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Emerging Opportunities in the Hydrogen Market

by Rachel Crouch, in Washington

Green hydrogen appears to be on the verge of transforming from an idea into projects on the ground. While many green hydrogen efforts are pilot projects that require government support to be economic, sponsors, investors and governments around the globe are starting to outline a vision for a mature hydrogen market developed on the back of bankable hydrogen projects that will be built over the next decade.

Financing these projects will require cataloging and allocating risks in a manner that is familiar to project financiers, but it will require them to pull tools from disparate toolkits.

The predominant use of hydrogen today is as a feedstock, primarily for the production of ammonia for fertilizer and for producing gasoline and diesel fuel from crude oil in refineries.

Hydrogen is expected to be key to the energy transition because of its potential applications to difficult-to-decarbonize sectors, including industrial production and heavy transport.

It can also be used in the power sector, notably for storing energy over the long term, complementing intermittent renewables and allowing for greater renewables grid integration with less curtailment.

To date, the overwhelming majority of hydrogen has been produced */ continued page 2*

IN OTHER NEWS

THE BIDEN ADMINISTRATION will face greater challenges than any recent administration, not the least of which is the possibility that Donald Trump will remain a constant thorn after leaving office. The news media has an incentive to keep him in the news and to look for controversy.

There is not the same feel in Washington that there was at the start of the Kennedy, Reagan, Clinton and Obama administrations when the incoming administrations felt like starts of major new chapters. On the other hand, maybe that is not what the country needs. It is hard to think of any other spontaneous celebrations in major US cities – like occurred on the Saturday the major news media declared the race for Biden – since the end of World War II. */ continued page 3*

IN THIS ISSUE

Hydrogen

continued from page 1

using fossil fuels (so-called "grey hydrogen"). Production of hydrogen using fossil fuels can be paired with carbon capture (so-called "blue hydrogen").

This article — and much of the current industry and regulatory attention to the development of a hydrogen market — focuses on "green hydrogen" produced using electrolysis powered by renewable energy to split water into oxygen and hydrogen molecules.

Existing Use Cases

There is no merchant market for hydrogen. To be financeable, a hydrogen project must have a bankable offtake scheme.

Existing use cases for hydrogen may be among the first green hydrogen opportunities to be financeable, because the offtake picture will be clearer and easier to model.

Ammonia is one such area. A market already exists for ammonia, and green ammonia projects have been proposed or are in early stages of development, including a project under development in Saudi Arabia benefitting from an offtake arrangement with Air Products, a project in Louisiana sponsored by CF Industries, the world's largest ammonia producer, and a project being undertaken in western Australia by Engie and Yara, a major fertilizer manufacturer. (See "Greening the fertilizer sector" in the October 2019 *NewsWire*.)

Petroleum refining is another area where bankable early hydrogen projects are most likely. Refineries are among the largest users of hydrogen as a fuel stock, and early-stage hydrogen projects may contract with refineries as offtakers. Several pilot projects are being developed in this sector. For example, a high-profile effort by BP and Ørsted aims to produce green hydrogen using offshore wind to power a 50-megawatt electrolyzer, replacing natural gas-produced hydrogen at BP's Lingen refinery in Germany.

The third area showing early promise is fuel for specialty vehicles. Hydrogen is already being used to power fuel cells. Fuel cells are used in specialty vehicles like forklifts and by energy consumers to complement electricity from the grid, to smooth energy costs and to ensure reliability. Today, they rely largely on grey hydrogen.

As an example of offtake opportunities involving fuel cells, Plug Power — a leading supplier of fuel cells for use in forklifts and other specialty working vehicles — has entered into partnerships with Apex Clean Energy and Brookfield Renewable Partners. The two developers will build utility-scale wind and solar projects whose output will be used to generate green hydrogen for use by Plug Power.

While fuel cells are a commercial technology employed today in certain sectors, as discussed below, major opportunities and challenges remain for applying fuel cells to other mobility sectors and for developing offtake structures to facilitate the financing of fuel cells put to such use.

Emerging Use Cases

Five areas are promising emerging use cases.

Electricity generation is one. Existing offtake structures can be readily applied to hydrogen in the power sector. Project developers and utilities are exploring options for hydrogen production, storage and use as a necessary piece of the net-zero emissions puzzle.

Hydrogen will benefit from lessons learned from the development of offtake contracts for battery energy storage, some of which employ a "Swiss Army knife" model for employing, and compensating project owners for, the multiple use cases of battery energy storage. (See "Energy storage: unique PPA considerations" in the October 2017 *NewsWire*.)

In areas with high renewables penetration, hydrogen projects may be particularly appealing to both offtakers and developers as a way to avoid curtailment.

The first bankable green hydrogen projects will involve three types of customers. Another five opportunities will emerge next.

Batteries will probably remain more efficient for relatively short-term storage — for example, for storing electricity generated during the sunnier parts of the day and discharging during peak-use hours in the evening — but using electricity to produce hydrogen will allow for the energy in electricity that goes unused to be deployed at a different season of the year altogether — for example, on the hottest days of summer when air conditioners are cranked up for days or weeks at a time across entire regions.

Several such power projects are underway in the United States. Municipal utilities in Utah and California are spearheading the conversion of a 1,900-megawatt coal-fired power plant in Utah owned by the Intermountain Power Agency into an 840-megawatt blended natural gas-and-hydrogen plant, with the intention of converting it into a 100% hydrogen plant in coming decades. NextEra has also announced plans to build a 20-megawatt electrolyzer to produce hydrogen to be used in an existing Florida Power & Light natural-gas-fired power plant.

Another emerging use case is heavy transport.

Fuel cells have advantages over batteries for powering heavy transport. Hydrogen refueling is generally much quicker than recharging batteries, and fuel cells are generally much lighter than batteries. Fuel cell bus fleets are being rolled out in China and Europe. The world's first fuel cell train, operated by Alstom, has seen a successful trial in northern Germany and shows promise for transporting passengers over routes that may be difficult to electrify.

The amount of hydrogen needed and the locations for refueling buses and trains are predetermined, so their operators can foreseeably constitute stable offtakers that may serve as the backbone for project financings in the transport sector.

While efforts to develop hydrogen-powered trucks have generated a lot of buzz lately, financing the infrastructure for, and producing hydrogen to service, a disperse refueling network for fuel cell long-haul trucks presents a more difficult case.

There is a clear chicken-and-egg problem related to the development of fuel cell trucks and hydrogen refueling infrastructure that may require government intervention to solve. Project financing, if ultimately feasible in this area, will probably become viable only once infrastructure plans have been established with government input and support.

Industrial heating holds promise.

Industrial processes requiring high-grade heat are notoriously difficult to decarbonize through electrification, so hydrogen strategies are particularly focused on deploying hydrogen for this purpose. Major, creditworthy manufacturers / *continued page 4*

IN OTHER NEWS

As for what the new administration will mean for renewable energy and the broader project finance market, it is useful to think in terms of two time periods. One is the lame-duck session of Congress that looks likely to run through at least December 18, and the other is next year.

Another economic stimulus bill appears likely, but talks could still fail. The federal government will run out of spending authority on December 11. Congress could extend the authority into March next year or all the way to the end of the current federal fiscal year next September after first buying a little more time to push the deadline closer to Christmas. A tax extenders bill is possible, but unlikely, to deal with 33 expiring tax breaks.

The Senate Republican leader, Mitch McConnell, has an incentive to do as much as possible before year end, but it is not an overwhelming incentive, and there is little remaining time. Senator Mark Kelly (D-Arizona) replaced Martha McSally (R-Arizona) the first week in December after winning a special by-election to fill the seat of John McCain, leaving McConnell with only 52 Republicans to 48 Democrats (including two independents who vote with the Democrats) for the remainder of 2020, which may not be an effective majority.

The bigger question is what happens in 2021. If Congress passes a stimulus bill during the lame-duck session, that will leave Biden with less room to maneuver. If there is no stimulus, then some form of economic relief measure can be expected between next February and June. New administrations must act quickly. By 2022, the US will be back in election season. The party holding the White House tends to lose seats in Congress.

The Georgia runoff election for two US Senate seats on January 5 is key. If Republicans win either seat, then Republicans will retain control of the Senate and the issue will be whether McConnell / *continued page 5*

Hydrogen

continued from page 3

of industrial products like steel or concrete could become a large market for bankable offtake arrangements in the hydrogen sector. In some regions, project developers may be able to develop bankable multi-project facilities combining large renewable generation projects and electrolyzers on-site or near major industrial producers or clusters of industrial producers.

Mining is another emerging use case. Mining companies often operate in environments where other energy sources may be expensive, dirty and subject to disruption, making them important potential corporate offtakers. In South Africa, Anglo American, Ballard and ENGIE have partnered in a project to retrofit an ultra-heavy-duty mining truck with fuel cells. Plug Power and Nel Hydrogen are developing a refueling system and an electrolyzer for use on-site.

Another potential market for hydrogen is as a replacement for natural gas for residential and commercial heating. In this market, even where there are longer-term contracts, prices are generally based on the spot market, making offtake structures in this sector more difficult to finance for early-stage hydrogen projects.

Risks

The gold standard for project financings, particularly in nascent industries, is a long-term, fixed-price offtake contract with a utility or other public or quasi-public purchaser. The power and public transportation sectors provide probably the best early opportunities for hydrogen project developers to sign such contracts.

However, many offtake structures will depend on corporate offtakers. While lenders have become accustomed to financing corporate PPAs in the power sector, many early hydrogen projects may have more in common with the analysis and treatment of offtaker risk in the LNG and mining sectors, where molecules or metals are physically delivered to a specific customer, and where the set of potential replacement offtakers may be more limited if a contract were to be rejected in bankruptcy or cancelled.

This counterparty risk will be particularly stark where the electrolyzer is located on-site or adjacent to the customer the project is designed to serve.

Financiers will also be focused on technology risk. While the market for green hydrogen is only on the cusp of viability, electrolysis technology has existed for some time. Its fundamentals are relatively well understood, and the technology may be in some respects less risky than, for example, solar photovoltaic technology was 15 years ago. As with any technology beginning to be commercially deployed, different variations of electrolysis technology are competing for preeminence. The cost has been declining in recent years and will probably do so more dramatically as deployments accelerate in number and scale.

Still, given the limited track records in electrolyzer deployment, financiers will carefully examine manufacturer and EPC warranties.

While some very large companies have entered the sector and partnerships are being announced at an accelerating pace, several of the principal technology suppliers in the market do not have very large balance sheets.

Major maintenance reserves may be required by lenders, and manufacturer warranties may need to be backed by insurance or other financial instruments to provide credit support. Given the limited track records of early projects, such security will probably be expensive (and could be an area in which government support may play a role in the early stages of hydrogen project financing).

Multi-Project Opportunities

An electrolyzer used to make green hydrogen is of no use without a sufficient source of renewable energy to power it, a way to store and transport the output, and an offtaker to buy and use the output.

Lenders to any part of the chain will have to ensure that all the linked elements will be developed as intended and on time to ensure debt repayment. At the same time, to find financing under a project finance model, hydrogen projects will have to be discrete enough that a revenue stream allocable solely to the individual project to be financed can be lent against, with a collateral package comprised of assets in which the special-purpose entity owning the project has an indivisible ownership or other property interest that can serve as security for the financing.

In some scenarios, end-to-end financing will be most appealing. An example of a relatively self-contained project is an electrolyzer together with a fleet of buses that will use the hydrogen fuel produced. More complexity arises when the power source and transportation of hydrogen are considered separately.

Financiers trying to evaluate and manage multi-project risk can look to knowledge developed through structuring other complex projects containing multiple elements.

For example, in LNG-to-power projects, the regasification, port infrastructure, pipeline and power plant components may be financed with the same debt package, which makes the most sense when the regasification facility is only intended to serve the associated power plant. Alternatively, separate special-purpose vehicles may be established for the separate financing of the power plant and the regasification facility, which may be financed by the same or different lender groups. The separate borrowers may or may not be jointly and severally liable for the loans. (See "Growth area: Regasification and LNG-to-power projects" in the February 2017 *NewsWire*.)

Another useful analogy is to the project financing of mining-related infrastructure. In some instances, a mining company may choose to develop a mine and related infrastructure (e.g., rail, port, power, water and communication-related infrastructure) under a single or related EPC contracts, to be financed as a package. In other cases, this infrastructure may be financed separately, developed through a public-private partnership or shared with other mining companies in the same region.

Where there are linkages between several projects, careful attention will have to be paid by technical advisors to timelines and the allocation of responsibility, by legal advisors to inter-creditor and security-sharing issues, and by both to the wrapping of construction contracts. As in other sectors, the more completely a contractor is required to wrap all elements of construction, the more costly the contract will be.

Creating a Market

Government support will be essential to get the green hydrogen market off the ground.

In some respects, hydrogen today can be compared to renewables 10 or 15 years ago, when government support in the form of feed-in tariffs, tax credits or guarantees was essential for accelerating the pace of deployment and, in turn, cost reduction.

Developers of electrolysis technology and projects anticipate a similar reduction of costs as deployment accelerates. Support for deployment will be necessary, but likely insufficient by itself for the development of a hydrogen market.

The demand side of the equation is less clear for the hydrogen market than it was for renewables at the beginning of the wind and solar revolution.

Hydrogen is not a broadly traded commodity and is today often produced on-site by its users. Governments have begun to tackle the need for creation of a / continued page 6

IN OTHER NEWS

decides the best path is to try to deny Biden anything that might be seen as a Biden success in the hope of limiting him to a single term.

Neither majority party in the House or Senate will have a strong hand. McConnell will end up at best with a two-seat majority in the Senate, but unable to rely on three Republican Senators (Susan Collins (R-Alaska), Lisa Murkowski (I-Alaska) and Mitt Romney (R-Utah)) who are not afraid to break Republican ranks. Nancy Pelosi, the House speaker, has only a five-seat majority out of 435 members in the House, with two seats still uncalled, Republicans leading in both and a frustrated Democratic centrist caucus that may not fall into line.

Thus, the odds of gridlock are high. In the end, the election may have replaced the man at the top to try to set a better tone, but otherwise provided no public consensus for broader change.

Renewables will do fine no matter the outcome. Coal plant retirements are accelerating. Use of coal to generate US electricity declined by 30% during the four years that President Trump was in office, on top of a 38% decline in the previous eight years of the Obama administration. Even the oil companies are now talking about the "energy transition."

There are two big winners within the renewables community no matter the outcome of the Georgia Senate races. One is offshore wind. Two things have been holding up construction in the Atlantic: a hold by the Bureau of Ocean Energy Management on issuing any construction permits and a tax rule that requires construction of new renewable energy projects to be completed within four years after construction has started for tax purposes. The four-year window is ill suited for massive offshore wind projects in the north Atlantic with limited construction seasons. Relief on both is within sight.

Solar is the other big winner. The solar industry has been working / continued page 7

Hydrogen

continued from page 5

market by providing support to projects using green hydrogen in industry and otherwise. It may go without saying that the broad adoption of carbon prices or taxes would accelerate the development of a market for green hydrogen.

Unlocking Green Financing

The rise of green or ESG-linked bonds and loans has been a major story in finance in recent years, but the wave of green liquidity that has overtaken the power industry has, for the most part, passed by the heavy transport, mining and industrial production sectors. Financiers and project developers targeting these sectors that can find answers to the challenges described in this article will be well positioned to catch this wave.

Hydrogen as an asset class defies current classifications in most banks. As early hydrogen projects are financed, developers and financiers will need to consider the credit story to tell about each project, including on which desk it should land within a financial institution.

In each case, financiers and their advisors will do well to take a multi-disciplinary approach by drawing on institutional experience in financing power, oil and gas, infrastructure transport and mining projects to analyze hydrogen project risks and structure financings. ◎

Climbing Insurance Premiums

by Jason Kaminsky with kWh Analytics in San Francisco, and Sam Jensen with Stance Renewable Risk Partners in San Anselmo, California

Property and casualty insurance premiums have increased as much as 400% over the last two years in the solar market, and some types of coverage may not be available at any price.

Deteriorating Terms

The market for property and casualty insurance for solar projects has been hardening over the past 18 months, which is causing concern for both asset owners and financiers of solar projects.

The insurance market goes through cycles of “soft markets,” which typically entail easier underwriting, increased capacity, and more preferential terms, followed by “hard markets” with stricter underwriting, reduced capacity and generally worse terms. The current hardening of the insurance market, coupled with other industry changes, has caused disruption in the project finance markets.

The global insurance markets are hardening across the board, with most types of insurance lines experiencing rate increases as insurers absorb and react to losses that have been increasing in both frequency and severity.

As it relates to renewables, this trend has been especially pronounced given both the rapid growth of the renewable energy sector and the increasing frequency of extreme weather events leading to outsized losses.

The solar property and casualty market was disrupted after a $70 to $80 million hail claim on a Texas-based solar project in late 2019. Additionally, two plants in Rosamond, California and a project in Bakersfield, California had significant wildfire claims during the 2020 wildfire season.

Against this backdrop, renewable energy projects are seeing even steeper cost increases, with underwriters and reinsurers struggling to secure adequate coverage for renewables projects. Some types of coverage may not be available at any price.

Five Challenges

As a result of this accumulation of losses, solar asset owners are experiencing a number of challenges from the market.

First, buyers are seeing increased premiums for coverage, with asset owners reporting increases of up to 400% over the past two years.

Second, policies have higher deductibles. During soft market conditions, deductibles under all-risk insurance policies were as low as $10,000 or capped at 2% to 5% of the total claim value for catastrophic perils. Deductibles have now shifted to much higher dollar amounts, and deductibles are now typically 5% of the total asset value for catastrophic perils.

Third, insurers introduced natural catastrophe sublimits for certain losses, namely from severe convective storms, such as hail, tornados and straight-line wind.

Insurance premiums have increased as much as 400% in the last two years in the solar market.

Large solar projects and portfolios are having difficulty securing capacity above $20 million for key risks amidst increased solar development in areas such as ERCOT, which face severe convective storm exposure.

Fourth, insurers have introduced more nuanced policy restrictions, such as microcracking exclusions. The vast majority of underwriters insuring solar now implement microcracking restrictions regardless of geographic location. These typically appear as policy amendments that place costs associated with testing for microcracks in solar panels with the insured, as opposed to the insurer. The insured must also demonstrate that more than a certain percentage or amount of individual solar modules have suffered microcracks before the policy will respond.

Fifth, the market is seeing inconsistency among insurers regarding policy terms, including terms associated with microcracking, sublimits, contingent coverages, and deductibles.

These changes in the market are introducing risk into the structuring of solar projects, particularly for projects exposed to hail.

/ continued page 8

IN OTHER NEWS

hard to get the investment tax credit extended. An extension has a decent chance of getting into any economic stimulus bill next year. The odds improve if the Democrats win the two Georgia Senate races.

It is harder to predict what the Biden administration might do on solar tariffs. It could head off a move that President Trump launched in October to extend existing tariffs on imported solar panels past their scheduled expiration in February 2022.

Several other green tax proposals remain in the mix for possible action in 2021. Odds are best for a proposal to give offshore wind projects more time to start construction to qualify for tax credits and next for a tax credit for standalone storage. A "direct-pay" alternative to tax credits is less likely, and depends on the state of the tax equity market. An extension of production tax credits for wind stands the best chance if the solar tax credit is extended.

Biden is expected to take a series of executive actions to help renewables. They include increasing federal agency purchases of renewables and requiring more stringent Securities and Exchange Commission and bank regulatory disclosures of climate-change effects.

The replacement of Neil Chatterjee as chairman of the Federal Energy Regulatory Commission the day after the November elections may give Democrats an effective majority at FERC before Chatterjee's term ends in June on some issues of interest to the renewables community on which Chatterjee has sided with Richard Glick, the Democratic commissioner. The commission will be back to five commissioners in December after the Senate approved the appointments of Allison Clements, a Democrat, and Mark Christie, a Republican. Biden can move the chairmanship to a Democrat.

/ continued page 9

Insurance

continued from page 7

Consistent Themes

The authors participated in a series of roundtables on this subject with lenders and tax equity investors, and a few consistent themes emerged.

Most tax equity investors and lenders have been asked to waive insurance requirements embedded within their financing documents due to the lack of market availability, as many financing agreements were negotiated during soft market conditions. Investors are beginning to focus on insurance availability as a key underwriting risk prior to the issuance of term sheets. In some instances, lenders require asset owners to provide a guarantee for uninsurable losses. The market is adapting to these changes in real time.

The market conditions have led to a focus on solar risk management, with emerging technologies and certifications that can help mitigate losses from these natural events. Larger developers with more sophisticated risk management programs are more easily able to secure insurance coverage.

Insurers have signaled to asset owners and financiers that insurance may no longer be the main basis for transferring risk, and that traditional risk management, site selection and technology selection must be considered by developers, purchasers and financiers amidst increasingly severe weather patterns.

In 2020, the demand for insurance for asset owners and financiers has exceeded the insurance market supply. In 2021, with a large pipeline of solar assets being developed in natural catastrophic prone areas, it will remain to be seen if balance can be achieved.

Property and casualty insurance, and solar risk management, will be an increased area of focus leading into 2021, especially against the backdrop of a tightening in the tax equity market and a flight toward lower-risk transactions. ◎

EXIM Has Work To Do At Home

by John Schuster with JLS Capital Strategies and Kenneth Hansen, in Washington

The US government's international lending agencies are occasionally deployed domestically.

The Trump administration issued an executive order recently directing the US International Development Finance Agency (formerly known as the Overseas Private Investment Corporation or OPIC) to use its project investment expertise to support domestic production of goods needed to fight the COVID-19 pandemic. That led to a single, awkwardly pursued transaction that fell off the rails because of an appearance of self-dealing by Eastman Kodak executives.

Nonetheless, the affair may stand not only for the proposition that any idea can be poorly implemented, but also that circumstances may exist in which the resources of the international lending agencies may be usefully deployed at home.

A better example may be the Export-Import Bank of the United States. EXIM is the official export credit agency of the US. It provides loans, guarantees, and insurance to foreign purchasers of products made in the United States. Its mission, as stated in its annual report, is to "support American jobs by facilitating the export of US goods and services."

Its existence has often been criticized as introducing non-competitive distortions into an otherwise free market and for "picking winners and losers." EXIM's key defense is that it "levels the playing field" for American producers facing foreign competition supported by export credit agencies in other countries. EXIM is needed for US goods and services to be able compete "on the merits" without being disadvantaged by foreign subsidies.

Whether EXIM truly levels the playing field for American businesses is debatable on many levels. To qualify for an EXIM loan, one must meet content, shipping, economic impact and other requirements that no other export credit agency in the world imposes. Thus, even before its five-year lapse of authority and lack of a board quorum, EXIM's support per unit of GDP was among the lowest in the world.

Perhaps the most important corner of the international playing field where US manufacturers have been left to confront subsidized competition without access to EXIM is the United States. This has incentivized developers of projects in the United States to procure goods and services offshore.

Consider a large infrastructure project being developed in the United States, with global bidding to provide equipment, materials and construction services. The bidders for that work hailing from Europe or Asia or even Canada could submit proposals with associated financing offering attractive terms -— the kinds of terms that EXIM could offer US bidders if the project were being undertaken elsewhere in the world. But because the project is in the United States, the jobs associated producing the equipment, materials and construction services for that project could well be induced to go offshore for lack of equally competitive financing available in the United States.

This has happened and will be happening again in increasingly competitive and complex markets. A decade ago, in the aftermath of the financial crisis, dozens of US and foreign companies sought project and structured finance from EXIM for domestic projects that used US goods and services, but typically received a quick no. EXIM could not help them. In constrained financial markets, they learned their only recourse was to use foreign goods and services that benefited from foreign export credits.

Between 2008 and 2018, the US was the world's largest country destination for OECD export credits.

In one case, a marquis power project was being developed by a European sponsor in the southwestern US. The US Department of Energy provided project financing. A portion of the sponsor's equity investment was to be provided in kind through the contribution of large, expensive turbines. A US manufacturer was in tight competition with a European company to supply those turbines. The European option came with below-market export credit agency financing that substantially reduced the cost of the turbines to the sponsor. The US product on its merits had advantages, but not so much as to overtake the financing advantage of the European product. The US manufacturer approached EXIM to see if it could provide financing on matching terms.

In this one case, the answer was not a quick no. Indeed, EXIM issued a letter of interest, indicating that there was "no policy impediment" to providing the requested financing. That was a bit surprising, since EXIM providing financing for the purchase of equipment that would not be exported might raise a question of mission creep.

/ continued page 10

IN OTHER NEWS

MULTIPLE TARIFF ISSUES are in play that could affect project costs.

A decision whether to impose tariffs on imported electrical transformers and their components made from grain-oriented electrical steel is expected by January 15.

The affected components are laminated steel used to make cores, wound cores and transformer regulators. If tariffs are imposed, they could add as much as 25% to the cost of the imported transformers and components. Vendors have been unwilling in many recent contracts to absorb the cost of new US import duties.

The US Department of Commerce sent its recommendations to the White House on October 15, starting a 90-day clock to run on a decision. The Trump administration is considering imposing tariffs on national security grounds. (For more detail, see "Possible transformer tariffs under review.") President Trump leaves office on January 20.

Transformers and transformer components made in Mexico will be exempted from any tariffs that are imposed.

The United States Trade Representative announced on November 5 that Mexico agreed to establish a "strict monitoring regime" for exports of transformer laminations and cores made using grain-oriented electrical steel supplied to Mexico from other countries. The US suspects steel companies in China, Japan and South Korea of circumventing a 25% US tariff on imported steel by shipping steel to Mexico or Canada for conversion into downstream products that then pass into the United States duty-free under the United States-Mexico-Canada trade agreement.

Goods imported into the United States from the Xinjiang region in western China face possible import restrictions. Senator Marco Rubio (R-Florida) is trying to get a Senate vote before year end on a bill that would ban "all goods, wares, articles, and merchandise mined, produced, or manufac-

/ continued page 11

EXIM

continued from page 9

Export in Substance

To be fair, a technical detail helped EXIM's comfort with the proposed financing. The turbines were not to be purchased by the US project company, but rather by the European sponsor. Although there was no plan to export the turbines from American soil, from an economic perspective, the transaction would create enhanced demand for dollars by the European sponsor and increase the US supply of foreign exchange, just as much as if the turbines had traveled overseas. And the same jobs were supported in the United States regardless of where the turbines ended up. From an economic perspective, in fact, the turbines were an export.

Consider a European tourist who travels to the US and consumes food while here. Those sales of US goods to a foreign purchaser count, in national income accounting, as exports whether or not the food consumed ever leaves the United States.

Foreign vendors looking to sell equipment to US projects have an advantage over US manufacturers.

So, the financed goods really were exports, and EXIM could have closed that financing in good policy conscience. But it did not. Concerns about acting beyond what Congress might narrowly have seen as its appropriate role trumped the letter of interest, and matching financing was not offered.

To be sure, EXIM already has a well-established program of domestic lending — its working capital program, which provides pre-export financing to companies planning to export goods produced with the support of EXIM loans.

This provides effective encouragement to mostly smaller firms to venture into exporting, but it is typically far removed from meeting head-to-head competition from foreign export credit agencies. US domestic lending is nothing like the supplier credit programs in Europe, Japan, South Korea and China, which are available to virtually all these countries' exporters.

Beyond the "supplier credit gap," the inability to provide export credits based on a broader definition of US exports will become a larger problem in markets that cross borders with increasing regularity. Satellite and telecommunications companies that are US-based, but sell services overseas or have foreign partners, cannot qualify for financing without taking extraordinary steps of creating offshore entities and restructuring sales processes that may be impractical or impossible.

Chinese Threat

The growing threat of Chinese government-supported exports will not be met without a more expansive view of export credits.

For example, the US is leading the way in creating global telecommunications networks that will eliminate the rural-urban broadband divide in the US and around the globe. US firms are — on the merits — well ahead of their Chinese competitors. But US companies cannot approach EXIM for finance related to the US market and face challenges getting support for global sales using EXIM's narrow criteria for financeable exports. In comparison, Chinese companies have access to supplier credits, domestic credits for their home market and export credits for US and other markets, all with opaque terms.

China is using its financing tools aggressively. According to EXIM's competitiveness report, long and medium-term export credits are six times those of the US. Even counting the DFC (formerly OPIC), which does not have a formal export mission, total Chinese export assistance from all sources is nearly nine times that of the US.

Beyond the technicalities of national income accounting, the real issue is whether EXIM, in its quest to support American jobs by leveling the playing field, should be prohibited from performing that key function when the relevant playing field happens to be in the United States. The United States is an important part of the global market. US manufacturers being put at a disadvantage in their home market when foreign export credit agencies are free to support their competitors is an imbalance EXIM is suited to redress.

EXIM's statutory authorizations are broad enough to permit it to meet such competitive at home as well as abroad. No Congressional action is needed. Congress, in its oversight function, just needs to let EXIM do what should be its job. ◎

IN OTHER NEWS

tured wholly or in part" in Xinjiang, unless US Customs is persuaded there is "clear and convincing evidence" that the products were not made with forced labor by Uigher Muslims. US Customs would have to report any such determination to Congress and make the findings public. The bill passed the US House of Representatives in September by a nearly unanimous vote but has run into opposition in the Senate from companies concerned about the difficulty of tracing supply chains.

Banned goods would be subject to seizure at the US border.

About a third of polysilicon used to make solar panels came from the Xinjiang region in 2019. China accounts for about 80% of global polysilicon capacity. One major polysilicon supplier, Dago New Energy Corp., has its headquarters in the southern part of the Xinjiang region. American depositary shares in the company trade on Nasdaq.

The Solar Energy Industries Association has been strongly encouraging US solar companies to move their supply chains out of the region.

Meanwhile, the Trump administration is considering imposing countervailing duties on goods made in Vietnam to offset what it charges is currency manipulation by Vietnam to make its goods more competitive in world markets.

The US Department of Commerce recommended preliminary duties in early November of 6.25% to 10.08% on automobile tires to offset subsidies. A final recommendation is expected in March. An internal Commerce memo attributed 1.16% to 1.69% of the proposed duties to currency undervaluation. The US Treasury told Commerce in August that it believes the Vietnamese dong is undervalued by 4.7%.

The US Trade Representative is investigating Vietnamese currency practices generally, which could lead in theory to duties on a large number of products. */ continued page 13*

Energy Storage Hedges

by Christine Brozynski and Rob Eberhardt in New York, and Deanne Barrow in Washington

Battery storage developers are looking more frequently for contracted revenue streams and for ways to manage commercial risks associated with their projects.

One way to do that is through commodity hedges or related derivatives.

While energy storage hedges are not particularly common today, that may change as capital costs for battery storage assets decrease and other factors fall into place.

Potential Trends

There are several revenue generation strategies for utility-scale battery projects, including pricing arbitrage (buying energy at low prices and selling at high prices), sales of capacity or ancillary services, or sales of demand response and transmission-related services.

In organized markets, merchant sales expose projects to market price risk. Developers, especially those seeking project financing, may prefer more predictable revenue streams where price risks are transferred to another party. A hedge or related derivative is a means to do that.

While many different transaction structures exist, the basic mechanism underlying all of them is that the project offloads price risk in exchange for upfront payments or giving away market upside to a counterparty that takes the price risk. Operating risks generally remain with the project.

In ERCOT, some developers have had success hedging revenue from ancillary services. The hedge provider pays a fixed price per megawatt hour, and the project company pays a floating price equal to the day-ahead clearing price for the ancillary services per megawatt hour. The two payments are netted. The project receives downside price protection in exchange giving the hedge provider the upside available during high price periods.

Similarly, in the past, some developers had success entering into Regulation D hedges in PJM. Regulation D is PJM's fast-responding regulation service to correct short-term changes in grid frequency.

Many market participants are trying to develop other products to help battery storage projects manage price risks.

Clearing prices in transactions with projects from other asset classes — for example, thermal, wind and solar — should play a central role in the attractiveness of these products to the power marketers likely to transact with projects.

Capital costs associated with battery projects should ultimately dictate pricing that make these products attractive to storage developers. As capital costs decline, so will minimum pricing that provides attractive returns for developers. If the federal government enacts legislation permitting standalone storage to take the investment tax credit, that may further reduce the clearing price for developers. The opportunities to "stack" other revenue streams with that provided by a derivative also may reduce the clearing price in certain situations.

If and when these factors converge, there is the potential for transactions to make sense for both parties and ultimately to get done.

Solar provides a potential analog. Solar hedges were not being executed in volume in the US until very recently. They only became viable as capital costs for solar projects fell and solar developers were able to accept lower offtake prices. Like other asset classes, the viability and timing of opportunities for storage hedges may vary in different organized markets.

When and where these products make sense, how will they be structured? The fixed-volume ancillary service swaps that have been executed to date for storage assets provide one option. These hedges in some ways resemble the fixed-volume swaps used by owners of wind and solar projects.

Some developers of standalone batteries in ERCOT are hedging revenue from ancillary services.

Given the dispatchability of storage assets, we also see opportunities to base products roughly on two structures that are used for thermal assets: the revenue put and the heat rate call option or "HRCO."

Repurposing a Revenue Put

A revenue put is in many ways similar to an insurance product. The developer pays a large premium to the counterparty upon execution. Often the revenue put is executed concurrently with the financing documents so that the developer can use the project's credit facilities to make the payment. The premium is a one-time payment rather than an annual or quarterly payment.

The basic idea is that the counterparty will true up the project company each year in the event that the revenue earned by the project company over the prior year is lower than a predetermined amount, calculated as a lump sum rather than a price per megawatt hour. However, there are several nuances.

The first nuance is that the measure of revenue earned by the project company is not actual revenue. Rather, the revenue is calculated as the amount of revenue that the project would have earned assuming the project had been operated at an assumed efficiency and dispatched at economically advantageous times. In this way, the developer retains operating risk, but the derivative is structured to account for the project's anticipated operational capabilities.

The second nuance is that project revenue is calculated by subtracting the plant's assumed start-up costs and certain operating and maintenance costs. Again, the developer retains operating risk, but the derivative reflects the projected operating expenses.

The third nuance is that the developer may negotiate the right to receive quarterly advances from the hedge provider calculated based on how the hedge would have settled if the settlement period were quarterly rather than annual. Once the annual calculation is run, the developer may be required to repay a portion of the advances during the year if the calculation shows that the hedge provider overpaid during the year.

The revenue put structure could be repurposed for a battery project. The developer would pay an upfront premium to the hedge provider, and in turn the developer would have downside protection in the event that the battery's assumed revenue, as recalculated under the derivative, is below a negotiated threshold. The revenue floor serves as a contracted revenue stream available for debt sizing. */ continued page 14*

IN OTHER NEWS

A labor advisory committee composed of more than a dozen large US labor unions urged the US Trade Representative in early November to impose duties of 8.4% across the board on Vietnamese products. The deadline for comments in the USTR probe closed on November 12.

The US Trade Representative is expected to hold virtual negotiations with the Vietnamese government in December. He could issue a formal finding in time for the Trump administration to act before leaving office. President Biden will appoint a new US Trade Representative.

US wind developers could face duties on wind towers from India, Malaysia and Spain. The US International Trade Commission found that domestic tower manufacturers are being injured by tower imports from the three countries in a unanimous vote in early December. The Commerce Department is expected to issue preliminary countervailing duty amounts around January 13 and anti-dumping duty amounts around March 29.

The administration has also been moving to impose duties on wind towers imported from Canada, Indonesia, Korea and Vietnam. (For more details about the tower investigations, see "Unpredictable tariffs" in the February 2020 *NewsWire* and "Tariffs: China, solar, steel, aluminum and wind towers" in the October 2020 *NewsWire*.)

A coalition of 300 companies is urging Congress to extend the generalized system of preferences (GSP) before it expires at year end. GSP beneficiaries are lesser developed countries whose products enjoy preferential access to the US market. Solar panels imported from GSP countries are exempted from tariffs that the US collects currently on imported solar panels as long as their solar panel exports to the United States do not amount to more than 3% of total US panel imports and as long as all developing countries whose individual exports are less than 3% each do not collectively account for more ***/ continued page 15***

Storage Hedges

continued from page 13

The battery revenue would be calculated assuming the battery had been operated at a set efficiency. The parameters around this calculation would be included in the derivative and may include power capacity (which could decline over time to account for cell degradation), maximum duration or run time, depth of discharge, maximum number of cycles per year, charging hours and round-trip efficiency (which is a measure of how efficiently the system takes in electrical energy, stores it in electrochemical form, assuming a lithium-ion battery, and converts it back to electrical energy). Charging costs also would need to be addressed.

One of the attractive aspects of a revenue put structure is market upside is retained by the project. The derivative provides a contracted floor on revenues, but does not expose to the project to significant ongoing payment obligations. The project would retain the flexibility to pursue other revenue streams.

Repurposing a HRCO

For a gas-fired project, the counterparty under a HRCO has an option to buy power for a price that depends on the market price for gas and on assumed characteristics about the plant's capability and costs to convert gas into electricity.

A HRCO can be physically-settled (meaning power is sold to the counterparty as part of the transaction) or financially-settled (meaning no power is sold to the counterparty).

In both physical and financial HRCOs, the hedge provider pays an fixed option premium each settlement period to the project company. This premium is a contracted revenue stream that is used for debt sizing.

Under physical HRCOs, power is actually sold to the counterparty as part of the transaction. The counterparty has the option each day to provide a notice to the project specifying the volume of power it wants to purchase the following day. The volume is subject to certain constraints negotiated before execution of the HRCO that reflect the project's assumed operational characteristics. The hedge provider pays the "strike price" per megawatt hour of power purchased. The strike price is equal to the market fuel price multiplied by an assumed heat rate, plus a fixed O&M charge per megawatt hour. The hedge provider also pays for assumed start-up costs for the plant.

Financial HRCOs likewise have a strike price calculated similarly to the corresponding concept in physical HRCOs. However, in financial HRCOs, the hedge provider does not buy power for the strike price. Rather, the hedge provider pays the strike price and the project company pays the market price. This settlement amount is netted against the option premium and start charge owed by the hedge provider.

Both physical and financial HRCOs could be repurposed for battery projects.

In a both physical and financial storage structures, the hedge provider would submit a schedule for each day specifying the purchase of a certain volume of energy (in the physical hedge) or notional amount hedged (in a financial hedge) per hour for the following day. The schedule would be subject to certain parameters mirroring the operational constraints of the storage project such as power capacity (which could decline over time to account for cell degradation), maximum duration or run time, depth of discharge, round-trip efficiency and charging hours.

Each settlement period, the hedge provider would pay the option amount.

In a physical transaction, the project would deliver energy during scheduled hours for the strike price, the product of the assumed round-trip efficiency and the charging electricity price during charging hours.

In a financial transaction, the counterparty would pay the strike price, the developer would pay the market price, and these payments would be netted, together with the option premium.

There are variations on the HRCO-based structure may be worth exploring, including so-called "look-back" options where settlement is based on optimal exercise schedules determined retroactively for each month.

The developer should be prepared to provide credit support to backstop its obligations under the offtake arrangement. This credit support would probably take the form of either a letter of credit, a parent guaranty from a creditworthy entity or a first-priority lien on the project assets and equity interests in the project company. ◎

Post-Election Analysis

Congress is back in Washington for a short "lame-duck" session before year end. President-elect Biden will take office on January 20. A new Congress will also be seated in January. Democrats will retain control of the lower house in the new Congress, but by a much narrower margin than before. Control of the US Senate will turn on the results of runoff elections in Georgia for two Senate seats in early January. Republicans will retain control of the Senate, unless Democrats win both seats.

A group of Washington insiders talked three days after the national elections in November about what the results mean for the renewable energy market and project finance transactions more broadly.

The group is Joe Mikrut, partner with Capitol Tax Partners and a former tax legislative counsel at the US Treasury and former senior legislation counsel on the staff of the Congressional Joint Committee on Taxation, John Gimigliano, principal in charge of federal tax and regulatory services for KPMG in Washington and a former Republican tax counsel to the House Ways and Means Committee, Christine Tezak, a managing director of ClearView Energy Partners, an independent research firm that advises investors and management of large energy companies about how policy is likely to affect the energy sector, Eric Wolff, one of several energy beat reporters for *Politico*, a highly respected specialized news service that was started by *The Washington Post* political team and is widely read in Washington, and Brandon Hurlbut, a partner with Boundary Stone Partners, a consultancy that helps business clients interpret what is going on in Washington, and a former chief of staff to the US energy secretary, former liaison to the energy and environment cabinet agencies in the Obama White House and co-host of the Political Climate podcast. The moderator is Keith Martin with Norton Rose Fulbright in Washington.

Lame-Duck Outlook

MR. MARTIN: Joe Mikrut, Congress must come back for a lame-duck session starting in late November. It has only funded the federal government through December 11. There is also the unresolved question of an economic stimulus bill. Do you expect a stimulus before year end?

MR. MIKRUT: As of today, yes. As of last week, I would have said no, but the Senate majority leader, Mitch McConnell, who had been opposed to doing a stimulus just a few days ago, made it clear that he thought a stimulus / continued page 16

IN OTHER NEWS

than 9% of total US panel imports.

Separately, President Trump announced an investigation on October 10 that could lead the US to continue collecting tariffs on imported solar panels beyond February 2022 when the current tariffs are scheduled to expire.

The United States has been collecting duties on imported solar panels since early February 2018. The duties started at 30% and have been dropping 5% each year. They are scheduled to remain in effect through early 2022. The duty rate had been scheduled to drop to 15% in early February 2021. Trump increased the rate to 18% in the same October 10 proclamation.

The proclamation also revoked an exemption from the tariffs for bi-facial solar panels effective on October 25. The administration had been trying since last fall to revoke the bi-facial exemption, but was blocked by the US Court of International Trade. (For earlier coverage, see "Solar and wind tariffs" in the December 2019 *NewsWire* and "Fluctuating solar and wind import tariffs" in the June 2020 *NewsWire*.) The court allowed the latest action to stand.

An industry-by-industry analysis by the Federal Reserve Board in October of the trade war that the United States has been engaged in with China concluded that US tariffs boosted employment by 0.3% in US industries for whom the tariffs provide a barrier from competition, but this was more than offset by US job losses elsewhere. The higher costs to import Chinese parts cut jobs at US factories that serve the US domestic market by 1.1% while retaliatory Chinese tariffs cut US jobs at companies that make sales to China by 0.7%.

Shipping costs from Asia to the US have soared.

Long-term rates charged by container shipping lines to ship from Asia to the US west coast were 63.4% higher in late October than a year before. / continued page 17

Post-Election Analysis

continued from page 15

would be important in a lame duck. Clearly the House speaker, Nancy Pelosi, wants to do one as well, so I expect some sort of stimulus in the lame duck. They still have to agree on the size and obviously the makeup of the provisions, but I think that now that there is a will, both sides will find a way to get it done.

MR. MARTIN: There was a wide gap when the talks broke off. Pelosi was at $2.2 trillion. The Senate had passed a bill, but it was for $650 billion, of which only $300 billion was new money. How do you bridge such a wide gap?

MR. MIKRUT: That will be one of the problems, but I think the way the Democrats will look at it is that if they don't get enough done in the lame duck, they can always come back for more when presumably Mr. Biden will be president. To the extent that there is a need, it will probably force things to come to a resolution some place in the middle between the half trillion that the Senate had passed and the $2.2 trillion that the House was proposing.

MR. MARTIN: John Gimigliano, do you agree with that, and if there will be a stimulus, will Trump sign it if he ultimately loses the election?

MR. GIMIGLIANO: I will answer the second question first because I think it is easier.

I think the answer is yes for no other reason than, if he doesn't sign it, it gives an incoming President Biden an immediate win. I don't see a reason why even an outgoing President Trump would refuse to sign.

As for whether there will be a stimulus before year end, I understand what Joe said and he is probably right, but there is still friction in getting a bill done this year. The biggest obstacle is what you mentioned, which is the wide gap in dollar amounts. I think the House Democratic position was that Senate Republicans needed a bill more than House Democrats, and that's why Speaker Pelosi was sticking to the $2.2 trillion number, thinking that eventually Republicans in the Senate would come around.

A lot of them proved that they could win without it. There is no new incentive for them to agree to a higher number. That leads me to think you are going to have both sides stuck at their numbers, and whether or not they can meet somewhere in between depends on other factors: will there be continuing acrimony around the election as well as the Georgia Senate run-offs. We will have to see what the political dynamic is when they get back to Washington.

MR. MARTIN: Fair enough. Joe Mikrut, there was talk about a year-end tax extenders bill. Do you see that happening either separately or folded into a stimulus or federal funding bill to keep the government operating?

MR. MIKRUT: It will not happen separately. It will have to be folded into something else.

The tax extenders are not as popular as they once were, although there is bipartisan support for the 30-odd provisions that are expiring at the end of the year. The really popular ones have all been picked off by being made permanent or being given long-term extensions.

Another factor is that when you talk to the Democratic staffs on the tax-writing committees, they say the optics of doing tax extenders, which are primarily business provisions, but not providing relief for individuals hurt by the pandemic, are bad, and they also think the policy is bad.

Unless we get a stimulus bill that provides relief for individuals, I think the extenders will have to wait on the sidelines until later. That said, if there is a stimulus bill, then I bet we will have the extenders attached to it, at least on a short-term basis.

MR. MARTIN: John Gimigliano, do you agree?

MR. GIMIGLIANO: Yes. It would be a bad look for Congress to do a business tax extenders bill and not do another round of COVID relief. So the COVID relief bill has to come first, and then extenders can come along.

To me the question is if that COVID bill is at the lower end of

> The renewable energy industry has had to spend the last four years on defense. Now it gets to start playing offense.

the cost spectrum that we talked about, how big can extenders get in cost? Obviously if the bill is closer to $2 trillion, there is more headroom to do business relief. If the bill is much smaller, then the optics concern that Joe talked about becomes more important.

Solar Tax Credits

MR. MARTIN: Joe Mikrut, how likely is Congress to extend the solar tax credit this year? As you know, the solar industry has been pressing for a five-year extension of the deadline to start construction of solar projects and qualify for a 30% investment tax credit.

MR. MIKRUT: They pushed for it last year, and it did not happen then. I think the extenders bill, if it happens this year, will be a minimalist bill, and the solar credit, because it is on the books and not expired, will be something that will have to wait to be done later. I think the focus will be on things that expire at the end of this year and go away in 2021.

MR. MARTIN: John Gimigliano?

MR. GIMIGLIANO: Joe is right. Congress is not very good at dealing with expiring tax provisions until they have actually expired. It was not always that way, but in recent years, as Joe said, because some of the most popular extenders have been addressed separately, the dynamic has become that they expire and then they are extended retroactively.

Help may be on the way. A group of extenders that is popular with Republicans out of the Tax Cuts and Jobs Act — the bonus depreciation provision, the expensing of research and experimentation costs, the relief on the interest limitation — is coming up and may become the new mega-extenders that can pull the other extenders across the finish line.

But we are still probably another year away before Congress grapples with those. It is hard to see provisions that have not yet expired being dealt with this year.

MR. MARTIN: Joe Mikrut, do you agree that the odds improve next year or beyond for a solar tax credit extension?

MR. MIKRUT: Yes, and I also think that if we get into next year and there is a need for a bigger stimulus bill very much like there was in 2009, then a long-term extension of the renewable energy provisions, not just solar but all of them, would be something that could fit into a package like that. So for the lame duck, no. Next year, maybe.

MR. MARTIN: What odds would you place on maybe?

MR. MIKRUT: I'd say it's 100% maybe. [Laughter]

/ continued page 18

IN OTHER NEWS

Prices to ship to the east coast were 25% higher.

The National Retail Federation said in November that it tracked 8.1 million shipping containers into US ports during the peak shipping season from July through October as retailers restock inventories ahead of the busy holiday season and prepare for the pandemic to worsen over the winter. The volume is a record and is up 6.6% over last year.

TWO PROVISIONS in the National Defense Authorization Act that Congress is expected to send imminently to President Trump are getting attention from the project finance community.

Trump has threatened to veto the bill for other reasons. Congress could override the veto.

One provision would extend the US Constitution and federal laws to the US outer continental shelf and specifically to "installations and other devices permanently or temporarily attached to the seabed, which may be erected thereon for the purpose of exploring for, developing, or producing resources, including non-mineral energy resources." The outer continental shelf is generally the area between 12 and 200 nautical miles offshore. It would be treated like a federal enclave.

This would have the effect of requiring offshore wind developers building on the US outer continental shelf to comply with the Jones Act when moving equipment from staging points on US land to the project sites. The Jones Act requires trade between points in the United States to be carried on US flag vessels.

It could have other implications as well. Similar questions could arise as came up when the US extended its territorial waters immediately adjacent to the US coastline.

The US formally declared that its territorial waters extend three miles from shore in 1793. President Ronald Reagan extended the US territorial waters to 12 nautical miles by presidential proclama-

/ continued page 19

Post-Election Analysis

continued from page 17

MR. MARTIN: John Gimigliano, what odds would you place on it?

MR. GIMIGLIANO: One percent less than what Joe said. [Laughter]

I think overall the climate is going to improve for all things renewables if you have a Biden White House. That doesn't mean anything is certain, but the overall climate will be better. Even with a Republican-controlled Senate, if that is the way it ends up, there are always deals to be made.

The environmental movement has largely shifted tactics away from carbon pricing to "standards and justice."

The question will be how much might Democrats have to give up to a Republican-controlled Senate to get some of these things? It just becomes a question of priorities. Is it the number one priority or is it the number 10 priority? You don't always get your top 10, but you might get the top one, two or three. It will put a lot of pressure on a Biden administration, as well as the Democratically controlled House to decide whether renewable energy and the climate agenda are in the top three? If so, then there is the potential to get some of these things done.

MR. MIKRUT: I agree with everything that John said, but I think that the Democratic priorities change if the Senate remains in Republican hands.

With Democrats in control, the priority will be health care, shoring up the Affordable Care Act.

That is not going to happen with a Republican Senate. So the priority will be something else and, if the economy continues to worsen, infrastructure might creep into the top three or four. If there is an infrastructure bill, then I think there will be a significant tax title like there was in 2009.

MR. MARTIN: We should say that control of the Senate seat will turn on run-off votes for two Senate seats in Georgia. Republicans control 50 seats and Democrats have 48. If Democrats can win both Georgia Senate seats, then they will have control over the Senate because the vice president can cast the deciding vote.

MR GIMIGLIANO: The Georgia run-off date is January 5. We could be waiting for some time after to get a resolution.

MR. MARTIN: One more question about this year, and then we will move into next year. The US Chamber of Commerce has been lobbying for a plan to allow quick refunds of 31 business tax credits claimed in 2019 or 2020, or carried into those two years from as far back as 20 years ago. Joe Mikrut, is that likely to be enacted?

MR. MIKRUT: I don't think so in the current climate.

The Democrats, even though they passed business relief in the original CARES Act and allowed a five-year carryback period for net operating losses, had buyer's remorse afterward and have been trying to repeal the carryback. If that is the dynamic, then it will be very hard to provide for refundability of the business tax credits, even though some of the credits that would be refunded are things that are generally Democratic priorities. I just don't see it for the lame duck.

If we get into next year and there is a dramatic need for an economic stimulus, then the issue will come up. There is some bipartisan support for the idea, but the bills have been introduced by Republicans and I think the idea will be viewed more as their priority. It could happen through horse trading if Republicans retain control of the Senate, but it will still be difficult to get that one done.

MR. MARTIN: John Gimigliano, same answer?

MR. GIMIGLIANO: Yes, for a bunch of reasons.

One is the cost of the provision is enormous and if Democrats truly view it as a Republican priority, then it would not be surprising for them to tell Republicans that they need to help find a way to pay for it. Republicans are not going to go for that. I am not sure how much of a Republican priority it actually is.

Keith, you know this as well as anybody that back in the financial crisis in early 2009 when we had a very similar conversation about the renewables credits and finding a way to add liquidity at a time when tax equity had all but vanished — you know, because I know you were involved in those discussions — Democrats were not that interested then in making those credits refundable, and that is what ultimately gave birth to the 1603 cash grant program. I don't think Democrats' thinking — although it have been 10 years — has really changed in terms of writing checks to the private sector, even businesses they favor, like renewables. You never say never, but I think it is a real uphill push.

Early 2021 Stimulus?

MR. MARTIN: Let's move to next year. I have two more questions for Joe and John, and then I want to bring in the larger group. The first question is, if Congress passes a stimulus in the lame-duck session, will that leave room for any large economic measures early next year? What would Biden be able to do?

MR. GIMIGLIANO: I think the answer to that is yes. One of the first things that a Biden administration will say is there is work left to be done.

If we do get any kind of COVID relief or stimulus bill during the lame-duck session, it will be on the smaller side, and I think there will be a lot more that the Biden administration feels is left to be done. Joe is right. It could be infrastructure oriented. When we talk about infrastructure, lots of things could happen. Republicans and Democrats generally view infrastructure differently. Republicans are less interested in sending money to state and local governments to do state-and-local spending, and Democrats are less interested in sending checks to the private sector to do private-sector spending. I think they will find a way to get something done, and that is the kind of thing that I expect to see early on.

MR. MARTIN: Joe Mikrut, if you agree with John Gimigliano that there will still be room for some sort of additional economic measures next year even if a stimulus bill passes in the lame duck, on what timeline do you see that happening next year?

MR. MIKRUT: An incoming administration likes to get things done in the first hundred days. I would put action toward the end of that period, maybe going into the second or third quarter of the year. The administration has to get its team in place. That will take time. All of this will depend on */ continued page 20*

IN OTHER NEWS

tion in 1988 after 104 other countries had already set their boundaries at 12 miles based on a 1982 United Nations convention on law of the sea. The US Navy had opposed extension in the past, as had the British Navy, as both wanted free passage closer to shore for naval vessels.

The US Coast Guard told a House committee three months after Reagan acted that the proclamation was intended to extend US jurisdiction only for international purposes, but was not meant to change the three-mile boundary for application of US domestic law.

Individuals born in the US are granted automatic citizenship. The manual used by US consular officials suggests that there are substantial legal questions around whether anyone born on a ship between three and 12 miles from shore is a US citizen.

Congress resolved the uncertainty about one aspect of the Reagan proclamation by clarifying by statute in 1996 that US criminal laws extend 12 miles out to sea.

The application of many US tax laws turns on whether activity takes place in the US.

Another provision in the defense bill would require corporations, limited liability companies and any "other similar entity" formed under US state or tribal law to file reports with the US Treasury disclosing their beneficial owners. Reports would also have to filed by foreign companies authorized to do business in the United States.

The provision is aimed at stopping money laundering by shell companies.

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

The first reports would have to be filed two years after the Treasury issues implementing regulations.

An additional report would have to be filed every time there is a change in ownership.

There are 10 pages of exceptions listing types of companies from whom reports would not be required. The ***/ continued page 21***

Post-Election Analysis

continued from page 19

what the economy and job report look like. If things worsen significantly, that could accelerate the pace.

MR. MARTIN: Let's broaden the discussion. Apart from the 2017 corporate tax cuts and the CARES Act last spring, Congress has largely been sidelined by partisan gridlock at least the last two years, and one could argue even the last four years. Is anything likely to change, particularly if Trump is waiting in the wings as a potential 2024 presidential candidate?

MR. HURLBUT: I am not totally sure that a stimulus will get done in the lame duck. Even if one is passed, you could have Mitch McConnell take the view that "we've done everything we can" and Biden will not get a second bite at the apple.

MR. MARTIN: Fair enough. John Gimigliano, do you see more partisan gridlock going forward? Has much changed?

MR. GIMIGLIANO: A lot of this comes down to whether the Republicans control the Senate. There is a history of Mitch McConnell and Joe Biden working together. Perhaps they can find a way to do what is needed, even if it is not everything that Democrats hope will be done. If the Democrats are able to wrest control of the Senate away from Republicans by getting to a 50-50 split, which would give them control, then I expect to see significant action because history tells us that when one party controls everything, it is go-for-broke time because you do not know when you will have that chance again.

Even if the Republicans maintain control in the Senate, there will be things that have to be done. There are the debt limit and government funding, and every time you have a must-pass bill, there is an opportunity to add other things, and some of those things might be in the energy sector.

MR. WOLFF: It is interesting to me how the actual election results have changed everyone's tune.

Before the election, when there was a widespread assumption the Democrats would take the Senate, we heard from Republicans that they were going to start calling for austerity and that we would hear about nothing but austerity from that caucus for the next two years, which suggests that Senate Republicans will not back any kind of spending. As soon as the results came in, we had Mitch McConnell saying, "I want to get a stimulus done before the end of the year."

So I ask, why before the end of the year? Probably because he would rather have Donald Trump sign it than have to worry about getting Joe Biden to sign it. Strategic considerations like these will play a role.

Does Nancy Pelosi agree to a deal? On the one hand, she is under pressure to help the American people who are hurting, but on the other hand, she is saying, "If I wait two months and have a friendly White House, then we can start talking about trillions of dollars."

The point is it is not clear we will get a deal in the next two months.

Likely Executive Actions

MR. MARTIN: Christi Tezak, the most visible actions by Trump have been executive or regulatory actions — rolling back environmental regulations, pulling the US out of the Paris climate accord, tariffs on solar panels, Chinese goods, steel, wind towers, you name it. In which areas is Biden most likely to use executive or regulatory action as president?

MS. TEZAK: I think Biden will be substantially limited to executive and regulatory action, even if he has a 50-50 Senate that is nominally under Democratic control.

Even if the Democrats were to eliminate the filibuster, they would still find it hard to move forward with massive policy initiatives. For example, legislating pollution limits on greenhouse gases does not pencil out for us. In fact, we could not make it pencil out, even if the Democrats had 54 Senate seats just because of the breakdown of Democratic senators from oil-and-gas producing states versus consuming states.

The only thing that might be possible in a 50-50 Senate is a clean energy standard, but likely not the one as ambitious as proposed by Joe Biden's campaign. Any such standard would need to define "clean energy" broadly to pass. It would probably need to target 2050 rather than 2035. A narrowly divided Congress implies that you probably need to bring nuclear and conventional hydro along just to start the conversation.

This takes us to what can be done on an executive and regulatory basis. The substantially more conservative judiciary that has materialized over the last four years of the Trump administration is likely to challenge any administration that tries to push the bounds of its statutory authority. We are even seeing judges appointed by Democrats be a little more attentive to things like standing and clear links back to statutory authority as they review cases that are coming before them now. Given this, something as ambitious as the Clean Power Plan looks doomed.

MR. MARTIN: If such a plan is proposed, you may not see it implemented for several years because of court challenges.

MS. TEZAK: If the Clean Power Plan was stayed by the Supreme Court in 2016, then it is hard to imagine the current court taking a more favorable view. Simply resurrecting the Clean Power Plan will not work.

That is why things like a clean energy standard would help. There are other things that a Biden administration can do, like revising the National Environmental Policy Act regulations that were recently finalized, pulling them back from judicial review and modifying those.

MR. WOLFF: The executive branch is huge and has vast authority, as we have witnessed for the last 12 years, in particular.

We probably will not see a new Clean Power Plan, but the environmental movement has largely shifted its tactics. There has been a big move away from things like carbon taxes and other economy-wide actions to what environmentalists call "standards and justice," where they hone in on particular industries. A clean energy standard could be a part of that. Clean energy standards have generally been popular. I don't know if you can move them through a Republican Senate, but certainly in 2018, we saw a lot of governors win on such standards at the state level.

Congress has waited in recent years until after tax credits have expired to extend them.

I had a bunch of people tell me before the election that the federal government has a lot of buying power, and merely shifting the federal government's buying power toward efficiency and renewables is wind in the sails of the renewables industry.

The Department of Interior has been dragging its feet on offshore wind. That will change.

The other issue you mentioned is tariffs and trade. The Obama administration put duties on imported solar panels. It is not clear to me that the Biden administration will drop the global tariff on solar panels that only has a year left. */ continued page 22*

IN OTHER NEWS

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

THE LIBOR TRANSITION remains a work in progress.

The US tax authorities issued more guidance in October in an effort to dispel fears that adjusting loan agreements and hedges so that they still work after the UK stops publishing LIBOR will have adverse tax consequences.

The UK Financial Conduct Authority plans to stop publishing one-week and two-month LIBOR rates after 2021, but will continue to publish remaining LIBOR tenors –- including the most commonly used one-month and three-month rates –- through June 2023.

US regulators are discouraging US banks in the meantime from entering into new LIBOR contracts after 2021 to add hardwired fallback language to both existing and new LIBOR-based instruments.

The US expectation is that the market will shift to use of SOFR, a replacement rate for dollar-denominated instruments, or use LIBOR but include so-called ARRC hardwired fallback language that will automatically adjust to another rate once LIBOR stops being published.

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

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

Andrew Coronios, */ continued page 23*

Post-Election Analysis

continued from page 21

Biden has real animosity toward China. He called the leader of China a thug. That is not the sort of thing that a Chinese leader forgets. It is probably a genuinely held opinion.

A lot of things can happen on the executive side without Congress. Sure, a Democratic Senate would make more things possible for renewables, but just shifting the White House is addition by subtraction.

MR. HURLBUT: When I was in the Obama administration, after we lost control of the Congress in 2010, we had to think really carefully about how to use executive branch authorities. You will have people going into the Biden administration who served in the Obama administration and have experience with that.

Over the last couple of years, while Democrats have been out of power, there has been a lot of thought behind the scenes about how to use executive branch authority. They will not start on day one from scratch. They will have a whole menu of policy options that people have been thinking about for years to go implement if they want.

One example, for the project finance folks, is the Department of Energy loan guarantee program has tens of billions of dollars in unused authority that can be a down payment on an infrastructure package. The Department of Agriculture also has unused loan guarantee authority. Those programs will be open for business, and you will see a lot of activity.

FERC

MR. MARTIN: Eric Wolff, last night, Trump replaced the Republican chairman of the Federal Energy Regulatory Commission, Neil Chatterjee, with James Danly. You broke the story. What is that all about?

MR. WOLFF: Tricky question for me to answer because I am working on further developments and hope to have another story out later today with my colleague, Gavin Bade.

The part that I can talk about is that there was concern within the administration about some of Chatterjee's more climate- and renewable-friendly policies. The administration was not thrilled with Order 222, which was the order that allowed distributed energy resources, like small batteries and rooftop solar, to aggregate and participate in wholesale markets. The administration did not love that there was a carbon pricing technical conference or a carbon pricing proposed policy statement.

So former Chairman Chatterjee might have been a bit on the outs. I can't get into why the Trump administration did this in the middle of counting ballots in an election. We are still working that part of the story. I guess the president felt the need to make a change, even though Danly will likely only be chairman for a couple of months.

I will be interested to hear the opinions of other panelists on whether the two nominated FERC commissioners will get Senate time. I am skeptical that they will. If they do not get confirmed, then you almost certainly will have Chairman Richard Glick as of January 20, which would give him control of the agenda even though he remains in the minority. Control of the agenda is not trivial. It means maybe we start to see things like downstream carbon dioxide emissions inside pipeline permits and some other things about which Glick has been very vocal during his time on the commission.

MR. MARTIN: Why would the Senate not take up Allison Clements and Mark Christie, the Democratic and Republican nominees for the two open seats on the commission? Wouldn't failure to confirm them just leave the field to Biden to appoint two Democrats?

MR. WOLFF: I would really rather defer to our Congressional experts, but there is only a certain amount of time left on the Senate clock. McConnell has already announced his preference for doing a COVID stimulus bill. Putting another Republican and another Democrat on the commission secures the Republican majority, so maybe McConnell will decide that is important, but he may just decide not to prioritize it.

MS. TEZAK: I agree with Eric. It depends on what McConnell wants. It is not uncommon at the end of Congressional terms, although not as common at the end of the presidency, for the Senate to do batches of appointments. If the Senate puts both of them on the commission, then you will have five FERC commissioners, with a three-to-two Republican majority, but not for long.

When Chatterjee was still chairman, he made it clear that he did not plan to leave before his term expires at the end of next June. Danly has not made such a commitment. He could take his short tenure as chairman, put the feather in his cap and move on to the next thing, clearing the seat for someone else.

If Danly goes back to being a regular commissioner, one of the interesting things is to what extent does Chatterjee become the Anthony Kennedy or the John Roberts of FERC, with a willingness to reach across the aisle? Does he become a swing vote at least on some electricity issues? He and Glick are not on the same page about PURPA, but on carbon pricing and potential offshore wind transmission interconnection and other issues, he is more aligned with Glick, and the two of them have moved orders over Danly's dissent.

MR. MARTIN: But only until June, Christi.

MS. TEZAK: Yes, but it takes time to get a new commissioner through the Senate. You know there will be things that are going to be on rehearing before the commission between now and June.

MR. WOLFF: I need to throw in one more interesting detail that my colleague Alex Guillen mentioned in terms of Chatterjee. There were rumors a month or two ago that Chatterjee was interested in running for governor of Virginia, and he did not slap those down. There is a Facebook group. The filing deadline for that job is the end of March. He says he will serve out his term, but if he seriously wants to run for public office in Virginia, he can't serve out his term. The question is how long the Republican majority at FERC will last.

Transmission

MR. MARTIN: Eric, developers of utility-scale renewable energy projects rank grid congestion as their number-one problem. It proved impossible to get Congress to pass the same siting authority for transmission lines as for gas pipelines during the Obama administration. The real action has to come from FERC. Is anything likely to be done on transmission?

MR. WOLFF: If nothing changes, no, because it is too easy to stall new transmission lines through litigation. Transmission lines have to go through red and blue states, and both types of states seem to agree that they don't like the look of transmission lines.

But it may be an area where an agreement is possible at the federal level. A number of Republicans want to promote new infrastructure projects. There is a fair amount of environmental support for transmission lines. I have talked to folks in gas trade groups and in some of the renewables trade groups who say they are ready to put real lobbying muscle behind trying to get siting authority over at FERC.

Can they get it done? Maybe some of the vote counters have a better sense of it, but the fact that trade groups on both sides are ready to make that a priority is interesting. If you talk to Abigail Ross Hopper at the Solar Energy Industries Association, she will tell you her group has had to spend the last four years on defense. It has had to defend against import tariffs and fight off a coal subsidy at the beginning of the administration. In a Biden administration, the solar industry / *continued page 24*

IN OTHER NEWS

a finance partner with Norton Rose Fulbright in New York, said banks do not seem enthusiastic at this point about hardwiring instruments to SOFR. The problems are "borrower concerns about not knowing a rate before an interest period begins, lack of clarity about the spread adjustment required to convert LIBOR instruments into SOFR instruments, quarter-end volatility in SOFR, and operational issues faced by banks in transitioning their systems to SOFR," Coronios said. (For further discussion, see "SOFR too volatile?" in the August 2020 *NewsWire*.)

The market is also waiting for US regulators to start publishing "term SOFR" rates that would be more consistent with current LIBOR rate-setting practice. Coronios said panelists on a November webinar hosted by the LSTA, the trade group for the North American syndicated loan market, said they are seeing more examples of lenders modifying the ARRC fallback language "to provide for a 'second flip' of the replacement benchmark to term SOFR if that becomes available after a loan has already transitioned from LIBOR to a SOFR replacement benchmark before term SOFR is available."

Jeremy Hushon, a project finance partner in Washington, said he suspects a "zombie LIBOR" rate is likely to play a larger role over the next few years. Lenders with large books of loans with tenors beyond 2023 delay amending their existing LIBOR instruments in the hope that term SOFR rates will emerge by June 2023. (For the effects of the transition on emerging markets, see "LIBOR end may disrupt emerging market lending" in the October 2020 *NewsWire*.)

Two competing references rates –- AMERIBOR and the Bank Yield Index –- have not gained much traction in the syndicated loan market, Coronios said, but may have appeal to some smaller and mid-sized banks who do not believe SOFR reflects their costs of funds.

Meanwhile, the ***/ continued page 25***

Post-Election Analysis

continued from page 23

gets finally to start playing offense. It believes that it should be able to win support from both Republicans and Democrats on some issues, and maybe transmission is one of them.

MS. TEZAK: I will take the other half of that bet.

Offshore Wind

MR. MARTIN: As already mentioned, offshore wind projects have been stalled. The Bureau of Ocean Energy Management placed a hold on construction permits in August 2019. Trump has been no fan of wind, but there has also been a political element to this. There is opposition from fishermen. Brandon Hurlbut, is offshore wind the market segment most likely to be helped by a Biden win?

MR. HURLBUT: It could be. What I will be paying attention to is the eventual structure of the White House clean energy and climate policy-making apparatus because that will provide insight into how Biden plans to exert influence over the agencies to drive his clean energy and climate agenda.

Some people are calling for a climate council within the White House that would have the equivalency of the National Security Council or the National Economic Council. Then you would have a kind of climate cabinet apparatus where you would drive a top-down policy agenda. I will be paying very close attention to whether they do it that way, or they have a smaller office like they had with Carol Browner, the Office of Energy and Climate Change, or just a top senior advisor who owns the issue.

MS. TEZAK: One problem with the extended review of Vineyard Wind is that it has almost become a programmatic-level analysis of offshore wind. However, at the end of the day, that might play out as a net positive because it not only could help approval of the Vineyard Wind project to withstand judicial scrutiny and challenges from the fishermen, but it might also prove to be a useful building block for other projects.

We think there is a possibility that the breadth and depth of the Trump administration's analysis, to the extent it has been a delaying tactic, may actually prove to be a step forward for the next round of offshore wind projects.

Politics of Climate Change

MR. MARTIN: Interesting point. Eric Wolff, you mentioned that FERC issued a policy statement recently suggesting it is willing to accommodate carbon pricing by RTOs. Does anyone see a shift in attitudes in Washington about climate change if Trump leaves? John Gimigliano?

MR. GIMIGLIANO: The real question is whether there has been a shift on the Republican side because the Democrats have been there for years.

I think there is some softening on the issue. During my time on the House Ways and Means Committee staff, a Republican-controlled Congress enacted the solar investment tax credit with broad bipartisan support. Something changed during the Obama years that sort of rallied Republicans against climate change, but I do think that opposition is softening. Is it a sea change? No, but maybe you don't need a sea change. If you just get a small group of Republicans to go along, you could have a policy change in terms of how Congress responds to the problem of climate change.

MS. TEZAK: Carbon pricing in the wholesale electricity market that FERC oversees is not as much a partisan issue. The carbon price in wholesale market tariffs is being offered as a bridge between the preferences of the states that want to decarbonize and the owners of conventional assets, particularly natural gas, that would like to remain in the market.

There is a common interest that has changed the conversation.

The hope is that something like carbon pricing, which would look at carbon more like SO_2 or NO_x emissions and start baking it into the price of dispatch, would be a more market-oriented solution than the individual policy initiatives that are still underway at the state level. It might be a way to harmonize the competing interests more effectively.

MR. WOLFF: Christi has accurately articulated former Chairman Chatterjee's hope and dreams for carbon pricing. What he really wants to see — and the natural gas industry in particular, also wants to see — is a nice carbon price that can work smoothly inside markets and hopefully motivate states to drop or at least relent on all of their carbon climate policies and renewable portfolio standards.

But that is not reality. During the period FERC adopted the minimum offer price floor that is intended to counteract subsidized state subsidies, we have only seen states increase their climate goals, increase their renewable portfolio standards and become more aggressive instead of backing down. They are having serious conversations about exactly how to extract themselves from the markets and take over their own resource capacity.

NORTON ROSE FULBRIGHT

Now that may prove too difficult. I talked earlier about how some big chunk of the environmental movement has shifted toward standards and justice and away from carbon pricing. Carbon pricing is old news.

MS. TEZAK: The environmental movement has never been a fan of carbon pricing. I agree.

MR. WOLFF: I am really skeptical that we will get a nice easy transition, which is certainly what Chatterjee wanted.

MS. TEZAK: I didn't say it would be easy. The question was whether the environment has changed. The conversation has changed. It is at least broadening a bit, but it remains to be seen where the conversation goes with different leadership in the White House and how active Trump remains on the political scene.

MR. WOLFF: We spent a lot of time talking about what happens to the Senate, which is not trivial, but if we get to a Democratic majority and a Democratic chairman at FERC, then does the minimum offer price rule even survive? Glick hates the MOPR, and I doubt Allison Clements is a fan of the MOPR.

If the MOPR goes, then you have state subsidized renewables competing against differently subsidized fossil fuels, but only one of these has to worry about a variable commodity price. The other one is zero margin.

MR. MARTIN: We are down to the last 10 minutes. Let's try to work in some audience questions, but before we do, I have one quick question for Joe Mikrut. Do you think a carbon border adjustment is likely next year?

MR. MIKRUT: No.

MR. MARTIN: That was short and sweet.

MR. MIKRUT: For the same reasons that people said carbon pricing is a step too far, carbon border adjustments are in the same category.

Audience Questions

MR. MARTIN: Moving to audience questions, if there is an infrastructure package in early 2021, do you think it will be paid for or debt-financed, and will the answer to that question affect the scope of the package that can be passed?

MR. GIMIGLIANO: The answer depends in part on who controls the Senate. If you have a Democratically controlled Senate, there will be a much greater willingness to dip into parts of the Biden tax plan to raise taxes in order to offset the cost, especially if the Democrats get rid of the filibuster. They could probably find a way to have at least a partially paid-for bill.

/ continued page 26

IN OTHER NEWS

Internal Revenue Service tried in a revenue procedure in mid-October to ease fears about the tax consequences of changing the benchmark interest rate in a debt instrument or hedge.

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

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

The new revenue procedure is an attempt to make things even simpler by saying that anyone adding the ARRC hardwired fallback language to a debt instrument or hedge will not trigger taxes.

Certain deviations are allowed from the hardwired fallback language without creating issues. If the deviations go beyond these, then the instrument will be analyzed as if the fallback language were part of the original instrument to assess whether the additional changes are a substantial modification.

There is no problem with deviations that are needed to make the instrument enforceable in another country or that omit part of the fallback language that cannot, under any circumstances, affect operation of the modified contract. An example is omitting any discussion about fallback rates tied to other interbank offered rates besides LIBOR if LIBOR is the current benchmark rate.

The new guidance is in Revenue Procedure 2020-44.

/ continued page 27

Post-Election Analysis

continued from page 25

If the Republicans control the Senate, then I don't see any way that an agreement will be reached to pay for it. In that case, it will end up having to be pitched as more of a stimulus kind of bill. Historically, Congress doesn't pay for stimulus bills. There would be a limit, in that case, on the size because there is only so much that Republicans and probably even Democrats are willing to do in terms of deficit-financed stimulus.

MR. MIKRUT: I agree. I think the Democrats' priorities would be a combination of debt finance and some of the tax raisers, like a higher corporate tax rate and perhaps an increase in taxes on individuals earning more than $400,000 a year. I don't think the Biden administration will be interested in doing tax reform just for the sake of tax reform. It will want to raise the revenue to spend it for specific reasons. It is hard to imagine a Republican-controlled Senate voting to roll back some of the 2017 revisions, unless there are significant concessions in the same package. But I can't see a fully paid-for package in any scenario.

MR. MARTIN: Let me go back to Eric Wolff. An audience member asked, can you say more about the future of the MOPR after the Biden victory?

MR. WOLFF: It will depend on the composition of FERC. Democrats hate it. Their constituents hate it. Environmentalists hate it. Environmentalists will talk your ear off about how it is a straight-up subsidy for incumbent fossil-fuel generation. Glick has made his opinion of the MOPR very clear. If you end up with a Democratic majority at FERC, my best guess is that they will simply withdraw the whole thing.

MS. TEZAK: FERC can't just withdraw it.

MR. WOLFF: It will figure out a way to neuter it.

MS. TEZAK: There are a couple ways.

MR. WOLFF: Go for it.

MS. TEZAK: One way to neuter it is for PJM to come up with an alternative plan. I think various stakeholders in PJM are currently considering what they can propose to FERC as an alternative. Certainly taking a different approach to basic generation services is step one. Revisiting the draconian limits on bilateral contracting for public power is a big deal for states like Virginia, where Mark Christie is from. The MOPR makes it more challenging for states like Virginia to meet future targets to be carbon free. FERC can withdraw orders that are under litigation in the US court of appeals for the 7th circuit. It could revisit them. However, I think what any FERC would prefer to see is for PJM to come back with a replacement program that makes stakeholders a lot happier than they are today.

MR. WOLFF: But not any FERC because the current FERC already had its chance at that and did not take it.

MR. MARTIN: Let's see how many other questions we can fit in quickly with very short answers by one person. Brandon Hurlbut, an audience member asks, what plans does the Biden administration have for green hydrogen?

MR. HURLBUT: Climate hawks want all options on the table. The Biden team will try to take every approach possible to addressing climate change. Hydrogen is one of those options, and I think you could see more support for it.

MR. MARTIN: Joe Mikrut, what is the likelihood the government will allow for direct payment of federal tax credits under a Biden administration?

MR. MIKRUT: I don't think refunds for all general business credits will happen. I think Biden will support the more limited direct-pay proposal for renewable energy tax credits that passed the House the first week in July. It allows owners of new renewable energy projects to apply to the IRS for quick refunds for 85% the federal tax credit amount. The haircut is recognition that when the government makes a direct payment, the project owner is able to keep the full payment, unlike a tax credit that must be bartered in the tax equity market.

Mitch McConnell and Joe Biden have a history of working together.

MR. MARTIN: Another audience member asks, if Secretary Bernhardt at Interior announces a decision on Vineyard's construction permit that is adverse to the offshore wind industry, will a Biden appointee be able to reverse that decision?

MS. TEZAK: Probably yes, because there is usually a procedure for administrative reconsideration and then there is also the opportunity to go to court. Once you go to court, a differently aligned administration could request an abeyance or a voluntary remand of the issue to Interior to revisit it.

MR. MARTIN: Related question, can Biden supersede Trump's executive order establishing a moratorium on new offshore wind leasing in North Carolina, South Carolina, Georgia and Florida? Same answer, Christi?

MS. TEZAK: Yes, executive orders can be superseded by their successors.

MR. WOLFF: Executive orders are even easier to reverse than an agency action.

MR. MARTIN: Eric Wolff, do you have a view on the fate of the Trump executive order on the bulk-power system that has bedeviled the power industry because it is so unclear?

MR. WOLFF: No, for some of the reasons that I said before. You have a real chance that Biden will bring in people who will try to untangle it, but Biden's view on China is pretty negative. It has been so for a while. There may be project developers and investors on this call who can at least rest a little easier that the Biden administration will not use the order to target all Chinese products in the same way people were really nervous about how the Trump administration would use the order.

In terms of cybersecurity, everyone agrees that grid cybersecurity is a concern. China is not a friendly player. The Biden administration may try to clarify the order and make it more straightforward, but it may also decide that this is a real issue that is worthy of its attention.

MR. MARTIN: Last question, as we are at the end of our allotted time. John Gimigliano, do you see section 45Q tax credits for carbon sequestration in the mix if Congress extends tax credits for renewable energy?

MR. GIMIGLIANO: Yes if Republicans are in control of the Senate. That is one thing that could be an area of bipartisan agreement by throwing a lifeline to some carbon-emitting facilities. If Democrats are in control, then the question will be whether the Democratic caucus will agree to it. In the context of a larger deal, I think it could. ◎

IN OTHER NEWS

CALIFORNIA CCAs signed 117 power purchase agreements during the period November 2019 through October 2020.

Community choice aggregators –- or CCAs – are county-wide entities that buy electricity to supply to county residents. There are 23 CCAs currently in California. They are expected to supply 36% of the electricity load in the state by 2022, according to the latest annual report of the California Community Choice Association in November.

Electricity customers must affirmatively select their local utilities as their electricity suppliers. Otherwise, they are assigned to the local CCA.

Contracts already signed by California CCAs will require construction of more than 5,000 megawatts of new renewable energy and storage projects. The 5,000 megawatts include 1,030 megawatts of wind farms and 3,860 megawatts of new solar projects. Forty-six percent of the new solar projects include storage.

CCAs are currently authorized in nine states: California, Illinois, Massachusetts, New Hampshire, New Jersey, New York, Ohio, Rhode Island and Virginia.

Another six states are actively investigating them: Arizona, Colorado, Connecticut, Maryland and Oregon.

PUBLIC UTILITY PROPERTY questions are taking up a lot of IRS time, but perhaps not for much longer.

The IRS released two more private letter rulings confirming that solar projects the utilities plan to build will not be "public utility property."

It is harder to claim an investment tax credit and accelerated depreciation on solar projects that are public utility property. (For more background, see "Utility tax equity structures" in the December 2019 *NewsWire* and "Utility partnership flips" in the June 2020 *NewsWire*.) */ continued page 29*

Mexican Rollbacks Move to the Courts

by Hernán González in Mexico City, and Javier Félix in New York

While the López Obrador administration has been dialing back private participation in the Mexican power sector, the Mexican federal courts have been holding firm against the government's changes in policy.

Generally, the Mexican federal government's energy agenda focuses on strengthening state-owned companies, CFE and Pemex, by favoring them over their competitors.

To achieve that goal, the Ministry of Energy (*Secretaría de Energía* or SENER), the Mexican ISO (*Centro Nacional de Control de Energía* or CENACE) and the Energy Regulatory Commission (*Comisión Reguladora de Energía* or CRE), among other authorities, have focused on changing the electricity market regulatory framework to the detriment of private generators.

Main Actions

Actions by the federal government to pursue its objectives include the expeditious enactment of a new electricity policy by SENER and the issuance of several resolutions by CENACE and CRE, respectively. These actions retroactively changed some of the operating rules for the grid to the detriment of privately-owned projects.

None of these actions was subject to public consultation as is required by Mexican law. What follows is a brief summary of those actions.

First, in late April 2020, CENACE, the grid operator, issued a resolution suspending all pre-operative tests for wind and solar power plants. Until such tests are done, new wind and solar projects cannot connect to the grid.

CENACE's resolution also provided for the registration of CFE's thermal power plant units as "must-run" units, violating economic dispatch rules and potentially leading to market distortions. (For earlier coverage, see "Mexican ISO prevents wind and solar projects from reaching commercial operation.")

CENACE argued that such a measure was required to preserve the system's safety and reliability during the low-demand period caused by the COVID-19 pandemic.

Second, in May 2020, SENER adopted a policy that significantly changed the grid's operating rules to the detriment of private power producers, especially wind and solar power projects. In general, SENER's policy strengthens the roles of SENER and CENACE by providing them with discretionary power. It also imposes roadblocks on the issuance of new power generation permits and additional restrictions for new wind and solar power plants. (For earlier coverage, see "New policy in Mexico puts dagger in private participation in the electricity sector.")

Third, CRE issued two resolutions disrupting legacy power projects operating under a superseded regime. Among other benefits, legacy power projects have postage-stamp wheeling tariffs and may incorporate offtakers to their generation permits unrestrictedly. A resolution by CRE in May 2020 led to at least a fivefold increase in wheeling tariffs for those projects. In late October 2020, CRE issued a separate resolution to limit the legacy permit holders' rights under existing power generation permits. As a result, legacy permit holders can no longer add large consumers and offtakers already being supplied by CFE to their generation permits. While the plan is for legacy projects to migrate to the current regime once their interconnection agreements expire, CRE seems determined to accelerate that process by changing former conditions. Such changes would presumably render CRE's

The Mexican rollback of private-sector participation in the electricity market is being slowed by the courts.

resolution illegal as it affects the legacy permit holders' rights granted under a law that is no longer in effect.

Reactions

Industry participants and other federal and state authorities have openly questioned the federal government's plans and have launched various legal challenges.

For instance, the Mexican Federal Competition Commission (*Comisión Federal de Competencia Económica* or COFECE) issued an opinion on May 7, 2020 harshly criticizing measures taken by CENACE. For earlier coverage, see "Mexican Competition Commission criticizes actions against wind and solar projects.")

More recently, a group of bipartisan US lawmakers also complained about the Mexican federal government's energy agenda. They claimed that its advancement granted preferential treatment to Mexican state-owned companies, violating the new US-Mexico-Canada free trade agreement that became effective in July 2020.

Private generators and NGOs filed constitutional challenges and sought injunctions in the Mexican courts against SENER's new policy as well as CENACE's and CRE's resolutions.

Separately, COFECE and state governments challenged SENER's authority to impose the new energy policy before the Supreme Court on constitutional grounds. As a result, the Supreme Court and federal district courts issued injunctive relief measures against the federal government's actions during the pendency of the constitutional trials. Generally, both courts held that the risks posed by imposition of the new policy and resolutions could lead to serious market distortions, result in setbacks to the energy transition and harm the environment. The courts highlighted that the consequent damage to society would be irreparable if the policy and the resolutions were allowed to stand.

CENACE and SENER retaliated by challenging the court decisions. The Mexican courts then reaffirmed their positions and validated the injunction relief measures. More specifically, the first chamber of the Supreme Court confirmed the interim relief granted to COFECE against SENER's energy policy without even debating SENER's challenge. Consequently, President Andres Manuel López Obrador harshly criticized the first chamber's decision and threatened to amend the constitution if need be.

A federal district court has recently resolved the merits of constitutional claims filed against CENACE's resolution and SENER's policy by private companies. In separate trials, the federal court concluded that both the resolution and the new policy are unconstitutional.

/ continued page 30

IN OTHER NEWS

One ruling, made public in October, involves a utility that applied to its utility regulatory commission for permission to recover the cost of a utility-scale solar project in rates, but ended up entering into a settlement with ratepayer advocates under which the utility agreed to charge a fixed rate for electricity from the project and not put the project into rate base.

The utility backed into the fixed rate by determining how much it would have to charge to earn its required rate of return. This had a lot in common with how rate-base rates are determined, but there will be no adjustment in the electricity price except where a change in the federal or state income tax rates leads to an adjustment in the utility's other approved tariff rates.

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

The IRS said the project will not be public utility property because the project will not go into rate base and the rates are not a function of the utility's rate base, even though they may have been set initially using a similar logic.

The ruling is Private Letter Ruling 202042005.

The agency released the second ruling in November.

A utility planned to use a small solar array installed on land belonging to a municipal airport to supply electricity to the airport and sell any excess electricity to the local grid.

Electricity will be supplied to the airport at a negotiated rate. Any sales into the grid will be at current wholesale market rates. The IRS said the solar facility will not be public utility property.

The November ruling is Private Letter Ruling 202047004.

The IRS released a priority guidance plan in November for the period through next June that lists subjects on

/ continued page 31

Mexico

continued from page 29

Among the various reasons for ruling against them, the resolving judge held that their imposition would ultimately affect end users and the people's right to a clean environment. The judge explained that the policy changes would prevent wind and solar power generators from entering the market and impair their ability to operate accordingly. The judge said that CENACE's and SENER's actions unjustifiably affected free competition in the power sector. He indicated that those actions gave priority to dispatch of CFE's old polluting power plants over more efficient and cleaner ones, violating the economic dispatch rules currently in effect.

Perhaps more importantly, the judge decided that both the resolution and the policy had failed to meet several legal requirements. He held that the issuance of CENACE's resolution exceeded its authority, as the power to regulate the electricity market and its operation resides in the CRE. As for SENER's policy, the judge explained that its expedited enactment violated due process and public consultation laws. Potential stakeholders had not been given a chance to comment on the policy's effects, the judge said.

The federal judge's decisions have essentially rendered CENACE's resolution and SENER's policy universally void.

Those decisions were, in fact, a result of constitutional claims filed by three companies, Desarrollos Eólicos Mexicanos de Oaxaca, S.A. de C.V., Desarrollos Eólicos Mexicanos de Oaxaca 2, S.A. de C.V. and EGP Magdalena Solar, S.A. de C.V. While normally decisions of this type would only benefit petitioners, the judge concluded that his judgments must be given general effect.

CENACE and SENER may still ask a higher court to review the district court decisions in an attempt to reverse them.

Federal courts also granted preliminary injunctions against the CRE's May 2020 resolution. However, they have not yet addressed the merits of the relevant constitutional claims.

The Mexican Supreme Court may have the final word. It has been more inclined to support the government.

The federal court decisions prove that checks and balances in Mexico continue to work despite governmental pressure. Indeed, the outlook is positive for private generators and renewables, but the Supreme Court will probably have the final word on the federal government's energy agenda.

Although the first chamber of the Supreme Court has been keen to suspend the application of SENER's policy, the merits of all claims may be ultimately resolved in a plenary session in the presence of all ministers. Overall, the Supreme Court has been inclined to support the federal government's plans. As such, the outcome of these cases remains unpredictable. ◎

Financing US Offshore Wind Projects

Five key players in financings of US offshore wind projects talked at the annual offshore wind conference organized by the American Wind Energy Association in October about the expected terms for US financings, the hot-button issues for lenders, tax equity investors and project developers and how much deal flow to expect in the next 12 to 24 months.

The panelists are Clay Coleman, director of finance for Avangrid Renewables, developer of the Vineyard project that was in the market last year seeking financing, Martin Pasqualini, a managing director of CCA Group, a tax equity advisory shop, Joel Spenadel, executive director on the tax equity team at JPMorgan, the largest US tax equity investor, Alberto Garcia, a managing director and head of energy for the project and acquisition part of Spanish bank Santander, and Chris Moscardelli, a managing director at French bank Société Générale.

Current Financing Efforts

MR. MARTIN: There are two kinds of projects taking shape off the Atlantic coast.

Some are owned by joint ventures that have plenty of capital. There could be a joint venture, for example, between an oil company and a utility that plans to allocate the tax benefits to one of the partners and give the other partner cash to equalize returns. The tax benefits on an offshore wind project amount to anywhere from 26¢ to 44¢ per dollar of capital cost, depending on when the project started construction. That's a lot of money for a $3 to $6 billion project.

There are other projects that will need to tap external debt and tax equity. This latter type of project is our main focus today.

No project in federal waters is in a position to start construction in the water today. The Bureau of Ocean Energy Management has had a hold on issuing construction permits since August 9, 2019. A decision is expected on the first permit around December 18. [Editor's note: This was later moved to January 15, 2021.]

With that background, Marty Pasqualini, to what extent are financing efforts currently on hold?

MR. PASQUALINI: For the most advanced project, we had gotten to an executed term sheet with tax equity investors and had awarded all of the top ticket for the debt side of the transaction before BOEM essentially stood us down.

/ continued page 32

NORTON ROSE FULBRIGHT

IN OTHER NEWS

which the IRS hopes to issue guidance. One item on the list is "[g]uidance on public utility property." Usually when the IRS issues general guidance, it does so in order not to have to keep issuing private letter rulings.

RENEWABLE ENERGY COMPANIES have managed to grow in recent years in a market with static demand for electricity by replacing aging coal and nuclear power plants.

The opportunities for such growth are expected to remain strong over the next decade.

S&P Global Platts Analytics calculated that 41,500 megawatts of coal-fired power plants were retired during the four years of the Trump administration, and close to 46,000 megawatts of new wind and solar projects came on line during the same period.

Coal accounts currently for about 21% of US electricity production. Platts Analytics expects that number to fall to 5% by 2030, assuming the US places a price on carbon starting in 2026. It expects wind and solar to grow to 30% of US electricity output by 2030 compared to 11% currently.

Meanwhile, the International Energy Agency said in its *World Energy Outlook 2020* report in mid-October that it expects renewable energy to supply 80% of growth in global electricity demand over the next decade. Solar is expected to account for an outsized share.

The International Energy Agency expects demand for all types of energy to take until 2023 to recover, after dropping 5% in 2020 as economies contracted in the face of COVID-19. The forecast assumes no change in current government policies.

The US President-elect, Joe Biden, called during the campaign for net-zero carbon emissions by 2050. The IEA said that to reach that goal globally would require using low-emissions energy sources to supply about 75% of global electricity by 2030, up from less than 40% last year.

– by Keith Martin in Washington

Offshore Wind

continued from page 31

As we approach what we hope to be an official go ahead in December, we have started to gear ourselves back up again and have had our first few calls to reorient the working group about the project timeline. Once we get a go ahead, that will be time for us to start polling the market again, putting the band back together to a large extent and moving forward while we wait out the comment period on the permit. For other projects, it is obviously difficult to do much more than inform the market about the project and the expected timeline in advance of receiving a blessing from BOEM.

MR. MARTIN: So things are on hold, but gearing up in the hope that financings will start rolling soon after December 18.

MR. COLEMAN: We should be ready to start within minutes after receiving the BOEM permit.

MR. PASQUALINI: The plan is to issue a full notice to proceed on the updated construction schedule with a full raft of project counterparties identified and contracted by the middle of 2021.

MR. MARTIN: The "we" to which Clay Coleman referred is the Vineyard project, which is roughly an 800-megawatt project off the Massachusetts coast. Joel Spenadel, you are part of the tax equity for that project. Is the timeline that Marty Pasqualini described consistent with your own planning?

MR. SPENADEL: Yes. I expect to be done with my other fundings and commitments on December 17, so December 18 sounds great. [Laughter]

MR. MARTIN: Alberto Garcia, you have been talking to lenders. Will lenders be prepared to move on the same timeline?

MR. GARCIA: Yes. It is the same situation with the debt. We did not yet have a signed term sheet when things shut down, but things will gear up quickly once the construction permit is in hand. The tax equity and debt need to move on parallel tracks.

MR. MARTIN: Chris Moscardelli, you have been advising other projects besides Vineyard, as have others on this call. How far in advance of the expected financial closing do you think sponsors should be out talking to tax equity investors and banks and by when do they need to have term sheets signed and have moved into documentation?

MR. MOSCARDELLI: It is a balance. You do not want to start too early because the market will have changed by the time you are ready. No one would have expected the COVID impact nine months ago, for example. The uncertain regulatory process has left a huge question mark as to when things will really happen.

It is frustrating that we have gone this long without having a sizeable offshore wind project built in the United States. We are proud of our role in Block Island, but who would have thought that the US would still have built only a single offshore wind project with five turbines for a total of 30 megawatts almost six years after the financial closing on that project?

MR. MARTIN: Let me provide more context to my question about when to start negotiating the financing.

Every project must clear a regulatory process at the Bureau of Ocean Energy Management. The developer must submit a construction and operations plan, or C-O-P for short. This is followed by a lot of back and forth on the COP, and then BOEM prepares an environmental impact statement. Preparation of the environmental impact statement can take up to two years. That leads eventually to a record of decision that is essentially a federal construction permit, after which the project must submit a detailed construction plan. Review of the construction plan takes another four to six months.

Do you start negotiating once the record of decision is issued or must the developer wait until the detailed construction plan goes in or even until it has been cleared?

MR. MOSCARDELLI: No. You start things early. I don't think you have to wait until everything is finalized and then turn to putting documents together. Assume six to nine months to negotiate all the financing documents and fund. Lenders will have a hard time funding without having all the permits and approvals in hand. You bridge that by signing documents with a series of conditions precedent to funding.

MR. MARTIN: Clay Coleman, you heard six to nine months to reach funding. Does that sound right?

MR. COLEMAN: Nine months is probably more realistic than six months, even in cases where everything goes relatively smoothly with BOEM. My view on this could be colored by the fact that circling the tax equity club for our project took a long time. Since ours was the first substantial project, there was an extended education process, which may not be required for later projects. I am measuring the nine months from when you send out the first teasers. Of course, you will have had to have done a lot of preparatory work to get to the teaser stage.

Advance Funding Commitments

MR. MARTIN: Marty Pasqualini, projects in the Atlantic are expected to take two to three years to complete after the record of decision. There are short construction seasons in the North Atlantic. Tax equity investors do not usually commit that far in advance to fund. How will that problem be addressed?

MR. PASQUALINI: I think there will ultimately be two paths. Tax equity is not as large a component of the final capital stack as for an onshore project. Therefore, one path is for the sponsor group to decide it can wait to put the tax equity in place. This path may take a lot of intestinal fortitude and a balance sheet that can be used to fill any gap in the capital stack, if needed. The other path is to find a way to compensate the tax equity investors for the longer commitment.

MR. MARTIN: Joel Spenadel, how far in advance will JPMorgan commit for a project like this?

MR. SPENADEL: We are prepared to commit up to two years in advance. As Marty suggested, the key is the proper compensation for that extended commitment. Clearly we have not had to make such long commitments for onshore projects, but under these circumstances, we are prepared to do it for offshore.

MR. MARTIN: Is the proper compensation an upfront fee?

MR. SPENADEL: Yes, a commitment fee.

MR. MARTIN: Is it paid in a lump sum up front or over time?

MR. SPENADEL: That can be negotiated. It is part of the commercial discussion.

Debt Tenors

MR. MARTIN: Alberto Garcia, you were in the market last year trying to raise external debt for offshore wind projects. Can you share any data about the debt that was on offer then? How many banks and what was the pricing?

MR. GARCIA: There are some confidentiality limits to what I can say. More than 50 institutions expressed interest in negotiating terms. Availability of debt will not be an issue for US offshore wind projects.

The question is how to optimize the debt in conjunction with other elements of the capital stack, like the tax equity in particular. The immaturity of the US sector, combined with the complexity of the structures, will affect the cost of capital here compared to the cost in Europe. The large number of institutions interested in lending here could be a counterbalance of sorts. The debt structures will look more to US onshore wind projects, than to European structures, with the debt back levered behind the tax equity.

MR. MARTIN: Is bank debt likely to have a term of seven years in a mini-perm structure, meaning cash sweeps?

MR. GARCIA: Mini perms, yes. If you asked me last year whether the term will be seven years, I would have said yes. After COVID, we will see. We will try to see whether we can do something in the intermediate range between the onshore projects in the US and the European offshore projects that have way, way longer debt tenors.

MR. MARTIN: How do you expect conditions to have changed early next year, assuming COVID-19 remains a drag on economic activity?

MR. GARCIA: That is hard to predict. Some of the banks that were ready to lend in early 2020 may not be ready.

There will be some tension between pricing and tenor. We will need to take stock of how things are evolving. There will be a lot of focus during diligence on supply chains, construction schedules and contingency plans.

MR. MARTIN: Chris Moscardelli, offshore wind projects have very good PPAs. They are long term and with utilities with good credit. The revenue stream is more predictable. How do you get value for that out-year revenue in a seven-year transaction?

MR. MOSCARDELLI: You get that value by amortizing the principal repayment over a longer term than the initial tenor. The mini-perm structure that Alberto mentioned is very common in the US. One of the main reasons why it is so common is the robustness of the US capital markets for refinancing. We expect most, if not all, of the financings for offshore wind in the US will use a mini-perm structure. You get that value for the long-term contract through a refinancing that pushes out the underlying amortization to match or come close to the end of the PPA term in 20 to 25 years.

Coverage Ratios

MR. MARTIN: Let's focus on the other terms on offer. We are talking about the bank market primarily. What debt service coverage ratio do you expect for offshore wind in the US?

MR. MOSCARDELLI: I don't think it will be dramatically different than what we have seen onshore. You have a probability-weighted coverage ratio on a P50 basis and a P99 basis.

MR. MARTIN: Is the P50 debt service coverage ratio 1.35x, 1.4x?

MR. MOSCARDELLI: Historically it has been 1.4x on a P50 basis. We are seeing a little more aggressive behavior from banks moving toward 1.35x and possibly even to 1.30x on a P50 basis. We should be in that range for offshore wind as well. I do not foresee a premium in sizing metrics to lend to offshore wind compared to onshore wind.

MR. MARTIN: Alberto Garcia, same numbers?

MR. GARCIA: Yes.

MR. MARTIN: We have been talking about bank debt. What about project bonds and term loan B / continued page 34

Offshore Wind

continued from page 33

debt? Are those markets flush with money for offshore wind?

MR. GARCIA: We will reevaluate again, but I suspect the answer will remain yes, subject to sponsor needs. These other markets are less able to take on construction risk, so they are more likely to be tapped for refinancing after some of the early projects are already in operation.

Banks v. Capital Markets

MR. MARTIN: Clay Coleman, I think you were ready to go with all bank debt before BOEM stepped in. Will you reassess that and, if yes, what is your thought process?

MR. COLEMAN: We will reassess everything given that it has been more than a year and we have obviously had some pretty severe exogenous shocks since we went pens down. Santander did the market sounding for us in early 2019 of the various sources. The term loan B market was not able to provide all of the debt and, as a co-lender with the banks, it was more expensive. Its big advantage is tenor, but at least in the market sounding we did before, we were seeing mini perms as long as 10 years post-construction and a fully amortizing loan as long as 18 years.

One big change obviously is that interest rates are very low today. It may make sense to take refinancing risk off the table by going with a fully amortizing loan because it is hard to imagine that interest rates that far out will be as low as they are today, even with step ups.

MR. MARTIN: So that suggests project bonds with a fixed rate or institutional debt with floating interest?

MR. COLEMAN: There were a number of banks that were willing to go to 18 years post-construction, which is probably about as long as we could go with either term loan B debt or project bonds. I don't know. There may be some issues with project bonds once we get into the post-PPA period. The whole thing will have to be put into the salad again and re-examined.

Gearing

MR. MARTIN: Chris Moscardelli, what debt-equity ratio do you expect for offshore versus onshore?

MR. MOSCARDELLI: There will be slightly lower leverage for offshore. One reason is offshore projects do not have a traditional lump-sum, turnkey, fixed-price construction contract. Each project will have a group of contractors bringing specialized expertise to specific tasks. That leads to heightened sensitivity to construction risk for offshore wind as compared to onshore. That said, I still think you can get gearing up pretty high. I think you can probably still get to 80% and maybe even 85% leverage on these projects.

MR. MARTIN: That is term debt. What about advance rates for construction debt?

MR. MOSCARDELLI: Higher. It depends on the structure of the tax equity. It was interesting to hear Joel Spenadel say that JPMorgan can commit two years in advance. That will help get to a higher advance rate. The construction loan advance rate turns partly on whether the lenders are bridging to tax equity or are making a construction loan that will convert to back leverage at the end of construction.

MR. MARTIN: Alberto Garcia, same story?

MR. GARCIA: Pretty much. Offshore wind has to be a little more contained on the leverage. We have been thinking 80% is most likely, but 85% is possible. We expect to see advance rates for construction debt of 95% to 97%.

Tax Equity Terms

MR. MARTIN: Marty Pasqualini, you were in the market last year trying to raise tax equity for offshore wind. What data can you share about the tax equity then on offer?

MR. PASQUALINI: Obviously much has changed since then, but we had more than two times coverage for the tax equity ticket, which was the better part of a billion dollars.

The most prominent tax equity investors, like JPMorgan, were very interested in playing a prominent role in the space and were highly motivated to dig into what is a new product at least here in the United States.

Even smaller players who lack the same ability as JPMorgan to predict taxable income in the out years were telling us that they were very interested not only in the space, but also in the particular project. Some potential investors had geographic ties that made the particular project of great interest. However, investors in this category are not able to make two-year forward commitments.

MR. MARTIN: How do you expect things to look next year?

MR. PASQUALINI: The post-COVID market for tax equity is considerably more constrained, especially for deals on which investment tax credits will be claimed. If you analogize to the solar market, you have smaller banks that have shut down at least for a period of time as they assess to what degree their loss reserves will turn into actual credit losses.

Those conversations could be more difficult next year if COVID persists. That is a potential overhang for a period of time. I do not expect COVID to affect players with very large balance sheets who are dedicated to the space generally. It may put them in a better position, from a competitive standpoint, to support the projects.

MR. MARTIN: Clay Coleman, how are pricing and other terms for offshore wind tax equity different than for onshore?

MR. COLEMAN: The flip return requirements are necessarily different. Because the weighted average life for a project on which an investment tax credit is claimed is so short, the tax equity investors are getting a good deal of their investments back through the tax credit pretty much in the first few months of the transaction, and they end up with a higher all-in return 25 years out than they would for an onshore wind project with production tax credits.

Obviously one of the dynamics is that you have a huge capital base with offshore that quickly absorbs the money the investors are putting in. You have to ensure the investors will have large enough capital accounts and outside bases to take all of losses and avoid tax credit recapture. There are a few tools in the toolbox to deal with these issues, including perhaps switching to 12-year straight-line depreciation. In terms of the flip return and other deal terms, I do not see a huge difference between offshore and onshore.

MR. MARTIN: Joel Spenadel, your colleague Yale Henderson said on this panel last year that the differences between offshore and onshore are dramatic. Do you have examples?

MR. SPENADEL: The simplest example is the amount of capital required, as Clay said. For a project with $3 billion in eligible equipment and an 18% investment tax credit, which is what you would get if you start construction this year, that suggests tax credits of at least $540 million. With depreciation and cash, we get easily to a funding of over $600 million. That is roughly twice the tax equity required for large onshore wind projects. Until we get to a point where someone will underwrite and maybe sell down pieces, as was happening in the solar market before COVID hit, the large investments required will be a challenge for the offshore market.

MR. MARTIN: One of the surprising things to me is how little cash the tax equity investor requires in an offshore project compared to a project on land. Am I correct?

MR. SPENADEL: That may be driven by particular sponsors who want to keep cash to borrow against at lower rates in the debt market.

There is a minimum we have to get. We have to have economic substance. We are used to funding a very high percentage of the capital stack in the onshore market where people are claiming production tax credits.

For offshore wind projects that rely on the investment tax credit, we see funding levels trending down. For a deal with an 18% investment tax credit, funding is moving toward 20% of the capital stack. We don't have the leverage at such a small share of the capital stack to dictate as many terms as we might in an onshore project where the tax equity percentage is higher.

There are issues around cash priorities and even uses of cash to support indemnities and the like that come up in offshore that are pretty well settled in onshore.

On the plus side, the good news for offshore is we generally see well-rated, regulated utilities at the other end of bus-bar PPAs. We rarely see such contracts today in the onshore market. Offshore does not yet have the same sort of grid congestion issues that we see in the onshore market in parts of Texas and the Midwest.

On the minus side is we are not as confident about predicting reliability and operating costs are we are with onshore.

MR. MARTIN: Marty Pasqualini, I'm surprised to hear people talk about ITCs. My impression was that most of these projects would end up with production tax credits. Do you disagree?

MR. PASQUALINI: It depends on the projected output and capital costs of each project.

Where a project will be built and financed in phases, some capital costs that benefit all of the phases are bunched into the first phase, making the ITC better for that phase. PTCs make more sense for the second phase. However, the projects would have to be treated as separate projects for tax purposes in order to mix tax credits in this manner.

We are seeing increases in turbine capacity from one year to the next. Sponsors are leery of committing to a particular turbine because they do not want to be locked into last year's technology.

If you had a tie, you would choose PTCs because there is more depth in the PTC market today. PTCs offer a friendlier profile for the tax equity investment community. But it does not appear to be a close call on some of the early projects facing high capital costs.

MR. MARTIN: Joel Spenadel, are you willing to accept physical work as the method to start construction of offshore wind projects? If yes, do you require the sponsor to represent facts that the investor can use to draw its own conclusion that construction started in time and must it represent / continued page 36

Offshore Wind

continued from page 35

the legal conclusion that construction started in time?

MR. SPENADEL: Yes, we will rely on a physical-work strategy, but with the right set of facts and with the proper sponsor supports.

In terms of the type of rep, ultimately we want the sponsor to take the risk that the project will qualify for tax credits. If diligence suggests we need a rep that has embedded in it a legal conclusion and not just facts, then that is what we will seek.

If the sponsors are concerned about representing the legal conclusion, then there are specialty tax insurance products to cover the risk. Just asking insurers for quotes is a way to price the risk.

MR. MARTIN: We are talking about $3 to $6 billion projects with a huge amount of tax benefits. We have heard from brokers that the premiums for a project that size could be a little under 2%.

Capital Stack

MR. MARTIN: We heard from Joel Spenadel that tax equity is trending down and will account for maybe 20% of the capital stack. Does that mean that debt will be 60% and sponsor equity 20%? How does the rest of the capital stack shake out?

MR. COLEMAN: For offshore, the EBITDA profile is much stronger than it is for onshore currently. Thus, there is the potential to support more leverage. Our current numbers suggest that we are at about a 60% overall leverage ratio for the debt. The tax equity is a little north of 20%. Sponsor equity is the rest.

MR. MARTIN: That assumes what percentage tax credit?

MR. COLEMAN: Eighteen percent.

MR. MARTIN: That is with an ITC. Does it scale so that if Congress increases the ITC for offshore wind to 30%, you get commensurately that much more tax equity?

MR. COLEMAN: Pretty much. Some things do not ramp up with the ITC. The tax equity investors are getting not only the ITC, but also cash and depreciation that pretty much equals the amount that they invest. These last two items are largely unaffected by any increase in ITC. If we move to a 30% ITC again, we would see a healthy increase in the amount of tax equity we could raise. That would let us reduce the amount of sponsor equity.

MR. PASQUALINI: A 30% ITC would probably take the tax equity to about 30% to 32% of the capital stack.

MR. MARTIN: The November elections are obviously a huge potential inflection point. If Biden is elected and the Senate shifts to Democratic control, offshore wind could be given more time to start construction at a larger tax credit. How is this affecting financing or construction-start strategies?

> The tax equity market expects to see two offshore wind projects in the market for funding in 2021 and another two in 2022.

MR. COLEMAN: The complexity and opacity of the construction-start rules have been so profound that they have forced us to spend an inordinate amount of time on this subject. If a change of administration would lead to more clarifications, that would not be a bad thing.

MR. MOSCARDELLI: Even if Biden were to win and the Senate flips, there is no assurance that Congress will do anything for offshore wind. The market does not put its money behind speculative positions.

Hot-Button Issues

MR. MARTIN: Alberto Garcia, as lenders look at these projects, what do you think are their hot-button issues?

MR. GARCIA: I think they will be most worried about construction arrangements and the interface risk among the different contracts. These constructions are much more complex than for onshore wind, and they will be more complex than they are in Europe. Contractors here are less willing to take the same risk they might in Europe because it is a new market and the regulation is more complicated. We have the Jones Act and other arrangements that complicate the logistics. There are the permitting complications that we discussed earlier. Americans are more litigious. Lenders will look carefully at the insurance coverage given the increasing number of hurricanes in the Atlantic.

MR. MARTIN: Premiums for casualty insurance have skyrocketed.

MR. GARCIA: Yes. We looked at that closely last year and were happy with what was on offer at the time. Hopefully, it has not changed.

MR. MARTIN: Chris Moscardelli, what do you think are the hot-button issues for lenders?

MR. MOSCARDELLI: I agree with Alberto. Construction is front and center. Lenders have heightened sensitivity to how the construction package will be designed. He also mentioned the Jones Act. Vessel compliance is a big deal. The only other areas I would add are potential supply-chain issues and transmission and interconnection issues. We anticipate that transmission and interconnection will be a lot different here than it is in Europe where the transmission lines are largely owned by the utility. It remains to be seen what path the interconnection and transmission concerns will take, but they are on lender radar screens.

MR. MARTIN: No one construction contractor will wrap everything. What are your options?

MR. MOSCARDELLI: The lenders will want to make sure the construction contracts fit together to mitigate the finger-pointing risk if something goes wrong.

MR. MARTIN: Marty Pasqualini, what do you think are the hot-button issues for tax equity investors?

MR. PASQUALINI: Sponsor quality is number one.

MR. MARTIN: These are all big sponsors. They are mostly large oil companies and utilities.

MR. PASQUALINI: For the most part. There are investment funds involved in some of the projects and lesser-known developer names.

It is one thing to enter into one of these projects at the dollar amounts we are talking about for someone with whom you are otherwise regularly doing business. It may be a different story to do it with a financial sponsor.

The tax equity market will also worry about the construction arrangements. It is used to looking at a single balance-of-plant construction contract. It will focus on what can go wrong where you have multiple contractors and no one contractor taking responsibility for the entire job. Someone will have to talk the tax equity investors and lenders through the arrangements and how everything holds together.

MR. MARTIN: Joel Spenadel, what are the hot-button issues from where you sit?

MR. SPENADEL: I came up with the acronym "QUOTE" which covers qualification for tax credits . . .

MR. MARTIN: Uh oh, five items. [Laughter]

MR. SPENADEL: There are only four because Q and U have to stick together. The O is offshore experience of the sponsor. Marty touched on the importance of how the sponsor manages large construction projects and large financings. T is timing considerations. E would be environmental and regulatory issues.

MR. MARTIN: Clay Coleman, can you come up with one that begins with U? [Laughter]

What are your hot-button issues as a sponsor?

MR. COLEMAN: Obviously having confidence in your schedule is pretty important because delays are expensive. On funding, we are pretty confident that the debt markets will be there for us despite any impact from COVID because everyone is awash with liquidity. The tax equity markets are more worrisome because we are asking for a very big check, and only a handful of folks can write a check that size.

European Comparisons

MR. MARTIN: Chris Moscardelli, how does the cost of capital for offshore wind compare in the US to Europe, and what is the gap?

MR. MOSCARDELLI: It should be better in the US, notwithstanding that US offshore wind is not yet a mature market. Europe uses longer-tenor financing. Borrowing long term costs more.

MR. MARTIN: This is surprising given how much less experience the US has with this asset class. Alberto Garcia, do you agree with Chris Moscardelli's assessment?

MR. GARCIA: It depends what you call cheaper. I think the combination of the pricing plus the tenor that the projects are getting in Europe makes the financing really, really cheap. Spreads are around 170 basis points for debt that has a term as long as 18 years.

In the US, we are going to see something really different. If projects finance in the bond market, they will be done using structures that look like a mini perm. There is tension between the price and tenor, particularly with the / continued page 38

Offshore Wind

continued from page 37

early projects. It would not surprise me if the first US projects are more expensive to finance than similar projects in Europe.

MR. MARTIN: Our London office reported earlier this year that construction debt in Europe covers about 60% to 70% of the project cost, and the equity does not fund until the debt has been fully drawn. The expectation is that a refinancing will follow at the end of construction and increase the gearing to 80% to 85%. This is the opposite of how debt works in the US. Why do things happen differently here?

MR. GARCIA: Europe had a very different experience after the last financial crisis. Europeans are less used to shorter debt tenors. Financing risk is different there. The US market never closed. The US market is more comfortable taking that risk and that helps to facilitate getting tighter pricing. In the US, debt will be drawn down after the equity has funded.

MR. MOSCARDELLI: My colleagues in Europe tell me they are seeing a shift to a bit more pro rata funding of debt and equity and some cases where leverage is 80% to 85% out of the box instead of waiting to refinance at the end of construction at the higher gearing. That said, US lenders are more accustomed to taking construction risk and are more willing to lever up out of the gate versus waiting until project completion.

Off to the Races?

MR. MARTIN: Clay Coleman, once BOEM issues the construction permit for Vineyard, will it feel like US offshore wind is truly rolling or will it be one project here and one there for quite a while?

MR. COLEMAN: It will remain a bit of an open question, I suppose. A lot of states are coming out with requirements for utilities to buy renewables, particularly in the northeast. Offshore wind procurements are spreading to the west coast, where we will be using floating turbines as opposed to fixed turbines given the depth of the seabed. The southeast is a bit of a question because of what President Trump has ordered. Several more RFPs are expected in the northeast.

MR. MARTIN: President Trump ordered a halt to leasing of offshore sites after mid-2022 off the Atlantic coasts of the four southernmost states, possibly spreading up to a fifth state, Virginia.

Marty Pasqualini, does it feel like offshore wind is really about to take off with release of the first construction permit, or will it be one project and then another sometime later?

MR. PASQUALINI: There is an enormous amount of capital poised to invest on top of an enormous amount of investment that project developers have already made. I could tick off 10 developers, equipment manufacturers and other service providers that have set up shop in Boston alone to be positioned for what they see as a multi- billion-dollar build out over the course of the next 10 to 15 years. I think we will be off to the races once the logjam is broken on construction permits, but it will be a question of how fast the race is. The answer depends in part of the outcome of the national elections.

MR. MARTIN: There are two federal issues that are hang ups. One is the delays at BOEM issuing the first construction permit. The other is the four-year period the IRS allows to finish construction to qualify for federal tax credits. The Treasury will have to do something to ease up on that.

Joel Spenadel, I am going to end with you. I suspect you sit at the intersection of almost every project since JPMorgan is such a large share of the tax equity market. What is your sense of how these projects will unfold? Vineyard is obviously at the front of the queue. Do you see a lot of others stacked up behind it in quick succession?

MR. SPENADEL: Our team has been having discussions with a number of developers, some of whom have multiple projects they would like to get going. The extension of the four-year window to finish construction is important. I suspect that without an extension, there may not be many projects able to raise tax equity.

MR. MARTIN: Assuming Vineyard gets its construction permit in the near term, do you think Vineyard will be the only project able to close on financing next year or do you expect another project -— maybe even two other projects — next year?

MR. SPENADEL: Based on what developers are telling us, we hope to see one and perhaps two projects in 2023 and one or two in 2024.

MR. MARTIN: That is closing on the tax equity or funding at the end of construction?

MR. SPENADEL: Funding at the end of construction. So back up two years from that for negotiation and document signing. That is one to two projects in 2021 and one to two in 2022 negotiating and signing tax equity documents. ◎

An Evolving Market in Asia for Offshore Wind

by Julien Bocobza in London, and Nicola Davies and Aditya Rebbapragada in Singapore

A number of key factors and trends will influence how the offshore wind market develops in Asia over the next decade.

In the meantime, opportunities to invest in offshore wind energy developments are being created by government measures from Japan to India.

Most of the activity to date has been in Taiwan.

Until recently, the Taiwanese market was dominated by international developers and international lenders able to lend in local currency, together with a limited number of Taiwanese commercial banks. However, Taiwanese government policy mandating greater local content for offshore wind projects, a trend toward a lower feed-in tariff and difficulties with liquidity in local currency are now driving developers to seek new opportunities elsewhere in Asia.

New Asian Markets

Opportunities in Japan, South Korea, Vietnam and India are attracting the greatest interest.

Japan has a target to install 10,000 megawatts of offshore wind capacity by 2030, and it has enacted legislation to take steps to meet this target. The government launched the country's first offshore wind auction for a floating offshore wind farm off the coast of Goto City in June 2020 and the country's first offshore wind auction for fixed-bottom offshore wind farms in November 2020. The tender for fixed-bottom projects will remain open until May 27, 2021 and covers four zones that are located off Akita and Chiba prefectures.

South Korea set a target of installing 12,000 megawatts of offshore wind capacity by 2030 in its Renewable Energy 2030 implementation plan announced in 2018. Offshore wind is critical to it achieving its separate net-zero emissions target by 2050. According to the Global Wind Energy Council, South Korea has installed only 132.5 megawatts of offshore wind capacity currently. It has several floating offshore wind projects in development.

Vietnam has the potential for 261,000 megawatts of fixed and 214,000 megawatts of floating offshore wind, according to the 2019 World Bank report Going Global: Expanding Offshore Wind to Emerging Markets. The Vietnamese government is considering a proposal to extend its feed-in tariff regime by another two years through November 2023. It is available currently at a tariff of 98¢ a kilowatt hour to offshore wind projects that reach commercial operation by November 2021. It is not clear whether the extension will be approved and if it does, whether the tariff would be maintained throughout the extended period at the current rate or potentially step down over time.

Mainstream Renewable Power, a UK developer, has submitted an application for a 1,000 megawatt offshore wind project in Vietnam in a joint venture with local player Phu Cuong Group. Mainstream received approval in June 2020 for a separate 400-megawatt project that is expected to start construction in the third quarter of 2021.

Copenhagen Infrastructure Partners, together with Vietnam based Asiapetro Petroleum Energy Corporation and Novasia Energy Company, signed a memorandum of understanding in July 2020 with Bin Thuan People's Committee to develop a 3,500-megawatt offshore wind project in La Gan.

Another UK-based wind developer, Enterprize Energy, revealed plans to develop a 3,400-megawatt offshore wind farm in Thang Long and received its site survey licence in June 2019.

India also has significant potential. The World Bank Going Global report estimates that India has potential for 112,000 megawatts of fixed and 83,000 megawatts of floating offshore wind. The World Bank, through its offshore wind development program, is in discussions with the Ministry of New and Renewable Energy and the Solar Energy Corporation of India to develop a demonstration project off the coast of Tamil Nadu in the next two years.

Corporate PPAs

As the offshore wind market matures in Asia and companies look for opportunities to offset their carbon footprints to meet their environmental commitments and satisfy their investors, offshore wind developers are likely to rely more heavily on corporate power purchase agreements to sell the electricity, building on a trend already well underway in Europe.

Denmark's Ørsted is leading the way. It already concluded a deal to supply the Taiwan Semiconductor Manufacturing Company with power from its Greater Changhua 2b and 4 offshore wind developments in Taiwan under what is reported to be the world's largest offshore wind corporate PPA.

Savvy developers are mindful of / continued page 40

Asia

continued from page 39

issues such as the creditworthiness of the corporate offtaker, the size of the offtake and the duration of the corporate PPA, which will all be subject to scrutiny from a bankability perspective.

Also, regulatory hurdles remain in some jurisdictions to entering into corporate PPAs, either due to licensing issues for generation and distribution or restrictions on wheeling where the power purchaser is not directly connected to the source of the renewable energy via a private wire connection, but is instead taking power from the national grid.

In Vietnam in particular, there have been a number of new regulations that are designed to promote the growth of renewable energy projects and enable corporate offtake, but it is a dynamic and fast-evolving market currently in terms of the regulatory framework.

Demand for virtual PPAs is also expected to increase. These are essentially a financial contract between the generator and the corporate offtaker that exchanges variable cash flows derived from the electricity market price and renewable energy credits for fixed price cash flows without any physical exchange of electricity. Such contracts are common in the United States for projects that sell their electricity into an organized power pool and, therefore, receive floating prices. A virtual PPA acts as a hedge that puts a floor under the electricity price. The project receives fixed payments from the corporate offtaker and pays it the floating revenue received from selling the physical electricity from the project into the power pool.

Virtual PPAs will become more common in Asia where the generator's main offtake is based on variable market pricing rather than a fixed tariff.

Leveraging Oil Infrastructure

Various elements required for offshore wind development, including foundation and substation development, use of installation vessels and subsea cabling, can leverage existing capabilities already well developed by the offshore oil and gas sector in a number of Asian countries.

A critical aspect of this is being able to use foreign flagged vessels and crew in these new markets.

Japan has strict cabotage regulations for foreign flagged vessels being used for offshore wind farm construction. However, the Japanese government is looking to ease the restrictions to promote offshore wind energy development.

South Korea already has significant shipbuilding and cabling expertise through companies like Samsung and Hyundai and may be able to support supply chains in the region by promoting the manufacture of offshore wind installation vessels domestically.

Other countries, like Vietnam, may require greater investment in the local onshore infrastructure and supply chains to support the growth of the offshore wind industry in order to capitalise fully on the opportunity.

Floating Offshore Wind

Floating offshore wind projects are expected to get significant traction in Asia. A number of experienced European developers are already circling the sector. For example, JERA, the largest Japanese utility company, ADEME Investissement, a 100% French state-owned investment company aimed at financing innovative infrastructure projects, and IDEOL, a global developer of floating offshore wind technology, have agreed on the key terms for the establishment of an investment vehicle dedicated to financing the development phase of at least 2,000 megawatts of floating offshore wind projects.

Most Asian offshore wind activity to date has been in Taiwan, but the new opportunities are in Japan, South Korea, Vietnam and India.

Floating turbines are particularly relevant for Japan, where fixed-foundation offshore wind projects are not suitable given the water depths of a large number of areas identified for offshore wind development.

South Korea is also a key market for floating turbines. For example, French oil company Total and the Macquarie Green Investment Group have concluded a 50-50 partnership to develop a portfolio of five large floating offshore wind projects in South Korea with a potential cumulative capacity of more than 2,000 megawatts. Norwegian oil company Equinor, the Korea National Oil Corporation and Korea East-West Power have also formed a consortium to develop a 200-megawatt floating offshore wind farm off Ulsan.

Floating offshore wind provides an opportunity for traditional oil and gas players, many of whom are now diversifying rapidly as part of the energy transition.

Green Hydrogen

In the longer term, offshore wind developers will pursue green hydrogen production as a potential use for the electricity generated by massive offshore wind turbines. Using the electricity to power electrolyzers will help mitigate curtailment risk, facilitate grid balancing and further maximise revenue.

A number of pilot projects are expected in the near term in Japan and South Korea before hydrogen production facilities can reach scale as demand for hydrogen increases. Hydrogen demand is already growing in the region, often with political support from governments. An illustration of this is that a number of Japanese companies have formed the Kobe-Kansai Hydrogen Utilization Council with a view to pursuing large-scale utilization of hydrogen in the 2030s.

Policy Support

How fast offshore wind develops ultimately in Asia, as in other regions, depends in large part on government policies.

So far, there are promising signs in most countries in the region. All countries in the region have committed to address climate change. The follow-through varies from one country to the next. The levels of government support and regulatory reform required to facilitate development and financing of offshore wind are also greatest in emerging markets where existing infrastructure is more likely to be found lacking. ◎

Financing California Hydrogen Projects Using LCFS Credits

by Jim Berger in Los Angeles, and Deanne Barrow in Washington

California is the cradle for the newborn green hydrogen industry in the United States. Multiple green hydrogen projects have been announced. Private infrastructure companies, equipment manufacturers and utilities have all shown interest, as have solar and wind developers who could supply electricity for making green hydrogen through electrolysis.

Despite the excitement surrounding green hydrogen, the technology remains expensive. Hydrogen producers and retailers can earn valuable credits under the California low-carbon fuel standard — called “LCFS” — to help cover the cost of projects. These credits can form the basis for a project financing. However, structuring transactions to get value for them takes work, especially where a developer wants the lender to assign value to them in the financing.

LCFS Credits

There are two main ways to earn LCFS credits with hydrogen. Credits can be earned by supplying hydrogen for use as a transportation fuel and by installing zero-emissions-vehicle refueling infrastructure.

Under the first method, credits are awarded when hydrogen is dispensed to motor vehicles in California. The credits accrue to the owner of the hydrogen fueling station. The upstream producer of the hydrogen can probably sell the hydrogen to the owner of the fueling station at a higher price to reflect the value of the credits to which the station owner will be entitled. The cleaner the source of the hydrogen — for example, a solar-plus-electrolyzer project will produce cleaner hydrogen than hydrogen produced from steam methane reforming — the more valuable it is to a station owner. The station owner should be willing to pay more for cleaner hydrogen.

Under the second method, credits are awarded for installing hydrogen fueling station infrastructure in California that is open to the public. The number of credits awarded is based on the dispensing nameplate capacity of the fueling station minus the quantity of actual fuel dispensed.

/ continued page 42

LCFS Credits

continued from page 41

The LCFS regulations allow the owner of the fueling station to transfer the right to the credits to the upstream producer of the hydrogen. If this approach is used, the hydrogen producer will end up selling the hydrogen to fueling stations for less cash, but the cash will be supplemented with LCFS credits. The drawback of using this approach is that it shifts the fuel-sale risk to the hydrogen producer because the amount of credits awarded depends on the amount of hydrogen put in motor vehicles.

If the same entity is earning both fuel-sale credits and the infrastructure credits, then any decrease in fuel sales will be compensated by more infrastructure credits since the latter reward spare refueling capacity.

LCFS credits can be lucrative. In 2019, more than 14 million LCFS credits were sold or traded at an average price of $192 per credit, representing a vigorous market with an annual transaction value of more than $2.7 billion.

Hydrogen developers can earn valuable credits under the California low-carbon fuel standard.

The market for them is suppliers of petroleum-based fuels. Such companies must turn in credits at the end of each year to the extent the carbon intensity of the fuels they supplied during the year for transportation use in California is above a baseline carbon intensity set by the California Air Resources Board.

Entities with LCFS credits can monetize them by selling them to companies that need credits under bilateral contracts or by selling them in an annual state-run auction.

The LCFS regulations allow petroleum-fuel suppliers that require credits to enter into over-the-counter agreements to transfer credits or to transact using a broker. Most parties choose to document their trades using a master agreement together with one or more confirmations. The master agreement has the general terms and conditions that apply to all trades between the parties like payment netting, close-out setoff, credit support, force majeure, invalidation of credits and dispute resolution. The confirmations contain economic terms like quantity and price for the particular transaction.

In order to finance a project based on LCFS credits, a creditworthy counterparty will have to have agreed to buy the credits over a long period of time. A predictable revenue stream is very important to project finance lenders.

While the price of LCFS credits is currently near the ceiling and has tended to trend up over time, project finance lenders will be reluctant to finance a project without a contract that sets a price floor. The price of credits can drop significantly. Lenders will not take that risk.

The sale of the credits can be analogized to the sale of electricity from a power project. The gold standard is a long-term power purchase agreement with a creditworthy utility. Similarly, a long-term LCFS credit sale agreement with a creditworthy entity would be the easiest way to ensure financing.

However, the market would probably consider other financing structures for LCFS credits just as it has been willing to accommodate quasi-merchant power projects. Some market participants are exploring use of an LCFS hedge product. If the hedge provides a price floor for a predetermined quantity of credits and is with (or backed by) a creditworthy counterparty, then it should be enough to support a financing.

The amount of credits awarded for installing hydrogen fuel infrastructure declines as sales increase. Lenders will not be able to lend against solely this type of LCFS credit. The loan will have to be supported by binding contracts not only for the sale of LCFS credits generated by installation of fueling infrastructure, but also from sales of credits for hydrogen put in motor vehicles so that any decrease in infrastructure credits is offset by an increase in fuel credits. A simple solution to this issue is to contract for the full amount of credits with one buyer and not differentiate the source.

Because the buyer of LCFS credits is often a major oil company, there is not usually an issue with offtaker credit. However, buyers of LCFS credits sometimes use a special-purpose entity as the purchaser. If this is done, the seller of the LCFS credits should ensure that there is a guarantee from a creditworthy parent backing the payment stream.

In addition, sellers should ensure that sales contracts include other typical project finance lender protections. A contract to sell LCFS credits should not prohibit a change of control of the seller that would be implicated if a lender to the project selling LCFS credits has to foreclose on the project. The buyer of LCFS credits (and its guarantor, if there is one) should agree up front to provide a customary consent to assignment and legal opinion. The excuses for buyer performance should be limited.

Long-term sales of LCFS credits will be at a discount to current market prices. A seller may feel that it is leaving significant money on the table. This discount is one of the costs of obtaining the certainty that lenders require about long-term revenue. Most lenders will work with a seller to structure some upside. This could be done by requiring less than all of the projected LCFS credits to be sold under long-term contracts.

A project could hold back some credits to sell in the spot market. Any such spot sales could fetch higher prices than under a long-term contract as long as the market remains strong. Lenders may give some credit to these sales when sizing the financing, but at a more conservative debt service coverage ratio. The lenders could also require cash sweeps from spot-market sales to pay down the debt principal more quickly while allowing the borrower to make larger cash distributions to its parent company.

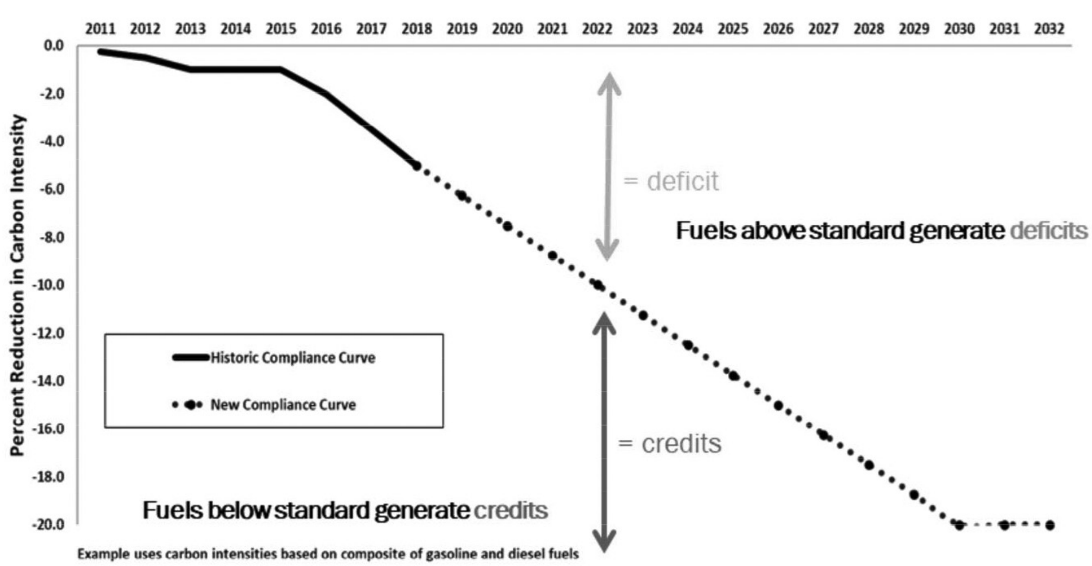
LCFS Basics

A starting point for hydrogen producers and anyone thinking about investing in a hydrogen project is to make sure that the project qualifies for LCFS credits and no money is being left on the table.

The goal of the LCFS program is to reduce the carbon intensity of the transportation fuel used in California. The production and use of petroleum-derived transportation fuels — such as gasoline and diesel fuel — are responsible for almost half of California greenhouse gas emissions.

The LCFS program was first implemented in 2011 under authority in the Global Warming Solutions Act of 2006. Californians call this law Assembly Bill 32 or AB 32. It created a comprehensive, multi-year program to reduce greenhouse gas emissions in the state. / continued page 44

Declining Carbon Intensity Curve



Source: California Air Resources Board

LCFS Credits

continued from page 43

The LCFS program has been extended and amended several times. The California Air Resources Board – called CARB — is the lead agency for implementing and enforcing the low-carbon fuel standard.

Petroleum fuel producers, importers, refiners and wholesalers who sell fuel in California are subject to the LCFS rules. The rules require these "regulated entities" to demonstrate that the carbon intensity, or "CI," of the mix of fuels they sell in California does not exceed an annual benchmark set by the LCFS program.

CI is a measure of greenhouse gas emissions over the lifespan of a fuel type, measured in grams of carbon dioxide equivalent per megajoule (gCO2e/MJ). The benchmarks become more stringent each year so that the CI declines over time. The 2030 benchmark represents a 20% reduction in CI as compared to 2010.

A regulated entity can meet its annual carbon intensity benchmark by reducing the carbon intensity of its fuels — for example, by substituting clean fuels for petroleum-based fuels — or by buying LCFS credits in the market. Credits are awarded when a fuel supplier produces fuels that are below the annual CI benchmark. Deficits are generated when a fuel supplier produces fuels that are above the annual CI benchmark.

To ensure that there are enough credits available for purchase, the LCFS rules allow renewable energy and low-carbon-fuel project developers, aggregators and utilities to opt into the program and become regulated entities. Credits are awarded only to regulated entities, and only regulated entities can sell credits. For example, a hydrogen producer who opts into the program would be expected to be awarded credits because the carbon-intensity of hydrogen is below the annual CI benchmark. It can sell those credits to a diesel refiner who is running a deficit because diesel is above the CI benchmark. Credits may be banked and traded within the LCFS market to meet compliance obligations in current or future years.

LCFS credit prices are determined by market dynamics of supply and demand.

Prices are volatile, but have generally trended upward over time. In fact, credits were becoming so valuable that state regulators imposed a price ceiling of $200 in 2016 that adjusts every year for inflation. The ceiling in 2020 is $217.97 per credit. Despite this intervention, regulators commented that the LCFS market is functioning as intended and providing a strong signal for investment in low-carbon fuels. In November, credits were trading at well over $200 per credit.

Demonstrating Compliance

A regulated entity must demonstrate that it met its annual compliance obligation by submitting an annual compliance report to CARB that shows that it owned and has retired the number of credits from its credit account required to satisfy its compliance obligation. The annual compliance period is January 1 through December 31 of each year. After compliance reports are filed, CARB retires the number of credits equal to each reporting entity's compliance obligation for that compliance period. If a reporting entity does not have enough credits to cover a deficit in its account, the entity will be liable for the shortfall and could have to pay a serious fine if it does not cover the deficit (plus interest) within five years.

There is a credit clearance market, or "CCM," for regulated parties that do not have enough credits to cover a deficit. If a regulated entity does not retire enough credits to meet its year-end compliance obligation, then it must purchase its pro-rata share of credits in the CCM if one is held. The CCM is also an opportunity for holders of excess credits to sell their credits.

The CCM, if one occurs, will operate in any year from June 1 to August 30. Parties participating in the CCM agree to sell or transfer credits at or below the maximum price for the pertinent year set by CARB until the market closes on August 30. Parties that have voluntarily pledged credits to sell into the market can negotiate the price but cannot reject an offer to buy those pledged credits at the maximum price.

The last CCM was held in 2016. CARB did not need to hold a CCM in subsequent years because all LCFS regulated entities met their compliance obligations for those years.

Qualifying for Credits

There are three ways to qualify for credits under the LCFS: fuel pathways, projects and capacity-based crediting.

Under fuel pathways-based crediting, suppliers of low-carbon transportation fuels used in California receive credits by obtaining a certified CI score and reporting the quantity of fuel put into motor vehicles on a quarterly basis.

The CI score depends on the production process used for converting feedstock to a finished fuel, called the "fuel pathway." The CI score can be determined by referring to a "lookup table" that contains the CI scores for different fuel pathways and types of fuels. This is the most straightforward way to obtain a CI score. There are other, more cumbersome, processes available if the fuel pathway in the lookup table does not apply.

Under project-based crediting, projects that reduce emissions at refineries and crude-oil production and transportation facilities can qualify for credits. An example is a carbon-capture-and-sequestration project.

Finally, capacity-based crediting is designed to support the deployment of zero-emissions vehicle infrastructure by awarding credits for ZEV infrastructure based on the capacity of the hydrogen fueling station or EV fast charging site minus the actual amount of fuel dispensed.

Green hydrogen projects will probably rely on the fuel pathways-based crediting and ZEV infrastructure crediting rather than project-based crediting.

The lookup table for fuel pathways-based crediting includes six different pathways pre-approved by CARB. Of the six pathways, two derive hydrogen from natural gas, two derive hydrogen from landfill bio-methane and two pathways derive hydrogen from water using electrolysis. Each pathway has a CI score.

LCFS credits are more valuable the lower the CI score. For example, a calculator provided by CARB estimates that hydrogen produced with clean electricity generates approximately 41% more credits per kilogram of fuel than hydrogen produced with the average California grid electricity.

The only pathway that would produce truly "green" hydrogen is the pathway for compressed, gaseous hydrogen produced in California from electrolysis using electricity generated from a 100% zero-carbon-intensity resource, which means renewable energy resources other than biomass, bio-methane, geothermal and municipal solid waste.

The applicant must demonstrate that energy from the renewable source in question is consumed directly in the hydrogen production process. There are three key ingredients to meeting this requirement. First, the electricity must be supplied from generating equipment under the control of the pathway applicant. Second, the generating equipment must be directly connected through a dedicated line to the facility such that the generating equipment and the load are both physically located on the customer side of the utility meter. The generating source may be grid-tied, but a dedicated connection must exist between the source and load. Finally, the facility's load must be enough to absorb all of the zero-carbon-intensity electricity claimed during a monthly balancing period.

There are other requirements for the other pathways. If electrolytic hydrogen is produced in California using California average grid electricity, an entity can be awarded incremental credits by using smart electrolysis. Smart electrolysis (like smart charging of electric vehicles) means the process draws power from the grid only during certain times of the day when demand is low. A smart electrolysis project applicant must provide CARB with records demonstrating the quantity of electricity dispensed during each hour for the most recent quarter.

The pre-approved pathways for electrolytic hydrogen are only available to hydrogen produced within California. If the hydrogen is not produced in California (but is sold in California), then the project may still qualify for LCFS credits, but will have to apply to CARB for approval on a case-by-case basis.

Hydrogen fueling station owners can earn capacity-based credits based on the capacity of the station minus the amount of fuel dispensed. Capacity-based credits can be earned every day for 15 years. These credits help to solve the chick-and-egg problem experienced by new technologies (such as hydrogen-powered vehicles) by encouraging construction of hydrogen fueling stations before there is enough demand from vehicle owners to justify the infrastructure.◎

Investing in Renewable Fuel Projects

by Kat Gamache and Chris Psihoules, in Washington

Among a handful of notable developments as 2020 ends is an uptick in interest in renewable fuel projects.

Renewable fuel is not an oxymoron. There are federal, regional and state programs to reward the use of fuels that have environmental benefits. The value and risks of renewable fuel projects depend heavily on government regulations.

This article is a primer for investors on the federal renewable fuel standard or "RFS" to assist with investment decisions.

Renewable Fuels

Renewable fuel is fuel produced from renewable inputs such as sugar cane, vegetable oil or municipal waste.

The renewable fuel standard was enacted in 2005 as a tool to reduce greenhouse gas emissions, expand the domestic renewable fuel sector and reduce reliance on foreign oil. The standard is administered by the US Environmental Protection Agency.

The RFS requires a specified volume of petroleum-based transportation fuel, heating oil and jet fuel to be displaced each year by renewable fuels. Basically, it requires renewable fuel, like ethanol, to be blended into petroleum-fuels so that gasoline mixtures sold for use in motor vehicles, for example, are 10% ethanol or other forms of biofuel.

There are four biofuel categories under the RFS: cellulosic biofuel, biomass-based diesel, advanced biofuel and conventional biofuel. The volume requirements are currently set by statute through 2022.

An example of cellulosic biofuel is ethanol produced from grass, wood or other plants. An example of biomass-based diesel fuel is fuel used in diesel engines or as heating fuel derived from plant and animal products. Advanced biofuels can be made from any type of renewable biomass (except biomass that could be used as food). An example is compressed natural gas from municipal wastewater treatment facility digesters. Ethanol made from corn starch or biodiesel made from soybean oil are examples of conventional biofuels.

The EPA has significant discretion to adjust the national renewable volume obligations for each of the four biofuel categories through an annual rulemaking process. It also has authority to waive the volume requirements if it determines the RFS is causing severe economic or environmental harm, or if there is inadequate domestic supply of biofuels to satisfy the mixture requirements.

The required mixture levels have been a touchy political issue the last four years, especially in the run up to the Iowa presidential caucuses in early 2020. Both farm and oil interests have been key Republican constituencies, but the Trump administration found it very difficult to strike a balance that satisfied both camps. The incoming Biden administration will face pressure from oil refiners for relief and competing pressure from farm interests to maintain a high biofuel blending ratio.

Some of the political pressure can be relieved by granting waivers. However, to date, the EPA has limited waivers to narrow classes of entities or individual companies.

There is obvious risk in a program that may change on an annual basis or be totally waived. However, EPA to date has maintained relative consistency with respect to the volume obligations and the limited waivers it has granted have not been enough to effect a material change in biofuel use. The bigger issue has been COVID-19. Fuel use is down across the board and both oil and farm interests are hurting.

Once an investor can get past the change-in-law risk, the focus turns to whether the biofuel project will produce eligible product on a reliable basis that can feed the RFS blending market.

Potential Market

The RFS program affects nearly every participant in the market for ground transportation fuels.

There are six different types of market participants in the supply chain.

They are refiners who manufacture gasoline and diesel fuel, renewable fuel producers who produce fuels like ethanol and biodiesel, importers who import both petroleum-based and renewable fuels, blenders who combine renewable fuels with petroleum-based fuel to create transportation fuel for use in US vehicles, retailers who purchase the blended transportation fuel and sell it to consumers at gas stations, and consumers who purchase transportation fuel for their vehicles at gas stations.

Refiners and importers of gasoline and diesel fuels are "obligated parties" that must comply with RFS. Each obligated party has an individual volume obligation to mix biofuels into the fuel it supplies by applying its percentage of gasoline and diesel fuel that it will introduce in the United States during the coming year, as compared to other obligated parties, to the volume of biofuels that the US government wants used during the coming year.

Obligated parties must demonstrate compliance with their individual renewable volume obligations, or "RVOs" annually.

The obligated party in the context of a project financing of a biofuel project will typically be the customer who signed a contract for the ethanol or other biofuel to be produced by the project being financed, or it may be one or more owners of the biofuel project (in the case where a refiner, for example, owns an ethanol plant).

Eligibility

The RFS creates a market for the output from biofuel projects. Biofuels qualify for inclusion in the renewable fuel program only if EPA has determined that the particular type of biofuel will help to reduce greenhouse gas emissions as compared to a 2005 petroleum baseline.

Biomass-based diesel must meet a 50% lifecycle greenhouse gas reduction.

Cellulosic biofuel must be produced from cellulose, hemicellulose, or lignin and must meet a 60% lifecycle greenhouse gas reduction.

Advanced biofuel can be produced from qualifying renewable biomass (except corn starch) and must meet a 50% greenhouse gas reduction.

Conventional biofuels like ethanol derived from corn must meet only a 20% lifecycle greenhouse reduction.

Common renewable fuel projects include municipal wastewater treatment facilities, public or private landfills generating biogas, and dairy farms, breweries and other entities that treat high-solids wastewater with anaerobic digestion and generate a biogas byproduct.

RINs

An obligated party can satisfy its compliance obligations by blending renewable fuels into transportation fuel or by obtaining renewable identification numbers, or "RINs," to meet its renewable volume obligations.

RINs are the credits that obligated parties use to demonstrate compliance with the RFS. One RIN is created for each gallon of RFS-eligible biofuel produced. RINs are defined using a unique 38-character number that is issued (in accordance with EPA guidelines) by the biofuel producer or importer at the point of biofuel production or the port of importation.

The RIN can be used by an obligated party for compliance in the year it is generated and the immediately following year. If the obligated party has excess RINs, it may sell them to others who may be short or save them for use in the following year.

A biofuel producer should plan ahead to ensure it is registered to generate RINs before producing fuel. The registration requirements for biofuel producers can be found at 40 C.F.R. § 80.1450.

Biofuel producers that generate RINs must register with the EPA at least 60 days before generating RINs.

The EPA may deactivate a biofuel producer's registration for several reasons. They includes inactivity lasting 24 consecutive months, failure to comply with registration requirements, failure to submit any required notification within the specified timeframes, and failure to pay any penalties imposed.

Trading RINs

Generally, RINs are to fuel as renewable energy certificates, or "RECs," are to electricity.

All RINs are tracked through the same system: the EPA Moderated Transaction System, or "EMTS." The EMTS is a "buyer-beware system," meaning all due diligence is the duty of the obligated parties to certify validity. There have been some well publicized cases of fraud.

Most RINs are bought and sold through private contracts registered with the EMTS, but there are also RIN spot markets. RINs can be traded in two ways. They can be assigned with the batch of fuel to which they relate and that travel with that batch of fuel from party to party, meaning any party buying the fuel also gets the RINs associated with it. Alternatively, RINs can be sold separately.

When a manufacturer produces a batch of biofuel, it must report certain information to the EPA through EMTS, including the type and quantity. The same holds true for a party buying, selling or retiring RINs by turning them into the government to satisfy its annual compliance renewable volume obligation. The party must report the transaction through EMTS, including the year generated, type of biofuel, quantity of RINs and per-unit price.

To reiterate: any party that owns RINs at any point during the year must be registered with the EPA and follow the RIN record-keeping and reporting guidelines.

A typical RIN lifecycle transaction might look like the following.

When a qualifying fuel is produced, a RIN is generated and belongs to the biofuel producer. The RIN may then be sold by the producer directly to an obligated party or a RIN trader on an assigned or separated basis. A RIN may be resold by a trader (or an obligated party with more RINs than it needs) on an assigned or separated basis.

/ continued page 48

Renewable Fuels

continued from page 47

A RIN that is originally sold as part of an assigned purchase may be separated from the fuel to which it was originally assigned and resold on a separate basis.

When the RIN is used to demonstrate compliance, it is retired by turning it into the government.

The EPA collects historical data on RIN prices to which the public can refer to get a sense of typical market RIN prices. Current published RIN price ranges per category of biofuel generally range from a minimum of 5¢ per RIN, except for more plentiful conventional biofuels where the minimum price is 1¢ per RIN, to a maximum price of $2 per RIN, except for cellulosic biofuel where the maximum price is $3.50 per RIN.

Investor interest in renewable fuel projects is growing.

Each RIN represents a gallon of biofuel.

Certain types of biofuel RINs are worth more than others because a fuel with a higher greenhouse gas reduction threshold can be used to meet the standards for a lower greenhouse gas reduction threshold and is therefore more versatile.

Cellulosic biofuel can substitute for all the other types of biofuel and, therefore, is the most valuable.

Noncompliance Penalties

RIN noncompliance can be costly for obligated parties. Penalty levels for noncompliance set an upper limit on the amount an obligated party will be prepared to pay for RINs.

A non-compliant obligated party could be subject to civil penalties of up to $47,357 a day (subject to annual inflation adjustments). Non-compliance may also require that the obligated party disgorge (or return) any economic benefits that resulted from its non-compliance.

Consequently, contracts for the purchase of RINs often include indemnity or significant liquidated damages provisions for failure to deliver contract quantities of RINs. There may also be an option to cover by purchasing RINs in the spot market in the event that a seller does not produce as many RINs as anticipated.

Biofuel Sales

In addition to RIN sales, the sale of the underlying renewable fuel may also provide an important revenue stream, even when the RIN has been separated. In practice, a biofuel producer will produce biofuel that generates RINs. The biofuel producer will often immediately separate the RINs from the fuel, sell the RINs to obligated parties, and then sell the fuel to a gas marketer. Income from separated RINs allows the biofuel project to offset the cost of producing the biofuel.

An obligated party may satisfy its renewable volume obligation by acquiring RINs or by blending biofuels into conventional transportation fuels. There is a controversial restriction called a “blend wall” that caps the amount of biofuels that can be incorporated into gasoline (currently, it is 10%). Some obligated parties have expressed concern that this blend wall inflates the value of RINs.

There are important downstream factors to consider in any biofuel sale, whether the sale is for use by an obligated party to satisfy its RVO or is a sale of the biofuel to an end user.

If the biofuel will be shipped via pipeline, the project will need to have an interconnection agreement to connect with the pipeline. This agreement will specify the quantity of biofuel permitted to flow into the pipeline as well as the gas quality standards necessary to permit entry into the pipeline.

In many instances the biofuel project will also require a gas transportation contract to move the biofuel from the biofuel project to the pipeline or on the pipeline to the customer. Use of third-party pipelines typically requires gas upgrading technology and gas compression to meet pipeline specifications. The interconnection and gas transportation agreements should be analyzed in connection with any biofuel offtake contract to ensure the project has the right to deliver biofuel to the customer in sufficient quantities and correct specifications.

In conclusion, there are several unique regulatory diligence topics to consider when analyzing the viability of a biofuel project that will depend on RFS-driven revenues.

They include proper feedstocks and conversion technology to qualify the project under the RFS, RIN registration and compliance, offtake contracts or spot-market sales plans for RINs and biofuel with special attention to the term, change-in-law risk allocation and consequences or indemnities tied to underproduction in such contracts, contractual rights to interconnect and move the biofuel, and controls to ensure the biofuel meets applicable quality specifications.◎

Environmental Update

As President-elect Joseph R. Biden assembles the environment and energy team for his new administration, he is honing his strategy to address climate change in the face of a divided Congress and a leadership in opposition intent on limiting his ability to keep his campaign promises.

Even if both Democratic candidates for the US Senate from Georgia win their January 5, 2021 runoff elections, the Democrats will have secured the narrowest of Senate majorities, 50-50, with ties to be broken by Vice President-elect Kamala Harris.

Biden has proposed spending $2 trillion on clean energy over the next four years to address climate concerns and to create jobs. But the Biden campaign's climate plan was largely dependent on a legislative push with a Senate led by Democrats. Much of the plan will be set aside in all but rhetoric for executive and regulatory action and a more pragmatic path in Congress.

Biden will look at the political realities and likely forgo as dead on arrival any early effort to put his broader plan through Congress in favor of trying to pass his climate change proposals in small increments, when and where he can.

He is expected to begin with a flurry of new executive orders.

He is also expected to use federal procurement and infrastructure investments to spur clean-energy tech and to create jobs.

It will take considerable effort and time to undue regulatory changes put in place under the Trump administration, let alone pass new laws.

Biden will more likely than not be able in his first four years to expand solar and wind, expand the network of charging stations for electric vehicles, reverse a significant share of the Trump administration's regulatory policies on the environment, and rekindle federal partnerships with state, local and global entities on climate change. He may find it harder to make progress after the first two years because the political party holding the White House usually loses seats in Congress in the mid-term elections: in this case in 2022. However, Democrats will have a favorable electoral map going into the 2022 elections.

/ continued page 48

Environmental Update

continued from page 49

Biden's actions as president can be expected to lead to a decrease in greenhouse emissions compared to what would have happened under another four years of Trump administration.

Paris

The United States under President Trump became the first nation to withdraw from the Paris climate accord in November. The agreement has been signed by more than 200 countries.

Biden is expected to rejoin the accord by February 2021.

The United States is currently half way to meeting the goal in the Paris accord of cutting greenhouse gas emissions to 28% below 2005 levels by 2025. In the absence of federal action, what success has been achieved is largely attributable to efforts by states and municipalities and the benefits of moving to renewable energy as a source of electricity.

The United States can be expected to re-focus on what steps it can take to meet the 28% target by the time world leaders meet at the United Nations climate summit in Glasgow, Scotland that is currently planned for November 2021.

Rejoining Paris will be easy. Reaching the 28% goal in the five years remaining will be more challenging, particularly if the incoming administration is unable to rely on help from Congress and as attention will also have to be given to economic recovery from the downturn caused by COVID-19.

Senate

A Senate that is split 50-50 would expand Biden's options on climate change, but only slightly. It would not be enough to pass a broad-ranging climate bill.

Major bills require 60 votes to pass the Senate because opponents can use the filibuster to prevent the Senate from cutting off debate.

One way around the Senate filibuster is a budgetary procedure known as "reconciliation." It allows one budget reconciliation bill a year to pass by a simple majority vote, but that bill can only contain measures related to tax revenue and spending.

Such a bill might be used for tax credits for wind and solar, assuming Democrats win both Senate races in Georgia.

Other climate measures would require the support of Democrats whose constituencies rely on the fossil fuel industry or on moderate Republicans to pass.

At least a few Democrats from states that produce fossil fuels have signaled a shift to favoring some action on climate change.

Polls show growing concern about climate change among the public over the last decade as scientific evidence mounts of melting polar ice caps, rising sea levels and changing weather patterns. Almost two thirds of Americans said in a Pew Research Center poll this year that the government is doing too little to confront climate change.

Nevertheless, opposition remains even among some Congressional Democrats, and members like coal-state Senator Joe Manchin (D-West Virginia) will play gatekeeper roles in any climate debate. Manchin is the senior Democrat on the Senate Energy Committee and would be chairman in an equally divided Senate.

Biden's lengthy legislative experience and willingness to work the middle may prove to be an asset.

The Democrats retain control of the House where they may try to inject more modest climate provisions into broader, popular or must-pass bills.

For example, if an infrastructure bill moves through Congress with bipartisan support, the House could add and then resist attempts to remove climate policy provisions. Measures to encourage construction of electric vehicle charging stations, promote energy-efficient homes or expand railroads stand a better chance than a carbon tax or a federal cap-and-trade plan to curb greenhouse gas emissions.

Modest spending and tax measures and reinstated environmental regulations will not be enough to reduce carbon emissions by 28% compared to 2005 levels by 2025.

Significant elements of Biden's climate plan require bipartisan support and would face pushback from Congress, even with a 50-50 Senate.

Biden called during the campaign for the government to mandate net-zero emissions by 2050 and to adopt a "clean energy standard" to push for more zero-carbon electricity generation from renewables like wind, solar, hydropower and nuclear energy. He wants the federal government vehicle fleet to consist solely of hybrid and electric vehicles. He wants to promote use of equipment on farms to capture methane emissions from manure and to create a new federal research agency that would focus on finding solutions to climate change.

EPA

The team that will help Biden with environmental and climate policy is still taking shape. So far, he is drawing on people with deep experience and knowledge of the inner workings of government.

Here is what we knew as the NewsWire went to print.

The leading contender to head the US Environmental Protection Agency is Mary D. Nichols, but she faces headwinds from both the right and left.

Nichols was the top air regulator in California and head of the California Air Resources Board. She engineered the state's cap-and-trade law that limits greenhouse gas emissions from power plants and allows utilities to buy and sell credits to cover emissions of greenhouse gases. She also set important regulations on auto emissions in California.

Nichols has been a prominent opponent of various Trump administration environmental rollbacks over the past four years.

Another contender for EPA administrator is the current head of the National Wildlife Federation, Collin O'Mara. O'Mara has ties to the Biden family from when he headed the Delaware Department of Natural Resources and Environmental Control from 2009 to 2014. Before that, he led the Regional Greenhouse Gas Initiative, or "RGGI," the cap-and-trade program now covering 10 states from the mid-Atlantic to New England. O'Mara also served on the Obama administration's task force on climate adaptation and preparedness.

Another name in the mix is Heather McTeer Toney, who served previously as administrator of EPA Region 4 during the Obama administration and is a former mayor of Greenville, Mississippi.

Some speculate with good reason that O'Mara or McTeer Toney might face an easier nomination process than Nichols, but Nichols remains the odds-on favorite despite opposition to her confirmation.

Nichols' detractors criticize the command-and-control culture in California and her role in it.

Nichols has a record of being tough, but she has also demonstrated an ability to work with industry. For example, she led an effort in which California and five major automakers agreed in 2019 on tailpipe emissions standards for autos that were not as strict as Obama-era rules, but that were stricter than those under the Trump administration.

Nichols cites the 2019 agreement as a template for regulators to make progress while avoiding lengthy litigation.

Nichols was confirmed before by the Senate as the Clinton EPA air chief in 1993 and is the candidate with the deepest resume.

EPA began communicating with Biden transition team in late November.

Interior

More people appear to remain in the running to head the Department of the Interior.

One contender is Michael Connor, a former deputy secretary of Interior under Obama. He also served in the department throughout the Clinton administration. If selected, he would be the first Native American to be named to a cabinet position. He is a member of the Taos Pueblo sovereign nation in New Mexico.

US Representative Deb Haaland (D-New Mexico) also remains in the running and is one of the few Native Americans elected to Congress. She serves on the House Natural Resources Committee. She was only elected to Congress in 2018. Haaland has support from a lot of her House colleagues.

A dark horse candidate is Senator Tom Udall (D-New Mexico). Udall is retiring at the end of this year. His father, Stewart Udall, served as Interior secretary in the 1960s. He has pushed to restrict oil and gas drilling on federal property and has favored protection of public lands as designated wilderness areas in Utah.

Council on Environmental Quality

The leading contenders to chair the White House Council on Environmental Quality appear to be Mustafa Santiago Ali and Brenda Mallory. The Council will help shape and harmonize environmental policy across the new administration.

Ali currently serves as vice president of environmental justice, climate and community revitalization for the National Wildlife Federation and has more than 20 years of experience at EPA. He started the EPA Office of Environmental Justice and also served as a senior adviser to the Obama EPA administrator, Gina McCarthy, on environmental justice issues.

Brenda Mallory served as the general counsel to the Council on Environmental Quality under Obama. Before that, she served in various roles at EPA over a 15-year tenure, including as the agency's principal deputy general counsel. She is currently the director of regulatory policy at the Southern Environmental Law Center.

/ continued page 52

Enviornmental Update

continued from page 51

Both Ali and Mallory are likely to be asked to serve in some capacity in the new administration.

Other Posts

While Biden has already announced a foreign-policy team that will focus on climate change as a national security matter, he has also created a new position of "presidential envoy on climate" to lead efforts "to combat the climate crisis and mobilize action to meet this existential threat."

Former US Secretary of State and Biden friend John Kerry will serve in this role. Climate change was one of Kerry's signature diplomatic issues during his time as Secretary of State. He is well-known in diplomatic circles

Kerry will have a seat on the National Security Council at the White House.

Another new high-level White House position for Biden to fill is that of White House domestic climate policy coordinator. The appointee will help keep the various federal agencies focused on reaching climate goals and push legislative options for addressing greenhouse gas emissions and climate change.

One person in the mix for this role is Ali A. Zaidi, the current deputy secretary of energy and environment for New York. He served previously as associate director of the White House Office of Management and Budget and was involved in creating Obama's framework for cutting greenhouse gas emissions, known as the White House Climate Action Plan.

Another front runner for the post is the former governor of Michigan, Jennifer Granholm. Granholm was also an adviser to Hillary Clinton on energy and has also been rumored to be under consideration for other posts.

Biden named Brian Deese to head the White House National Economic Council. Deese advised President Obama broadly on climate issues and was a key player in work on the Paris climate accord. His official roles included deputy director of the Office of the Management and Budget and deputy director of the National Economic Council during the Obama era. He spent the last three years as global head of sustainable living for BlackRock.

Biden has asked Senator Thomas Carper (D-Delaware) to push his climate agenda in Congress. Carper is in line to become chairman of the Senate Environment and Public Works Committee — if the Democrats win the two Senate seats in Georgia.

— contributed by Andrew Skroback in New York