NORTON ROSE FULBRIGHT

PROJECT FINANCE
NewsWire
December 2018

Uncertainty in Mexico as New President Takes Office

by Raquel Bierzwinsky and Javier Felix, in New York, and Carlos Campuzano, in Mexico City

Many people have been asking since Andrés Manuel López Obrador took office as Mexican president in early December what this means for the power and infrastructure sectors in the country.

The short answer is that unlike the new Mexico City airport project, López Obrador has not moved yet to dismantle the energy reforms that the previous government put in place in 2013. He is taking time to evaluate the reforms even though he criticized them on the campaign trail and continues to do so.

López Obrador — or AMLO as he is known in Mexico — rode to victory at the head of a left-leaning populist movement after running unsuccessfully for the presidency in 2006 and 2012.

Mexican voters were ready for a change after nine decades of increasing inequality in a country flush with natural resources and a privileged location.

The new political party he formed for the 2018 election, *Movimiento Regeneración Nacional* or Morena, surged ahead of the PRI and PAN, the two parties that have ruled Mexico for the last 90 years to win not only the presidency, but also control of both houses of the Mexican Congress and the governors' races in five states. Morena now controls the state legislatures in 19 of 32 states. AMLO took 53% of the popular vote. */ continued page 2*

IN OTHER NEWS

US TARIFFS are causing some types of Chinese imports to surge.

At the same time, there is an incentive to delay importing more solar panels until a scheduled reduction in the tariff on panels on February 7, 2019.

Requests by importers for exemptions from the US tariffs meet a very different reception depending on whether they are submitted to the US Department of Commerce or the Office of the US Trade Representative.

The United States is collecting a 25% tariff on a list of Chinese products that accounted last year for $50 billion in imports, and it is collecting a 10% tariff on another $200 billion worth of Chinese products. The 10% rate was scheduled to increase to 25% on January 1, */ continued page 3*

IN THIS ISSUE

Mexico

continued from page 1

AMLO made a number of promises during the campaign that were not well received by investors and the markets in general.

As in many countries, a degree of political uncertainty can be expected when a new administration takes office.

Mexican presidents serve for a single term of six years. Thus, the Mexican federal government usually experiences a transition phase after each new administration takes office. The transition can be more jarring when the new president belongs to a different party.

Just as in the United States, in Mexico the first 100 days of a new administration are crucial for the incoming government to make progress on implementing its agenda.

With new government officials replacing outgoing ones, it is not uncommon in Mexico for business as usual to slow significantly for the first six months of any new administration, especially in a case like this one where a fundamental shift in direction is expected.

It is not surprising for officials to suspend, at least temporarily, some of the plans carried out by the former administration, as happened when the Trump administration took office in the United States. This buys time for the new government to analyze what fits with its policies and campaign commitments.

President López Obrador made the central theme of his campaign to end corruption, fight poverty and give a stronger voice to the people in the federal government's most important decisions.

AMLO also ran a platform of complete repudiation of "neoliberal" policies of the last 36 years that he said left behind a significant share of the population, impoverished the middle class and enriched particular sectors of society. Recent governments have been plagued by corruption scandals.

Mexico City Airport

AMLO promised during the campaign to cancel the new Mexico City airport, even though it is about a third built. He called it "a monument to corruption."

The project is expected to cost US$13 billion, most of which is supposed to come from private sources through the issuance of bonds in international capital markets and the issuance of local bonds through a real estate investment trust vehicle known as a Fibra E. (For more information about the Fibra E structure, see "Fibra E Rules Relaxed" in the June 2016 *NewsWire*.)

The new Mexico City airport is not as easy to cancel as the government would like.

AMLO based his corruption charge on the fact that many of the construction contracts for the project were awarded without a competitive tender process, but no actual evidence of corruption has emerged thus far.

This past October, while still president-elect, AMLO held a skewed public consultation for people in Mexico City to vote on whether to continue or cancel the project. The polling stations were set up by his party without involvement of the Federal Electoral Commission, and the polling stations were strategically located in areas of Mexico City that support his political party. Fewer than a million people voted. Predictably, the results were against the airport.

The consultation has created anxiety among the investor community. Roughly US$2 billion in liquid capital is reported to have left the country since the referendum and the Mexican peso has been trending weaker after suffering big losses in value earlier against the dollar after AMLO was elected. The erosion in investor confidence led AMLO to clarify that not all federal government decisions will be subject to public consultation.

The Mexican government also clarified that all commitments made to holders of airport bonds will be honored by the government since cancellation of the airport project is a default under the bonds that can lead to an obligation for immediate repayment.

The federal government and the bondholders are negotiating a buyback. The government has made three proposals so far, all of which have been rejected by bondholders.

The more recent proposal made by the federal government included the repayment of US$1.8 billion of the US$6 billion in bonds outstanding at the par price plus interest accrued, as well as a $10 premium for every $1,000 repurchased, in exchange for adequate repayment assurances. Repayment of the remaining US$4.2 billion would be secured by the current Mexico City airport's user fee.

The bondholders said they rejected the most recent proposal over concern that the government's plans to build two new runways at a nearby air field, Santa Lucía, where the Mexican military currently has an air base, and to increase the capacity of a nearby airport in the city of Toluca cast doubt on the projected user fees that will be earned at the Mexico City airport.

In an effort to assuage these concerns, the government offered a commitment to maintain the passenger volume at the Mexico City airport and revised the bond terms to make it an event of default if there is a decrease in user-fee collections due to operation of an alternate airport within 70 kilometers of the current airport and if commercial operations at the Toluca airport increase beyond five million passengers a year.

The new default trigger is at odds with the policy of expanding the capacity of nearby airports to alleviate congestion at the Mexico City airport.

The government has also offered to apply the Santa Lucía and Toluca airport user fees toward repayment of the Mexico City airport bonds and potentially to increase such fees. This is an unpopular proposal among many airport users, who may be willing to pay higher user fees if the end result is construction of a new airport, but not to repay debt for an abandoned project.

Local pension funds will also play a key role. During the first quarter of 2018, local pension funds invested more than US$650 million toward construction of the new airport through a Fibra E. So far, the government has only focused on repaying the bondholders first. It has yet to announce a plan to repay the pension funds.

The government has four main options. One is to cancel the airport project and be sued in both */ continued page 4*

IN OTHER NEWS

but the increase has been delayed for 90 days to give US and Chinese negotiators more time to diffuse trade tensions. Trump is also threatening tariffs on all remaining Chinese goods. China exported $505 billion in goods last year to the United States.

Chinese exports to the United States have surged as companies rush to make shipments ahead of any further increase in tariff rates. Exports in October rose 15.6% in dollar terms compared to October 2017. Exports grew 13.2% in October compared to September this year and by another 10% in November. The threats to impose more tariffs is leading in the near term to a widening of the US trade deficit with China due to the surge in orders to buy goods before they become more expensive.

Meanwhile, solar developers considering importing solar panels may be wise to lock in prices today but wait until after February 7, 2019 to ship them past US Customs. The US is currently collecting a 30% import duty on all solar panels. The rate is scheduled to drop to 25% on February 7.

Higher Chinese demand for solar panels may put upward pressure on panel prices next year. The CEOs of a Chinese solar panel manufacturer and of a Chinese polysilicon producer said on earnings calls in November that they understand from government sources that the government pullback last June on subsidies to install more solar capacity in China is temporary and there could be a large increase in the solar target when the next five-year economic plan is announced. Other analysts are more cautious. Any new solar policies could be announced before the Chinese New Year on February 5.

The Chinese government scaled back central government support on June 1 for new utility-scale solar projects and placed a low cap on distributed solar deployments. The government had already stopped issuing permits for new solar facilities in parts of the country where existing plants are ***/ continued page 5***

Mexico

continued from page 3

Mexican and international courts (including New York) by the bondholders and be left with a massive debt that will significantly harm the finances of the country, probably leading to a downgrade of Mexico's credit rating and increase the cost of borrowing for the entire country. This would also lead to a significant drain on funds from the national budget, preventing AMLO from implementing all the social and anti-poverty programs on which he campaigned. It would be political suicide.

The second option is to attempt to buy back part of the outstanding bonds and convince the remaining bondholders to modify the terms of the notes and the contractors to convert their contracts to construction of the Santa Lucía airport. This option is not viable, as numerous aviation and aeronautics experts have voiced strong opposition to it on safety and economic grounds.

The third option is to continue with construction of the project and audit the contracts awarded by the previous government to root out any corruption in the awards, recognizing that the airport is a key building block of infrastructure modernization in Mexico. Unfortunately, the referendum results make this too difficult as it would infuriate AMLO's base.

The fourth option is to privatize the project by putting the airport concession out for tender to the private sector, relieving the government of the financial burden. This would be the most sensible outcome for the country and one that is being strongly lobbied by the private sector.

Austerity Measures

One of President López Obrador's favorite slogans is that "a rich government cannot exist when its people are poor."

He believes that public officials should have a true vocation for public service rather than seek high salaries. These ideals have earned him the sympathy of many Mexicans and contributed to his political success. He is proposing to implement a government austerity plan as one of his main campaign commitments.

In line with this commitment, the Mexican Congress voted in November to cap the salaries of Mexican public officials so that none of them earns more than the president. In line with this, AMLO is committed to lower his monthly salary to MX$108,000 (approximately, US$5,270) starting next year.

Although the effects of this are yet to be seen, many public employees have voiced discontent and a significant number, particularly in decision-making positions, are leaving for the private sector.

The Mexican Supreme Court issued an injunction to suspend implementation of the cap until the case can be heard and a final judgement is entered.

Foreign Investment

President López Obrador committed in his inaugural address to safeguard investments based on clear rules, honesty, economic growth and trust.

Some commitments made by AMLO during the campaign that were also mentioned in his inaugural address touched on the energy sector.

He is determined to strengthen the government-owned oil & gas company, PEMEX, by investing in exploration and production infrastructure, refurbishing six oil refineries and building a new one in his home state of Tabasco in southeastern Mexico. He also wants to help the Mexican electric utility, CFE, by modernizing, retrofitting and expanding its existing power plants, principally the hydroelectric ones, and by promoting clean energy power sources.

López Obrador criticized past privatizations of public assets. He also criticized the energy reforms of 2013 that gave independent generators a stronger foothold in the electricity sector. He called the results of the reforms disappointing and said they have led to reductions in oil production and increases in gasoline, gas and electricity prices.

At the same time, he has assured investors that all existing contracts entered into with foreign and Mexican companies as an outgrowth of the energy reforms will be honored, while urging winners of the oil exploration and production tenders to demonstrate the benefits to the country within a three-year "truce period." Until then, he has cancelled any further E&P tenders.

His views about the 2013 reforms are not shared by the authors of this article. The energy reforms were desperately overdue. Oil production had decreased alarmingly before the reforms due to corruption and mismanagement of resources and PEMEX's finances, including crippling obligations to the PEMEX labor union. PEMEX and the Mexican government lacks the technology, expertise and resources to continue to develop the country's natural resources. It is cheaper for the country to have its crude oil refined in the United States than to do it locally. PEMEX was the Mexican government's cash cow until this became unsustainable.

On the power side, the same can be said of CFE. CFE has been unable to match the country's growth with its old fleet of majority heavy-fuel oil power plants that have kept electricity prices high. Not having a competitive and open power market that relies more on cheap natural gas and renewable energy was no longer viable. The Mexican energy sector cannot rely solely on two government-owned entities.

Goals

One of AMLO's objectives is to strengthen PEMEX and CFE. Even though AMLO is a populist, he is a native of the state of Tabasco, one of the states where PEMEX has its main production areas and employs a significant percentage of the local labor force. He wants to increase oil and gas production, and significantly decrease the dependency on natural gas coming from Texas and the US portion of the Gulf of Mexico.

He also wants to reverse what he calls the "dismantling" of CFE as part of the 2013 reforms.

The reality is that the reforms are meant to restore both PEMEX and CFE to financial stability by restructuring the companies, implementing much-needed corporate governance structures, maintaining a monopoly in strategic sectors where a monopoly is still warranted (for example, power transmission and distribution), while making PEMEX and CFE compete in areas where private competition will benefit the industry and will bring down energy prices.

Most of the details of what the new government plans are still to come.

However, on December 8, one week after taking office, López Obrador and the new head of the CFE — Manuel Bartlett — announced the government's new plan for the electricity sector. Although no official document has been published, AMLO said the CFE will be audited to determine whether private entities have unduly benefited from CFE's restructuring by selling expensive energy to CFE.

He was probably not referring to the clean energy power auctions that were undertaken after the 2013 reforms, as these have led to the lowest electricity prices yet for CFE. The average price for energy sold to CFE and other offtakers in the third long-term power auction was US$20.57 a megawatt hour. The lowest price bid in the auction for an awarded bid was US$17.76 a megawatt hour.

He probably was referring to the independent power contracts awarded before the energy reforms under the old regulatory scheme, mainly to owners of gas-fired power projects, many of which depend for fuel on private natural gas pipelines that have long-term transportation and maintenance contracts with the CFE and are still under construction to bring natural gas to northern and central Mexico. AMLO has said / continued page 6

IN OTHER NEWS

sitting idle due to grid congestion.

Chinese demand was expected to fall to 30,000 to 35,000 megawatts in 2018 compared to 53,000 megawatts in 2017.

IHS Markit is now projecting 40,000 megawatts of Chinese solar installations this year. Bloomberg New Energy Finance expects China to account for 39% of global demand for panels this year. The Chinese market share was 54% in 2017 before the pullback.

US importers are much more likely to be granted waivers from US tariffs on steel and aluminum than on Chinese products.

The US Department of Commerce had processed 17,051 of the 38,000 requests filed for exemptions from steel tariffs through November 15 this year. It granted 12,616 and rejected 4,435 for a 74% success rate, according to Congressional Research Service figures. It had processed 972 of the 6,504 requests for exemptions from aluminum tariffs, granting 830 and denying 142 for an 85% success rate.

Commerce has only 100 employees and outside contractors sifting through the applications, which accounts for the slow processing time.

It tends to grant requests to which no domestic manufacturer objects.

The New York Times reported in late November that two companies accounted for a disproportionate share of the waivers. Greenfield Industries in South Carolina, which is owned by Top-Eastern Group in China, was granted 1,000 steel waivers. The company makes saw blades and other cutting tools. Mandel Metals, an aluminum distributor outside Chicago, was granted 443 waivers from the aluminum tariffs. Mandel Metals imports low-grade aluminum and cuts it to size for customers.

Requests for exemptions from the special tariffs imposed on Chinese products go to the Office of the US Trade Representative rather than the Commerce Department. That office has denied 1,300 requests / continued page 7

Mexico

continued from page 5

these pipelines that were promoted and tendered by CFE are too expensive and without enough benefit to justify the high cost.

As part of his plan and consistent with his campaign agenda, AMLO repeated after the inauguration that he supports renewable energy, particularly hydro, solar and wind.

During the announcement of the government's new plan for the electricity sector, López Obrador and Bartlett indicated that, besides refurbishing many of the CFE heavy-fuel-oil power plants, they are considering trying to increase Mexico's hydropower capacity by 26%, equivalent to 3,300 megawatts, but without building new hydroelectric plants.

The previous government did an assessment of the CFE generation fleet and concluded that the utility has 10,000 megawatts of obsolete and inefficient power plants that run on heavy fuels and should be replaced with renewable and gas-fired power plants. Most of the replacement plants were to be built and operated by the private sector and supply their power to the CFE.

The new government drew headlines when the independent system operator, CENACE, announced the suspension of the fourth long-term power auction that was scheduled to take place on December 18.

The suspension does not come as a surprise as the new government wants to review the objectives and scope of the auction and to allow time for the new heads of the CFE, Ministry of Energy and CENACE to take office and familiarize themselves with the reforms. The suspension does not mean the fourth long-term energy auction or auctions in general have been canceled. Even among auction participants, the suspension is considered a reasonable and expected outcome.

The electricity sector reforms created a wholesale electricity market with complex regulations that members of AMLO's government will need time to master.

The 2013 energy reforms would require a constitutional amendment to unravel, including ratification by a majority of Mexican states.

New Faces

President López Obrador has appointed new heads for each of the public entities in charge of managing, regulating and operating the power sector, as well as CFE and PEMEX. Some of these positions have been filled by people with vast experience in the energy sector while others are being used for political patronage.

The new Minister of Energy is Rocío Nahle García. Ms. Nahle is a chemical engineer, specializing in petrochemistry, who worked for both PEMEX and private companies. Most recently, she served as a congresswoman for Morena and advisor to the Mexican Congress on energy-related matters. As the head of the Ministry of Energy, Ms. Nahle will be in charge of implementing the federal government's energy policy.

Alfonso Morcos Flores is the new director of CENACE. Mr. Morcos is a mechanical electrical engineer with more than 50 years of experience in the electricity sector. He worked at CFE from 1966 to 1989 and was the head of CENACE from 1983 to 1989, when CENACE was part of the CFE. After leaving the CFE, Mr. Morcos became a consultant in the private sector. CENACE is responsible for operating of the national electricity grid and the wholesale power market.

The Energy Regulatory Commission, called the CRE, has not had any changes, as it is governed by a board of commissioners with staggered seven-year appointments that are not revocable by the president. The chairman was appointed in 2016 and his term ends in April 2023. Although the CRE is a federal government entity, it has autonomy and acts independently. It regulates both the electricity and the midstream and downstream oil & gas sectors.

The new head of the CFE is Manuel Bartlett. Mr. Bartlett is a former member of the long-time governing political party, the PRI, where he pursued a political career from 1962 to 2006. His past roles have included serving as head of the national executive committee of the PRI, Minister of the Interior from 1982 to 1988, Minister of Education from 1988 to 1992, and governor of the state of Puebla. He has been a vocal opponent of the 2013 energy reforms.

Despite AMLO's opposition to the 2013 energy reforms, so far he has not publicly threatened to undo them. The energy reforms in the oil & gas sector are the most at risk as AMLO, Ms. Nahle and Morena have harshly criticized them. They charge the effect is to sell off the public resources and in a manner that has been tailored specifically to benefit certain interest groups. The reforms would require a constitutional amendment to cancel. Both houses of the Mexican Congress would have to pass any such amendment by two thirds votes. In addition, a majority of Mexican states would also have to ratify the amendment.

Rather than undo the reforms, AMLO has said he wants to review existing processes and contracts and work within the existing regulations. ◎

Effects of the US Mid-term Elections on the US Power Sector

America went to the polls on November 6. The Republicans held on to the Senate, but lost the House. In the Senate, where there are 100 seats, Republicans increased their majority from 51-49 to 53-47. There are 435 seats in the House. Democrats flipped 40 seats, wresting control of the House with a new ratio of 235 Democrats and 199 Republicans, with one seat still undecided while the local authorities investigate possible fraud in the vote count.

A group of veteran Washington insiders talked three days after the election about what the results mean for the US power sector, particularly renewable energy.

The panelists are John Gimigliano, principal in charge, KPMG Corporate Finance LLC, and a former Republican counsel to the House Ways and Means Committee, Tom Hassenboehler, partner, Coefficient Group, and former Republican chief counsel for energy and the environment, House Energy and Commerce Committee, Joseph Mikrut, partner, Capitol Tax Partners, and former tax legislative counsel, US Department of the Treasury, Jonathan Weisgall, vice president for */ continued page 8*

IN OTHER NEWS

and approved none, according to the *Times*. Bloomberg reports that the US Trade Representative has received 11,565 requests and denied almost 1,500 of them.

All of the requests were for waivers from US tariffs on the first $50 billion of Chinese products on which the Trump administration imposed tariffs in July and August. The deadline to apply for waivers from tariffs on the first $34 billion in Chinese products that have been subject to tariffs since July 6 expired on October 9. The deadline for the next $16 billion in Chinese products on which tariffs were imposed on August 24 expired on December 18.

It is not clear what an importer would have to prove to be granted a waiver.

The stinginess in granting waivers may reflect the US government desire to keep maximum pressure on China.

No process is in place yet to request exemptions for the additional $200 billion in products on which tariffs were imposed in September.

The process differs at the two agencies.

Commerce requires a separate request for each product and each importer. For example, a tariff waiver granted to company X to import steel type Y from Canada would not apply to other importers of the same product. The US Trade Representative considers requests by product, so that if a waiver were granted, it would apply to anyone importing the product.

CALIFORNIA will decide next year whether to conform to the tax changes the federal government made in late 2017.

US states piggyback on the federal tax laws by using federal taxable income as a starting point for their own income tax calculations.

The California legislature must vote periodically to move the date forward through which it "conforms" to how the federal government calculates taxable income.

The state conforms currently to the federal income tax calculations */ continued page 9*

Mid-term Elections

continued from page 7

government relations, Berkshire Hathaway Energy, and Kathleen Weiss, vice president for government affairs, First Solar. The moderator is Keith Martin with Norton Rose Fulbright in Washington.

Overall Assessments

MR. MARTIN: Without getting into all the details, how do you see the election results: positive, negative, or neutral for the power sector and particularly for renewable energy?

MR. WEISGALL: I would call it neutral. Some were expecting a Democratic tsunami in the House. I think it was merely a wave. Despite control of the House flipping, I do not see much change down the road. I think the polarization and legislative paralysis will probably continue in Washington. The state ballot initiatives were a mixed bag. I see some gains in state houses and governor's races. On balance, I give it a neutral.

MS. WEISS: I think the results were more positive. The GOP-controlled House had some pretty powerful opponents that really did not support policies to help our sector grow. The Senate was always more balanced. We had some champions in the Senate who helped us move forward with some important policies over the last couple years. Now with Democratic control of the House, not only is there an opportunity to support positive legislation, but we also have a firewall against backsliding.

MR. HASSENBOEHLER: I view it slightly positive. There is an opportunity, with the Democrats taking control of the House, for Republicans who may have been a little gun shy about supporting renewable power or who may have been more inclined to support the party line under a completely Republican House to get a little more unconventional and bold in their thinking. There is an opportunity for new alliances to form. There is precedent in passage of the Energy Independence and Security Act in 2007 at a time when the parties split control of the White House and Congress. That said, I do not see anything big happening in the next two years.

MR. MIKRUT: It was a slight net positive. The presumptive new chairman of the House tax committee, Richard Neal, is more of a supporter of renewables than the current chairman, Kevin Brady. Moving to the Senate, the likely new chairman of the Senate tax committee, Chuck Grassley, has always been a supporter of renewables. That's positive.

However, I also agree with Jon Weisgall. It is hard to see how the parties can get together with the White House to produce anything.

MR. GIMIGLIANO: I think it is positive. I largely echo what others have said.

Obviously Democratic control in the House is helpful. There was a lot of antipathy on the Republican side toward renewables. If Nancy Pelosi regains her post as speaker, she has been a pretty reliable supporter of renewables. Policy has tended to be set in recent years by the leadership.

On the Senate side, we are probably going to have Chuck Grassley move back to chairman of the Senate Finance Committee. He has been called the godfather of the wind tax credit, but it is really more than wind. The last time he was committee chairman, many of the provisions we have today in the tax code to encourage renewable energy were enacted.

MR. MARTIN: Was that a different era? It seemed like after Obama was elected, you had an entering class of Republicans who felt support for renewables must have started with Obama and, therefore, they were opposed. Have times changed?

MR. GIMIGLIANO: Yes, something did change. It has never been entirely clear why. The Democrats will be more or less able to do what they want in the House. On the Senate side, the outcome was about as good as could have been expected, including with Grassley moving over apparently to be the next chairman of the Senate Finance Committee.

MR. MARTIN: Let me posit this and get reactions. If there is a larger Republican caucus in the Senate, then the Senate will move to the right. Susan Collins and Lisa Murkowski, two moderate Republican Senators who have been moderating influences, will have less sway. Whether we get two years of gridlock or there is room to work together depends on whether the House Democrats vote as a bloc or there is a large enough blue dog caucus of more conservative Democrats that emerges that can combine with Republicans to put through part of the remaining Trump program. Reaction?

MR. WEISGALL: In general, moderates were hurt in this election. You are right that Susan Collins and Lisa Murkowski will have less influence. The blue dogs — the conservative Democrats — currently are at about 18 and are hoping to double in number. They could vote as a bloc on some of the more business-friendly issues. They were successful at this in the late 1990s. They want to get back to their heyday. I see them more as a bloc on non-energy issues than most energy issues.

MR. MARTIN: Does anyone disagree?

MR. HASSENBOEHLER: I have a slightly contrary view. The blue dog views on energy and climate issues will be less relevant given how much is decided by the House leadership, and so I also don't think it makes a big difference in the Senate that Lisa Murkowski will have less influence.

The new House leaders will have to decide on what issues they want to work with the Senate and what issues they just want to be in pure partisan posturing. My guess is energy and infrastructure could be in the former category where there is room to work.

Infrastructure

MR. MARTIN: Then let's move to the infrastructure. Does anyone foresee action on infrastructure?

MR. WEISGALL: I can see infrastructure as a vehicle for incremental progress on climate change: investments in electric vehicle technology, for example. I think it can get bipartisan support. How you get there, I don't know.

It reminds me of the expression, "Everybody wants to go to heaven, but no one wants to die."

In polling, everybody is for infrastructure, but there is no agreement on how to get there. Democrats want direct spend. They want to maintain environmental rules and not ease permitting, and Republicans want pretty much exactly the opposite. And you have the opposition from fiscal conservatives.

I can certainly see a continued course of permitting reform, and I can see infrastructure being expanded from the usual roads, bridges and tunnels to include some renewable-energy issues, which could bring Democrats on board.

MR. MARTIN: Are the renewable energy issues more than just electric vehicles? Transmission, for example? All Trump proposed early in the year was basically to sell off federal transmission assets.

MR. WEISGALL: That isn't going to happen, but there could be bipartisan progress on grid modernization. Throw in some cyber security, hardening of the grid and things like that. The devil will be in the details. I can't remember the last time anyone decided the government should pay a utility to improve transmission. That is normally a private-sector job.

MR. MARTIN: The prospects are a little worse than you suggest, no? There is no agreement on how to pay for anything. Not only are they split on general approach, but there is also no money.

MR. WEISGALL: I think that's right. Democrats want to spend. What the President proposed right after the election was private-public partnerships, tolls, tax incentives, things like that. It is very hard to see where the money / continued page 10

IN OTHER NEWS

only through January 1, 2015.

The Franchise Tax Board has been gathering input on which tax changes since then should be accepted by the state. The comment window closed on December 15.

The board will report to the state legislature next.

A number of big issues are in play.

California still takes the position that partnerships terminate for income tax purposes after a transfer of 50% or more of the profits and capital interests within a 12-month period. The federal government stopped treating such partnerships as terminated at the start of 2018.

The federal government stopped collecting an alternative minimum tax from corporations in 2018. California must decide whether to follow.

The federal government now caps the interest that a company can deduct each year on debt at 30% of an expanded definition of the company's taxable income. California has no cap.

The federal government now limits how much a company can use net operating losses carried forward from an earlier year to reduce its current income. Such losses can only be used to reduce current taxable income by up to 80%. The federal government also no longer allows NOLs to be carried back up to two years as it did before 2018. California has not yet adopted these changes.

The federal government used to tax US companies on worldwide income. It now has a more complicated approach. Active income that US companies earn through foreign subsidiaries conducting real businesses — rather than making passive investments — is no longer taxed in the US, unless the foreign subsidiary has more than a 10% return on its depreciable tangible assets, in which case the US will look through the foreign subsidiary and require the US parent to report the excess return as income in the / continued page 11

Mid-term Elections

continued from page 9

will come from.

The Democrats are talking about raising the corporate tax rate above 21% and eliminating some tax benefits. That will be hard to get across the goal line.

MS. WEISS: I see this as the biggest challenge with doing something on infrastructure.

You could do a lot of good things that would benefit various sectors of the economy. The challenge is one of leadership and the ability to compromise. My biggest concern is that the last two years don't provide any indication that the current group of leaders will be able to find common ground.

It could be done, but it is not clear who would be the driving force to force that compromise.

There is also no appetite to add more to the deficit. Whatever is done would have to be put together in a way that brings more private money into the sector.

Tax Extenders

MR. MARTIN: Let's start with the lame-duck session and then work beyond this year. Congress will return in late November for a short lame-duck session. It has to pass new spending authority to allow a number of government agencies to remain open past December 7. A tax extenders bill is potentially on the agenda. Joe Mikrut, do you see the tax extenders bill passing, and do you expect anything in it to affect the power or infrastructure sector?

MR. MIKRUT: There is a chance that an expired provisions package will go forward in the lame duck. There are 30-some provisions that expired at the beginning of the year. Many of them are energy related. Democrats want the energy extensions. Republicans want to make technical corrections to the tax reform bill that was enacted last December. I don't see technical corrections being done broadly, but there are a couple provisions that have become more important than others. Maybe there is enough there to make a deal. There are also a couple bipartisan pieces of tax legislation dealing with retirement savings and IRS administrative issues that are teed up and waiting for a vehicle on which to move.

MR. MARTIN: Do you see anything happening on production tax credits or investment tax credits?

MR. MIKRUT: The parts of sections 45 and 48 that have expired could be extended. I think that is a possibility.

MR. MARTIN: You are referring to tax credits for biomass and geothermal projects, correct?

MR. MIKRUT: Yes. Those are the primary ones.

MR MARTIN: John Gimigliano, some more time for biomass and geothermal projects to qualify for tax credits?

MR. GIMIGLIANO: I agree with everything Joe said. Congress has fallen into a pattern lately of extending tax benefits retroactively after they have already expired. It is sort of the worst possible tax policy to reward people with tax incentives for things they have already done. You almost wonder whether somebody might think it would be better to wait until January in the hope of getting a longer-term, prospective extension. You always hate to leave behind a chance to get them extended when you can, but it seems like the biggest impediment to getting extenders through has always been House Republicans and, in January, if you have House Democrats dealing with Senate Republicans, you might get a better deal. I would not be shocked to see somebody come up with the idea that maybe we should wait until January.

Tariffs

MR. MARTIN: It seems like there are two areas where the parties might truly find common ground. One is prescription drug prices. Another is trade. Ironically, Trump will pick up support for import tariffs among the Democrats. So is a rollback of import tariffs now out of the question?

MR. WEISGALL: My general view is that the tariffs have a lot more to do with US-China relations and US security policy than pure trade policy. Trump himself has talked about economic security as national security. This is one area where he has flipped the Republicans. Traditionally there has been more Democratic support for tariffs, but their use

The US mid-term election results were a slight positive for renewable energy.

in this context is more complicated. There will be a lot of stops and starts. Trump is using tariffs to put his foot on and off the gas pedal on other issues.

MS. WEISS: I agree, but I also think it is really a strategy to reset trade practices. It is appropriate periodically to relook at the rules of engagement. The administration has not wavered on this. The unknown is at what point does the economic disruption become so great that the administration is forced to claim victory and back off.

MR. MARTIN: The tariffs that Trump imposed in September on $200 billion a year in Chinese imports at 10% bump automatically to 25% on January 1. The 25% steel tariffs that were imposed last March are also starting to affect the broader economy. They are hurting the wind tower manufacturers; there are 200 tons of steel in a wind tower. Also some solar companies may not have anticipated them when bidding to supply power at contracted prices. Some of these companies are hoping that the revamped NAFTA trade agreement will provide some relief from the 25% steel tariff by allowing steel to come in through Mexico. When do you see this revamped NAFTA treaty moving through the Senate?

MR. GIMIGLIANO: It doesn't seem like a sure thing. We will have to see when the new Congress comes back in January how quickly the Senate majority leader, Mitch McConnell, moves to put it on the agenda and whether, if he does not feel he has the votes, what happens next.

MR. MIKRUT: My understanding from talking recently to committee staff is they are still going through the treaty text and finding new details that may be challenging to put through the Senate.

Climate Change

MR. MARTIN: There have been conflicting stories since the election about whether House Democrats will press for action on climate change. Some people say Nancy Pelosi will insist the House lie low on this issue because tackling it now would be a fruitless exercise. What do you think? Is action on climate change possible in the next two years?

MR. WEISGALL: I do not see anything crossing the finish line. Pelosi would like to revive the now-defunct House Select Committee on Energy Independence and Global Warming that was scrapped in 2011, but she still has war wounds from the effort to put through a cap-and-trade program to limit greenhouse gas emissions in 2010 when a number of Democrats were defeated after a / *continued page 12*

IN OTHER NEWS

US without waiting for the foreign earnings to be repatriated to the United States. This is called a "GILTI" tax. California must be decide whether to include such income in the corporate tax base in California.

INTEREST AND PROPERTY TAXES must sometimes be capitalized rather than deducted.

Three partnerships that are in the business of farming almonds were told by the Internal Revenue Service on audit that they had to capitalize not only the interest the partnerships pay on loans taken out to buy the almond groves, but also the annual property taxes they pay.

Each partnership deducted the taxes and interest as it paid them. The IRS said the payments had to be added to the tax basis each partnership had in its almond trees.

Section 263A of the US tax code requires amounts that are indirect costs of producing "real property" to be added to the tax basis of the real property.

A US appeals court agreed with the IRS in early December.

The court said that almond trees are "real property" for this purpose and the taxes and interest payments are part of the cost of growing the almond trees.

The case is *Wasco Real Properties I, LLC v. Commissioner*. The US Tax Court had come to the same conclusion earlier.

US SOLAR INSTALLATIONS dipped 15% in the third quarter 2018 compared to the same period the year before, according to a report that Wood Mackenzie and the Solar Energy Industries Association released in mid-December.

However, a "strong project pipeline lies ahead," the report said.

The report said the dip to 1,500 megawatts of solar capacity additions in Q3 2018 was fallout from the uncertainty that solar developers faced during most of / *continued page 13*

Mid-term Elections

continued from page 11

bill passed the House.

Having said that, Paul Tonko of New York, who will chair the House subcommittee on environment and the economy, will probably work on a cap-and-trade bill. There may be pressure from some rank-and-file Democrats for a carbon tax and to reopen debate about US participation in the Paris climate accord, although nothing could happen there since foreign policy is totally up to the President. Pelosi is clever enough not to bring up bills that have no chance of becoming law, even though she may feel pressure on these issues from a more left-leaning House.

There is a risk in the next two years that the US corporate tax rate could increase.

MR. MARTIN: Tom Hassenboehler, you were chief counsel for the House Republicans on these issues until late 2017.

MR. HASSENBOEHLER: Yes. I have a few thoughts. The likely incoming chairman of the House Energy and Commerce Committee, Frank Pallone, put out a press release yesterday that shows what will be on the Democrats' agenda. They have about eight issues: health care, undoing the Trump administration's efforts to roll back Obamacare, lowering health costs, strengthening Medicare, rebuilding America by investing in green energy, drinking water. Climate change does not even get on the agenda until number five, and it is presented in terms of looking at the impacts on communities and holding the administration accountable for its policies.

I can foresee individual efforts by some members. There will be conversations about how to bring about the next wave of climate solutions. But the primary organized effort by the Democratic majority, when it comes to climate change, which again is issue number five on the list, will be about holding the Trump administration accountable, doing a lot of oversight, and then maybe taking some of the types of incremental actions — on grid modernization and electric vehicles — that we talked about earlier in an infrastructure bill.

Tax-Change Risk

MR. MARTIN: Let me ask a few questions of the tax guys. Trump called, in the last two weeks before the election for another tax cut bill. He said at his press conference after the election that he would be open to increasing the corporate tax rate to pay for a middle-income tax cut. How much risk is there of a change in the corporate tax rate in the next two years and in which direction?

MR. GIMIGLIANO: The direction is easy. I can't imagine it going down. If it moves, it will go up. I think there is a meaningful risk that it could go up. We have already seen Senate Democrats put out proposals to pay for infrastructure by raising the rate to 25%. The rate in President Obama's framework on tax reform was 28%. I think those are all plausible scenarios that we can see Democrats propose.

I am still trying to pick my jaw up off the floor when I heard the President say that he would be willing to consider that scenario to pay for middle-class tax cuts. I am sure it was not a happy day for Mitch McConnell when he heard that statement. Nothing is likely, but it is something that cannot be ruled out in the coming years.

MR. MARTIN: Joe Mikrut, not likely, but possible. Do you agree?

MR. MIKRUT: Yes. It was surprising to hear a President, who was pushing just last year for a 15% corporate rate, say he would not mind raising the current rate to something above the current 21%. The incoming House tax committee chairman, Richard Neal, has said that he would willing to do a middle-class tax cut, but he would not look necessarily at the corporate rate but at raising the top individual rate, which suggests the Democrats may be reserving the corporate rate to pay for something else. Perhaps it becomes the funding for an infrastructure bill.

MR. GIMIGLIANO: It does not get you that much money. Here's the problem. Say the rate goes from 21% to 25%. Raising the corporate tax rate does not bring in as much money and you lose when lowering it, for technical reasons. The reality is a rate increase does not raise the trillion or more dollars needed to fund a large middle-class tax cut, so there has to be more money elsewhere.

MR. MARTIN: Kevin Brady, the outgoing chairman of the House tax committee, suggested before the election that the House might address misuse of tax credits as one way to pay for the Trump middle-class tax cuts. Do you think he was referring to anything specific?

MR. GIMIGLIANO: That mostly dealt with the individual refundable credits.

MR. MARTIN: The Solar Energy Industries Association wants to make tax credits for renewable energy easier to transfer by borrowing from language in the tax code for nuclear production tax credits. The Edison Electric Institute, which is a trade group for the utilities, wants to bring back the equivalent of Build America bonds to fund utility and other infrastructure improvements. A bipartisan group is promoting tax credits for energy storage. Another group wants a longer period for offshore wind projects to be built to qualify for tax credits. Do you see any of these proposals moving in 2019?

MR. GIMIGLIANO: Refundable tax credits are something that was considered in 2009. We got the Treasury cash grant program instead. True refundability or transferability was considered a bridge too far. I could see Build America bonds or something like them getting into an infrastructure bill. They have to be wrapped into something bigger. These are not the kind of thing that will move on their own.

MR. MIKRUT: Refundability is very difficult, but you could see something more in the nature of transferability if it is patterned after what was done for the nuclear industry. There is a lot of support for storage on a bipartisan basis, so you could see an investment tax credit for energy storage moving. Jon Weisgall mentioned changes, perhaps, in the electric-vehicle credit. There is a lot of activity there. Unfortunately, it is in both directions. Some members want to repeal it immediately. Some want to extend it.

None of these items moves on its own. They need to hitch a ride on a larger vehicle.

Perhaps it is an infrastructure bill since energy provisions can be supported as infrastructure. / *continued page 14*

IN OTHER NEWS

2017 while the US talked about rewriting its income tax laws and considered imposing tariffs on imported solar panels.

The third quarter was the third consecutive quarter in which new solar capacity additions were flat or marginally up.

Wood Mackenzie is projecting 11,100 megawatts of solar capacity additions in 2018, up from 10,600 megawatts in 2017. There were 14,626 megawatts of new solar installations in 2016. A strong rebound is expected in the fourth quarter 2018 when Wood Mackenzie expects 3,500 megawatts of new solar additions.

NEW GAS-FIRED POWER PLANTS are expected to eclipse wind and solar installations this year.

The latest capacity report covering the period through September issued by the US Energy Information Administration in mid-December predicts that more than 22,000 megawatts of new gas-fired power plants will be put in service this year.

Many are in PJM, the part of the utility grid covering the mid-Atlantic states out as far west as parts of Illinois and Michigan.

This is the first time since 2013 that that gas capacity additions will have outstripped renewables.

The numbers reflect a collapse in natural gas prices in the Appalachian basin in 2015, leading to a rush of new development two and three years ago.

The broad market shift to renewables is expected to continue, but any forecast has to take into account that US electricity demand is barely growing, and the best opportunities to add generating capacity are in parts of the country where coal and nuclear plants are being retired. Gas may have an economic advantage in such places over renewables. On the other hand, what load growth there is tends to be in places like Texas and Arizona, where renewables have the advantage.

/ ***continued page 15***

Mid-term Elections

continued from page 13

Traditionally there would have been a separate tax title to such a bill. It is hard to see such a tax title in the short term. The problem with tax provisions is they are like a fine wine. They have to sit and mellow for a few years before they are ripe to be included in something.

MR. WEISGALL: It is possible to see something happening on tax credits for offshore wind. There were no offshore wind projects in the US until the Block Island project a couple years ago off Rhode Island, and it is still the only operating project. So you could view offshore wind as a newer technology. Offshore wind is also the one area of renewable energy that is getting remarkably strong support from the Trump administration.

Regulatory Issues

MR. MARTIN: The Federal Energy Regulatory Commission is effectively down to three commissioners: two Democrats and one Republican. President Trump nominated a pro-coal Department of Energy official, Bernard McNamee, to fill a slot. His confirmation requires, 60 votes in the Senate. Do you see him getting through and, if so, when? And what difference does it make whether FERC has another commissioner?

MR. WEISGALL: I think he will get through by the end of this year, and another commissioner will be important. We could have a flip. For example, the two Democrats, Cheryl LaFleur and Rich Glick, have big issues on permitting for new natural-gas pipelines. Bringing on another Republican will make a difference. LaFleur will reach the end of her term next year and Kevin McIntyre, who has health issues, could retire. We may see next year a pairing of a Democrat and a Republican to move both through the Senate to get the commission back to full strength with five commissioners: three Republicans and two Democrats.

MR. MARTIN: Both PJM and FERC have suggested that renewable generators should be required to bid at least a minimum offer price to supply capacity to PJM. They can bid $0 today and be certain to be selected and then get a capacity payment at the same market-clearing price that others receive, but FERC has seemed unable to reach a consensus. The 2019 auction is expected at this point to be delayed by three months. Is this a big deal for renewable generators?

MS. WEISS: Yes. Existing renewables projects probably will not be subject to the minimum-offer rule. There seems to be a fundamental misunderstanding at PJM about the cost of renewables. The first attempt at creating a minimum-offer price for solar was based on taking 2011 capacity costs and then escalating them to 2023, which is essentially the opposite of what is happening in the real world where costs have declined significantly year over year. This is definitely an important issue to watch.

MR. MARTIN: In the same vein, the plan by the US energy secretary, Rick Perry, to require grid operators to dispatch coal and nuclear plants ahead of other generators and pay them enough to keep them profitable appears to have stalled at the White House due to the potential effect on electricity prices. Is the plan dead or are we going to see some other version of it?

MR. HASSENBOEHLER: I do not think it is dead, even though it has lost air.

There are a lot of things in the works at the Department of Energy that could affect the market. They include the new NERC assessment of capacity margins and lack of excess capacity for the next three to five years and new studies on grid and gas pipeline security.

The administration has been working on an inventory of critical assets. I think you will see it try to steer the overall debate in that direction. The revamped Perry plan will not look like it did when it was first proposed a year ago.

RTOs and ISOs are starting to receive a lot more attention from Congress as the issues of grid reliability and grid security are moving into the mainstream. They are potential oversight issues for the House Energy and Commerce Committee. I can see House Democrats taking on everything from how the Trump administration is handling the critical infrastructure designations and the ideas behind the need, or the lack thereof, for these kinds of capacity-market interventions all the way to looking into how the RTOs are handling new technologies and looking at their boards and oversight.

MR. MARTIN: The Perry plan, the FERC minimum-offer-price proceeding, and lawsuits in Illinois and New York to block zero-emissions credits that keep nuclear power plants operating are all manifestations of a battle among different types of generators for market share in what is otherwise a stagnant market for electricity. Where else do you see this battle playing out?

MR. HASSENBOEHLER: There is emerging interest in where and how data can be aggregated. There is talk about this at the state level and at the RTO level about using industrial data, smart-meter data and upstream data to differentiate products. This is part of the food fight among generation classes about how to market and how to value their energy in an evolving market.

MS. WEISS: Another potential new battlefront is a report in the works by the Department of Energy on the accelerating retirements of coal and nuclear plants. How the study was performed, the results and what will be done with the information will be of interest in the battle for market share.

State Issues

MR. MARTIN: Let's move to the state level briefly. There were three big state ballot initiatives with potential effects on the power industry. All three lost. One is a carbon tax in Washington state. It went down for the second time. Another is a target of 50% renewables by 2030 in Arizona. That failed. The third was a move to end the monopoly that utilities have on the retail electricity supply in Nevada. That failed. There was a modest increase in the renewables target in Nevada. Jon Weisgall, you were in the thick of a lot of this. What should one make of this pattern?

MR. WEISGALL: Well, it is not a pattern. That is the problem. Look at the contrast between those two purple states where Nevada votes to move to 50% renewables by 2030 and the identical ballot initiative, 50% by 2030, fails in Arizona. Both were backed by billionaire Tom Steyer. The Nevada proposal is a constitutional amendment. It will have to go another round.

One lesson in all of this is that the most money spent on a ballot initiative wins. That lesson holds when you throw in the anti-fracking measure in Colorado.

It was really very much a mixed bag. Washington tried a new version of a carbon fee, not a carbon tax, but that still didn't work. In Colorado, while the anti-fracking ban lost 57% to 43%, the proponents were outspent something like 40-1. The spending was something like $38 million to less than $1 million.

I think voters in general were concerned about the impact on pocketbooks. The ballot initiative that failed in Nevada was very close to my company and is a complicated issue that is hard to put into soundbites, but a matter that would have dismantled and deregulated Nevada's existing electricity system. I think voters were affected by a report from the public utility commission that suggested adoption of the initiative would lead to higher electricity rates and make it harder to make rapid progress on renewable energy.

MR. MARTIN: We have to mention the gubernatorial races. Democrats were elected in Illinois, Michigan and Colorado, all of whom support 100% renewables. Maine and Kansas elected Democratic governors who may also push their states toward more renewables. That does seem to be */ continued page 16*

IN OTHER NEWS

A megawatt of gas capacity adds 2.9 times the electricity output as a megawatt of utility-scale solar because solar plants can only produce electricity during the day.

Capacity factors for solar vary by state. The best states are California with a 28.1% capacity factor, Arizona with 27%, Nevada with 26.7%, New Mexico with 25.8%, Colorado with 22.7% and Texas with 21.7%.

US INSTALLED WIND CAPACITY stood at 90,550 megawatts at the end of the third quarter 2018, according to the American Wind Energy Association.

There are operating wind farms in 41 states, Guam and Puerto Rico.

The average wind turbine installed in 2017 was 2.32 megawatts. However, new orders in the third quarter included the first orders for onshore turbines above 4.0 megawatts.

AWEA says there is a near-term pipeline of 37,965 megawatts of projects moving to market. "Near term" means the projects are either actively under construction or they passed a major milestone like signing a power purchase agreement and placing a turbine order.

The number of corporate PPAs signed by wind companies this year has already set a record. It was 2,700 megawatts at mid-year. Total corporate PPAs signed this year for all renewables reached 6,430 megawatts in December, a record.

Wind companies signed 1,522 megawatts of PPAs with utilities in the third quarter, bringing the total through September to more than 6,100 megawatts. Development of new projects had slowed in 2017 due to uncertainty about tax reform and tariffs, but originations have picked up significantly this year because of growing demand not only from corporations who want to buy renewable energy, but also from utilities that have decided it is time to lock in low wind electricity prices before the tax credits for wind farms disappear.

/ continued page 17

Mid-term Elections

continued from page 15

a positive. On balance, at the state level, despite the fact three ballot initiatives went down, was the result mainly positive?

MR. WEISGALL: I think it was. Maine and New Mexico will make some changes in renewables. The count is now 23 Democratic governors and 27 Republicans. Illinois, Kansas, Michigan, Maine, Nevada and New Mexico all flipped to Democrats who want to act on renewable energy. You had Democrats winning attorneys general positions and a couple of new trifectas where both branches of the legislature and the governor's house are now in the hands of the Democrats. That is the one clearly positive trend line for renewables.

Tax credits for offshore wind and energy storage will be in play in the next Congress.

2020 Outlook

MR. MARTIN: Last question. Is Trump now in a stronger position to be reelected in 2020? The electoral college, which determines who is elected president, works more like the Senate than the House, and Trump did well in the Senate races.

MR. GIMIGLIANO: It is a good question. When you ask, "Is he in a stronger position," the first question is relative to what? Is it relative to 2016, when he first won, or relative to his position in 2018 going into the mid-term elections?

By almost any measure, he will be in a better position in 2020 than he was in 2018, just because history tells us that first-term mid-term elections are always terrible for the President and the President's party. So if history stands, the playing field should be more in his favor.

The real question is whether it will be better than it was in 2016. We expected him to do reasonably well in the Senate, but some of these races are still not resolved. If, in the end, with the very favorable math that the Republicans had going into the mid-terms for control of the Senate with so many more Democratic seats up for vote, the Republicans manage only to maintain the status quo of 51 Republicans and 49 Democrats, then I am not sure you can point to that as really a successful outcome for the President. Let's see how those races settle.

MS. WEISS: I completely agree.

MR. WEISGALL: You had in the Senate races this year 25 Democrats and only nine Republican seats up for votes, and something like 10 of the Democrats were running in states Trump won in 2016.

The math changes in 2020 when you will have 22 Republican and 12 Democratic seats up for votes, but the challenge for the Republicans may not be as great as it looks. I believe 20 of the 22 Republicans are in Trump-carried states. The exceptions are Maine and Colorado that Clinton had carried in 2016. Something like 10 of the 12 Democratic seats are in Clinton-carried states with only two in Trump states: Michigan and Alabama.

It is interesting that 2016 was the first time in the history of popularly-elected Senators that the Senate outcomes completely matched the Presidential outcomes. In that sense, you are right that the results in Senate races are a better guide to Trump's prospects since they matched the outcome in the 2016 electoral college. ◎

State of the Wind Industry

Michael Garland, CEO of Pattern Energy, Tristan Grimbert, CEO of EDF Renewable Energy, and Tom Kiernan, CEO of the American Wind Energy Association, had a wide-ranging conversation in San Francisco in October about the state of the US wind industry. The moderator is Keith Martin with Norton Rose Fulbright in Washington. The following is an edited transcript.

MR. MARTIN: Mike Garland, Pattern was in five countries. It sold its Chilean operations in August. How do you rank the opportunities in the other four: the US, Canada, Mexico and Japan?

MR. GARLAND: It depends on your measure, whether it is profit or megawatts.

MR. MARTIN: Profit.

MR. GARLAND: In terms of profit, Japan first, US, Mexico and Canada in that order.

MR. MARTIN: Why is Japan more profitable than the US?

MR. GARLAND: It could be that our average power contract price is $250 a megawatt hour compared to $25 a megawatt hour or less in the US.

MR. MARTIN: Tristan Grimbert, your immediate focus is the US, Canada and Mexico, but you are also on the global investment board of EDF, so you see the whole world. How does EDF rank opportunities? Where is the US in the rankings?

MR. GRIMBERT: I wish I were in Japan, and I have been telling EDF that for five years now. Overall in North America, the margins are very, very tight, and globally that is true as well. The main places on which the company is focusing today are China, India, Brazil and France.

MR. MARTIN: Is there anywhere where the power prices are as low as in the US?

MR. GRIMBERT: The Middle East, but it is mostly on the solar side where we see very, very low prices in the Middle East. On the wind side, the pricing in Brazil is even lower than in the US.

Tariffs and Inflation

MR. MARTIN: Tristan, you said before we started this morning that you worry about tariffs and the potentially rising cost of capital? How and where are you being affected?

MR. GRIMBERT: The tariffs have a ripple effect on a lot of things. It is not only the steel that you / continued page 18

IN OTHER NEWS

PREPAID POWER CONTRACTS are harder to make work after the US tax reforms last December.

The IRS said in October that it plans formally to withdraw the part of its regulations that let an electricity generator report the prepayment as taxable income over the same period the prepaid electricity is delivered.

In some power purchase agreements, the utility taking the electricity pays in advance for a share of the electricity to be delivered over time. The structure is used mainly where electricity is being sold to a municipal utility or electric cooperative. It is also used to supply natural gas to such utilities.

The generator or gas supplier reports the advance payment as income over the period the electricity or gas is delivered.

Prepayments are also common in the solar rooftop market.

The tax reform bill last December requires such prepayments to be reported immediately as income or, at best, partly in the year the prepayment is received and the balance the year after.

The change was effective in tax years starting after 2017.

Generators that received prepayments before the change must report the remaining balance as income in 2018, according to tax experts in Congress who had a hand in drafting the new law.

An electricity or gas supplier who wants to use the structure in the future would have to structure the prepayment as a loan that is repaid in kind with electricity or gas. In order for the loan characterization to work, ideally the supplier should have the option to make loan payments in cash and the electricity or gas should be credited against the loan balance at its market value at time of delivery.

The fact that a 100% "depreciation bonus" can now be claimed on any new power plant used to supply the electricity may help shelter the prepayment. / continued page 19

Wind Industry

continued from page 17

are buying for your project, but it is also the microwave in the trailer. They affect everything.

If the trade war continues, they will lead to US inflation. The huge budget deficits will also have an inflationary effect.

I am very concerned about that. Fortunately, we have master turbine supply agreements and balance-of-plant contracts that protect us to a very large extent, but —

MR. MARTIN: For how many years are you protected?

MR. GRIMBERT: For the next two years until the end of 2020. There is still a portion that is not completely hedged, and that is making my life difficult right now to work on that.

The second aspect is the cost of capital. It is undeniable that the cost of capital is going up. We are insulated somewhat at EDF because we have a large allocation of capital that we can use in the next couple of years, but we need to see an inflection point in PPA pricing. The current PPA pricing is not sustainable with both the costs of capital and equipment increasing.

MR. MARTIN: Mike Garland, are you worried about inflation and a rising cost of capital? The banks supplying capital to this industry complain that their returns are half what they were three years ago and that they are taking more risk.

MR. GARLAND: I am not really worried about either. You have to deal with the market the way it is. We like change because we feel like we can adapt more quickly than some of our competitors. So having change in the marketplace is good for our company.

There are a couple ways we are affected by inflation and the cost of capital. One is our valuation of our existing assets. Inflation causes the discount rate to increase so, in theory, the value of our assets goes down.

On the other hand, if you have sustained inflation, your residual values go up. The two effects are probably a net positive because we have been pretty conservative in how we look at the future value of assets.

We do not think energy costs will go up much in real terms.

You and I have been around long enough to have seen these cycles before. The market takes a couple years to adjust to higher prices. People use higher discount rates to value assets. Margins contract for a year or two. Even though the money indexes move up, there is pressure on the banks to keep debt rates low. Our cost of capital does not change radically unless there are sustained year-over-year inflation and interest rate increases. So you just adjust to that and then eventually you have hopefully better returns.

MR. GRIMBERT: Do you see the PPA market adjusting?

MR. GARLAND: I think it has to. Do you see it adjusting?

MR. GRIMBERT: I agree on the long term. I am more concerned about being squeezed in the next couple of years.

MR. GARLAND: I am okay with that. We always bounce around. Japan will keep us busy for a couple years if things do not go well in the US.

That said, a number of offtakers are starting to get that this is a good time to lock in power prices by signing long-term contracts. You have to look at how interest rates, the cost of capital and tariffs are likely to affect the price at which you can offer power. It is still possible to maintain a relatively competitive PPA price.

Post-2020 Outlook

MR. MARTIN: One of the slides that John Hensley of AWEA put up immediately before this session showed forecasts by MAKE, a consultancy, and UBS, the Swiss bank, about annual US wind turbine installations over the next few years.

They both see a pronounced drop off after 2020 when projects must be completed to qualify for tax credits at the full rate. You guys are on the front lines. What do you expect after 2020?

MR. KIERNAN: Some of those estimates were even worse a year ago. The point is that a number of analysts have been bumping up the post-2020 turbine installations as the levelized cost of electricity and turbine efficiency improve. There are some things that we can be

Electricity buyers are moving to lock in supply while the prices on offer still benefit from tax subsidies.

NORTON ROSE FULBRIGHT

doing about market design and valuing essential reliability services to increase the floor in the 2022 to 2024 window. So I would not take the latest forecasts as gospel. The numbers may continue to improve.

MR. GRIMBERT: We expect in 2020 to do two or three times more business than usual. By comparison, 2021 will be a low year, but not a dramatically low year.

I am a little more concerned for 2022 and 2023, to be honest, until there is enough further improvement in turbine productivity to offset the disappearance of production tax credits.

MR. MARTIN: Is it too late at this point to find a construction contract to erect turbines in 2020?

MR. GARLAND: No, but it is getting tighter and tighter. The contractors are pretty clever folks in figuring out how to hire more people and get more equipment. I think you will see a tightening up and some of the pricing being driven up by that, but they will figure it out or we will set up our own shop to bring in labor and contractors to build ourselves.

MR. GRIMBERT: I may be more focused on profit than Mike, but I think that it is really, really hard to find a supply contract today that will accommodate the PPA pricing of today. If you want to make profit on your project, you had better already have secured your supply.

MR. MARTIN: I was asking about the Mortensons of the world who are erecting turbines. Is it too late to find BoP contractors?

MR. GRIMBERT: I'm talking about both turbine suppliers and BoP contractors.

MR. MARTIN: Tom Kiernan, you teased us with one of your comments earlier. You said there are things that can be done to increase wind capacity additions after 2020. Give us some examples.

MR. KIERNAN: We have been going through a strategic planning process, and we have three priorities for the next several years.

The first is transmission and market design. On that front, we are working with regional transmission organizations on assigning a greater value to reliability and ancillary services that wind projects can provide. If we can increase value there, it can lead to greater deployment. We are also looking at long-distance transmission. Clearly that will take a long time to address, but there are some things we can do on the interconnection queues and to relieve congestion that can help.

The second priority that can help is to assign a price to carbon. There may be a way to get some state carbon legislation in the next couple years and federal legislation */ continued page 20*

IN OTHER NEWS

A 100% depreciation bonus means that the full cost of the power plant can be deducted as depreciation in the year the project is put in service. In a solar project where a 30% investment tax credit is also claimed on the project, only 85% of the project cost can be deducted as depreciation.

— contributed by Keith Martin in Washington

Wind Industry

continued from page 19

in the early 2020s.

Finally, in the category of avoiding a problem, we can try to reduce some of the barriers to siting new wind farms.

MR. GARLAND: A forecast of 6,000 megawatts of new turbine installations in 2021 or 2022 is not a bad market for us given the roll off of production tax credits for wind and the continued availability of investment tax credits for solar. As Tom said, the post-2020 forecasts are improving.

We have seen an acceleration of coal plant retirements under the current administration. I think that will continue, and it will free up from more of the market to be supplied by renewables.

Corporate PPAs, hedges and other non-utility contracts could make up as much as 80% of future offtake arrangements.

There are two other factors also at work. One is people now understand how inexpensive wind electricity is. There is a bit of a land rush now. Electricity buyers are moving to lock in supply while the prices on offer still benefit from a production tax credit of $24 a megawatt hour. But even without the PTCs and over the next few years as PTCs step down in amount, electricity is still being offered at a damn attractive price.

As solar builds out in some regions, there will be a need to balance solar with wind and other resources. Wind and solar reach peak output at different times of the day. We are also seeing a huge increase in spending on transmission by the utilities. That could create additional transmission capacity that will help create room for new projects.

Corporate PPAs

MR. MARTIN: Another slide that John Hensley put up earlier was that the wind industry had already signed 4,600 megawatts of new utility PPAs and 2,700 megawatts of corporate PPAs through June this year. Many people think the market is shifting to a corporate PPA and hedge market. Are you surprised by the number of utility PPAs? Is the market shifting to corporate PPAs and hedges?

MR. GARLAND: There is clearly a shift. The number of corporate PPAs represents a substantial increase. That market will continue to grow. Our expectation is that our future contracts will be 20% to 30% utility PPAs and 70% to 80% non-utility PPAs. The non-utility PPAs may be corporate PPAs. They may be contracts with community choice aggregators in California. They may be other things that are not pure offtake contracts, such as virtual PPAs or hedges.

MR. KIERNAN: The Renewable Energy Buyers Alliance — REBA — announced that it plans to establish itself as a section 501(c)(3) or (c)(6) organization. The group has selected a new CEO.

The group is stepping up in a big way to create new business models for corporations to purchase renewables. This is a plus for us that the corporate community is getting that much better organized and trying to figure out new ways to buy renewables.

MR. MARTIN: Tristan, did I hear you say before this panel that a third of your PPAs are with corporations?

MR. GRIMBERT: Yes. We think about a third of our activity is going to be with corporate buyers. We are part of REBA and are pleased that they are stepping up to try to make the terms more bankable. The quality of the corporate PPAs today is very low. It has been a buyer's market with huge requests for proposals and terms that I do not think are sustainable.

There is a lot of activity, but to get a good PPA with a corporate buyer today that makes sense is very difficult. If we can find a way to make these contracts more balanced in the way risks are taken on both sides, then I think corporate PPAs could account for 50% of our activity.

MR. MARTIN: What is the hit rate for bids to supply power in corporate RFPs? Less than 10%, 20%?

MR. GARLAND: We are quite proud. We are terrible at bidding. We have maybe a 20% hit rate. I praise our guys for being disciplined and not just trying to do a race to the bottom.

Maybe it is little better than that, but we do not want to win that many PPAs because a lot of people are being extremely aggressive on bidding, so I don't mind losing where we are uncertain about making a profit. This time I am thinking about profit.

MR. GRIMBERT: I feel better. I am not sure I can give you a percentage because it depends on the design of the solicitation. For example, right now you have solicitations that you have to go through with some very large purchaser, where we could submit 10,000 megawatts, and we may expect to get zero out of that, but it is a way to build a relationship.

Like Mike, we try to avoid huge RFPs that are going nowhere. They are a race to the bottom. The winner is the bidder who made a mistake. Nobody wins in the end.

If you really want a percentage, it is in the 10% to 20% range at best. There is a lot of competition.

MR. GARLAND: We are talking about the US market. In Japan, our hit rate is very high.

Basis Risk

MR. MARTIN: One of the problems with corporate PPAs is many of them are virtual PPAs or hedges. The electricity price under the hedge is different than the price at which the electricity is actually sold into the grid. The difference is called basis risk. Some financiers are growing concerned about the basis risk being taken by developers.

Mike Garland, how do you deal with this?

MR. GARLAND: [Laughs] Basis is really painful. Until now, we have been pretty good at most of our offtakes. We pushed it off. We have a few in Texas that have been very painful as a result of underestimating the build out that creates this basis problem in many locations.

Unfortunately, we are going to have to take it. All of the corporate customers and a lot of the utilities have wised up to this problem and are passing on that risk to generators.

We are putting a huge amount of time into modeling and managing local issues around this, things like how people get permits. Do we need to take an active position on competitors coming into an area that can create additional basis problems?

Do we need to be more active in managing the outlook by ERCOT and other grid operators and how they sign up generators? Texas is really bad because anybody can sign up any time.

It is not as bad in other markets because they will not hook you up until you have paid your price and they have upgraded the system. The point is basis risk varies by location. In the future, we are all going to have to have a hell of a lot better understanding of the transmission grid and where the inflection points are where the price changes.

In some cases, the price shift can be dramatic. There can be 500 megawatts of build out without any real basis problem, but you get to 700 or 800 megawatts and, all of a sudden, the gap between the node price at which electricity is sold into the grid and the hub price used for the hedge goes from $2 to $10.

We are doing a lot of modeling and analysis, and I think politically we are going to have to be much more involved with regulators and development approval processes in those areas where we are taking that risk.

MR. KIERNAN: The industry as a whole needs to get better organized on working with RTOs. Historically, this is where the oil, gas and coal industries have been active in setting those policies. The wind industry has been active company by company. Basis risk is just one of the issues where we need to have a coordinated wind and solar agenda at the RTO level.

MR. MARTIN: Tristan, is it just cross your fingers or is there more you can do about basis risk?

MR. GRIMBERT: I agree with Mike. We have eight or nine people modeling all the time. The number of simulations we do for each project is staggering.

This is one of the key risks that we need to understand, so we are putting a lot of effort into it. It is very important that we not make a mistake there.

The first thing is to establish criteria. We will not do projects in certain areas and under certain conditions, even if the market seems good, because the basis risk is not very well controlled. We focus on RTO regulation. We focus on the voltage level at which projects interconnect.

We do a lot of hedging. Down the road potentially battery storage will help, but it will not fix the issue in the short term, so you have to be very, very disciplined.

One thing we have seen this year that I really don't like is the zero dollar, non-negative product that you can bid under a virtual PPA. We are drawing the line there. A number of us have said we are going to pull back from that market. I think the corporate buyers have realized that. They are still signing some such PPAs, but there needs to be a dialogue about how much of that risk they want the developer to take.

MR. KIERNAN: Basis risk is not everywhere. It is in some places. People should not come away thinking the whole market has wild basis risks.

You see it in ERCOT and Oakland and places like that. It could become an issue in other parts of the / continued page 22

Wind Industry

continued from page 21

country over time. Tristan's point about negative pricing or very low pricing is a bigger concern everywhere.

MR. GRIMBERT: The other issue is that in northwest Indiana, for example, seven wind companies have invested money in NIPSCO studies on ways to relieve grid congestion. We have reached 62% curtailment on some of the projects.

MR. MARTIN: We saw 97% curtailment on one project in Ohio due to grid congestion.

MR. GRIMBERT: I haven't seen that, but one other thing is we do not rely on the utility and the consultant. We redo everything ourselves. While we always have one or two outside consultants, we try to question, question, question. My shareholder asks why our development costs are rising. This is the kind of thing where we are having to spend more money to develop a deeper understanding ourselves of the potential risks.

MR. MARTIN: To be clear, the problems you are describing are due to grid congestion. There just is not enough room on the grid to move the electricity.

MR. GRIMBERT: The interconnection studies were done based on a certain landscape. The utility did the same study for seven developers. Each was given the same study. There were about 1,800 megawatts. The assumption was made in each case that there was nobody else.

MR. MARTIN: One trend in the corporate market is moving towards smaller corporations and perhaps aggregating them, having an anchor corporation. Another trend is corporations no longer want to take shape risk. Do you see multiple corporations buying from a single project? How do you get rid of shape risk?

MR. GRIMBERT: I think this is a real challenge how to do a load-following PPA for corporate buyers. We have a trading arm that allows us to shape, but that is a different level of service. It adds quite a few bucks to be able to provide shaped power depending on the request. It is not simply delivering the output from a project as it is generated. It is a very interesting market evolution where we can generate more value.

On the aggregation of small buyers, this is already happening, but it is difficult to do and is unlikely to transform the market in the next couple years.

MR. GARLAND: It is not just corporate buyers that are more interested in shaped power, but the utilities are also interested in it. The entire market is moving in that direction.

I agree with Tristan. That is where we can start seeing some margin increases by providing a greater service and getting paid for it. I think the utilities are starting to recognize that there is real value to their ratepayers and even shareholders from working with companies like Tristan's and mine to have more flexible offtake arrangements. It may be we end up just being a base-load supply. How we get there is up to us, and they just contract for the supply.

Storage

MR. MARTIN: Let me ask one more question of Tristan and Mike, and then we will go to Tom Kiernan, and then I want to go to the audience. The last question is about storage. It is being adopted much more quickly than people expected. How is it changing what you do?

MR. GARLAND: It changes everything. For everything we do now, we analyze the value of storage. The first reaction is "It's fantastic, go apply it everywhere." Then, after you run the numbers, you realize, "Hmm, this isn't that interesting." But looking at storage over the last seven years, if in 2010 to 2011, it was something like $1,000 for batteries, today it is closer to $200 and, if you keep that trend line going, the cost will come down to a point where the question is where is it best used.

One potential game changer that has not been highlighted enough is the solar rooftop guys are going to start fading a bit in terms of the amount of new rooftops that they are building out, but they still have an incredible opportunity to put in storage in homes and commercial buildings. The margins are much higher. There are five- or six-year payback periods. This activity will affect the market, but will take time to reach scale.

We are looking for major opportunities to help both with our projects by co-locating, and then other places where it is just standalone storage. Batteries will come on fairly strong over time, and then they will hit a wall because they will not be needed as much as the grid gets smarter.

MR. MARTIN: Tristan, let me change the question for you. What percentage of your projects have batteries currently? When do you think you will reach 100%?

MR. GRIMBERT: For contracts we are signing today on the wind side, there is no storage even though we evaluate it every time. On the solar side, it is about 50%. Starting 2020 and 2021, we should start to see utility-scale batteries being added to wind.

On the distributed side, we went from zero a year ago to about 40% to 45% of all the proposals including batteries, and we will have signed five distributed battery-only storage contracts in front or behind the meter on the distributed side before the end of the year.

Storage is a game changer. What I like about batteries is they are complicated. The use case is very important. The chemistry is very important. The energy management system is very important.

Compared to a commoditized solar business, you bring more value. I don't think the demand for batteries will diminish. The market is suffering currently from what we call a cannibalization. The more wind you put at an interconnection point or the more solar you put on the system, the less value per megawatt hour because everything comes at the same time.

A battery is the other way around. The more batteries you install, the less volatility there is in the supply of renewable energy. By installing larger numbers of batteries, the market can accommodate larger volumes of renewable energy.

MR. MARTIN: Tom Kiernan, we are about four weeks away from the mid-term elections in November. How could the election results affect the wind industry?

MR. KIERNAN: A couple thoughts. If the House flips, the partisan tension will continue, but there is latent interest in an infrastructure bill both on the Republican and Democratic side and by the president. We need to keep working as an industry with the Hill to see if there is room for some form of infrastructure bill that deals with transmission. Maybe the odds for an infrastructure deal go up slightly.

Second, while obviously we have some disagreements with the president, whether it is on promoting coal, a nuclear bailout and other issues, we are doing a fair amount with Secretary Zinke at the Department of Interior both on offshore wind and on the permitting and regulatory side. That should continue.

MR. MARTIN: Those are two places where the Trump administration has proven an ally for the wind industry: offshore wind and permitting. Kevin Brady, the chairman of the House tax committee, says he wants to take up an extenders bill in the lame-duck session after the election. The Republicans very much want to put through some technical corrections. They rushed the last tax bill so badly that there is a lot of cleanup to be done. Do you see anything that might be done in this context to help wind?

MR. KIERNAN: Yes. I think everybody is trying to figure out the dynamics and different scenarios depending on how the election unfolds.

There is the potential for a storage investment tax credit. There is a Heinrich-Heller bipartisan bill on the Senate side to promote storage that would be helpful for wind and solar. That is something that we are pushing. It could potentially be done in lame duck or could be done in the next Congress. There is an opportunity for the industry to go on offense to get a storage ITC.

MR. MARTIN: Any audience questions?

MR. CARGAS: Jack Cargas from Bank of America Merrill Lynch. Is there a possibility of another extension in the construction-start deadline for wind projects to qualify for production tax credits?

MR. KIERNAN: That is not something we are pushing. As we said during tax reform, a deal is a deal. We got the phase out we asked for earlier. We want that protected as well as the four-year IRS guidance and the 10-year period to claim PTCs. We need to protect all of that.

There may be some things we can do on the margin. We have been working with Senator Cantwell and others who are looking at some type of improved usability of the 60% and 40% PTCs. She has some language, and we are talking with others, too. There may be ways of optimizing the PTCs as we go down to 60% and 40%.

MR. OSHA: Joe Osha from JMP Securities. Returning to storage, have you have seen anything other than lithium ion used? Has there been any interest in flow batteries? Are all the numbers to which you referred for lithium ion?

MR. GARLAND: We see a few flow batteries and compressed air storage getting installed, but the vast majority of what we look at is lithium ion. The quotes we receive for the other technologies are still not competitive.

MR. GRIMBERT: Ditto.

MS. BARROW: Deanne Barrow with Norton Rose Fulbright. The Federal Energy Regulatory Commission just made reforms to its generation interconnection process and some might benefit storage and the co-location of storage with wind, particularly storage that can use surplus capacity from existing wind farms. Do you think that will lead to more projects and more storage?

MR. GARLAND: The big issue is price. Where can you make the economics work? We think you can probably qualify batteries if you still had the Treasury cash grant for wind projects, but if you don't, you are at a disadvantage compared to solar where an investment tax credit can be claimed on not only the solar project, but also the battery.

MR. GRIMBERT: That is one aspect. There are two other aspects. When you do a battery on solar, you can charge your battery with your surplus energy. */ continued page 24*

Wind Industry

continued from page 23

Basically your battery has 105% efficiency. The second thing is that solar is very predictable. You have a cycle a day. By adding a battery, you simply extend the period during the day that you can supply solar electricity.

The problem in wind is that if you have five days of wind. You have loaded up the battery after six hours, you wait for four days, and then you have five days without wind. So you unload your battery for six hours, and then you are done.

The problem is that wind is not as predictable. Wind has a tremendous advantage because there is not so much cannibalization on price of wind on wind. You have more diversity. That is great, but that does not make it as palatable to battery storage. Battery storage will grow with solar first, and we will find areas like the Texas panhandle where storage makes sense for wind, but most of the activity in the next five years will be in solar. ◎

Cap on Interest Deductions Explained

by Keith Martin, in Washington

The Internal Revenue Service filled in detail in late November about how a new cap works on the interest expense that a company can deduct each year.

The cap has the potential to make borrowing more expensive.

It was part of the tax reforms that the US adopted at the end of December 2017.

Starting in 2018, interest on debt cannot be deducted to the extent a company's net interest expense exceeds 30% of its adjusted taxable income. Its income for this purpose means income ignoring interest expense, interest income, NOLs and — only through 2021 — depreciation, amortization and depletion. Thus, the limit on interest deductions is less likely to come into play through 2021 than after when the 30% will be 30% of a smaller number.

There is uncertainty about whether power companies can add back depreciation through 2021 to income for calculating the cap. The IRS said that depreciation that is treated as a cost of producing "inventory" is not added back to income. The IRS takes the position that electricity is inventory.

The limit is on net interest expense. Interest expense is first netted against any interest income for the year. The cap limits the deduction for what remains.

Any interest that cannot be deducted in a year can be carried forward indefinitely.

The limit on interest deductions does not apply to any business with average gross receipts of $25 million or less.

It does not apply to regulated public utilities. It is elective for real estate businesses.

Congress estimated that 95% of businesses will not be affected through 2021.

The limit is calculated at the partnership level where a project is owned by a partnership. Any interest that cannot be deducted by the partnership because of the limit is allocated to the partners and held by the partners for use solely to offset any future "excess" income they are allocated by the partnership.

There is no transition relief for existing debt. Interest on debt that was already in place when the cap was enacted is subject to the cap just like interest payments on new debt.

Interest

The IRS issued proposed regulations in late November to implement the cap. It is collecting comments on its proposals through late March.

It defined interest payments that are subject to the cap more broadly than some in the market expected.

Commitment fees on loans are considered interest for this purpose to the extent the financing is actually provided.

"Guaranteed payments" that a partnership makes to partners for use of capital are considered interest subject to the cap. A guaranteed payment is an amount the partnership is required to pay a partner for use of capital the partner contributed or for services regardless of whether the partnership has income to cover the payment. The partnership deducts such payments, unlike normal cash distributions where there is no deduction at the partnership level. Some tax counsel have speculated that preferred cash distributions to a tax equity partner could fall into this category, but the preferred cash distributions would have to be a debt by the partnership to the partner rather than simply a first use of cash to the extent there is cash to make the payment.

Swaps are taken into account when determining how much interest was paid. Thus, a company that takes on floating-rate debt, but enters into an interest-rate swap under which it makes fixed payments to a swap counterparty for floating payments back, is considered to have made the fixed interest payments for purposes of the cap.

Prepaid rent in a sale-leaseback transaction is considered a loan by the lessee to the lessor that is worked off over the lease term. The imputed interest on such a loan may not be deductible by the lessor unless there is room within its 30% cap.

Partnerships

Many projects in the project finance market are owned by partnerships.

The cap is applied at the partnership level.

The partnership calculates its income or loss for the year. The income or loss is allocated to the partners. In the process, the partnership must determine its cap on the amount of interest expense it can deduct. It determines that by first calculating its "adjusted taxable income" or what the IRS calls "ATI."

Its ATI is its taxable income calculated normally and then adjusted by backing out interest expense, interest income, NOLs and — only through 2021 — depreciation, amortization and depletion.

The cap on interest the partnership can deduct is 30% of ATI plus any interest income the partnership earned during the year.

To the extent there is room within the cap to deduct all the interest the partnership incurred during a year, then interest deductions at the partnership level are simply reflected in the shares of partnership net income that are allocated to each partner.

If the partnership had room within its cap to deduct more interest, then the extra room is called "excess taxable income."

If the partnership does not have room within its cap to deduct all the interest it incurred, then the interest it could not deduct is called "excess interest expense."

The partnership must report to each partner at the end of each year the partner's share of ATI at the partnership level, the gross interest expense and gross interest income at the partnership level, and any excess taxable income (unused cap) or excess interest expense (interest that the partnership could not deduct because of the cap).

The calculations then move to the partner level.

First, each partner adjusts its "outside basis" in its partnership interest by its share of the ATI at the partnership level minus the gross partnership-level interest expense that it is allocated. For example, if its share of partnership ATI is $50 and its share of partnership-level interest expense is $20, then its outside basis goes up by $30, even if the partnership has a cap that allows only $15 of the $20 in interest expense to be deducted when calculating partnership income.

Next, each partner must determine whether it can use any excess interest expense (interest that could not be deducted by the partnership due to the partnership-level cap).

It must jump through three hoops to do so.

First, it must not have run out of outside basis. If the partner has run out of outside basis, then use of the excess interest deduction is suspended.

"Outside basis" is a way of tracking what each partner put into the partnership and is allowed to take out. It is one of two metrics for doing this. (The other is called a "capital account.") A partner cannot deduct losses allocated to it by a partnership once it has run out of outside basis. Use of the losses is suspended until the partner has more outside basis. Two things give it more outside basis: being allocated income in the future by the partnership or making a capital contribution to the partnership.

Second, even if the partner has enough outside basis to use the excess interest expense allocated to */ continued page 26*

Interest Cap

continued from page 25

it by the partnership, it must wait until it is allocated excess taxable income against which to use the excess interest expense. Basically, it can only deduct the extra interest as the partnership allocates it unused partnership-level cap in a future year.

Third, the partner must do its own 30% cap calculation to determine whether there is room within its own cap to deduct the amount. The partner does this by calculating its own adjusted taxable income or ATI, but in so doing it ignores everything allocated to it by the partnership other than any allocation of "excess taxable income" (unused cap at the partnership level). For example, a partnership with $200 in ATI can deduct up to $60 in net interest expense (30% x $200). Suppose it is has only $30 in interest expense. It will have used only half of its cap for the year. The unused half of the cap translates into $100 in ATI. The $100 is "excess taxable income."

If a partner sells its entire partnership interest before it is able to deduct the excess interest deductions it was allocated by the partnership, then the un-deducted amount is added back to its outside basis immediately before the sale. This reduces its gain on sale.

The IRS said interest expense and income on a loan from a partner to a partnership should be ignored in the cap calculations. It asked for comments.

It also asked for comments on how to apply these rules to tiered partnerships.

Utilities and Real Estate

The regulated utilities made a trade with Congress. They gave up the ability to write off the full cost of new and used assets put in service during the year — called a 100% "depreciation bonus" — in exchange for being freed from the cap on interest deductions.

The trade applies to the extent a company is engaged in the business of furnishing electricity, water, sewage services, local gas or steam distribution or pipeline transportation of gas or steam where the rates at which these services are provided are established or approved by a federal, state or local government agency on a cost-of-service or rate-of-return basis. Electric cooperatives are treated as regulated utilities for this purpose if their rates must be reviewed by "the governing or ratemaking body of an electric cooperative."

Real estate businesses can take the same trade. They do so by filing an election with the IRS.

Groups of corporations that join in filing a consolidated federal income tax return are treated as a single company.

This creates complications. Many utilities have a utility holding company that joins in filing a consolidated return with a regulated utility subsidiary. The group usually also has other companies engaged in non-regulated businesses.

Interest deductions are capped to the extent the interest relates to the non-regulated business. This requires calculation of the ATI of the non-regulated businesses and a determination on which side of the company the interest expense resides.

The proposed IRS regulations take the position that money is fungible. Therefore, interest expense anywhere in the consolidated group must be allocated between the regulated and non-regulated parts of the group in the same ratio as the assets owned by each part. The group looks at its adjusted bases in the assets. The IRS felt this would be easier for companies to track than using the relative fair market values of the assets.

Depreciation for adjusting asset bases in equipment is calculated under the old depreciation rules immediately before MACRS depreciation was enacted in 1986. The original cost basis is used for land, buildings and other "inherently permanent structures" like gas pipelines or electric transmission lines, wind towers, and steel uprights and underground wires at utility-scale solar facilities. The basis is

Independent power companies may face a lower cap on deducting interest than other types of businesses.

not reduced as buildings and other "inherently permanent structures" are depreciated.

Assets are ignored until they are placed in service. Thus, no interest is allocated to projects while they are still under construction.

The only interest expense that does not have to be allocated across all assets is interest on "qualified" nonrecourse debt. This is debt, in theory, that was borrowed on a nonrecourse basis secured solely by particular assets. It is not considered fungible. However, it is hard for most nonrecourse debt to qualify in practice.

All other deductions are allocated to the part of the business to which they are directly related. An example is property taxes.

Intercompany transactions between members of a consolidated group are ignored. Stock in a subsidiary that is also part of the consolidated group is not counted as an asset when allocating interest expense between the regulated and non-regulated parts of the group by asset basis.

If 90% or more of the company's tax basis in assets in a year is in either the regulated or non-regulated part of the business, then the company can treat all the interest that year as tied to the 90%-or-more side of the business.

Infrastructure Projects

The IRS said in a revenue procedure released the same day as the proposed regulations that public-private partnerships undertaking certain kinds of infrastructure projects can opt out of the interest cap.

Any such project opting out will be treated like a real estate business, which also has the option to opt out. Depreciation on any project that has opted out would have to be taken on a straight-line basis over a longer "class life" for the type of assets rather than the normal depreciation period. However, this would be required anyway to the extent the project is financed with tax-exempt bonds.

The project would have to jump through several hoops to qualify to opt out.

First, it would have to be a type of project that can be financed by issuing tax-exempt private activity bonds. Examples are hydroelectric power plants, power plants whose electricity remains within a two-county area or one city and one county, local district heating and cooling facilities, airports, roads, ports and high-speed intercity rail lines.

Second, the private company undertaking the project would have to have a contract with a government with a term longer than five years that requires it to build, manage or operate and maintain the project. The project must be made available for use by the general public.

Third, the assets must be owned by a government or, if they are privately owned, they cannot be used in a regulated utility business whose rates are regulated by a body like a state public utility commission or the Federal Energy Regulatory Commission on a cost-or-service or rate-of-return basis. However, the rates charged the general public for use of the assets must be subject to regulatory or contractual control by a government or to government approval.

The conditions for opting out are in Rev. Proc. 2018-59. ◎

Buying Assets From Financially Distressed Sellers

by Christy Rivera, in New York

When a developer that has sold assets later files for bankruptcy, many of its transactions that it engaged in during the time leading up to its bankruptcy filing will be scrutinized in the bankruptcy case.

Many times, a potential buyer of assets is aware that a developer is struggling financially, and the buyer may be worried about challenges that could be asserted later to the purchase of the project that it is considering.

The concern that we most frequently get asked about is "fraudulent conveyance" risk.

What is "fraudulent conveyance" risk?

If a developer were to file later for bankruptcy, it may try to unwind a payment or asset transfer made to another party before the bankruptcy filing under an "actual fraud" theory or a "constructive fraud" theory.

The United States bankruptcy code offers two different avenues that a trustee or debtor in possession may pursue to unwind a transfer of assets.

Section 548 of the bankruptcy code lists the elements for unwinding a fraudulent transfer that was made, or an obligation that was incurred, within the two years before filing the bankruptcy case.

Section 544(b) of the bankruptcy code allows fraudulent transfers made before the two-year reach-back period of section 548 to be unwound in certain circumstances by relying on a longer reach-back period under whatever state or other non-bankruptcy laws apply to the transaction. Examples of other laws that might apply are the Uniform Fraudulent Transfer Act or the Uniform Fraudulent Conveyance Act at the state level. The reach-back periods to challenge transactions under state law are for four or six years and sometimes even longer.

Creditors of the developer may sue to unwind an asset sale or payment obligation that is considered a "fraudulent conveyance" even if the developer does not eventually file for bankruptcy.

Fraudulent Conveyance

When a bankrupt company goes into liquidation, a trustee or the company itself as the "debtor in possession" may try to claw back money into the bankruptcy case.

The trustee — or, in appropriate circumstances, a creditor — may unwind any transfer of the bankrupt company's property within the relevant reach-back period if it can be shown that there was actual fraud. The trustee or creditor would have to show the transfer was made with actual intent to hinder, delay or defraud the company's creditors.

This type of fraudulent conveyance claim is less likely to be an issue for someone who bought assets from the bankrupt company than a claim that there was a "constructive" fraudulent conveyance.

Constructive fraud does not require any evidence of intent. The trustee or creditor trying to unwind an asset sale would have to show two things.

The first is the now-bankrupt company did not receive "fair consideration" (for claims governed by a state Uniform Fraudulent Conveyance Act) or "reasonably equivalent value" (for claims brought under the US bankruptcy code or a state Uniform Fraudulent Transfer Act) for the assets.

The trustee or creditor would also have to show that the developer was insolvent at the time of the asset sale, became insolvent or was left with unreasonably small capital as a result of the asset sale, or intended or believed that it would incur debts beyond its ability to pay such debts as they matured.

Both elements are necessary for a constructive fraudulent transfer claim.

This means that so long as a seller receives what is determined to be roughly equivalent value in exchange for the assets, an asset sale will not be unwound as a fraudulent conveyance, even if it is later determined that the seller was insolvent at the time of sale. Likewise, an asset sale by a solvent and adequately capitalized seller is not subject to unwind as a constructive fraudulent conveyance even if the seller did not receive fair value in exchange for the sold assets.

There is no precise formula to determine whether a seller received reasonably equivalent value or fair consideration for an asset. Instead, the transfer is reviewed in its entirety, with a court taking into account all the facts and circumstances surrounding the transfer. To that end, while a buyer may not be able to completely avoid any subsequent review of the transaction, it can take certain actions to help reduce the likelihood that a bankruptcy trustee or creditor will be able to unwind the sale later.

Below are some suggestions that will help protect interested buyers from potential fraudulent conveyance claims, as well as other general risks that exist in connection with buying assets from a distressed seller.

Tips When Buying Assets

First, do your homework on the assets. This serves at least two purposes.

First, and more generally, it may very well be the case that the seller will have limited (if any) business operations and liquidity after the proposed sale transaction, meaning that you should not assume that you will be able to recover any losses from the seller through breach of representation or warranty claims under the sale contract.

Buyers of assets from financially distressed sellers should take steps to reduce risk that the sales will be unwound later.

Second, as part of your diligence, get a better understanding of the financial struggles that the seller is facing. Is the seller late with bill payments? Is it having trouble paying debt service on its existing debt? What other creditors does it have? Depending on how dire the financial condition is, it may be wise to tell the seller that you are only willing to purchase the assets through a "363 sale" in bankruptcy. (For more information on 363 sales, see "Asset Sales in Bankruptcy" in the February 2010 *NewsWire*.)

Second, sweetheart or insider deals with a distressed seller are not a good idea. The benefit of paying what may be a below-market price is significantly offset by the fraudulent conveyance risk that has been introduced to the transaction.

The best way to avoid a fraudulent conveyance challenge to an asset purchase is to ensure that you have paid reasonably equivalent value for the assets. If the developer has run a sale process for a project, working with a banker and marketing the project to the right audience of potential bidders, then the ultimate price that the developer agrees to with the winning buyer is going to be reasonably equivalent value for that project. The seller will have received what the market is willing to pay.

It may be that what the market is willing to pay is still less than the developer could have received if it were not in some financial distress, but that will not change the result — when the developer chose to sell the project, it received what the market was willing to pay for it, which should eliminate fraudulent conveyance risk.

SunEdison sold many project assets outside of its bankruptcy case through a market process, and this process gave buyers some comfort that the SunEdison subsidiaries that made the sales, and that had not filed for bankruptcy, would not later file and be able to challenge those asset sales.

Third, whether or not a project has been put out for bid, a buyer should consider requiring the seller to provide a fairness opinion in connection with the proposed transaction. That opinion is typically prepared by an investment bank, and provides an opinion as to whether the proposed sale price is fair to the seller. If the transaction is later challenged as a fraudulent conveyance, the fairness opinion will serve as evidence for the buyer that the price it paid provided the seller with reasonably equivalent value, thereby making it difficult for the sale to be unwound.

Getting a solvency opinion, if possible, is helpful for the same reason. If the sale is later challenged, the buyer can use the opinion as evidence that the seller was not insolvent at the time of the transfer, which thereby undercuts the other allegation that a bankruptcy trustee or creditor would have to prove (that the seller was insolvent at the time of transfer) in order to unwind the sale later on grounds that it was a fraudulent conveyance.

If an opinion is not possible, then obtaining an appraisal or expert valuation of the project can also provide comfort to the buyer that it is paying fair price.

Fourth, the buyer should memorialize its discussions when negotiating the sale price and related agreements with the seller. This will happen naturally to some extent through emails between the parties and their counsel and to changes in the documentation. Phone calls should also be memorialized afterwards, and this also happens to some extent already when people send emails updating others on their team of the results of phone calls. */ continued page 30*

Distressed Sellers

continued from page 29

Buyers should be more systematic, though, about memorializing the negotiations if they have any concern about the seller being in financial distress. The emails and other documents should also be saved in files with the related sale documentation, so that the buyer has them if the transaction is later challenged. Remember that if the transaction is later challenged, a court will take into account all circumstances surrounding the sale, so if there are unique challenges or considerations that are affecting the sale price, including that should be considered value to the seller, make sure that those are documented as well.

Fifth, consider whether it makes sense to provide for a "holdback" for a portion of the purchase price. These funds can be used to cover any losses to the buyer if there are breaches under the sale agreement. Absent such a holdback, if the seller were to file for bankruptcy after the sale, then any claim by the buyer under the sale agreement for indemnification or a purchase price adjustment will typically be treated as an unsecured claim after a a bankruptcy filing, frequently leading to a recovery of only pennies on the dollar. Holding back some of the purchase price, or putting it in escrow, ensures that the buyer will not be left without any recourse against the seller.

Sixth, limit as much as possible the time between signing and closing the asset purchase. If the seller were to file for bankruptcy after signing but before closing, the seller will have the option to "reject" (in essence, terminate) the transaction in its bankruptcy case so that it does not need to proceed with closing.

This same advice applies if there are multiple agreements that will be entered into as part of the transaction. These agreements should be executed as much as possible at the same time. In addition, include language in each agreement that states the parties' intention that the agreements should be integrated and treated as a single agreement and transaction. The goal is to limit the seller's ability in a subsequent bankruptcy case to cherry pick among the agreements to keep those that favor the seller, but reject those that it views as less favorable.

Finally, when structuring the sale, if possible consider arranging it as a sale of assets and not equity. While this may not always work because a purchase of the project company is unavoidable, when structured as an asset sale, the buyer is more likely to avoid inheriting all of the debts of the seller relating to the project. While there are exceptions, the general rule is that a buyer of assets (as opposed to equity) will not be liable for the debts of the seller related to the assets. ◎

Current Issues in Community Solar Projects

The community solar business model is still relatively new. The developer of a small utility-scale solar project signs up customers who pay it subscription fees. The electricity goes to the local utility. The customers receive bill credits for the electricity from the utility. Projects are getting financed, but usually in portfolios of multiple projects. Most of the activity to date has been in Colorado, Minnesota and Massachusetts, but the model is expanding to other states.

Three community solar developers and one aggregator of community solar customers talked at the Infocast Community Solar 2.0 conference in New Orleans in October about the how the basic business model is evolving and current issues in the market.

The panelists are Rick Hunter, CEO of Pivot Energy Solutions, Joel Thomas, manager of community solar for independent power developer Community Energy, Inc., Jesse Grossman, CEO of Soltage, and Laura Pagliarulo, senior vice president for community solar and commercial sales at CleanChoice Energy. The moderator is Keith Martin with Norton Rose Fulbright in Washington.

New Trends

MR. MARTIN: Rick Hunter, what new trends do you see this year in the community solar market?

MR. HUNTER: More projects are providing electricity to low and moderate income customers.

It is a critical proving time for the industry around customer acquisition. A lot of new developers have gotten into the space. They are all trying to figure out how to nail down the revenue piece and feel confident about it. That has led to a rise of third-party customer acquisition firms. There is a lot of attention being paid to whether those firms can really sign up customers at scale.

MR. MARTIN: Are you able to finance projects with low and moderate income customers without credit support from someone like a green bank?

MR. HUNTER: Yes. There are a bunch of ways to skin the cat. It depends on whose money is being put to work and how they want to see it structured. We have been working with housing authorities as either a backstop or at least a conduit for connecting to the low-income community.

MR. MARTIN: Joel Thomas, what new trends?

MR. THOMAS: New states that are embracing community solar are requiring residential customer participation. The early markets in Colorado and Minnesota involved largely commercial customers. Now states are requiring or placing very big incentives for residential participation.

MR. MARTIN: What percentage residential?

MR. THOMAS: It is usually 60% in the northeastern states.

MR. MARTIN: So each project must be at least 60% residential.

MR. THOMAS: I should say small subscribers as it could be small commercial customers, but it typically goes to residential.

MR. MARTIN: Is that by number of subscribers or capacity?

MR. THOMAS: Percentage capacity of each project.

MR. MARTIN: Next trend?

MR. THOMAS: New states that are adopting community solar are putting in program caps so that the programs are more than pilots, but we are not talking about a whole lot of megawatts. In New Jersey, the cap is 75 megawatts per year as just one example. The programs are a little smaller to start than we would like.

MR. MARTIN: Is the cap a limit on participation by community solar projects in net metering programs? How do the caps work?

MR. THOMAS: Yes. It is a cap on projects that can get bill credits to sell to customers, which is what you need to make a community solar project work.

MR. MARTIN: Jesse Grossman, new trends.

MR. GROSSMAN: A whole ecosystem of companies is emerging that bundle solar residential customers and some commercial customers and provide the full package for folks like us that want to own projects for the long term, but do not necessarily want to administer 100 to 150 residential customers per megawatt of capacity.

Separately, people are moving from other parts of the distributed energy sector to serve this space. Utilities are starting to administer their own community solar programs by offering their customers a green subscriber choice. The utilities are playing offense to prevent customers from defecting to other electricity suppliers.

Another interesting theme is the efforts being made to get capital into this space. From tax equity to debt even to sponsor equity, people are wrestling with how to put this type of project into the standard project finance box. There is no consensus yet on best practices or the right market outcome for this sector.

MR. MARTIN: Laura Pagliarulo, your company focuses on aggregating customers. How are you compensated? By the customers? By the community solar developer?

MS. PAGLIARULO: We are compensated by the asset owner. We have a contract with it for upfront customer acquisition and then longer-term management. It is a nascent market. Even with 100 megawatts under management, we have not reached any kind of real scale. There is a lot of emphasis now not only on how to acquire customers, but also on how to retain them.

MR. MARTIN: Does the asset owner pay a percentage of the subscriptions collected? How does it work?

MS. PAGLIARULO: It depends on when we come into the project. We get projects at different stages. We prefer not to work on projects that have already been subscribed. When we take over asset management, we put a lot of emphasis on the sales process. The better the sale, the more likely the customers are to stay. Often it is a three-way negotiation among the developer, the asset owner and us where the developer gets paid a little less if we are paid more on upfront acquisition.

MR. MARTIN: Jesse Grossman, what percentage do customer aggregators get?

MR. GROSSMAN: It varies. Different customer aggregators charge varying amounts. The charges are usually broken down into two areas. One is an upfront fee or customer acquisition cost that we have seen run anywhere from $10,000 to $25,000 per megawatt, and then there is a long-term asset management fee for managing churn — folks drop out, having a phone line to pick up if customers are curious about what is going on or have issues with their bills — that really ranges all over the place, but is also on a capacity basis.

MR. MARTIN: Laura, are there any new trends you see in the market besides what others have already mentioned?

MS. PAGLIARULO: Three and a half years ago when I started in this space, the typical financier wanted a long-term contract with essentially liquidated damages that would never fly in the residential market. It would raise a lot of consumer protection concerns. Now there is more flexibility in terms of percentage of the project that must be subscribed by the time construction starts.

There is also more flexibility in the contract length. There is more flexibility in termination fees, especially now that the Minnesota attorney general has suggested that a termination fee of $1,000 is too high. Some financiers are getting a little more comfortable with these types of assets.

/ continued page 32

Community Solar

continued from page 31

Basic Proposition

MR. MARTIN: Going back to the developers, Rick Hunter, what is your basic business proposition, and has it changed in the last year?

MR. HUNTER: It depends on the market and on whether we are focused on residential or commercial subscribers.

For residential, the typical pitch is the customer will receive an economic benefit while at the same time doing something good for the environment. For commercial, we emphasize the economic benefits and talk though the hedge component in more detail.

MR. MARTIN: So residential subscribers are not as focused as commercial subscribers on the math. What is the typical contract term? Does it differ for residential versus commercial?

MR. HUNTER: It varies market to market. It varies investor to investor. Where we are seeing the most movement today is in terms of how quickly we can get away from credit scores and long-term contracts on the residential side while holding on to a reasonable cost of capital. Everyone is pushing in that direction. We will find out pretty quickly in the next year or two if we can find that right balance.

MR. MARTIN: What is preventing you from moving there immediately?

MR. HUNTER: Getting investors comfortable with a new space that is untested and has no data that can be used to justify assumptions. It will be a process.

MR. MARTIN: What contract term are you using today: 10 years? 20 years? Do you give a 15% discount to the customer from the local retail rate?

MR. HUNTER: We are pushing to a year or less.

MR. MARTIN: Trying to move under a year.

MR. HUNTER: We are pushing there. We are not there yet.

MR. MARTIN: Where are you now?

MR. HUNTER: Five or more. It depends on the market and who the subscriber is. It probably needs to stay at 20 years for municipalities, universities, schools and hospitals, but for residential, I think the market may settle out in the five- to 10-year range. We will see.

MR. MARTIN: Are you selling subscribers a percentage of the output from the solar array or bill credits?

MR. HUNTER: It depends on the market. [Laughter] Usually the subscriber is buying bill credits.

MR. MARTIN: How much of a discount are you giving people to make a sale?

MR. HUNTER: I hate to sound like a broken record, but it depends on the market. We find we need to offer at least 10% savings in year one to move the needle.

MR. MARTIN: Joel Thomas, same questions: what contract term are you using and what discount are subscribers receiving on electricity compared to the price on offer from the local utility?

MR. THOMAS: Our contracts are usually 20 to 25 years, and the discount is 10% or greater, but typically not much more than 10%.

Perhaps this goes in the category of new trends, but a year or two ago, no shops existed to do residential customer acquisition. Developers did it on their own. Third parties are now offering to do it as a service. As a consequence, we are no longer doing our own residential customer acquisition. We find our own commercial customers, but not residential.

In fact, residential is also different in that the offtake can come later in the process. With a utility-scale project, the largest defining moment of value creation is when you land an offtake contract. With community solar, it is more of a marketing process and so there is a little less value creation on getting that offtake. There is the option of selling a project for a potentially meaningful value before the residential customers have been lined up.

MR. MARTIN: What happens if a customer wants to cancel?

MR. THOMAS: He has to pay a termination fee, but states like New York are placing limits on termination fees.

MR. MARTIN: The residential rooftop companies are moving to longer-term contracts. They were at 20 years. Some of them are now moving to 25 years because they can raise more capital against a 25-year contracted revenue stream. Yet you and Rick Hunter say community solar developers are moving in the opposite direction. Why does that make sense?

MR. THOMAS: We do not think our customers want to be locked into 20- and 25-year contracts. The average homeowner moves every seven years. I agree with Rick Hunter that community solar contract terms are probably going to land in the five- to 10-year range since that is the term of the debt on these projects.

MR. MARTIN: Jesse Grossman. Same questions: contract term and business proposition.

MR. GROSSMAN: That is one of the hot topics in this space today.

We come from a traditional project finance mindset, so the

Experienced developers suggest probing in four or five areas when financing a community solar project.

longer the contract term, the better. We have been able to maintain longer terms, but we see pressure to go shorter over time. We have a large diversified portfolio, so we can wrap in 20 or 30 megawatts of residential community solar with short tenors as part of a larger portfolio.

We are still in an interesting early stage in the community solar market. There is a wall of capital chasing deals. Some banks and investors may be willing to relax their underwriting standards a bit just to get money into this space. The traditional project finance lenders have more trouble, but some regional banks and specialty debt shops are willing to assume a longer revenue stream than just the contract term for purposes of debt sizing. However, the rates can start to look like equity.

MR. MARTIN: Are you able to finance standalone community solar projects?

MR. GROSSMAN: We have not tried to do a standalone portfolio of community solar projects that are all residential. We have done it with muni and C&I customers, and that has not been a problem, but I am glad we have a larger portfolio of long-term creditworthy assets that we can combine with residential community solar to raise capital.

MR. MARTIN: Rick Hunter, have you been able to finance standalone community solar portfolios?

MR. HUNTER: They have all been portfolios to this point. The time is coming when there will be more standardization and when owners will get a little more comfortable with smaller and smaller portfolios or even one-off projects because they know the partner with whom they are transacting and can do it efficiently.

MR. MARTIN: How many projects do you need in a single portfolio today to have a financing?

MR. HUNTER: Even though we have not done it, I think there are single projects getting done.

MR. MARTIN: Joel Thomas, have you been able to finance community solar projects on a standalone basis?

MR. THOMAS: Yes, but the only cases where that has been true is where we own the projects ourselves and act as the tax equity and backstop the debt with our corporate balance sheet. That is what it takes to finance a standalone project.

MR. MARTIN: So that is not a project financing, but a borrowing on credit.

MR. THOMAS: Correct. It is recourse debt.

MR. MARTIN: The community solar tax equity and debt financings we have seen have been portfolios of 18, 20, 22 projects at a time.

MR. THOMAS: Sounds right.

MR. MARTIN: Laura Pagliarulo, you are a customer aggregator. What contract term and discount do you need to offer to attract customers?

MS. PAGLIARULO: I agree with Jesse. We have sold one-year deals, but we prefer five years and longer. We are selling five-year deals, three-year deals, 25-year deals. You want customers to know that they are locking into something for at least a five-year term. It makes our role easier. It keeps the portfolio more stable.

The first year of any portfolio is always the most tumultuous. The most churn occurs when customers start getting that first bill.

Likewise, I like the idea of reducing standards for FICO. This has to be a fungible product. Community solar is unlike rooftop. An asset owner or tax equity investor about to deploy big dollars to put assets on rooftops needs to see some sort of credit value in the customer base. I don't think that will go away anytime soon.

I think there are alternative scores that are probably a better indicator of how likely a customer is to pay bills.

Turning to the value proposition, customers are more focused on the fee they must pay to terminate a contract than the contract term. When you are selling to a customer at the door, he or she wants to know how much am I going to save and what do I need to do if I want to get out of it? So the days of $500 and $1,000 termination fees are gone. We / *continued page 34*

Community Solar

continued from page 33

probably will not work on a project unless we can sell a termination fee of $150 or $250. We have really good relationships with state attorneys general and that is our sense of what is becoming the acceptable range for termination fees.

Customer Attrition

MR. MARTIN: Let me throw out a few statements for the whole panel. Correct them if they are wrong. Developers are assuming customer attrition rates of about 5% a year in financial models, but in fact the attrition rates have been less than 1%. However, there is not much data: perhaps three years at most. True or false?

MR. GROSSMAN: True.

MS. PAGLIARULO: It depends. We worked on a portfolio in Minnesota where the customers were subscribed and were hanging out for more than a year before the project came on line. We saw 25% attrition. Those are not customers we sold. We inherited that project. It depends, in my view, on how long ago they were sold versus when the project comes on line. We are a society that expects instant gratification.

MR. MARTIN: That is certainly true. How long does it take to replace customers when you have 25% attrition?

MS. PAGLIARULO: We replace customers fairly quickly, but depending on the size of the project, if you have a 40-megawatt portfolio in Minnesota and 25% of the customers drop out, it takes some time to replace that 25%.

MR. MARTIN: Next statement. The customer acquisition cost in this market needs to be about 5% of the project cost for the market to work, but it is currently higher, at least where developers go door-to-door trying to find customers. True or false?

MR. THOMAS: True.

MR. GROSSMAN: Absolutely true. We have seen instances where folks have tried to price their services at higher than the marginal benefit of acquiring a community subscriber.

MR. MARTIN: In the rooftop solar market, the customer acquisition cost is as high as 25%. Rick Hunter, you are picking up the microphone. Where is your cost?

MR. HUNTER: I was going to make a more general comment. One of the key things for community solar as an industry to accomplish is to drive down the customer acquisition cost. We cannot pay $1,000 a customer and make the business model work. The cost should be lower. With a $25,000 rooftop system, you would expect to pay maybe $1,000 to acquire that kind of customer because the customer is making a much bigger commitment. Part of the reason we want these shorter-term contracts is so that people have an easier time saying yes and the acquisition cost goes down. Community solar today is more expensive than it should be. If we want to see sustainable growth, we have to optimize up and down the value chain and, to me, customer acquisition cost should be the major focus now.

Utility Hostility?

MR. MARTIN: Are utilities hostile to community solar?

MR. HUNTER: Is this going to be posted? [Laughter]

MR. MARTIN: Depends on what you say. {Laughter]

MR. HUNTER: I don't know. [Laughter]

MS. PAGLIARULO: I think in markets like Minnesota, the utility has been great to work with. Xcel has established the infrastructure. In states like Massachusetts when you cannot assure when a customer will receive his or her bill credits, the utilities might not be openly hostile, but they are making our ability to do business difficult. Every state is different.

MR. THOMAS: The main way that we engage with utilities is on interconnection. Utilities are not hostile as much as they do not have a very strong incentive to invest in their distributed generation divisions. The lack of

Customer attrition rates are low on three years of data. Customer cancellations spike if there is a long delay before a project starts operating.

incentives to put the best foot forward means things tend to move slowly.

MR. MARTIN: One of the challenges in this market is the mechanics of billing. How would the market change if the utilities did all the billing?

MR. GROSSMAN: It would make the market a lot more efficient. Utilities across the country have different strategies. Some are pro innovation and some are putting their heads in the sand. Dominion and a few other utilities are doing green purchasing programs in an effort not to lose customers to renewable energy suppliers, so they are allowing them to sign up for community solar services and then entering into large PPAs for renewables. This is a fairly efficient structure.

MR. MARTIN: If utilities handle all the billing, will community solar developers complain that they have no contact with the subscribers? The subscribers will contact the utility to drop out. You won't hear about it.

MS. PAGLIARULO: Our experience with utility consolidated billing with POR — purchase of receivables — is excellent. If we could get that in place, everyone would be happy. If there were utility consolidated billing without POR, the utility gets paid first. If a customer defaults by paying just a little bit, the utility takes that to offset its cost first and we have no ability to go after the customer for payment of any type. So not only do we not have visibility in terms of who is late in a timely manner, we also do not control the payment flow. There is no ACH setup. There is no credit-card information on file. They need to go together — POR plus consolidated billing. Otherwise, there would be a lot of lost revenue.

MR. HUNTER: Utilities need to own a bigger piece of this space. They already have the customers. We would do better to try leveraging its relationships and the trustworthiness of the utility's brand.

Lots of companies are trying to pitch to consumers who have never heard of them. They are spending tons of money to create brand recognition. There is hostility from utilities, and rightly so, because we are taking their customers and they are not getting any credit for enabling this investment in clean energy. It is some fly-by-night company that just came on the scene and is taking their customers from them.

That model is not sustainable. I think over time you will see a trend, starting with some of the more progressive utilities, of modeling community solar after efficiency programs where the utility hires a third-party implementer who does the work under the utility brand of developing projects in a way that costs less money. Our company is preparing with that future in mind.

MS. PAGLIARULO: What Rick just said makes sense in regulated markets. But the truth is most of the community solar states with prescribed programs today are in deregulated markets where the utility is not allowed to have its own community solar or green product offering. States like Massachusetts, Maryland, New York and New Jersey cannot have utility-driven programs. In other markets that are regulated, it makes sense to do things under the utility brand.

MR. GROSSMAN: This is really a credit question. The challenges that we have been talking about — term of contract, type of entity, low and moderate income customers, FICO scores, etc. — are important because there is really no credit or balance sheet that we can look to in traditional ways. This is an area where innovation is needed for this industry to move from tens of megawatts per year in various markets to hundreds of megawatts.

A large balance-sheet entity like a utility or a utility subsidiary could play a role. They could be important intermediaries. The community solar company would have a contract with one of them and what the utility partner does on its side does not matter. The community solar company can then price the project like a 20-year creditworthy investment and revenue stream.

Alternatively, the insurance companies could play a role here if they priced their product correctly. So could the commodity desks of some of the larger banks. I think that is where the market needs to get. We need to get more data and more analytical ability around this space. We are wrestling with a problem that comes down to the creditworthiness of the revenue stream, and this is the most important issue after permitting and interconnection. How are we getting paid?

Where to Probe

MR. MARTIN: Let me ask one more question, and then I will ask the audience whether it has any questions. Suppose you switched sides and you are now working for a bank or tax equity investor thinking of financing a community solar project. Where would you probe first in looking at a project for potential problems?

MR. THOMAS: The first thing I would do is to ask to see a sample customer agreement.

MR. MARTIN: What would you look for once you have the sample contract?

/ continued page 36

Community Solar

continued from page 35

MR. THOMAS: I would look at the rate the customers are being charged in relation to the value that the customers can expect and then develop a view on the likely rate of customer attrition.

MR. MARTIN: So you want a long-term economic advantage to hold the subscriber in place.

MR. THOMAS: Yes.

MS. PAGLIARULO: I would really enjoy the ability to do this for a few days. I would look at the total solution. Managing mass-market customers is like dealing with a five-headed dragon. It is not just about the platform or the sales process or consumer protection, it is looking at everything as a whole. The truth is you have to be able to do everything well and not just one or two things to have a good project.

MR. MARTIN: So you would park yourself at the community solar company for a day or two to see how it is functioning.

MS. PAGLIARULO: Yes.

MR. GROSSMAN: I think Joel gave a great answer and would echo that. I would focus on all the traditional risks plus how solid the revenue stream is.

MR. HUNTER: The deals I know that soured went bad because of poor execution. The subscriptions were not filled in a timely manner.

MR. MARTIN: Would any of you focus, number one, on the status of any net metering debate within the state — these projects do not work without net metering — and , number two, on the aggressiveness of the local utility in trying to package its own community solar offering?

MR. GROSSMAN: Yes, absolutely.

The location is very important in terms of assessing the viability not only for upfront subscription, but also for resubscription over time as the market gets more competitive. We have purchased portfolios in areas that have hundreds of thousands if not millions of potential customers. Some folks drop out. Some folks move. The market must be one where it will be easy to replace departing customers.

We have passed on other portfolios in low population areas where, if minimum FICO scores are required, you are reducing your potential population of subscribers even further. We say to ourselves maybe this area can only handle 10 megawatts of community solar projects. If someone tries to build another community solar project and undercuts me by 5%, then I am sunk from a revenue perspective. Maybe it is an area where a utility is thinking of offering its own program and can do so efficiently.

MR. MARTIN: Audience questions?

MS. PETERS: Kacie Peters with Pivot Energy. My question is about the acquisition piece. If you start signing up residential customers too early, people drop out before the project is built. If you start too late, you run out of time. What has your experience been for that perfect secret sauce? When for residential should you be looking to start the process?

MS. PAGLIARULO: We look at the percentage of the total market that must be subscribed. For example, if someone comes to us with a 20-megawatt portfolio that is 100% residential in Central Hudson or Eversource territory, we look first at what percentage of residential customers we will have to persuade to switch to community solar. Say it is 1% of the total available market. Then we work backwards. We have a sense of how many customers we can sign up a month. That tells us how many months it will take to get the project fully subscribed.

Developers have an advantage because they know the true project schedule. Where things get messed up is if the developer insists things are totally on time and the project ends up being delayed. There must be real transparency and communication. We like to sign up the residential customers as late in the process as possible. ◎

California CCA Outlook

Community choice aggregators in 19 counties in California have become an important market for independent generators. Representatives of three California CCAs talked at an American Wind Energy Association finance conference in San Francisco in October about their needs for additional power and some of the challenges they face. The panelists are Siobhan Doherty, director of power resources for Peninsula Clean Energy, the CCA serving San Mateo County, Don Eckert, director of finance for Silicon Valley Clean Energy, the CCA serving Santa Clara County, and Lindsay Saxby, power supply contracts manager for MCE (formerly known as Marin Clean Energy), the CCA serving Marin and Napa Counties, unincorporated Contra Costa County and several other adjacent cities and towns. The moderator is Deanne Barrow with Norton Rose Fulbright in Washington.

Two regulatory issues are in play in California that will affect community choice aggregators.

Future Procurements

MS. BARROW: Tell us how much wind you have in your portfolios, and give us a sense of your portfolio needs going forward in terms of wind.

MS. SAXBY: MCE has approximately 1,800 gigawatt hours of wind in our portfolio.

We have a pretty solar-heavy portfolio, so looking forward, we will mostly be looking for wind or hydro. There is a lot of opportunity there.

MS. DOHERTY: Peninsula Clean Energy launched in October 2016. Right after we launched, we signed two short-term power purchase agreements with existing wind farms because we wanted to get some renewables in our portfolio right away without having to wait for the whole development cycle associated with a project.

Since then, we have also signed a number of solar PPAs. Now we are looking to get more wind into our portfolio. Our goal over the long term is to be 100% renewable by 2025. We see wind as a great way to balance the solar in our portfolio because of the different generation profile.

MR. ECKERT: Silicon Valley Clean Energy is in the same position as the other CCAs. Wind is a valuable resource for us. Most of our deals right now are short term; however, we just inked a 200-megawatt wind deal with Pattern Energy. Silicon Valley Clean Energy and Monterey Bay Clean Power are purchasing power from the project.

We look forward to including more wind in our portfolio for reasons already mentioned, such as balancing the duck curve and having a diverse generation profile.

MS. BARROW: All three CCAs want more wind in their portfolios. What additional value are you willing to provide wind? Are you willing to pay more or are you using any special criteria when valuing wind?

MS. SAXBY: When we do an RFO, we try and get an apples-to-apples comparison of all the offerings from the different technologies. We look for a net value that takes into account the congestion in the area and how we expect the supplier to perform.

When we do that, we often find that wind performs well and looks competitive against other types of technologies because wind is less likely than solar to be located in really congested areas. So although the PPA prices may look a little higher compared to solar, the net value tends to be competitive to other types of technologies.

MS. DOHERTY: We do a similar evaluation where we look at congestion. We also look at whether there might be any resource adequacy or capacity value where the wind is located and whether that can provide any local / continued page 38

CCAs

continued from page 37

resource adequacy or capacity value for us. We also look at how the wind going to help us fill out our load curve.

MR. ECKERT: About a year ago, we issued an RFO with the CCA that serves Monterey Bay requesting wind, solar and solar-plus-storage. We emphasized that we would not move forward with solar unless it has storage. Wind comes into play as a desired resource because of the time of day when it hits the grid.

We are in the process of looking for more long-term power, but we have some challenges facing us from a CCA perspective. One is on the legislative and regulatory front, where we have new developments such as SB 237 and uncertainty regarding the amount of power charge indifference adjustment or exit charge that our customers have to pay to exit the utility and join the CCA. These two items limit our ability to lock in more long-term deals.

However, if the price is right, we will move forward with long-term deals. Seventy percent of our load in Silicon Valley is commercial and industrial, so even though our customers love 100% carbon-free energy, price does matter.

Competition

MS. BARROW: Don Eckert and Lindsay Saxby, you mentioned your RFO processes. On the first panel this morning, several wind developers said their success rate when bidding on corporate solicitations is really dismal. Are CCAs offering any better results?

MS. SAXBY: MCE received a lot of offers in our last open season. We issued the request for bids in January and received offers in March. It was the largest number of offers that we have ever seen.

MS. DOHERTY: Peninsula Clean Energy did an RFO earlier this year as well. We got quite a few offers. I think we are looking for high volumes pretty similar to what Lindsay mentioned.

The vast majority of offers were for solar, including a lot of solar plus storage, but also a good number of wind offers.

We would love to do more in California. It is important to our board to build new projects in California in order to create jobs in California. We saw fewer bids from California projects than we were hoping to see.

MR. ECKERT: As I mentioned, last October we issued an RFO jointly with the CCA for Monterey Bay. We just wrapped up one of those deals for a wind project, and we are still working on the solar-plus-storage piece.

Overall we had about 90 offers, and ultimately we settled on a wind project that is out of state. The project was cost competitive and had a very attractive capacity factor, and as long as we could impose some of our must haves, such as prevailing wage and environmental considerations, we moved forward with it.

MS. BARROW: You are referring to the Duran wind project in New Mexico. What were the motivations behind picking that project? Please go into some more details for the audience.

MR. ECKERT: We are purchasing 55% of the output, and Monterrey Bay is purchasing the other 45%. One of the reasons we did a joint RFO with Monterey Bay was to attract projects, such as the Duran project, to take advantage of the economies of scale with a larger project.

Also, we thank Pattern Energy for working with us. Unlike MCE, we do not have a credit rating. Pattern is easy to work with on an operational basis as well.

MS. BARROW: How is the power getting transported from New Mexico to California?

MR. ECKERT: There are going to be some risks with transmission, but Pattern Energy has that covered and we are looking

There were 90 bids into a joint solicitation by the Silicon Valley and Monterey Bay CCAs for a long-term power contract.

forward to having the power delivered to us starting in 2025.

MS. BARROW: Does that project qualify for production tax credits at the full rate?

MR. ECKERT: Yes.

MS. BARROW: Lindsay Saxby or Siobhan Doherty, have you signed any recent PPAs?

MS. DOHERTY: Peninsula Clean Energy has not signed any PPAs yet this year due to regulatory uncertainty. As Don Eckert mentioned, the PCIA is an open issue at the California Public Utilities Commission, and our board has asked us to wait until that proceeding is settled because it introduces a lot of risk and uncertainty into our economics.

Once that is settled, we look forward to working with some of the developers that we shortlisted early this year to finalize PPAs.

MS. SAXBY: We are excited to announce that out of our very competitive open season this year, we signed a deal with BayWa r.e. for a 99-megawatt wind project in Santa Barbara.

Regulatory Risks

MS. BARROW: Let's delve a little deeper into obstacles and how you are dealing with those. Siobhan Doherty, you mentioned the regulatory risk with the PCIA and that the Peninsula Clean Energy board is waiting until that is resolved. The Public Utilities Commission is expected to deliver a decision any day now on phase one of the proceeding, but then there is phase two, where the commission will looking at rebalancing the investor-owned utility portfolios. How long before you expect to start seeing your PPA activity pick up?

MS. DOHERTY: We are waiting on the phase-one decision. Once that is finalized, we will obviously remain engaged in the next phase. We work closely with CalCCA on that.

MS. BARROW: Don Eckert and Lindsay Saxby, are you also holding off on long-term contracts until the PCIA proceeding is resolved?

MR. ECKERT: Absolutely. We are concerned about a couple risks. One is the unknown with the PCIA, but also there is a Senate bill, SB 237, that raises the cap on direct access. In Silicon Valley's area, where 70% of the load is commercial and industrial, that could have a big impact on our customer base and load.

The other risk is we index our rates to PG&E rates, and we do not know where those rates are going. If it looks like those rates will move down and, in addition, we have a drop in load, then we will be a little more cautious about moving forward with a long-term deal.

We are also in the process of trying to get a credit rating. We have talked to the Moody's folks that gave one to MCE. One challenge we face is the fact that, unlike regular utilities, we do not have a captive customer base. If we are not price competitive with PG&E, customers can immediately opt out of our service and go back to PG&E. To obtain a credit rating, which is very important to us, we are somewhat then limited on how much of our load we want to tie up with long-term deals.

MS. SAXBY: The regulatory uncertainty is significant.

While we are being strategic about what kind of deals we are looking into, we are still moving forward with procurement. But we are holding off on novel projects, like battery storage, until the impact of the PCIA proceeding is clear.

MS. BARROW: Is the risk associated with the PCIA proceeding that the PUC might establish a methodology that causes the PCIA to increase, which could cause customers to leave CCAs and go back to utilities?

MS. DOHERTY: It influences how tightly we have to budget ourselves if we want to maintain competitive rates. So, yes, the impact would be an increased charge to our customers and we would have to make up for that by buying less expensive energy.

MR. ECKERT: We are in the same boat. We have an index to PG&E's rates that is slightly lower than PG&E to keep us cost competitive. We have our power supply cost and then everything between would be our margin, which then gets eaten up by the PCIA.

We want to get the PCIA right. We do not want to put costs unfairly on the customers that are still with PG&E. We want to have it transparent, be able to understand it, and have some certainty.

Even if the PCIA goes up by 20%, as long as I have some certainty, I can do financial planning and move forward with long-term deals. The regulatory uncertainty is a major issue for us.

MS. BARROW: Don Eckert, you also mentioned SB 237. That is the bill that increases the cap on direct access so more C&I customers can purchase power from electric service providers instead of you guys or the investor-owned utilities. Siobhan Doherty and Lindsay Saxby, is that also a concern that is influencing your procurement activity?

MS. SAXBY: A little bit, but less so than the PCIA because we have a smaller number of C&I customers in our territory than Don has in his.

MS. DOHERTY: We are in the same boat. There is still a cap on direct access, and we don't see a huge exposure, but it is something that we are monitoring for sure. */ continued page 40*

CCAs

continued from page 39

Credit Ratings

MS. BARROW: Lindsay Saxby, one of the big success stories this year for CCAs was MCE obtained a credit rating. What obstacles were you facing without a credit rating? Now that you have one, how have things changed? Did the market consider MCE investment grade even before you got rated?

MS. SAXBY: MCE has been in operation for almost eight years. We have done a lot of deals in that time. We were able to operate very well without a credit rating. We got the developer community comfortable with our financial statements, our strong reserves and our good track record of working with the developers.

There was an internal discussion at the very end when we thought we would probably get an investment-grade credit rating, but we discussed whether we even needed it. If it goes down, there is a negative impact, and we have been able to contract pretty easily without it. In the end, we went ahead. It happened after our open season process, but in the future, we hope it will lead to lower power prices that we can pass through to our customers.

MS. BARROW: Peninsula and Silicon Valley, are you getting pushback from developers because you lack credit ratings? Are you providing credit support? How are you dealing with the credit risk of not having a rating?

MS. DOHERTY: Peninsula Clean Energy signed two long-term PPAs with new solar projects, so it has not been a barrier. We learned from what MCE has done. One thing we focused on during our first two years of operations was building up our financial reserves so that we have a strong balance sheet, which is helpful in negotiations.

We are also transparent. Because CCAs are public agencies, almost everything we do is transparent. We have monthly public meetings that anyone can attend, and we publish all of the information related to those meetings.

When financiers and developers come to us asking for information, we can provide that pretty easily. Similarly, all of our financials are on our website. They are readily available.

MR. ECKERT: I came from a traditional vertically-integrated utility, where when power deals were done, the finance team would come in at the very end and look at the credit language and move on. With the CCAs, it was the opposite. We would start off the conversation talking about credit and spend a couple months on that.

Ultimately, we have moved forward. It has helped that both sides want to do a deal and that we have a board that supports a cash reserves policy. We are shooting for 50% of our operating expenses to be in reserves in the next couple years.

It is worth noting that we have a board that can set our rates. Even though we have a tendency to index our rates to PG&E, if circumstances get tough, we can set rates for our service territory.

Another large hurdle was concern that customers can leave us at any moment. Currently, Silicon Valley Clean Energy has an opt-out rate of about 3%. I think the other CCAs on this panel also have opt outs under 10%. We are in pretty good shape as far as keeping our customers.

Parting Thoughts

MS. BARROW: Please share any parting thoughts.

MS. SAXBY: In the integrated resource planning proceeding before the California Public Utilities Commission, CalCCA submitted all of the CCAs' plans for procurement through 2030. The data show a strong desire for wind.

There are about 2,700 megawatts of wind already under contract, and around another 1,500 megawatts of new wind is expected in the future. There is definitely still a lot of interest from CCAs in wind.

MS. DOHERTY: We talked about credit ratings and how CCAs have been able to get deals done. Peninsula Clean Energy is still very interested in getting a credit rating despite being able to do deals without one. We are learning from MCE about where Moody's focused, and we are working with Moody's to make sure we are in the right place once we have the operating data to get a credit rating. Hopefully this will make it easier for developers to work with us.

MS. BARROW: When do you expect to have a rating?

MS. DOHERTY: Our official goal is 2021, but we hope to have one sooner than that.

MR. ECKERT: We talked about risk on this panel. I want assure the developers that the CCAs are here to stay. We want to do business with you in the future, and wind is going to be an important part of our portfolios.

I also want to mention local control. It is one of the reasons why we have staying power and why customers are unlikely to return to PG&E. Our customers appreciate the fact that they have a say in the generation portfolio, rates and programs such as energy efficiency, and we reinvest any profits back into the community. For political reasons alone, we are here to stay. ◎

Mitigating Weather Risk in Existing Offtake Contracts

by Christine Brozynski, in New York

Project sponsors and corporate electricity purchasers are entering into two new types of arrangements to mitigate risk in existing offtake contracts.

The product used by project sponsors is called a "balance of hedge."

This might be used by a project company that owns a wind or solar project to mitigate against weather and covariance risk. Covariance risk is the risk that when the wind blows or sun shines in a particular area, all the wind or solar facilities in that area generate electricity at the same time, causing the market price for electricity to fall.

A balance of hedge is most likely to be used when a project sells its electricity on a merchant basis into the local grid and enters into a fixed-volume swap. The project company has no long-term power purchase agreement with a utility or other customer. Instead, it sells to the local grid and is paid the spot price at the nearest "node" on the grid for electricity produced. It enters into a fixed-volume swap to put a floor under the electricity price so that the project can be financed.

One problem with the arrangement is that the project may generate less electricity in a given hour than has been promised under the fixed-volume swap for that hour.

A balance of hedge addresses this problem as well as the covariance risk. The project company supplements the fixed-volume swap by also entering into a balance of hedge. How this works is discussed in more detail below.

The other product is called a "firming swap," and it is being used by corporations to protect against weather risk when they have entered into "virtual" power purchase agreements.

In a virtual PPA, the project owner sells the electricity to the grid for whatever market price applies at the time of sale. The project owner then pays the electricity revenue (or deemed revenue if priced at the hub) to a corporation with which it has signed a virtual PPA in exchange for fixed payments back from the corporation.

Cutting through everything, the project owner receives fixed payments for the electricity it generates. The corporate offtaker receives floating payments that match what it has to pay at any given time to buy electricity from the local utility. The problem for the corporate offtaker is the pattern of electricity output during the day may not match the pattern of electricity usage by the corporation. That leaves the corporation either over- or under-hedged.

Fixed-Volume Contract Risks

More and more project companies are entering into fixed-volume offtake arrangements.

Fixed-volume offtake arrangements can be "physical" or "financial."

A physical arrangement requires the project company to deliver a predetermined fixed amount of power each hour to the offtaker.

Two new types of hedges are being used to mitigate risks in existing power contracts.

A "financial" arrangement requires the offtake contract to settle with respect to a predetermined fixed notional volume of power each hour, regardless of how much power is produced by the project that hour.

In either case, the hourly volumes tend to be shaped roughly to mirror expectations for P99 production.

The project company retains many risks if its offtake involves fixed-volume hourly quantities.

/ continued page 42

Hedges

continued from page 41

One of these risks is volume risk, or a mismatch between the annual volumes produced by the project and the annual volumes required to be delivered under the hedge. Another is shape risk, or the risk that those volumes may not be produced on schedule; the project company may produce more power when the delivery requirements under the hedge are low, or produce less power when the delivery requirements under the hedge are high.

These two risks together are weather risk, as they are correlated with the amount and timing of the wind or irradiation, as applicable.

Project companies enter into fixed-volume hedges to offload price risk, but financial risks borne of weather-related factors may end up eating into the price-risk relief.

Project companies with existing fixed-volume offtake arrangements at operating projects may also find that, in addition to weather risk (represented by volume and shape risk), they face increasing covariance risk.

Projects with fixed-volume offtakes looking to bank some of the upside when the project is exceeding hourly requirements under the hedge may find that the upside is lower than originally modeled if other generators have come online in the area.

Balance of Hedge

To manage these risks without modifying the existing offtake arrangement, the project company (or a higher-level entity in the project company's ownership chain) can enter in a balance of hedge that will de-risk the project on volume, shape and covariance, while the existing offtake agreement continues to de-risk the project on the price of power.

The balance of hedge was first offered by Nephila Climate, Allianz Risk Transfer (Bermuda) Limited and REsurety, the same entities that designed another product called a proxy revenue swap, which is a weather hedge that can serve as an offtake for wind or solar projects.

The balance of hedge is a financial hedge that is a form of contract for differences, with a quarterly settlement amount that is the net amount owed in one direction or the other after a "fixed payment" made by the hedge provider is netted against a "floating payment" made by the sponsor entity.

The fixed payment (made by the hedge provider) is a predetermined lump-sum payment; it does not vary in accordance with the energy produced by the project. Because the fixed payment is not linked to production, the project is guaranteed revenue even if the amount of wind or irradiation during the settlement period is low. This is how the weather risk and covariance risk are transferred to the hedge counterparty.

The floating payment (made by the project company) consists of the project company's "proxy revenue," which is the hub price multiplied by the "proxy generation" in megawatts. The proxy generation is the amount of power the project would have produced assuming fixed operational inefficiencies.

Because the project's operational inefficiencies reflect a pre-agreed formula rather than actual operational losses, the project company retains the risk that the turbines or panels malfunction or become unavailable to a greater degree than is reflected in the formula.

The total floating payment is the sum of the proxy revenue plus the settlement received (or minus the settlement paid) under the existing fixed-volume hedge, without taking into account any tracking account settlements. (For existing hedges that are physical, meaning power is sold physically for a contract price in lieu of financial settlements on notional quantities of power, the "settlement" for the existing hedge is treated as the contract price minus the hub price for the contracted quantity for each hour.) Therefore, the balance of hedge settlement reflects a project revenue stream that is already at least partly de-risked on price.

The fixed payment and floating payment are then netted out, such that the sponsor entity receives downside protection to the extent the floating payment is below the fixed payment or forfeits the upside to the extent the floating payment exceeds the fixed payment.

Because the operational risk (retained by the sponsor entity) and price risk (already hedged under an existing offtake arrangement) have each largely been removed from the floating payment, the balance of hedge ultimately reflects a hedge of weather risk and covariance risk.

The balance of hedge settles at the hub, so the sponsor entity retains "basis risk." "Basis risk" is the risk that the electricity price at the node where the electricity is sold into the grid will differ from the price at the "hub" where the electricity price is determined for swap payments under a financial fixed-volume swap or where the project repurchases electricity to supply to a hedge counterparty under a physical fixed-volume swap.

Sponsor Issues

Sponsors should consider which entity in the project company's ownership chain should execute the balance of hedge. If the balance of hedge is executed by the project company, then any tax equity investor will benefit from the reduction in risk. Some tax equity investors may prefer this.

Another consideration for the sponsor is the type of credit support provided by the sponsor entity to the balance of hedge provider.

If the sponsor wants to offer a lien on the assets of and equity interests in the project company as credit support when the existing offtaker already has such a lien, then the sponsor will need to get the existing offtaker comfortable with sharing the lien and manage the negotiation of intercreditor arrangements between the two offtakers.

In the alternative, the sponsor could provide a letter of credit as credit support, which would require the sponsor to pay letter-of-credit fees.

The sponsor could also provide cash collateral, although that is not generally viewed as an optimal use for cash.

Lastly, sponsors should consider building flexibility into their debt, tax equity and price hedge documents expressly to permit the project company to enter into a balance of hedge, as the financing documents or price hedge would not typically permit this without consent. Clearing this with counterparties upfront may reduce future delays resulting from counterparty negotiations or withholding of counterparty consent.

Firming Swap

Corporate power purchase agreements in their simplest form are financial hedges that are contracts for differences. The notional volumes on which the hedge settles are the volumes actually produced by the project.

Corporate offtakers use corporate power purchase agreements to manage their energy prices and encourage development of renewables projects, but under traditional corporate power purchase agreement structures, the corporation ends up with risk that the total amount and shape of electricity supplied does not align with the corporation's energy usage. While corporate power purchase agreements usually shift some operational risk on to the project company, the corporate offtaker often ends up absorbing some degree of operational risk as well.

Corporate offtakers can mitigate some of these risks by entering into a firming swap with a weather-risk investor. While weather-risk investors are not necessarily interested in price risk, they can offer protection on volume risk and some shape risk by functionally re-aligning the contracted volumes with the corporate offtaker's predicted usage.

Microsoft recently adopted this model by pioneering a new form of corporate power purchase agreement that shifts operational risk to the sponsor by settling on proxy revenue rather than actual revenue and can be executed concurrently with a firming swap. The firming swap allows Microsoft to offload some of the volume and shape risk.

Microsoft makes fixed payments that are a dollar amount per megawatt-hour of proxy generation. This means that the Microsoft power purchase agreement in many ways looks similar to a typical corporate power purchase agreement except that, because the contract volume consists of proxy generation rather than actual generation, the project company retains operational risks.

Upon executing the corporate power purchase agreement, Microsoft then enters into a firming swap with a weather-risk investor. Under the firming swap, the weather-risk investor gives Microsoft downside protection to the extent the project's proxy generation is below a predetermined megawatt-hour volume for each month and retains any upside above that volume. In this way, Microsoft is able to pass on some of the volume and shape risk to the weather-risk investor. The operational risks are still retained by the project company.

The weather-risk investor charges a premium for the firming swap. Microsoft attempts to pass through this premium to the project company. ◎

Both types of hedges address volume and shape risk. One also addresses co-variance risk.

Environmental Update

The meaning of "critical habitat" and the scope of protection offered by the Endangered Species Act are being hotly litigated in the appellate courts, with potentially significant implications for developers.

The US Supreme Court sent petitions filed by Weyerhaeuser and landowners disputing protections for the dusky gopher frog back to the court of appeals in late November and early December with instructions to determine what falls within the definition of "critical habitat" under the endangered species statute.

The Supreme Court unanimously vacated the lower court decision affirming a US Fish and Wildlife Service designation of 1,544 acres of land in Louisiana as critical habitat for the frog.

Weyerhaeuser and the landowners argued that the frog has not been seen on the land for decades and areas where the frog could not currently survive should not be designated a critical habitat for it.

The appeals court rejected that argument, holding that there is no "habitability requirement" before designating an area as a critical habitat.

In overturning that decision, the Supreme Court said, "according to the ordinary understanding of how adjectives work, 'critical habitat' must also be 'habitat.'"

Thus, the appeals court must now decide what "habitat" means, and whether the land at issue falls within that meaning.

Such a designation can require significant changes to planned projects.

Among the issues the appeals court has been instructed to consider is whether the Fish and Wildlife Service went too far by concluding that the conservation benefits of designating the area a "critical habitat" for the frog would outweigh the costs of barring development. The appeals court felt that the courts should defer to the agency's decision, but the Supreme Court disagreed.

The entwined cases are *Weyerhaeuser v. U.S. Fish & Wildlife Service* and *Markel Interests LLC et al. v. U.S. Fish and Wildlife*.

Coal

The US Environmental Protection Agency proposed on December 6 to allow significant increases in carbon dioxide emissions from new and modified coal-fired power plants.

The proposal would revise the "new source performance standards" for greenhouse gas emissions from new, modified and reconstructed fossil-fuel-fired power plants.

Specifically, the power plant emissions limit would increase to 1,900 pounds of carbon dioxide or CO2 per megawatt hour of output, a rate achievable by using a type of coal-burning technology known as "ultra-supercritical." Smaller units would be subject to a higher rate of 2,000 lb/MWh, allowing for less-efficient technologies.

EPA also said it plans to create separate standards for any new plants that burn coal refuse, meaning waste left over from mining coal seams. Such plants could emit up to 2,200 lb/MWh.

These are significant increases from the current cap for CO2 emissions of 1,400 lb/MWh.

In order to make these changes, EPA now finds that the best system of emissions reduction –- the regulatory standard — for newly constructed coal-fired units is the most efficient demonstrated steam cycle in combination with the best operating practices. This proposed standard would replace the determination reached by EPA in 2015 that the proper standard is partial carbon capture and storage.

The move is seen as a retreat from the Trump administration's support for "clean coal" technology. "The primary reason for this proposed revision is the high costs and limited geographic availability of" carbon capture and storage, EPA said.

EPA also welcomed public comments on what the Clean Air Act means by authorizing regulation of any emissions source that "causes, or contributes significantly to" air pollution, and on whether a 2009 finding by EPA that greenhouse gases are a threat to public health should apply not only to existing power plants, but also future power plants.

This suggests that the agency is considering further easing of or even doing away with greenhouse gas rules for newly built coal plants.

Paris Redux

Diplomats from almost 200 countries met in Katowice, Poland in early December to try to put climate negotiations back on track after findings by the global scientific community that climate change is happening at a faster rate than previously predicted and after portents of increasingly severe impacts become apparent.

The conference is being hailed as a partial success.

The meeting, called COP24, was intended to establish a set of rules for the Paris climate agreement to nudge countries to cut greenhouse gas emissions far more deeply in the years to come. Under the Paris deal, every nation on the planet agreed in 2015 or shortly thereafter to submit a plan for curbing emissions, with promises to take more significant steps as years pass.

A fight over the dusky gopher frog may lead to a reassessment about what protections must be provided for endangered species.

The Paris deal did not include binding obligations or penalties for failure to meet those promises. The goal of COP24 was to write a "rule book" on enforcing action and thereby achieve practical results from the promises of Paris.

The larger goal of Paris is to limit global warming to between 2.7 and 3.6 degrees Fahrenheit, which the scientific consensus suggests is necessary to limit more extreme weather, rising sea levels and losses of species. The subtext for the COP24 conference was Paris only decided what was needed, but did not set a concrete path for how it could be done.

The delegates reached agreement on December 15 on a detailed set of rules governing implementation of the Paris accord.

The deal will eventually require each country to follow a uniform set of standards for measuring its greenhouse gas emissions and to track its efforts to reduce them.

A sticking point was the US position that all countries should abide by the same emissions-accounting rules and be subject to the same outside scrutiny. China and some other countries wanted different reporting rules for developing countries. The delegates agreed to a compromise around a clearer methodology to ensure that major developing polluters like China and India are meeting their targets.

The deal calls for greater cuts in emissions ahead of the next round of talks scheduled for 2020, but there are no consequences for failure.

It includes a process that countries struggling to meet their emissions goals can use to try to get back on track.

Developing countries had hoped for more concrete promises of financial assistance from wealthier countries to help them reduce emissions. The issue was largely postponed. The deal calls for further clarification about the aid that the developed world intends to offer.

The US agreed to the deal, notwithstanding that the United States plans to withdraw from the Paris agreement at the first opportunity in November 2020. Until then, every country on earth remains a signatory.

Most of the delegates wanted formally to endorse an October report by the United Nations scientific panel on climate change, but the US, Saudi Arabia, Kuwait and Russia pushed back. Compromise language welcomes with "appreciation and gratitude" the timely completion of the scientific report and invites countries to make use of its findings.

Thus, the delegates left Poland with new rules to implement the Paris accord. More concrete pledges to cut emissions by each country will be on the agenda for the next climate-change meeting in 2020, when the parties will reassemble and the agreement will come into force.

The business community in the United States is facing some uncertainty. A loss by President Trump in the 2020 election would probably see the United States reenter Paris, as well as reconstitute many of the regulatory structures that the current administration has been actively dismantling since it took office.

/ continued page 46

Environmental Update

continued from page 45

At the close of the G20 meeting in Argentina the week before the start of the COP24 conference, the leading industrialized nations — except the United States — reaffirmed their commitments to implement the Paris deal.

The United Nations has a goal of raising $100 billion each year from 2020 for climate action. The World Bank Group recently pledged another $200 billion from 2020 to 2025.

Mounting scientific evidence, including two UN climate reports published since October and a late November report by the US government, suggest that countries have not committed to enough emissions cuts to avoid some of the worst impacts of climate change.

US Science

Thirteen federal agencies issued a 1,656-page "authoritative assessment of the impacts of climate change on the US and its territories" in late November.

The scientific report offered shockingly blunt warnings about the consequences of climate change for the United States, laying out devastating effects for the US economy, public health and the environment.

EPA is proposing to allow a 36% to 43% increase in CO2 emissions from new and rebuilt coal-fired power plants.

It predicts that the expected impacts will cut as much as 10% off the size of the US economy by 2100 if significant steps are not taken globally in the near term.

The report concludes, "Earth's climate is now changing faster than at any point in the history of modern civilization, primarily as a result of human activities." "Climate-related risks will continue to grow without additional action."

The report is the second volume of the National Climate Assessment, which the federal government is required by law to produce every four years. It was compiled by hundreds of experts across more than a dozen agencies.

"Impacts from climate change on extreme weather and climate-related events, air quality, and the transmission of disease through insects and pests, food, and water increasingly threaten the health and well-being of the American people, particularly populations that are already vulnerable," the report says.

It paints a dark picture. It says the impacts of climate change are already being felt in the form of more frequent and intense extreme weather and changes in average climate conditions. Impacts to date include record wildfires in California, crop failures in the Midwest and crumbling infrastructure in the South.

Future climate change impacts are expected to intensify further, exacerbating problems with the nation's aging and deteriorating infrastructure, which was designed for historical climate conditions and lower sea levels.

The report says that unless significant global mitigation actions and regional adaptation efforts are taken, rising temperatures, higher sea levels, and changes in extreme events are expected with increasing frequency to disrupt and damage critical infrastructure and labor productivity and shackle of the rate of US economic growth. The report projects that some economic sectors may suffer hundreds of billions of dollars in annual losses by 2100.

Rising temperatures are projected to reduce the efficiency of power generation while increasing energy demands, resulting in higher electricity costs.

Rising air and water temperatures and changing precipitation patterns are already intensifying droughts, increasing heavy rainstorms, reducing snowpack and decreasing surface water quality.

Future warming is predicted to stress water supplies in some regions. Changes in the relative amounts and timing of snow and rainfall may lead to disruption of hydropower, especially in the southwest and northwest, and adversely affect US power plants in some areas that rely on a steady supply of water for cooling.

On the positive side, the report recognizes that increased use of cleaner-burning natural gas and renewable energy, along with mitigation and adaptation efforts by local, state and federal officials, have already begun to reduce US greenhouse gas emissions. However, much more needs to be done.

The report lays out a number of adaptation strategies to cope with adverse impacts and describes how the authors think the nation will have to adapt.

Without significant reductions in global greenhouse gas emissions and regional adaptation measures, it predicts that many coastal regions will be transformed by the second half of the century. The US will need to spend many billions of dollars to harden coastlines, rebuild sewer systems and overhaul farming practices to protect against floods, wildfires and heat waves.

Depending on how rapidly global emissions increase, the report predicts that sea levels are likely to rise between one to four feet by 2100, potentially putting trillions of dollars' worth of coastal homes and businesses in the US at risk of flooding and, eventually, millions of people may have to move back from the coasts.

While the previous report, issued in May 2014, determined that climate impacts had already started to cause damage across the country, it did not offer the same precision. The new report pins price tags of projected impacts to various sectors of the US economy, such $32 billion from infrastructure damage, $118 billion from sea level rise and $141 billion from heat-related deaths by the end of 2100.

The 2018 report emphasizes that the actual outcomes depend on how quickly the US and other countries act to mitigate global warming.

The medicine prescribed by the report is threefold. First, put a price on greenhouse gas emissions, such as through a carbon tax on emitters who currently pay nothing to discharge into the atmosphere. Second, establish government regulations on how much greenhouse gas may be emitted and ratchet those caps down over time as markets and technology adjust. Finally, vastly increase public funding of clean-energy research.

Scientists who worked on the report said the Trump administration did not try to alter or suppress its findings.

President Trump responded to the report by saying he does not believe its findings.

Acting EPA Administrator Andrew Wheeler subsequently accused the Obama administration of focusing the report on the worst-case outcomes and indicated that the Trump administration might shape the next study of the issue. "Going forward, I think we need to take a look at the modeling that's used for the next assessment," Wheeler said.

Some of the report's authors disputed the criticism that the report focused on worst-case scenarios, pointing out that it includes a wide range of projections, including forecasts where greenhouse gas emissions are sharply curtailed from their current trend.

John Holdren, who served as Obama's science adviser and who initiated the assessment, said he had no role in selecting the report's authors. "My only instruction was that the USGCRP should continue the distinguished tradition of the first three by drawing on the most current peer-reviewed science to illuminate what climate change is doing and is projected to do across the geographic regions and economic and ecological underpinnings of well-being in the United States," he said.

Work on the report started in the final year of the Obama administration, but the majority of the work was done during the first two years of the Trump administration, including the final three drafts, collection of comments and agency review.

Global Science

The US climate findings were released a month after a panel of scientists convened by the United Nations issued a similarly detailed and alarming report on the severe economic and humanitarian crises expected to hit the world by 2040 as a result of climate change.

The October report from the Intergovernmental Panel on Climate Change warns that net emissions need to reach zero by 2050 to keep temperature increases to the Paris goal of 2.7 degrees.

In November, the World Meteorological Organization also reported that the concentration of carbon dioxide in the atmosphere is the highest it has been in three to five million years. Its annual assessment finds that greenhouse gas levels in the atmosphere have not been this high since sea levels were 33 to 66 feet higher than they are now.

Concentrations of greenhouse gases increased last year to levels 41% higher than in 1990, driving a long-term increase in the global temperature.

/ continued page 48

Environmental Update

continued from page 47

House Oversight

The Democrats, who take control of the House of Representatives in January, appear poised for aggressive investigation into the rollback by the Trump administration of various regulations intended to moderate climate change.

The House members who are expected to chair the Energy and Commerce Committee and various other environmental panels in the next Congress sent a letter to acting EPA Administrator Andrew Wheeler on November 20 seeking detailed information and documents from the agency about three measures to overturn or limit agency rules for power plants, motor vehicles and drilling.

While the House leadership and committee and panel appointments remain to be decided and in-fighting is already apparent among the Democrats, additional oversight of EPA is a certainty. Regular and early hearings on climate risk and mitigation options will follow early in the new year as will a flurry of subpoenas.

The Trump administration plans to finish a host of EPA deregulatory measures by March, including replacement power plant greenhouse gas rules and a new rule defining the scope of Clean Water Act jurisdiction. The House is unlikely to be able to block these steps on its own, and the Senate will remain in Republican hands.

Bipartisan Carbon Tax?

US House members from both political parties introduced a bill in November to impose a carbon tax.

The bill will have to be reintroduced in January at the start of the next Congress. It would impose a $15-per-metric-ton carbon fee on the US oil, gas and coal industries, but rebate that revenue to households to shield them from increased fossil-fuel costs related to the tax.

The bill is not expected currently to get any traction, given the failure of a ballot measure to impose carbon taxes in Washington state in November and the troubles that Justin Trudeau and Emmanuel Macron have been having in Canada and France making carbon and fuel tax increases stick that were imposed in an effort to reduce greenhouse gas emissions. ◎

— contributed by Andrew Skroback in New York and Washington

CHADBOURNE MERGER

Chadbourne & Parke merged into Norton Rose Fulbright on June 30, 2017. The combined firm has roughly 3,900 lawyers in 58 offices in 33 countries.

WANT TO LEARN MORE?

Check out **Currents**, the world's first project finance podcast from a legal perspective. Learn more at www.projectfinance.law/podcasts; subscribe on Apple Podcasts, Google Play or your preferred podcast app.