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PROJECT FINANCE

NewsWire

June 2016

Argentina Launches Innovative Renewables Program

by Talbert Navia, Amanda Sewell and José Avila in New York

Argentina will hold a public auction on August 22 to buy 1,000 megawatts of renewable energy under an innovative program called "RenovAR" that includes a "green trust fund" to provide security and confidence to investors.

The government wants 600 megawatts from wind energy, 300 megawatts from solar energy, 65 megawatts from biomass, 20 megawatts from small hydroelectric plants and 15 megawatts from biogas.

The bid documents are expected to be published on July 1 and be available for purchase from the government on July 2. Winning bids will be announced on September 28.

Argentina has set an aggressive program to reach 20% renewable energy by the end of 2025. Currently, 1.8% of power demand in Argentina is supplied through renewable energy.

The FODER Advantage

One of the key features of the new framework is a sector-specific trust fund, the "Trust Fund for Renewable Energy" or "FODER," that has been set up to provide payment guarantees for all tendered power purchase agreements as well as project financing assistance.

Argentina allocated ARS 12 billion (US$860 million at current exchange rates) to FODER. FODER is divided into two separate accounts.

The project finance account is funded by a mix of treasury funds, / *continued page 2*

IN OTHER NEWS

SOME FOREIGN-OWNED US COMPANIES will have to file additional reports.

The Internal Revenue Service proposed in May that all US limited liability companies that are owned by a single foreign individual or entity should apply for an "employer identification number" or EIN on IRS Form SS-4. This will require disclosing the foreign owner.

The LLC will also have to file an annual information return on IRS Form 5472 reporting any transactions between the LLC and its foreign owner or any other foreign related parties. This is the same annual information that section 6038A of the US tax code already requires be filed by US corporations with 25% or more foreign ownership. / *continued page 3*

IN THIS ISSUE

Argentina

continued from page 1

public offerings, ANSES (the Argentine government-administered pension fund) and multilaterals, and will be used to offer long-term project loans as well as to provide interest rate subsidies and equity contributions to renewable energy generation project companies.

A separate payment guarantee account will be used to guarantee payments for electricity under all PPAs tendered through the RenovAR program. This account must always have on deposit at least 12 months' worth of payments due by the offtaker under the PPAs. Although this account is primarily funded by a specific charge to consumers, if at any point FODER does not have enough funds, then Argentina's Ministry of Finance has an obligation to replenish the account. This mitigates the risk that the Administrator of the Wholesale Electricity Market (CAMMESA), which depends on the Argentine state, will lack sufficient funds to purchase the power contracted under the PPAs. Winning bidders take advantage of FODER's protections by signing an accession agreement with the FODER trustee at the time the PPA is signed.

FODER also provides the winning bidder with an option to "put" the power project back to the government that can be exercised in any of six situations. The put can be exercised if the offtaker fails to make payments over a certain period, it breaches an Argentine court judgment under the dispute resolution clause in the PPA, the Argentine currency becomes inconvertible or non-transferable, there is a change in certain Argentine laws, the project is expropriated, or there is an early termination of the PPA, the World Bank guarantee (described below) or the FODER accession agreement.

The occurrence of any of these events will, after the exhaustion of a specified cure period, allow the winning bidder to sell the project to FODER in exchange for payment in US dollars of a pre-determined amount. The amount is the book value, without depreciation, of the project assets based on the winning bidder's most recent audited financial statements. This FODER purchase payment will be guaranteed by the World Bank up to US$500,000 per megawatt of capacity contracted for from the particular project.

On the other hand, FODER has a purchase option over each tendered project that it may exercise in the event that the offtaker terminates a PPA due to an event of default (including failure to achieve a critical milestone) by the winning bidder. FODER has the right to acquire the project, as is, in exchange for a payment in US dollars to the winning bidder for 70% of the book value, determined the same way as for the put described in the previous paragraph.

The August tender follows enactment of an Argentine law last September, called Law No. 27,191, that laid out the framework for the push to increase the share of renewable energy as a percentage of the total Argentine electricity supply.

Below are answers to the most common questions being asked by potential bidders.

What is Law No. 27,191?

Law 27,191 sets mandatory renewable energy targets through the year 2025 for all consumers. The law sets targets of 8% renewable energy by December 31, 2017 and 20% renewable energy by December 31, 2025. The Ministry of Energy and Mining will tender renewable energy PPAs for 100% of the mandated target, with the costs of these PPAs being passed on to consumers. Power users with an average power demand greater than 300 kilowatts (labeled "large users") will have the option to opt out of the tendered PPAs and instead to source renewable energy directly or through self-consumption projects. However, large users who opt out will have to meet annual renewable energy goals and will be subject to penalties if they do not reach them.

Argentina will auction long-term PPAs to buy 1,000 MWs of renewable energy in August.

Does Law No. 27,191 provide any incentives for renewable energy projects?

Yes. Law No. 27,191 provides for various fiscal and local supply chain incentives for renewable energy projects.

The fiscal incentives are greatest for projects starting construction before 2018 and decrease gradually over time until 2025. Fiscal incentives include exemption from import duties (for projects starting construction before 2018), accelerated depreciation of assets, VAT refunds, exemption from a minimum deemed income tax, exemption from dividend tax (if there is reinvestment in infrastructure), extension of income tax loss credits to 10 years (from five years), a tax deduction for all financial expenses and a tax credit on locally supplied capital expenditures.

There are also local supply chain incentives. For local suppliers and manufacturers, there will be a FODER sector-specific development credit line and an import duty exemption for equipment parts and supplies. If independent power projects purchase locally, then they will receive priority access to FODER project financing and a 20% tax credit on locally supplied capital expenditures (subject to certain terms).

What are the terms of the PPAs?

The offtaker will be CAMMESA on behalf of distribution utilities and large users. Each PPA will have a maximum term of up to 20 years from the commercial operation date. The PPA will also specify the type of energy and energy technology to be supplied, the amount of energy committed to be delivered per year, generation capacity, the energy price to be paid by the offtaker, conditions that the electricity seller must meet to preserve the PPA performance guarantee, the contractual penalties for non-compliance, FODER's payment guarantee obligations and the PPA's position as first priority for payments by CAMMESA.

CAMMESA will make monthly payments for the electricity delivered under the PPA. Each payment will be the product of 1/12th of the awarded annual price and an incentive factor that may vary by project. The incentive factor gradually reduces over the PPA term.

How does the bidding process work?

CAMMESA already released preliminary versions of the bid documents for public comment. CAMMESA is collecting comments through June 12 on the draft bid terms and conditions and the PPA that will be used for the public auction in August. The final bid documents and PPA will be released

/ continued page 4

IN OTHER NEWS

The new filing requirements will apply starting in tax years ending at least 12 months after the IRS republishes these proposals in final form. The agency is collecting comments in the meantime.

An LLC with a single owner does not exist for US tax purposes. The IRS is concerned that such entities are being used to shield foreigners from reporting obligations that apply to other types of entities. The proposal is essentially to treat them the same as foreign corporations with at least 25% foreign ownership for purposes of reporting obligations.

US DEPRECIATION ALLOWANCES would be rewritten under a draft bill that the ranking Democrat on the Senate tax committee, Ron Wyden (D-Oregon), is circulating for comment.

The bill is a discussion draft.

It could become important if the Democrats take control of the Senate in the November elections.

It would move the United States to a pooled depreciation system. All equipment would be put into one of six asset pools. Each year, a company would deduct a fixed percentage times the aggregate unrecovered cost of equipment in the pool. Any new capital spending on equipment during the year would be added to the pool. When assets are sold, the sales price would be deducted from the pool.

Companies would transition to the new system by transferring the remaining unrecovered bases in their assets into the pools.

This would simplify not only how depreciation is calculated, but also the calculation of gain or loss on asset sales. A company would report gain only to the extent the balance in the pool is driven negative by asset sales in a year. The negative balance would be reported as ordinary income. Asset sales would not trigger losses.

The depreciation percentages are 49% for assets in pool 1, 34% for pool 2, 25% for pool 3, 18% for pool 4, 11% for pool 5 and 8% for pool 6.

/ continued page 5

Argentina

continued from page 3

after the government has had time to sift through the comments.

Each bid must comply with specified legal and technical requirements for qualification including, among other items, providing certain legal and accounting documentation, a description of the project, an evaluation of the availability of necessary resources, a description of the technical characteristics of the offer, details of technology and estimated energy production and confirmation that environmental clearances have been received for the project.

The bidder must also obtain a "certificate of inclusion" to participate. To obtain this certificate, the project owner must register as an agent for participation in the wholesale power market and must file certain fiscal and tax information and submit details of the project. The bidder must also post a bond together with the application for the certificate for 10% of the total value of all tax benefits requested.

Each bidder should (individually or collectively) have a minimum net worth of US$500,000 per megawatt of capacity offered, have experience in construction and operation of projects with similar technology that are at least a third of the size of the proposed project, and provide the required bid-stage guarantee in the form of a bond, standby letter of credit or surety for US$50,000 per megawatt of capacity offered. The bond must be for a term of 180 days and be automatically renewable for an additional 90 days.

The winning bidder must also provide a performance guarantee when the PPA is signed to guarantee completion of the project. The performance guarantee should be in the form of a bond, standby letter of credit, surety or cash-collateral deposit to a controlled account for US$250,000 per megawatt of capacity contracted for. It must remain in place until at least 180 days after the commercial operation date. Winning projects must reach commercial operation within 730 days after the PPA is signed (with limited exceptions) and must have a minimum capacity of one megawatt (with the exception of small hydroelectric plants, which must have a minimum capacity of 0.5 megawatts).

How will the successful bid be chosen?

The government will weigh five factors when deciding which bids to accept. They are the price (in US dollars per megawatt hour), the location of the project and interconnection node, the committed date to reach commercial operation, compliance with the requirements in the bid documents and compliance with the requirements to obtain the certificate of inclusion. There will be an electricity price ceiling for bids.

What are the key deadlines for the bidding process?

The preliminary versions of the bid documents have been released and will be available for public non-binding consultation and comment until June 12, 2016. Any comments must be submitted in writing to CAMMESA. The final bid documents, as well as the bid terms, are expected to be available for purchase from CAMMESA on July 2. From July 2 until August 8, 2016, there will be a period of consultations with interested parties. On August 8, 2016, the trust contract setting up the FODER trust will be executed. Also on August 8, CAMMESA will publish the final version of the term sheet and World Bank guarantees. Bidders will need to submit their offers by August 22, 2016. The winning bids are expected to be announced on September 28. The PPAs and guarantee contracts between FODER and the winning bidders will be signed on October 28, 2016.

A special trust is being set up to guarantee payments.

Mexico Gears Up For Second Power Auction

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

Mexico issued bid guidelines in early May for its next auction of long-term power contracts expected to be awarded in September.

The first auction at the end of March awarded contracts to buy electricity from 2,180 megawatts of renewable energy projects at a weighted average price of approximately $47.70 a megawatt hour.

Prices in the second auction are expected to be roughly equivalent.

The second-round contracts will be 15-year contracts for the sale of capacity and renewable energy and 20-year contracts for clean energy certificates with the Mexican national utility, CFE, as offtaker.

The initial version of the bid guidelines is available on the websites of the Mexican independent system operator, CENACE, and the Ministry of Energy at www.cenace.gob.mx and www.sener.gob.mx.

Terms

According to preliminary information disclosed by the Ministry of Energy and subject to official confirmation by CFE during the auction process, CFE is expected to acquire through the auction seven terawatt hours of electricity and 1,000 to 2,000 megawatts of capacity. All technologies may participate in the capacity auction, but only "clean energy" technologies – that is, mainly renewables – may participate in the auction for electricity and clean energy certificates.

Along with the bid guidelines, CENACE published the expected prices of energy at the different nodes. Expected price differences will be used to compare offers in different price zones or nodes. CENACE will adjust the price of the offers by adding or subtracting the expected price difference. This adjustment will not alter the offered price, but will be a determining factor in selecting winning offers.

The nodal price differences are so important that CENACE, in announcing the winners of the first auction, had to retract preliminary results that it had announced without having applied the nodal price algorithm to the bid evaluation process, only to come out 12 hours later with a revised list of winning bids that was significantly different than the first / continued page 6

IN OTHER NEWS

Wind, solar, geothermal and fuel cell projects would be in pool 2. The depreciation percentage for assets in a pool would be applied against a declining balance. Thus, for example, if an asset in pool 2 cost $100X, depreciation the first year would be $34X and the second year would be $66X x 34% = $22.44. However, if the company added another $100X asset in year 2, then depreciation that year would be $166X x 34% = $56.44.

It would not matter when during the year the new assets are put in service.

Gas-fired power plants and LNG terminals would be in pool 5.

Hydroelectric facilities are in pool 6.

Wyden asked in late April for comments on all aspects of the draft bill and in particular on transition rules.

Congress usually writes transition rules to give companies that already own or have made binding commitments to invest in assets before the tax law changes are first approved by one of the Congressional tax-writing committees the chance to see the investments through with the existing tax subsidies. There is no such transition relief in the Wyden bill. The bill says the pools would start with the unrecovered bases of a company's assets at the start of the tax year the bill takes effect. Transition relief could still be added. However, an issue will be whether to let companies keep existing subsidies while also benefiting fully from lower corporate tax rates if the depreciation bill is enacted as part of a broader corporate reform package that reduces corporate tax rates.

Senator Max Baucus (D-Montana), who preceded Wyden as the ranking Democrat on the Senate tax committee, introduced a pooled depreciation proposal in November 2013 before leaving the Senate to take up the post of US ambassador to China. The Baucus bill would have put equipment into four asset pools and slowed down depreciation rather than accelerated it.

The pooled concept makes it easy to adjust the depreciation percentages once Congress gets into corporate tax reform and can assess whether / continued page 7

Mexico

continued from page 5

one. An initial review of the nodal pricing information for the second auction shows that the most favorable price zones are in the state of Baja California Sur (mainly in Villa Constitución, La Paz and Los Cabos), with expected price differences of minus $26.23 a MWh from the pricing proposals presented by bidders.

Companies interested in participating in the auction must pay roughly $1,700 for the bid guidelines.

Bids must include technical and pricing proposals. Technical proposals are analyzed during the pre-qualification stage. If bids are approved at this stage, then the bidder may submit its pricing proposal in a subsequent stage. Technical proposals must address legal, financial and technical requirements such as interconnection availability at the bidding power plant's site and node pricing related issues, among others. Pricing proposals will be presented in two stages. First, a bidder must indicate the interconnection status of the bidding power plant or unit and whether the offer will be indexed in pesos or in dollars. Two business days following the delivery of this information, the bidder may submit the proposed pricing for its bid.

Technical proposals are due with the pre-qualification applications between August 1 and 5.

Pricing proposals are due in two stages on September 19 and 21.

Mexico will hold another power auction in September.

Multiple offers may be submitted by a single bidder. These offers may be conditioned to the acceptance of other offers, be mutually exclusive or a combination of both.

Bidders interested in participating in the auction must pay a flat evaluation fee of approximately $17,000, plus a fee of approximately $1,700 for each individual offer.

As with the first auction, bidders will be required to provide a commitment guarantee in the form of a standby letter of credit issued by a Mexican financial institution. The minimum amount of the guarantee must be calculated based on the following components: a flat fee of approximately $88,000, independent of the number of offers the bidder intends to present, plus approximately $19,000 for each megawatt of capacity a bidder intends to offer, plus approximately $9 for each MWh of clean energy a bidder intends to offer, plus approximately $5 for each clean energy certificate that a bidder intends to offer.

These amounts add up. For a 100-megawatt plant offering capacity only, the letter of credit would come to $1,988,000 and for the same plant offering 800,000 MWh of energy and associated certificates on an annual basis, the letter of credit would come to $11,288,000.

Upon execution of the PPA, the winning bidders must replace the commitment guarantee with a performance guarantee that must remain in place during the full term of the PPA. The amount of the performance guarantee is less than the amount of the commitment guarantee, and it decreases over time upon completion of certain milestones. CFE is also required to provide a payment guarantee in the form of a standby letter of credit issued by a Mexican financial institution that must remain in place for the full term of the PPA. If drawn, these guarantees must be replenished.

Projects awarded contracts in the next round must be in commercial operation by January 1, 2019.

What are some of the key terms of the PPA?

Payments under the PPA will be made on a monthly basis, with an annual settlement, and will be adjusted for inflation and exchange rate should the PPA be indexed in US dollars. The commercial operation date may be delayed for reasons outside the control of the generator for up to three years, including a delay by the government, the provider of wheeling or distribution services or CENACE, or unforeseen adjustments in the interconnection process, among other reasons. The PPA includes change-of-control restrictions that will remain in place for the first 12 months after the plant commences commercial operation, with limited exceptions. If the financial, technical or operational qualifications of the winning bidder were satisfied through its shareholders, either directly or through affiliates, then the PPA will require that any such shareholders maintain a minimum ownership threshold in the winning bidder until certain milestones or dates are reached.

If the CFE defaults, then the generator may terminate the PPA and set up a payment trust into which the offtaker will be required to deposit over time the amounts it would have had to pay had the PPA remained in place. If the CFE terminates the PPA due to an event of default of the generator, then CFE may still require the generator to continue, to the extent possible, selling to it the products sold under the PPA for the remainder of the term of the PPA and for the same price and terms.

Key Dates

The deadline for acquiring the bid guidelines and paying for pre-qualification is July 22, 2016.

At least one consultation session will be conducted before the auction. Initial comments about the proposed bid terms were submitted and responses were issued by CENACE on June 3. Participants may submit follow-up questions on June 6. CENACE will then publish its final responses to the follow-up questions no later than June 10. Once this consultation session has concluded, CENACE is expected to publish the final version of the bid guidelines by June 20.

By June 27, CFE must submit its purchase offers to CENACE. CENACE will publish the amounts, prices and parameters of the offers approved by the Energy Regulatory Commission by July 4.

Participants must submit their pre-qualification applications between August 1 and August 5 and their commitment guarantees by September 7. Bidders may file no later than September 7 any modifications to their technical proposals, but only if these are the result of changes in the zones where their facilities are interconnected or to the capacity of the plant due to changes to interconnection availability. CENACE will then issue pre-qualification certificates to eligible bidders by September 13 and publish a list including all pre-qualified bidders on September 15. Once eligible bidders receive their pre-qualification certificates, they will be able to file their pricing proposals in two stages on September 19 and 21.

CENACE will publish the auction results and the winning bidders by September 30, 2016.

Contracts awarded in the auction must be signed no later than January 31, 2017. ◎

IN OTHER NEWS

it needs to use depreciation to raise revenue to pay for corporate rate reductions. The current bill draft sets the depreciation percentages at levels that leave the overall bill revenue neutral.

TWO STATE-MANDATED POWER CONTRACTS were set aside in court.

The US Supreme Court said in April that power contracts that Maryland and New Jersey ordered utilities in those states to sign with an independent generator had the effect of setting the wholesale power rate the generator would receive for its electricity.

Only the Federal Energy Regulatory Commission can set wholesale power rates for electricity sold in interstate markets. States retain the power to regulate retail sales of electricity within their borders. The case raised the issue whether the state action to encourage a new capacity resource crossed the line into wholesale ratemaking.

The court said Maryland and New Jersey went too far.

Maryland regulators became concerned around 2009 that not enough new power plants were being built in the state to supply electricity, and out-of-state power from the PJM grid was becoming more expensive to import.

The Maryland Public Service Commission solicited proposals from generators for construction of a new gas-fired power plant in a particular location. Competitive Power Ventures, or CPV, was the winning bidder. The Maryland PSC then ordered all utilities in the state to enter into a 20-year contract for differences with CPV at the rates in the CPV proposal. A contract for differences is a form of hedge. CPV sells the capacity from the project into the PJM grid by bidding into annual auctions to supply capacity for a single year three years in the future. If the price CPV is paid exceeds the fixed price in the contract for differences, then CPV must pay the utilities the excess revenue. If the price is below the fixed price, then the utilities pay CPV the shortfall.

/ continued page 9

New Trends in Financing Wind Farms

Four top executives of prominent wind companies talked at the Global Windpower 2016 convention in late May in New Orleans about new trends in financing wind farms, whether we have reached a tipping point where most future power contracts will be with corporate offtakers rather than utilities and the financing challenges created by heavier reliance on such contracts, new financial products for which there would be demand from wind companies but that no one is offering currently, the current cost of capital, the ratio in which companies are drawing from different types of capital, current discount rates being used to value projects, and a range of other topics.

The four are Tom Festle, chief financial officer of E.On Climate & Renewables North America, the North American arm of the German utility, E.On, Pete Keel, chief financial officer of Longroad Energy Partners, a new company established by the core team that was behind First Wind, Jim Murphy, executive vice president, chief financial officer and president of the operating business group at Invenergy LLC, and Michael Storch, executive vice president and chief corporate development officer of Enel Green Power North America, the North American arm of the Italian utility, Enel. The moderator is Keith Martin with Chadbourne in Washington.

MR. MARTIN: Tom Festle, what new trends are you seeing in financing wind farms?

MR. FESTLE: We see an ever-increasing interest among commercial and industrial users of electricity in wind and solar. That is not a financing trend per se, but it drives what we need to do to get transactions built and financed. Being a German utility, we use our own capital to pay for construction, and we raise tax equity once our projects have been built, and that really has not changed much.

MR. MARTIN: Pete Keel, new trends?

MR. KEEL: Another trend is a focus on minimizing the share of cash that the tax equity is taking so that it can be monetized through back-levered debt or retained by the sponsor. Your cheapest capital is going to be debt. It is much cheaper than tax equity, so trying to maximize the cash that can go to that part of the capital structure is very important.

MR. MARTIN: US Bank pioneered a structure where it takes cash each year equal to 2% of its investment as a preferred cash distribution and not much beyond that. Are you seeing other tax equity investors offering the same structure?

MR. KEEL: The US Bank structure is really more of a product for use in the solar market where projects qualify for investment tax credits. It does not work as well for wind farms on which production tax credits are claimed. Solar sponsors, for the most part, really like the structure. We are not seeing anything exactly like that structure from any other tax equity provider, but most tax equity are trying to be more accommodating on leaving more cash for the sponsor. The days are long gone with the tax equity investor takes 99% of cash before the flip.

MR. MARTIN: Is the most common cash sharing ratio today 60-40, 50-50, 40-60?

MR. KEEL: More like 70% for the sponsor and 30% for the tax equity investor.

MR. MARTIN: When that happens, the sponsor's capital account, or the measure of what he put in and what he takes out, tends to go negative.

MR. KEEL: That's right.

MR. MARTIN: Are you seeing tax equity investors require you to promise, as a sponsor, to put cash equal to the capital account deficit back into the partnership for redistribution to the tax equity investor when the partnership liquidates?

MR. KEEL: In some cases. The fact that the capital account goes negative may be a limiting factor in the ability of the sponsor to keep a disproportionate share of the cash. The other limiting factor is the cash-on-cash return that the tax equity investor is looking for. The investor needs at least a minimum cash-on-cash return. Some investors are more aggressive than others. You see a pretty big difference across the market in terms of what people will do.

MR. MARTIN: How do you feel as a sponsor agreeing to put cash back in? You thought you had a deal where you were getting 70% of cash, but there is an asterisk.

MR. KEEL: We are not crazy about it. We never promised to put any money back into the deal at First Wind.

MR. MARTIN: Jim Murphy, what new trends are you seeing in financing?

MR. MURPHY: In addition to greater interest from corporate offtakers, we are seeing more utility interest in owning assets to put in rate base.

Pete Keel talked about tax equity. Maybe I will touch on so-called cash equity, or what some call true equity. There has been a surprising resiliency of capital sources filling in where we had some contraction from the yield cos. We have seen strategics. We have seen funds. We have seen some REITs and other institutional investors coming into the space, and it has been helpful and surprising, and I think it will continue.

MR. MARTIN: I assume the REIT is Hannon Armstrong, and REIT participation in the wind market is lending? Are the other investors pension funds, insurance companies? What types of investors are they?

MR. MURPHY: Pension funds, insurance companies, and as I mentioned, strategics, primarily domestic utilities, looking to take positions. Hannon Armstrong also takes equity positions.

MR. MARTIN: When the utility comes in, does it just want to buy the project in order to put it in rate base, or will utilities sometimes just put in a share of the equity?

MR. MURPHY: We have done both.

MR. MARTIN: Mike Storch, new trends?

MR. STORCH: I feel like they are probably old trends by now it took so long to get to me. [Laughter] One thing that is interesting is the tax equity market has become much more competitive. There is much more willingness to break away from the mold in terms of trying to tailor deals to better meet the sponsor's needs.

A good example, and Tom Festle can probably appreciate it as well, is sponsors whose parent companies are not domiciled in the US are subject to international financial reporting standards and, under those standards, tax equity is treated as debt. The primary reason for that is there is a target return in the financial arrangements with tax equity and, until the tax equity investor achieves that return, it owns certain entitlements, particularly with respect to cash, and that triggers treatment as debt.

That can have a fairly significant impact. We have done a few billion dollars of tax equity in the past few years alone here in the United States, all of which gets treated as debt. If you eliminate the target yield and have a fixed flip date, then the tax equity is not treated as debt. We are in the middle of such a transaction now. We would like to see it become a trend. With the entry of so many new investors, we finally have a competitive market for tax equity.

Another trend that has financing implications is low PPA pricing. We are seeing power contracts with electricity prices in the teens per megawatt hour of electricity, and it creates a lot of challenges with tax equity since there is not as much cash. The PTC is worth more than the cash you get from power sales in a lot of cases.

MR. MARTIN: Why do you care whether the tax equity deal is treated as debt or equity for purposes of international financial accounting?

/ continued page 10

IN OTHER NEWS

New Jersey implemented a similar plan around the same time, except that the New Jersey contract runs for 15 years rather than 20 years.

CPV receives no payment under the contract for any year in which the price it bid into the auction to supply capacity to PJM fails to clear the auction. Therefore, it has an incentive to bid as low a price as possible to ensure it wins, knowing that it will always receive the fixed price in the contract for differences.

A US appeals court said in 2014 that the arrangement has the effect of setting an interstate wholesale price for electricity. The Supreme Court agreed.

The Supreme Court said FERC approved the PJM auctions as the "sole rate setting mechanism" for wholesale electricity sales into the grid. Maryland went too far, it said, by guaranteeing CPV a different price than the rate set in the auction.

The case was being watched with great interest for whether the decision might leave a cloud over the ability of states to order utilities to buy power in other contexts: for example, from renewable energy generators under state renewable portfolio standards or under legislation requiring utilities to buy a certain amount of power from offshore wind.

The decision is "limited," the court said. "Nothing in this opinion should be read to foreclose Maryland and other States from encouraging production of new or clean generation through measures 'untethered to a generator's wholesale market participation.' So long as a State does not condition payment of funds on capacity clearing the auction, the State's program would not suffer from the fatal defect that rendered Maryland's program unacceptable."

The decision came in a case called *Hughes v. Talen Energy Marketing*. The Supreme Court released its decision on April 19. On April 25, the Supreme Court issued a short decision applying the *Hughes* decision to the New Jersey program in *PPL Energy Plus v. Solomon*.

/ continued page 11

Wind

continued from page 9

MR. STORCH: We are very sensitive to how much debt we have on our corporate balance sheet. We are a public company. We have more than €40 billion in debt, much of it related to the acquisition of Endesa. Every CFO is always focused on his credit rating and maintaining adequate coverages to maintain or get to investment-grade status, because it affects the cost of money.

Corporate PPAs

MR. MARTIN: Tom Festle, in the fourth quarter last year, 75% of PPAs signed by wind developers were corporate PPAs. Have we reached a tipping point where we expect to see more corporate PPAs in the future than utility PPAs?

MR. FESTLE: I hope so. Certainty of offtake is important to all of our investors, whether they are providing debt, tax equity or true equity. Certainty of offtake and creditworthiness of the offtaker are of paramount importance. It is great to have utility customers, but it is even better that there is growing demand from potential commercial and industrial customers.

MR. MARTIN: Does any of the rest of you think we have reached a tipping point? Mike Storch, you told me before the panel that you think we will be at a point soon where half the power contracts are with corporate offtakers.

MR. STORCH: Yes, but I am not as enthusiastic. It is good from a competitive standpoint, but the commercial players are very difficult to contract with.

MR. MARTIN: Harder than utilities?

MR. STORCH: Utilities pass through the cost. It is a different environment. With a corporate customer, you really have to think whether the proposed terms will help the customer be more competitive in terms of the long-term impact on its credit profile. You have to care about that more from a commercial perspective.

Also, the commercial players almost always want the project to take basis risk for the spread between the cost of electricity at the bus bar and at the pricing node, and that type of risk is very difficult to hedge, especially when dealing with a resource like wind. Those spreads can be huge, plus they move around a lot because of the changes in membership in different RTOs that manage the grid. New groups are joining different RTOs, not necessarily in a logical way. Entergy is part of MISO. Why does that make sense?

MR. MARTIN: If the sponsor has to take such a large risk to secure a corporate PPA, then why do you think the market will shift to 50% corporate PPAs?

MR. STORCH: Industrials will continue to want to contract directly for power. The financing folks will eventually develop products to hedge this risk more effectively or we will figure out how to share it with the industrials. We just did an industrial deal where the industrial will take the power at the bus bar. It did not push the basis risk back to us because the risk would otherwise get baked into the electricity price and it can be very, very expensive and very difficult to quantify.

MR. MARTIN: Where is the basis risk in the typical utility deal?

MR. STORCH: Utilities are used to taking electricity at the bus bar. They can pass through the full cost of the electricity as a purchased power expense. It is just a different way of thinking. Utilities, too, are getting more sophisticated. Utility PPAs look different than they did five or 10 years ago in terms of the risk sharing that takes place and the burden that is imposed on the generator.

MR. MARTIN: Jim Murphy, have we reached a tipping point where most PPAs will be with corporate offtakers in the future, and what special financing challenges do corporate PPAs present?

MR. MURPHY: I don't know whether we have reached a tipping point. We have had cycles before where utilities have backed off PPAs and then come back in force. I think we are seeing a move by utilities toward ownership and not PPAs. We appear to be in the middle of such a trend today.

Will it tip back? I don't know. There is a limit on the number of corporate PPAs that are possible because you can only do those deals in organized markets. You have to have the right mechanism to be able to do a contract for differences, which is the way most corporate deals are structured.

Corporate PPAs shift electricity price risk between the bus bar and the pricing node to the sponsor.

Clearly it is a trend. The last four deals we have done as a company are with corporate offtakers.

In terms of special financing issues, Tom Festle touched on those. How creditworthy is the offtaker? Is the credit the top entity that has a credit rating or is it a subsidiary that owns a data storage facility, for example? If it is not the credit-rated entity, then how much security is appropriate? Is the security a letter of credit? Is it a bond? All of that is fairly unique to these contracts.

The last thing is to echo in spades what Mike Storch said about basis risk. Most deals we have seen involve allocating basis risk to the sponsor, which is different than the utility model.

MR. MARTIN: Are you comfortable taking basis risk?

MR. MURPHY: Yes. We have to fold it into the electricity price, and we have to think about ways to hedge it as well.

MR. MARTIN: Pete Keel, what special financing challenges do corporate PPAs present?

MR. KEEL: Basis risk, absolutely. The proliferation of corporate PPAs is a great trend. We are happy to have more buyers for our product, but, on balance, corporate PPAs are not as clean as utility PPAs. Other things being equal, they are less valuable because of the basis risk. The tenors are also not as long.

MR. MARTIN: What are the tenors?

MR. KEEL: Ten to 12 years seems to be the sweet spot, so 10 to 12 years with an entity that may or may not be investment-grade and with basis risk versus a 20-year contract with an investment-grade utility whose terms are down the middle of the fairway. Those are very different deals.

New Financial Products

MR. MARTIN: Tom Festle, what new financial products have investment bankers and others been pitching to you recently?

MR. FESTLE: We avoided the yield co out of an abundance of caution. That was the last major product being sold to us in which we declined to participate. For us, it was a tradeoff between the very low cost of borrowing as a German utility versus some passable upsides we might have had on the cost of equity. No one has been pitching us any new ideas recently.

MR. MARTIN: Mike Storch?

MR. STORCH: We are hearing noise that turbine loans might make a comeback. The recent IRS guidance means that people may be looking now at holding turbines for as long as four years. It is a long time to hold equipment, especially for companies that expect significant growth over the next four years.

MR. MARTIN: Turbine loans used to / *continued page 12*

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IN OTHER NEWS

PRODUCTION TAX CREDITS for renewable energy projects will remain unchanged in 2016 from 2015 levels, the IRS said in late April.

Credits for producing refined coal increased slightly in amount.

The credits for generating electricity from wind, geothermal steam or fluid or closed-loop biomass (plants grown to be used as fuel in power plants) are 2.3¢ a kilowatt hour. They are 1.2¢ a kilowatt hour for generating electricity from open-loop biomass, landfill gas, incremental hydropower and ocean energy.

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

The credits phase out if contracted electricity prices from a particular resource reach a certain level. That level in 2016 is 12.4448¢ a KWh. The IRS said there will not be any phase out in 2016 because contracted wind electricity prices are 4.50¢ a KWh going into 2016. It said it lacks data on contracted prices for electricity from the other energy sources.

Production tax credits for producing refined coal are $6.81 a ton in 2016. Refined coal is coal that has been treated with chemicals to make it less polluting than regular coal. The IRS said there will not be any phase out of refined coal credits in 2016. The refined coal credit phases out as the reference price for raw coal moves above 1.7 times the 2002 price of raw coal. The 2016 reference price is $53.74 a ton. A phase out would have started at $84.38 a ton.

The tax credit amounts are in IRS Notice 2016-34.

NETWORK UPGRADE PAYMENTS had to be reported as income, the IRS said.

Independent generators must connect their power plants to the utility grid. The utility requires the generator to pay the cost of the intertie and any improvements to the grid to accommodate the additional electricity.

/ *continued page 13*

continued from page 11

be a product on offer from German banks. Are such banks back pitching such loans?

MR. STORCH: The talk is coming mostly from investment bankers who wonder whether a market will develop.

MR. MARTIN: Pete Keel, are you seeing any other new products?

MR. KEEL: Given what happened to yield cos, I think the exotic stuff is out right now and it is back to basics. Whether it is yield cos, high-yield debt, the term loan B market, none of those products is getting much traction at the moment.

Capital Stack

MR. MARTIN: Let's move to another topic. Renewable energy companies raise capital from six tiers of capital from cheapest to most expensive. The cheapest capital used to be Treasury cash grants. They remain available only for solar. Next cheapest are export credits and government loan guarantees. Then you have straight debt, tax equity, subordinated or mezzanine debt, and true equity in that order.

Tom Festle, in what ratio do you draw on these different sources of capital to finance projects?

MR. FESTLE: We only use two of those in the typical project. The first one is sponsor equity. It comes from our German parent, which has really low borrowing costs, and covers maybe 30% to 40% of our typical project cost. The remainder is tax equity.

Like my colleagues, we try to minimize the amount of cash that we take from the tax equity investors as well as end up paying back to them. We want them to use the tax attributes.

MR. MARTIN: Do you use back leverage to monetize the cash?

MR. FESTLE: We have used it in only one joint venture transaction involving three Treasury cash grant projects. We used portfolio debt. We have not used back leverage otherwise.

MR. MARTIN: So 30% true equity and 70% tax equity. Mike Storch, it is the same ratio for Enel?

MR. STORCH: The tax equity percentage may be creeping up a little because we are seeing these incredible capacity factors. It is not unusual to see capacity factors above 50%.

MR. MARTIN: That means more production tax credits. Therefore, you raise more tax equity. Jim Murphy, what does your capital stack look like?

MR. MURPHY: A little different. We are an independent, privately-held company, and so we are doing 100% project financing. We do not have a corporate parent to lean on.

I agree that the percentage of tax equity has gone up. A few years ago, it was not unusual to have maybe 40% in tax equity. Now we are seeing 60% in some cases. We sometimes put back leverage behind the tax equity. Back leverage can be quite a headache, and we are running into a lot of difficulties working with tax equity investors to accommodate the back leverage and what they want on issues like change of control.

The back leverage tends to work better on projects with long-dated offtake agreements because we can stretch out the tenor and get some volume. Whether or not we use back leverage, we are filling out the stack with a combination of sponsor equity and third-party cash equity. The ratio between the sponsor and third-party equity varies. Sometimes we offer the third-party cash investor common equity and sometimes we offer it preferred equity. When we do the latter, we can increase the percentage held by the third party.

MR. MARTIN: You said there is tension between the tax equity investors and back-levered lenders. You said one source of tension is restrictions on changes of control. I imagine another issue is a cash sweep to pay indemnities. Are there other issues besides those two?

MR. MURPHY: I think those are the main issues.

MR. MARTIN: On change of control, why does the tax equity chafe at the lender coming in and replacing the sponsor?

There may be renewed demand for turbine loans now that wind companies are looking at holding turbines for as long as four years.

MR. MURPHY: It cares about who is operating the plant. If the sponsor is no longer there, then it wants to make sure there is another experienced operator with deep pockets.

MR. MARTIN: Pete Keel, does your capital stack look more like Jim Murphy's than the E.On and Enel capital stacks?

MR. KEEL: Yes, definitely more like Jim's. The other thing to consider is where are you in the life cycle of the project because that affects the shape of the capital stack. During development, it is all equity. This is the period of greatest risk, and it is hard to raise financing.

To get into construction, we try to borrow construction debt to cover as much as possible of the cost. The construction debt will be sized to what the takeout financing looks like. Usually it comes in at 70% to 80% of the total cost and the remaining 20% to 30% is equity.

The permanent financing once we get to commercial operation is some combination of tax equity, debt, and true equity.

The development equity is high risk, high return, and the permanent equity is lower risk, lower return.

MR. MARTIN: Do any of you rely on export credits from foreign export-import banks? Mike Storch, you are shaking your head no.

MR. KEEL: We do some of it in Latin America, but nothing in North America.

MR. FESTLE: No.

MR. MARTIN: What about government loan guarantees?

MR. FESTLE: We have not used the DOE loan guarantee program.

MR. KEEL: We did at First Wind. One of the lessons for us was you end up with a more complicated structure and a lot of legal fees and questions whether the time and cost are worth the benefit. It sounds good, but we decided we were better off keeping things simple.

MR. MURPHY: We looked at it as well back in 2009 when the first program came out. We had the same experience. We took it well down the road on one project and had to push the eject button because we could not wait that long. The wind turbines were arriving at the site and we had a schedule and the process at DOE was moving too slowly.

MR. STORCH: There is no substitute for dealing with experienced lenders and sponsors, because there are always challenges. When you deal with the right people, they understand that and they can make informed decisions reasonably quickly. The government is usually not in that category.

/ *continued page 14*

IN OTHER NEWS

Such payments do not normally have to be reported by a utility as income under a policy the IRS laid out in a notice in 1988 and updated in additional notices in 1990, 2001 and 2005. The IRS is in the process of revising its policies in this area. A new notice that will replace the earlier notices is expected in June.

The problem if the utility has to report the payment from the independent generator as income is the utility will charge a tax "gross up" on top of the cost of the intertie and grid upgrades. This makes interconnection more expensive.

The key to avoiding income is for the generator not to be a customer of the utility to whom it makes the payment, even for wheeling power. Thus, it is important to transfer the electricity to someone else before the electricity reaches the grid. For a more detailed explanation, see the December 2001 *NewsWire* at http://www.chadbourne.com/IRS_Clarifies_Tax_12-2001_Projectfinance and the August 2005 *NewsWire* at http://www.chadbourne.com/IRS_Addresses_Interconnection_8-2005_Projectfinance.

The IRS said in a private letter ruling issued to a utility, made public in May, that the utility had to report payments from a generator as income. The ruling is Private Letter Ruling 201619007.

The generator had what appears to be corporate PPA under which it agreed to sell its electricity to a corporate buyer. The buyer took title to the electricity at the bus bar for the power plant.

The principal issue was the power plant connected to a distribution line rather than a transmission line. The IRS read its existing notices narrowly to say that the policy of not taxing utilities on such payments only applies where the independent power plant is connected to the transmission grid.

The IRS mentioned one other issue. The IRS has applied a two-step analysis in the recent past to determine whether a utility must report a payment as income. Step one is to determine whether the facts fit within the existing notices where the IRS has said the utility does not have to report income. Step two is / *continued page 15*

Wind

continued from page 13

Cost of Capital

MR. MARTIN: What is your weighted average cost of capital? Tom Festle, you are laughing.

MR. FESTLE: I'm sorry. I think I am prohibited from sharing that number, but I can say the trend line is modestly downward. Our company is very focused on maintaining a strong credit rating in the German public markets. Borrowing costs are very low at this point in time. Renewable energy projects are now considered investment grade, and that helps with the cost of equity, as well.

MR. MARTIN: So the trend line is down due to two factors. One is macroeconomic and the other is the market is getting more comfortable with this type of project. Pete Keel, do you have a weighted average cost of capital?

MR. KEEL: We look at every opportunity as a discrete opportunity and then divide things into development versus permanent financing. Development capital needs to earn a 20+% return, and it is probably more oriented around a multiple on the money invested because it can be pretty short duration. It demands a higher internal rate of return. It is short duration. It has been playing more for multiples.

For permanent financing, the cost of debt is going to be LIBOR plus 175 to maybe 300 basis points, depending on where the debt sits in the capital stack. Tax equity is around 8%. Third-party cash equity is 9% to 12%, maybe even 13%, depending on what the PPA looks like.

MR. MARTIN: Then you take the ratio of each in the capital stack and that gives you the weighted average cost of capital.

MR. KEEL: Correct, but the capital structure changes over time as you amortize tax equity, as you amortize debt, so you really need to layer in the third-party money, tax equity, debt, and then discount the cash flow on that strip of equity. That is the truest way to value an asset.

If you can raise capital at the parent level and put a bond on that is not amortizing, then the equation changes.

MR. MARTIN: Jim Murphy, what is your weighted average cost of capital?

MR. MURPHY: Yes. I guess I will have to take some evasive action . . . . [Laughter]

MR. MARTIN: In which direction is it moving?

MR. MURPHY: I agree with Tom Festle. It is going down.

I am a little frustrated, frankly, that tax equity has not come down more, and I think all of us on this panel share that view and have for a long time. There have been some new entrants, and that is helping a bit, but tax equity has remained stubbornly at 8%. You will hit the flip yield at maybe 7.5%, but the tax equity has a residual interest and there are limitations on what the sponsor can pull out of the project if the tax equity has not reached certain hurdles on the cash side.

The tax equity has a secure enough position that its yield feels overpriced to us. An 8% after-tax yield is equivalent to a 12% pre-tax yield. The fact that the debt is prepared to take the identical risk for a hugely lower cost continues to confound us.

MR. MARTIN: Your company took the lead years ago in pressing for master limited partnerships. The initial thought was that this could be a route to bring in more individual and institutional investors as tax equity. Are you as enamored today with the MLP as a potential source of financing?

MR. MURPHY: Definitely not. An MLP could be a source of cash equity. It really never made sense to view it as a route to additional tax equity investors. We thought that there could be a way to modify the structure, but at the end of the day, it is a cash-oriented product.

MR. MARTIN: Has the fact that people figured out how to do yield cos supplanted the need for MLPs?

MR. MURPHY: Yield cos were developed as a response to the inability of Congress to add wind as an eligible class for MLPs, and I think it has done a fine job filling the gap.

Missing Products

MR. MARTIN: Mike Storch, I can see the pattern here on weighted average cost of capital, so let me take this in a different direction.

MR. STORCH: Thank you. [Laughter]

MR. MARTIN: Development loans used to be on offer for smaller developers. For example, Heller Financial in Chicago offered such a product. You don't see it much anymore. What financial products are missing today for which there could be a market? We need a product to hedge basis risk. What else?

MR. STORCH: Development capital is certainly an area that requires a lot of attention. A lot of what goes on in a public company is tied to the accounting results. Development costs are expensed for book purposes. Until a project is certain to move forward, you do not capitalize them. This has a pretty big hit on P&L. For a company like Enel, lending money to a smaller developer for the rights to buy a project if the project succeeds can be a very effective way to achieve our goal of building a development portfolio without owning it and having to expense all of the development costs.

Companies like Enel and E.On can make development loans to smaller developers at far less than the 20+% cost to which Pete Keel referred. It makes sense for strategics to offer this product. Commercial banks have much less interest in it.

MR. MARTIN: So turbine loans might make a comeback. There is a clear need for development loans. What other financial products are needed in the current market?

MR. FESTLE: One of my colleagues pointed to inability to hedge basis risk, or the variation in electricity price between the bus bar and the hub node. I would love to see a more effective and more tailored product for the wind industry that can help to address that in an efficient way.

MR. MARTIN: Are there are any other missing products?

MR. KEEL: I am curious whether anyone thinks that turbine loans are really coming back. There was a lot of carnage related to turbine loans seven or eight years ago.

MR. MARTIN: Why was there carnage?

MR. KEEL: The carnage bled right into the financial crisis. A lot of developers had turbine loans. They had gone long on equipment, and this drove up turbine prices. There were a lot of developers sitting on excess turbine inventory. Repayment of the turbine loans was often guaranteed by the parent. You had a lot of secured debt maturing against assets that were illiquid and were overpriced. I wonder if the banks will do that again and I wonder whether it is the best thing for the industry, having seen what happened the last time.

MR. MARTIN: Are any other products needed? Are you using tax credit insurance, for example?

MR. MURPHY: No, we are not. The product that is missing, but for which I am not holding my breath, is a more effective way to monetize tax benefits.

MR. MARTIN: It is called a Treasury cash grant, right?

MR. MURPHY: Refundability, transferability, those features. We are still pushing to see whether we can make some inroads on those sorts of features.

MR. STORCH: I always wanted to see the PTC be something that all of us in this room could buy on line and use on our personal returns and feel like we are supporting the renewable energy industry. There could be an on-line clearing house. People could buy them at face value or maybe there would be a bidding process. A larger share of the subsidy would end up being spent on the project rather than going to middlemen and being spent on transaction costs.

The government would not have to write checks. The credits are getting used, and every American could participate. It would not be that tough to implement. / *continued page 16*

IN OTHER NEWS

to determine when the payment to the utility should be viewed as a "nonshareholder contribution to capital" of a corporation under a trio of Supreme Court decisions in the 1940's. The IRS said the generator in this case "lacked the requisite motivation to make a nonshareholder contribution to capital" under these cases because it made the payment "in order to sell electricity."

It is unusual to see an adverse ruling. A ruling request is usually withdrawn if the company that submitted it does not like where the IRS is headed.

This is also the first time the agency found an interconnection payment did not have the right motivation under the 1940 Supreme Court cases.

The IRS is holding at least two other private ruling requests in suspense until a new policy, expected to be favorable to generators, is announced in June.

TREASURY CASH GRANT cases are now moving forward.

A trial in April before the US Federal Court of Claims about the basis that the US Treasury used to calculate section 1603 payments to the owners of a California wind farm could lead to a decision in the case as early as July. The case is being closely watched. The project was sold and leased back. The Treasury reduced the basis by almost 23% on grounds that part of the what the lessors paid should have been treated as basis in intangibles like going concern value. Treasury cash grants are paid only on equipment.

Thirty lawsuits have been filed against the US Treasury by companies that believe they should have been paid more money under the section 1603 program. Companies have up to six years after grants were paid to file suit.

Two of the lawsuits have been decided. The government won one and lost one. Both decisions have now been affirmed on appeal. The decision in the case won by the taxpayer –- a fuel cell company called RPI Fuel Cell, LLC –- was upheld in early April. / *continued page 17*

Wind

continued from page 15

It is hard to explain to foreign investors why you have to raise financing in order to monetize a government incentive. It is a foreign concept in Europe. In Italy, it is actually illegal to do something like the tax equity deals in this country.

They are not efficient. They are incredibly complicated. They put a lot of expensive people, known as attorneys, to work, but that is what we do. It is our culture. In Europe, they are much more sensible. They use feed-in tariffs and very simple mechanisms that do not require the same level of complexity and transaction cost.

Private Yield Cos

MR. MARTIN: Next topic. Yield cos were the shiniest new object within the last three years. Yield co share prices took a hit after July 22 last year. Some people expect them to make a comeback later in the year once there is a change in shareholders from the hedge funds who were the initial investors to insurance companies, pension funds and other sources of more patient capital.

None of your companies set up a public yield co, although Pete Keel's company, First Wind, sold its assets to one. Is the basic concept of separating operating assets from the development pipeline a good one, so that you can raise capital more cheaply against the operating assets?

MR. KEEL: I think so. The asset classes are different. A development property is far different than a fully-financed construction or operating property. It makes sense to separate those given their different risk profiles. The market forces a separation. There are lots of infrastructure players who are in the market acquiring assets, and none of them will take development risk.

MR. MARTIN: E.On and Invenergy have not split the two types of assets. Enel did a private yield co. E.On and Invenergy, do think the concept makes sense and, if so, why aren't you using it?

MR. MURPHY: I think the concept makes sense. There are two reasons we have not done it. One reason is we did not understand the model with the promise of growth. We have no problem separating development from operating assets. They have different risk profiles, but we did not understand the growth component that the market was looking for, and so we were not attracted to it for that reason.

The second reason is we are a private company and we want to stay a private company, and we do not want to add all of the bells and whistles and complexities of being a public company. At the end of the day, we are in the development business. It is a complicated business. It is one where it is difficult to explain why you do what you do because you have to make things happen simultaneously and be very creative in how you execute.

So we do not like the public model. We do not like to have to dedicate management time to reporting, to shareholder calls, and the like. Those are the reasons we avoided it.

MR. MARTIN: Mike Storch, Enel did a private yield co. It put something like 49 operating projects into a separate vehicle and brought in a co-investor. If you had to do that over again, would you?

MR. STORCH: Yes. It made perfect sense. We did not sell it as a growth engine.

I agree with Jim Murphy. The whole yield co model did not make sense. You are selling the idea that you will issue equity in the future to support buying more projects. Interest rates are at an all-time low, so why would you do that? Interest rates are likely to go higher, and yield expectations will go up. It just did not add up.

Separating operating assets from the development portfolio makes sense as long as you are clear that you are selling something close to an annuity. We will consider offering future assets to that vehicle for a fair price based on where the market is at the time under a right of first offer.

Wind debt is pricing at LIBOR + 150 to 300 bps, tax equity is around 8%, and cash equity is 9% to 13%.

MR. MARTIN: Next topic. The IRS issued a notice in early May about starting construction of wind farms. Projects must be under construction by the end of this year to qualify for full tax credits. If the project is then finished within four years after the year in which construction starts, tax credits can be claimed. If the project takes longer, then the developer must prove the work on the project was continuous.

The notice has caused a lot of pain for developers who in 2012, 2013, 2014 did modest amounts of physical work at the project site in order to claim their projects were under construction. This has come back to haunt them. The new four-year clock runs from that earlier date. Tom Festle, have you seen much of this pain in the market?

MR. FESTLE: It is the downside of something that was really good for the industry overall. Certainty is great, and having a clear path to PTC eligibility is great. The way you describe the situation is accurate. People are having to sort out the effect of the early start on the four-year clock for individual projects. Some projects may be in jeopardy.

Lightning Round

MR. MARTIN: We have only a short time remaining, and I want to cover a lot of ground. I will throw each remaining question at just one of you. If others want to add to the response, please do.

Jim Murphy, you said earlier that we need to increase the number of tax equity investors. Are you seeing new tax equity investors come into the market now that tax credits have been extended?

MR. MURPHY: Yes. We have seen it, and I think others here have said they have seen it. The returns on the product are attractive. It is not surprising that we have seen a number of new entrants.

MR. MARTIN: How would you characterize the growth? Is it rapid? Painstakingly slow?

MR. FESTLE: It is modest growth. If I were looking to start a business, tax equity investing would be a great place in terms of risk versus reward.

MR. MARTIN: And you would have a five-to-seven-year business at least if you also diversify into solar. Mike Storch, do you sense much appetite among tax equity investors and lenders for financing merchant wind projects, particularly in places like Texas? Is that interest increasing? Receding?

MR. STORCH: I was just talking to one of the investment banks two days ago, and it was definitely */ continued page 18*

IN OTHER NEWS

The Claims Court dismissed a case in late April that had been pending since 2012 after the lawyer for the company asked to withdraw because his client failed to respond to a request for a new engagement letter and retainer after the lawyer changed law firms. The company, Clean Fuel LLC, sued the Treasury after being denied grants on Cummins generators that it added at two existing biodiesel plants in Florida. The plants make biodiesel from waste soy, palm nuts and some waste animal fats. Clean Fuel bought them in early 2009 from the original owner and added the generators a year later to make electricity for use in the plants. Treasury appears to have denied grants on grounds that the company was asking for grants on used property.

Proceedings in the case had been on hold since June 2013 because of a pending criminal investigation against the company as well as 15 civil forfeiture proceedings filed in a federal district court in Florida. After the lawyer withdrew, the Claims Court dismissed the case "without prejudice," meaning the company can refile.

The owner of 20 utility-scale solar projects in California asked a US appeals court in late April to look at whether the Treasury should be ordered to make full payment of grants on 15 of the projects. The solar company applied for $614.8 million in grants, but said it received only $360.5 million. The company asked a federal district court in July 2015 to order the Treasury to pay the difference. The court told the company in March that the case had to brought in the Claims Court. The company hired new counsel and is now appealing the district court decision rather than refiling the case in the Claims Court.

MAURITIUS will no longer be as good a gateway for investments into India after the two countries agreed to amend a tax treaty.

According to an August 2013 report by the India Department of */ continued page 19*

Wind

continued from page 17

open to financing merchant. Very conservative assumptions are bring applied, but there is absolutely a continuing interest, which kind of surprises me, frankly, because merchant pricing has been anything but predictable.

Every year you look at the forward curve, and the first thing you notice is last year's forecast was wrong. Forget about forecasts three, four and five years down the road. We have not done a great job predicting prices.

I would like to circle back to one question that was asked earlier about start of construction. I see a double standard emerging in the tax equity market. Tax equity investors were loathe earlier to finance projects that started construction by doing minimal physical work. Now are they likely to rule out financing such projects on grounds that they projects were under construction too early in time so that the four-year clock will run out?

I say, "Well, I think I put a shovel in the ground." They say, "Then maybe the project does not qualify for PTCs." I am directing this to you, Keith. Are we going to end up with a double standard where we could not raise tax equity earlier because there was not enough physical work, and we cannot raise tax equity today because what the investors thought was too little now looks to them like too much?

MR. MARTIN: Yes, and you will see this in two places. One is when you go to the tax equity market. The other is if you try to sell a project, or you, in your case, buy a project from a smaller developer. You are going to be very conservative.

Jim Murphy, why hasn't there been more of a move toward portfolio debt? You, Duke and NextEra have used portfolio debt. We have not seen a lot of other companies use it. Why not?

MR. MURPHY: It is a complicated product for a number of reasons. We did our first portfolio debt deal in 2006. We did a portfolio financing for three wind farms as first lien debt with the tax equity behind it when you could do that in the market. That was hard enough because you needed to have all the projects complete development almost simultaneously so that you could close the financing around them.

The timing challenges are tough regardless of whether you could even do that structure today. The tax equity market is not as keen today on project-level debt. All debt has been kicked upstairs and is now back leverage, but you would still have the same timing issues were you to try to put a portfolio debt structure in place behind the tax equity in the capital structure, at least for projects that you are trying to finance for the first time.

If you are doing a refinancing at the portfolio level, then maybe that is a bit easier to do in theory, but you do not have that much cash flowing through these tax equity structures in practice to support back leverage. The sponsor is going to want to capture whatever cash there is rather than try to leverage it.

MR. MARTIN: I think all of you have either been buyers or sellers recently of operating projects. What discount rate is the market using to price wind deals currently?

MR. KEEL: It depends on the PPA. Assuming everything else about the project is clean, you can get below 10% for a levered equity IRR. However, it is more common to see 10% to 11%. Then as you get into projects that are hedged and have some more complexity, you start to get into the low teens.

MR. MARTIN: That seems high from what we have seen in the market. Does anyone have a different view?

MR. STORCH: I was going to say a lot depends on how you model, but 8.5% to 9% for an operating asset seems more in line with what we are seeing.

MR. MARTIN: That is for a fully contracted project?

MR. STORCH: And with tax equity.

MR. KEEL: I think it depends on whether you are on the sell side or buy side. Mike is on the buy side. [Laughter] I am sure he would say to me, "Pete, what are talking about? That's an 8.5%." But he is using a 20-year model versus a 30-year model and he has taken all my cost assumptions and added 20%.

MR. STORCH: Yes, I was being realistic.

MR. KEEL: The discount rate does not tell the whole story.

MR. STORCH: Agreed.

MR. MARTIN: Congress reduced taxes in December on foreign pension funds investing in US assets. Are you seeing an increased interest among foreign pension funds and, if so, from which countries?

MR. MURPHY: That was really a real estate-oriented provision, right Keith?

MR. MARTIN: That is correct.

MR. MURPHY: So as it relates to wind farms, we have not seen a material difference.

MR. MARTIN: Next question. Development pipelines had thinned by last year because people thought the tax credits would run out. Do you see wind companies diving back into new development in a big way or was the tax credit extension too

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short for wind and developers are now moving to solar instead?

MR. FESTLE: I wish our development pipeline was a little bit stronger. That said, going into these coming years, this extension of the PTC is fine for us. The future is predictable. We still worry about the certainty of the current policy, but speaking for our company, we like wind. We also like solar. We want to continue aggressively to feed our development pipeline.

MR. MARTIN: So you are diving back in. Is everyone else doing so as well?

MR. KEEL: Yes, absolutely.

MR. MURPHY: Yes, for sure.

MR. STORCH: The interconnection queues will be getting very long very quickly.

MR. MARTIN: Mike Storch, do you see a rush to repower older wind turbines this year while you have a shot at getting 10 years of production tax credits on the electricity output?

MR. STORCH: It is definitely an area of interest. The guidance the IRS issued in May was helpful. The constraints are whether the existing PPA allows a repowering and whether there have been significant enough advances in technology to justify the cost.

At least one turbine vendor is working pretty hard to persuade wind companies to repower, but most vendors are really not focused on repowering the old stuff and I think that is one negative consequence of the PTC extension. There will be a lot more focus on building new projects rather than trying to figure out how to make the old projects economically compelling again.

MR. MARTIN: Pete Keel, what lessons should be drawn from the SunEdison bankruptcy?

MR. KEEL: Speaking in general terms as we look forward and think about how best to run Longroad Energy Partners, developers need to be very sensitive to the fixed cost structure. Projects reach closing in a lumpy and volatile pattern. You need to have a lean cost structure to survive as a developer. You cannot be in a position of having high overhead and having to meet payroll every couple weeks regardless of whether you have had a win lately on a development project. It puts a lot of pressure on the organization. You can only afford to add fixed costs if you have high recurring cash flow.

MR. MARTIN: Next question. Jim Murphy, what have you learned about parent guarantees? What practical advice would you give to a new CFO?

MR. MURPHY: Don't give them.

MR. MARTIN: And if you have to?

/ continued page 20

IN OTHER NEWS

Industrial Policy, 38% of foreign direct investment into India comes through Mauritius. Singapore, which also has a favorable tax treaty, accounts for 11%.

The Mauritius treaty has been in effect since 1983.

It provides two benefits. Foreign investors using Mauritius companies to hold investments in India can avoid capital gains taxes upon sale of the investments. The treaty also limits India from collecting more than a 5% withholding tax on dividends paid by Indian companies, but India neutralized this benefit years ago by moving to replace its higher withholding tax on dividends with a tax on the Indian company when it distributes earnings.

A protocol to the Mauritius treaty released on May 12 will allow India to tax Mauritius residents on gain on the sale of shares in Indian companies acquired on or after April 1, 2017. Gains on sales of shares acquired before that date will remain exempted from Indian taxes, regardless of when they are sold. Indian capital gains rates range from 15% to 20%. A transition tax rate at 50% of regular levels will apply to taxable share sales for the first two years from April 1, 2017 through March 31, 2019.

However, the transition rate is available only if the Mauritius company can satisfy a "limitation of benefits" clause in the protocol. The Mauritius company cannot have been formed with the primary purpose to take advantage of the treaty. A shell company with no or negligible real business operations in Mauritius will not be able to satisfy this test. A Mauritius company will automatically be considered a shell if its spending on operations in Mauritius was less than 1.5 million Mauritian rupees (about US$22,500) in the 12 months preceding the share sale. However, it will not be considered a shell if its spending was more than this figure.

In a helpful change, the protocol caps withholding taxes that can be collected on interest at 7.5% of the gross interest amount. There had not be a limit earlier. Indian withholding

/ continued page 21

Wind

continued from page 19

MR. MURPHY: There are situations where a guarantee cannot be avoided. We saw that with the grant program, where cash grant recapture indemnities were a requirement. You were not going to get your tax equity deals done without a parent guarantee.

But nonrecourse means nonrecourse, and we try to be very disciplined about that and try to limit guarantees to unique situations where it just is not acceptable to allocate a risk to the investor. Those situations should be very few and far between.

MR. MARTIN: Tom Festle, anything to add?

MR. FESTLE: I feel lucky to be owned by a European public utility because, as Mike Storch mentioned, we view this as debt for book purposes and whatever we can do to reduce the cost of that debt is acceptable to us. It is an upside of being able to access the public markets in Europe.

MR. MARTIN: Are there any questions from the audience? Jim Tynion from Morgan Lewis.

MR. TYNION: What role will storage play in future wind farms?

MR. STORCH: We are starting now to work on storage. We see it as an area of great opportunity. The marriage of wind with storage is necessary in terms of controlling the grid and optimizing the output. The challenge is that most storage plays in the US are merchant if you are talking about pure storage deals, and for hybrid deals where you marry storage with a wind farm, it is all about cost. Batteries are still very expensive. As battery costs start to move down, we will be more interested in adding batteries to projects in the ordinary course.

MR. JAIN: Pramod Jain from Innovative Wind Energy. I am not a finance buff, so my understanding of these things is limited, but with electricity prices at $15 a MWh under the most recent PPAs, how is anybody making money?

MR. STORCH: The PTC is worth $36 to $38 a MWh in terms of equivalent revenue. If you are getting that for 10 years and can monetize it in the tax equity market, then you are supplementing the revenue and it is possible to make money. Your operating costs for wind tend to be very low and are getting lower still thanks to greater use of big data and bigger and more reliable equipment. Capacity factors of over 50% are not unusual today.

Recurring Nightmares

MS. KIZIRYAN: Hi, I'm Yana Kiziryan from Pattern Energy. My question is, as CFOs, what keeps you up at night?

MR. STORCH: A good movie? [Laughter]

MR. MARTIN: That was going to be our exit question, so let's go across the panel, starting with Tom Festle.

MR. FESTLE: The most frequent loss of sleep is trying to make the projects align. At the core, we are a developer. You need the project to come through, the interconnection, the turbines, the tax equity financing, potentially a source of cash equity, the FAA permits, the environmental permits, and it all has to happen within a really pretty short window of time. That is the recurring nightmare,

MR. MARTIN: So you are like a cook preparing a complicated meal. Everything has to come out hot at the same time. Pete Keel?

MR. KEEL: You have a lot of exposure built up against a single asset. Getting that exposure off the balance sheet by getting to financial close is one thing that tends to keep me up. The other is just the thankless part of the job, the part of the job where nobody notices unless there has been a mistake, like getting your audits done in a timely manner.

MR. MARTIN: Jim Murphy, you look well rested.

MR. MURPHY: I don't know if these things are keeping me up at night, but there are some major concerns. One is regulation. There is increasing regulation of the business, whether you are a public company or a private company. Dodd-Frank is a burden on private companies. Just

Europeans do better to lend development capital to smaller developers and later acquire the projects than to incur development spending directly.

understanding other new regulations takes an army and then execution and compliance are very much of concern because they are not areas where developers historically have had a strong skill set. That is one area.

Another area is interest rates. We have been in this tremendously low interest rate environment for such a long time that we are all taking it for granted. When it changes, we are going to have to reset customer expectations on the price for electricity or innovate in other ways.

MR. MARTIN: Mike Storch?

MR. STORCH: The general lack of commercial savvy and understanding in Washington about how things get done in the market.

MR. MARTIN: How do you think things will change with Trump in the White House?

MR. STORCH: It is just a new nightmare on top of an existing nightmare. The other thing is, looking to the future, is when wind projects become so large in number that we start seeing wind on the margin. What will that do to the price of power? There are models showing a $0 per MWh price for electricity during many hours of the day. That could have a profound effect on the market.

MR. MARTIN: You have just given us a bridge to what could be another interesting panel discussion. ◎

Death, Dying and Debt Restructuring

by John Schuster, with 32 Advisors in Washington

A little over a decade ago, I was asked to deliver a luncheon speech to describe how financial restructurings work and how to avoid them.

At that time, I was a managing director at the US Export-Import Bank and was dealing with the fallout from the Asian financial crisis, along with dozens of public agencies and private lenders. As a veteran of a dozen or so debt workouts following the boom and bust of international coal and oil and gas investments in the 1980s, I had a somewhat unique perspective.

The perspective I presented then and in which I still believe surprised everyone: the stages of a financial restructuring mirror the five stages of death and dying, as */ continued page 22*

IN OTHER NEWS

taxes on interest range from 5% to 40%, depending on the lender.

This should make Mauritius more attractive for lending into India.

Capital gains from asset transfers other than shares will remain exempted from taxes under the treaty.

The protocol will let India tax "other income" that was previously exempted from tax. This may let India collect taxes where a Mauritius company acquires shares in an Indian company for less than their value. India has been asserting the right to tax multinational corporations that make capital contributions in exchange for shares in Indian subsidiaries to the extent the shares are worth more when issued than the contributed capital. Both Vodafone and Shell have been hit with such tax claims. For prior coverage, see the November 2014 *NewsWire* at http://www.chadbourne.com/India-11-20-2014_projectfinance.

Singapore has a similar exemption from capital gains taxes in its treaty with India, but it is harder to qualify as a resident of Singapore due to the limitation-of-benefits language in its treaty. Nevertheless, that treaty is also now expected to be amended to drop the capital gains tax exemption in line with the changes in the Mauritius treaty.

INDIA is not giving up on trying to collect taxes from Vodafone.

The country has been locked in a long-running dispute with the British telecom company, which India says owes at least $2.1 billion in capital gains taxes that were triggered when Vodafone bought a 52% interest in an Indian mobile phone business, plus options to take its interest to 67%, from Hong Kong-based Hutchison Whampoa, for $11.2 billion in 2007.

Vodafone bought a Cayman Islands subsidiary of Hutchison Whampoa that owned an interest in a mobile phone company in India through several tiers of other offshore companies. */ continued page 23*

Debt Restructuring

continued from page 21

presented by Elisabeth Kübler-Ross in her seminal work *On Death and Dying*.

The reaction to the speech —- raucous laughter —- was even more surprising. Maybe it was just restlessness at a luncheon speech or nervous laughter elicited by talk of death —- always a source of comedy. I had first heard of Kübler-Ross' book through the movie *Annie Hall*, in which Woody Allen's Alvie Singer forces the book on Annie, who breathes a huge sigh of relief as she pushes the book back to Alvie during their break up. (He sneaks the book back to her.) Maybe laughter ensued because someone else's financial troubles are always more funny than our own.

Regardless, the speech struck a chord. We in the financial industry care deeply about money and our jobs. When there is a loss, it is personal and we do not let go without enduring the same process as when loved ones pass (which, before we go too far here, we should all acknowledge as more important). I cannot promise that an article read outside of a luncheon speech context will elicit the laughs, but the insights are still helpful as we sadly enter a new age of debt workouts.

The first stage of death and dying is denial. In dealing with personal matters, we rarely consider denial as constructive; it is a foible we learned as children as a way to avoid problems. But denial, like rationalization and convenient amnesia, are comforting things we all must have in times of need.

In debt workouts, my experience is that denial satisfies basic interests and can be constructive. Borrowers have an obvious interest in denial, as it helps keep one's management, board and lenders at bay, but unless one has a real white knight to save the day, pushing problems aside is rarely constructive and can make problems bigger. Denial is a form of concealment, and just as concealment led to the fall of Barings Bank, denial contributed to the global financial crisis and the fall of Lehman.

Lender denial is more likely to be constructive. It often takes the form of market and engineering studies, which often yield valuable insights about the cover value of an asset and provide space to find solutions. In my experience, studies have been used successfully for several deals, including a power plant loan in Kentucky and a mining deal in Australia. All studies found value, but the lenders recovered the most when they used the time and space provided to stay together, stand their ground, and work things out.

On to step two: anger. As with a personal loss, anger is understandable, and as with personal loss, it serves a purpose, but usually only to the extent that anger is a bridge to the other side, which is a viable solution.

To the extent that lenders are not being paid, they have a right to get angry, and part of the art of the workout is being able to express anger clearly and effectively. However, tirades are rarely credible or useful. For that reason, many banks separate the people making the loan from those working out the loan. One would think that the original lender would be more likely to reconcile than the nasty debt restructuring specialist. The opposite is true. The people who made the original lending decisions are likely to feel personally betrayed by their old friends, the borrowers. Many banks believe this emotional baggage gets in the way and bring in a new team to "work out" the new terms of the debt.

Borrower anger is an interesting phenomenon. Defaulting borrowers are the ones not paying the debt and have no reason to get angry, but they do. Borrowers inevitably know more about their business than their lenders and can, depending on the personalities involved, hold their lender in contempt and may not take lender threats to foreclose seriously.

At some point, this anger boils over into their bringing in their restructuring lawyers, the borrower equivalent of the workout team. Their purpose is to move beyond anger, to explain how disappointed the borrower is with the sad actions of its lenders and scare the lenders into submission. When I was on the lending side, after getting over a moment of fear, we would seek to dismiss quietly the restructuring team and get back to business, but on deals

A debt restructuring follows the same pattern as working through the five phases of grief.

with which I have not been involved, borrower teams have achieved some jaw-dropping outcomes such as converting debt into equity and buying assets for pennies on the dollar.

Precisely because one cannot count on anger to solve one's problems, debt workouts inevitably move on to stage three: bargaining.

Everything in a workout is negotiated and most of it involves minute terms that would bore most people to tears, such as cure and notice periods, default and remedy triggers, debt covenants, exclusions to covenants and carve-outs to exclusions. You get the point.

Often a business deal materializes early and both sides can move on. But sadly for all except the attorneys who are billing by the hour, the final stage of the process of acceptance is two steps away, and both sides typically postpone the inevitable. While workout negotiations are intriguing, deals move towards the next stage of depression.

As in life, stage four – depression – can be the hardest stage to manage.

Lenders become depressed with their lack of repayment, and borrowers become depressed by a lack of credit and limitations imposed on their businesses. In macroeconomic restructurings and large-scale sectoral debt crises, depression often means economic depression. The carnage dates to before the tulip bulb bubble of the 1600's and the recent list seems endless. The Lehman default sent the US and global economies into the worst recession since the Great Depression. Indonesia took decades to emerge from the Asian financial crisis. Latin America lived with a stagnant economy for years after its debt crisis. Greece's financial problems have pushed Europe into economic stagnation. The US oil economy took years to recover from the troubled 1980's and is poised for hard times again.

Depression can be, should be, and usually is, the driving force toward acceptance – the fifth and final stage toward fixing problems and starting over.

For a bank to get 50¢ on the dollar is a bad outcome, but it is better than languishing with nothing. A borrower may wish to squeeze out a better deal, but no business can operate in default with the type of flexibility companies need.

In dealing with a financial loss, for acceptance to be the final stage and not to give way to more depression and anger, acceptance needs to include acceptance of responsibility. Borrowers who got into trouble need to fix their businesses; lenders need to examine practices. Those responsible for failures in private economies can lose jobs and stand / *continued page 24*

IN OTHER NEWS

Vodafone said that even if a tax was triggered by the sale, it *bought* the shares, and the *seller* — not Vodafone — should be taxed on the gain. However, Indian law requires a buyer to withhold tax from the purchase price where the seller is outside the Indian tax net.

Vodafone had the tax set aside in a case that went all the way to the Indian Supreme Court in 2012.

The Indian government then put a bill through parliament to impose such taxes retroactively on offshore share transfers back to April 1962.

This set off another round of litigation in India leading to a decision in the High Court of Bombay in favor of Vodafone in October 2015.

The Indian government announced via Twitter in April that it plans to appeal the high court decision to the Supreme Court.

Vodafone is also pursuing an international arbitration before the International Court of Justice in The Hague. It asked that court in The Hague in May 2014 to commence an arbitration under the bilateral investment treaty between India and Holland, where the Vodafone subsidiary that bought the shares is located. An issue in the arbitration is whether the bilateral investment treaty can be used in connection with tax disputes.

The Indian government renewed its demand that Vodafone pay the taxes in a letter earlier this year.

AFRICA may be moving to tax gains on indirect share transfers in African companies.

Uganda is trying to collect $85 million in back taxes from a Kuwaiti company called the Zain Group that sold a Dutch holding company that owned mobile telephone carriers in 15 sub-Saharan African countries. The Dutch holding company owned each of the 15 telephone carriers through separate Dutch subsidiaries.

Zain sold the Dutch holding company to a mobile telephone company in India called Bharti Airtel. The sale took place in 2010.

/ *continued page 25*

Debt Restructuring

continued from page 23

accountable for any criminal wrong doing. Countries restructuring sovereign debt need to enact reforms, and the leaders responsible leave office.

Failure to accept and enforce responsibility can have far-reaching consequences. Just as failure to deal with a personal loss properly does grave harm to families, failure to accept responsibility has long-term consequences for borrowers, lenders and the economies touched by crises.

Sadly and without trying to make any political statements, the record following the global financial crisis sparked by the fall of Lehman does not reflect acceptance of responsibility that would indicate anyone has learned anything. Banks have taken bailouts without facing business restrictions, almost everyone has avoided criminal charges, and the movie version of Michael Lewis's *The Big Short* suggests we are at the stage of "blaming immigrants and poor people." This could all suggest a relapse into depression. I hope I am wrong: I prefer laughing audiences to crying ones.

IRS Issues More Construction-Start Guidance

by Keith Martin, in Washington

The Internal Revenue Service said in May that developers will have four years to complete a new wind farm or other renewable energy project and qualify for federal tax credits without having to prove that the construction work was continuous.

The four years will be measured from the end of the year in which construction starts on the project.

For example, if construction of a new wind farm started in 2013, then the project must be completed by the end of 2017.

If it takes longer, then the developer will have to prove that work after 2013 was continuous.

The IRS made the statement in the first of two new notices expected after Congress extended the deadlines to start construction of new renewable energy projects to qualify for tax credits.

It is Notice 2016-31.

The notice is causing pain for developers who did minimal physical work on projects at the site in 2012, 2013 or 2014 in order to claim their projects were underway ahead of earlier deadlines to start construction. They are now finding it hard to sell the development rights.

A second notice is expected later and will focus on solar issues.

The first notice is focused mainly on wind, geothermal, biomass, landfill gas, incremental hydroelectric and ocean energy projects.

Developers of such projects must have the projects under construction by December 2016 to qualify for full tax credits.

Wind developers who start construction of their projects in any of the next three years after 2016 can qualify for tax credits at reduced levels. The levels are 80% for wind farms starting construction in 2017, 60% in 2018 and 40% in 2019.

There is no phase down of tax credits for geothermal, biomass, landfill gas, incremental hydroelectric or ocean energy projects. They must be under construction by December 2016 or they will not qualify for any tax credits, with one exception. Geothermal projects qualify for a permanent 10% investment tax credit no matter when work on the project is started.

There are two ways to start construction of a project.

One is by starting physical work of a significant nature. There is no fixed minimum quantity or dollar amount of work required to be considered "significant." The IRS looks at the task. For an analysis of how much work is required and on what tasks, see the September 2014 *NewsWire* at http://www.chadbourne.com/additional_construction_start_guidance_0914_projectfinance.

The other way to start construction is by "incurring" at least 5% of the eligible project cost by the deadline. Costs are not incurred merely by spending money. They only count once equipment or services are delivered, with one exception. A developer who pays for equipment at year end and takes delivery within 3 1/2 months after the payment can count the payment as incurred on the payment date. Delivery can be at the factory.

It is not enough merely to start construction. There must also be continuous work on the project after construction starts. Until now, the IRS has not made developers prove continuous work as long as the project is completed within two years after the construction-start deadline.

New Rules

The new notice takes a different approach.

Counsel will have to determine when construction of a project started. That sets a four-year clock running starting at the end of the year in which construction started. Thus, for example, if construction started in 2013, then the project must be completed by December 2017 or else the developer will have to prove continuous work.

Projects that were under construction on account of significant physical work and then run past the four-year mark to be completed must prove "continuous construction." This may be impossible to do for many projects.

Projects that were under construction on account of the 5% test and then run past the four-year mark must prove "continuous efforts." This is easier to do because development-type tasks qualify as part of the continuous efforts.

It is always a good idea to keep detailed records of what is being done on the project in case construction takes longer than expected. For practical lessons from the last two rushes to start construction, see the February 2016 *NewsWire* at http://www.chadbourne.com/another-race-start-construction-practical-advice_Feb2016.

The IRS repeated in the new notice that "preliminary activities" do not qualify as significant physical work. Examples of preliminary activities are securing financing, obtaining permits or doing test drilling at a geothermal site.

There can be a break in construction due to events outside the developer's control. The IRS had given nine examples earlier of things that are considered outside the developer's control. The new notice adds two more. The earlier list said that financing delays of "less than six months" can be excused. The new notice says simply "financing delays" without setting a time limit. The new notice adds "interconnection-related delays." Many developers had asked in the past whether they can work backwards a year, for example, from when the utility will be ready to interconnect a project to start work in earnest on the site.

The new notice addresses three other issues.

First, the IRS said a developer who relied on physical work to start construction — say in 2015 — cannot now incur at least 5% of the costs in 2016 to buy more time to complete the project without having to prove continuous work.

Second, the agency is taking a more relaxed view of what happens if construction extends beyond the four-year mark. At worst if the developer cannot prove continuous work on the project, only the wind turbines that took / continued page 27

IN OTHER NEWS

Bharti Airtel is India's largest cellular service provider. It paid $10.7 billion. Of that amount, $1.7 billion was assumption of debt.

Zain took the position that it did not owe taxes on its gain in any of the African countries involved.

The African telephone companies had 41 million subscribers, including 1.7 million in Uganda.

A Ugandan trial court struck down the assessment in December 2011. An appeals court overturned the trial court decision in September 2014 and sent the case back to the trial court to make a "proper assessment."

Zain then invoked a competent authority procedure in the Dutch-Uganda tax treaty in September 2015 to try to get a resolution in the matter. A decision in the treaty claim is not expected for some time.

In a similar long-running tax dispute between Vodafone and India, India went after the buyer on grounds that it should have withheld taxes from the seller. It would have been the ultimate irony if Uganda had done the same in this case since the tax would have fallen on an Indian company.

US COAL RETIREMENTS would be 50,000 megawatts greater if the Clean Power Plan is implemented.

Coal accounts currently for 33% of US electricity supply. The US Energy Information Administration said in May that coal retirements should be 40,000 megawatts under its base case compared to 90,000 megawatts under the Clean Power Plan, with nearly all the retirements occurring by 2020.

The Clean Power Plan is an effort by the Obama administration to require states to reduce carbon emissions. It is expected to remain tied up in the courts until early 2018. Donald Trump has said he would retract it if elected US president. / continued page 27

Construction-Start Guidance

continued from page 25

more than four years to get into service will be denied tax credits. The rest of the project will qualify for tax credits without having to prove continuous work.

Repowering

Finally, the notice addresses how to determine whether new tax credits can be claimed when wind turbines are repowered or retrofitted.

The tax credit extension opens a short window of opportunity for turbine manufacturers to make a vigorous push to upgrade turbines at older US wind farms.

In general, the owner must spend at least four times on the repowering the value of the equipment that the owner retains from the original project in order for the repowered turbines to qualify for new tax credits. This test is applied on a turbine-by-turbine basis, meaning that each turbine, pad and tower is considered a separate facility. Thus, if $300,000 in equipment value is retained from the original turbine, pad and tower, then at least $1.2 million must be spent on the upgrade to claim another 10 years of production tax credits on the electricity output or an investment tax credit on the new spending.

Construction of the repowering must start by the deadline to qualify for tax credits.

The 5% test requires incurring only 5% of the new spending, not the total project value.

The new notice gives the following example of how these rules work in practice. Suppose there is an existing wind farm with 13 turbines. Each of the turbines is more than 10 years old. The developer retrofits 11 of the 13 turbines and spends $1.4 million per "facility" — turbine, pad and tower — on the retrofits. It retains used components with a value of $300,000 at each facility. Thus, the new spending is more than four times the retained equipment value. The total spending on all 11 retrofits is $15.4 million.

The developer treats the 11 retrofitted turbines as a single project with a total cost of $15.4 million.

Therefore, if the developer incurs at least $770,000 in costs by the deadline, then it will be considered to have started construction on the full repowering (5% x $15.4 million = $770,000). It does not have to show at least 5% in incurred costs for each individual turbine.

No additional tax credits can be claimed on the two turbines that are not repowered.

An IRS notice is causing pain for developers who did minimal physical work on wind farms in 2012, 2013 or 2014 to qualify for tax credits.

Stuck

Many wind companies and counsel set a low bar in 2012, 2013 or 2014 when they wanted to say projects were under construction in time to qualify for tax credits when faced with earlier deadlines that have since been extended.

It will be hard to walk that back now that the tables have turned. If a project was under construction in 2013 on account of physical work, then the company cannot give itself more time until 2020 to complete the project by now incurring 5% of the project cost. There are not many good options. Here are five.

One is to conclude that the company did not do enough on the project in the earlier year to qualify as "physical work of a significant nature." This will almost certainly require a legal opinion to that effect to get financing.

Alternatively, if the company did "physical work of a significant nature," then get as many turbines in service as possible within four years after the end of the year it started work. At least their output will qualify for production tax credits even if the output from the remaining turbines does not.

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The company could try to do enough to change the project so that it is no longer the same project on which work started in an earlier year. This will be hard. The only test the IRS has for assessing whether a project is a different project is something called an 80-20 test. This test looks at heavy spending to retrofit an existing project, and it does not work where a project has not been built yet. The only standard in this case is common sense. At a minimum, the company would have to change one or both of the site and the offtaker to have a different project.

Alternatively, a project would not have been treated as under construction in time as of the early date if the physical work was not actually used in the final project. However, the company cannot jettison the earlier work for tax reasons to buy more time to complete the project. There would have to be a clear non-tax reason why the work was not used.

Finally, it may be possible to break the project in two so that the work was considered to have started earlier on a small part, and treat the rest as a different project. However, the IRS will treat all the turbines as a single project if many of the following factors are present. All the turbines are owned by the same legal entity. They are on contiguous parcels of land. All the electricity is sold to a single offtaker under a single power purchase agreement. All the electricity moves to the grid through a common substation and intertie. There is a common set of permits for all the turbines. There is a common turbine supply agreement and balance-of-plant construction contract. All the turbines were financed under the same construction loan or tax equity transaction. ◎

IN OTHER NEWS

BAD-BOY GUARANTEES do not turn nonrecourse debt into recourse debt for tax purposes, the IRS said.

Most power and other infrastructure projects are owned by special-purpose project companies. If the project company borrows to build the project, it tries to do so on a nonrecourse basis, meaning that if the project company defaults on the debt, then the only recourse the lenders have is to take the project. They cannot go after the owners directly for repayment of the debt.

Whether debt is recourse or nonrecourse has tax consequences.

For example, in a partnership, each partner has both a "capital account" and an "outside basis." These are two ways of measuring what each partner put into the deal and what it is allowed to take out. A partner's outside basis includes his share of debt at the partnership level. Therefore, the more debt he can put in his outside basis, the more room he has to be allocated tax losses and to be distributed cash by the partnership.

Nonrecourse and recourse debt are shared differently by partners in outside basis. One way a partner who wants to have more of the debt in his outside basis can do so is to guarantee repayment of the debt: in other words, make it recourse to him.

The IRS said in an internal memorandum made public in April that a bad-boy guarantee does not turn a nonrecourse debt into a recourse debt until the event that triggers the guarantee occurs.

A "bad-boy guarantee" is a guarantee that kicks in only when the partner does something wrong. For example, he transfers part of the security that backs the debt without getting consent from the lenders. Another example is he makes a voluntary filing for bankruptcy protection or admits in writing that he is insolvent.

Bad-boy guarantees are used by lenders to protect themselves against bad acts in cases where they are otherwise */ continued page 29*

Solar Gains Ground in the Middle East

by Richard Keenan, in Dubai

The world-record-breaking tariffs received by the Dubai Electricity and Water Authority last month to supply solar electricity from phase III of the Sheikh Mohammed Bin Rashid Al Maktoum Solar Park in Dubai have sent shock waves through the global energy sector.

Bidders were invited by DEWA to submit a mandatory base bid proposal for a 200-megawatt photovoltaic plant and had the option of also submitting alternative proposals for a 500-MW PV plant and an 800-MW PV plant. If Dubai decides to go with an 800-MW proposal, then this plant will be the largest solar plant in the world.

Record low solar prices of 3¢ a KWh are being bid in the Middle East.

A consortium of Saudi Arabia's Abdul Latif Jameel, Spain's Fotowatio Renewable Ventures and the United Arab Emirate's Masdar, submitted a bid for the base proposal with a world-record low tariff of US3¢ per kilowatt hour. Jinko Solar, on the back of its recent success in Mexico, submitted the second lowest base proposal tariff of 3.69¢ per kilowatt hour. A consortium of First Solar and Saudi Arabia's ACWA Power is in third place with a tariff of 3.96¢ per kilowatt hour. Engie (formerly GDF Suez) and Marubeni are in fourth place with a tariff of 4.44¢ per kilowatt hour, and EDF Energies Nouvelles and Nebras are in fifth place with a tariff of 4.48¢ per kilowatt hour. Significantly, each of the five consortia that submitted bids offered DEWA tariffs of less than 5¢ per kilowatt hour.

The tariffs offered by bidders in connection with the alternative proposals have not been made public.

It was unclear as the *NewsWire* went to press which of the bidders will be awarded the phase III project. The bids are still being evaluated by DEWA and its advisers. The bidders that remain in contention will need to demonstrate that they can deliver the project based on the tariffs they have offered. We think it is fairly safe to assume that phase III will be awarded to one of the top three bidders, each of whom submitted a base bid proposal with a tariff of less than 4¢ a kilowatt hour.

This will be a very significant outcome for the energy sector in the Middle East.

Only a few years ago, parity between conventional and renewable energy in the Middle East seemed a long way off. Until very recently, few would have believed that by April 2018 (scheduled date for completion of DEWA phase III), the cost of solar power would fall below the cost of conventional power, particularly given the subsidized price at which gas and oil are sold to developers of conventional oil and gas-fired power plants in the Middle East.

Bids for the Sweihan 350-MW solar PV IPP in Abu Dhabi are scheduled to be submitted in September. It is expected that the winning bid for this project will be less than 3¢ a kilowatt hour.

The tariffs set by Dubai and the anticipated result in Abu Dhabi in a few months' time may prove to be the catalyst to the opening of the flood gates for solar power in the rest of the Middle East.

All eyes are now back on Saudi Arabia following an announcement in April by Saudi Arabia's deputy crown prince that Saudi Arabia intends to procure 9,500 megawatts of renewable energy by 2023.

The Saudi government is under tremendous pressure to reduce its domestic energy consumption. The ambitious Saudi K.A.Care renewable energy program appears to have been discarded and the Saudi energy crisis will only worsen with any further inaction by the Saudi government on energy reform.

Ironically, the challenge that may now be faced by the solar industry in the Middle East is a softening of appetite among developers to compete in a market where tariffs are at world record lows.

Phase I of the DEWA program is a 13-MW solar PV plant that was constructed by First Solar pursuant to an engineering, procurement and construction contract with DEWA. Phase II is a 200-MW solar PV plant procured as an independent power project and is currently under construction. This project is being developed by a sponsor consortium consisting of ACWA Power and TSK. The tariff bid by the consortium to win this project was 5.84¢ per kilowatt hour which, at the time of bid submission in 2014, was the lowest tariff for a solar PV plant anywhere in the world.

DEWA has, in the last few days, announced the launch of phase IV, an IPP for a 200-MW concentrated solar power plant. All four phases of the Sheikh Mohammed Bin Rashid Al Maktoum Solar Park are part of a DEWA-backed plan to invest US$3.3 billion in solar power in Dubai as part of a wider goal of installing 3,000 megawatts of solar PV by 2030.

Underachievement

While not wishing to diminish the importance of some significant achievements by the solar industry here in the Middle East over the last 10 years, solar power has so far not lived up to anything like its full potential. There are a number of reasons for this.

Consumers along the Arabian Gulf benefit from some of the world's lowest electricity prices due to government subsidization of the price of natural gas and oil. State-owned oil and gas companies supply conventional power producers in the Middle East with cheap oil and gas at a fraction of the prices prevailing in the international markets.

Further subsidies are then applied to the price at which electricity is sold by state-owned utilities to consumers.

Cheap conventional power has, until recently, proven to be a barrier to market entry for renewable energy developers. The governments of some of these countries have embarked on electricity price reforms, but they are happening very slowly. The cost of water and power is a very sensitive subject in the Middle East, and the governments and rulers of the Middle East must tread carefully when it comes to energy and water reform.

Another key factor has been the lack of government support for renewable energy in the form of feed-in tariffs or other government backed incentives for renewable energy investment. Various commentators on this subject have for a long while championed the need for support in the Middle East similar to the European models. Apart from a few notable and quite recent exceptions, the governments in the Middle East have chosen not to embrace such reforms.

/ continued page 30

IN OTHER NEWS

prepared to lend on a nonrecourse basis. They are more common in real estate transactions than in the broader project finance market.

The IRS analysis is in an internal memorandum, AM 2016-001.

MEXICO dropped a requirement that a Fibra E can exist for only 10 years in an effort to make the structure more attractive to investors in the infrastructure and energy sectors.

The change took effect in April.

A Fibra E is the Mexican version of a master limited partnership. It is a Mexican trust that invests in shares of Mexican companies that are active in the Mexican infrastructure or energy sectors. There is no income tax at the level of the Fibra E, and there is a liquid market in theory in the shares. These two attributes are supposed to make it possible for Mexican infrastructure and energy companies to raise equity more cheaply.

No such trusts have been formed to date.

At least 70% of the average annual value of total assets must be in shares in companies in the targeted sectors, and at least 90% of the income earned by portfolio companies in which the Fibra E invests must come from targeted sectors.

The targeted sectors are electricity (generation, transmission, distribution), various types of private-private partnerships to undertake infrastructure implemented through concession agreements with terms of at least seven years (roads, highways, railways, bridges, inter-city transportation, ports, terminals, marinas, airports, prisons, potable water, drainage, sewage treatment plants, expansion of the main telecommunications network) and downstream oil and natural gas (treatment, processing, refining, transportation, storage, distribution, but not exploration and production or retail sales).

The trust issues certificates that are listed on the Mexican stock exchange.

It must distribute at least 95% of its income to shareholders each year by the following March 15. There is generally no income tax at the Fibra E level. Tax is collected from the shareholders

/ continued page 31

Solar

continued from page 29

Solar plants procured as part of Dubai's solar program do not benefit from any form of feed-in tariff or subsidy. Developers of IPPs benefit from sovereign support through long-term power purchase agreements backed by credit support from the government in the form of a payment undertaking. The Dubai government also takes an equity stake in the project company (60% for phase III). This very bankable structure should help developers secure competitive margins and favorable terms and conditions from their banks. This structure is not unique in the Middle East. The DEWA structure is similar to the Abu Dhabi and Saudi conventional IPP models. Each of the different conventional IPP models in the Middle East features significant elements of sovereign debt support.

The Shams 1 concentrated solar power plant in Abu Dhabi that was commissioned in 2013 benefits from a subsidy in the form of a direct payment from the Abu Dhabi government to cover the difference between the average price of electricity produced in Abu Dhabi from conventional power and the cost to produce power from the Shams 1 concentrated solar power plant. However, this is a project-specific incentive and is not underpinned by any wider government policy or regulation.

The Sweihan 350-MW solar PV IPP that was launched recently by ADWEA is not expected to benefit from any form of government support, other than through government participation in a project structure that is similar to the DEWA structure described earlier.

A power auction in September in Abu Dhabi could bring in bids below 3¢.

Jordan has so far led the way with an unsolicited proposals scheme that was launched in 2011 by the Ministry of Energy and Mineral Resources. The first round of this program saw development of two wind projects and 12 solar PV projects with an aggregate capacity of 370 megawatts. The second round includes four solar PV projects with an aggregate capacity of 200 megawatts.

Egypt, in 2014, launched an ambitious program to procure 12,000 megawatts of renewable energy by 2020, the largest renewable energy target in the Middle East and North Africa region after Saudi Arabia. Egypt's feed-in tariff program was approved by the Cabinet of Ministers in September 2014. The deployment of the program is phased over so-called regulatory periods or rounds. For solar photovoltaic projects with a capacity of between 20 and 50 megawatts, the round 1 feed-in tariff is US14.34¢ per kilowatt hour. Projects that have qualified for round 1 must be fully funded by October 28 this year. Any projects that do not meet this deadline will not be eligible to receive the round 1 feed-in tariff. Unless a solution is found to some key bankability issues that continue to undermine the financing of these projects, there is a real possibility that the round 1 projects will not be funded in time to meet the October 28 deadline.

Solar energy projects on the Arabian peninsula also face challenges thrown up by the elements. Much of the Middle East falls within the "sun belt." The Gulf region receives the highest daily solar irradiation in the world, an average of approximately 2,200 kilowatts per square meter. In contrast, Germany, the world's largest producer of solar power, has less than half the solar irradiation of the Middle East. This should make the Middle East ideally suited to solar power. However, the deserts of the Middle East are dusty and windblown. High levels of dust and particles in the air and the prevalence of sandstorms can, in a short space of time, leave solar panels and mirrors caked in a thick layer of dust, significantly reducing their efficiency. High levels of humidity caused by proximity to the sea also contribute to this problem.

Mirrors used in connection with CSP plants need to be cleaned almost daily in order to maintain adequate levels of efficiency. Much has been written about the impact of dust on the performance of the Shams 1 CSP plant in Abu Dhabi. Inefficiencies caused by dust required the installation of additional mirrors in order to ensure the 100-MW capacity of the plant could be achieved. This significantly added to the cost of the plant. Now in operation, the plant's 258,000 mirrors, covering an area of 2.5 square kilometers (or 285 football fields), are cleaned daily by a series of trucks with robotic arms spraying water over the lines of mirrors.

Most methods of cleaning dust and sand off solar panels and mirrors still involve using water. However, there have been some important advances in technology that does not require water.

A company, named Nomadd, came up with an innovative solution a few years ago. The company takes its name from the technology it has developed, a no-water mechanical automated dusting device known as a "Nomadd." The Nomadd robots are mounted on tracks along rows of panels that they pass at least once a day cleaning them with a brush designed not to damage the panels. Importantly, the Nomadds do not require any water. This technology allows entire arrays of solar panels to be cleaned in a short space of time which is essential after a sandstorm.

Another water-free cleaning solution is known as electrostatic cleaning. This technology, which was initially developed by NASA for lunar missions, involves using an electrostatic field to repel dust and particles on solar panels. When dust accumulates on the surface of a panel, an electric charge flows over the panel pushing the dust off the surface and back into the air.

The challenges have not by any means disappeared, but the future for solar in the region looks good.

Breakthrough

A number of factors have led to the record-breaking solar bids in Dubai.

Fierce competition among bidders has helped drive prices to rock-bottom levels. This highly competitive bidding environment is to some extent the result of a lack of opportunity elsewhere in the Middle East. For many bidders, winning either DEWA phase II or phase III has been just as much strategic as anything else: an opportunity to gain a foothold in a market with significant but largely untapped potential.

The bidders have been helped by the dramatic fall in the cost of producing solar power over the last few years.

According to a recent study by Oxford University researchers, solar power costs are falling so fast that the technology is likely to outstrip mainstream energy forecasts quickly. Solar technology is currently on course to supply 20% of global energy requirements by 2027. The International Energy Agency had previously predicted a generation figure of 16% of electricity by 2050.

Since the 1980's, solar panels have */ continued page 32*

IN OTHER NEWS

through a 30% withholding tax on distributions. Mexican shareholders can claim credit for the tax withheld. Foreign shareholders can treat the withheld tax as their final tax. The trustee must pay tax on any income that is not distributed.

Earnings at the level of the portfolio companies are also less heavily taxed. They can be distributed to the Fibra E without a 10% withholding tax that would normally be collected on dividends.

NEW JERSEY denied deductions for interest a corporation doing business in the state paid on a loan from its parent company.

The case is a reminder to companies with intercompany debt between affiliates that interest on such loans may not be deductible.

Most US states require companies to calculate state income taxes by starting with the income they reported on their federal tax returns, determine the share that was earned in the state and then make adjustments to account for any differences in state versus federal tax rules for calculating taxable income. The differences could lead to "add backs."

Kraft Foods Global, Inc. makes and markets macaroni and cheese, processed meat products, coffee and other groceries across the United States, including in New Jersey.

It has an immediate parent, called Kraft Foods, Inc. and an ultimate parent, Philip Morris.

It owed money under three notes to its ultimate parent. Philip Morris assigned the notes to a subsidiary.

The immediate parent, Kraft Foods, Inc., borrowed $9.6 billion from third parties and lent the money to Kraft Foods Global. Global then used the money to repay the outstanding notes that had originally been held by Philip Morris and were by then held by another Philip Morris subsidiary.

Global paid interest on the $9.6 billion loan from its immediate parent. The interest matched what the parent owed the third parties from whom it borrowed the */ continued page 33*

Solar

continued from page 31

gotten 10% cheaper each year. Most of the reductions have been due to falling equipment costs: for example, module costs fell by nearly 30% annually between 2008 and 2013. The global blended average price for a tier-1 Chinese-produced multi-crystalline PV module reached 57¢ per watt in the fourth quarter of 2015, from 1.31¢ per watt in 2011. This is primarily due to a reduction in prices of consumables such as polysilicon -- driven mostly by oversupply -- and the falling costs of Chinese labor and processing, and an improvement in technology and conversion efficiencies. Further price reductions are likely to occur in response to improvements in scale and operating efficiencies with some predicting that global blended prices will reach 44¢ per watt by 2020.

Inverter prices are also falling by about 10% to 15% per year. Larger solar installers are now achieving 25¢ per watt with cost reductions in components and production efficiencies helping to drive savings. Balance of system (i.e. the components of a PV system other than the panels themselves, including wiring, mounting system, inverters, battery banks and battery charger, etc.) costs also fell rapidly between 2007 and 2014, and account currently for between 39% and 64% of the overall cost.

The Saudi energy mix is unsustainable. The country consumes more oil than Germany whose population is three times larger.

Reductions in "soft costs," such as installation, maintenance and financing, could be even greater: the 2013-2014 fall in the cost of solar was almost entirely due to reductions in soft costs including marketing, system design, permitting and inspection aided by information technology improvements.

These dramatic cost reductions should prove to be the game changer for solar power in the Middle East. Bids for Abu Dhabi's 350-MW solar development at Sweihan are scheduled to be submitted by September 19. Based on the bids received in connection with DEWA phase III, it is expected that the winning bidder for the Sweihan IPP will need to submit a tariff of less than 3¢ per kilowatt hour.

The interesting next question is the extent to which developers will continue to have an appetite to develop solar IPPs at DEWA prices. The number of bids that the Abu Dhabi Water & Electricity Authority ultimately receives in September in response to the Sweihan IPP tender should prove to be a reliable indicator of the continued appetite among developers for utility-scale IPPs at low pricing.

If the results of DEWA phase II and III are anything to go by, solar PV can now arguably stand on its own two feet in the UAE without incentives. The era of feed-in tariffs in the western world is coming to an end and it is unlikely that they will now be adopted by the governments of the Gulf countries who will be keen to avoid implementation of incentive schemes that are generally perceived as being expensive.

It is important for the sake of the sector's growth beyond the Gulf countries that the same conclusions are not drawn by Middle Eastern governments whose sovereign credit ratings and balance sheets cannot offer investors and lenders the same level of equity and debt support that some of their oil rich neighbors are able to provide. The feed-in tariff program in Jordan has been critical to its development of solar power. Foreign investment in solar power in Egypt is dependent on a feed-in tariff. Project financing and other development costs in these countries are higher than in the UAE, and this will remain the case for the foreseeable future. It is also important to acknowledge in this context the relative stability that the UAE has enjoyed since the Arab Spring in comparison to any other country in the Middle East. This has undoubtedly contributed to the high level of support DEWA has received from developers, investors and lenders.

IN OTHER NEWS

Saudi Arabia

Saudi Arabia's domestic consumption of oil and gas and its rising energy demand are not sustainable. The statistics on this are mind blowing. Some of these are set out in the table below.

A few years ago, Khalid al-Falih, Saudi's new energy minister and chairman of Saudi Aramco, observed that, if left unchecked, domestic energy consumption in Saudi Arabia would rise to 8.2 million barrels of oil a day by 2030. To put this in perspective, Saudi Arabia's current oil production averages at around 9.22 million barrels a day. A widely circulated Citigroup report in September 2012 also concluded that Saudi Arabia could cease to be an oil exporter by 2030.

Significant reforms are needed. Reducing oil and gas subsidies and raising the price of energy would be the most effective way to restrain domestic consumption. However, this is a very sensitive area for any Middle Eastern government, particularly in the aftermath of the Arab Spring. Implementation of energy price reform in Saudi is expected to be gradual.

Diversification of Saudi's energy mix is probably a more realistic medium-term goal. Solar power is expected to be a significant part of this.

The King Abdullah City for Atomic and Renewable Energy or K.A.Care was established in 2010 to oversee the realization of the country's renewable and nuclear energy ambitions. In 2012, Saudi Arabia launched an ambitious renewable energy program through K.A.Care. However, ever since issuance of a white paper on the program's tendering procedures in March 2013, the K.A.Care program amounted to nothing more than a distant mirage. For the last three years, the renewable energy industry has been waiting for renewed direction from the Saudi government.

This renewed direction now appears to have come. In April, Prince Mohammed bin Salman, the Saudi crown prince, unveiled plans as part of the "Saudi Arabia Vision 2030" policy paper to develop 9,500 megawatts of renewable energy. No date by when this goal is expected to be achieved was given by the crown prince in his April address. However, the Saudi government has subsequently confirmed that the 9,500 megawatts are an initial target that Saudi Arabia plans to achieve by 2023. The information released by the Saudi government so far is limited on detail and no quotas for solar and wind have been provided. However, this announcement, which has been made against the backdrop of a major shakeup within the Saudi government, is significant.

Development of 9,500 megawatts of renewable energy is an ambitious target, but it appears to be a / *continued page 34*

money. However, there was no provision for repayment of principal to the immediate parent, and the third-party lenders had no rights to enforce repayment of the debt from Global directly.

Global deducted the interest for purposes of determining its federal taxable income that was the starting point for calculating New Jersey income for the state corporate income tax.

The state tax department made Kraft add back the interest.

By law in New Jersey, interest paid to a related company must be added back, unless one of five exceptions applies. The only one that could possibly have applied is where "the taxpayer establishes by clear and convincing evidence, as determined by the [state tax department], that the disallowance of a deduction is unreasonable . . . ."

The state tax court said it agreed the interest had to be added back. It said it could see the logic of allowing the interest deduction where the parent is a mere conduit for borrowing from third parties, but that is not this case since the subsidiary, Global, is not liable on the debt to the third parties.

The case is *Kraft Foods Global, Inc. v. Director, Division of Taxation*. The New Jersey tax court issued its decision on April 25.

RELOCATION PAYMENTS that a company received to make room for a highway expansion did not have to be reported as income.

Compensation must usually be reported as income. The payment in this case was compensation to the company because the state had taken its main office building and warehouse by eminent domain. The company also had moving expenses. These are normally deductible. However, in this case, the IRS did not make the company report the relocation payments as income, and the company could only deduct the moving expenses to the extent they exceeded the compensation it received.

/ *continued page 35*

Solar

continued from page 33

more meaningful and realistic target than those set by K.A.Care a few years ago. The K.A.Care program contemplated development of 41,000 megawatts of solar capacity by 2032. This would have required the development of more than 2,000 megawatts of solar power each year over a 20-year period.

K.A.Care appears to lack the authority needed to implement its renewable energy program. A number of Saudi government entities have a significant say in energy policy. These include the Saudi Electric Company, the largest utility in the country, and Saudi Aramco. It has been widely reported that the K.A.Care program has been stifled by bureaucratic disagreements over the scale and ownership of the program and how it should be implemented. At the time of writing, K.A.Care's role in implementation of the Saudi governments' new plans for solar development appears to be much diminished.

Ever since K.A.Care, in 2011, announced its intention to develop 16 nuclear reactors by 2030 at an estimated cost of US$7 billion per plant, the development of the nuclear energy program has been sluggish. Last month at the Menasol conference in Dubai, Ibrahim Babelli, Saudi Arabia's deputy economic minister (and former K.A.Care representative), cast doubt on whether Saudi Arabia would proceed with its nuclear plans. He indicated that he did not think nuclear power plants are needed in Saudi Arabia and that solar power is preferred to nuclear energy.

The Saudi government must address the challenges faced by K.A.Care or any other entity that may replace it. Otherwise the recent announcement by the crown prince will end up being just another ambitious statement about Saudi energy reform consigned to the policy waste bin. ◎

Saudi Arabia – At a glance

- Approximately 90% of Saudi Arabia's revenue comes from oil.
- Saudi Arabia consumes an estimated three billion barrels of oil per day or one quarter of its total oil production.
- Saudi Arabia now consumes more oil than Germany, a country with a population three times the size of the Saudi population and an economy nearly five times as large.
- Saudi Arabia is the world's largest consumer of oil for electricity, burning an average of around 700,000 barrels per day. According to the US Energy Information Administration, Saudi Arabia burned 900,000 barrels per day in July 2014 .
- The International Monetary Fund estimates that energy subsidies cost Saudi Arabia US$107 billion in 2015 or 13.2% of its gross domestic product .
- Estimated 2016 installed generation capacity: 58,000 MWs.
- Saudi Arabia's domestic energy demand has increased at an estimated 8% per year for the last three years.
- Forecasted installed generating capacity by 2032: 120,000 MWs.
- Average price of electricity sold in Saudi Arabia: ranges from US1.3¢ to 6.9¢ per kilowatt hour.

Is US Offshore Wind About to Get Traction?

The trade press has been running stories lately that offshore wind is finally coming of age in the United States. Several big players are now moving into the sector. Offshore wind is becoming a discussion topic again at wind industry conferences, and at least three US conferences are expected this year to be devoted entirely to US offshore wind.

Four CEOs of offshore wind developers talked at a conference in Boston in May about whether the renewed attention to the sector is justified. The panelists are Jim Gordon, CEO of Cape Wind, Chris Wissemann, CEO of Fishermen's Energy, Alla Weinstein, CEO of Trident Winds, and Kirby Mercer, CEO of Beothuk Energy, a Canadian offshore wind developer. The moderator is Keith Martin with the Chadbourne office in Washington.

MR. MARTIN: Jim Gordon, are news reports that offshore wind is finally coming of age in the United States for real and, if so, what has changed recently?

MR. GORDON: There is no question that there is a huge wind resource off of our shores. The question is whether we will put together the development expertise and capital to exploit it. We now have a regulatory framework in place for such projects.

I am thrilled that there are more market entrants coming in here, because it validates what everybody is trying to do. The key will be to have contracted revenue streams that can attract the development capital to build these projects.

Look at what the governors are doing in some northeastern states and around the country where they are finally starting to take climate change seriously. They are putting policies in place that will make very significant reductions in CO_2 emissions. If the Clean Power Plan gets through the Supreme Court, then all the better.

The right elements are coming into place. What kick started construction of new combined-cycle gas-fired power plants was power purchase agreements where investors knew they would get some kind of return if they put in capital. That is what we need to kick start the offshore wind market.

MR. MARTIN: You waged a lonely battle for 14 years. Now you have an army forming behind you. Chris Wissemann?

MR. WISSEMANN: One of the things that has scared regulators is the price of offshore wind. The electricity costs more than $200 a megawatt hour.

That fear was reinforced to a great extent by the pricing coming out of Europe. What has happened in the last year or two is the price for electricity from offshore wind has dropped to €100 a megawatt hour in Europe. This gives us hope that we will be in a position soon to deliver electricity at similar prices in places like New York City, Long Island, downstate New York, Massachusetts and California. That is how offshore wind will finally start to get traction.

MR. MARTIN: Did I hear you right that you expect to see bids in the US that are close to $110 to $120 a megawatt hour?

MR. WISSEMANN: Not so much here because we are not in this bidding arena yet. But what you see in Europe is the most recent price for the Horns Rev 3 project is €110. The Dutch auction that is due tomorrow should set a new price hurdle somewhere in that range. You have all the vessels, ports and other infrastructure in place already in Europe to support offshore wind.

The first projects in the US do not stand a chance of coming near that price, but the fact that it is being done in Europe shows the kind of cost curve that is feasible with larger turbines.

/ continued page 36

chadbourne

IN OTHER NEWS

The highway project was a federally-assisted project. The state paid compensation as directed under title II of the federal Uniform Relocation Assistance and Real Property Acquisitions Policies Act. That statute has a special provision that says compensation paid under it does not have to be reported as income.

The IRS addressed the issues in Private Letter Ruling 201617002. It made the ruling public in late April.

PRE-FILING AGREEMENTS may now be prohibitively expensive.

Pre-filing agreements are a tool that companies can sometimes use to reach agreement about the proper treatment of a US tax issue before filing a tax return. Another tool is to apply for a private letter ruling. The IRS will not issue a private ruling if the matter is too factual. However, the agency might enter into a pre-filing agreement, even though it requires digging into the facts.

In the last five years, the IRS has received an average of 30 requests a year for pre-filing agreements, accepted 20 and closed an average of 17.

The IRS charges a user fee of $50,000. The fee has not changed since 2007.

The IRS said in May that the user fee will increase to $134,300 for requests filed after June 2. It will increase again to $218,600 in 2017. It made the announcement in Rev. Proc. 2016-30.

Pre-filing agreements may be issued for any issue "that requires either a determination of facts or the application of well-established legal principles to known facts" or "a methodology used by a taxpayer to determine the appropriate amount of an item of income, allowance, deduction, or credit."

The transaction has to have closed before the IRS will enter into a PFA.

The new fees will mean PFAs will be limited to very large dollar issues.

MINOR MEMOS. The Republican-led House voted in April to bar the IRS from hiring anyone new as long as any IRS */ continued page 37*

Offshore Wind

continued from page 35

MR. MARTIN: So what is new is we starting to benefit from economies of scale. The regulatory regime is falling into place. The Clean Power Plan is providing some impetus. Has anything else has changed?

MS. WEINSTEIN: We now have US states requiring that utilities deliver 50% or more of electricity from renewable energy. That creates a market that was not there when Jim Gordon started work on Cape Wind.

MR. MERCER: We now have a regime in place in Canada to support offshore wind. In Canada, we have to deal only with the federal government. We don't also have to worry about the politics at the provincial level.

Saudi Arabia wants to buy 9,500 MWs of renewable energy by 2023.

We also have a lot of the infrastructure in place already to support offshore wind. We have some world-class ports. We have good sites in shallow waters close to transmission lines. We don't have the Jones Act to push up transport costs. It is all about design and getting the levelized cost of energy down to reasonable levels. All we have to do now is to get one big project going.

MR. GORDON: I think one of the worst things that this industry can do is to create false expectations on pricing. Chris Wissemann pointed out, rightly so, that the infrastructure is not in place yet in the United States. We have the Jones Act that puts us at a significant disadvantage.

There are new developers coming into the market who have not done the feasibility studies to find out what the challenges are for specific projects. One mistake the industry can make is to extrapolate €100 per MWh prices from a European market where the industry has been flourishing for 25 years to a US market where we are just getting started and many challenges still await.

MR. MARTIN: How important is it that the oil and gas industry has fallen on hard times, freeing up people with knowledge about building things offshore?

MS. WEINSTEIN: It is very important, especially for deep water installations. Floating offshore wind technology has developed on the backs of offshore oil platforms. All the skills are transferable. Having people with those skills will certainly help because that is labor that you do not have to train.

Massachusetts

MR. MARTIN: Let's move past the big picture to some of the details. Jim Gordon, the Massachusetts legislature is expected to unveil a bill soon that would create demand for up to 2,000 megawatts of offshore wind. What do you expect this bill to say, and how important is it?

MR. GORDON: It is critically important to attract the capital to build these projects. It will probably require competitive bidding. It is not clear yet whether the support for offshore wind will be in the form of ORECs or feed-in tariffs. The projects with the best prices will get the contracts.

MR. MARTIN: The expectation is that it will require the Massachusetts utilities to hold an auction and buy up to 2,000 megawatts?

MR. GORDON: Various proposals are still under discussion. We don't know yet what the final bill will require, but we assume it will be similar to the Green Communities Act where there is a regional utility purchase to spread the cost over a greater number of customers, and the contracting will be done through the Department of Public Utilities. The DPU will confirm that the utilities can pass through the contract prices in their rates.

MR. MARTIN: Jim Lanard, CEO of Magellan Wind, who spoke just before this panel, gave an excellent survey, particularly for Europeans looking for the first time at the US market, about which states have the greatest promise. He put Massachusetts on that list. What is your assessment -- you live here -- about the politics of that bill? Will it pass? Will the governor sign it?

MR. GORDON: I think it will pass. I think that there are enough interests who will have a stake in seeing the bill signed. The bill will cover a number of subjects, including authorizing hydroelectricity to be imported from Canada, and there will be a solar component. Massachusetts wants to move to more distributed generation and renewables. The days of the big, large gas-fired power plants in New England are numbered.

MR. MARTIN: The US government has set aside new areas for offshore wind development farther off the Massachusetts coast than you were looking for Cape Wind. Will those or any other offshore wind projects be able to move forward in Massachusetts if the bill does not pass?

MR. GORDON: I do not see any projects moving forward unless there is some type of state support in the form of a framework from which people can be compensated for the development, construction and operating risk to build these projects.

People say offshore wind requires paying an above-market price for electricity. What does that really mean? You are comparing offshore wind to dirty brown power? Once you start calculating the costs of dirty brown power from the societal standpoint, it may come at a higher price than offshore wind.

[*Editor's note:* A draft bill was released in the Massachusetts House in late May that would require Massachusetts utilities to procure 1,200 megawatts of offshore wind electricity by 2025, but bar Cape Wind from bidding for the contracts. Cape Wind said in a statement that "We were extremely surprised and disappointed" to see Cape Wind excluded from bidding. "We will talk to the appropriate people in the legislature and we will ask them to rectify this language so that we can be part of the competitive process." The bill is expected to be heavily amended and debated in the House in June. The state Senate is not expected to release its version of the bill until after the House acts.]

MR. MARTIN: You have put 14 years of effort into Cape Wind. You came very close in late 2014 to closing on the financing. The financing failed due to inability to fill a very small gap in the capital structure. Since then, the project lost its power contracts, and the state siting board decided in April not to extend, for the time being, permits to build the underwater transmission line to bring the electricity to shore. How do you see that project getting back on its feet? Is it your goal to get the project back on its feet?

MR. GORDON: It is our goal to build Cape Wind. Every project has challenges, and Cape Wind has certainly had its share. The project has faced strong political headwinds. It has navigated through five different state administrations. We have had to deal with more than 26 lawsuits coming from an organization that gets its primary funding from a coal billionaire and some very wealthy trophy home owners.

We have done the geotechnical work for every single foundation. We have done the surveys for every inch of cable that will cross through Nantucket Sound. We are */ continued page 38*

employee owes a tax debt. Budget cuts have forced a 19% reduction in the number of IRS employees since 2010. There has been a 27% reduction in IRS agents who do audits. IRS audits of partnerships are down 23% and of mid-sized corporations with $10 million to $250 million in annual revenue are down 42%. Audits of large corporations with more than $250 million in annual revenue are down 7% . . . . The United States installed 8,600 megawatts of additional wind generating capacity in 2015, an 80% increase over 2014, the American Wind Energy Association reported in late April. Total US wind capacity stood at 74,472 MWs at the end of 2015. Another 520 MWs of wind turbines were installed in Q1 2016, the fastest first quarter growth since 2012. At least 10,100 MWs of new wind farms were under construction during the first quarter.

— contributed by Keith Martin in Washington

Offshore Wind

continued from page 37

the only project in the United States that has an approved construction and operating plan from the Bureau of Ocean Energy Management.

We have a 28-year lease on the site. We have two appeals that we are still battling, and just as we have prevailed in all of the other legal challenges, we think we will prevail on this. It is just a matter of time. We are very patient people. We are excited that the market looks poised to take off. We should be well positioned with the best site in the United States from which to build a very good project.

MR. MARTIN: You answered my next question, which is, will the project remain in Nantucket Sound? The answer is yes. My last question is, what lessons have you taken away from the 14 years you have invested in this project?

MR. GORDON: Jim Lanard mentioned all the constituencies that you have to deal with, and we have dealt with every one of them. We have had enormous public meetings. The people in this room may not understand that public opinion surveys show that 86% of the public wanted this project to be built. Fourteen percent were against it.

What I have learned is this. Jim Lanard pointed out that environmental groups have organized around the protection of specific endangered species. I didn't know that billionaires are an endangered species around whom one must navigate carefully. [Laughter]

New Jersey

MR. MARTIN: Let's move to Chris Wissemann. You have had notable struggles with the New Jersey Board of Public Utilities over your pilot project. It is a 25-megawatt project off the New Jersey shore. The BPU was supposed to have worked out a financing mechanism for offshore wind in 2010. It has not done so. What is the status of that effort?

MR. WISSEMANN: The BPU legitimately worked on a financing mechanism in 2010, but got derailed shortly after that when the governor decided to run for president and raided the renewable energy fund to help balance the state budget.

That derailed creation of a financing mechanism and, frankly, nothing has happened in more than three or four years. Just to give you a sense of how topical this is, here is a headline from today's paper: "BPU boss grilled by Senate committee about $1 billion in diverted funds."

MR. MARTIN: Do the diverted funds have anything to do with offshore wind?

MR. WISSEMANN: The defunding affected not only the offshore wind financing mechanism, but also support for solar and several other things.

MR. MARTIN: Why is it important for New Jersey to have a funding mechanism when other states do not? Massachusetts went a different direction.

MR. WISSEMANN: The phrase "funding mechanism" is a misnomer. Rhode Island, with which I am also familiar, passed legislation in 2008 to allow a power purchase agreement to be put in place. That created a pathway for an RFP and an auction and a PPA. The United Kingdom had an OROC mechanism. All of these steps are simply payment mechanisms to ensure offshore wind projects can be built on economic terms.

New Jersey put in place a mechanism to make offshore projects financeable. It is not a PPA where you have a single creditworthy utility buying all the output. We need in New Jersey to rely on a regulatory mechanism, and it needs to be robust enough that an incoming governor, for instance, cannot undo it.

MR. MARTIN: Your project would have sent its power to whom?

MR. WISSEMANN: New Jersey is a deregulated market, so at any given time there are 70-odd wholesalers selling power in the state. The funding mechanism has the effect of causing each wholesaler to purchase its pro rata share of the output from our

At least three US conferences are expected this year devoted entirely to offshore wind.

project. If you serve 20% of New Jersey, then you have to buy 20% of our output.

The wholesalers are reshuffled every three years. None of them has a 20-year contract. Whoever is selling power, whoever is doing business that particular month in New Jersey, has to buy a pro rata share of our output at a price that we bid.

MR. MARTIN: The Board of Public Utilities rejected your proposed project. It said the cost is too high. The state legislature voted in March to give you more time to go back and present an alternative proposal. Where does that effort stand?

MR. WISSEMANN: Let me start with the too high first. Too high was sort of amusing once we got used to it, because the board essentially declared that our electricity price was too high, but by looking at a price that was 30% higher than we proposed. At the price that we proposed, the project passed all of the statutory requirements, which are that the project must create more benefits than it costs.

The process going forward is that the BPU has to open a window to accept an application, and it has been unwilling to open a window to reevaluate the project. The legislature in New Jersey is pro-offshore wind. The legislators like the jobs. They like everything to do with the project.

The legislature has gone multiple rounds – in January and most recently in March -- sponsoring legislation and passing it to reopen the window. A bill landed on the governor's desk about seven weeks ago, and he vetoed it about a week-and-a-half ago.

MR. MARTIN: Then what is the future of the 25-megawatt project?

MR. WISSEMANN: It comes down to politics. The Republicans, not to mention the Democrats of course, but even the Republicans are upset with the governor for following Donald Trump around. The quickest route for offshore wind to flourish in New Jersey is to vote for Donald Trump. [Laughter]

MR. MARTIN: For Trump to get elected --

MR. WISSEMANN: . . . and then Christy will be gone.

MR. MARTIN: Oh great, speaking as someone who lives in Washington. [Laughter]

MR. WISSEMANN: That's the future. Yes.

MR. MARTIN: For how many years have you been working on the project?

MR. WISSEMANN: I have been working on it for four years since I joined Fisherman's, but the company was founded in 2007 and has had a single-minded focus on this project.

MR. MARTIN: Let me ask you the same question I asked Jim Gordon. What lessons have you taken away from the experience with this project?

MR. WISSEMANN: Lots and lots of lessons. Our two projects and many others, frankly, are ground zero for political risk. While you have an administration that is in favor of your project, you need to do everything possible to convert that into a commercial arrangement while you have its support. Do not squander a day of time.

Several big players are now moving into the sector.

California

MR. MARTIN: Move quickly. The politics change. Let's move to Alla Weinstein. Your project is near Morro Bay in California about 33 nautical miles offshore. Morro Bay is midway between Los Angeles and San Francisco.

MS. WEINSTEIN: The proposed project is 650 megawatts. The electricity will be delivered to the California grid. The turbines will be in deep water with a depth of 800 to 1,000 meters. We chose Morro Bay because the project will fit into the existing infrastructure that is onshore left from a now non-operational thermal plant. It was a cooling plant. That provides all the tunneling and water flow infrastructure that we can reuse for bringing our power to shore.

MR. MARTIN: Let's provide some perspective. Jim Gordon, how far offshore is Cape Wind?

MR. GORDON: We are approximately six miles offshore. Six miles from Senator Kennedy's veranda, 13 miles from Nantucket, and nine miles from Martha's Vineyard.

MR. MARTIN: And Bill Koch?

MR. GORDON: Bill Koch is about six miles.

/ continued page 40

Offshore Wind

continued from page 39

MR. MARTIN: Chris Wissemann, how far offshore is your project?

MR. WISSEMANN: It is 2.8 miles off the Atlantic City beach.

MR. MARTIN: So Alla Weinstein, 33 miles is a good deal farther than any of these other projects.

MS. WEINSTEIN: There is a reason why it is where it is. First, we wanted to avoid visual pollution. We are looking to put eight-megawatt turbines on floating structures far out to sea. The structures will be over 120 meters or 394 feet in height, so it is important to be far enough offshore so that they are not visible from shore. The only place the turbines could potentially be seen is from the Hearst castle.

The castle is pretty high up, but this is the Pacific coast, and there is a lot of fog.

MR. MARTIN: You sent an unsolicited proposal to the Bureau of Ocean Energy Management for a lease, and you cleared the initial hurdle. When do you expect to hear whether you have the lease?

MS. WEINSTEIN: Probably sometime during the summer. My guess is about July or August. BOEM said on its website, when it announced acceptance of our lease, that it will take four months or so to do a full evaluation.

MR. MARTIN: What overall timeline do you expect for the project?

MS. WEINSTEIN: Let's talk first about what will happen during the summer. There will be a request for interest, or an RFI, where BOEM will be looking for anyone else who may be interested in the same site. If others are interested in the site, then that site would go for auction. If there is no interest, then we will get an initial lease and we will start the National Environmental Policy Act process.

MR. MARTIN: How much do you expect to pay for the lease? I know the rent for leases off the east coast was established by auction.

MS. WEINSTEIN: The annual rent for an unsolicited lease is $3 per acre until the project starts generating electricity, and then the rent becomes a percentage of the electricity revenues. If there are other interested parties for the identical location, then the rent will be set by auction.

MR. MARTIN: What timetable do you expect overall for the project?

MS. WEINSTEIN: It is California. California is very different from any other state in the United States. The last time Californians permitted any new offshore development was in 1969. Californians don't like offshore oil rigs. Our challenge is to persuade Californians that this is different.

BOEM gives you five years to get through the permitting. We probably will take all of that and then some more time. California has two state agencies whose missions are to protect the shoreline.

MR. MARTIN: So 2021 for permits at the earliest and then how long actually to put the project . . . .

MS. WEINSTEIN: About three years. We are planning to start delivering power in 2025.

MR. MARTIN: To whom will you deliver the power?

MS. WEINSTEIN: California is a deregulated market, so you can sell it to just about anybody. Utilities cannot own generation. They buy energy from independent power producers and then resell it to consumers. The California independent system operator – CAISO – is the entity that operates the transmission grid and, therefore, would move the energy.

We do not expect to have a long-term power contract in hand until sometime after 2020. It is way too early to start that dialog with utilities. You have to do it at the right time, and now is not the right time.

Massachusetts is expected to direct utilities to buy 1,200 to 2,000 MWs of offshore wind.

MR. MARTIN: You need capital with a lot of staying power. Where is the capital to develop this project coming from?

MS. WEINSTEIN: The capital is available. I don't think that will be an issue.

MR. MARTIN: Two more questions. We have heard from both Jim Gordon and Chris Wissemann that state support is very important. Is there support from California for offshore wind?

MS. WEINSTEIN: Until we submitted the application, nobody seriously talked about offshore wind in California. People are starting to understand what it can provide to the state. Last October, the state passed a law that requires utilities to obtain 50% of their generation from renewable energy sources. Today it is solar, but solar alone would not provide for 50% renewables because it is not available all the time and, when you add storage, it becomes pretty expensive.

California is a deregulated state, so we are not really expecting a lot of support from the state. We will have to compete on market rates and that is how the project is structured. The technology is developing at a pace that, by the time we get through the NEPA process and permitting, at least two floating support structure technologies should be commercially available.

MR. MARTIN: Last question. You have bitten off a lot here. You have potentially a merchant project with prices that float with the market. You have an unproven technology. You are trying to build in a notoriously difficult state where it is very hard to build. Why not do something easier?

MS. WEINSTEIN: I guess I am not one who does the easy stuff. I am a little like Jim Gordon; I don't shy from a challenge. Let's look at those three things that you said. You need three basic elements to make a project viable. You need a market, technology maturity and a defined permitting regime.

By the time we get to 2025, California will need to add – and I underline add – 30,000 megawatts of renewable energy just to comply with its 50% target. Thirty thousand megawatts means that the state must add approximately 150 300-megawatt power plants between now and then. That's a lot of energy, and that basically says the market is there.

Technology maturity: the technology is there, and it will be commercially viable and available. The technology is already being deployed in Europe. By the time we need to build, the banks will already have financed it elsewhere.

Californians are a different breed. I don't know how they compare to the billionaires with whom Jim Gordon has had to contend, but they are very, very protective of their environment and the coastline. So far in our public outreach, we have been able to get people to accept that floating offshore wind could be one of the most benign types of renewable energy generation out of all the sources.

The use of floating offshore wind eliminates the Jones Act limitations because structures are built on shore, and they are towed fully assembled. This reduces the cost of construction as compared to fixed-foundation projects on the east coast.

The Energy Policy Act of 2005 designated BOEM as the lead federal agency for offshore wind.

MR. MARTIN: The project will have a long gestation period, so we should see a lot of you at future offshore wind conferences.

Kirby Mercer, turning to you and Beothuk Energy, I looked at your website. I couldn't tell whether you are an equipment vendor, a construction contractor, or a developer.

Nova Scotia

MR. MERCER: We are a developer, but we thought it was smart strategically to put all the key facilities in place to implement our plan. That is why the website may be a little confusing. But we are a developer and our project that we have come to talk about today is in southwest Nova Scotia. It is designed as an export project. We are more than 200 miles away from the Canada geese, so we are not going to upset them there.

We are in shallow water. We have the issues with fishing with which we will have to deal. We are using gravity-based structures as our substructure. We have been building gravity structures on the east coast of Canada for the last 25 years. We are in the gas space, so we have been using that technology there. We are taking advantage of skill sets that are already in our backyard. We have a lot of the ports and other parts of the necessary infrastructure already in place.

We are thinking about mating the gravity-based structure with the topside as one unit and floating it out. We will do a lot of stuff at dockside.

MR. MARTIN: Let me unpack this a bit. How far offshore will you put your project?

MR. MERCER: From Nova Scotia, about 18 kilometers. From Massachusetts, about 220. [Laughter]

MR. MARTIN: What capacity?

MR. MERCER: A thousand megawatts.

MR. MARTIN: How large will the turbines be?

MR. MERCER: We are looking at seven-megawatt turbines.

MR. MARTIN: Explain what a gravity-based structure is.

MR. MERCER: It is a concrete foundation. It is pretty benign for

/ continued page 42

Offshore Wind

continued from page 41

the environment. We can amortize our project over a much longer life expectancy than if we drive a monopole into the ocean floor. One of the other reasons for a gravity base for us is we have had pack ice in the Gulf of Saint Lawrence farther north, so we are designing a substructure to deal with that.

There is also no disposal at sea. When the project reaches the end of its useful life, we can pull out the foundations. The environmentalists like that.

MR. MARTIN: How far advanced is the project?

MR. MERCER: That project is still in planning, although we do have a map route with a bathometric survey on it, getting it to a grounding site in New Hampshire, but we are still going through the environmental process. Our western Newfoundland project is a lot farther ahead. That project will be about 18 kilometers offshore, next to a major transmission route, where we have a world-class port and an international airport.

That project is moving very quickly. We are negotiating for offtake agreements right now and talking to major utilities about coming in as partners on that project.

MR. MARTIN: How many projects are you trying to develop?

MR. MERCER: We have six projects for about 4,500 megawatts of potential capacity.

MR. MARTIN: All in Canada?

MR. MERCER: All in Canada.

MR. MARTIN: What support are you getting from the Canadian government?

MR. MERCER: The new prime minister, Justin Trudeau, is keen to promote green technologies. This is a new space for Canada, and the federal government feels it can have national significance. The new government has put in place a couple billion dollars of infrastructure funding to support green energy development. Some of it should be available to help offshore wind development.

It is not just federal support, but there is also provincial government support for this new sector. With the downturn in the oil and gas space in Canada, just like in Europe, people who were working in offshore oil and gas have moved to offshore wind. A number of Atlantic Canadian companies think there is a huge opportunity.

The developers of the Deepwater project had to go to the Gulf of Mexico to get a lot of things made. We have that capacity right next door in Atlantic Canada.

Kick Start

MR. MARTIN: Let's move to a general question, and then we have to wrap up. Jim Lanard said in his opening speech at this conference that for offshore wind to succeed, there has to be competition on price for the utility PPAs on offer. You do not get such competition when the bidding is over who gets the offshore lease, and then there is only one leasehold owner to whom the PPA can be awarded. Did you agree with that part of his speech? Chris Wissemann?

MR. WISSEMANN: Absolutely. Competition is needed to give agencies that are awarding these contracts the political cover to say that the prices are as competitive as they can be. Competition is also one of the biggest drivers to get costs down.

MR. GORDON: I take a different view. Competition is critically important and it is great that it is coming, but we are at a point where we need to kick start this industry. Let me give you an illustration. The solar industry is flourishing in Massachusetts and New Jersey. What happened was that many, many people within the industry -- panel manufacturers, installers, developers -- got together, built up a stakeholder group and started lobbying. They talked to regulators. They lobbied legislators. It was not just a couple pioneers or lone voices in the wilderness. It was a crowd.

The price of installed solar capacity has come down by 60% to 70% in the last 10 years. When it first started, in Massachusetts,

A 650-MW wind project with floating turbines is under development off Morro Bay in California.

you had solar renewable energy credits trading for 40¢ a kilowatt hour. Cape Wind's price back when we had our contracts was 18.7¢. Solar was getting 40¢ for the SRECs plus 10¢ for the energy.

The first movers in solar got rewarded with the higher prices because the equipment and installations were going to cost more and the first mover always takes more risk.

Here is something else. You can't fly here from Europe once a year to come to a conference and go back thinking this industry is going to progress as quickly as you want it to. What you need to do is think about getting involved in Offshore Wind Massachusetts, Matt Morrissey's group, by contributing toward the funding, the expertise, to start really building a stakeholder group that will be listened to by the legislators, the regulators, and the public. One of the fastest ways we can kick start this industry is by putting our money and knowledge together to make it happen. ◎

Ideas for Cash Investors in US Solar Projects

by Scott Cockerham, in Washington

Private equity funds, pension funds and foreign investors have a hard time investing in US solar projects because they cannot use the tax benefits to which the owner of such a project is entitled.

Worse, their participation could cause the project to lose eligibility for most of the tax benefits.

Wealthy individuals, S corporations and closely-held C corporations also have a hard time investing in solar, but for a different reason. (A closely-held C corporation is a corporation in which five or fewer individuals own more than half the stock.) Their problem is that passive loss and at-risk rules make it hard for them to use the tax benefits.

However, there are still ways for such investors to participate.

US solar projects qualify for tax benefits worth 56¢ per dollar of capital cost. Few solar developers can use them. The benefits are a 30% investment tax credit and five-year accelerated depreciation. Most developers try to enter into complicated tax equity transactions to get value for them. A developer must have a significant amount of equity in the project before the tax equity market will be interested. This creates demand for cash investors to help put in equity.

This article discusses three financing structures that cash investors might use.

As a starting point, a cash investor must invest through a "blocker" corporation – a US entity treated as a corporation for tax purposes – if the cash investor is a government or tax-exempt entity or a partnership with any such entities as investors. This is to prevent its participation from denying the project the investment tax credit and accelerated depreciation. It must also be careful to ensure the blocker is not considered owned 50% or more by tax-exempt or government entities or the blocker will itself be treated as a tax-exempt entity.

Cash investors should understand how the tax equity works since they will be investing alongside it. It will also affect what the cash investor can get out of the deal.

Partnership Flip

Many solar tax equity transactions use a partnership flip structure where a partnership holds the solar asset, either directly or through a project company.

In a typical partnership flip, the sponsor forms the partnership with a tax equity investor. The partnership allocates 99% of the taxable income and loss to the tax equity investor until it hits a certain threshold, at which point the tax sharing ratios shift to a different ratio. The threshold can either be a fixed point in time, or a variable point at which the tax equity investor hits a target yield.

Cash can generally be distributed in any manner the parties wish, subject to one major caveat: the demands of the tax equity investor.

Tax equity will require enough cash to allow it to reach a minimum pre-tax yield. Most tax equity investors require at least 2%, treating tax credits as equivalent to cash. There will be additional cash flow requirements depending on the flip mechanics. In a yield-based flip, tax equity will need to get enough cash to allow it to reach its target internal rate of return by a specified deadline. If the flip is delayed, tax equity will want a greater share of cash until it reaches its target, up to 100%. In a time-based flip, the tax equity investor usually asks for preferred cash distributions ahead of the other partners.

Tax equity may require cash that the other partners would

/ continued page 44

Solar

continued from page 43

normally get to be diverted to it to cover indemnity payments or other obligations of the partners. A cash investor can expect to be subject to this kind of cash sweep in cases where it is affiliated with the sponsor. Otherwise, it should be able to avoid having its share of cash swept. The sweep will be an issue when the cash investor partners with the sponsor in an upper-tier partnership above the project-level partnership.

Potential demands on cash flow to cover sweeps lessen the appeal of a partnership flip from a cash equity investor's perspective. The balance of this article discusses two alternatives to standard partnership flips. The structures are intended to maximize cash returns and minimize sweeps. The alternatives are inverted lease transactions and sale-leasebacks.

Inverted Lease

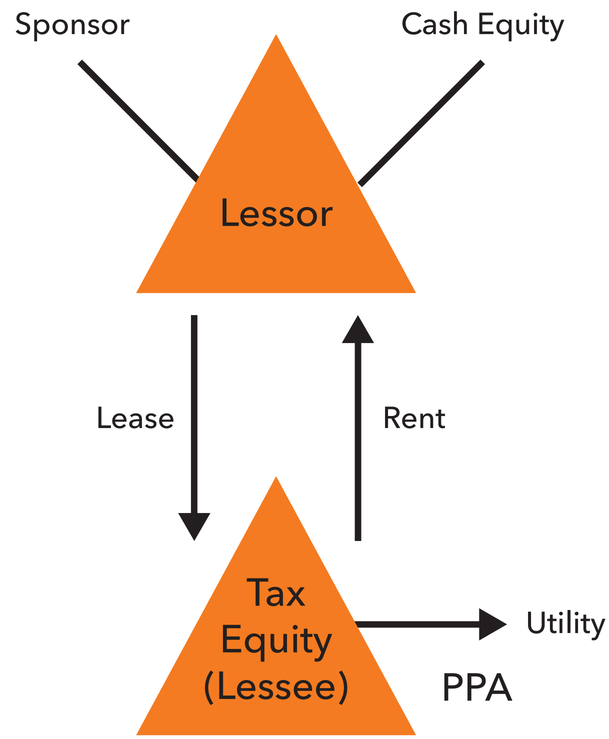
One alternative is an inverted lease. There are two types: a basic structure where the sponsor is the lessor and leases the project to a tax equity lessee, and an overlapping-ownership structure where the lessee is also a partner of the lessor. Only the basic structure would make sense as a cash equity investment.

In a basic inverted lease, the sponsor forms a lessor to own the project, and then leases the project to a tax equity investor and assigns it the associated customer agreements. The lessor makes a tax election to treat the lessee as if it had purchased the project from the lessor at its fair market value. The lessee is entitled to claim the investment tax credits. The lessee collects the revenue from the customer agreements and pays it to the lessor as rent under the lease. The lessor still owns the project for tax purposes, so it keeps the depreciation. The asset comes back to the lessor automatically at the end of the lease.

There is an investment opportunity at the lessor-level. A cash equity investor could form the lessor as a partnership with the sponsor. The sponsor would be responsible for managing the entity. The lessor could be structured either as a partnership flip or with fixed cash and tax sharing ratios. The cash investor can negotiate to get as much cash as it can out of the lessor. The sponsor can keep most of the depreciation. The sponsor could also receive an option to purchase the cash investor's interest after it hits a target return, and get the asset back from the lessee at the end of the lease term.

The structure is shown in chart 1.

Chart 1: Inverted Lease



For cash investors, this structure avoids a direct partnership with tax equity and any associated cash sweeps. Like a back-leverage lender, the cash investor is investing against a share of the sponsor's cash flow, with the added benefit that it will receive some share of depreciation. It can negotiate for as much cash as it can get without having to pay for unwanted tax benefits.

This structure is also attractive for sponsors in need of additional funds in the capital stack. Basic inverted lease transactions usually only raise a portion of a project's cost, in part because the sponsor cannot monetize the depreciation. Other sources are needed to build the project. Sponsors often seek back-leverage loans that are repaid from the sponsor's cash flow. The loans are typically secured by the sponsor's equity interest in the lessor and the assets. From the sponsor's perspective, an upfront investment by a cash investor in exchange for a share of the cash flow is functionally similar to back-leverage financing, and the sponsor avoids having to pledge its equity interest as collateral.

The structure is essentially the same as a standard inverted lease for the tax equity investor. The investor receives the investment tax credits and a step up in its tax basis for calculating the tax credits from cost to fair market value.

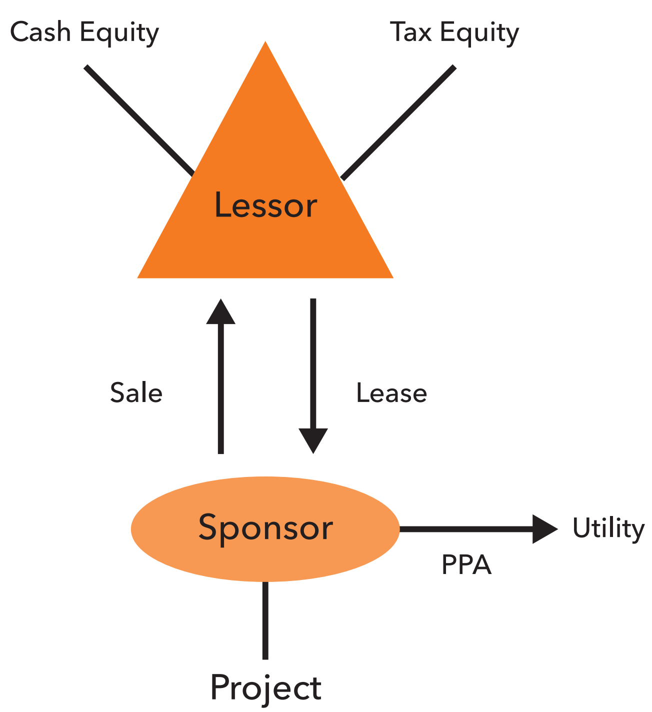
Sale-Leaseback

Another option is a sale-leaseback. In a typical sale-leaseback, the sponsor sells a project to a tax equity investor for its fair market value, and the investor leases it back to the sponsor. The tax equity investor keeps all of the tax benefits, and receives cash from the sponsor in the form of rent paid under the lease. The sponsor has taxable gain on the sale to the extent the value of the property exceeds what it cost to build.

The lessor position in a sale-leaseback is not usually appealing to a cash-focused investor. It might make sense, however, if the cash investor can bring in another investor with a greater appetite for the tax benefits. The cash investor could purchase the project, lease it back to the sponsor, and then sell a portion of its lessor interest to a tax equity investor before the project is placed in service. The cash investor can negotiate to keep a percentage of cash flow and depreciation as a syndication fee. The cash investor would recognize taxable gain to the extent it charges a premium on the sale of its lessor interest.

Chart 2 illustrates the structure after the cash investor has sold a portion of the lessor interest.

Chart 2: Sale Leaseback



The main benefit of the structure from a cash investor's perspective is flexibility. It acquires the project prior to tax equity coming on to the scene. Cash equity is in a position to negotiate to sell as much or as little of an interest in the lessor as it wants, and retain as much of an interest in the cash flow as it can get. If cash equity has some appetite for tax benefits, but not enough to justify being a full tax equity investor, then this structure allows it to retain tax ownership to the extent needed to claim the tax benefits that it can actually use. Like a standard partnership flip, however, the tax equity investor would have certain cash flow requirements that would need to be met. There would also be some time pressure to find a tax equity partner before the project is placed in service for tax purposes.

From the sponsor's perspective, this is just like a typical sale-leaseback. Sale-leasebacks are attractive to sponsors because they offer 100% financing for a project. The sponsor bears operational risks and offtaker credit risks. A downside compared to an inverted lease is that the sponsor has to pay fair market value for the project to get it back at the end of the lease term. The investor's initial purchase price may also not capture as much residual value as the sponsor would like.

This structure is not ideal from a tax equity investor's perspective. Tax equity investors usually have up to three months after a project is placed in service to buy it and lease it back in order to claim an investment tax credit. The three months would not be available in this case. The tax equity investor would have to become a member of the lessor before the asset is placed in service, and would therefore have to take on some degree of construction risk. Other than the three-month rule, however, this is similar to the lessor position that tax equity would hold in a standard sale-leaseback.

Net Metering Debate Moves East

by Megan Strand and Ana Vucetic, in Washington

The debate over standard net metering benefits in the US has migrated east. During the first five months of 2016, revised net metering policies were implemented in Massachusetts, rejected in Maine and Pennsylvania, and teed up for further action in New Hampshire, Rhode Island and New York.

Polarizing policy decisions in 2015 on net energy metering programs in three leading solar states out west led to an overhaul of such programs in Hawaii and Nevada, while California reaffirmed its existing net metering framework until the issue is revisited in 2019. By contrast, state policymakers in the northeastern states appear willing to implement incremental changes to compensation, including allowing below retail, but above wholesale, rates and adding fixed monthly or other new charges on net metered customers in an effort to equalize the impact of net metering costs across ratepayers.

The northeastern states are also looking to loosen program restrictions and encourage deployment of net metered systems, for example, by raising state- or utility-level capacity caps and increasing system sizes eligible for net metering.

New Hampshire and Rhode Island

New Hampshire and Rhode Island are cases of new policies poised for further action.

The New Hampshire Public Utilities Commission opened Docket No. DE 15-271 in July 2015 to examine the utilities' customer-generator interconnection and net metering queue management procedures. The New Hampshire commission approved new procedures in March 2016. The new procedures include certain revised application requirements and project milestones that must be met to ensure that a proposed project is closer to being built before it is allocated capacity under the statewide cap. The procedures apply to both new and existing projects; the latter were given until June 1, 2016 to demonstrate compliance with the new requirements.

In parallel on the legislative front, the governor signed a bill (HB 1116) in May 2016 that doubles the previous statewide cap on total capacity of systems eligible for net metering from 50 megawatts to 100 megawatts.

At least one utility, Eversource, which serves about 20% of the New Hampshire population, is already nearing the new cap for larger projects (between 100 kilowatts and one megawatt). Eighty percent of the 50 megawatts of additional capacity was allocated to projects at or below 100 kilowatts, while the remainder was allocated to larger projects.

HB 1116 also requires the New Hampshire commission to develop alternative net metering tariffs, leaving New Hampshire a state to watch for further policy developments in 2016. Related legislation, SB 378, also enacted in May, directs the New Hampshire commission to review group net metering arrangements that, along with virtual net metering and community solar, are variations on standard net metering and allow multiple customers to benefit from the excess output of a system.

Rhode Island is also discussing its net metering policy. The Public Utilities Commission opened a new docket, Docket No. 4600, in February as a forum for reviewing the changing distribution system.

On the legislative front, HB 7006 passed in the Rhode Island House in February and has moved to the Senate. The bill would double the maximum eligible system size, from five to 10 megawatts, to participate in net metering and restrict interconnection charges imposed on customers.

Massachusetts and Maine

Massachusetts and Maine are a tale of two governors: one supporting incremental net metering reform and the other rejecting more extensive changes.

In April, the Republican governor of Massachusetts signed a bill (HB 4173) that increases the net metering cap from 4% to 7% for projects with private entity offtakers, and from 5% to 8% for systems with public (*e.g.*, government) offtakers. The caps generally do not apply to residential systems, which accounted for almost half of solar systems installed in Massachusetts last year.

On the compensation front, the new law preserves close to retail rates for residential, small commercial and public projects. Generally, private systems installed after Massachusetts reaches its target of 1,600 megawatts of installed net metered solar capacity will be credited at decreased rates closer to the wholesale rate, by allowing customers to be credited for only 60% of excess generation. Customers who qualify for net metering prior to this cap being reached are grandfathered and will be able to maintain the higher rate for 25 years. Utilities will be allowed to submit requests to impose a minimum monthly bill on customers to help pay for the grid. However, the Massachusetts commission may only approve such minimum charges once the 1,600 megawatt cap is reached.

The new caps are expected to be reached in 2017. Meanwhile, lifting the public and private net metering caps will allow project development to move forward in the near future, alleviating the backlog of hundreds of projects that have stalled since local utilities hit their respective caps last year.

The debate over net metering is moving east.

By contrast, Maine punted. The legislature and the governor have been unable to reach a consensus on proposed revisions to net metering.

The state legislature voted in April to replace existing retail net metering and allow new residential and small commercial customers (with systems up to 250 kilowatts) to enter into long-term contracts with local utilities, including Central Maine Power and Emera Maine, to sell aggregate generation. Payments under such long-term contracts would be credited against a customer's monthly utility bill. Utilities would aggregate, then sell or use the output in a manner that maximizes ratepayer value. Rates under these contracts would be set by the Maine Public Utilities Commission, with compensation declining as the aggregate number of residential and small commercial systems installed reaches certain statewide targets.

The legislature proposed to grandfather existing net metering customers. They would remain eligible for the current tariff rates for 12 years.

The Republican governor vetoed the bill over concerns it would be a burden to ratepayers because it did not include all renewable technologies, return renewable energy credits to ratepayers or cap the price paid under the proposed long-term contracts.

The state House fell just short of the super-majority two-thirds vote necessary to override this veto at the end of April. In the absence of legislative action, the issue of net metering moves to the Maine commission. Net metered systems exceeded 1% of Central Maine Power's peak load by the end of 2015, and Emera Maine is expected to reach its 1% cap later this year.

Pennsylvania

Pennsylvania is a case of straying outside the statute.

The state is focused on incremental changes. The Pennsylvania Public Utility Commission largely reaffirmed existing policy in February. Although a state regulatory review body recently struck down the commission action, the controversy appears to center primarily on the perceived lack of statutory basis for one particular provision in new rules the commission proposed.

The Pennsylvania commission voted 3-2 in February in Docket No. L-2014-2404361 to retain net metering at the full retail rate (approximately 8¢ per kWh). The decision reaffirmed statutory caps on nameplate capacity at 50 kilowatts for residential systems, three megawatts for non-residential systems, and five megawatts for industrial systems.

The most controversial addition by the Pennsylvania commission was a new requirement that any system participating in net metering cannot be sized to generate more than 200% of the customer's historic annual electric consumption. The commission had initially proposed a much lower percentage of 110% in February 2014 when it first initiated the rulemaking proceeding. However, it ended up increasing this to 200%, citing a desire to balance allowing future load growth and limiting excessive oversizing of systems, while aiming to ensure that default service is provided at the least cost to customers over time.

In late May, the five-member Pennsylvania Independent Regulatory Review Commission (IRRC) unanimously voted to disapprove of the Pennsylvania commission rules. The primary basis for the decision was a lack of clear statutory authority for the Pennsylvania commission to impose a 200% size limitation. The IRRC also determined the commission failed to show a compelling need for the changes and to consult with the legislature in drafting the rules.

The Pennsylvania commission now has three options: to withdraw the proposed regulation, to resubmit the regulation with revisions within 40 days after the disapproval order issued by the IRRC in early June or to submit the regula- */ continued page 48*

Net Metering

continued from page 49

tion without revisions for approval to the state legislature.

An interesting twist could be the changing makeup of the Pennsylvania commission. One of the three majority voters, Pamela Witmer, left the commission after her term expired in April. Governor Tom Wolf (D) has nominated his senior energy adviser, David Sweet, to fill the vacancy, but the nomination must first be confirmed by a majority of the Pennsylvania Senate. This leaves the Pennsylvania commission with only four members, two of whom favor the commission's recommendations and two of whom are against.

At issue are caps on participation in the programs and the prices credited for net-metered electricity.

New York

New York is moving toward a compromise worked out between the utilities and solar companies.

Net metering is being addressed as part of the broader statewide REV — "Reforming the Energy Vision" — initiative. The Department of Public Service issued a white paper in January 2016 for comment. The New York Public Service Commission is expected to make a decision on policies proposed in the white paper later this summer.

In the meantime, the department has temporarily suspended the state's net metering caps and instructed utilities to continue accepting interconnection applications from prospective net metering customers. Comments were due in April on an interim successor to the net metering program in Case 15-E-0751.

A group of utilities and solar companies submitted a proposed compromise in April. The group includes all the major New York utilities (Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc. and Rochester Gas and Electric) and three large solar developers (SolarCity, SunEdison and SunPower).

The compromise would transition net metering rates to a formulaic LMP + D + E approach. "LMP" is calculated using the New York Independent System Operator's established location-based marginal price, which includes the wholesale price of energy, transmission congestion charges and transmission line losses. "D" is the full range of additional values provided by the distribution-level resource, calculated using each utility's benefit cost analysis handbook, a handbook developed by each utility to guide distributed energy resource providers in structuring their projects. "E" is the cumulative value of external benefits from the project, both quantitative and qualitative, such as renewable energy certificates and emissions reductions. Existing customers would be grandfathered at their current rates of compensation.

A decision on the compromise is expected later this year. ◎

Environmental Update

The US Fish and Wildlife Service proposed boosting the annual incidental take limit for bald eagles in early May from 1,103 to 4,200 nationwide, an increase that it said reflects the continued growth in eagle populations. The move was most certainly intended to support the wind industry.

At the same time, the Fish and Wildlife Service released for comment a proposed programmatic environmental impact statement as part of the improvements to its eagle conservation and management program. It also proposed changes to its regulations governing permits for incidental take of bald and golden eagles.

Permits for "incidental takes" of eagles may be issued in the future for 30 years, but with reviews at five-year intervals.

Among other things, the proposed regulations direct how eagle populations are to be monitored and managed and address how data on permitted eagle take will be collected and used. They also explain how the incidental take permitting system is supposed to fit within the overall framework of eagle management.

Perhaps most important to wind developers, the proposed regulations would extend the maximum permit for incidental take of eagles to 30 years, subject to a recurring five-year review process throughout that period. However, only applicants who commit to measures to ensure the preservation of eagles will be considered for permits with terms longer than five years.

The Bald and Golden Eagle Protection Act establishes a "preservation standard" for take permits. The Fish and Wildlife Service must determine that any take of eagles it authorizes is "compatible with the preservation of bald eagles or golden eagles." Each take permit must be "consistent with the goal of maintaining stable or increasing breeding populations."

"The permitting system provides a mechanism for private companies to do the right thing," said Fish and Wildlife Director Dan Ashe. "Many companies are making efforts to avoid killing migratory birds during design, construction and operation of industrial facilities, and we look forward to working with additional permit applicants to ensure their operations are compatible with efforts to conserve eagles."

In support of the proposed changes, the agency released a report assessing the current status and continued resiliency of bald and golden eagle populations, called "Bald and Golden Eagles: Status, trends, and estimation of sustainable take rates in the United States." The report is a compilation of the most current research.

The bald eagle was once in danger of extinction in the lower 48 states, with fewer than 500 nesting pairs remaining. First listed as endangered in 1967, the Bald Eagle was removed from the list of endangered and threatened species in 2007 because populations had recovered. The new eagle status report indicates the bald eagle population has continued to rise throughout the United States and now numbers more than 143,000.

At the same time, data suggest the golden eagle population -— now just over 26,000 —- has declined, heightening the importance of taking conservation measures. The take limit on golden eagles would remain at zero, unless */ continued page 50*

those deaths or injuries are mitigated. The Fish and Wildlife Service takes a "no-net-loss" approach to golden eagles and compensatory mitigation is required to avoid any reduction in the current population.

For bald eagles, compensatory mitigation depends on the quantity of local take and is calculated using the concept of "local area populations." The Fish and Wildlife Service looks at the existing population and take within 86 miles of the project. If projected take within the relevant area would exceed 5% of the bald eagle population on an annual basis, then compensatory mitigation will probably be required. In other circumstances, compensatory mitigation is discretionary with the Fish and Wildlife Service.

Both bald and golden eagles are protected under the Eagle Protection Act, the Migratory Bird Treaty Act and the Lacey Act. The Eagle Protection Act imposes criminal and civil penalties for any take of a bald or golden eagle. "Take" is broadly defined to mean "pursue, shoot, shoot at, poison, wound, kill, capture, trap, collect, molest or disturb." The US government has said it intends to pursue companies that violate these laws, raising concerns for developers and project owners who might unintentionally harm the birds.

Few eagle permits have been issued to date.

Few applicants have been granted take permits since the Fish and Wildlife Service first authorized incidental take permits for eagles in 2009. This has made it more difficult to develop wind farms in certain areas. A goal of the new proposed regulations is to increase the number of permits issued and rely on compensatory mitigation of unintentional harm.

The public may submit comments on the proposed regulations and the programmatic environmental impact statement until July 5, 2016. Both are available at http://www.fws.gov/birds/management/managed-species/eagle-management.php

Methane Emissions

The US Environmental Protection Agency issued final regulations in May that are supposed to reduce methane emissions from new and modified oil and gas industry infrastructure, including wells, processing plants and pipelines. The agency is still working on regulations to reduce emissions from existing oil and gas operations. The Obama administration wants to reduce methane emissions from the oil and gas sector by 45% from 2012 levels by 2025.

Natural gas usage has increased steadily in the US as fracking has increased supply and brought down prices. Production, transportation, and use of natural gas causes significant quantities of methane to be released into the atmosphere. Methane emissions are of particular concern for climate change because, pound for pound, methane traps significantly more heat in the atmosphere than carbon dioxide. EPA says that the amount of methane leaking from oil and gas wells is much higher than previously reported.

The regulations will require oil and gas companies to detect and repair leaks, capture gas from hydraulically fractured wells, limit emissions from new and modified pneumatic pumps, and limit emissions from several types of equipment used at gas transmission compressor stations. The agency says the regulations will reduce methane emissions by 520,000 short tons and also reduce 210,000 tons of volatile organic compounds or "VOCs" that contribute to smog. EPA estimates that compliance with the regulations will cost the oil and gas industry about $530 million in 2025 and result in health care and other benefits of approximately $690 million.

In addition to the requirements for new and modified equipment, the regulations require oil and gas companies to provide information on existing sources of methane emissions, the presently available emissions reduction technologies, and the costs of reducing existing emissions. Information gathering by EPA is the first step in regulating existing sources. Existing sources emit significantly more methane and VOCs than new and modified sources. EPA regulation of existing sources is expected to be much broader and costly than regulating new and modified sources.

The oil and gas industry is unhappy with the regulations. "Imposing a one-size-fits-all scheme on the industry could actually stifle innovation and discourage investments in new technologies that could serve to further reduce emissions," Kyle Isakower, vice president for regulatory policy at the American Petroleum Institute, said.

Environmentalists see the regulations as a positive first step, but are "urging EPA to move expeditiously on its commitment to address existing sources," according to Michael Brune, executive director of the Sierra Club.

Clean Power Plan Update

The full US court of appeals in Washington will hear oral arguments about the Clean Power Plan on September 27, bypassing a hearing before a three-judge panel that had been set for June 2. This should speed when the plan lands before the Supreme Court.

Earlier this year, the Supreme Court took the unprecedented step of deferring implementation of the plan while it is being litigated.

The Clean Power Plan requires a 32% reduction in carbon dioxide emissions from most existing coal- and gas-fired power plants by 2030. Each state has been assigned individual carbon reductions and is required to submit an implementation plan demonstrating how it will achieve the reductions. The federal government will impose a federal plan on states that fail to submit their own plans or that submit plans that fall short of what the Clean Power Plan requires.

The Clean Power Plan should land sooner before the US Supreme Court.

The immediate effect of the decision by the full US appeals court to hear the case is to delay oral argument by three months, but ultimately it will expedite judicial review of the plan. As any decision by the court will almost certainly be appealed to the Supreme Court, the decision shortens the path to review by the high court.

The appeals court did not explain its decision to bypass a hearing before a three-judge panel. One possible explanation is that several of the judges concluded that some of the issues involved in the case are of such significance that they warrant the full court's attention in the first instance. EPA has attempted to frame the Clean Power Plan as a routine exercise of its Clean Air Act authority. Opponents characterize the plan as an unconstitutional restructuring of the US energy sector.

/ continued page 68

Environmental Update

continued from page 67

Notwithstanding the stay imposed by the Supreme Court, 14 states have asked the EPA for assistance as they prepare to comply with the Clean Power Plan. EPA has said it will work with states that want to take voluntary measures to comply with the Clean Power Plan should it be upheld.

Environmental regulators in California, Colorado, Connecticut, Delaware, Maryland, Massachusetts, Minnesota, New Hampshire, New York, Oregon, Rhode Island, Vermont, Virginia and Washington asked the EPA in late April to provide model rules to guide their compliance with the Clean Power Plan. The states have also asked for guidance on how to track emissions allowances, credits for trading programs, and how to measure and verify energy efficiency gains, and for additional guidance on the Clean Energy Incentive Program, a voluntary program that provides incentives for early investments in renewables and energy efficiency programs in low-income communities.

Opponents of the Clean Power Plan argue that the Supreme Court stay means that all work on the plan should stop until litigation is complete. Texas Attorney General Ken Paxton and Ohio Attorney General Patrick Morrisey emphasized this point in a May 18 letter to EPA asserting that "[b]ecause the [Clean Energy Incentive Program] and the carbon trading rules have no legal significance without a legally effective Power Plan, efforts to push these programs forward at this time can only be understood as an attempt to make the Power Plan a fait accompli and to undermine the Supreme Court's order."

- contributed by Andrew Skroback and Richard Waddington in Washington

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01-01 PF NewsWire June 2016

* Legal services in Poland are provided by Radzikowski, Szubielska i Wspólnicy sp.k., an independent law firm that is part of Chadbourne's international legal network.