional corridors that will be driven by applications from utilities and transmission developers.

DOE has also indicated that it will give special attention to corridors that take advantage of existing rights of way, such as utility or railroad rights of way.

With regard to the authority that Congress gave us for backstop transmission siting, it remains to be seen how often it will be used. Utilities have been reluctant to go around their state commissions. I do not foresee many of them asking FERC to override their state commissions.

We are working with the Department of Energy on guidance for designating corridors.

MR. MARTIN: If someone asks for help siting a specific transmission line, how long a process do you think that will be first to get the national interest corridor designation and then to get FERC to help override any state rejection of the proposed line?

MR. GLICK: It will take time because, if I recall the law correctly, parties cannot come to us for backstop siting until the state has said yes or no. They have to wait another year after the state acts. It will probably be a couple years before we start seeing applications.

MR. MARTIN: FERC asked for comments last July on how to improve a number of things: regional transmission planning, cost allocation and generator interconnection processes. You held a technical conference in November. Did you hear any good new ideas?

MR. GLICK: We got 10,000 pages of comments, so I suspect there were a lot of good ideas.

There were two items on which we saw near consensus. One is that the transmission planning process should be substantially updated, taking into account what type of generation is likely to be built in the future, state policies and everything else that drives generation decisions. We saw a lot of support for a major revamping of the way we plan for transmission.

Second, and Abby mentioned this, almost everyone agrees the generator interconnection process takes too long. There are too many projects in the queue. Needed / *continued page 24*

IN OTHER NEWS

between the old and new benchmark rates.

The IRS said that if other changes are made — for example, extending the maturity of the loan — then whether the other changes are a "significant modification" should be analyzed separately as if the switch from LIBOR and other associated modifications are already part of the base instrument.

The form of the covered modification does not matter. For example, the parties can enter into a new loan or other contract or merely amend an existing contract.

The same rules apply broadly to all types of contracts, including debt instruments, derivatives, stock, insurance policies and leases.

LIBOR does not have to be replaced with a single rate. The replacement can include one or more fallback rates.

However, all bets are off if the parties cross one of four tripwires.

A change in the amount or timing of cash flows under the debt instrument or other contract crosses a line if it is intended to do one of four things.

One is induce a party to "perform any act necessary to consent" to the change in the benchmark rate.

Another is to compensate the party for other changes besides the change in the benchmark rate.

Another is to make concessions to a party that is experiencing financial difficulties or to a party to account for credit deterioration of another party.

The last tripwire is if the change in amount or timing of cash flows is intended to compensate a party for a change in rights or obligations not derived from the contract being modified. (For related other coverage, see "SOFR Too Volatile?" in the August 2020 *NewsWire* and "LIBOR End May Disrupt Emerging Market Lending" in the October 2020 *NewsWire*.)

A UTILITY STRUCTURE for raising tax equity solves a so-called section 707(b) issue with / *continued page 25*

Policy Outlook

continued from page 23

projects cannot be built because they cannot get connected to the transmission grid.

There was less agreement on what to do about cost allocation. However, it is an important issue that we are going to have to address along with regional transmission planning.

Cost Allocation

MR. MARTIN: One of your predecessors, Jon Wellinghoff, said about cost allocation that the current approach is like making the last car entering a congested interstate highway pay the full cost of a new lane. Do you have a guess where cost allocation is headed?

MR. GLICK: I have only one vote and can only speak for myself and not my colleagues, but I think the analogy you just used is a perfect one. When a generator applies to interconnect to the grid, sometimes significant network upgrades have to be built that benefit everyone using the grid.

The way our policy has worked in the past, the first generator in line has to pay what can be a staggering amount of money for grid improvements. The amounts can make needed projects uneconomic to build.

We need to look at who benefits. The courts have told us we can only allocate costs on that basis. If a network upgrade reduces congestion, increases reliability and hence resilience, then the cost needs to be shared by all of the beneficiaries.

MR. MARTIN: The principle to date has been he who causes the upgrade pays. You are saying it should be he who benefits pays.

MR. GLICK: There is a conflict between the two theories. We need to rethink our approach, and that is one of the issues we will be debating at FERC.

MR. MARTIN: Transmission reform is a massive area. Some people have suggested you should issue a series of proposed rules on subtopics rather than wait for everything to gel. Is that likely? If so, which topic is first, and what is the timetable for getting the proposed rules out?

MR. GLICK: We are still discussing that internally. There may be some merit in breaking it into subtopics, but we do not want to take one topic, deal with that, and then wait until it is finished before moving to the second topic. This is too urgent a subject.

If we end up breaking it into subtopics, my hope is that we would issue a proposed rule in one area, and then maybe two months later address the next area, and another two months later address the third area.

MR. MARTIN: When do you think the first will be out, and what is the likely topic?

MR. GLICK: I am going to refrain from guessing because, as I said, I have only one vote. My hope is that we will have something within a couple months.

> FERC received 10,000 pages of suggestions for what to do about transmission. It hopes to start issuing proposals in April.

Reliability

MR. MARTIN: Grid reliability is back on the FERC agenda. It was an important issue for the Trump crowd, particularly for Rick Perry for whom grid reliability meant dispatching fossil fuels ahead of renewables. For you, grid reliability means a need to focus on more frequent extreme weather events, and both of you have been concerned about potential cyberattacks. What should FERC do?

MR. GLICK: You have it exactly right. There are two major threats to grid reliability: cybersecurity, which we can talk about if you like, and the growing threat of extreme weather. We had a technical conference recently on the subject. Just in the last year, hurricanes, wildfires and extreme heat and cold have had major consequences for the grid.

What should be done is to use some combination of reliability standards developed by NERC and incentives to cause utilities to invest in making the grid more resilient.

MR. MARTIN: Is one answer to bury transmission lines like we sometimes do with distribution lines?

MR. GLICK: People are looking at that, but it costs a lot of money. It also costs a lot of money every time transmission lines are blown down by a hurricane or other big storms and then have to be rebuilt. We are seeing a growing number of transmission developers come to us with plans for undergrounding certain parts of their facilities. That seems to me to make sense, but they have to weigh the high cost against the benefits.

MR. MARTIN: How do you characterize current cybersecurity threats to the grid?

MR. GLICK: They are constant. All you need to do is look at comments by our government officials about the increasing number of attacks against our utilities or other energy companies. We saw it recently with the shutdown of the Colonial gasoline pipeline after an attack by ransomware companies. We take this very seriously.

I believe we need to spend a significant amount of time on the supply chain. Utilities use many different kinds of equipment. It is very difficult for them to figure out whether all of the components going into the equipment they use came from reputable companies. The government is taking a more serious look at that. There is a process underway now to figure out what to do about the supply chain.

One thing I have suggested, but that not everyone is on board with, is for the government to have either a blacklist or whitelist to help utilities identify potentially harmful equipment. It seems to me that providing this information would help everybody.

MR. MARTIN: Trump issued a bulk power system order that caught many people by surprise because it instantly made it illegal to buy equipment from foreign adversary suppliers that might be used to harm the grid, but there was not enough detail to tell what exactly was proscribed. Biden set aside the Trump order. The issue the order tried to address is real. Is there work on a replacement order and, if so, when are we likely to see it?

MR. GLICK: You have it exactly right. It was set aside in large part because it was unworkable. There were questions about how power companies can figure out whether an adversary made any components or larger pieces of equipment, so the current administration asked for suggestions. I know they are going through the comments received and should be out with something relatively soon. The threat / *continued page 26*

IN OTHER NEWS

some utility tax equity partnerships.

Utilities want to raise tax equity on renewable energy projects and keep the electricity.

This can be a challenge because such projects usually throw off tax losses for the first three years due to accelerated depreciation. The US tax code bars claiming a loss on the sale of property to an affiliate. Electricity is considered property for this purpose.

A regulated electric utility formed a subsidiary to buy the development rights to a large solar project from an independent solar developer. The developer sold the utility the project company with the development rights and was then hired back by the utility to finish development and oversee construction.

The subsidiary plans to resell the project company near the end of construction to a separate partnership between the regulated utility and a tax equity investor.

The utility opted to treat the subsidiary that bought and will resell the project company as a corporation for US tax purposes. The regulated utility interposed a partnership between itself and the tax equity partnership as part of a strategy to step up the tax basis used to calculate the investment credit and depreciation on the project at the end of construction.

The tax equity partnership will allocate the tax benefits disproportionately to the tax equity investor. After the investor reaches a target yield around year eight, its economic interest will flip down to 5% and the utility will have an option to buy the investor's post-flip interest for the fair market value at the time.

The project is in an organized market. MISO operates the transmission grid. The project company will sell the electricity from the project to the grid at spot prices. The utility will buy an equivalent amount of electricity from the grid.

Meanwhile, the utility will enter into a swap with the tax equity / *continued page 27* *continued from page 25*

the order attempted to address remains real.

We used to have categories of high-risk, medium-risk and low-risk facilities, but now we know that bad actors can get into a low-risk facility through some supply-chain mechanism and then end up infecting a high-risk facility. We need to take a fresh look at this. I don't know exactly when the administration will issue something, but I think it will be relatively soon.

MR. MARTIN: Relatively soon meaning by the summer?

MR. GLICK: I can't speak for the administration on this. We are an independent agency. I just know that we have been having some discussions with other departments, and I know they are working hard on it.

Capacity Markets

MR. MARTIN: Going back to reliability, how important are capacity markets for reliability? A number of RTOs — PJM, MISO, New York, New England — hold periodic capacity auctions. Some other big states, like Texas and California, do not.

MR. GLICK: There has been an enormous amount of debate about capacity markets during the entire four years I have been at FERC. Are they good? Are they bad? Different regions have different approaches. From my perspective, they have been very complicated and have been administered in a way that unnecessarily raised costs and unnecessarily subsidized older, less efficient, generating units. Admittedly, a lot of that was FERC's fault.

The Biden administration could issue a replacement for the Trump bulk-power system order soon.

There are some people who believe that capacity markets are very important to ensure that older baseload facilities remain available when they are needed.

The winter storm last year in Texas raises questions about that approach. Texas does not have a capacity market. Texas had a lot of capacity last winter when the storm hit. The problem was a lot of that generation failed, either because the equipment froze or because generators were not able to access fuel like natural gas. The problem was not lack of capacity. Texas had more than enough capacity to meet demand for electricity. It just didn't have capacity that worked.

I think we need to take a new look at the way our markets operate. We know we need generating facilities that are more flexible, that are able to ramp up and down quickly, depending on whether the wind is blowing or sun shining or whatever other changes there might be on an almost instantaneous basis. We need to figure out a way to compensate properly for the value to the grid and not just compensate facilities for sitting around and doing nothing. If I could design the markets, that is where I would focus.

MR. MARTIN: That sounds like more storage.

MR. GLICK: Storage absolutely will play an important role in addressing the flexibility and ancillary service needs in the various markets. There are also other technologies. There are certain storage types and natural gas facilities that are able to ramp up and down quickly and provide that flexibility.

Texas

MR. MARTIN: You mentioned the four-day Texas cold snap last February. Is there a way for FERC to provide ERCOT access to emergency electricity without subjecting ERCOT to interstate commerce and FERC jurisdiction?

MR. GLICK: I will answer that question in two parts. The first part is Texas definitely needs, in my opinion, to be better connected to the rest of the grid. Winter Storm Uri is the perfect example. We saw the massive blackouts in Texas. The same weather occurred in neighboring states like Louisiana, Oklahoma and Arkansas, but without similar disruptions.

There were about 30,000 megawatts of power plants that were not working in Texas and a similar number in neighboring states. The difference was Texas had massive, long-term blackouts because it was not able to import power. The other states were able to bring in power from PJM. The problem is Texas is not well-enough connected to the grid.

Texas spent a lot of time organizing ERCOT in a way to avoid being subject to FERC regulation and federal oversight. I understand the point, but something needs to change. I don't think FERC has the authority on its own to address that. I think that needs to come from two sources.

One is Texas, which needs to be more willing to interconnect to the grid. The other is Congress. The exemptions for ERCOT in the Federal Power Act should be closed. I understand the point about Texas being Texas and not wanting to be subject to regulation from Washington, but sometimes you can end up cutting off your nose to spite your face, and that is what happened last winter.

MR. MARTIN: So Texas should subject itself to more regulation because it will be better off?

MR. GLICK: It may be possible to fix the problem in a way that does not make Texas subject to full FERC regulation. That is for Congress to decide. My only point is let's not argue about who has jurisdiction. Let's try to figure out a way that people don't freeze to death next time.

MR. MARTIN: You have been concerned that some FERC policies, like access for storage and distributed energy to wholesale energy markets, apply only to parts of the country that are covered by RTOs. Something like 15 states are not. You said in October that you hope the commission will be able to even this out. What did you have in mind?

MR. GLICK: We have much broader regulatory authority over RTO regions than we do over the non-RTO states. My concern is that a lot of our rulemakings are focused exclusively on RTOs. This creates an incentive for utilities not to join RTOs because joining will subject them to more regulation.

We are looking at different regulatory approaches in an effort to broaden the appeal of joining organized markets. The most recent example is we issued a ruling requiring transmission facility ratings to be more flexible over */ continued page 28*

IN OTHER NEWS

partnership where it pays the partnership a fixed price for a notional quantity of electricity that is expected to mirror the actual output in exchange for the floating revenue the project company receives on the same notional output. The utility will also pay the partnership for the renewable energy credits and zonal resource credits — RECs and ZRCs — to which the project company is entitled at current market prices.

At the end of the day, the utility will end up effectively with the electricity from the project for a fixed price. The floating revenue it receives from the project company should cover what the utility has to pay the grid for electricity.

The Internal Revenue Service blessed the structure in a private letter ruling made public in early February. The ruling is Private Letter Ruling 202205002.

Partnership-flip transactions raise several issues for utilities.

One is any investment tax credit on the project becomes harder to claim if the project is considered "public utility property." A project is public utility property if the electricity is sold at rates that are established or approved by a utility commission on a rate-of-return or cost-of-service basis.

The IRS has confirmed multiple times in the last few years that projects owned by regulated utilities indirectly through partnerships are not public utility property as long as the electricity is sold at a negotiated or spot market price. (For earlier rulings, see "Utility Tax Equity Structures" in the December 2019 *NewsWire*, "Solar Projects and 'Public Utility Property'" in the October 2020 *NewsWire*, "Public Utility Property: More IRS Rulings" in the December 2020 *NewsWire*, and "Utility Tax Equity Structures" in the August 2021 *NewsWire*.)

The other issue has been more difficult. Tax losses cannot be claimed on property sold to an affiliate. Independent generators using partnership flips to raise tax equity usually get around this issue between selling the electricity to the grid and acting */ continued page 29*

Policy Outlook

continued from page 27

time, and we subjected all transmission providers around the country, not just in RTOs, to that regulation.

Environmental Justice

MR. MARTIN: The Biden administration has made environmental justice a priority. It seems like a paradigm shift is underway at FERC in how it will consider siting of fossil-fuel infrastructure in communities of color and low-income areas. What does it mean for siting of renewables and electric transmission lines?

MR. GLICK: When we site any energy project, whether it is a hydroelectric facility, transmission line, natural gas pipeline or LNG facility, we are required to follow the requirements of the National Environmental Policy Act. One of the issues we are supposed to consider under NEPA is the potential impact of any proposed project on environmental justice communities.

In my opinion, FERC has not done a very good job of that. The DC circuit court of appeals sent a case back to us recently because it said we did not do the environmental justice analysis as carefully as we have should have.

We are trying to provide more legally durable opinions by taking a hard look at the environmental justice impacts of proposed projects and mitigating them if we can before approving a project.

MR. MARTIN: I have heard some critics complain that this ends up in some cases reopening some projects that have already been financed. What do you say to that?

MR. GLICK: That really makes me mad. I can't get into too much detail, but there is a compressor station in Massachusetts that has become controversial because it was sited in two different environmental justice communities. We have never reopened the commission decision to grant the project a certificate of public convenience and necessity. For instance, with pipelines, you have three different decisions to be made at FERC. First, we have to approve the certificate. Second, when the project is ready to begin construction, FERC has to say it can begin construction. Third, after construction is complete, the developer has to come back to FERC for permission to place it in service.

The particular project was at a stage of asking the commission for permission to start operating. We said, "Let's take a look at the impact on environmental justice communities before we do that." We have not second guessed the previous commission's decision to approve the certificate.

Carbon Pricing

MR. MARTIN: Different subject. FERC said in a policy statement at the tail end of the Trump administration that it is open to having RTOs incorporate carbon pricing into their markets. When should carbon price adders be considered a legitimate cost of service?

MR. GLICK: That policy statement said basically that if a state or group of states has developed its own carbon pricing mechanism, we would consider including that mechanism in pricing for the RTO involved. Those are market-based approaches. It is not cost-of-service regulation. It would not require a finding that a particular generating plant has a higher cost of service. The cost of carbon would be priced into how the entire market operates. The adder would apply to all fossil generation across the particular region.

MR. MARTIN: So if the market is 43% fossil, what do you do? Do you have an adder to reflect the average fossil generation?

MR. GLICK: You could require fossil generation to bid a higher price or you could discount cleaner generation during bidding to be dispatched by that market. There are variety of ways to do it.

I will say that since we issued the policy statement, no state is closer to adopting a carbon pricing mechanism for its electricity generation. In fact, New York has been talking about it for years, but has not made much progress. What FERC put out was a nice policy statement, but I am not sure it will have much meaning for the way our markets operate.

MR. MARTIN: Two more questions, and then we will wrap it up.

There is growing interest among dairy and hog farmers in the Midwest in renewable natural gas, or converting animal manure into a gas substitute that can be fed into natural gas pipelines. Some pipelines have proposed their own standards for what is responsibly sourced gas. There has been a push for a national standard. Is a national standard likely?

MR. GLICK: I don't think FERC will wade into that particular area. Whether gas is responsibly sourced or renewable is an issue to be addressed at the local level.

The question made me chuckle a bit because Congress has been talking about having some sort of national standard for what is renewable electricity for a number of years now, and it has proven impossible to reach agreement. These issues are more easily addressed on a state or regional level.

MR. MARTIN: The Office of Public Participation is now up and running at FERC with a new director as of October. People have worried that it will be a mechanism to require companies applying for FERC orders to fund interventions by non-profit public interest groups. Has the fear been disproven?

MR. GLICK: Congress ordered FERC in 1978 to establish this office. For whatever reason, it was not established and we just established it last year pursuant to further Congressional direction.

Many FERC proceedings are so technical that it is hard for people who are affected to understand the issues and how to intervene. Take a natural gas pipeline siting case, for instance. Many people are affected by it. They don't know how to participate. The main goal of the office is to facilitate their participation.

There is a provision in the statute that says FERC can create an intervenor funding mechanism. We are pursuing a proposed rule that will lay out the associated issues in detail and ask for public comment.

The statute says the intervenor has to be successful in order to be reimbursed for its costs.

For that reason, I don't think this will lead to a flood of intervenors because there is no guarantee costs will be covered. ◎

IN OTHER NEWS

as an agent to place the electricity for the partnership or, in cases where the tax equity investor requires a floor be placed under the electricity price, by entering into a swap to put such a floor in place, at least during the first few years until the project turns tax positive.

Many tax equity partnerships lately have been electing 12-year straight-line depreciation that may leave the partnership without net losses in any year.

Unlike a utility, independent generators do not need to keep the electricity. The ruling is a roadmap for utilities for how to keep the electricity.

The IRS suggested in its latest priority guidance plan last fall that it is revisiting loss disallowances in cases where a partnership sells property to an affiliate.

— contributed by Keith Martin in Washington

Representations and Warranties Insurance Data and Claims

by Stephen Davidson in New York and Jennifer Drake in Toronto, with Aon Transaction Solutions

Roughly 20% of representations and warranties insurance policies issued between 2016 and 2018 had claims made on them within three years after the policy inception.

The most common claim is for breach of financial statement representations.

Representations and warranties insurance, or RWI, has become common in M&A transactions where sellers require buyers to look to an insurance policy, rather than to the seller, for damages in excess of a deductible, that result from breaches of representations given in connection with the sale. The policies do not cover breaches of covenants. (For more detail, see "Representations and Warranties Insurance" in the October 2018 *NewsWire*.)

The claims rates on policies issued since 2019 are still developing.

There were few claims before 2016, so most North American claims activity has occurred over the past six years, and claim frequency has remained steady year over year.

The 20% claim rate does not mean that all of the claims allege loss greater than the retention amount. Many claims are made in an abundance of caution or with knowledge that loss will merely erode the retention.

Roughly 5% of policies have claims where loss is alleged to be greater than the retention, but that number has risen over the past 18 months, and now we see more claims where the insured is seeking a payment than we did a few years ago.

Nature of Claims

Financial statement breaches are the most commonly alleged breach of a representation and warranty, having been cited in almost 20% of all claims.

Representations regarding undisclosed liabilities, compliance with laws, and taxes are the next most common bases for claims, with breaches of the material customer representation following close behind.

In terms of claim payments, financial statement breaches remain at the top as well, accounting for over 35% of the total amount paid by insurers despite making up only 20% of claims.

Material customer breaches also have resulted in a disproportionate amount of claim payments, accounting for fewer than 10% of all breaches noticed but more than 17% of claim payouts.

It is not surprising that financial statement and material customer claims have seen significant payouts. Both types of breaches often lead to a larger insurance payout than the dollar-for-dollar amount of the loss, whether as a straight multiple of EBITDA or some other type of loss calculation. However, we also have seen greater pushback from insurers where they believe that the impact of the breach does not lead to long-term recurring losses. The calculation of loss can be a source of debate between insurers and insureds in the claim process.

Most claims are made in the first 12 months after a policy is issued. This makes perfect sense, as many breaches should become apparent either when a buyer takes over the target or goes through the first audit cycle.

However, as use of representations and warranties insurance grows, we have begun to see more claims being made in the subsequent two years. Many of those claims — particularly those made in the third year after inception — tend to be third-party claims that would not become apparent until the claim is raised by an outside party, but more first-party claims are being made after the first 18 months as well.

Claims Process

Many companies have not yet had to make an RWI claim and do not know what to expect from the process.

Aon's North American Transaction Solutions practice has seen more than 600 claims on RWI policies in the last four years through the end of 2021 and has assisted during that period with claim resolutions resulting in payments of nearly $600 million, with over $850 million of loss recognized by insurers, including erosion of retentions. (Insurers recognize a larger loss than the actual claim paid because the amount of retention eroded does not count towards the payout.)

Most policies allow a claim to be filed at the first sign of a potential loss.

Here are some common pitfalls to avoid.

First, do not delay in submitting notice of a claim.

Throughout the RWI claim process, communication with the insurer is key. This starts when the policyholder becomes aware of a breach or potential breach of the transaction agreement. A policyholder should submit a claim to the insurer as soon as

Roughly 20% of representations and warranties insurance policies have had claims made on them.

possible after it has sufficient knowledge and information to confirm the reasonable likelihood of a breach, even if the resulting loss is still being determined.

Unlike some other insurance policies, absent unique circumstances, there usually is no downside to submitting a claim under an RWI policy. Each policy is transaction specific, meaning there is no renewal process during which claim history may be scrutinized. An ordinary claim on one transaction is unlikely to influence an insurer when underwriting a separate future transaction, unless the insurer believes that the insured somehow has acted inappropriately in the claims process.

In our experience, insurers have very rarely denied a claim on the basis of a failure to provide timely notice. However, informing the insurer early of any issues that the policyholder encounters has proven to be important to ensuring that all potential avenues of mitigation can be considered, and insurer input can be given in a timely manner. For example, when an insurance carrier is kept up to date in real time about new developments, it is better able to react quickly, including by providing consent in time-sensitive situations, such as a settlement with a third party.

In addition, this also usually means that the insurer has early notice about any costs that are being incurred by the policyholder to deal with the breach, which can prevent a situation where an insurer feels prejudiced by actions taken or costs incurred without its knowledge.

Next, preserve, compile and assess supporting information and documents.

One potential area of friction in the RWI claim process relates to the detailed investigation that often is undertaken by insurers to confirm that there is a breach and that the resulting loss is covered by the policy.

A policyholder faced with a breach that has led to notable damages may feel certain what happened and how it was a breach of the transaction agreement and why the loss calculation methodology is appropriate. However, when a claim is filed with the insurer, it is important to bear in mind that the claims professionals are different from those who underwrote the deal and are learning the details of the transaction and the claim from the ground up.

Policyholders should be proactive at the start of the claim process by taking steps to preserve, compile and assess the information and documents that provide support for the breach and associated loss.

Try to consider the facts and supporting information from the viewpoint of a third party starting from a place of limited knowledge and assess gaps in information as well as potential inconsistencies or facts that could be interpreted in more than one way.

Pulling the information together in a way that is easy for the insurer and its advisors to understand and being prepared to address grey areas, inconsistencies and possible questions can go a long way to making an investigation progress run more smoothly and efficiently.

Loss Calculation

Determine how best to support the loss calculation both before and after a claim arises.

When Aon reviewed its North American RWI claims data at the end of Q3 2021, only about 3.75% of all claims had been denied by the insurer. Most of these denials resulted from deal-specific exclusions that were contemplated during the underwriting process. While denials remain rare, we have seen many claims where the policyholder and the insurer disagree about the quantum of loss arising from a breach, in particular where loss calculations are more complicated than / continued page 32

Insurance

continued from page 31

usual because the alleged loss is more than just dollar-for-dollar.

Where a policyholder alleges that a breach has led to recurring loss or a diminution in value of the target company and seeks to apply a multiple to calculate the damages, the insurer will take a close look at internal presentations, such as an investment committee memo and board minutes, and presentations to lenders as part of its investigation to confirm the appropriate damages methodology.

When a claim alleges that a breach has affected the value of the target company, insurers may also pay close attention to the deal negotiation process and could ask whether changes to the EBITDA over the trailing 12 months or other factors driving the valuation resulted in corresponding changes to the purchase price. This is something that a policyholder should be prepared to discuss with the insurer during the claim process and expect that an insurer may question a situation where the EBITDA being used to value the deal changed during the negotiation process, but the purchase price did not.

While this should not necessarily be determinative of whether the loss alleged is valid, it is an area we have seen insurers focus on when evaluating an insured's claim.

Some policyholders hire a forensic accounting expert to assist with the calculation of loss for complex claims. Situations where this may be warranted include breaches of the financial statements representation, a claim where the quantum is expected to be large, or the claim involves a multiple or other manner of calculating loss that is not dollar-for-dollar.

Experts also may be helpful when a breach involves an esoteric issue, such as compliance with a law or regulation or the condition of an asset. The assessment of whether it is worthwhile to retain this type of expert should be done on a case-by-case basis, but it may assist a policyholder in some instances to have an outside objective party help pressure-test the claim and the methodology for calculating loss, as well as identify various strengths and weaknesses.

The costs to work with an expert may ultimately be reimbursed under the RWI policy where the covered loss exceeds the policy retention and the language allows for it.

Insurer Subrogation

Beware of insurer rights under the RWI policy when negotiating a settlement.

Many RWI policies do not require the policyholder to pursue recourse against the seller in order to make a recovery from the insurer.

However, if the policyholder is negotiating a settlement of an indemnification or other claim against the seller, it is important to remember the RWI policy may give the insurer a right of subrogation against the seller. This right exists in the event of seller fraud (as specified in the policy) and only to the extent that the insurer makes a payment under the policy. Even in cases where there is no clear indication of fraud, insurers often are reluctant to give up this right and agree to a global release of the seller before its investigation is complete.

If a policyholder reaches a settlement with the seller on a claim that has the potential also to result in a payment under the RWI policy, a release containing a carve out for claims arising out of fraud generally avoids this issue, though it is a good idea to get the insurer's sign off on any release language before signing the settlement agreement.

If a seller insists on a full release, the insurer should be alerted as soon as possible to determine what information is needed for the insurer to consent to the language. In a claim situation where there is an indication of potential fraud by the seller, be prepared for substantial pushback from the insurer to a request to release its subrogation right.

When discussing a potential settlement with a third party that is not the seller, keep in mind that RWI policies typically require consent from the insurer in order to proceed and that the insurer will want to understand why the settlement is reasonable. Sometimes the consent requirement will apply to any settlement with a third party, while other policies will establish a threshold settlement amount above which consent is required.

To avoid undue delay in finalizing the settlement once it is reached, keep the insurer updated about settlement discussions and negotiations. This includes advising the insurer of any counteroffers, especially where it is anticipated that some or all of the ultimate settlement amount will be paid by the insurance policy. ◎

All descriptions, summaries or highlights of coverage are for general informational purposes only and do not amend, alter or modify the actual terms or conditions of any insurance policy. Coverage is governed only by the terms and conditions of the relevant policy.

The Road Ahead

The talk at the annual Infocast Projects & Money conference in New Orleans in late January was about the rapidly evolving US renewable energy market. Asset valuations have been pushed sky high by $10.6 trillion in global fiscal stimulus. Is this a good time to be a buyer? Are current supply-chain woes and other difficulties really as bad as the news media make them sound? Is it true that 30% of solar power purchase agreements for development-stage projects have been canceled due to escalating costs? Is the hype about green hydrogen warranted? Three veteran market participants talked about these and other questions on one of the opening panels.

The panelists are Hunter Armistead, chief development officer of Pattern Energy, Kevin Smith, CEO of the Americas for Lightsource BP, and Ted Brandt, CEO of Marathon Capital. The moderator is Keith Martin with Norton Rose Fulbright in Washington.

Headwinds and Tailwinds

MR. MARTIN: We start 2022 with an unusually large number of headwinds: supply-chain difficulties, labor shortages, uncertainty about tax law, Customs seizures of solar panels, inflation and rising international political tensions.

Hunter Armistead, is there anything you would add to that list?

MR. ARMISTEAD: There is also a strong tailwind, which is that people actually want our product. That is not something any of us were able to say in the last 20 years.

I have been doing this a long time, but have never had to operate in an inflationary environment. I was joking with someone before the panel, and he said, "I remember the 1970s." I said, "I was eight."

MR. SMITH: I remember the '70s.

MR. BRANDT: I do, too.

MR. ARMISTEAD: Yes, but this is new. There are two things that are new for me. There is more long-term demand for the electricity we are trying to sell, and the electricity price is no longer falling. It is rising. Those are both new.

MR. SMITH: I agree with that. The difficulty we are all facing is the transitions that we are being forced to make, whether they are moving from panel prices in the mid-20¢ to mid-30¢ range per watt, or an investment tax credit that may be falling from 30%, to 26% to 22% to 10% or may be going back up to 30% or higher. The biggest challenge is the risk of getting stuck on the wrong side of those transitions.

The industry is growing dramatically. There is huge demand for the product. There are a lot of power purchase agreements that are on the wrong side of current costs on labor, panel prices and other equipment costs. The biggest challenge is making sure you are on the right side, or even mostly on the right side, of those transitions.

MR. BRANDT: I view it like a teeter totter. There are the negatives on the one side, but the optimism comes from the massive liquidity. There has never been a time with so much global money from every possible source — the public markets, the private markets, the infrastructure funds — in search of investments. There is a major movement away from non-ESG investments into ESG-oriented investments, and it is accelerating.

MR. MARTIN: I asked about additional headwinds. For the most part, all of you cited tailwinds. Despite the short-term challenges, all of you feel like the renewables market is in a good place.

Lasting Pandemic Effects

MR. MARTIN: Next question: Life is never the same after a period of upheaval. We have all been working from home for two years. Many people say the pandemic has acted as an accelerant, accelerating trends that were already underway. What do you expect to be different for our industry after we reemerge?

MR. ARMISTEAD: Humans.

MR. MARTIN: Humans? How so?

MR. ARMISTEAD: If you are not forcing everyone to move to the same city, you end up with a much deeper potential talent pool. The pandemic has opened that up for us by forcing us all to be more flexible.

MR. SMITH: Our development teams have always been pretty mobile people, but the rest of us all went remote overnight and it was not really a very big deal.

We are now hiring people across the US. Our head US office is in San Francisco, but we now have offices in Denver, Philadelphia and Austin, and we also have people scattered across the US in such places as Utah, Arkansas, Louisiana and Alabama where I did not expect to have people.

MR. MARTIN: They are working from home?

MR. SMITH: Yes.

MR. ARMISTEAD: Another thing to add is I am crazy energized by some of the young people that are coming into our industry right now, and coming up behind the next tier of senior managers that are eventually going to push me / continued page 32

Road Ahead

continued from page 33

out. The passion they bring for renewable energy is wonderful. It makes me excited about the future.

MR. BRANDT: There were three effects of what all of us have just been through.

The first is by having everybody go virtual, execution actually got better. Second, on origination of new deals, we stayed alive with repeat clients and existing relationships. We did not do a great job of meeting new clients.

Third, where virtual just flunks is on the transfer of knowledge to younger generations. We are a knowledge company and an 80-person investment bank. We did not see the senior people teaching the junior people anywhere near the knowledge that they will need to move up the ranks.

We are recommitting to real estate. You clearly have to put up with people living wherever they want, given the talent shortage, but we are recommitting to real estate in our various locations.

Delays

MR. MARTIN: The speakers on the panel just before us said that they set record years in terms of deal flow last year. It was no wonder. People are more efficient working from home, to a degree, until exhaustion sets in.

We started with two general questions. Now let's switch to trying to draw out useful facts, starting with the supply chain.

Hunter Armistead, did you have projects slip into 2022? Are some of your 2022 projects already slipping into 2023 due to supply-chain issues?

MR. ARMISTEAD: We just commissioned a 1,000-megawatt wind farm, single build with a transmission line, on time, on budget, without any supply-chain issues. I don't know whether I should knock on wood. It took a lot of attention to send people to the sites to get early warnings. We had issues, but we managed through them.

That is not to say we have not had delays. We have been unable as a company to get the assurances we need from some panel suppliers that their panels were ethically sourced. We have basically said, "No, we are not going to do that." Our main issues have been around panel suppliers in China.

MR. MARTIN: Have any 2022 projects slipped into 2023 due to supply-chain issues?

MR. ARMISTEAD: Not supply chain, but on account of forced labor concerns.

MR. SMITH: Our target for 2021 was to finance 1200 megawatts of solar. We did 1207 megawatts and about $1.5 billion in financings. We also completed construction on time on about 600 megawatts that closed financing at the end of the previous year. We were fortunate with some of our panel suppliers. Everything was on time, like clockwork.

This year does not look like that.

Even though we closed projects on time in 2021, the returns were not quite what we thought they were going to be at the beginning of 2021. Some projects took hits on returns. We made the decision that we were going to power through and close. We do not have access to BP's balance sheet, so our projects are fully project financed with third-party tax equity structures.

Last year was a record year for us.

We are looking this year to build 1500 megawatts or more, but 2022 looks tougher than 2021 to reach those goals.

MR. MARTIN: Due to panel supplies or cost?

MR. SMITH: A bit of both. We did a big deal with First Solar for module supply for about 4,500 megawatts of delivery of solar panels over a multi-year period. The 2023 deliveries will only be about 60% of what we need. We are out in the market looking for what we can buy from other suppliers. Cost issues are also a big deal. EPC prices are going up.

MR. ARMISTEAD: Prices have been moving up and exposures have been moving to the left. In order to manage supply-chain issues, everyone is basically looking for us to commit earlier. It increases our exposure as well as our cost.

MR. MARTIN: We have heard from some solar developers that as many as 30% of PPAs for development-stage projects have been canceled because the costs have gone up to a degree that the electricity cannot be delivered at the originally-promised price. Does that sound accurate?

MR. ARMISTEAD: Yes, but I am not sure whether the issue is the supply chain or the fact that people for many years have been counting on the levelized cost of energy from solar and wind to keep falling over time. That changed about two years ago, and electricity prices have been going up since then. I suspect the PPAs being were entered into more than two years ago.

MR. SMITH: My guess is that more than 30% of PPAs are under water. The question is what should developers do with those.

We have been renegotiating some of our power contracts. We have not yet walked away from anything, but it is a tougher market. I agree with Hunter. People bidding for PPAs were optimistic and bet that the downward curve would continue. There was a pretty steep uptick in contracted electricity prices in 2020 and 2021, and it does not sound like we should expect any relief in 2022.

Interestingly enough, panel prices are coming down internationally. We are bidding on power contracts in Brazil and various markets in Europe. We are seeing some softening of the panel supply markets. The US has all kinds of issues that are specific to it, like solar panel import tariffs and forced-labor legislation that are a lot tougher than in the rest of the world. Panel prices are falling in other parts of the world, but not yet in the US.

MR. MARTIN: Have you had any solar panels seized by US Customs?

MR. SMITH: No, fortunately. We had a big supply of First Solar, and we also had Canadian Solar in our mix. We have not had any issues so far.

Power Contracts

MR. MARTIN: Hunter Armistead, you said that the change this year is that people want to buy more of the product, electricity. Some developers have been telling us that PPAs are no longer the scarce resource; the scarce resource is the ability to interconnect. Do you agree?

MR. ARMISTEAD: Absolutely. I think how we manage the interconnection queue is the challenge for the next generation of solar and wind developers.

MR. MARTIN: Some of the RTOs are trying to sweep the queue of projects that have no real chance of being built. Is that working? Perhaps developers with poorly-conceived projects are now less willing to post high letters of credit to stay in line?

MR. ARMISTEAD: Yes. The challenge is you have a lot of potential electricity customers who still want to enjoy a party that ended two years ago. The revenue side of the equation takes longer to adjust. EPC contractors and equipment vendors are much faster to increase prices to adjust to current conditions.

The conversations that I am sure Kevin and I have both had with electricity customers can be uncomfortable. Some have gone okay; some have not gone so well.

MR. MARTIN: Kevin Smith, where are PPA prices today for solar and wind? Say you are signing a new long-term power contract with a US customer.

MR. SMITH: They vary by region.

To return to the previous question, I think the biggest change over the last several years has been the number of corporate offtakers coming into the market. Our PPAs previously were probably 80% with utilities and only 20% with corporate customers, but that number is more like 50-50 today. Lightsource BP's first projects only went into construction in 2019, so it has been a relatively short period for us. We are signing contracts today with McDonald's, Verizon, eBay and all kinds of players, in addition to the Xcels and other utilities.

We are still seeing low prices in the West — Colorado was under $20 a megawatt hour but is moving up significantly. We are also seeing prices moving up in PJM and MISO. In cases where prices were in the high $20 to low $30 range, we are now seeing prices in the high $30 to $40+ range.

Prices vary by market, but we have seen prices move up in general by at least 20% to 30%.

MR. MARTIN: Hunter, where are prices currently?

MR. ARMISTEAD: When is the industry going to stop talking about power prices? If you go back to the very beginning, we were always competing against our fellow renewables developers for a limited demand.

Now what is getting really interesting is the other components of the product — resource adequacy, capacity allocations, RECs — that are contributing to revenue. Maybe I'm dodging your question, but . . .

MR. MARTIN: Sounds like it. [Laughter]

MR. ARMISTEAD: One of the changes in the industry in the last five years is that we used to get our return principally from the PPA, and there were actually good returns for equity during that period, but that does not exist anymore. You need a view about how markets are going to price a commodity that is not just power.

All of that said, I think PPA prices are up by $4 in almost every market.

MR. MARTIN: Okay.

MR. ARMISTEAD: That was answer; just remember that. [Laughter]

MR. MARTIN: I will.

MR. ARMISTEAD: Kevin, do you agree that $4 is where things have gone?

MR. SMITH: I think it is higher than that, actually.

It depends on what is included in the power price. The developer usually takes the risk on capacity and reactive power payments. The offtaker wants the energy and RECs. We are seeing prices up by as 20% to 30% and higher in some markets. That is certainly more than $4.

SPACs

MR. MARTIN: SPACs appear to have flamed out spectacularly. The Wall Street Journal reported over / continued page 36

Road Ahead

continued from page 35

the weekend that about half of SPAC-backed companies' shares are now down by more than 40%. SPAC investors can pull their money out once the target is identified. BuzzFeed went public recently with a SPAC. It was hoping to raise $287.5 million, but ended up with $16 million because 95% of the investors pulled their money.

What new ideas are investment bankers pitching now that the SPAC boom seems to have run its course?

MR. BRANDT: The SPAC idea would not have had much traction if the traditional initial public offering was a great process. The reason that everybody gravitated to SPACs is it was touted as an easier, faster way to go public.

It worked for a while, and then it was broken, and then the way the investment bankers fixed it is they made the SPAC sponsors put in more capital that could be redeemed. And guess what? The hedge funds and individual investors that buy into these IPOs are basically withdrawing their money as opposed to converting into the equity of an overpriced target.

This is a classic case of Wall Street having an interesting idea, but the investors that are behind the IPOs are completely disconnected from the process. SPACs are a great deal for the sponsors who organize them, but there is a misalignment of interests between the SPAC sponsors and the investors, and the chickens are coming home to roost. These are not good deals, and a whole bunch of people are going to lose money.

MR. MARTIN: Hunter Armistead, is there a new idea that investment bankers are already pitching?

MR. ARMISTEAD: I was on a panel with you are few years ago soon after we went public with a yieldco.

There will always be some really good ideas that get pushed to the point that they become bad ideas. This is just the latest example. For a time, everyone wanted to be in SPAC. I was asked to start a SPAC, and I said, "I don't think so." This one had a shorter shelf life than many others.

The bigger trend is that ESG investing is no longer just a catchphrase. People used to say "ESG really matters," but actually it really didn't. Now it actually kind of does.

Ted's original point was there is a significant amount of capital that wants to be in this industry. The disciplined ways of putting capital into it are more tried and true.

Asset Valuations

MR. MARTIN: Ted Brandt, let's use that as a bridge to some questions for you. I read in The Economist magazine that there has been $10.6 trillion in fiscal stimulus globally during the pandemic. The money has to go somewhere. It has pushed up asset valuations. Why be a buyer in such a market?

MR. BRANDT: I was on a panel you moderated in March 2020 shortly after the COVID lockdowns started. The markets were crashing, and I made a statement that "I'm worried the wall of money has gone away." The next month, I got lots of calls from people who had raised funds that were dedicated to ESG who said, "We can't go anywhere else. The money has been raised for a purpose. The investors are paying us fees in order to find clean-and-green investments. The biggest sin is not deploying the capital."

Some of this money is on the sidelines, but we are clearly seeing yield compression and record premiums being paid for development companies.

Right now, the perception among investors is, "I can't make any money at the project level. All the money is going to be made at the developer level."

That is translating into premiums for companies that are pretty new but have really great pipelines. That used to be a nine-figure type of appraisal, and now were are seeing ten figures and even moving up from there.

MR. MARTIN: There has been a broad move out of equities. Tech stocks have been battered this year. The tech rout is spreading to other parts of the equities market. Three fifths of the stocks on the blue chip S&P 500 index are down at least 10% from recent highs and a fifth are down at least 20%. Is this starting to affect power sector valuations?

MR. BRANDT: Asset valuations tend to vary by region and are driven by the revenue contract. We are seeing lots of problems in project pipelines. PPAs that were won in RFP processes 18 months ago are ending up in massive renegotiations because nobody foresaw the supply-chain problems. We are watching projects being canceled.

In many parts of the country, we would almost rather sell a to-be-built asset without a power contract than one with a contract.

MR. ARMISTEAD: These cycles tend to repeat. I remember around 2006 when everyone would claim a huge pipeline, and we would view the claims skeptically. Development is more artistry than it is assets.

A lot of times with art, you get really bad art. With a lot of the pipelines that people are peddling today, unless you have developers that have delivered consistently, I think you are going to be surprised when you look under the hood.

MR. MARTIN: That's a warning from a developer who knows what is under the hood.

MR. SMITH: I will echo that. The industry has gone through a few cycles over the years. I have been through a few of those cycles. I remember when I was at Invenergy in 2006, 2007 and 2008, the huge influx of Europeans into the US market pushed up asset valuations. People were buying project pipelines where you had a little bit of land and maybe an application for the interconnection queue. Buyers were paying $50,000 to $100,000 per megawatt for those kinds of projects.

Buyers are paying as much as 20¢ a watt for development rights to projects with site control and access to transmission, but no power contract.

That ended a few years later. People were rationalizing those pipelines. Now we are seeing the same thing again, but on steroids. You talk to people that have not been through a few cycles, and they insist, "This is different." Perhaps they are right. The world has changed. We are going to see continuous growth in this market. Maybe cycles are a thing of the past and it is all up from here. Maybe. Mark me a skeptic. I think people are overpaying a bit.

We did an acquisition with BP of a group called 7X in the first half of 2021. It was a bilateral deal. I think we got a pretty good deal on it. BP made the numbers public; half of it was equipment, and it was in the $100 million range for a 9,000-megawatt pipeline. Who knows what that would go for today.

The market is massively strong, and you still have a lot of people looking to enter.

MR. ARMISTEAD: I love the words "It's different this time." It might be, but those words are painted across history. The one truth is we are still in the early stages of what will be a 30-year transition to renewable energy. Maybe that justifies some of the optimism among buyers. Maybe it is a little different this time.

Bid Metrics

MR. MARTIN: Ted Brandt, what discount rate would you say winning bidders are using currently to discount future cash flows?

MR. BRANDT: We just closed about a month ago on a utility-scale solar project with a 20-year bus-bar PPA. We think from a reverse engineering standpoint, the leveraged after-tax return that the buyer got was below 6%.

MR. MARTIN: What about for wind?

MR. BRANDT: I actually think the number I just gave you is an outlier. For wind, I think 7.5% to 8% is the right discount rate for leveraged returns. Solar is probably 50 to 75 basis points tighter than that. It is really important, given that these are 35-year assets and that most of the contracts are 12 to 15 years, to realize how critical your out-year electricity price assumptions are. If your power curves are off, the math just goes out the window because you have 20 years on the back end. With low discount rates, the power curves mean everything. If you are 30% below Ventyx or the equivalent, you are not going to win anything, even with a 5% discount rate.

MR. ARMISTEAD: We have transitioned to thinking of contracts as a percentage of the net present value of the asset. For example, if you have a 15-year contract and you discount it, even if you have sold 100% of the electricity during the contract term, you have really only sold, I don't know, 50% to 60% of the future revenue. The discount rate discussion is interesting, but not super interesting. The assumptions are way more interesting.

A perspective on the post-contract revenues and a perspective on whether you are in a place / continued page 39

Road Ahead

continued from page 37

where it will be more expensive to interconnect might be more important. I believe very much in the residual revenue, but I don't believe necessarily in projecting 35 years of revenue when you only have 15 years under contract.

MR. SMITH: We have not talked much about interconnection queues. They are the biggest reason why we will see 2022 projects move into 2023, not only supply-chain disruptions, although they are a big issue as well.

As a developer, we can see returns much greater than what Ted is talking about. If you are buying the rights to a fully-developed project with a 20-year bus-bar PPA, you are going to see discount rates well below 6% to buy — into the 5% range, and some people are even looking at buying below that.

Developers can still see pretty decent returns after developer fees, structuring options and sell downs are taken into account. But, as Hunter said, there are all kinds of issues on assumptions. For example, is it a hedged project in Texas, which you don't often see anymore? Is it a project in PJM or MISO where you are taking capacity risk, reactive power risk, and risk tied to other revenue streams, and maybe only 50% of the revenue is coming from a fixed contract?

Is it a 12-year, 15-year or 20-year contract? The projects with 20-year bus-bar PPAs that Ted mentioned are the stars in the portfolio, and those are the ones where returns get driven down into the 5% range by buyers.

MR. MARTIN: Ted Brandt, people used not to assign any value to a project until it had a PPA. Is that still the case?

MR. BRANDT: No. If the project is in an area where people are confident that they will be able to get a power contract, where there is access to transmission and the developer has land control, those are assets that are being sold for as much as 20¢ a watt right now.

Hydrogen

MR. MARTIN: All three of you, last topic, maybe starting with Hunter Armistead: Is the hype about green hydrogen warranted? If so, when do you see green hydrogen changing the renewable energy market, and how?

MR. ARMISTEAD: The biggest challenge with the transition to renewables is how we manage not just shifting surplus electricity from daytime to the peak load in the evening, but also how to create a reliable, long-term grid that supports true de-carbonization. That is where I think hydrogen has its most obvious play.

Hydrogen today is still a wonderful industrial gas that is used for manufacturing, but the idea that it is going to be combusted to generate electricity is really kind of like burning your food. It is not an awesome application. I see it as one of several possible responses over time to the need for long-duration storage.

MR. MARTIN: So there is an issue that needs to be addressed, but it may not be addressed ultimately by hydrogen. Kevin Smith?

MR. SMITH: New technologies do not really take off until they become cost competitive. Solar and wind did not take off until they became cost competitive with conventional energy.

I think we will see that with green hydrogen. There is lots of talk about it. There is more talk internationally than in the US, largely because we still have a very plentiful supply of low-priced natural gas. That makes it hard for green hydrogen projects to compete in the US. When hydrogen becomes cost competitive, it will ramp up dramatically. Until then, the market will be slow to develop.

MR. BRANDT: We are bullish and see it largely as an inside-the-fence phenomenon because of the difficulty moving hydrogen through pipelines and the size of the molecules. I understand that it leaks like a sieve. Moving hydrogen is hard with our existing infrastructure. The fastest-growing part of our business is the energy transition and helping companies think through what will happen next.

I don't know a single heavy natural gas user who is not thinking it is going to have to supplement its local natural gas supply with some amount of hydrogen.

MR. ARMISTEAD: Maybe to bridge all three of our comments, I think we all see a need for hydrogen. The question is when and on what scale. It is just like batteries. Batteries were hyped for years and years before they took hold. One question is how far away are we before hydrogen takes hold. The other question is when do you have to start participating to make sure you are well positioned when it really does take hold. When will it be too late to have ignored it and hope to catch up? ◎

Carbon Offsets as a Potential Source of Revenue

by Christy Rivera and Adrienne Sebring, in New York

Renewable energy developers are showing more interest in the voluntary carbon offset market as a potential source of additional revenue for their projects.

Most trading is over the counter. There are various exchanges on which trades can be made. Prices for "avoidance" offsets, which are the kind generated by wind and solar projects, were averaging $7 a ton in February as the *NewsWire* went to press.

Technology companies, airlines and oil and gas companies have been among the early buyers.

Demand is expected to increase as more companies look to offset their carbon emissions for reputational reasons.

Almost 200 companies committed to "net zero" emissions by signing the Paris climate accord. Many more have made similar pledges since the COP26 UN climate summit in Glasgow in October 2021. These companies can credit carbon offsets purchased in the voluntary carbon offset market toward reaching these goals, as long as certain rules established by article 6 of the Paris climate accord are followed.

However, the lack of standards and quality controls are dampening demand. Companies are reluctant to buy offsets without a way to verify that the promised carbon reductions have actually been delivered.

Once the market can get past these issues, look for offset prices to rise significantly. All signs point to extreme future growth in demand.

Offsets v. Credits

A carbon offset is different from a carbon credit.

A carbon offset represents one metric ton of carbon dioxide or equivalent greenhouse gases that has been avoided or permanently removed from the atmosphere. For example, wind and solar projects can create carbon offsets because the energy produced by these renewable energy projects reduces the amount of energy that must be procured from other projects using fossil fuels. Carbon offsets can also be created by planting and preserving forests that absorb carbon dioxide. There are also various experimental offsets being researched, including enzymes that capture carbon and other processes that capture CO2 in the ocean and turn it into a usable product.

Carbon offsets are traded in voluntary markets, meaning no one is compelled to buy them. The demand for them comes from companies that have set voluntary emissions reductions targets that can be met either by reducing their own emissions directly or effectively by paying someone else to do something that reduces emissions.

In contrast, a carbon credit is a tradeable permit, or right, that allows the holder to emit one metric ton of carbon dioxide or greenhouse gas into the atmosphere. Carbon credits are a creature of government regulations that limit the amount of CO2 or greenhouse gas that can be emitted. When a company subject to such regulation finishes below its required emissions cap, the company earns a carbon credit for every metric ton it is under its cap. It can then sell its carbon credits to other regulated companies that can use the purchased carbon credits to reduce the amount of CO2 or greenhouse gas that they are deemed to emit.

Carbon credits are traded in compliance markets. Trading is limited to the entities and regions covered by the compliance market. Europe is in the forefront of the compliance market with the EU actively managing prices at which credits trade. In the United States, the only large compliance carbon offset program is in California, where the California Air Resources Board oversees trading in "ARB offset credits" which are issued by the Air Resources Board to projects that meet specific requirements.

Companies trade carbon credits because they have to, and they trade carbon offsets because they want to.

The more valuable carbon offsets are those issued by programs with more rigorous rules and standards for offsets.

Voluntary Programs

There are several voluntary carbon offset programs that register projects in the United States, including the American Carbon Registry, the Verified Carbon Standard and the Climate Action Reserve. Once projects are certified and registered by such a program, then the registrant can sell the offsets on the open market. Each program has its own criteria and a dizzying number of acronyms.

The American Carbon Registry standard v7.0 sets out the eligibility criteria for registration of project-based carbon offsets. Following its requirements, according to the American Carbon Registry, will "ensure that project-based offsets represent emissions reductions and removals that are real, additional, permanent, net of leakage, accurately and / continued page 40

Carbon Offsets

continued from page 39

conservatively quantified, verified by a competent independent third party, and used only once."

Projects verified by the American Carbon Registry are issued verified emissions reductions (VERs).

Developers are showing more interest in the voluntary carbon offset market as an additional source of revenue for projects.

Projects verified by the Climate Action Reserve end up with registered offsets called Climate Reserve tons (CRTs). CRTs can be converted into verified carbon units (VCUs) and transferred to a VCU registry with Verra.

The carbon offsets created under these programs are traded on various platforms. Each platform is nothing more than a registry. The main voluntary carbon offset registries include the American Carbon Registry, APX Inc., Markit and Verra.

Trading on the American Carbon Registry and Verra is limited to offsets created under programs administered by those platforms while trading on Markit and APX is of multiple environmental-related credits. For example, APX partners with multiple carbon offset programs and administers registries for VCUs, CRTs and VERs.

Valuing Offsets

Carbon offsets are not all equal in terms of value and determining the value of carbon offsets is far from straightforward given the variety of offsets and their varied attributes.

The value of a carbon offset is a function of several factors, including its vintage, the type of project, the volume of credits traded at the time, the geography of the project, the delivery time and whether the offset can be certified.

The "vintage" is the year an offset is created and is a principal marker considered by buyers. Older vintage carbon offsets sell for a discount compared to those of a more recent vintage typically for two reasons. First, some buyers are focused on buying offsets only from "additional" projects. A project is additional if it would not have been developed without the ability to sell the offsets as a source of revenue. Second, some buyers are concerned that older vintage offsets are only still available on the market because the underlying project may be of lower quality.

The type of project from which an offset is created is another key driver of valuation. Carbon credits can be categorized into two broad categories: projects that avoid emitting greenhouse gas emissions elsewhere and projects that remove greenhouse gases from the atmosphere. Avoidance projects include wind, solar and other renewable energy projects, while removal projects include carbon recapture and reforestation.

Carbon offsets generated by removal projects tend to trade at a premium. For example, nature-based removal offsets (those that fall within the forestry, farming and land management category) were trading at a near record high of $22.30 a ton at the beginning of February 2022.

While demand for removal offsets is high, supply continues to lag. The US Department of Agriculture has launched a Climate-Smart Agriculture and Forestry Partnership Initiative that is supposed to create a framework and standardization around "climate-smart" offsets from nature-based removal projects. Others are working to provide farmers with the information and tools they need to document the carbon offsets they are creating so that they will be able to offer them in the voluntary markets.

In contrast, there is a large supply of carbon offsets stemming from existing avoidance projects. If all of these existing avoidance offsets were certified by the existing programs, the number of carbon offsets from older projects would dwarf the demand for such offsets, leading to very low prices.

Many environmental groups object to the certification of these older offsets as there is no real, practical avoidance of global emissions given that the projects have existed for years and the purchase of the related offsets is not an investment in a new project that could lead to additional reductions in future CO2 and greenhouse gas emissions. As a result, the ability to register carbon offsets tied to older avoidance projects is limited under the leading carbon offset programs. For example, with certain exceptions, the Climate Action Reserve does not allow for the issuance of CRTs on a retroactive basis for existing projects.

Finally, the market is moving toward more uniform standards for offsets, but has not yet coalesced around a single set of standards.

Standards are typically set by NGOs. For example, the Taskforce on Scaling Voluntary Carbon Markets announced in September 2021 the formation of an independent governance body for voluntary carbon markets. The group has representatives from 12 countries and is focused on drafting a list of "core carbon principles" that are supposed to serve as a global benchmark for carbon credit quality.

One quality control standard expected to be adopted by the group is that the underlying project must be "additional," meaning that the project would only exist due to proceeds received from its carbon offsets. Other standards address the permanence of the reduction, the accuracy of the estimation of the net greenhouse gas reduction and the presence of additional environmental attributes or benefits.

Oversight of Carbon Markets

Many startup companies have been formed in recent years to focus on carbon reduction issues. These carbon startup companies have been catching eye of investors who are putting significant funding into them.

Some of these startups provide data and insight to voluntary market participants so that companies can have the transparency they need. For example, Sylvera, a London-based startup founded in 2020, aspires to act like a rating agency for carbon offsets in the voluntary market.

These data collecting and verification services will be critical for the voluntary carbon offset market to gain legitimacy with larger, corporate buyers.

S&P Global Platts already tracks sales of carbon offsets that have been certified by the following standards: the Gold Standard, Climate Action Reserve, Verified Carbon Standard, Architecture for REDD+ Transactions and American Carbon Registry. S&P Global Platts provides valuable price data.

Although many transactions in the voluntary carbon market are over-the-counter trades, there are exchanges, such as New York-based Xspansiv and Singapore-based AirCarbon Exchange, on which carbon offsets may be traded.

Seven banks announced plans recently to launch a voluntary carbon market settlement platform called Carbonplace by the end of 2022. The seven banks are CIBC, Itaú Unibanco, National Australia Bank, NatWest Group, UBS, Standard Chartered and BNP Paribas.

The platform will give project developers direct access to customers looking to fund carbon reduction and removal projects. And as the carbon markets continue to gain legitimacy, developers can expect to see many more customers.

Sophisticated Use of Political Risk Insurance

by Julie Martin with Marsh McLennan in Greenville, and Kenneth Hansen in Washington

By making more sophisticated country risk analyses, lenders and equity investors in emerging market projects can insure selected risks in a manner that increases the internal rates of return on projects.

The increased return more than covers the insurance premium.

A recent study by IHS Markit and Marsh Specialty, called "A New Perspective on the Cost and Benefits of Political Risk Insurance for Foreign Direct Investments," suggests that many equity investors systematically underestimate the benefits of political risk insurance (PRI) relative to its cost.

Such insurance brings the obvious benefit of at least a partial recovery if a covered loss occurs.

It also can affect the determination of an appropriate country risk premium when projecting the internal rate of return of a proposed investment. The country risk premium is added to the weighted average cost of capital when estimating an overall cost of capital. A lower country risk premium yields a higher IRR.

The study concludes that, although the magnitude of the effect depends on the country and the nature of the project, there is necessarily a non-zero, and more typically a substantial, reduction of the appropriate country risk premium when the investment is covered by conventional political risk coverages.

That reduction alone can more than justify the cost of PRI, without even taking in to account the benefits of claim payments if an insured event happens.

New Risk Analyses

IHS Markit has developed over 20 years a country risk investment model — called CRIM — that estimates the adverse impact of country risks on the cash flow projected for an investment. The CRIM offers a far more nuanced approach to measuring country risk than the common simple adoption of the premium for sovereign debt as a proxy for country risk.

The model identifies 21 distinct country risks, each of which is scored in their review of a given country and project.

The study mapped conventional political risk coverages to the CRIM and applied the enhanced model to an illustrative power generation project with a long-term power purchase agreement with a government offtaker in three emerging markets: Ghana, Brazil and Indonesia.

PRI does not mitigate all of the scored risks (for example, natural disasters). However, conventional PRI coverages are relevant to a number of key risks scored in the IHS Markit model. PRI thus invariably reduces the country risk premium that comes out of the model. The only questions are by how much and what is the benefit of that reduction relative to the cost of the insurance.

Applying the CRIM to the sample power generation project proposed to be developed in Ghana (which has an S&P sovereign rating of B-), yielded a country risk premium of 6.30% without PRI.

The country risk premium fell to 2.23% if the project purchased conventional political risk coverage.

The effect of incorporating PRI into the financing plan improved the simulated S&P rating from B- to BBB. (While the initial country rating is based on actual S&P ratings, IHS Markit calculates a revised, simulated rating for purposes of comparison.)

Thus, the PRI substantially improves the project economics without any direct weighting of the benefit of ultimate claim payments.

The study then transported the same project to both Brazil (with an S&P sovereign rating of BB) and Indonesia (with an S&P sovereign rating of BBB). Because the IHS Markit estimates of the relevant risks in those two countries are different from Ghana and from each other, the financial impact of mitigating those risks also varies.

The reduction of the country risk premium in Brazil was from 2.91% to 1.41%, with a corresponding increase in the project's simulated S&P rating from BB to A -, leaving a narrower margin, but still possibly feasible for PRI to be worth its cost.

In Indonesia, the impact of PRI was to reduce the country risk premium from 1.84% to 1.05% and to improve the S&P rating from BBB to A-.

In both cases, the margin for PRI pricing is narrower than in Ghana, although it may still make sense for an investor to obtain PRI if it is available at a price point that avoids depressing the project's returns. Then, without giving up any upside, the insured still benefits from the "safety belt" that PRI provides for a class of risks that are inherently difficult to forecast, especially over longer investment horizons. Additional benefits can include comfort to prospective lenders and enhancing the options for exit.

Premiums

This sample suggests that a more compelling case for PRI may arise in certain countries with lower sovereign risk ratings.

That depends on the PRI premium. PRI pricing on its own is an interesting topic, in which institutional factors and intuition have historically dominated analytics. The determination of the premium required for PRI coverage of a given project in a given country at a given time is more a function of tradition, on one hand, and recent anecdotal experience on the other, with some reflection of competitive pressures on prospective insurers.

A general impression in the market is that the risk elasticity of the price of PRI is lower for agency insurers than for commercial insurance companies. That is, coverage costs more in higher risk countries, regardless of whether that coverage is sought from the public or private sector providers, but the price is likely to rise more quickly with perceived risk with the commercial insurers. Thus, as an opening bid, a commercial insurer may be the best bet for lower risk countries, while the agencies may be the better bet in more challenging environments – assuming coverage is available at all.

However, what has traditionally been the case is no longer necessarily so, with the continued growth of the private market.

Offered rates in the private market tend to vary widely. For example, in a recent large 2021 placement for an infrastructure project in a Latin American country that, like Indonesia, is a BBB rated country, the quoted insurance pricing sourced by Marsh ranged from 150 to 50 basis points per year, and a policy limit of $800 million was secured at a market-clearing price very near the bottom end of the range. Marsh's view is that PRI would typically be available at a cost that is exceeded by the benefits implied by the CRIM as applied to the sample project in Ghana and Brazil and perhaps also in Indonesia.

Going Deeper

The CRIM analysis provides a basis for going deeper than just a go or no-go decision with respect to the full basket of PRI coverages. The costs and benefits of PRI can be broken down coverage by coverage.

Scores for particular risks can vary widely within a single country. For example, a country can have low fiscal risk, but a high risk of political violence. For that reason, political risk insurance underwriters shy away from a single risk score, like a sovereign rating.

Different insurers have different views about unbundling coverages and their corresponding */ continued page 44*

CRIM country risk events:

- Corporate taxes
- State contract alteration
- Contract enforcement *
- Expropriation *
- Environmental regulations
- Business regulations
- Capital transfer *
- Currency depreciation
- Construction material shortages
- Energy shortages
- Labor costs
- Skilled labor shortages
- Recession
- Export disruption
- Import disruption
- Infrastructure disruption
- Strikes and protests *
- Manmade disaster *
- Natural disaster
- Corruption
- Criminal violence

**Risks mitigated in whole or substantial part by PRI.*

Conventional PRI coverages:

- Expropriation
- Selective discrimination
- Forced divestiture
- Forced abandonment
- Political violence
- Business interruption (following political violence)
- Non-repossession, deprivation
- Arbitration award default / breach of contract
- Currency inconvertibility/non-transfer
- Deprivation of creditor's rights (for debt investments)

Insurance

continued from page 41

premium amounts, but the CRIM provides a basis for negotiating optimal coverage from the perspective of maximizing investment value.

Some PRI coverages correlate only imperfectly to the risks measured in the CRIM. An example is expropriation. A PRI claim will typically require total expropriation, where the government action is so adverse that the investor prefers to abandon the project in exchange for the insurance claim payment. Partial expropriation, in which government actions reduce the value of an investment without wiping it out, tend not to be covered. To address this difference, the CRIM assumes that a host government will, on average, provide compensation for 50% of the loss, so it considers expropriation risk to be only partially mitigated by expropriation coverage.

Lenders and equity investors in emerging market projects are using political risk insurance and more granular analyses of risk to increase returns on projects.

The CRIM model focuses on cash flows. So do some PRI coverages, such as business income coverage, which replaces income lost for up to one year as a result of political violence. On the other hand, political violence coverage of the cost of repairing or replacing damaged assets provides assets-based, not income-based, compensation. The impact on cash flow will depend on the impact of the damage on operations and the time required for such repair or replacement. That could vary from hours to years.

Thus, the impact of some coverages on the risks measured by IHS Markit is speculative, although IHS Markit says it has been conservative in projecting benefits in such cases.

IHS Markit may have been too conservative in the credit given to PRI. The joint report notes that "the Marsh co-authors felt that IHS Markit did not give enough credit to the presence of the element of PRI cover commonly called 'breach of contract' or 'arbitration award default,' which would further improve the predicted financial benefits of PRI."

Such coverage is relevant to the sample projects assessed by CRIM since the expected revenues are derived under a power purchase agreement with a government offtaker that has a termination payment that could be subject to arbitration and thus benefit from arbitral award default coverage. Breach coverage is only relevant to projects that depend importantly on contracts with host governments, but that would include most substantial energy and infrastructure projects.

A key consequence of the PRI-enhanced CRIM is that potential investment projects with IRRs that otherwise would not have qualified for pursuit by an investor may, with PRI, clear the required hurdle.

Using a single discount rate for country risk rather than digging deeper and adding insurance for particular risks can inadvertently inflate the discount rate used to value cash flows. Applying PRI through the lens of the CRIM tool can improve the return.

Of course, the math only works if the lenders or equity investors agree with the CRIM's weighting of the benefits of PRI. But the CRIM model has a broad following in the market, so its approach is likely to have some influence.

The CRIM model methodology is not the final word in evaluating the relevancy of PRI to investment decisions. Work will continue on how best to reflect the impact of PRI in calculating country risk premiums, IRRs and the net present value to assign to a project. However, the work to date appears sufficient both to improve the project economics available to current emerging market investors and to expand the universe of investors who might take seriously investment opportunities in emerging markets. ◎

Calculating How Much Tax Equity Can Be Raised

by Keith Martin, in Washington

Developers of renewable energy projects in the United States sometimes struggle to calculate how much tax equity can be raised to help pay the project cost.

A simple current rule of thumb is that tax equity accounts for 35% of the capital stack of a typical solar project, plus or minus 5%. It accounts for 65% of the capital stack of a typical wind farm, plus or minus 10%.

A more precise calculation requires adding four blocks of figures to the financial model for the project.

A developer can raise an amount of tax equity equal to the present value of four items discounted at the target internal rate of return required by the tax equity investor.

The four items are the tax credits the tax equity investor will receive, the cash it will receive and its anticipated tax savings from depreciation, interest and other deductions, minus the taxes it will have to pay on its share of taxable income from the project.

Target returns in the US tax equity market have moved into the low- to mid-7% range, unleveraged and after taxes, for most utility-scale projects.

Basic Concepts

The chief financial officer of a renewable energy company must cover the capital cost of his or her project through a combination of true equity, tax equity and debt.

The US government pays roughly 44¢ per dollar of capital cost of a typical wind or solar project through tax incentives.

Few developers are in a position to use the incentives because of inadequate tax base.

The most common way to get value for them is through a "partnership flip" transaction. The developer brings in a bank, insurance company or other tax equity investor to own the project as a partner with the developer. The investor invests a share of the capital for the project and is allocated 99% of the taxable income and loss and tax credits until it reaches a target internal rate of return, after which its interest drops usually to 5%, and the developer has an option to buy out the investor's post-flip interest for fair market value determined at the time. Cash may be distributed in a different ratio. The developer takes a majority of the cash before the flip and usually 95% after.

Partnership flips are the only way to raise tax equity for wind and other projects on which production tax credits will be claimed. There are three possible tax equity structures for solar, fuel cell and other projects on which investment tax credits will be claimed: partnership flips, solar-leasebacks and inverted leases. About 80% of ITC transactions still involve partnership flips. (For more details about tax equity structures, see "Partnership Flips: Structures and Issues" in the February 2021 *NewsWire* and "Solar Tax Equity Structures" in the December 2021 *NewsWire*.)

The Internal Revenue Service issued guidelines for partnership flip structures in October 2007. The agency said it is okay with the structure, but that anyone straying outside the guidelines should expect to be subjected to "close scrutiny" on audit. The guidelines were addressed to partnership flip deals involving wind farms. However, the market has followed them in other types of projects.

At most, 99% of the tax subsidies can be transferred to an investor in a partnership flip deal.

In practice, the percentage may be smaller.

Any tax subsidies that cannot be transferred to the investor can be carried forward by the developer for up to 20 years.

Each partner in a partnership flip transaction must track its "capital account" and "outside basis." These are different ways of measuring what each partner invested and took out of the deal. If either measure goes negative, then it is a sign that the partner took out more than its fair share. The two measures are also limits on the capacity of the investor to absorb tax benefits. Consequently, it is important to model both accurately.

Capital Accounts

A partner's capital account starts with the cash the partner paid to buy into the deal or contributed to the partnership. It also includes the fair market value of any property contributed.

There are several forms of partnership flip deals.

In some deals, the investor pays a purchase price to the developer directly to buy an interest in a limited liability company that owns the project. Call this the "purchase model."

However, in most cases where an investment tax credit will be claimed, the investor makes a capital contribution to the partnership for an interest, and the partnership uses the capital contributions by the investor and the */ continued page 46*

Tax Equity

continued from page 41

developer to buy the project company from an affiliate of the developer.

In some cases, the capital contributed by the investor is used instead to repay project-level debt or remaining construction costs and the balance is distributed by the partnership to the developer partner. Call both of these cases the "contribution model."

In both the purchase model and the contribution model, the investor takes an opening "capital account" equal to what it pays the developer or contributes to the partnership to buy into the deal.

The entity that will become the partnership usually does not exist for tax purposes until the investor funds. Until then, it is usually a limited liability company with only one owner: the developer. Such companies are "disregarded" for tax purposes until they have at least two owners.

When the investor funds, the project company turns into a partnership for tax purposes. In the purchase model where the investor pays the developer for a partnership interest, the investor is treated as having purchased an undivided interest in — or percentage of — the project assets from the developer and contributing it to a new partnership with the developer. The developer contributes the share of the project it retains.

In the contribution model where the investor makes a capital contribution to the partnership, the investor is treated as having made a capital contribution to a new partnership in exchange for an interest. The developer is usually treated as if it contributed the entire project.

However, if part of the capital contributed by the investor is distributed by the partnership to the developer, then there is a risk of the distribution being treated as purchase price for the partnership to make a "disguised" purchase of part of the project from the developer. (For more details, see "Tax Triggered When Partnership Formed?" in the October 2016 *NewsWire* and "Disguised Sales and Earnings Stripping" in the October 2017 *NewsWire*.)

In both the purchase model and contribution model, the investor has an opening capital account equal to its cash payment.

In the purchase model, the developer has an opening capital account equal to the fair market value of the share of the project it retained. In order to calculate the developer's opening capital account, set up a fraction. The numerator is the amount paid by the tax equity investor. The denominator is the fair market value of the entire project. The fraction is the share of the project the investor purchased. The developer retained one minus that fraction.

In the capital contribution model, the developer has an opening capital account equal to the fair market value of the entire project. However, the developer must subtract the opening capital account of the investor plus the amount of any project-level debt. By subtracting these amounts, the developer ends up with an opening capital account equal to the equity value it has in the project. Its opening capital account is the claim it would have on the project assets if the partnership were to liquidate the next day. The lender would have a claim for the outstanding project-level debt. The investor would have a claim for the capital the investor contributed. The developer has a claim for what is left.

Capital accounts are a fluid concept. They go up and down each year to reflect partnership results.

Add to each partner's capital account at year end its share of income earned by the partnership. Subtract the losses the partner is allocated and cash it is distributed. In other words, increase the capital account each year as the partner suffers detriment; having to report income is a detriment (because taxes will

Developers can calculate the amount of tax equity that can be raised on a project by discounting a net benefits stream by the target tax equity yield.

have to be paid on that income). Reduce the capital account by the benefits the partner receives; being distributed cash or allocated losses is a benefit.

The income and loss that are reflected in capital accounts are "book" income and loss.

The "book" amounts are not the same as what is reported on financial statements. They are not the taxable income and loss that get reported on tax returns, either.

Rather, they are the income or loss computed at the partnership level the same way as the taxable income the partnership reports to the IRS, except that the project is depreciated by starting with its fair market value when the investor funds (and the partnership is formed) rather than the actual cost of the project. Otherwise, the depreciation is calculated the same way as tax depreciation. Thus, the only difference between "book" income and taxable income is the depreciation used to calculate book income may be a higher amount; it starts with the fair market value of the project rather than its cost.

A partner's capital account serves two purposes.

First, it is the claim the partner will have on the assets in the partnership if the partnership liquidates.

Second, it is a limit on the amount of losses the partner can be allocated.

A partner's capital account cannot go into deficit unless the partner is willing to contribute additional capital to the partnership when the partnership liquidates.

Most investors in the tax equity market are willing to step up to such a "deficit restoration obligation" or "DRO"; however, they will agree only to contribute up to a fixed dollar amount or percentage of their original investment. The dollar amount is the amount of deficit that the computer model suggests will reverse itself on its own under reasonably conservative assumptions about how the project will perform.

For example, in wind farms and geothermal projects, the tax benefits are largely exhausted after 10 years. After that, the partners receive both cash and taxable income. If the income to be reported exceeds the cash — for example, because cash must be used to repay project-level debt — then the partners will have "phantom" income to report from the partnership. For example, a partnership might earn $100 from electricity sales, but have to use $80 to repay debt principal; the partners must still report the full $100 in income even though they are distributed only $20 in cash. The amount of this phantom income will increase their capital accounts. An investor will usually step up to a deficit restoration obligation in the amount of the aggregate phantom income expected over the remaining life of the project.

Another way to deal with deficit capital accounts is to pay part of the cost of the project with debt at the project level. IRS rules allow capital accounts to go into deficit to the extent they are driven into deficit by depreciation claimed against the share of project cost funded with nonrecourse debt. Thus, for example, suppose a project costs $100 and the cost is paid with $40 in equity from the partners and $60 in nonrecourse debt. The first $40 in "equity" depreciation will usually have to be shared in the same ratio the partners contributed equity, but the last $60 in "nonrecourse" depreciation can be shared in any ratio the partners wish, as long as the ratio is consistent with some "other significant item," like the 99-1 ratio used to allocate other partnership items. (This is an oversimplification; it is discussed in more detail later.)

The reason the nonrecourse depreciation can be shared 99-1 in favor of the investor is that US tax rules require the partners to report the later phantom income tied to repayment of the nonrecourse debt principal in the same 99-1 ratio. In other words, any deficit created by the nonrecourse deductions will reverse itself because it will be matched by future phantom income.

After calculating the capital accounts, the computer model should show the balance at year end in each partner's capital account.

It should then have another line adding back the "nonrecourse" depreciation the partner was allocated. The next line should show the balance in the "adjusted capital account." It is the adjusted capital account that cannot go into deficit unless the partner has agreed to a deficit restoration obligation.

If a partner has a deficit in its adjusted capital account that exceeds the deficit the partner has agreed to restore, then the standard partnership agreement shifts any losses the partner is allocated that year to the other partners to prevent a deficit.

There is a common misconception in the market that investors are able to absorb the tax incentives fully from a project simply by stepping up to a large enough deficit restoration obligation. Stepping up to such an obligation may prevent losses from being shifted to another partner, but it does not ensure the investor will be able to use the losses fully. Even if the partner can keep the losses, its use of them may be suspended if it does not have enough "outside basis" to absorb them fully. Outside basis is the next block of figures that it is important to calculate.

If losses shift in a year because of inadequate capital account, then most tax counsel take the position that the shift will drag production tax credits with it. The US government allows production tax credits of $25 a megawatt hour */ continued page 48*

Tax Equity

continued from page 47

to be claimed on electricity from wind farms and geothermal projects for 10 years after the project is placed in service. Credits of $13 a megawatt hour can be claimed on the electricity from a biomass project for 10 years. The credit amounts are adjusted each year for inflation.

Four blocks of figures should be added to the financial model for the project.

Production tax credits must be shared by partners in the same ratio they share in “receipts” from electricity sales. The IRS has not said how to determine in what ratio “receipts” are shared; receipts are not the same thing as cash. Most tax counsel assume receipts are shared in the same ratio as net income and loss for the year. Thus, if net losses are supposed to be shared in a 99-1 ratio in favor of the investor, but the investor has too little capital account in a year to absorb the full net loss in that ratio with the result that part of the loss shifts back to the developer, the production tax credits will end up being allocated that year in the actual ratio that losses were shared.

Outside Basis

A partner’s outside basis is another potential limit on the ability of an investor to absorb tax incentives. It is the same thing as the partner’s capital account, with three exceptions.

The investor’s opening outside basis is the same as its opening capital account — what the investor paid or contributed to the partnership — but the developer’s outside basis is its “basis” or cost of the share of the project the developer is treated as having contributed.

Thus, in the purchase model, take the fraction of the project that the developer is viewed as having retained. Multiply the cost of the entire project by that fraction. The developer’s outside basis is that fraction times the original project cost.

In the capital contribution model, the developer’s outside basis is the cost of the entire project, less the capital contributed by the investor and less the amount of any debt assumed by the partnership.

Outside basis goes up and down each year in the same way as capital accounts. Add income. Subtract cash distributions and losses allocated to the partner. However, instead of using the “book” income and loss, use taxable income and loss.

Finally, a partner’s outside basis includes not only what the partner contributed to the partnership, but also its share of any debt at the partnership level. Put differently, a partner’s capital account is just his equity in the deal. A partner’s outside basis is its equity plus its share of debt at the partnership level.

Each partner includes a share of project-level debt in outside basis by working down a three-level waterfall. The model should recalculate the amount of debt in each partner’s outside basis at the end of each year. It should have a line showing the outstanding principal amount of the debt there is to put in partners’ outside bases. Then give each partner first an amount of debt equal to the nonrecourse deductions it has been allocated to date and that have not been charged back. (How to calculate this is discussed below.)

Next, give the developer an amount of debt equal to the “built-in gain” or appreciation there was in the share of the project the developer was treated as contributing when the partnership was formed. The built-in gain gets worked off over time, so the amount to put in the developer’s outside basis on account of built-in gain reduces gradually over time. (The concept of built-in gain is discussed later in the article.)

Finally, the remaining debt is shared by partners in the same ratio that income is allocated (therefore, 99-1 initially in favor of the investor and then usually 5-95 after the flip).

If one of the partners or one of its affiliates makes a loan, then that debt must go entirely into its outside basis, and any depreciation tied to such a loan must also be allocated entirely to that partner.

The model should show each partner's outside basis at year end.

Then it should have two more lines.

If the outside basis is negative, then the model should treat the cash the partner was distributed that year — to the extent needed to get the outside basis back to zero — as an "excess cash distribution," meaning the partner must report it as capital gain. It is inefficient to be in such a position, since the partners will have already had to have reported the income in full that the partnership earned from electricity sales. When cash is later distributed to partners, it is not normally taxed again. An excess cash distribution is a form of double taxation.

If the partner still has a negative outside basis after converting all of the cash it was distributed into an excess cash distribution, then the model should suspend the use of any losses the partner was allocated that year to close the remaining gap. The partner keeps the losses, but it cannot use them until a later year when its outside basis goes back up.

If there is an excess cash distribution, then the model should increase the "inside basis" — or basis that the partnership has in the project — by the amount of the excess cash distribution. The partners' capital accounts should also be increased by the same amount. However, the investor's capital account will usually increase by 99% of the excess cash distribution if it occurs before the flip, and the developer's capital account will increase by only 1% of it. The increase must bump up partner capital accounts in the same ratio that a gain in the same amount would have been reported by the partners.

It is important in deals with project level debt that will remain outstanding after the flip to check whether the flip will cause an "excess cash distribution" to the investor. When the flip occurs, the investor's share of partnership income will drop from 99% to around 5%. This will lead potentially to a large amount of debt being shifted from the investor's outside basis to the outside basis of the developer. The mechanism by which this shift occurs is the investor is treated as if the investor was distributed an amount in cash equal to the debt that shifts. If this "deemed" cash distribution exceeds the investor's remaining outside basis at the time, then the investor will have an excess cash distribution that must be reported as capital gain.

In some deals, the investor's interest flips down to 5% in two stages to try to manage this problem. The first flip is to an intermediate sharing ratio that avoids such a deemed distribution.

Minimum Gain Chargebacks

"Minimum gain" is a fancy term for a simple concept. The model will need another block of figures to track minimum gain. The concept is as follows.

Suppose two partners form a partnership. The partnership builds a project at a cost of $100. It pays the cost with $40 in equity contributed by the partners and $60 in nonrecourse debt borrowed from a bank. The partnership will have $100 in depreciation. However, the partners are really only exposed to $40 in loss in value in the project, because they can always walk away and hand the keys to the nonrecourse lender. It is the bank that is exposed to the last $60 in depreciation; depreciation represents erosion in value of the project.

As a general rule, partners are only supposed to claim losses that they really suffer.

However, the IRS will let the partners claim the full $100 in depreciation in this case on one condition: they must agree to report the "phantom" income when the debt is repaid in the same ratio they claim the "nonrecourse" depreciation tied to the loan.

Therefore, in any deal where there will be project-level term debt, the model must track the amount of "nonrecourse" depreciation and how it was allocated to the partners.

This is simple enough to do. There should be a line showing the outstanding debt principal. Next, a line should show the inside basis, or unrecovered "book" basis that the partnership has in the project. There is no "minimum gain" until the inside basis in the project drops below the remaining debt principal. At that point, the lender is exposed in theory to a loss if the project company walks away from the project and hands the lender the keys. The shortfall, or potential loss, is the "minimum gain."

At each year end in which the minimum gain increased, the amount of the increase is the amount of book depreciation the partners were allocated that year that is considered nonrecourse depreciation, or depreciation that reflected an erosion in value to which the lender is exposed. In the first year in which the gap starts to narrow, the partnership must "charge back" income to the partners in the amount of the decrease. This income must be reported by the partners in the same ratio they were allocated the nonrecourse deductions earlier. */ continued page 50*

Tax Equity

continued from page 49

These chargebacks are not additional income. They are simply a direction that the first amount of income that year must be shared by partners in the same 99-1 or other ratio that they were allocated the nonrecourse depreciation earlier. The remaining income for the year is allocated according to the business deal.

The point is that in any deal where term debt will remain outstanding after the flip, the investor will be allocated phantom income as the debt principal is repaid in a 99-1 ratio. It will be allocated income in that ratio at a time —- after the flip —- when it is being distributed only 5% of the cash.

This will take the investor's return backwards.

Investors in such situations insist on one of at least two fixes. One is the investor might insist on being distributed enough cash to cover its taxes. It will also need additional income to restore its capital account. (Cash distributions reduce the investor's capital account; income pushes it back up.) It is an iterative calculation to figure how much additional cash and income the investor needs to remain whole.

Alternatively, the investor might only credit the time value of the nonrecourse depreciation in determining when it reaches its target return (rather than treat each dollar of depreciation as saving investor 21¢ in taxes). It should be possible to calculate when the depreciation will reverse due to chargebacks.

Built-In Gain

There is one more concept that must be reflected in the model in order for it to work properly. It is called "section 704(c) adjustments." Once again, the concept is simple.

Suppose two partners form a 50-50 partnership. The deal is that each must contribute $100. Partner A contributes $100 in cash. B contributes an asset worth $100 but that has been fully depreciated. This is not a fair deal for A, since the partnership will have a gain of $100 one day when it sells the asset that B contributed, and A will have to pay taxes on 50% of that gain.

Section 704(c) of the US tax code addresses this by requiring B to pay taxes on the full $100 in gain when the asset is sold. However, it also requires B to try to make it up to A in the meantime without waiting for the asset to be sold. B makes it up to A by shifting depreciation to which B would otherwise be entitled to A until A has received $50 in deductions.

In many partnership flip deals, the developer is viewed as contributing appreciated assets, and there is not enough depreciation to shift to make A, the investor, whole.

There are three ways to make section 704(c) adjustments.

Under the "traditional" method, the partnership allocates A the full amount of tax depreciation each year up to the "book" depreciation that A was allocated. For example, suppose the partnership has $20 in book depreciation, but only $15 in tax depreciation in a year, and the business deal is the investor gets 99% of income and loss until the flip. The investor gets 99% of the book depreciation, or 99% x $20 = $19.80. The investor also gets all $15 in tax depreciation. Since there is not enough tax depreciation to shift, when the partnership sells the project or liquidates, any remaining built-in gain that was not worked off by shifting tax depreciation will have to be allocated to the developer.

Under the remedial method, the investor gets an amount in tax losses equal to the "book" depreciation the investor is allocated. If there is not enough tax depreciation, the investor still claims a tax loss equal to its book loss, and the developer must report an offsetting amount of taxable income. For example, in the example earlier where the investor is allocated $19.80 in book depreciation in a year, but there is only $15 in total tax depreciation, the investor would be able to claim a tax loss of $19.80 under the remedial method. The developer would have to report income equal to the gap of $19.80 minus $15 = $4.80.

Use of the remedial method has the effect of requiring the developer to pay taxes on any appreciation in the project when the tax equity funds over the same period the project is depreciated.

Pre-Tax Return

The model should also calculate the pre-tax return for the investor. Most investors require a pre-tax return of at least 2%. This means that the cash and production tax credits the investor is projected to receive, when discounted at 2%, must equal or exceed the amount of his investment. Investors want at least this level of return to ensure that they are not viewed as having invested solely for tax benefits. The IRS confirmed in guidelines in October 2007 that production tax credits can be treated as equivalent to cash. They are a substitute for higher electricity prices.

Most equity investors also treat the investment tax credit in solar deals as a cash equivalent for purposes of the pre-tax return test.

Investment Tax Credits

In solar and fuel cell projects, the parties are entitled to an investment tax credit in place of the production tax credits that are claimed in wind, geothermal and biomass projects. An election can also be made to claim an ITC in place of production tax credits.

The investment credit is claimed in year one when the project is placed in service, with one exception. It can be claimed during construction on progress payments paid to the construction contractor in any project with a normal construction period of at least two years.

The credit must be shared by partners in the same ratio they share in income in the year the project is placed in service. However, because solar and fuel cell deals generate losses for at least three years due to accelerated depreciation, it is important to hold the 99-1 sharing ratio used in the first year in place for at least a year after the deal starts generating income, lest the IRS argue that the 99-1 ratio for sharing income was illusory.

Investment credits vest over five years at the rate of 20% a year. If the solar or fuel cell project is sold or the investor disposes of his interest in the partnership during the first five years, then any investment credit the investor was allocated will be recaptured to the extent it has not yet vested. A reduction by more than a third in a partner's sharing ratio for income will also lead to recapture of any unvested investment credits.

A partnership must reduce its basis in any solar project by half the investment credit on the project. For example, if a project cost $100 and it qualifies for a $30 investment tax credit, then only $85 can be recovered through depreciation. The depreciable basis is reduced by $15, or half the investment tax credit. The partners must also reduce their outside bases and capital accounts by the same $15. They do so in the ratio they are allocated the tax credit. If the tax credit is later partly recaptured, then the basis adjustment is commensurately reversed. ◎

Environmental Update

Hamstrung at the legislative level, the Biden administration is looking for other ways to press banks to prepare for potential threats to the nation's financial system from climate change.

Lenders should expect pressure to come in a variety of ways from an array of agencies, including the Securities and Exchange Commission, the Federal Reserve, the Federal Deposit Insurance Corporation and the Office of the Comptroller of the Currency, among others.

Debate will focus on the scope of any new regulatory obligations to mitigate climate change and whether that is part of the mandate of federal regulators to protect the financial system.

The SEC is expected to propose broad rules that would require banks and other public companies to disclose more information about financial exposure to risks driven by climate change and about their own contributions to climate change.

Lenders will be pressed to measure how their investments could be threatened by flooding, wildfires and other forms of extreme weather.

Agencies may ratchet up scrutiny of investments in fossil fuel projects like oil and gas. Federal Reserve Chairman Jerome Powell promised action on climate issues recently, but also suggested that it is not the central bank's job to pick and choose which industries get financing.

Phase I Site Assessments

The standard for conducting most phase I environmental site assessments of industrial and commercial properties was updated in late 2021.

ASTM International released a new standard, ASTM E1527-21, to replace the version that has been widely used since 2013, ASTM E1527-13.

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

ASTM E1527-21 now makes crystal clear when a phase I site assessment is too stale. The revision confirms — what most environmental counsel have long understood — that the date on the report cover is irrelevant for that purpose. Instead, each specific diligence inquiry required by the standard —- the site visit and

/ continued page 52

Environmental Update

continued from page 51

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

A report older than 180 days may still provide valuable diligence information, but it is considered too stale to meet US Environmental Protection Agency standards for making "all appropriate inquiries" when evaluating a property's environmental condition. Parties follow the EPA regulations not only to assess risk and meet best practices, but also to preserve the ability to claim a defense to CERCLA liability as an innocent landowner, contiguous property owner or bona fide prospective purchaser by having conducted what EPA considers "all appropriate inquiry."

ASTM E1527-21 also now updates the necessary historical records review to require that aerial photos, topographic maps, city directories and fire insurance maps all be reviewed, or the consultant must explain why the review was not possible. More detailed site reconnaissance requirements were also added to confirm what is considered good commercial and customary practice.

The ASTM E1527-21 standard defines what is considered good commercial and customary practice for conducting an environmental site assessment of a property on which there may be contaminants that are regulated as hazardous substances under the Comprehensive Environmental Response, Compensation & Liability Act, or CERCLA, or there may be petroleum products.

A phase I requires a qualified environmental professional to assess potential environmental risks from those substances by physically inspecting sites, observing adjacent properties, interviewing knowledgeable persons, reviewing government regulatory data bases and considering certain historical information that may yield information relevant to site conditions. Although a phase I requires the inspection of a property to look for visual evidence of contamination or risk of such contamination, no invasive sampling is typically performed.

The new ASTM E1527-21 standard makes changes that are intended to reach more consistent results when consultants apply the updated standard to the information gathered about underlying properties. Important changes and clarifications in the updated standard are discussed below.

The key goal of a phase I is to identify what are referred to as recognized environmental conditions, or "RECs." A REC includes not only the presence of hazardous substances or petroleum products on a site, but also the "the likely presence" of such "due to a release or likely release."

The new standard now clarifies what consultants should consider "likely" contamination. "Likely" contamination "is neither certain nor proved," but contamination that "a reasonable observer" would expect "based on the logic and/or experience and/or available evidence." The phase I must now provide the logic behind the consultant's assessment of a "likely presence" of contamination, but does not have to show proof.

The goal of a phase I is also to disclose lesser issues of potential environmental concern and to distinguish them from current RECs. Thus, the new standard revises current definitions distinguishing among a REC as opposed to a controlled recognized environmental condition, or "CREC," or a historical recognized environmental condition, or "HREC." The updated standard adds a new section that provides guidance on how a consultant should determine whether a particular issue qualifies as a REC, CREC or HREC. It also includes a helpful flow chart and provides examples of each type of condition to achieve greater uniformity.

If releases of hazardous substances or petroleum have been addressed to the satisfaction of the regulatory authority such that the site meets unrestricted use criteria, then an HREC label is warranted because the contamination is purely historical with no current obligatory control. Properties with releases of hazardous substances or petroleum that have been addressed to the satisfaction of regulators but with an obligation to maintain certain controls — such as use restrictions — can be characterized as CRECs.

ASTM E1527-21 also creates the new term "property use limitation," or "PUL," and explains its relationship to the term "activity and use limitation," or "AUL," in qualifying certain circumstances as controlled RECs. The new standard now allows a site condition to be characterized as a controlled REC in certain circumstances where either AULs are in effect or PULs are in place to restrict use. Specifically, a controlled REC is now "a recognized environmental condition affecting the

Biden is expected to require more extensive disclosures from banks and public companies about the effects on climate change on their businesses.

subject property that has been addressed to the satisfaction of the applicable regulatory authority or authorities with hazardous substances or petroleum products allowed to remain in place subject to implementation of required controls (for example, activity and use limitations or other property use limitations)."

One example of a situation where the new standard more clearly requires consultants to classify a condition as a current REC involves cases where the regulatory standards have tightened over time. If a site previously achieved approved regulatory closure by meeting the unrestricted use standards in effect at the time of the release or subsequent cleanup, then the condition may nevertheless be classified as having a current REC in a new phase I if the available data show that site conditions do not meet applicable new, stricter regulatory standards. In other words, consultants will have to confirm whether the available cleanup data satisfy the standards that are currently in effect even if a site was cleared earlier by the regulators.

Complicated scenarios may arise for users of phase I site assessments in cases where current standards are stricter than in the past, but where a particular state regulatory program did not impose a "reopener" triggered by new regulatory requirements and state frameworks do not necessarily require further action in light of the prior approved regulatory closure.

The revised standard encourages more comprehensive research as to the use of adjoining properties in line with what was already required of the site itself, where such information is available.

ASTM E1527-21 also specifies that a report's user must have a title search conducted to determine whether there are any environmental liens or activity and use limitations on the subject property. The title search must review the relevant records from 1980 through the present. This should be coordinated with whatever real estate due diligence work being conducted.

Finally, it is important to note that, though the new ASTM standard now specifically explains that a gap exists in phase I coverage of certain new contaminants of concern, it still does not close that gap.

While the scope of hazardous substances regulated under CERCLA overlaps broadly with most other environmental laws, the overlap is not 100%. Because the ASTM standard only requires assessment of hazardous substances already regulated under CERCLA, plus petroleum products, phase I assessments are not required to consider known or suspected releases of contaminants that do not currently fall within that scope. This is true even if a particular contaminant found on a property is already being regulated under state law or it is already receiving increased regulatory scrutiny at the federal or state level.

The poster child for this limitation on phase I reports is the emerging contaminants class known as per- and polyfluoroalkyl substances, or PFAS (pronounced "PeeFAS"). PFAS are sometimes referred to as "forever chemicals" due to their durability and reported persistence in the environment. They are a large group of fluorinated chemicals that have been widely used since the */ continued page 54*

Environmental Update

continued from page 53

1940s in hundreds of industrial applications and consumer products. Historical activities suggesting possible PFAS use include carpets and textiles, airport and other firefighting using certain foams, leather tanning and leather production, metal plating, cosmetics, furniture, food paper products and cosmetics. This list is incomplete.

PFAS are under increasing regulatory scrutiny at both the federal and state levels, with many states already having taken steps to regulate in advance of federal action. Congress is actively considering action, including whether to classify some PFAS as hazardous under CERCLA.

Despite that scrutiny, PFAS remain non-scope substances falling outside of the obligatory scope of a phase I assessment because they remain outside the CERCLA regulatory sphere — for the moment.

The new E1527-21 standard simply clarifies the status quo that, until an emerging contaminant is specifically regulated as a federal CERCLA hazardous substance, a phase I is not required to flag even a known release of such a substance on a site. The new standard merely notes the obvious, that consultants can be asked to include such substances in their assessment as a "non-scope consideration."

Many consultants flag in their phase I assessments the possibility that there may be PFAS or other emerging contaminants of concern on a site, but a buyer or financier cannot count on the consultant to do this, particularly in cases where it is merely a relying party who did not actively engage the consultant to do the assessment.

With the failure of ASTM to close the gap, expect counsel for lenders and buyers to take contractual action to require the phase I site assessments on which they are being asked to rely to confirm coverage of such emerging contaminants as within the scope of the reports. While broader regulation is likely at state and federal levels, this is already an obvious data gap for assessments performed in states that have already adopted or are considering adopting regulatory standards.

The new standard now awaits final EPA sign-off, expected later this year. In the interim, ASTM E1527-13 remains in place.

Waters of the United States

The US Army Corps of Engineers posted new guidance on its website in January that could affect hundreds of projects.

The guidance states that the Army Corps and the EPA "will not rely on" determinations made under a Trump-era rule governing whether a project affects federally protected waters and thus needs a federal permit.

Projects that affect federally protected "waters of the United States" must go through a federal permitting process under the US Clean Water Act. The Army Corps determines on a case-by-case basis whether waters of the United States are affected. The definition

Any phase I site assessment written more than 180 days before financial closing is too stale.

Projects that were only part way through the process with Trump of getting permits for projects that affect "waters of the United States" may have to restart the process.

of what does or does not qualify as a regulated water changed multiple times under President Obama, then Trump and now Biden.

The new guidance is intended to clarify the impact of recent court decisions that set aside the Trump-era regulation, called the navigable waters protection rule.

Going forward, pre-2015 standards for what constitutes a regulated water will control agency decision-making while the Biden administration comes up with a replacement for the Trump rule.

The open question has been what happens to those projects that received jurisdictional determinations or actual permits from the Army Corps based on the narrower parameters of the Trump rule, now that the rule is no more.

The Army Corps said it will not reconsider permits already granted under the Trump rule, but at the same time, it will not accept any jurisdictional determinations made pursuant to the Trump rule.

In other words, those projects holding a determination of no impact made under the Trump rule will probably require a new determination under the pre-2015 rules until a new rule is issued by the current administration.

Approved jurisdictional determinations are supposed to remain valid for five years after being issued. Many projects may now be in an uncertain position. Proponents may be required to reconfigure project footprints to avoid areas still protected under the pre-2015 rules even if those areas were not considered waters of the United States under the narrower Trump rule.

What happens at a particular project site will turn on the facts. Permit applicants will be asked whether they would like to receive a new jurisdictional determination under the pre-2015 rules.

An approved jurisdictional decision requires a site visit by the Army Corps to determine which waters on the site are federal protected waters while a preliminary jurisdictional decision presumes that all waters and wetlands are federally protected and does not require a site visit.

Clean Water Act Limits

While the EPA and the Army Corps consider replacing the now vacated Trump rule that specified a narrow definition of federally protected waters, the US Supreme Court has agreed to hear a case that may limit the reach of the Clean Water Act.

The court will hear an appeal this fall from Chantell and Michael Sackett, an Idaho couple waging a 15-year long battle to build a house on land that regulators say is protected wetlands.

The Sacketts' appeal asks the court to revisit a 2006 Clean Water Act case, Rapanos v. United States, that failed to produce a majority decision. Antonin Scalia and three other justices said the law covers wetlands only if they have a continuous surface connection to a river, lake or other major waterway.

A fifth justice, Anthony Kennedy, created his own test, explaining the Clean Water Act covers / *continued page 56*

Environmental Update

continued from page 55

wetlands with a "significant nexus" to one of those larger bodies of water.

Justice Scalia is now deceased, and Justice Kennedy is now retired.

The Sacketts are hoping the current court will adopt the narrower Scalia view of the scope of the Clean Water Act.

The Biden administration maintains that the Scalia approach would create a regulatory gap:

> The agencies would lack authority to protect wetlands separated from a navigable river by a small dune or other natural barrier, even if overwhelming scientific evidence showed that the wetlands significantly affect the river's chemical, physical, and biological integrity.

The EPA says that the Sacketts' land is connected to a lake through a subsurface flow of water.

The administration also told the justices they should wait to hear the case until after the EPA and Army Corps finalize a proposed revision to the federal Clean Water Act regulations.

The legal fight began in 2007 when the EPA issued an administrative compliance order requiring the Sacketts to restore land they had already begun preparing for construction.

The case is *Sackett v. Environmental Protection Agency*.

— contributed by Andrew Skroback in New York

Project Finance NewsWire
is an information source only. Readers should not act upon information in this publication without consulting counsel. The material in this publication may be reproduced, in whole or in part, with acknowledgment of its source and copyright. For further information, complimentary copies or changes of address, please contact our editor, Keith Martin, in Washington (keith.martin@nortonrosefulbright.com).

nortonrosefulbright.com