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PROJECT FINANCE
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FERC Directed to Favor Coal and Nuclear

by Robert Shapiro, in Washington

Most United States competitive markets would be forced to dispatch nuclear and coal power plants ahead of other power plants and have them receive cost-based rates under a proposal the US Department of Energy sent the Federal Energy Regulatory Commission at the end of September.

It would amount to a bailout of operating nuclear plants and coal plants that are not price competitive in the regional power markets and ensure them market share at the expense of gas and renewable energy plants.

US Energy Secretary Rick Perry used an obscure provision in the Department of Energy Organization Act to propose rules that FERC is supposed to decide within 60 days to force competitive regional transmission organizations or RTOs — like PJM, MISO, New York ISO and ISO-New England — that FERC regulates to modify their rate structures to pay nuclear and coal plants the full operating and capital costs whether or not the electricity offered from these plants is cost competitive.

This proposed rule only applies to these competitive markets. In parts of the United States with such markets currently, the RTO takes bids each hour from electricity generators to supply the power the market requires that hour and then dispatches power plants in economic merit order from least cost to most expensive until the full needs */ continued page 2*

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TAX CUTS should start to come into clearer focus this month.

Budget resolutions in the House and Senate set a deadline of November 13 for the tax writing committees to have reported tax-cut bills to the full House and Senate. The budget resolutions have not yet cleared Congress.

The Trump administration and House and Senate Republican leaders released a broad outline of a bill that all three groups can support on September 27. The eight-page framework suggests that the "big six," as the negotiators were called, have had trouble reaching consensus after four months of effort. Martin Sullivan, a respected tax economist read by policymakers in Washington, called the framework */ continued page 3*

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that hour have been met.

Since the regional power markets set prices based on competitive bids, not on the bidder's operating costs, the proposed rule would undermine the fundamental approach to economic dispatch of generation resources in these markets.

Justification

The authority that DOE is using to direct FERC to act has not been used since the early 1980s. The Department of Energy was created in 1977. FERC has exclusive jurisdiction over wholesale electric rates charged in the United States. DOE has authority to propose a rule to FERC and direct FERC to act within a reasonable period.

DOE says emergency action is needed because reliability of the power supply in these regions may be being threatened if baseload nuclear and coal plants are not able to operate. Many nuclear and coal plants are no longer cost competitive with other plants, like baseload gas-fired plants and intermittent renewable resources like wind and solar projects.

DOE cited selectively from its own recent study of grid reliability, as well as certain selective statements from the NERC — the North American Electric Reliability Corporation — and FERC about the need to understand the implications of the changing resource mix in power sources to assure reliability.

However, it did not cite any statement from any reliability council or regional transmission organization or FERC that any particular region's reliability is inadequate now or in the immediate future. In fact, the DOE study itself concluded only that "[a] continued comprehensive regional and national review is needed to determine how a portfolio of domestic energy resources can be developed to ensure grid reliance and resilience."

Scope

The proposed rule that DOE wants FERC to adopt does not expressly limit the cost-based subsidization to nuclear and coal projects. However, support would be provided only to any project that has "a 90-day supply on site enabling it to operate during an emergency, extreme weather conditions, or natural or man-made disaster." Coal plants and nuclear plants, unlike gas plants and renewable power projects, require substantial on-site fuel storage.

Many coal plants would have to buy more coal to qualify. US power plants that burn coal had average stockpiles in August of 71 to 91 days.

RTOs generally operate with generators bidding every day on an hourly basis to supply their energy. Subject to certain transmission constraints, the generators are economically dispatched, with the lowest bids dispatched until the entire load on the system is met. Those projects that offer non-competitive priced bids above that level of system demand will not be dispatched and will not receive any revenue for their energy. In the last couple years, some coal and nuclear plants have not been able to compete with newer, more fuel-efficient natural gas power projects that are benefiting from very low gas prices and therefore have low operating costs.

Several states have been moving separately to subsidize nuclear power plants. New York and Illinois have recently put in place subsidized pricing for operating nuclear plants in their states that are having a hard time competing in the energy markets in MISO (for Illinois nuclear) and NYISO (for New York nuclear). These programs, which created a value for a new environmental attribute known as a zero-emission credit or ZEC for nuclear-only energy, are currently subject to litigation by competitive generators who claim that even this limited price support is disrupting competitive markets. (For more detail about the litigation, see "Zero Emissions Credits Upheld" in the August 2017 *NewsWire*.) Other states with nuclear power plants are considering similar state legislation.

The US energy secretary wants grid operators to dispatch coal and nuclear units ahead of other power plants.

Timing

DOE initially delivered its proposal to FERC on September 28, 2017. FERC then issued a notice of proposed rulemaking on October 2 seeking initial comments on the DOE proposal by October 23. On October 4, FERC issued another notice requesting that commenters address a list of questions in a variety of categories including whether there is need for reform, what types of entities should be eligible for compensation, how the 90 days of on-site fuel supply should be determined, how environmental regulations and weather conditions could affect the reliability of the fuel supply, and how eligible projects should be dispatched given the systemwide economic dispatch of the current RTO systems.

On October 6, DOE reissued its notice of proposed rulemaking for publication in the Federal Register on October 10. The 60-day window for action by FERC would expire 60 days from publication, or December 11, unless the DOE changes its deadline.

DOE made clear that the proposed rule does not apply to any utility that operates outside of an RTO. The proposed rule only applies to projects that are "not [already] subject to cost of service regulation by any state or local regulatory authority." Therefore, utilities that have coal and nuclear plants in their rate bases and are subject to state rate regulation will not benefit from the proposed subsidies. However, since state utility rate regulation is outside of FERC jurisdiction, DOE may have recognized the limits on its ability to influence these utility rates.

The irony of this exclusion is that most of the utilities in regions that do not have RTOs, which include most of the southeastern United States and the west and northwestern United States (except for California, which has only one nuclear unit and no coal plants), have been shedding their coal assets as rapidly as possible and replacing their capacity with new gas-fired and solar and wind capacity to increase their investment rate base and return on investment. Most of the existing coal plants are 40 to 60 years old and are largely depreciated, causing cost-based regulated utilities to earn little on their coal plants.

It appears from the list of questions that FERC suggests commenters should address that the DOE proposal took the FERC commissioners completely by surprise.

It also appears that the entire natural gas industry, which the President had sworn to encourage and which have the most to lose from this nuclear and coal subsidy proposal, was also blindsided. It has roundly condemned the proposal.

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"Cheez Doodle tax reform: a lot of puff and color, but mostly air."

There are nine paragraphs of text about how corporate income taxes will be revised. House leaders needed something to show members who were unwilling to vote on the budget resolution without more detail. The framework is a product of compromise: the carefully chosen words suggest where tensions may remain over details.

The corporate income tax rate will be 20%. With the lower rate, tax equity will become a somewhat smaller percentage of the capital stack for US renewable energy projects. Before the rate reduction, tax equity accounted for 40% to 50% of the capital in a typical solar project and 50% to 60% in the typical wind farm. Many tax equity investors have been calculating their investments this year by assuming a reduced tax rate and then planning to have a one-time adjustment in the pricing at the end of 2018.

There will be a separate "maximum tax rate" of 25% on income received from partnerships, S corporations and other pass-through entities. The NFIB, the politically potent trade group for small business, has been pushing hard to set the pass-through rate at the same level as for corporations.

The framework "aims to eliminate" the corporate alternative minimum tax.

The cost of new investments in equipment — not buildings — made after September 27, 2017 could be written off immediately. This policy will remain in place for "at least five years." Permanent full expensing would cost more than $2 trillion over 10 years. House Republican leaders are more keen on this than Trump or the Senate.

Until this year, few tax equity investors had been taking the current "depreciation bonus" that allows half the cost of new equipment to be written off immediately. However, many tax equity investors have been claiming it in 2017 as a way of mitigating the potential effects of a tax rate reduction after 2017. Full expensing would have the effect of eliminating the tax bases of most utilities. Most states */ continued page 5*

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Legal Impediments

There are certain legal requirements that will prevent FERC from issuing any rule consistent with the DOE proposal, even if it were inclined to do so.

Under the Federal Power Act, the authority to modify a utility's or an RTO's rate structure requires a prior determination by FERC that the existing rates are unjust and unreasonable. FERC cannot find that an existing rate is unjust and unreasonable without a hearing. If it determines after hearing that the existing rates are unjust and unreasonable, it would then not only have to explain why the existing rate is unjust and unreasonable, but also explain why the changed rate would then become the just and reasonable rate.

Typically, a cost-of-service rate determination would require the submission of expert testimony covering many disciplines, which would be subject to a hearing, cross-examination and subsequent briefing by the parties to the proceeding. The typical ratemaking issues would include what should be allowed as the investment in rate base, what taxes, depreciation and operating costs should be included, what is an appropriate rate of return, what costs should be classified as generation, transmission or distribution costs, and what percentage of the costs should be allocated to specified customers.

In the case of the DOE proposal, the hearing would likely have to be expanded to consider the relevant components of the proposals, including the reasonableness and scope of the 90-day on-site fuel storage requirement, which specific resources should be eligible for these cost benefits, what energy services each eligible resources should be required to provide, what the impacts will be on electric consumers, and how a new cost-based rate program should be incorporated into a market system based on economic dispatch using competitive bids.

It remains to be seen if the DOE proposal will be seriously promoted by the Trump administration or is merely a political document. If the former, a process far longer than 60 days will be required. ◎

Utility-Scale Solar Trends

Four solar industry veterans had a conversation in late August about the top trends in the US utility-scale solar market during a short webinar organized by Infocast.

The group was Ed Feo, president Coronal Energy, Andy Redinger, managing director and group head of utilities, power and alternative energy at KeyBanc Capital Markets, Rhone Resch, the longtime head of the Solar Energy Industries Association and currently a board member of Sunworks Inc., and Jigar Shah, who is co-founder of Generate Capital and a well-known figure in the industry as one of the founders of SunEdison. The moderator is Keith Martin with Norton Rose Fulbright in Washington.

MR. MARTIN; Ed Feo, what do you think are the top trends and challenges currently in the utility-scale solar market?

MR. FEO: Let me name a few and keep it brief. I am sure the others will come up with even more.

One trend is diversification of the customer base. Use of PURPA, a 1978 federal law, to force utilities to sign power contracts is waning. Voluntary arrangements are on the upswing. We are seeing more purchasers who are not investor-owned utilities — for example, electric cooperatives, community choice aggregators and corporate purchasers, and also emergent financial hedge deals. Then there are all the related issues in terms of how contracts change with the different customers.

Another trend is an increase in utility self-procurement. That seems to be growing.

Another trend is continuing reductions in the cost of solar equipment. There were pretty significant decreases in equipment costs from 2016 into 2017. Whether that will continue depends on the outcome of the Suniva tariff case.

Policy uncertainties remain a challenge, such as the looming phaseout of the federal investment tax credit for solar, the post-PURPA world and how that works and, most significantly, the Suniva tariff case that could have significant consequences if it goes in the wrong direction.

Another trend is the incorporation of storage into solar. It is allowing us to come up with a more useful product and putting us in a position to earn more revenue by providing ancillary services.

Turning to financing, there is a lot of money chasing standard, middle-of-the-fairway stuff. The fun starts when you start to see new customers, shorter tenors, different credit profiles and new financial instruments. It will be interesting to see how the financial world deals with these.

MR. MARTIN: Good list. Andy Redinger, what is left?

MR. REDINGER: In no particular order, there is abundant debt and equity, and the costs of both continue to trend lower. Small-scale utility projects continue to dominate the activity. Lenders like us are beginning to look at providing credit past the expiration of the power purchase agreement. There are a couple things going on there in the solar space that are interesting.

The institutional debt market has been lagging the bank market, but seems to be roaring up to speed. Both institutional lenders and the rating agencies have realized there is a lot of potential business in refinancing bank debt with institutional debt. The rating agencies are becoming more aggressive in how they rate projects.

A challenge is we are having to find a way to deal with unrated offtakers. I have several more, but let me leave some, as I would hate to go last in this group.

MR. MARTIN: Rhone Resch, any trends or challenges to add?

MR. RESCH: All of this has the shadow of the Suniva trade case over it and, until we fully flush that out, these other issues may not be as important because the trade case has the potential significantly to increase the cost of solar modules.

Solar panel demand in China is going to be almost twice as big as people assumed at the beginning of the year, closer to a 45- to 50-gigawatt market, which is putting upward pressure on solar panel prices globally. The uncertainty about whether tariffs will be imposed on imported panels into the United States has already led to upward pressure on panel prices as companies buy up the existing inventory ahead of any tariffs that might be imposed.

Looking a little farther into the future, we continue to see new technology coming to market. This will provide new opportunities for companies to lower costs. An example is use of new panel designs with higher-voltage inverters. Optimizers are now being used in utility-scale solar projects. Trackers have a growing percentage of that market. We now have technology to address PID issues with modules.

Finally, a positive development is the number of companies interested in buying operating assets. We are seeing that across the board. A decent resale market has developed for existing solar projects. That bodes well in the long */ continued page 6*

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piggyback on the federal definition of taxable income. Some states could decouple from the federal tax calculations to avoid punching a hole in state budgets, depending on the degree to which Congress eliminates other deductions or tax credits to broaden the tax base.

Interest deductions by C corporations will be "partially limited." The House tax committee chairman, Kevin Brady (R-Texas), said the plan is to grandfather existing debt and provide exemptions for small business and agriculture. There does not appear to be any effort underway by developers to lock in debt in advance of any vote by the House tax committee later this month. (Under the US constitution, the House must act first on taxes.) Interest may revive in sale-leaseback transactions that allow the financing cost to be deducted as rent.

Tax credits for research and development and low-income housing will be retained. "While the framework envisions repeal of other business credits," the document says, "the committees may decide to retain some other business credits to the extent budgetary limitations allow." The expectation is that Congress will not disturb the current phase-out schedules for wind production tax credits and the solar investment tax credit that were negotiated in 2015, but until the tax committees engage fully, it is hard to know for sure. Changes in how inflation adjustments work are possible. The section of the framework on individual income taxes says it "envisions the use of a more accurate measure of inflation for purposes of indexing the tax brackets and other tax parameters."

US multinational corporations hold more than $2.6 trillion in offshore holding companies. These earnings would be treated as repatriated to the United States, triggering a US income tax at a reduced rate. Earnings held in illiquid assets will be subject to a lower rate than cash and cash equivalents. Payments of the taxes may be spread "over several years."

The US will move closer to a territorial system of not taxing US */ continued page 7*

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run for utility-scale development. The key is to ensure that the electricity prices that we are agreeing today to deliver under long-term power purchase agreements can be delivered, given where module prices may be headed in the next six months.

MR. MARTIN: Back up. You said there is a new technology to address PID. What is it?

Looming import tariffs on solar panels have left US solar developers uncertain at what price they can offer to supply electricity from new projects.

MR. RESCH: It is an issue that we are finding increasingly problematic for some existing projects with lower-quality modules. PID stands for potential induced degradation. It is a process where you see a rapid degradation of modules in the field. When it occurs, there can be a severe decrease in module output.

The good news is we have new technology that can be used to reverse PID where it has set in, but is not yet severe.

MR. MARTIN: Jigar Shah, is there anything left?

MR. SHAH: One thing to add is the utility-scale solar market has a value challenge. Bids have been quite aggressive and, with the upward pressure in module prices, instead of figuring out how to cut costs, companies may do better to find ways to increase value in the asset.

An example is adding battery storage to an existing project.

We have also found companies opting to take advantage of a loophole around section 25D of the US tax code, where they sell individual panels in community solar arrays to homeowners at much higher prices than the infrastructure folks are willing to pay for them. The homeowners claim a 30% residential solar tax credit.

These are just two examples. We have been pretty focused on increasing the value of existing solar projects as opposed to cutting costs.

Suniva

MR. MARTIN: Let's dig more deeply, starting with the Suniva case. How many of you think tariffs will be imposed?

MR. RESCH: I suspect we will see a combination of tariffs and different import quotas for different countries.

MR. REDINGER: Some tariff will be implemented.

MR. SHAH: I think the industry still has the ability to avoid tariffs by advertising on Fox and Friends and Morning Joe. It is crazy that it has come to that.

MR. MARTIN: Ed Feo, as the lone solar developer on the panel, you are the one person who would actually have to pay tariffs if they are imposed. What do you think?

MR. FEO: The trade case is a big deal, but mainly in the near term from a market-disruption perspective.

If tariffs are imposed at a material level, then there is an incentive to move production to the US, which presumably would be the administration's aim. The cost of US manufacture would be higher in the longer term, but not a huge number, at least for efficient manufacturers, which the petitioners are not. US manufactured panels will be more expensive because of labor and regulatory costs, and there will be an adder for effectively constrained competition.

That said, there is no reason to think that US-based manufacturing will engage in any more rational decision making than the panel manufacturers as a whole have shown, so I would expect cut-throat competition to return. When we work through all of that and add in the cost improvements in non-panel costs, the conclusion is that the solar industry in the US will still be fine: the cost curve will take a jump up with the tariff and there will be a time lag before US manufacturing can be re-established, after which costs will trend down. There are currently 29 states with viable solar markets. Maybe the list goes down to 20 to 22. Maybe the growth curve stalls and gets pushed out a couple years.

It is "in the meantime" that is of concern: the period between now and the end of 2018 or even into 2019 for all of this to play out. Developers will need a lot of cash to survive.

MR. MARTIN: How is the threat of tariffs playing out currently in the market?

MR. FEO: There has been the near-term effect on the panel market. All crystalline panels that were available, and arguably have a case for not being subject to tariffs, sold out, and the prices went up pretty dramatically as people looked to cover their 2018 projects.

There was a knock-on effect for thin-film modules. This technology is not subject to the tariff case, so developers turned to suppliers such as First Solar, which promptly sold out its production for 2018. So you now have a real constraint on the market in terms of availability of panels for 2018 projects. And First Solar is signaling it has already allocated its 2019 production.

The second impact has been the difficulty in pricing new long-term contracts to deliver electricity. As a developer, you say to customers, "I can deliver a product to you in 2019, 2020 or 2021 at the following cost," but it is based on assumptions about what the equipment will cost.

The uncertainty has left developers having to strategize about how to mitigate any potential tariffs. How much pain can I take? At what point does the deal basically not make sense? It is hard to find utility and commercial customers who are willing to bear the risk of panel cost increases as a result of the case.

MR. MARTIN: Andy Redinger, how is the risk of tariffs being allocated among market participants?

MR. REDINGER: Banks have a hard time taking any of that risk. In one deal recently where it was an issue, we structured around it by putting all the risk on the developer.

MR. SHAH: For better or for worse, it has been good for our business at Generate. We are willing to take those risks because we have our own module supply, so we have been able to clear deals at 100-basis-point savings from what people thought they were going to have to pay for capital. It has become a way for us to clear the market where we provide construction and tax equity financing, but I get the fact that it is not great for the industry.

MR. MARTIN: Rhone Resch, you said demand for solar panels in China is turning out to be a lot larger than expected. That is leading to upward pressure on prices. The business model for some US solar developers has been to bid a low electricity price to win a power purchase agreement and figure that, by the time the project has to be built, panel prices will have fallen enough to make the power contract economic to perform. Are we now in a period where that business model no longer works and, in fact, developers need to prepare for the reverse?

MR. RESCH: Correct. Since the Suniva petition was filed last April, module prices have increased by 30% to 40%. The trend for the last three years of rapidly declining */ continued page 8*

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companies on their earnings from doing business abroad by exempting dividends from offshore holding companies in which the US taxpayer is at least a 10% shareholder, but it will take other unspecified steps to "protect the US tax base by taxing at a reduced rate and on a global basis the foreign profits of US multinational corporations." There will be rules to "level the playing field between US-headquartered parent companies and foreign-headquartered parent companies."

Agreement on the budget resolution is central to the prospects for the tax bill in the Senate, as it will allow any tax-cut bill to clear the Senate by a simple majority rather than the 60 votes that would be required otherwise. The Republicans hold 52 Senate seats.

One issue with which Republicans are still wrestling is to what extent tax cuts will be allowed to add to the US debt. The debt stands currently at $20.3 trillion. The Senate budget resolution would allow tax cuts to add another $1.5 trillion to the debt, while the House resolution requires any tax bill be revenue neutral.

The politics of any tax-cut bill are complicated. Senator Bob Corker (R-Tennessee) said he will not support any bill that adds to the US debt. The Senate tax committee chairman, Orrin Hatch (R-Utah), said his committee will not be a "rubber stamp" for the framework agreement. Hatch is interested in corporate integration, or the idea that corporate earnings should only be taxed once, perhaps by allowing corporate shareholders a dividends-received deduction that has the effect of reducing the tax rate on dividends. Corporate integration did not get much traction with House Republicans. The framework said the tax committees "may consider methods to reduce" the double tax on corporate earnings. The big six hoped to make up some lost revenue by eliminating the deduction for state and local income taxes. Republicans from blue states with high income taxes are large enough in number to block the tax bill in the House.

Timing is another issue. The president and House Republican leaders insist the bill will be enacted this year. Congress */ continued page 9*

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module prices has reversed. This is leading to a number of PPA cancellations across the country.

Obviously solar panel demand in China can change from one year to the next. It cannot be sustained at current levels, but this year at least, many Chinese solar panel manufacturers have chosen to keep their modules in China. They are not going to run the risk of import tariffs in the United States. They also get better pricing in China. They find the political uncertainty here frustrating. The sales agents for the Chinese panel manufacturers cannot get modules. They think this will remain true for a while.

Any tariff imposed as a result of the Suniva petition will remain in place for a minimum of four years. Different scenarios could play out. For example, the tariff could be declared illegal by the World Trade Organization. Suniva could ask for another four years beyond the initial four.

Chinese companies could end up setting up new panel manufacturing facilities in countries with little or no tariff. They could set them up in the United States or Canada.

PPAs

MR. MARTIN: Ed Feo, your number one trend is diversification of the customer base. Is that another way of saying that it is getting harder to find power contracts?

MR. FEO: Not really. Putting aside the potential effects of the trade case, the cost of solar electricity has been falling steadily to a point where solar electricity is a viable alternative for a variety of customers.

We had a huge wave of utility-scale solar PPAs that was driven principally by PURPA or by big renewable portfolio standards. Now you see a lot smaller entities — not the Southern California Edisons of the world, but pretty small utilities — looking to do solar because it is a good economic and environmental decision.

You start to see PPAs for 10 and 20 megawatts instead of the multi-hundred-megawatt projects. Corporate PPAs fall in the same boat, although some of them are much larger.

Then there is the incipient financial hedge market. We have seen merchant wind projects, with hedges to put a floor under the electricity price, for several years now. This has also been a feature of the gas-fired power market. Solar will be next.

However, a lot of this stuff is on hold until the Suniva case is decided and prices settle down.

MR. MARTIN: Has anyone seen solar revenue puts or other forms of hedges already employed in solar?

MR. SHAH: Deals in New Jersey rely on floating SREC prices for a large part of the revenue. We have been able to get 10-year contracts from hedge providers to lock in the price. The electricity price is not as important because it is something like 3.8¢ a kilowatt hour. For us, not being a truly merchant project is important. We need more predictability to the revenue stream.

Tax Change Risk

MR. MARTIN: Ed Feo mentioned the looming phase out of the investment tax credit in his list of areas where there is uncertainty about government policy. Andy Redinger, what effect is the threat of tax reform having on the market?

MR. REDINGER: In the solar space, not as much as people originally thought, because the principal tax subsidy is an investment tax credit that is taken entirely in year one and has the same value regardless of the corporate tax rate. Changes in tax rates have an effect on the deal model, but they are easily handled through a bit of structuring. Tax change risk has really not affected the market in terms of getting deals done.

MR. MARTIN: The wind tax equity market was down 70% in the first half of 2017 compared to the same period in 2016. Solar was flat during the same period. Solar tax equity was a $3.66 billion market in the first half of 2017 compared to $3.7 billion during the same period in 2016.

Does anyone see the potential for corporate tax reform having an effect on the market currently?

Banks and tax equity investors are having to find ways to finance projects with unrated offtakers.

MR. RESCH: I don't. I do not think the investment tax credit will be targeted in tax reform. We already cut a deal so that the ITC phases out gradually after 2019. The ITC reduces to a permanent level of 10% at the end of the phase-out period. Any corporate tax reduction and other corporate tax reforms are likely to be phased in over a number of years. I think Congress will decide to leave the current phase-out schedule alone.

You could lose the permanent 10%, but I doubt anyone is factoring that into any projects after 2023, which is the deadline for putting projects in service to qualify for a 30% investment tax credit or a partially phased-out credit that is still above 10%.

The Republican supporters of the solar industry that are on the House Ways and Means and Senate Finance committees will make sure that the ITC is protected. They were the primary architects of the current phase-out schedule a couple years ago.

MR. FEO: I think that's right. The reality for 2017 deals is no one is worried about loss of the ITC on projects that are put in service this year. The deal papers address what happens if a corporate rate reduction reduces the value of the depreciation. Depreciation is taken over five years. The rate reduction is either being taken into account in the initial pricing or the developer is protecting the investor from the adverse effects of a corporate rate reduction.

MR. MARTIN: Ed Feo, you referred obliquely to community choice aggregators as a new potential customer. Do you see a rush by CCAs in California to sign long-term power contracts? How much of an opportunity are they?

MR. FEO: I would not call it a rush, but they are definitely signing contracts, and the good news is that they are another customer class. Banks will have to address whether they are creditworthy and evaluate how likely they are to be able to hold on to their customers for the entire PPA term.

MR. MARTIN: The California Public Utilities Commission staff estimates that as much as 85% of the retail load in California will flee the three investor-owned utilities for CCAs and other suppliers by the mid-2020s. CCAs are the default supplier if a customer does not choose another supplier.

The investor-owned utilities are charging exit fees to departing customers to help pay stranded costs. How will exit fees play into financeability of projects, if at all?

MR. FEO: They are two steps removed. The exit fees are paid by the customers. The CCAs are owed for the electricity they deliver at the contract price times the quantity of electricity delivered. They have not been around for very long, so their credit profiles can be difficult to evaluate.

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has only 23 work days remaining after October in the current session and a lot pressing business has already been pushed to year end. The last time, in 1986, that Congress passed a major tax reform bill, the process took 13 months from the first vote in the House tax committee to when the bill became law.

The framework was understandably light on details of "pay fors" to cover the cost of the tax rate reduction. Attention is focused on a bill that Dave Camp, a former House tax committee chairman, introduced in 2014 that was a serious effort to cut tax rates while keeping the books balanced. The bill included more than 200 revenue raisers. A description of the revenue raisers that would have affected the project finance market can be found in "Camp Tax Reform Bill" in the April 2014 *NewsWire*.

US IMPORT TARIFFS on solar panels look more likely after the US International Trade Commission concluded September 22 by a 4-0 vote that US solar panel manufacturers have been injured by increasing solar panel imports.

The commission listened to 10 hours of testimony on October 3 about potential remedies.

It has until November 13 to make recommendations to the president, and the president has another 60 days until January 12 to decide on any relief. Any tariffs would take effect prospectively within 15 days after the decision

The potential tariffs are capped by statute. They cannot increase the cost of imports by more than 50%.

Suniva, a bankrupt solar panel manufacturer headquartered in Georgia that asked last April for import tariffs, asked at the October 3 hearing for a tariff of 25¢ a watt on solar cells and 32¢ a watt of panels and a floor price on panels of 74¢ a watt. Suniva is owned 63% by Chinese company Shunfeng International Clean Energy.

Suniva said the 32¢ tariff it wants on panels is equivalent to 50% of the value of solar panels during the period 2013 through 2015. It is closer to three quarters of the price of panels today.

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Discount Rates

MR. MARTIN: Andy Redinger, you said there is lots of liquidity: debt, tax equity. The cost of money is coming down. You have also said in the past that there is a wall of money chasing contracted projects. What current discount rates are buyers using to bid for operating projects?

MR. REDINGER: Investors are using discount rates that are below 9% for levered equity returns. In some cases, the rates are much lower than that. There is some really aggressive money chasing projects, but the majority of buyers are using levered rates in the 8% to 9% range.

On CCAs, there is a lot of capital out there. I have no doubt that projects holding power contracts with CCAs will find financing. The issue is at what cost. The cost may be prohibitive once the banks understand that the customers can leave whenever they want.

Borrowers may soon be allowed to count two to three years of revenue past the PPA term to calculate advance rates on loans.

MR. MARTIN: Ted Brandt of Marathon Capital says that the winning bidders for utility-scale solar projects currently are bidding at discount rates of 6.5% to 7% unlevered. Do your and his ranges equate or do you just think the rates are higher?

MR. REDINGER: Ted is not wrong. There is some really cheap capital chasing deals.

MR. FEO: Tell me the assumptions, and you will find that two sets of numbers that seem wildly different are not different at all. What has been interesting in the utility-scale solar market to me is how much the valuation is now being driven by an ever-extending life of the asset. A few years ago, people doing deals were assuming a 20-year life. Now the assumed life is usually 35 years or even 40 years

A lot of value is created by the assumptions on power prices in those post-PPA years and the performance levels of the solar project in those years. People are thinking that these assets will be around for a long period of time. The ability to enhance performance of the asset over its life, as Jigar Shah and Rhone Resch mentioned, could have a huge effect on value.

This is not the world of just do your project, finance it, throw it in a drawer and forget about it. You have the opportunity to drive value through four decades.

MR. SHAH: To be clear, I think there is a bubble of sorts. I cannot imagine that the utility-scale assets will be able to command the same PPA price in 40 years. I think we will have an oversupply of power and batteries will be a necessity to help shift the power curve.

MR. MARTIN: Are you taking into account the possible shift to electric vehicles? The Economist magazine reports that some countries in Europe are expected to have banned cars with internal combustion engines by 2040. SSI, an independent research house, predicts that the shift to electric vehicles will lead to a one-third increase in electricity demand in this country.

MR. SHAH: You can have both. If we are adding 15,000 megawatts of solar a year to the grid, that is 150,000 megawatts over 10 years. You are not doing it across all 50 states. You are doing it mostly in 20 states. It is entirely possible to have 50% to 70% of power coming from solar during the day, which means excess solar power during the day.

Deal Flow

MR. MARTIN: Andy Redinger, earlier in the year, lenders were complaining there are not enough deals and there was downward pressure on interest rates. That seems still to be the case, although we have heard lately that some lenders think the deal flow is starting to pick up. What are you seeing in the market?

MR. REDINGER: I would not say the deal flow is starting to pick up. It has been flat all year.

There is so much competition now versus just three or four years ago in this space. Margins continue to be compressed because there is not as much growth in borrowing in the economy at large as the press portrays. A lot of banks are chasing a limited number of solar projects. I don't think margins have been any tighter than they are now since we started in the business.

MR. MARTIN: Ed Feo, to what do you, as a developer, attribute the dearth of projects seeking financing this year?

MR. FEO: If you look at the numbers, 2016 was a pretty robust year. A lot of projects were pulled forward because of the uncertainty around how long the ITC would be available. That uncertainty lasted until the end of 2015. My guess is that this year we are at half to two-thirds of the 2016 activity.

It does not surprise me that, from the perspective of people looking to invest in or finance projects, it looks like there are not a lot of assets compared to 12 months ago. Valuations have been bid up because of the amount of equity chasing construction-ready or operating assets. There is a supply-and-demand imbalance.

MR. MARTIN: That should bring more developers into the business. When do you see the cycle turning around?

MR. FEO: Assuming away the whole issue of the trade case that, I agree with Rhone, is the wild card, 2018 is going to be a so-so year, and then there will be increasing volumes in 2019 through 2021 to take advantage of the higher investment tax credit before it phases out, and the activity will probably tail off at the end of 2021. Then the question will be what product you have to offer. At some point, the combination of solar and storage should start firing pretty hard, perhaps as early as the 2020 to 2021 time frame. The industry should be able to ride that for the rest of the decade.

MR. MARTIN: Andy Redinger, you suggested that with abundant debt and tax equity on offer, the cost of capital is continuing to trend lower. How much lower? Where do you put interest rates today? Where do you put tax equity?

MR. REDINGER: Margins for tier-one developers are in the area of 162.5 to 175 basis points above LIBOR. There are a few deals involving operating projects with some history getting done at around LIBOR plus 150. I don't think tax equity yields have changed much in years. They remain around 8%. Maybe someone else on the panel can speak to that, but they have not changed from where I sit.

MR. MARTIN: Jigar Shah, you are in the tax equity market. Where do you think yields are?

MR. SHAH: The pricing in the tax equity market has remained rather static. Most of the tier-one developers are being offered between 1.25 to 1.3 times the investment tax credits on their projects. Early in the year, tax equity / continued page 12

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SolarWorld, another bankrupt solar panel manufacturer that is based in Oregon, but German owned, joined in the tariff request. Instead of a floor price, SolarWorld asked the commission to limit imports in 2018 to 220 megawatts of cells and 5,700 megawatts of panels. Average annual solar panel imports over the last three years have been 8,600 megawatts, according to SEIA. There were 12,800 megawatts in 2016.

The uncertainty caused by the tariff proceeding has left US solar developers uncertain at what price they can offer to supply electricity from new projects. Solar panel prices have increased roughly 40% since Suniva asked for tariffs last April. Panels are now selling for prices in the low- to mid-40¢-a-watt range, and the panel supply for 2017 and 2018 projects has largely sold out. Skyrocketing demand for panels in China and India has also contributed to the price increases. One analyst predicted a 19,000-MW market in China for solar panels at the start of this year, but is now predicting demand for 48,000 MWs for 2017 and 41,000 MWs in 2018.

The main parties to the tariff proceeding may be exploring a possible settlement. SEIA proposed using section 1102 of the Trade Agreements Act of 1979 to auction import licenses and use the proceeds to help domestic manufacturers. SEIA suggested a fee equivalent to roughly 1¢ a watt on all imported panels would generate enough funds over a three-year period to cover the adjustment expenses of US panel manufacturers. It said another possible source of funds is the countervailing and anti-dumping duties that are being collected on solar panel imports from China and Taiwan.

Suniva and SolarWorld urged President Trump to issue an executive order requiring solar cells and panels used by federal agencies to be made in America. SolarWorld also suggested that the 30% investment tax credit should be extended past the current expiration date for domestically- / continued page 13

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investors were more likely to say they were at capacity, but now that we are farther along, some are coming up short. I am getting calls from investors who have had deals fall through and are falling short of the numbers they hoped to achieve this year.

MR. MARTIN: Andy Redinger, you said that banks are preparing to lend past the term of the PPA and "a couple interesting things are going on there." What are they?

MR. REDINGER: It is an indication of how aggressive lenders are becoming as they try to put money to work. They need loan growth. We and others are starting to look at giving credit for a couple years past the end of the PPA term. We would start to sweep cash a couple years before the end of the term so that the loan would still be paid off within the PPA period.

It helps the developer increase the leverage on a project because more cash flow is taken into account in determining the advance rate on the loan.

That is just an interim step. Eventually, I think we are moving toward giving full credit for revenues two or three years past the PPA term with no sweeps before the end of the loan. It is a function of the aggressiveness of the marketplace.

There is a wave of refinancings we see coming, starting late this year into next year and the year after. These are refinancings of deals that were done in 2009, 2010 and 2011. The tax equity is rolling off. We see strong competition from the institutional market as well as the bank market for this business. In the past, it was just banks that went after this business. Now you have a whole new group of lenders vying for those assets as well, which to me screams more competition and lower pricing.

MR. SHAH: The reset of the market creates value. The market has found the new ultimate owners of the assets. A few years ago, yield cos were thought to be the ultimate owners. Now pension funds, insurance companies and others with access to low-cost capital are stepping in as the permanent equity and debt capital for these assets.

MR. REDINGER: I agree, Jigar. The player that still needs to get up to speed is the rating agencies. They have come a long way in the last year, but a lot of projects will need ratings, and the agencies are getting better at analyzing risks, but they still have a way to go in regard to things like the haircuts to which they subject deals. They are moving in the right direction.

Other Trends

MR. MARTIN: Does anyone see rapid consolidation among utility-scale solar developers. Tom Buttgenbach of 8minutenergy Renewables said earlier in the summer that he thinks we will be down to five utility-scale solar sponsors within a reasonably short period of time.

MR. REDINGER: I doubt it.

MR. RESCH: I don't think five is necessarily the right number, but consolidation is underway and will continue.

MR. SHAH: There is definitely consolidation, but there is an expansion on the other side. For example, look at what the First Wind guys were able to do in terms of raising development capital in New Zealand. They have re-entered the market as a new sponsor. TIAA-CREF has backed four new development platforms. I agree that the traditional players are consolidating into five, but then there are 15 new players that are able to find financial backing.

MR. MARTIN: Ed Feo, you said one of the interesting things about the diversification of the customer base is how power purchase agreements change with different customers. Say more about that.

MR. FEO: The tenor of the contracts is affected. Corporate PPAs have shorter tenors than the 20 to 25 years with which the market was accustomed for utility PPAs. However, the tenors on utility PPAs are also becoming shorter.

The other place we see a difference is the point of interconnection. Sponsors are more likely to have to take basis risk in corporate PPAs. Their power is delivered at a different place than is used for pricing.

MR. MARTIN: We have come to the final minute. Let me sum up what I took away from the conversation. Ed Feo put on his list of new trends diversification of the customer base and a phasing out of PURPA, a 1978 law that requires utilities to buy electricity from independent generators, as a tool to secure utility PPAs. There are more coops, corporate purchasers, community choice aggregators and financial hedges. You just heard him describe how the PPAs change with the change in customer.

Another thing on his list was the uptick in utility self-procurement. Another trend was continued cost reductions in the cost of solar equipment. We have seen a pretty significant decrease in solar panel prices, although the rate of decrease is moderating, if not reversing, due to the threat of import tariffs in the United States and an unexpected doubling of demand this year in China.

He also had on his list two significant policy changes that are potentially in the offing: the Suniva trade case could lead to import tariffs on solar panels and there are potential changes ahead in corporate taxes. We heard that potential tax changes are not having much of an effect this year. However, the potential for tariffs is having a deleterious effect, even ahead of any tariffs actually being imposed. It is nearly impossible to buy panels for 2017 and 2018 projects.

The rating agencies are gearing up for a possible wave of refinancings of bank debt in the institutional market.

We heard another trend is more developers are looking to incorporate storage into their projects. Storage makes the electricity more valuable because the electricity can be shaped to meet customer need and storage injects more revenue into projects through the ability to provide ancillary services to the grid. We heard there is a lot of money available for down-the-middle-of-the-fairway stuff. There is plenty of money, especially for tier-one developers who can show a successful track record.

The shorter PPA tenors, potential uses of new financial instruments and new types of offtakers with less established credit histories are all posing challenges for lenders and tax equity investors, but the dearth of deals is forcing them to figure out a way to deal with each of them.

Andy Redinger had on his list of trends abundant debt and tax equity, putting continued downward pressure on yields. It is a good time to be a developer in terms of access to capital. Small projects dominate. We heard that solar tax equity deal volume in the first half of 2017 was $3.66 billion compared to $3.7 billion during the same period in 2016. In the competition for deals, lenders are looking at giving credit for revenue up to two years past the PPA term as a way of justifying higher advance rates on loans.

The institutional debt market is gearing up. Deals that were financed in 2009, 2010 or 2011 in the bank market might refinance in the institutional debt market. / continued page 14

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made cells and panels. However, this would require Congress to act.

The remedies cannot last for more than four years initially, but can be extended for up to another four years. Any remedy that remains in place longer than a year must phase down after the first year.

Roughly a third of imported solar panels come from countries with whom the US has free trade agreements. The trade commission voted separately on whether increasing imports from each of the free trade countries have contributed to the injury suffered by US panel manufacturers and found such injury only in the case of imports from Mexico and Korea, but not other countries such as Canada, Singapore and Australia. The president will consider these findings, but is not required to exempt such countries from any remedies.

GTM Research calculates that a 30¢ tariff with annual step downs would reduce solar capacity additions by 38% over four years. Suniva suggested that the 32¢ tariff it wants would drop by 1¢ in each of the next three years after 2018. The trade commission and ultimately the president are free to decide on whatever remedy they consider appropriate.

FERC SECTION 203 FILINGS will no longer be required before closing most tax equity partnerships to finance US renewable energy projects.

The Federal Energy Regulatory Commission said in an order on October 4 that section 203 filings are not required in partnership flip transactions where the tax equity investor has a passive interest.

Transfers of equity interests that effect a change in control of a US power plant that is used to sell power in to the wholesale electricity market usually require FERC approval. FERC has up to 180 days to review the sale, but in practice waves the remaining notice period after 30 to 60 days if no interveners object to the transfer.

A group of banks that are frequent tax equity investors in wind and solar / continued page 15

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The rating agencies, Andy Redinger said, are becoming more aggressive in how they rate these projects.

We are also seeing an increase in unrated offtakers. Community choice aggregators in California are an example. Andy said the market will figure out a way to lend to projects with CCA contracts.

Rhone Resch pointed to the Suniva trade case as probably the biggest cloud over the market this year. Solar panels could increase significantly in cost if tariffs are imposed. He thinks there will be a mix of tariffs and import quotas for certain countries. He pointed out that any tariffs would remain in place for four years, although they phase out over that four-year period, unless set aside more quickly by the World Trade Organization.

Solar panel demand in China and India is very hot and is contributing to additional upward pressure on prices. He thinks the demand in those two markets will be much bigger than people thought at the start of the year.

He also pointed out that new technology is coming to market, particularly to deal with sudden degradation in solar panels. He said another positive trend is the intense competition for existing solar assets.

Jigar Shah suggested focusing on how to enhance the value of utility-scale solar projects rather than focusing solely on cutting costs. He looks in deals where operating assets are purchased to try to enhance the value. Adding storage helps, he said. He also pointed out that many people have opted to take advantage of what he called an IRS loophole around section 25D of the US tax code — that's the residential solar credit — to sell individual panels, presumably in community solar arrays, directly to homeowners. ◎

Financing Projects with Virtual PPAs

by Matt Gurch, in Washington

Virtual or synthetic power purchase agreements present unique issues for developers, offtakers and lenders due to their novelty in the market and relative complexity.

A virtual PPA is a power contract under which the electricity generator sells its electricity in the spot market and then exchanges the floating revenue it receives for fixed payments from a corporate offtaker. This is in contrast with a more traditional PPA where there is physical delivery of electricity to the offtaker.

Some market watchers estimate that between five and 10 virtual PPAs are significantly delayed or aborted for every successful transaction. Developers often ask whether any projects with virtual PPAs have been financed. The answer is yes.

Building Blocks

More than half of Fortune 500 companies have sustainability goals to reduce their carbon footprints though increased energy efficiency and use of renewable energy. Many of these companies have high power consumption needs that represent a substantial portion of their operating costs and their operations are often widely dispersed across regional power grids. Their future energy needs are also difficult to predict accurately.

These factors make it difficult for these large corporates to contract with captive renewable energy projects. Moreover, achieving their corporate sustainability goals through energy efficiency and the purchase of renewable energy credits alone is not realistic due to the aggressive scope and tight deadlines often involved.

Securing a long-term, contracted revenue stream is fundamental to the bankability of a project. Historically, long-term power purchase agreements have checked this box. However, developers are finding it increasingly difficult to secure PPAs with utilities and other traditional market players on favorable economic terms.

In the face of these challenges, large corporates and developers are forging a path forward through a relatively new power purchase structure commonly referred to as a synthetic or virtual PPA. Cumulative corporate power offtake agreements with renewable energy projects grew from 600 megawatts in 2009 to 8,000 megawatts in 2016 and the trend (which has been primarily driven by only 23 companies) is expected to continue.

Lenders have been willing to finance projects with virtual PPAs, provided key issues differentiating them from a traditional PPA are adequately addressed in the documentation.

Pricing

Pricing is usually the primary consideration in any PPA.

Virtual PPAs mitigate the cash flow risk and price volatility of merchant spot-market sales: a critical factor in securing commercial financing. Because virtual PPAs are hedges, their pricing mechanisms are considerably more complicated than under a traditional PPA and require the parties involved carefully to consider several resulting risks.

To better understand the risks, it is worth considering how cash flows work under a typical virtual PPA.

Under a virtual PPA, the project owner sells power into the wholesale market and is paid the prevailing market price. At the end of each negotiated settlement period (usually a month), the project owner calculates its aggregate sales proceeds. If this amount exceeds the product of the fixed or "strike" price and the quantity of power specified in the PPA, then the project owner pays the difference to the corporate offtaker. If this amount is less, the corporate offtaker pays the difference to the project owner.

It is worth noting that, unlike energy payments made under traditional PPAs, payments under a virtual PPA are often calculated based on a scheduled notional quantity of electricity instead of actual output.

The floating-price component of virtual PPAs exposes the parties to several market risks.

Project owners trade the potential upside of pure merchant sales for the certainty of a fixed price. Corporate offtakers also often offer better pricing than utilities can afford to offer in crowded local markets where energy prices are relatively low. Corporate offtakers bet that energy prices will continue to rise and that the PPA will remain "in the money" — meaning the floating price that the project owner pays the offtaker will exceed the fixed price that the offtaker pays the project owner over most of the PPA's term.

Getting the strike price right is therefore crucial for the parties to get closer to their respective goals. Striking this balance usually requires substantial involvement by third-party specialized consultants to develop accurate long-term forecasts of the project's wholesale sales market, the corporate / continued page 16

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projects asked FERC for a declaratory order that no such filings are required in standard partnership flip tax equity transactions. In such a transaction, the tax equity investor is a passive partner. The sponsor makes day-to-day decisions about the business. A list of major decisions requires tax equity investor consent. The investor can remove the sponsor as managing member in limited circumstances, like fraud or gross negligence or a managing member bankruptcy.

Market practice to date has been to make section 203 filings.

The new order can be found at 61 FERC ¶61,010.

A NEW BUSINESS MODEL using blockchain to allow consumers to buy electricity directly from generators at wholesale prices is taking hold in several countries.

Grid+ in the United States sold $40 million in GRID tokens in September ahead of a planned "initial coin offering" at the end of October. The pre-sales of tokens were to investors willing to spend at least $50,000 on the venture. Each token entitles the holder to buy up to 500 kilowatt hours of electricity on the company's platform at the wholesale prices that Grid+ will pay upstream generators. Each token is like a software license allowing access to the platform. Once on the platform, customers can buy electricity using cryptocurrencies like Ethereum, BOLT and possibly eventually Bitcoin.

The GRID tokens are expected to sell for $1.15 each in the eventual initial coin offering. Pre-sale participants were given the tokens at discounts of 25¢ to 40¢ from the expected offering price, depending on the dollar amount of tokens purchased. The maximum discount was for investors spending at least $4 million.

The company hopes to have lined up 20,000 customers by the end of 2018 and to have reached 100,000 by the end of 2019 and, by then, to be handling 120,000 MWhs of electricity a month. / continued page 17

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offtaker's projected energy needs and its retail energy costs, and systemic trends affecting energy pricing in general (such as renewable energy penetration, natural gas pricing, anticipated transmission and distribution upgrades, and planned energy capacity additions and retirements).

Due to the need for price transparency and the accuracy of deep, liquid spot markets, most virtual PPAs are signed with projects selling into deregulated markets, such as the Electric Reliability Council of Texas (ERCOT), PJM Interconnection (PJM), the New England Power Pool (NEPOOL) and the New York Independent System Operator (NYISO).

Price Risk

Project owners try to mitigate market price risk though the inclusion of price escalation provisions.

Traditional PPAs rarely include index-based price escalation provisions due to the complexity and uncertainty of projecting power market trends. However, price escalation is a much-negotiated issue with virtual PPAs.

Project owners often prevail in these debates, as the shorter term of most virtual PPAs (ranging from 10 to 15 years) makes price escalation more palatable for offtakers not locked into a 20-year commitment. Also, even in longer-term virtual PPAs, the escalation provisions only apply to the first three to five years of the contract term.

Negotiated trade-offs between tenor and escalation should be expected.

Corporate purchasers also try to mitigate market price risk though the careful identification and selection of projects that complement their operating facilities and projected energy needs.

A well-structured virtual PPA can help a corporation not only to fulfill its sustainability mandates, but also to hedge its overall energy costs. If a company's retail energy costs either decline compared to, or rise in parallel with, the project's wholesale sale prices, the net effect can be a smaller overall power bill.

Achieving this correlation requires careful consideration of a company's present and future operations, the project's local power market and regulatory regime and potential changes of law affecting a project owner. Such analysis could, for example, reveal that it actually makes better economic sense for a California tech company, with power-hungry server sites located across Nevada and Florida, to pass on a West Texas wind farm offering attractive initial pricing if the company as a whole has a better long-term correlation with a Pennsylvania solar project selling into the PJM market.

Parties to virtual PPAs, particularly corporate offtakers, must also remain vigilant about negative price risk.

If a virtual PPA provides that the corporate purchaser is unconditionally obligated to pay the absolute difference between real-time market rates and the fixed price, it might be obligated to cover a hefty, unexpected settlement payment to the project owner.

Recent market trends in two popular renewable power markets are reminders of the need for caution. The renewable portfolio standard in California contributed to an upsurge in mid-day solar energy supply that, in turn, has increased both the frequency and severity of negative pricing in the real-time market. In West Texas, home of the largest installed wind capacity in the US, the fact that wind production is generally strongest at night when demand slackens has also resulted in numerous negative pricing events over the last decade.

This is a more salient issue for wind farms relying on federal production tax credits because, unlike solar assets claiming federal investment tax credits, wind project owners are incentivized to continue generating despite negative pricing so as to not lose the value of the tax credits.

To address this risk for corporate offtakers active in wind power, some virtual PPAs provide that the corporate offtaker's payment obligation is subject to

More than 8,000 megawatts of synthetic or virtual power contracts were signed in the US through 2016.

a price floor that is tied to the negative pre-tax production tax credit value. This approach attempts to preserve the project owner's economic interest in the tax credit while mitigating the risk of over production in a negative price market.

In the case of solar projects, parties to virtual PPAs sometimes reach an agreement either to cap the corporate offtaker's total payment obligation during periods of negative pricing (measured on a monthly or annual basis) or the parties set a negative price floor beyond which the offtaker is not obligated to pay the project owner.

Basis Risk

Basis or locational risk is the possibility that there is a mismatch between the market energy price realized at a project's actual delivery point (its bus bar) and the prevailing price at the agreed-upon trading point (which may be a regional hub or another node close to the project bus bar) specified in the virtual PPA.

Corporate offtakers and lenders tend to prefer to index the floating price component of the hedge settlement price at liquid, high-volume regional hubs. While this may ease the burden of analyzing historical and projected pricing trends, it also creates the risk that the revenue counted for purposes of calculating settlement payments does not correspond to reality.

In order to share this risk and structure a bankable project, some virtual PPAs provide for pricing adjustments (on a fixed or floating basis) or caps to limit the potential basis risk. Alternatively, some project owners (whether on their own initiative or as required by lenders) enter into ancillary agreements with third parties to hedge the basis risk.

Regardless of where the price is indexed, one standard practice is to count energy price at the time of delivery instead of looking to the actual price realized. This shifts the risk of sub-optimal scheduling failure and delays to the project owner.

Term

When it comes to securing long-term financing, traditional PPAs benefit from their long terms — usually 15 to 20 or more years. Virtual PPAs often have a significantly shorter duration than the underlying financing. This may be attributable to the relative novelty of virtual PPAs, as corporate purchasers have only recently gotten comfortable with making long-term commitments to match their ever evolving, unpredictable energy needs.

An unhedged merchant tail creates significant financing challenges. It could impose pressure to increase / *continued page 18*

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Traditional electricity suppliers allow their customers to buy on a credit basis. The customers pay at the end of the month for the electricity they use. Electricity purchased through Grid+ would be paid for as the electricity is delivered.

Customers with rooftop solar panels could sell excess electricity back to the market via Grid+.

An Australian start up, Power Ledger, raised A$17 million (US$13.5 million) in September in token pre-sales using a similar business model. The company's POWR tokens act the same way as the GRID tokens offered by Grid+, and are convertible into Sparkz tokens that will be used actually to purchase electricity or into cash. Power Ledger will pay electricity generators in Sparkz tokens.

Jason Lewis, a Norton Rose Fulbright lawyer who specializes in power trading, said the Power Ledger platform is flexible enough to permit trading by individual users or groups of users. "For example, a building, a club, a community solar farm, or a micro-grid could transact as a group," Lewis said. The company hopes to be operational in 2018.

Power Ledger is partnering with several electricity distribution companies in Australia and New Zealand in the meantime to run trials of the platform.

Lewis said a wide range of other organizations worldwide are testing similar business models. "SunContract, a Slovenian company, made a similar token offering recently for a blockchain-based energy trading platform," he said. The Australian government investigated the use of peer-to-peer networks for the trading of renewable energy, and partially funded a trial of such technology by AGL Energy, a large energy company in Australia. A demonstration project has been underway in Brooklyn, New York since 2016 to run a community micro-grid that will allow excess electricity from rooftop solar systems in the neighborhood to be sold to local residents via a distributed ledger.

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the level of scheduled debt amortization beyond what the project can sustain or lead to a balloon payment and the attendant refinancing risk.

As the market for virtual PPAs continues to mature, project owners will probably continue to push for longer terms in order to support longer debt tenors and corporate counterparties may prove more accommodating as they become more comfortable with virtual PPAs in general.

In the meantime, to address this issue, some projects are structured with multiple offtake contracts. For example, if the project economics require a 15-year debt tenor, the project owner may enter into a pure financial swap with a hedge bank covering the first five years and a virtual PPA with a corporate counterparty covering the final 10-year debt period. However, this solution is imperfect as it raises significant collateral and intercreditor issues.

Security and Intercreditor Matters

Unlike traditional PPAs, most corporate counterparties to virtual PPAs require not only liquid performance security, but also a security interest in the collateral. This causes friction with project lenders, as they are accustomed to having an exclusive, first-priority security interest in project assets.

Lenders, project owners and corporate offtakers sometimes compromise by giving the offtaker a second-priority security interest over all project assets and a first-priority lien over either a specified subset of project assets or, more frequently, a capped first-priority lien over collateral shared with lenders. If there are different offtakers under multiple virtual PPAs, which is more common in long-term financings, the second lienholders must negotiate their respective voting and other rights over the shared second lien. If the terms of these virtual PPAs do not overlap, then the purchaser under the first PPA to take effect can be granted an exclusive second-priority security interest and the purchaser under the second PPA to take effect gets an exclusive third-priority lien. Upon the termination of the first PPA's term, the second PPA automatically steps up to the second-priority position.

Corporate offtakers can also get comfortable with a subordinated security interest by ensuring that they have a payment priority in the project's operating cash waterfall that is superior to debt service — often by insisting that regular settlement payments under the virtual PPA are paid at the same level as operation and maintenance expenses.

Corporate counterparties typically also have lower credit quality compared to traditional utilities and, due to their variable future energy needs, there is less confidence that corporate counterparties will remain incentivized to perform a long-term contract fully. Lenders and project owners will therefore often require both substantially more performance security from corporate purchasers and limit the form of acceptable security to liquid letters of credit or cash reserves.

Other issues distinguishing virtual PPAs from traditional PPAs also warrant the careful attention of developers and corporate counterparties. They are beyond the scope of this article, and include differences in accounting treatment, regulatory and tax risks and energy management issues. ◎

Nuts and Bolts of Financing Storage

by Keith Martin and Brian Greene, in Washington

The next big challenge for energy storage, after bringing down the cost so that storage is economic and finding a suitable business model, is financing.

There are two ways to look at project finance.

One is that borrowing a large amount of money to build a project requires locking down costs and locking in a revenue stream so that the bank can determine how much money the sponsor will have to pay debt service. Traditional project finance involves borrowing to build a project on a "nonrecourse" basis: the lender looks to the project company that owns the project rather than the ultimate owners for repayment. Therefore, it is keenly interested in the certainty of the revenue stream and the predictability of costs. It focuses on the net amount the project company will have to pay debt service after covering costs. This allows it to calculate a debt-service-coverage ratio. That, in turn, determines how much can be borrowed. For example, if the lender requires a debt-service-coverage ratio of 1.4x, then the net revenue stream each payment period must be at least 1.4 times the required interest and principal payments on the debt.

Another way to think about project finance is it is an exercise in risk allocation. Nothing gets financed until all the risks have been identified and allocated among the parties to the transaction. A rule of thumb in the project finance market is the party that best understands the risk is the one that takes it. For example, if an asset must not be in service before the tax equity investor funds, the sponsor takes the risk because it is in the best position to know when the asset was put in service.

The first challenge with storage projects is to find a fixed revenue stream.

Business Models

There are four basic business models currently for utility-scale standalone storage facilities in the United States.

One is a regulation service model. For example, a 20-megawatt battery might be connected to the grid in PJM by an independent storage company to participate in the ancillary services market. The storage company bids into the market each hour indicating it is willing to accept or deliver up to 20 megawatts of electricity that hour. The market sets the price for the regulation services by auction. Say the price is $25 a megawatt that hour. On average over the hour, the storage facility will never be near the limit. In practice, what happens is the grid might shed power to the battery for three minutes, then draw back for two minutes, then shed for 30 seconds, and so on.

The grid pays the owner of the storage facility $25 times 20 megawatts for the right to control the battery that hour.

The actual energy charged to or discharged from the battery is netted, and the battery owner or the grid also makes a payment at the end of the hour for the net electricity used that hour at the wholesale market rate for that hour. In practice, the battery owner expects to make net payments over time to the grid as power is lost during conversion from AC to DC for storage and back to AC as the electricity is returned to the grid.

Standalone batteries using this model are most common in organized electricity markets: PJM, ISO New England, New York ISO, MISO, CAISO and ERCOT.

The Federal Energy Regulatory Commission issued two orders to encourage storage. FERC Order 755 in 2011 is an attempt to create a level playing field in organized markets, like PJM, by allowing storage to compete to provide ancillary services on the same terms as power plants. FERC Order 819 in 2015 addresses storage in other parts of the country where there is no independent system operator or regional transmission organization managing the statewide or regional */ continued page 20*

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In an interesting variation on the same theme, MyBit held a token offering for a platform that pools small investors who want to invest in large projects as a form of crowdfunding for renewable energy projects. (For earlier coverage about crowdfunding in the energy sector in the United States, see "Crowdfunding: A Good Way to Raise Capital?" in the February 2015 *NewsWire*.)

MARYLAND OFFSHORE WIND projects could be imperiled by a provision that Rep. Andy Harris (R-Maryland) added to a House appropriations bill.

The provision would bar the US Department of Interior from spending money to review site assessments and other plans for wind farms with any turbines less than 24 nautical miles off the Maryland coast. Harris represents the Maryland eastern shore.

The bill passed the House in mid-September. It must also pass the Senate to become law.

Congress has had a poor record of passing appropriations bills for federal agencies in recent years and usually ends up folding all spending authority into an omnibus "continuing resolution" at year end authorizing agencies to continue spending at the same level as the year before.

Maryland has signed contracts with two offshore wind farms.

The American Petroleum Institute and the US Chamber of Commerce have joined wind groups in opposing the ban.

PENNSYLVANIA took a step back in early October from imposing a new tax on virtual electricity trades across the PJM grid.

The tax had the potential to affect electricity trades as far west as Illinois and Michigan. It was stripped from a budget bill by the house rules committee.

Pennsylvania is trying to close a $2.2 billion hole in the state budget.

The proposed tax already cleared the state senate. */ continued page 21*

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grid. It allows individual utilities in those areas to negotiate terms with standalone storage units without having to get prior approval for the rates from FERC. The parties merely have to let FERC know the terms on which they agreed.

Another standalone model is a tolling agreement. In the typical tolling agreement used in the power sector, the owner of gas pays a power plant a fee to convert the gas into electricity, and the gas owner takes back the electricity. In the storage market, a utility owning electricity might pay a battery owner a fee to store the electricity, and then the utility takes back the electricity. The battery owner might be paid a fixed fee per hour, like a capacity payment or reservation charge. It might be paid a fee based on the quantity of electricity stored each hour, like an energy payment. Or it might be paid a combination of the two.

There are not a lot of tolling arrangements. They are more likely to be found in deregulated markets, like California, where utilities have had to divest all their generating assets and are merely wires companies. The Southland project in southern California is an example of this model. The project was financed in late June. It involves a 100-megawatt battery in California and a 10-megawatt battery in Arizona as adjuncts to two combined-cycle gas-fired power projects with a combined capacity of 1,284 megawatts. Southern California Edison has a tolling agreement with the project company that owns the 100-megawatt battery where the project company receives a large capacity payment, in addition to a smaller variable operations and maintenance payment. Southern California Edison is responsible for supplying and paying for the energy to be charged, and has the right to charge or discharge the battery at its discretion.

Another standalone model is a buy-sell model. The battery owner buys electricity during off-peak periods when the electricity is cheap and then sells it back to the grid during peak hours.

This model is not widely used. Its main use is on a demonstration basis. The model is not considered economic currently, but it could become economic in the future as batteries and other storage technologies become more efficient. The model involves time-based arbitrage.

The last basic standalone model for utility-scale storage is where a battery is added to a wind, solar or other power plant. The battery controls the ramp rate at which the electricity is fed into the grid and puts the project in a position to earn additional revenue for ancillary services to the grid.

A battery might be added to an older fossil fuel power plant in order to give the plant the ability to respond more quickly to instructions from the grid to ramp up or down instead of having to do an expensive rebuild of the plant to comply with new, tighter response times the grid imposes on power plants that are interconnected with it.

There is also a distributed behind-the-meter model in the rooftop solar market where a large number of batteries are combined to offer storage capacity to the local utility. The solar company receives capacity and energy payments. The batteries can also provide demand services to host customers, by discharging to the customer when the customer's onsite load will peak. Host customers pay a monthly fee for this service. The battery owner must ensure that the battery is available when called by the utility, or the battery owner will be subject to penalties. (For further discussion about business models, see "Emerging Storage Business Models" in the April 2017 *NewsWire*.)

The challenge for storage is the only revenue that banks will credit in deciding how much to lend is a fixed capacity payment that is locked in for a specific contract term. Merchant power plants that sell electricity into the spot market can be financed, but only with a hedge that sets a floor under the electricity price. Storage needs the equivalent of such a hedge.

CIT financed 50 megawatts of distributed behind-the-meter batteries earlier this year. It lent for the term of a contract under which Southern California Edison made capacity payments for use of the capacity.

Risks

Most of the risks in energy storage projects are not dissimilar from any other project financing. Lenders focus first on anything that might interrupt the revenue stream. They confirm that the ability to use the site is secure and that the project has all the permits required to operate. They analyze the counterparty credit on the contract that is the source of revenue to pay debt service.

The market is not settled as to whether lenders will require a fully-wrapped engineering, procurement and construction contract for most energy storage systems, or whether deals will

Four basic business models are being used currently for utility-scale standalone storage facilities.

typically be financed with separate battery supply and construction contracts. The Southland project did not have a fully-wrapped engineering, procurement and construction contract.

However, there are also regulatory, technology and operating risks that are unique to storage. The Federal Energy Regulatory Commission and regional transmission organizations are struggling with whether to classify storage as generation, transmission or a hybrid. Projects are more likely to be financed the clearer the regulatory framework.

Most lenders consider lithium-ion technology bankable and require an extended warranty from a supplier with a strong credit rating. A 10-year warranty appears to be standard for lithium-ion technologies. Lenders are less comfortable with other emerging technologies and may not be ready to lend against them without an additional performance guarantee.

The role of the asset manager is extremely important. The asset manager optimizes dispatch. Lenders will insist on an asset manager with a good track record, although this is difficult in the short term given the nascent nature of the industry. (For more analysis of risks, see "Financing Energy Storage Projects: Assessing Risks" in the June 2017 *NewsWire*.)

Financing

Turning to forms of financing, there are various sources of capital. The chief financial officer at a storage company would normally stack capital from cheapest to most expensive until he or she covers the full cost of the storage facility.

Government grants or subsidized debt are likely to be the cheapest. Export credit agencies may be willing to offer subsidized debt for imported storage units. If the project qualifies for federal tax credits, then it might be best to / continued page 22

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It is a 5% tax on the "gross transaction amount" of three types of electricity hedges transacted in PJM. PJM would collect it from the person initiating the trade. It would be collected at financial settlement. (For more details, see "Pennsylvania Virtual Transactions Tax" in the August 2017 *NewsWire*.)

A CHINESE ACQUISITION of a US company was blocked in September.

President Trump issued an executive order on September 13 barring a proposed acquisition of Lattice Semiconductor Corporation by a Chinese-owned US investment vehicle called Canyon Bridge Merger Sub., Inc. The ultimate parent of the buyer is China Venture Capital Fund Corporation Limited.

CFIUS had recommended blocking the deal on national security grounds. CFIUS — short for the Committee on Foreign Investment in the United States — is an interagency committee of 16 federal agencies, headed by the Treasury Department, that reviews potential foreign investments in US companies.

Lattice and Canyon Bridge reportedly withdrew and refiled their notices of the deal to CFIUS as many as three times in an unsuccessful effort to try to address the national security issues.

This is only the fourth time a president has blocked an acquisition in the 27 years since CFIUS was established.

President Obama blocked a proposed Chinese acquisition of another US semiconductor firm, Aixtron, Inc., in December 2016, and he ordered Chinese-backed Ralls Corporation in September 2012 to divest itself of the rights to four wind farms that Ralls bought from Greek company Terna Energy. At least one of the four projects was near a US Navy base that trains pilots of drone aircraft. (For more details about the Ralls case, see "CFIUS" in the December 2013 and November 2015 *NewsWires*.)

Meanwhile, CFIUS reported to Congress in late September on its actions during 2015.

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focus in the first instance on how to get value for them and then build the rest of the capital stack around tax equity.

There are three main tax equity structures. A sale-leaseback is the simplest. The storage facility is sold to a bank leasing company and leased back. This raises the full cost of the storage facility in theory, but the developer must usually prepay 15% to 20% of the rent. A sale-leaseback and be arranged up to three months after the storage unit is put in service. If the storage company wants to keep the storage facility after the lease ends, it must buy it back form the lessor.

Partnership flip transactions are more complicated structures. A tax equity investor owns the storage project in a partnership with the developer and is allocated 99% of the tax benefits and a share of the cash until a flip date anywhere from five to nine years out. The investor is allocated 5% of the economics after the flip. The developer has a "call" option to buy the remaining interest of the tax equity investor after the flip. Partnership flips raise 40% to 50% of the capital cost of a typical solar project, and 50% to 60% of the capital cost of a typical wind farm. The tax equity investor must be in the partnership before the project is placed in service.

An inverted lease is the third tax equity structure. There are two tax benefits for which a storage project qualifies potentially: a tax credit worth 30¢ per dollar of capital cost and depreciation worth 26¢. The developer keeps the depreciation and transfers the tax credit to an investor. The attraction of an inverted lease is that the tax credit can be calculated on the fair market value of the assets rather than their cost to construct, and the developer gets the assets back at the end of the lease without having to pay anything for them. An inverted leased raises the least amount of capital, in part because the tax benefits are bifurcated: the developer keeps the depreciation. The inverted lease must be in place before the assets are put in service.

The tax equity investor usually insists on being ahead of any debt in the capital structure. The rest of the capital stack is usually back-levered debt and true equity. (For more detail about tax equity structures and issues, see "Solar Tax Equity Structures" in the September 2015 *NewsWire*.)

Tax Credits

Batteries qualify for a 30% investment tax credit at the federal level if they are considered part of the generating equipment at a solar project.

The battery should be on the project side of the step-up transformer or customer side of the inverter. It should be owned by the same legal entity that owns the solar project. It should be physically adjacent. It should work like a knob on a motor in the sense that its primary use is to regulate the ramp rate at which the solar electricity is fed into the grid. A battery at a wind farm also qualifies, but only if an investment tax credit, rather than production tax credits, will be claimed on the wind farm.

The Internal Revenue Service issued two private letter rulings confirming that batteries added to large wind farms qualify. In both cases, the projects received Treasury cash grants under section 1603 of the Obama economic stimulus program rather than claimed production tax credits.

The IRS confirmed in a separate private ruling issued to a solar company that an investment tax credit can be claimed on batteries installed as part of rooftop solar systems, but because the solar company was unable to represent that the batteries would be used primarily to store solar electricity from the rooftop systems, the IRS said a "75% cliff" would apply. At least 75% of the electricity used to charge the battery must come the first year from the solar rooftop system and whatever percentage solar charge there is the first year is the percentage of tax credit that can be claimed. For example, if the solar charge is 80%, then the tax credit is 80% x 30% = 24%. If the percentage of solar charge in any of the next four years drops below the benchmark set the first year, then all or part of the unvested investment tax credit will have to be repaid to the US Treasury. The tax credit vests ratably over five years. (For more details about the rules in this area, see "Batteries and Tax Credits" in the October 2016 *NewsWire*.)

The IRS is rewriting its regulations on when investment tax credits can be claimed. The issues are complicated and could take well into 2018 to resolve.

Solar projects must be under construction by December 2019 and in service by December 2023 to qualify for tax credits at the full 30% rate. A lower percentage tax credit may be claimed on projects that start construction in 2020 and 2021. A storage coalition has been pressing Congress to allow tax credits on standalone storage. The proposal faces an uphill climb.

A tax reform framework released by Republican leaders in Congress and the Trump administration in late September suggests Congress will allow companies to write off — or depreciate — the full cost of investments in new equipment immediately for investments made after September 27, 2017. It said this policy will remain in place for at least five years.

Another tax issue in play in Washington is the cost of interconnecting large batteries to the grid. The IRS said in June 2016 that utilities should not have to pay taxes on interconnection payments from storage projects, but there is an unresolved technical issue. (For earlier coverage, see "IRS Updates Tax Treatment of Interconnection Payments" in the August 2016 *NewsWire*.)

Independent generators and storage owners connecting their projects to the grid must reimburse the utility for the cost of any upgrades to a utility substation or the grid to accommodate the project. The utility will charge a tax "gross up" if it must report the reimbursement as income. It does not have to report the reimbursement as income as long as, among other things, no more than 5% of the expected total power flows in both directions over the intertie will be power flowing back to the generator or storage owner. This was intended to identify situations where an independent generator is a customer of the utility. Payments that utilities receive from customers must be reported by utilities as income. The test obviously does not work for standalone storage or an independent generator that has added storage. The IRS is working on updating the 2016 notice.

Energy Storage: Unique PPA Considerations

by Caileen Kateri Gamache, in Washington

Developers are focusing on what terms to put in new offtake agreements for energy storage facilities.

Many in the industry are starting with pro forma power purchase agreements designed to sell output from conventional or renewable power plants. While several provisions of these PPAs are appropriate for "plug-and-play" use in storage contracts, there are issues unique to energy storage that warrant special consideration. This article discusses 10 issues that deserve careful analysis when drafting offtake contracts for energy storage facilities.

Defining the Product

Energy storage is exciting technology because it can perform multiple functions essential to the US electric system. It can operate as a generation resource, as energy load or a "sink," and as a transmission and distribution asset. */ continued page 24*

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Foreign companies submitted 143 proposed acquisitions of US companies to it for review.

Close to half (66) went into an investigation phase. CFIUS required mitigation measures in 11. Thirteen proposed deals were withdrawn. Nine of these were resubmitted with revised terms. Three transactions were permanently withdrawn because the parties could not come up with mitigation measures to address the national security concerns. One was withdrawn for commercial reasons.

CFIUS rejected one notice because the US government had information that suggested the filing was inaccurate. The parties did not resubmit the transaction for review.

Looking over a broader period of 2009 through 2015, there has been a general increase in number of filings, but CFIUS said this appears due to macroeconomic reasons rather than any other discernible trend. Over the entire period, 40% of filings moved into an investigation phase and 7% of proposed deals were withdrawn.

Submission of proposed deals is voluntary. However, the committee has authority to set aside transactions after the fact that were not submitted for review.

Review takes 30 days. Transactions that raise potential issues then move into an investigation phase that takes another 45 days.

The report lists as potential areas of concern investments in US companies that have access to classified or sensitive US government information and acquisitions by foreign companies that are controlled by a foreign government, especially where the foreign country has a poor record on nuclear non-proliferation or other national security matters or the country has a coordinated strategy of trying to acquire critical US technologies. Concerns are also present in acquisitions of projects with offtake contracts with federal, state or local government agencies that have functions related to national security, and projects that "involve various aspects of energy production, including extraction, generation, transmission, and distribution" or that are */ continued page 25*

Storage PPAs

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As a consequence, many PPAs for more traditional generating facilities do not work properly given the intended use of a storage unit or else they lack flexibility to accommodate multiple uses. It is of paramount importance for the parties to a PPA to understand all the ways in which the storage system will be used. The rights to various services and products from the system must be allocated and appropriate compensation determined. Each service or product that will transfer under the PPA should be clearly defined. Similarly, services and functions that the seller will retain should also be clearly documented to avoid confusion (and litigation).

There are several energy storage models, each requiring different approaches to product definitions and performance parameters.

The most prevalent model appears to be storage combined with a solar project, where the two are treated as a single system. Therefore, the power contract covers both.

There is a natural synergy. The storage system, which is typically comprised of batteries, can charge from the solar system and then provide back-up electricity at times of no or low sunlight. The popularity of behind-the-meter solar systems located on the premises of net-metered host customers has also driven adoption of co-located storage systems. Under this model, the storage system is generally treated by the host customer as simply a part of the overall generating unit, and the pricing terms of the PPA are generally set at a per-megawatt-hour basis, regardless of whether electricity is coming from the solar panels or the storage unit. In other words, nothing extra is charged for storage.

Larger solar-plus-storage systems may specify rights to additional products from the system, such as renewable energy credits or certain ancillary services, but these are also generally treated as stemming from one integrated source, with solar playing the leading lady. In contrast, the Kauai project that Tesla developed in Hawaii reportedly relies on a PPA with a local cooperative for sales in the evening hours from batteries discharging energy captured from a co-located solar project during the day. The grid is too saturated during the day to be able to accept any of the solar energy.

We are beginning to see a rise in co-located storage plus other resource units where the generating facility and storage are treated like two separate projects. The products from the storage system in these instances may be measured and paid for separately from energy sales. Anyone drafting a PPA for this type of system must consider the extent to which the co-located systems should be treated separately or as one and what each party's attendant rights and obligations are with respect to each system.

Aggregated behind-the-meter storage is another growth area. Storage can respond to grid needs relatively rapidly by charging to store excess energy or discharging to supply electricity. Certain markets permit companies to offer capacity from aggregated energy storage systems placed behind customer meters. The aggregated storage capacity is offered to the local utility. In such cases, the product is responsiveness rather than energy sales.

Another model is a stand-alone storage facility selling energy, capacity and ancillary services to the grid. Absent particularly lucrative products or government mandates, it remains difficult to bring stand-alone utility-scale storage to market under a PPA structure.

Small stand-alone storage systems such as Tesla's "powerwall" are often purchased or leased outright without a PPA. The success of larger systems typically depends on a market for products other than electricity because storage is not yet economically competitive with other forms of pure generation. For example, flywheel storage units were built in both the New York ISO and PJM markets based on the value they were paid for providing regulation ancillary services in each market. Certain states also have policies that incentivize or require storage

Adding storage to a solar or wind project requires means the power contract must address another 10 issues.

deployment. In California, for example, regulators ordered utilities to achieve a minimum amount of utility-scale battery storage capacity. Some corporate customers have expressed an appetite for storage that may result in above-market PPA prices. As with lucrative markets or governmental directives, this would require special circumstances.

Setting the Term

There are mixed approaches to setting the term for energy storage PPAs.

Some forms of energy storage are considered to have a longer useful life than the related generating source. In a battery system, for example, individual batteries can often simply be replaced and the unit will carry on. This is marketed as a benefit that has value and may warrant a longer term than PPAs for other generating sources.

On the other hand, most energy storage resources are "unproven" technology, in that there has not yet been operating experience over the full life of a system and there are risks of the unknown. This may cause parties to look at shorter terms (and lenders to seek shorter financing terms), with the option to renegotiate as the technology advances and more data on operations can be collected.

Establishing the delivery term is more complicated if the storage system is co-located with other generating resources. The storage unit will often be ready to come on line much sooner than other resources and, as already mentioned, may have a significantly different useful life. A PPA for a combined unit may require separate delivery terms for various products and services depending on which resource will be the predominant provider.

Performance Guarantees

The parties should determine whether the storage system will be expected to perform at a certain rate and, if so, what the penalty is for non-performance.

A seller may want to look to warranties to determine whether it has any recourse if the storage unit does not perform as anticipated. Because the technology is relatively new, it may be more challenging to guarantee performance as confidently as a seller may with another resource.

The seller should also understand how performance may be affected over time. For example, a battery storage system will typically degrade by some percentage each year until or unless the batteries are replaced. Certain factors */ continued page 26*

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near US military bases or other sensitive US government facilities.

The committee makes recommendations. The president has ultimate authority to block a transaction. Presidential action to block a transaction is rare.

Most transactions that raise problems are voluntarily withdrawn. Many are later resubmitted on revised terms. In some cases, transactions are approved after the acquirer agrees to mitigation measures.

CFIUS reports annually to Congress.

In 2015, 15% of proposed acquisitions brought to the attention of CFIUS were in the "mining, utilities and construction" sectors. The majority (11 of 21) involved electric power, transmission or distribution.

Filings in 2015 were concentrated among buyers from the following countries: China (29), Canada (22), the United Kingdom (19), Japan (12), France (8), Cayman Islands (8), Holland (5) and Australia (4). The few filings by buyers in the Middle East were from Saudi Arabia (1), Turkey (2) and the United Arab Emirates (1).

Most of the power industry transactions involved buyers from China and Canada.

SOLAR outpaced other forms of electricity in the United States for the first time in 2016 in terms of new capacity additions.

It accounted for 38% of all new capacity additions in 2016, more than any other power source, according to a National Renewable Energy Laboratory report called "Utility-Scale Solar 2016" released in September. Focusing on new capacity additions, utility-scale solar was 2.5 times the volume of distributed solar in terms of market size.

Installed costs continue to fall. The average installed cost was \$2.20 a watt AC (or \$1.70 a watt DC) for projects completed in 2016. The least expensive 20% of projects in terms of cost were below \$2.00 a watt AC, with the bottom of the range at \$1.50 a watt */ continued page 27*

Storage PPAs

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may accelerate degradation, and it may be prudent to pre-assign liability if any of these factors occurs. The parties to a PPA will need to account for natural degradation in negotiating any performance guarantees, as well as the overall term of the PPA. Consideration should also be given to how the reduced performance of the storage unit may affect or correlate to the performance of any co-located generating resources.

Allocating Control Rights

Closely related to product and performance is determining who will have the authority to control the storage system.

Some offtakers intend actively to use storage systems rather than passively to purchase project output. For example, the buyer may want to deploy the system to reduce energy costs during peak hours or use it as a demand-response resource. The offtaker might also want to use the system to meet load obligations or to balance a distribution system that it operates.

The practicalities of which party will control the system, whether control will be on-site or remote, and what authority the other parties to the PPA have to step in are all key to this analysis. Secondary issues of access, liability, maintenance, and compliance with permits and other regulatory obligations should also be thought through. It may be that control rights change depending on the year of the term, the season, or even the time of day.

To tie back to the discussion of product, there is also the question of how the right to control the energy storage system is compensated, if at all.

Manufacturer's Requirements

Building on the concept of performance requirements and control is the need to comply with the manufacturer's operating requirements for the storage system.

Some operating requirements are unique to storage. For example, most battery storage systems require a certain amount of "cycling" (charging and discharging) each day. The party controlling the unit will need to control the facility within these parameters. The other party should be aware of the requirement in order to manage performance expectations.

Operating storage outside of the manufacturer's requirements could adversely affect the life and performance of a facility, as well as any outstanding warranties. It could also have safety and reliability impacts that could increase potential liability. It may be appropriate to account for any failure to comply with the manufacturer's requirements in default and indemnity provisions.

Preserving Tax Incentives

Combining an energy storage system with other forms of generation may affect the tax status of the entire project. Many of these considerations have been discussed in prior NewsWire articles (for example, see "Batteries and Tax Credits" in the October 2016 *NewsWire*). How the storage system is combined with other resources and treated under the PPA will affect whether tax credits can be claimed on the entire project.

Accelerated depreciation and investment tax credits generally cannot be claimed on any equipment considered "leased" to a government agency or tax-exempt entity. It is helpful to say that the parties to the PPA intend it to be a "service contract" for federal income tax purposes, but this may not be enough if the PPA permits the offtaker substantial unfettered control over the facility. The analysis may also be harmed if the storage facility is on land leased by the offtaker and there are other factors that tend to support a finding that the facility is really being leased to the offtaker.

The expected useful life of the particular energy storage technology should also be considered in determining the term of the PPA. If a contract term is too long, there is the chance the offtaker will be treated as the tax owner of the facility. An asset that is dedicated for substantially its entire life and value to a single customer may be considered owned by the customer from inception. This is why typical solar PPAs are 20 years for solar panels so that the solar company can show it has retained a meaningful residual interest in the solar panels.

Charging the System

The type of technology is important to the charging analysis. A concentrating solar power project, for example, should factor in the risk of reduced sunlight available to charge the storage unit. This may be built into performance guarantees, force majeure events and default provisions. It may also appear in the form of restrictions on the offtaker from interfering with insolation and possibly maintaining vegetation if the project is on the offtaker's premises.

The PPA for a battery storage system should specify charging parameters. If the battery is allowed to charge from the grid, when may it draw from the grid and at what percentages? The answer may have regulatory or tax consequences.

Moreover, the manner in which the energy used to charge the system versus the manner the output is measured will need to be determined. If the PPA offtaker is the same entity that is supplying the electricity to charge the system, the pricing mechanisms may need to be negotiated. The seller could end up paying more to charge the unit than the PPA price it receives for selling the product from the system.

Setting the Purchase Price

The costs of some forms of energy storage systems such as batteries are declining. The rate of decline is expected to accelerate over the next few years. Nevertheless, the costs are still high and may remain high for new energy storage technologies.

There are several aspects of a PPA for energy storage technologies that are still in the developmental phase that should be considered. First and foremost is whether the PPA price will justify the cost of construction and operation. Will the cost of construction decrease by the time purchase orders will need to be submitted to meet the milestones in the PPA? May the term of the PPA be delayed if it becomes difficult or more expensive to procure construction materials? If the system will receive any federal or state funding under various incentive programs, there will probably be ongoing compliance requirements that the PPA parties must satisfy and that should be built into the contract.

Many early entrants into the energy storage space rely on stacked revenue streams to make the economics of developing the system work. For example, storage facilities are typically combined with tested resources that have proven production streams (such as solar, discussed above). The storage system may also sell multiple streams of products, such as energy and ancillary services or demand response. The PPA will need to be clear regarding the rights to each product and service if a single offtaker will not be entitled to all of the multiple revenue streams.

Anticipating Changes in Law

To date, there is a lack of clear precedent about how energy storage units are to be regulated under the Federal Power Act. The regulatory regime may influence how the system is used, the ownership structure, and how any co-located or integrated systems, such as solar resources, may also be treated in the PPA. (For more on regulatory implications, see "Solar + Storage: US Regulatory Issues" in the August 2017 *NewsWire*.)

There is also uncertainty about the scope of services and products that energy storage systems will be able to monetize during the term of a PPA. For this reason, it */ continued page 28*

AC. Projects using single-axis trackers cost 15¢ more per watt on average than fixed-tilt projects. NREL said there was less variation in costs from one state to the next in 2016.

PPA prices were mostly at or below \$50 a megawatt hour with a few priced aggressively at around \$30.

Adding storage helps with pricing. According to NREL, a 100-MW project in Arizona with a 30-megawatt, four-hour battery was able to command \$45 a megawatt hour, with storage accounting for roughly a third of the price.

At the end of 2016, there were 121,400 megawatts of solar projects in interconnection queues in the United States, with 83,300 of that number added to queues during 2016.

Meanwhile, the US residential solar sector grew only 1% from Q1 to Q2 2017, according to the Solar Energy Industries Association. The sector was down 17% in Q2 year on year. Much of the growth was in new states like Texas, Utah and Florida, but was not enough to offset declines in other states. Residential rooftop companies have been focused on showing profits rather than continuing to stress rapid growth in number of installations, and they continue moving to direct sales of systems to customers in a gradual shift away from long-term contracts to supply power or lease systems to customers. Vivint aims to have 30% direct sales this year, up from 19% in 2016. Tesla reported that 37% of its customers opted for direct purchases in Q2 2017.

Non-residential solar grew 31% in Q2 2017 compared to the year before and is expected to grow 9% overall this year. Utility-scale solar accounted for 58% of all solar capacity additions in the second quarter.

PARTNERSHIPS will not have to pay penalties for missing a new, earlier deadline to file 2016 tax returns, the IRS said in September.

The IRS made the statement in Notice 2017-47.

Partnership tax returns used to have to be filed by April 15 for */ continued page 29*

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is important to incorporate flexibility into the PPA. The Federal Energy Regulatory Commission has taken steps to facilitate storage, including making it easier to interconnect storage systems. FERC has also proposed wholesale market rules to encourage storage, such as ensuring energy storage resources are eligible to provide all of the products they are capable of providing in organized wholesale markets. FERC has not taken further action in this rulemaking to date, but it has sparked considerable discussion about the many possible value streams of storage.

Energy storage is relatively new and such a different animal than other generation resources that we are sure to see new products and services unique to storage develop. There will invariably also be policy changes and changes in subsidies and incentives for both energy storage and any co-located generating facilities.

For these reasons, it is especially important for energy storage PPAs to address what happens if a revenue stream develops or goes away during the term, and which party has the risk or benefit related to such changes.

In the rooftop solar-plus-storage context, we frequently see the owner or developer retain the right to any new "green attributes" that may be awarded during the term. This makes sense where the host customer is not able to monetize new revenue streams. In contrast, a commercial and industrial offtaker may want to split the value of new revenue streams, and a utility offtaker may want to be able to claim all new facility attributes.

Along with who gets the new revenue streams is the question of how the parties are compensated. In some instances, PPAs contemplate splitting any increases in value stemming from new products or incentives. Other PPAs simply let the party claiming the new attribute also claim all of the additional revenue.

If a party has the potential to benefit from a new attribute, then it would make sense also to place the risk of the reduction in value on such party. Other PPAs bring the parties back to the negotiating table to reform the contract in the event there is a change of law that reduces the value of the product, especially when a substantial portion of the PPA value is at stake.

End of Term

No one wants to think about early termination and it may be hard to imagine the end of a 20+-year contract term, but the PPA should contemplate these eventualities.

One benefit of certain types of storage resources is that they may be portable. For example, a battery can be moved to another location to be used by another offtaker more readily than a generating facility can be moved. It is important to specify when the right is triggered and which party must pay for the removal and any damages. Alternatively, the seller may want the right to leave the equipment in place and sell products and services to a nearby third party or market in an event of offtaker default or an extended force majeure event.

Many PPAs include purchase options at set times and upon termination of the PPA. Any purchase option is usually at fair market value at time of purchase. It may be difficult to predict the future value of unproven technology. For that reason, it may be necessary to include certain floor prices for the system that ensure the seller can satisfy any debt obligations in the course of selling the facility.

Once a storage device has reached the end of its useful life, it will need to be discarded or recycled in some fashion. The proper disposal techniques and related costs may be relatively uncertain and higher for novel storage technologies. Nevertheless, the cost of properly disposing of the system should be factored into overall project economics. ◎

Your Project's Just Not Into You

by John L. Schuster, with JLS Capital Strategies LLC in Washington

I have been struck by the substantial number of stalled projects. You see them — literally — driving along the road in certain parts of Africa and Asia. They are evident in available statistics and from the number of parties calling for help.

The trend is unsurprising, given chronically low oil and commodity prices. What is noteworthy is how developers and lenders respond. Things have gone wrong. Various problems have emerged such as loan defaults, project degradation, and permit lapses. Yet project parties press on as before.

Some may characterize this behavior as a form of insanity according to a popular, but misused, definition of doing the same thing repeatedly and expecting a different result. But this behavior is understandable. In my experience, the problems facing most projects are not a result of poor development and financing strategies, but rather weak markets, force majeure, bad luck and similar uncontrollable factors. If this is the case, why change?

However, this behavior is irrational and remarkably similar to that identified in a popular self-help book — the inspiration for the romantic comedy that is a big favorite at my house — *He's Just Not That Into You*.

The book, written by Greg Behrendt and Liz Tuccillo, and the movie are directed toward women who, constantly in search of the "spark," overlook the obvious signs that relationships are going nowhere and instead grasp for a few clues that tell them they are the exceptions to the rule. Following advice from well-meaning parents who tell them that the real reason the little boy who was mean to her was because he liked her, they look for subtle clues to give them hope for a commitment that never materializes. Convincing themselves that they are exceptional, they overlook the obvious facts before them.

Projects are gender-neutral, inanimate concepts that have no feelings and are not "into" anyone. But in this analogy, the project is "the guy." The advice of this article is directed to those who care, who have become excited about the promise of the project, believing they have found "the spark." Anyone who has ever seriously pursued a project has done so because he or she believes in the project's concept economics and believes that the project will achieve success. */ continued page 30*

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partnerships that report income on a calendar-year basis. Congress moved up the deadline to March 15 in the Surface Transportation Act in late 2015 as a way of raising more money for the federal government.

The change applied for the first time to 2016 tax returns that had to be filed in 2017. Many partnerships missed the deadline. The IRS said it will not make any partnership pay a penalty that filed its 2016 return or asked for an extension by the old deadline. Similar relief is not expected in 2018.

THE US TREASURY moved closer in early October to withdrawing two sets of tax regulations the IRS issued in 2016 that would affect the project finance market.

One deals with "disguised sales" of assets by partners to partnerships.

A developer forming a partnership with an investor to own a project on which the developer has been working is sometimes treated as having made a taxable sale of the project to the partnership rather than a tax-free capital contribution. A developer is assumed to have made a "disguised sale" of the project if the developer is distributed cash by the partnership within two years after contributing the project.

This basic principle is not in dispute, but the Treasury said it is considering withdrawing detailed rules the IRS issued for calculating the amount paid by the partnership for the project. The withdrawal is most likely to affect tax equity partnerships formed to finance projects in cases where the projects were already subject to construction or term debt. (For more information, see "Tax Triggered When Partnership Formed?" in the October 2016 *NewsWire*.)

The other regulations in play deal with affiliate or shareholder debt.

Many foreign investors investing in US projects form US holding companies to hold the investments and inject capital into the US partly as equity and partly as a shareholder loan to the US holding company. */ continued page 31*

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While excitement about and commitment to a project are important, the spark is never enough. Just as in the relationship world, impasses can impede project success at almost every turn. But instead of dating, commitment and marriage, it is development, funding and repayment.

When things go wrong, project parties look for clues of hope: they focus on what could have been. In search of "the spark," they stop focusing on the large realities before them.

The key to breaking the impasse is to assess the practical facts that are in plain view and then pick up the pieces and move on.

Recognizing Signs

If you are out of money, you are out of the project.

Most projects that encounter impasses early on are those with enough capital to get started with the rest "on the way." The sponsors hope that the initial undertaking will adequately demonstrate to the world that the project is happening and will happen. Most lenders will not (or should not) finance without 100% of committed equity supported by an approved credit, in which case the premature start becomes just that — with no debt to continue. Even if lenders do commence financing, they are likely to halt funding in order to avoid uncapped exposure if the equity money does not materialize.

Ultimately, progress stops and everyone is left facing dry-hole risk. Even after years without progress, some borrowers will grasp for signs that the money is on the way. Here are some popular hopeful refrains.

1. "*We had a really productive and positive meeting with the bank.*"

The only meeting one needs to have with a bank is punctuated with sentences like this.

Borrower: "We have the equity we need to cover the cost of the delay and ensure completion."

Lender: "Thank you for meeting our requirements and for committing those funds first. We will be moving forward with our loan approval and funding process now."

Anything else is just talk.

2. "*We have a promising sale that will be the key to more equity and debt.*"

The only sale that will bail out a deal with a cash deficit is a sale with money that looks, smells and acts like equity. There are such sales — condo-sats, for example — that are satellite capacity sales where the buyer pays upfront and agrees to forgo certain security and voting rights that are troublesome to lenders. But most sales are conditioned upon completion of the project, which depends on the ability to secure enough funds, which was the problem in the first place.

If several years have passed, the rest of the money still has not shown up and productive negotiations have long since ceased, there is no reason to think it will all turn around tomorrow.

Focus

If you cannot complete phase one, it is not time to plan phases 2 through 10.

Most projects get started with the idea that an initial project is just the starting point. This is especially true for new, inexperienced developers. If the idea is good for one project, it can be used for many projects, right?

That may seem true where sites and permits are easy to obtain, or where sales contracts are standard, as with certain renewable energy projects. So why not keep the spark of the great idea going? While writing this article, I found several websites devoted to showing how small projects can be transformed into additional and potentially larger projects, but alas, the websites show no tangible evidence of success.

There is a reason for that. Projects do not have an inner essence that can be copied like paper. Site conditions, offtaker circumstances, regulations and other factors are subject to change. Even if they were not, seed money cannot be turned into long-term equity any more than straw can be spun into gold. It is best to stick with phase 1.

If lenders and sponsors are not aligned, no one is into anyone.

Most project financing negotiations start (or should start) with an alignment of interests between lenders and sponsors. But market changes, tax consequences or other factors can change incentives, causing the sponsor to lose interest in project success.

When interests diverge, the choice is not whether to adopt a new strategy — a change in direction is a must. Projects with unmotivated sponsors are less likely to work out issues with host governments. They may divert talented personnel to other projects or lose them to other enterprises. They may engage in the less-than-transparent uses of funds, prompting lending and all progress to stop. They may be slow to undertake new developments. On one mining project — let's call it project X — the sponsor made more money in tax losses by avoiding profitable new developments. Sponsors of petrochemical, satellite and other projects reliant upon ongoing market sales will be less motivated to make these sales if the sales will not generate dividends.

When things go wrong in a project, the parties sometimes look for signs of hope instead of seeing the larger realities before them.

The problem is how to move on. Lenders are loathe to enforce security and change sponsors because the sponsor may be well positioned to make the project a success. Changing sponsors might not re-align interests and may exacerbate problems. However, if interests cannot be re-aligned with the current sponsor or if sponsors have misbehaved, then it is time to change horses.

How to Move On

Here are a few tips for discerning how to move on:

On project X, the poorly motivated sponsor X was amazingly transparent about its disregard for the lending group. It failed to share information, piled up costs through expensive mining practices, and refused to adopt new mine plans with demonstrated profitability. When the lenders began exploring options to sell the project, sponsor X openly denigrated its mine, seeking to poison the market for a sale. The lenders failed to pick up on the obvious, grasping at straws about how sponsor X was going to improve, allowing sponsor X to disrupt the sales process. Ultimately, sponsor X acquired the project for cents on the dollar and, within a year, implemented the mine plan it had just refused to adopt.

Lenders are usually quicker to pick up clues. On a different mining deal, an inexperienced sponsor wasted funds on poor mining and imprudent spending, which demonstrated a lack of good faith and commitment, if not outright conspiracy. Fortunately, the deal facilitated an overhaul of sponsor arrangements and a resolution to problems. On a telecom deal, a new entrant agreed to substantial cash sweeps with the intention of making money through less-than-transparent activity. However, the sponsor was corralled early during operations, and new equity ultimately came in to prepay the debt.

If you are serious, follow all the money.

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The loan allows the foreign investor to "strip" US earnings by pulling them out as interest on the shareholder loan. Earnings pulled out as interest are not taxed in the United States, since the US holding company paying the interest can deduct it. The only tax is a possible withholding tax on the interest at the US border, but many US tax treaties reduce or eliminate any such withholding taxes.

The IRS said in 2016 that it would require companies with shareholder debt to have four kinds of documents to prove the loans are really debt. The documentation was considered burdensome. Therefore, the IRS proposed requiring it only where the shareholder making the loan owns the holding company at least 80% by vote or value and then only in cases where a publicly-traded company is involved somewhere in the ownership chain or else the entire chain of affiliated companies has more than $100 million in assets or revenue of more than $50 million a year in any of the three prior years.

In early August, the IRS said in Notice 2017-36 that it will delay the need to produce such documentation until 2019.

In early October, the Treasury said that it now plans to withdraw the documentation requirements entirely and come up with new rules that will be "substantially streamlined and simplified."

The part of the regulations that reclassify some shareholder debt as equity will remain place for the time being to see what Congress does in a tax reform bill later this year. (For more detail on when shareholder loans may be reclassified as equity, see "New US Tax Rules Could Reclassify Debt as Equity" in the April 2016 *NewsWire*.)

This part of the regulations was part of a package of steps the Obama Treasury took to try to stop corporate inversions where US corporations move their headquarters to lower-taxed countries. The Treasury said while it expects Congress to address inversions as part of any tax reform bill, revoking the */ continued page 33*

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As a rule, project finance lenders — especially multilateral lending or export credit agency lenders — are very good at tracking total equity at risk and understanding how it affects incentives for future action. What gets murkier is following that equity down the rabbit hole to understand the obscure and complicated inner details of the shareholder arrangements, like the incentives of individual partners and dynamics among shareholders and project management. One can understand why these details are overlooked: these realities extinguish "the spark."

I recall a large US pipeline that overcame a host of logistical, marketing and profitability issues only to be tripped up after less interesting, but (in hindsight) more important tax issues prompted one particularly affected sponsor to drop out. After other parties failed to step in and fill the gap, the deal descended into litigation. On deals where the size of sponsor equity is crucial, no one wants to assess the details that might show that the sponsor in control of the deal may not be the party with real equity risk.

Know your limitations and your counter-party's strengths.

My aim in this article is the same as Behrendt's and Tuccillo's *He's Not That Into You*: to provide guidance on "picking up the pieces and moving on." The key challenge facing parties doing so is to understand realistically one's circumstances and discern what to do given that reality. That means forgetting about things that developers and sponsors justifiably hold dear, like millions of dollars in equity investments and loan disbursements.

Economics 101 taught us that these are sunk costs that are irrelevant to decision making, but no one should try to tell someone who is out millions of dollars that the money does not matter. It does matter — even to decision making — but in the opposite way most think. Investors and lenders focus on recovering money contributed from the liability side of ledgers (which is indeed irrelevant), leading to unproductive loss-avoidance strategies. The focus should be on the value of assets and a re-orientation of the deal.

Loss avoidance leads us to stay the course and avoid rocking the boat, and to at least three foibles. One sponsor foible is to focus solely on the primary lending option. This gives the lenders 100% leverage, and if things falter, a lengthy loan process hurts market perceptions and project value.

A second sponsor foible is to keep saying yes to demands in the hope of appeasing lenders and facilitating loan disbursement. The problem is that desperation confirms negative perceptions. Lenders may also suspect sponsors are not paying attention.

The third sponsor foible is to be patient, stay the course and hope for the best. This is not a strategy, but a prayer. Hail Mary passes are for US football teams and have no place in project finance; even football teams view them as acts of desperation.

Sunk costs are irrelevant. The focus should be on the value of assets and a reorientation of the deal.

To pick up the pieces and move on, one needs to face potentially inconvenient truths and be prepared to re-orient the deal process.

Rather than focusing solely on the primary deal (foible 1), one should turn outward and assess realistic alternatives. Perhaps the value of a sale to another company is less, but that value is better than nothing and, more importantly, is instructive about how far one should go in pursuing the primary deal. Even if concessions are dear, if they result in a deal that is better than alternatives, they create value. The value of alternatives defines when one should stop saying yes to everything (foible 2) and enhance one's credibility.

At each step, the key is to understand the value of alternatives, and to then use that value as leverage to get the best deal possible within a reasonably expeditious period.

Ironically, no one focuses on the value of alternatives because they may be the obvious signs that no one wants to face. The value of the development in progress (sites, permits, contracts, construction, etcetera) is probably less than the cost of development. If the project is really stuck, then it may be that the best option is to sell the project to another party at a loss. For lenders, if debt funds have been advanced, the lenders' interests may be best served by taking 50¢ on the dollar rather than losing everything. None of this is what parties want to hear, but understanding options along the way has to be better than waiting until no other options remain.

To maximize the value of their options, parties should include the value of a counterparty's potential losses as an asset. A lender may be willing to grant concessions if doing so minimizes debt write offs. In other words, a lender may expect a borrower to accept lower returns if that is better than lost investments.

Ultimately, a realistic assessment of the facts about one's circumstances is always better than reliance on hope and prayer for what one wants (foible 3). Funds are rarely extended for a deal one wants to have, but rather for the deal that actually exists. That is the only way to pick up the pieces and move on.

Africa Investor Forums: Key Takeaways

by Ike Emehelu and Clare Karabarinde, in New York

An energy and infrastructure boom across Africa has given rise to a motley group of mega-projects on the continent that is attracting investors (particularly from China) and boosting economic growth.

Low interest rates in the United States and other western countries are contributing to interest in African projects among institutional investors.

Investors should prepare for the long haul and manage expectations accordingly. Africa is still not an easy place to invest.

Norton Rose Fulbright hosted several Africa forums in New York in mid-September on the sidelines of the 72nd meeting of the United Nations general assembly. The forums included an investor roundtable with Ugandan President Yoweri Museveni and senior ministers in the Ugandan government, including the finance minister, Matia Kassaija, the foreign affairs minister, Sam Kutesa, and the Ugandan UN ambassador, Adonia Ayebare.

They also included the fourth annual "Africa Alternative Investment Intensive" that Norton Rose Fulbright hosted in partnership with Africonomie, an institutional investment

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regulations before the tax reforms are enacted "could make existing problems worse."

The Treasury made the announcements in a report to the president on October 2. The report responds to a Trump directive in Executive Order 13789 to examine all regulations issued by the Obama administration during the last 13 months before Trump took office. (For earlier coverage, see "Recent IRS Regulations in Limbo" in the June 2017 *NewsWire* and "IRS Revisits Debt-Equity and Disguised Sales" in the August 2017 *NewsWire*.)

PRIVATE BUSINESS USE of municipally-owned power plants and transmission lines can subject the interest paid on bonds used to finance such projects to federal income taxes.

An example of private business use is where a long-term power purchase agreement is signed to supply the electricity from a municipal power plant to a private company.

No more than 10% private business use is allowed.

A joint action agency that supplies, transmits and distributes electricity for municipal utilities in two states asked the IRS whether several contracts that one of its members signed could be viewed as private business use of a power plant that is owned partly by the joint action agency. The member entering into the contracts is a municipal utility.

The joint action agency financed its share of the power plant using tax-exempt bonds.

The joint action agency signed a long-term PPA to sell the municipal utility a share of the capacity and energy from the power plant. The municipal utility had to pay the joint action agency the same share of the fixed costs (including debt service on the bonds) and variable operating costs of the power plant on a take-or-pay basis, meaning the municipal utility had to pay even if it chose not to take its share of the electricity from the plant.

The municipal utility is required as a load-serving entity — meaning a utility that serves retail customers —

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communications firm, that examined the complexities of investing in Africa — particularly what works and what does not — and drew an audience of developers and US-based institutional investors, fund managers and other industry stakeholders. The discussions featured Obie McKenzie, a managing director of BlackRock, Paul Hinks, founder and chief executive officer of Symbion Power LLC, Lynn Nguyen, acting vice president of investment funds at the US Overseas Private Investment Corporation, Kerry Adler, CEO of SkyPower, Ikenna Emehelu, a Norton Rose Fulbright partner, and Donna Sims Wilson, chair-elect of NASP and president of Smith Graham & Co., among other notable speakers.

Here are key takeaways from the forums.

Big Projects

There is continued interest and growth in energy and infrastructure. Nearly 54% of the 154 guests who attended the roundtable with President Museveni focus on energy and infrastructure. President Museveni said Uganda will offer incentives to attract investments with a catalytic impact on the economy in the manufacturing, energy and infrastructure sectors.

Museveni also said that infrastructure development has to take priority because it is the best way to reduce the cost of doing business in developing countries. "In order for the private sector to make profits, they need to lower costs of doing business, lower costs of electricity, transport and labor."

Financing remains a huge challenge. The 2008 global financial collapse and recent economic turmoil in China have not spared Africa. African governments have had to be creative in financing a growing infrastructure deficit and are interested in re-engaging traditional African allies in the West to diversify and increase foreign direct investment in the continent.

The Ugandan government, through the Uganda National Roads Authority (UNRA), is preparing to invite bids from the private sector to design, build, finance, operate and transfer a limited access tolled expressway between Kampala and Jinja. This would relieve the current congestion on the existing Kampala-Jinja highway and create future growth. The project — known as the Kampala-Jinja Expressway PPP — is strongly supported by development partners, including the International Finance Corporation, European Union, Agence Française de Développement and the African Development Bank. The project is expected to cost US$1.1 billion and is one of Uganda's top priorities for investment.

Uganda and Tanzania signed an agreement in May to construct a crude oil pipeline, originating in Kabaale, Uganda and terminating in the Tanzanian port of Tanga. The project is estimated to be worth US$3.55 billion. French oil company Total, in partnership with China's CNOOC and Britain's Tullow Oil, will fund construction. Upon completion in 2020, the pipeline will transport 216,000 barrels of oil daily.

The Norwegian power company W. Giertsen Energy Solutions struck an agreement in February with Uganda Electricity Generation Company Limited (UEGCL) to begin constructing solar power plants, solar water pumping stations and hydro-solar hybrid power plants. The projects are supposed to service rural areas in Uganda.

In other African countries, developments in the energy and infrastructure sectors remain vibrant.

Kenya is in the process of constructing Konza Technology City: its very own Silicon Valley just outside Nairobi. An entire government department has been created for the endeavor (Konza Technopolis Development Authority).

In July, Nigeria, in partnership with the China Civil Engineering Construction Company, began constructing a coastal railway between Lagos and Calabar. The railway is due to be completed in 2018.

The Grand Ethiopian Renaissance dam project is expected to generate 15 million megawatts hours of electricity a year once it is built. There has been political resistance because the project will displace 20,000 people who live near the project site. However, Salini Impregilo (the Italian construction firm awarded the contract) and Ethiopia have agreed to move forward.

Foreign Investment

The fact that Africa has one of the youngest and fastest-growing populations in the world and incomes and markets are growing is drawing attention from foreign investors. Many governments are implementing reforms across different sectors and removing bureaucratic barriers that delay investments.

Regional trade blocs are helping reduce barriers. The East African Community (EAC) market has about 146 million consumers, while the Common Market for Eastern and Southern Africa (COMESA) has 20 member states with a population of more than 460 million. The Southern African Development Community (SADC), established in 1992, now has 15 member states. (There are 54 countries in total in Africa.)

At the roundtable, President Museveni pointed out to a packed room of investors that Africa is four times the size of the United

States, with a population of 1.3 billion that is expected to grow to 2.5 billion by 2050.

Chinese investor activity surpasses Western involvement. US investment in particular still lags behind China by a considerable margin. President Museveni said, "Chinese companies are more adventurous than you [American] people." There are many reasons.

One reason is political. Presidents George W. Bush and Barack Obama both implemented new programs to help Africa. Bush created the Millennium Challenge Corporation that gives development aid in the form of grants to developing countries that adopt economic and political reforms and has made trips to Africa since leaving the White House to promote aid to the region. Obama created a Power Africa Initiative and pushed an Electrify Africa Act through Congress, but the amount of resources devoted were not enough to shift the needle. President Trump has left the post of assistant secretary of State for African affairs vacant, and has been advocating an "American first" approach to engaging with the rest of the world.

Another reason for lagging US investment in Africa may be legal. For example, the Foreign Corrupt Practices Act may make US companies uneasy about investing in regions where bribery is a tacitly understood manner of conducting business. The Foreign Corrupt Practices Act makes it a crime to offer anything of value to an official of a foreign government or international public organization in an effort to win business or secure an improper advantage. The statute has extra-territorial reach. Foreign companies raising capital in the United States may also be prosecuted.

The US Agency for International Development (USAID) launched a new program recently whose aim is to expose US institutional investors to co-investment opportunities with African counterparts in sub-Saharan African infrastructure. The program is called MiDA (Mobilizing Institutional Investors to Develop Africa's Infrastructure) and is a partnership with the National Association of Securities Professionals (NASP). Donna Sims Wilson, chair-elect of NASP, and Aymeric Saha, managing director of MiDA, said at one of the forums that MiDA organized meetings recently between local African fund managers and US pension funds, money managers and asset consultants representing $7.7 trillion in assets.

Sims said a big gap remains between real versus perceived risks of investing in Africa and mentioned that US investors have been surprised by the level of development in some parts of the continent, like South Africa. */ continued page 36*

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under the rules of the independent system operator that runs the state or regional grid to have an amount of "zonal resource credits" or ZRCs equal to its retail load during the year.

There are four ways for a utility to get the ZRCs it requires: by owning a power plant (in which case it is awarded ZRCs by the ISO), by entering into a take-or-pay PPA to buy power (which the ISO considers equivalent to an ownership interest in the power plant), by contracting to buy ZRCs from a third party, or by buying ZRCs in an annual auction run by the ISO.

If it comes up short on number of ZRCs, then it must pay a penalty to the ISO. If it has too many ZRCs, then it can sell the excess in the ISO auction.

The municipal utility signed three contracts.

The IRS said in a private letter ruling made public at the end of September that none of the contracts is a private business use of the power plant owned partly by the joint action agency. The ruling is Private Letter Ruling 201739002.

The municipal utility arranged for a tax-exempt electric cooperative to supply all the city's electricity needs. Thus, it no longer needs the power from the joint action agency's power plant. Therefore, it will resell that power into the spot market or under short-term contracts.

It plans to enter into a swap with another "G&T" electric cooperative (of which the coop supplying electricity to the city is a member) to swap its floating electricity sales revenue, to the extent it exceeds the amount the municipal utility pays the joint action agency for variable operating costs (but not the fixed costs like debt service on the bonds), in exchange for payments by the swap counterparty for any shortfall in merchant revenue below the variable operating costs.

The resource adequacy burden of having to have enough ZRCs to match the municipal utility's load will transfer to the coop serving the city. Thus, the ZRCs the ISO issues the municipal utility for entering into the long-term PPA with the joint action agency will free up. The municipal utility plans to sign a long-term */ continued page 37*

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An informal poll of investors at the forum showed that in the short to medium term, US institutional investments in Africa will be primarily through private equity investments in development companies rather than direct investments in projects.

Challenges

There are many challenges when investing in Africa, and participants in the roundtable and the forum focused on three: renegotiation of contracts, non-cost-reflective tariffs and the policy environment.

In the power sector, the need for balanced and clear contracts is particularly crucial since the agreements can cover decades-long projects that involve multiple developers, financiers and buyers. Many investors attending the forums complained of a continued fear of governments in Africa re-negotiating tariffs long after execution of power purchase agreements with national utilities. Panelists actively investing in Africa pointed out that when selecting a country to invest in, three main considerations are contractual frameworks within that state, the country's hunger to close deals and, most importantly, the country's track record for renegotiating contracts. When there is consistency and transparency in contract negotiations (including equal treatment of all investors), this mitigates, but does not eliminate, fear that there may be a future renegotiation.

South Africa cancelled many of its existing bilateral investment treaties with European nations in October 2012, chilling investor activity within the country. Last December, Dangote Cement threatened to close its new cement plant in Mtwara, Tanzania after a new government attempted to withdraw promised investment incentives.

Developers should be cautious and consider the sustainability of investment incentives and the potential impacts on the project should the incentives be withdrawn at any stage.

There is also a concern that governments often dictate extreme terms based on empty threats. The likelihood of closed deals (and continued good relations with investors) increases when governments accept market-return expectations from investors. Just as investors are pragmatists, governments are expected to be the same.

Power prices in many African countries are currently incoherent and do not cover project costs. Retail electricity prices are a sensitive political issue, seemingly more so than failure to deliver power. The current price of electricity is 9¢ a KWh in Ethiopia after the Ethiopian government throws in a subsidy of 3¢. In Uganda, the average tariff to consumers is 17¢ a KWh (11¢ a KWh for industrial users), with the first 15 units of electricity consumed subsidized by the government. The estimated average tariff in Rwanda is at 22¢ per KWh. Given that significant infrastructure upgrades and new construction are required for new generation and transmission lines, there is a growing concern among many developers about the necessity for tariffs to be cost reflective.

What makes a country attractive to investors is the strong support of the government to implement projects and technical capacity, both within the government and in the private sector. When these factors are missing, the transaction cost of developing projects is higher. Investors need a good understanding of the regulatory framework and policies of countries of interest.

Many countries offer special incentives. For example, in Kenya and Cameroon, governments provide tax breaks for companies that list on their stock exchanges. Kenya established special economic zones, creating incentives for varying industry sectors to complete tasks in designated zones in the country. Rwanda published a new investment code with incentives for foreign and local investors. Nigeria, South Africa and Tunisia all offer cash grants as incentives for investment activity.

Despite the challenges, there is a silver lining. With more governments in Africa unwilling to provide guarantees or take on currency risks traditionally covered by government

African pension funds, with US$334 billion in assets, may be interested in co-investing alongside US fund managers.

guarantees, many factories that currently self-generate are finding renewable energy an attractive option. Self-generation of power is hugely popular for industrial facilities across Africa. For example, in South Africa, Solea Renewables constructed the first off-grid, utility-scale photovoltaic solar power plant in Southern Africa at a chrome mine; the plant is near Thabazimbi. IAMGOLD Corporation is setting up a 15-megawatt solar power plant for its Essakane mine in Burkina Faso.

Fundraising for investments in Africa is increasingly difficult without evidence of local offices or partnerships. To address this challenge, many development finance institutions (DFIs) now have offices across the continent.

African pension funds, which currently hold approximately US$334 billion in assets, are beginning to invest in large infrastructure projects across Africa. By forging relationships with US institutional investors, African asset owners and fund managers could attract co-investments from US asset owners. For both African and non–African investors, co-investing is a preferred strategy. Falling currency values across the continent in 2016 chilled big buyouts, but did not dent interests in smaller private equity deals. Many deals that were too small for global funds remained attractive to investors.

Multilateral banks and institutions have too often focused on supporting the big economic players and only recently started working with private-sector actors in order to strengthen development of small- and medium-sized companies. Platforms such as Venture Capital for Africa have created places to connect entrepreneurs with investors, both institutional and individual. This platform showcases startups in varying industries. One investment opportunity, Powah Limited (based in Kampala), offers off-grid solar solutions. Another, BeepTool (already being used across Africa), is a mobile application that allows for communication, digital pay and money transfers. These companies are a few success stories among thousands of microfinance opportunities on the continent.

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contract to sell the ZRCs to the coop.

The IRS said none of these contracts involves any use of output from, or gives the contracting parties any control over, the power plant owned partly by the joint action agency. They are being undertaken on the sidelines of that power plant. The joint agency must have asked the question because electricity is fungible.

MINOR MEMO. The latest forecast by the International Energy Agency in early October is for another 920,000 megawatts of renewable generating capacity to be added worldwide through 2022. Almost two thirds of new capacity additions in 2016 were from renewables.

— contributed by Keith Martin in Washington

When Criminal Liability Attaches to a Busted Project

by Keith M. Rosen and Ilana Sinkin, in Washington

Executives and directors of infrastructure developers may be wondering under what circumstances they could face individual criminal prosecution for a busted project in the wake of news that there may be a criminal investigation after SCANA, an investor-owned utility holding company in South Carolina, said it is cancelling plans to add two more reactors to the V.C. Summer nuclear power plant after it and Santee Cooper, another South Carolina utility owned by the state, had already spent $9 billion on the project.

SCANA, a publicly traded company, announced in late September that South Carolina government officials have asked the state's law enforcement authorities to conduct a criminal investigation into its handling of the shuttered V.C. Summer nuclear project.

Frustrations over expensive aborted projects can sometimes lead to criminal investigations.

This announcement came only a few days after SCANA and its partner, Santee Cooper, received a subpoena from the US Department of Justice requesting documents related to the project.

According to press reports, questions have been raised about whether SCANA and its affiliates made fraudulent statements to enable the company to charge customers — and seek rate increases — for what it allegedly knew was a failing project.

There is no reason to believe the investigations reflect anything other than frustration over the amount of money spent. The rest of the article is intended to help infrastructure executives understand where lines are drawn.

Public companies have a legal obligation to shareholders not to release misleading information. Electric utilities have the same obligation to their regulators. Private companies can similarly cross a line into criminal fraud when they make material false or misleading statements to obtain funds from banks or equity from investors. Private companies also risk prosecution if they make false representations to regulators, even if those false statements are not designed to obtain funding or other benefits.

Knowledge

Since 2015, with the announcement of the so-called Yates memorandum, the US Department of Justice has had a renewed focus on the prosecutions of individual officers (and not just companies) for corporate malfeasance. The Yates memorandum expesses the department's view that fighting corporate misconduct requires accountability from the individuals involved. While the Trump administration has recently signaled that changes to the Yates policy may be forthcoming, it has emphasized that a central focus will remain on individual prosecutions in corporate fraud cases.

Scienter, or the intent or knowledge of wrongdoing, is the critical element in determining individual liability in criminal fraud cases.

It is well understood that individual criminal liability can arise when a corporate officer intentionally undertakes an act, or agrees that someone else will take an act, that is wrongful. In most instances, the government must prove that the individual knowingly participated in a scheme to defraud – that is, the individual acted voluntarily and intentionally and did not act through ignorance, mistake or accident.

To prevail, the government must usually establish that the individual intentionally participated in the making of the alleged fraudulent representations with an awareness that the claims were in fact false or misleading.

But what if the corporate executive did not personally make or direct the fraudulent statements?

Even if an individual officer or director did not directly participate in the alleged fraudulent submissions, a prosecution could still proceed if the government can demonstrate that the individual acted with "deliberate ignorance." A person cannot have his or her head in the sand. The legal terms for behaving like an ostrich are "willful blindness" or "conscious avoidance," and they reflect the notion that an individual cannot avoid responsibility for his or her role in allowing fraud to occur by deliberately ignoring what is obvious.

Put differently, the government can demonstrate an individual's guilty knowledge in a fraud case by showing that the individual was presented with facts to put him or her on notice that illicit activity was likely or strongly suspected, and the individual intentionally failed to inquire further into the facts.

If a corporate officer strongly suspects that misrepresentations are being made to a government agency, he or she cannot avoid liability by failing to ask questions.

To be clear, this is not a negligence standard. It is not enough for the government to prove that management was negligent in its supervision of junior employees who engaged in misconduct. To establish culpability based on willful blindness, the government must prove that a corporate executive deliberately closed his or her eyes to misconduct at the company when the executive was presented with evidence that would create a strong suspicion that fraud was occurring.

It is not necessary that the government prove that the defendant knew to a certainty that a fraudulent scheme existed; rather, it is enough for the government to prove that the defendant was aware of a high probability that wrongdoing was afoot. Therefore, even when an executive lacks direct knowledge that the statements being made to the government are false, an executive may be held criminally liable for deliberately closing his eyes to facts that should have prompted further investigation.

Good Faith

On the other hand, it is generally a defense to fraud allegations if the individual acted in "good faith." That is because good faith is inconsistent with intent to defraud.

A person who acts on a belief or opinion that is honestly held, even if by mistake or error, does not act with criminal intent. For example, if an officer makes a false statement believing the facts are true, then he or she could not have made a false statement "knowingly." However, executives or officers cannot contend to have acted in good faith when they consciously have chosen to remain ignorant.

The bottom line for executives overseeing representations made to government agencies in connection with similar projects, care must be taken to ensure that accurate information is being provided. A failure to know the truth or the failure to undertake reasonable good faith steps to ensure the transmission of accurate information to regulators and the public can result in the threat of criminal investigation.

Deal-Contingent Hedges

by Todd Alexander and Monika Szymanski, in New York

Deal-contingent hedges are becoming more common in project financings.

A deal-contingent hedge is a hedging arrangement that is signed before closing on a financing transaction and does not take effect until the transaction closes. If the transaction does not close within a specified period, then the parties just walk away, without any liability so long as they do not close a similar financing within an agreed period of time.

The attraction is such hedges are a way to lock in interest rates or electricity prices to take advantage of current market conditions while the sponsor is still trying to pull a lot of moving pieces together so that the transaction can close.

Deal-contingent hedges were used in the past primarily to manage foreign exchange risk in merger and acquisition deals.

They are now playing a useful role in project financings to manage interest rate risk, particularly where financial close is not anticipated for several months.

They are being used especially in bid situations where suppliers are asked to bid fixed prices at which they are prepared to supply a commodity, such as electricity, and once awarded the offtake contract, have several years to reach commercial operation.

When to Use

Deal-contingent hedges are an alternative to other, more traditional derivatives, such as options or forward-starting swaps. They are used when a company is confident that financial closing will occur, but where the financing documents are still being negotiated and there are still conditions to satisfy that could take several months, such as obtaining required governmental approvals. An example is a so-called section 203 filing with the Federal Energy Regulatory Commission or a filing with CFIUS (the Committee on Foreign Investment in the United States) that may be conditions to transferring ownership of a US power plant.

If financial close does not occur as */ continued page 40*

Contingent Hedges

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anticipated within a specified period, then the hedge never becomes effective or terminates before taking effect without liability to either party. Unlike an option, there are no upfront payments when the deal-contingent hedge is put in place. Deal-contingent hedge providers charge a swap premium, which is reflected in the fixed rate, and sometimes an additional swap premium is collected at financial close.

For example, if a borrower wants to lock down the interest rate on a floating-rate loan by entering into a fixed-for-floating 10-year swap, the borrower could enter into the swap early. A 10-year swap today may have a rate of about 2.15%, including an assumed 15-basis-point credit charge. A 10-year swap that is "forward starting" by up to a year could cost as little as 2.25%, a premium of just 10 basis points. Recent deal-contingent swaps have traded five to 40 basis points higher than a vanilla forward-starting swap that starts immediately, depending on the probability of deal closure after considering any remaining regulatory approvals and the likelihood of successfully raising financing.

Some sponsors choose to use forward-starting swaps to lock in rates, but such swaps are not always available, such as where the project company is not creditworthy (for example, if it has no assets other than the permits and contracts for the project), so such sponsors need to consider other alternatives. Also, a sponsor may not want to lock itself into a forward-starting swap because if financial close does not occur, then the forward-starting hedge would need to be unwound and the company may be required to make a termination payment.

Deal-contingent hedges have been used lately in a variety of project financings (such as solar and liquefied natural gas) and are not specific to a particular sector. They can be used not only to manage interest rate risk, but also currency risk and in some cases credit spread risk. Frequent users of deal-contingent hedges are private equity funds and companies that would have difficulty obtaining credit prior to closing.

Timing and Structure

Companies can take advantage of deal-contingent hedges as soon as they know they will require financing, which may be before any lenders commit to the financing. In acquisition deals, deal-contingent hedges are usually entered into when the bid is won, but not prior to then.

"A project has interest rate risk starting on the day it wins the bid and anticipates raising financing in the future. A rise in interest rates can significantly decrease transaction value, whether the project debt is ultimately issued fixed or floating," says Ranga Dattatreya, a managing director who handles derivatives at Goldman Sachs. "We help issuers quantify that risk and understand what their options are. Deal-contingent hedges can form a critical part of a risk management strategy while waiting for regulatory or other approvals."

A date certain for financial close is not necessary when the deal-contingent hedge is being entered into because the hedge provider will typically work with the company to determine a suitable backstop date, which usually can be designed to match the timeframes in any permits or other project contracts.

A deal-contingent hedge is similar to a vanilla forward-starting hedge with the additional provision that if the project financing does not occur as anticipated within a specified period, then the hedge ceases to exist, with no unwind payment being due. The dealer and the borrower work with their respective counsels to customize the definition of a successful financing as well as any other legal provisions.

The financial terms of the swap such as payment dates, calculation periods and notional amounts are usually aligned with the anticipated amortization schedule of the financing. There may be further flexibility added if certain terms of the financing, such as the initial borrowing date or the expected maturity date, are not yet known.

While hedge providers have historically been chosen from project lenders, not all lenders can provide deal-contingent hedges. Deal-contingent hedge

Hedges that are signed before closing, and are contingent on closing, are becoming more common.

providers can be a subset of the anticipated lender group, but if the lender group has not been set, some dealers can provide deal-contingent hedges even if the company does not anticipate the hedge provider becoming a lender in the financing or the hedge provider chooses not to be a lender.

In order to determine the deal-contingent premium, the hedge provider will need to understand the financing structure and principal terms and conditions. It will need to determine how likely the closing is to occur and will look for strong economic incentives for the company to close. Since the deal-contingent hedge provider's fees are contingent on financial close occurring, the deal-contingent hedge provider will want to be confident that financial closing will occur by the backstop date.

Documenting the Deal

Deal-contingent hedges are usually documented in one of two ways.

One is a long-form "confirmation" as if the parties had entered into an International Swap Dealers Association, or ISDA, master agreement with standard terms, and the confirmation is just filling in specific details of the transaction. The assumption is the parties will be governed by the standard ISDA terms.

Alternatively, in some cases, the parties sign an ISDA master agreement, schedule and confirmation, but the papers may leave specific provisions to be negotiated later once the financing is farther along, such as negotiated events of default, termination events and covenants that are customarily included in closing date hedges.

There usually is no ISDA credit support annex or other credit support documentation for the transaction, as deal-contingent hedge obligations are generally unsecured (if permitted by the new margin rules adopted by the Commodity Futures Trading Commission and US prudential regulators).

Although covenants in deal-contingent hedges are limited, the parties may negotiate certain company covenants related to achieving financial close, such as, for example, the company agreeing not to amend certain key existing project documents in a manner that could hinder the financing or the timing of financial close, agreeing not to assign certain project documents, agreeing to notify the hedge provider of circumstances that could delay the financial close, or agreeing to use commercially reasonable efforts to achieve financial close.

The deal-contingent hedge provider often negotiates a post termination settlement payment if the financial closing (or similar floating rate funding) is achieved within a certain period after the backstop date. The period usually ranges from six months to about two years after the backstop date. This provision exists to avoid a "moral hazard" of delaying a deal to trigger certain swap provisions.

The hedge provider's position may be transferable. The company, the deal-contingent hedge provider and the lenders may negotiate to move the deal-contingent hedge simultaneously upon financial close from the deal-contingent hedge provider to one or more lenders on commercial and economic terms (including credit spreads) acceptable to all parties. Depending on the needs of the financing arrangement, the hedge may instead be designed to be unwound (with a termination being payable by the deal-contingent hedge provider or the company) upon financial close, such as, for example, if the lenders insist that they be the post-closing hedge providers and are unable to agree to assumption of the existing hedge.

As with any derivative, the deal-contingent hedge documentation usually requires delivery of certain items at signing such as tax forms, corporate authorizations and incumbencies. Tax representations and other standard hedge representations are also included. In addition to the deal-contingent hedge documentation, the parties will also need to ensure that all regulatory requirements for hedges are satisfied, such as swap reporting under the Dodd-Frank Act. Some such requirements must be addressed prior to entry into the deal-contingent hedge.

When financial close occurs and if the parties intend for the hedge to continue as-is, the deal-contingent hedge usually becomes subject to a negotiated ISDA master agreement and schedule that is linked to the financing documents, including having additional termination events, events of default and covenants. Additional document deliverables, such as opinions, are often required. The obligations are usually secured by the same collateral that secures the loan obligations, and intercreditor provisions are negotiated.

When negotiating the deal-contingent hedge, the company should ensure that the documentation does not contain economic or commercial terms that would be unacceptable to its lenders or other potential hedge providers. The provisions in the deal-contingent hedge documentation should be carefully negotiated as the company may be subject to a termination payment for certain covenant breaches or if certain additional events occur, even when financial close is not achieved by the backstop date.

"No two projects are identical, so the hedge providers must be flexible," Dattatreya says. ◎

Environmental Update

A US appeals court heard arguments in mid-September on the legality of permitting rules that the US Environmental Protection Agency issued in 2014 for cooling water intake structures at power plants. A decision is expected in the case by early next year.

The case involves competing challenges seeking to overturn Obama-era rules under the Clean Water Act, with the power sector arguing the rules are too strict and environmental groups arguing that the rules leave local regulators with too much discretion in determining whether Clean Water Act standards are met on a case by case basis.

The rules are supposed to limit harm to fish and other aquatic species from water intake structures at existing power plants by setting technology standards for preventing them from being pulled into the cooling system.

Environmental groups want the agency to designate a single method as the "best technology available," but EPA instead offered a list of options that regulators can choose from when issuing a permit for a particular facility. Permit writers have considerable latitude under the rule as written to consider site-specific factors in deciding which technology to require.

Briefing in the case was completed before President Trump took office. Government attorneys at oral argument continued to defend the rule using largely the same arguments set out in the Obama-era briefing.

The case is *Cooling Water Intake Structure Coalition v. EPA*.

Clean Power Plan

The extent of US regulation of greenhouse gas emissions will remain uncertain for the power sector for the foreseeable future. EPA moved formally on October 10 to withdraw the Obama-era Clean Power Plan covering existing power plants, but did not indicate clearly what would follow. The options still under consideration by the Trump administration range from simple repeal — a course more easily challenged in court — to repeal with some form of substantial substantive replacement.

EPA is expected to make a firmer decision after collecting public comments, with the issuance of an advance notice of proposed rulemaking to follow. EPA Administrator Scott Pruitt has been reexamining historical assessments of the authority EPA has under the Clean Air Act to regulate greenhouse gas emissions, and it was no surprise that EPA said it plans to withdraw the Clean Power Plan because the plan exceeds EPA's legal authority.

The Clean Power Plan would set limits on greenhouse gas emissions by existing power plants. The limits vary by state.

Current betting is that the Trump administration will eventually propose to replace the Obama-era plan with one that sets greenhouse gas emissions targets in a manner that will vary from one power plant to the next depending on what can reasonably be done at each power plant.

Most industry advocates have been pushing for a more easily defended replacement approach, recognizing the hazards of outright repeal given that the US Supreme Court has said EPA is required by the Clean Air Act to regulate greenhouse gases.

The coal power industry argues that states should have authority to establish source-specific standards based on factors such as the useful life remaining in a particular power plant, cost and the difficulties of installing emissions control equipment at particular existing coal plants.

A Trump replacement plan will probably give each

The current betting is that EPA will replace the Obama Clean Power Plan with more easily achievable greenhouse gas emissions targets that vary by power plant.

state significant latitude to decide what each plant within its borders must do to limit greenhouse gas emissions. The states would probably have the primary role in regulating greenhouse gas emissions from existing power plants through the establishment of carbon performance standards under section 111(d) of the Clean Air Act.

In contrast, the Obama Clean Power Plan relied mainly on a cap-and-trade regime. It would have given each state broad authority to determine how statewide obligations must be met within that state, and focused less on how facility-specific emissions targets could be reached based on "inside-the-fence" considerations. The plan was stayed by the US Supreme Court in 2016.

Any move to limit such emissions on a facility-by-facility basis is more likely to keep aging facilities with greater emissions in service for longer.

The power industry also wants changes to the "new source review" permitting program that affects new power plants and existing power plants that have been significantly modified. EPA recently announced the formation of a new source review task force that will consider options for scaling back the air program that requires new power plants and existing power plants that undergo major modifications to install state-of-the-art pollution control equipment.

It will take years for whatever regulatory changes are made in these areas to take effect, possibly extending into the next administration. It will take that long for the inevitable legal challenges to work through the courts. Many in the power sector recognize that regulation of greenhouse gas emissions is inevitable and have advocated for certainty over the regulatory and policy vacuum that will likely follow the expected announcements.

Environmental groups argue that any narrow replacement of the Clean Power Plan would be insufficient and inconsistent with the Clean Air Act. For example, if an "inside-the-fence" rule replaces the Clean Power Plan, EPA would be forced to explain why it is changing its previous interpretations, such as its conclusion that regulators should consider the option of switching fuel sources at coal-fired power plants when regulators set emissions reduction goals.

Any replacement based on a narrow interpretation of EPA's authority is unlikely to reduce the nation's greenhouse gas emissions meaningfully in comparison to the reductions projected under the Clean Power Plan, which was the key means by which the United States intended to meet its obligations when it signed the Paris climate agreement.

EPA Deputy

President Trump nominated coal industry lobbyist Andrew R. Wheeler in early October to serve as deputy EPA administrator, the number two position at the agency. Wheeler is a former aide to Senator James Inhofe (R-Oklahoma), a vocal critic of climate change science. Wheeler was Inhofe's chief counsel and served as the staff director for the Senate Committee on Environment and Public Works before becoming a lobbyist.

Infrastructure Environmental Review

President Trump issued an executive order in August that is intended to accelerate approval of infrastructure projects by streamlining the environmental review and permitting process.

The order applies to energy production and transmission, water treatment, transportation and certain other infrastructure projects. Under the order, agencies may be held accountable if they fail to meet new, tighter deadlines it sets for completing environmental review and permitting.

The White House Council on Environmental Quality will oversee its implementation and resolve interagency disputes relating to environmental review and permitting.

The on-the-ground impact is somewhat uncertain as the deadlines imposed are not binding and the enforcement authority provided to the executive may be affected by congressional oversight of agency budgets.

Flood Risk Management

Trump also revoked by executive order in August an order issued in 2015 by the Obama administration that requires projects built in coastal areas and other flood plains to be built to more rigorous standards so that they can withstand 500-year storms. The timing was awkward coming shortly before Houston was pummeled by Hurricane Harvey leading to widespread flooding. It was the third "500-year" flood to hit Houston in three years.

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Environmental Update

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The rescission means federal agencies are no longer required to make the ability to withstand floods and heavy storms a condition for issuing permits for new construction. However, the Trump order does not explicitly preclude the discretionary consideration of these risks. It also does not change the obligation to consider the potential impacts of climate change under other laws, such as the National Environmental Policy Act.

— contributed by Andrew Skroback in Washington

CHADBOURNE MERGER

Chadbourne & Parke merged into Norton Rose Fulbright on June 30. The combined firm has 4,000 lawyers in 59 offices in 33 countries.

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