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PROJECT FINANCE
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Cost of Capital: 2015 Outlook

More than 1,700 people listened in January as a group of project finance industry veterans talked about the current cost of capital in the tax equity, bank debt, term loan B and project bond markets and what they foresee for the year ahead.

The panelists are John Eber, managing director and head of energy investments at JPMorgan Capital Corporation, Jack Cargas, managing director in renewable energy at Bank of America Merrill Lynch, Thomas Emmons, managing director and head of renewable energy finance for the Americas at Dutch bank Rabobank, Jean-Pierre Boudrias, vice president and head of project finance at Goldman Sachs, Steven Greenwald, a senior advisor in project finance at Credit Suisse, and Jerry Hanrahan, vice president and team leader in the power & infrastructure, bond & corporate finance group at John Hancock. The moderator is Keith Martin with Chadbourne in Washington.

MR. MARTIN: John Eber, what was the tax equity volume in 2014? How did it break down among wind, utility-scale solar and rooftop solar?

Tax Equity

MR. EBER: We were able to get a pretty good handle on the wind tax equity market. It is more challenging with solar, and the solar numbers are still being gathered.

For wind, 29 deals came to market last year. We track on the basis of deals being awarded rather than when they closed. The deals amounted to almost 6,000 megawatts of wind and close to $5.8 billion of tax equity. There were 19 tax equity investors in wind.

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OFFSHORE INVESTMENT FUNDS are up in arms over an internal memo the Internal Revenue Service released in January.

The memo said that an offshore fund using an independent agent with an office in the United States to make regular loans to US borrowers and underwrite equity issuances by placing the equity with both US and foreign persons is engaged in a US trade or business. That means the fund would be subject to US corporate income taxes at a 35% rate plus possibly a branch profits tax for another 30% of the remaining earnings, for a total tax on its US earnings of as much as 54.5%.

The IRS memo is Chief Counsel Advice 201501013.

It discusses a fund that was formed in a country / continued page 3

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That is sizable growth in the market last year compared to 2013 when we saw about $3.5 billion in wind. It is one of the larger years for wind tax equity that we have seen in some time.

The solar market could end up being comparable in size. Last year, solar was slightly larger than wind. It is more difficult to compile the final figures so early after the start of the new year.

MR. MARTIN: Do you have a feel for whether most of the solar activity was in rooftop solar or utility scale?

MR. EBER: I think it is similar to 2013 when we saw a significant amount of activity in rooftop; it accounted for about a third of the tax equity volume in solar. It would not surprise me to see the same breakdown in 2014.

MR. MARTIN: In 2013, there was something like $6.5 billion in total tax equity. You are talking about a very significant increase in volume over 2013.

MR. EBER: Without a doubt, there was a significant increase over 2013, certainly in the wind sector. If you recall, wind started out slowly in early 2013 because the extension of production tax credits came literally on January 1. It took a while for the market to ramp up in the first half of the year.

MR. MARTIN: The trend has been for solar to exceed wind in volume. If that happened last year, then you are talking about an $11.6 billion tax equity market in 2014, which would just be a phenomenal size.

MR. EBER: I am not predicting that that is what happened last year, but there was a sizeable solar market in 2014. Whether it will end up having exceeded wind remains to be seen.

MR. MARTIN: How does 2015 look?

MR. EBER: My sense is 2015 will be a very strong year, especially after Congress extended the deadline to start construction of new wind farms through the end of 2014 to qualify for tax credits. Solar was going to be a strong year regardless because the entire solar market has been working toward a deadline of the end of 2016 to qualify for the investment tax credit. We are as busy as we have ever been right now working on prospective opportunities and expect 2015 to be an extremely active year in both solar and wind tax equity.

MR. MARTIN: When do you think people need to be talking to you about 2015 deals to have any hope of having your attention to close this year?

MR. EBER: There is still plenty of time.

MR. MARTIN: Jack Cargas, the same?

MR. CARGAS: Yes, but we encourage people to alert us to possible 2015 transactions early in the year. The entire tax equity market saw a significant back-end weighting of transactions in 2014 to the fourth quarter. There was tremendous pressure on everyone's time, and that is not only on the time of the investors, but also sponsors, external counsel and third-party experts. The pressure on human resources last year was extreme.

MR. EBER: I agree with Jack. The bottleneck is with due diligence. There was a notable bottleneck toward the end of last year getting the independent engineering resources to complete diligence.

One reason I think 2015 will be strong is we saw plenty of deals last year that did not really need to close until 2015. We asked folks to be a little patient with us, and we would try to take them up this year versus tying up time last year when we were so busy with other closings.

There were almost 50% more tax equity investors in 2014 than 2013.

MR. MARTIN: Moving rapidly through a series of questions, tax equity yields have been fairly stable over the last four or five years, but they seem to be creeping up lately due to the addition of commitment or structuring fees on the front end and use of higher, 20-year yield targets on top of the flip yield at the back end. Do you agree with that statement?

MR. EBER: There is a lot more competition in the market than before because we have more investors now. The 19 investors

that we saw last year in wind is an increase over what we saw the year before.

MR. MARTIN: That would normally bring yields down if you have more supply, correct?

MR. EBER: Yes, it should. We are talking about deals that are mainstream deals, meaning deals with leading sponsors, tier-one suppliers of equipment and long-term fixed-price power purchase agreements.

MR. MARTIN: Lance Markowitz said on this call last year that he thought yields for the benchmark wind deals, meaning with the largest sponsors, were 50 basis points above or below 8% unleveraged. That band may be a little wide. What we have seen ourselves is a band of perhaps 20 basis points below to 25 basis points above 8%. How many basis points would you say we are up or down this year compared to last year?

MR. EBER: The market pricing continues to be very stable.

MR. MARTIN: Jack Cargas, agree?

MR. CARGAS: Yes.

MR. MARTIN: How common are structuring or commitment fees at the front end or unused commitment fees at the back end on top of the yield?

MR. CARGAS: We are seeing more of that in our shop, in particular in transactions that include a forward commitment of capital. An example is wind deals that commit capital forward in order to accommodate construction financing. Another example is residential solar funds where there are multiple draws over time. Both kinds of transactions often include up-front structuring fees. Turning to back-end non-utilization fees, those are also common in residential and commercial and industrial solar funds. Once an investor decides that a program is a worthwhile investment, it would like to see its capital deployed.

MR. MARTIN: John Eber, we have seen such fees all over the map. Fees might range from 37.5 basis points to 75 or 100 basis points. There does not seem to be a "market" level of fee.

MR. EBER: They can vary depending on what is happening in the deal. If a lead investor is providing a significant amount of advisory work and services to the other investors and there is a long-term commitment by all of the investors, then you are more likely to see fees at the high end of the range.

If no advisory or support services are required from the lead investor, but there is a long-term commitment, then you might see an up-front fee at the lower end of the range.

MR. MARTIN: What is considered "long term" for a commitment?

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outside the US. The country did not have a tax treaty with the United States. If it did, then the fund might limit any US tax on its earnings to a possible withholding tax on interest and dividends at the US border, as long as the fund does not have a "permanent establishment" in the United States.

The fund is a partnership for US tax purposes. A "feeder" fund immediately above it is a corporation for US tax purposes. Both are organized in the same country, probably the Cayman Islands.

The fund has no employees. It relies on an independent agent that originates all its deals, negotiates them and does diligence. The agent has an office in the US. It does similar work for other funds.

The fund regularly makes loans to US borrowers and also engages in underwriting of equity interests. It enters into "distribution agreements" committing to buy up to a fixed dollar amount of shares for resale. There is a notice period: the fund buys the shares within an agreed number of days after notice from the client, and it arranges during the notice period to place all the shares. The stock is bought at a discount from current market and then resold at market. The fund also earns fees on both the loans and the underwriting.

Under the US tax code, any foreign corporation that engages in a US trade or business must pay full US corporate income taxes on its income from that business. Partners in partnerships are treated as if they engaged directly in any business in which the partnership engages.

There is no clear line for what is considered a trade or business. Activities undertaken for profit are a trade or business if they are "considerable, continuous, and regular."

The IRS said in the memo that business that a foreign person does through an agent is treated as if done by the foreign person directly, regardless of the degree of control the foreign person exercises over the agent.

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MR. EBER: A commitment of 12 months or into the next tax year could be considered long term.

MR. MARTIN: What is the current spread between yields in the benchmark wind deals versus utility-scale and rooftop solar?

MR. EBER: We don't see much of a difference in our shop on those.

MR. MARTIN: Among all three?

MR. EBER: Between utility-scale solar and wind.

MR. MARTIN: When you get to distributed solar, is the spread 100 basis points higher, 150, 75?

MR. EBER: Those deals are not very homogenous, so they are difficult to talk about in generalities, especially as it pertains to pricing.

MR. CARGAS: There can be a meaningful spread between wind yields and solar yields, but yield is really only one of the metrics by which we and other investors compare these investments. There are different structures potentially and different repayment profiles both from a tax and cash perspective. Obviously wind deals have 10 years of PTCs, and sometimes they have a cash reversion period. Solar deals have an ITC on day one that is a significant part of the yield. Some deals are inverted leases with a constant coupon.

The point is that yield is interesting, but it is not the be all and end all. It is not the only method that we use in evaluating these investments and, frankly, it is not the only thing that sponsors should consider when contemplating structures and pricing.

MR. MARTIN: John Eber has made the same point repeatedly on many calls and panels that we have done together.

How much of a yield premium should one expect currently if one adds leverage, meaning that the tax equity is behind a lender in the capital stock?

MR. EBER: We are seeing few leveraged tax equity deals, certainly very few in the wind space and not much more in the solar market. The tax equity will clearly require a premium because it has a greater risk of not reaching its return. The premiums run a few hundred basis points, but there are so few leveraged deals today that it is impossible to say what is "market."

MR. MARTIN: What do you consider "market" for lender forbearance where there is leverage? Or is there no market at this point?

MR. EBER: We have not seen much. In solar where there has occasionally been leverage, anybody on the tax equity side would want forbearance at a minimum through the recapture period for the ITC.

MR. MARTIN: Forbearance means the lenders would have normal remedies after a payment default, but could not take the asset for non-payment defaults? All they could do in such a situation is push out the sponsor?

MR. EBER: Right. You would want a minimum of five-year forbearance if you are willing to go into one of those deals in the first place.

MR. CARGAS: I think one of the reasons why we are not seeing that much leverage is because lenders are loathe to agree to those sorts of forbearance provisions. None of the leveraged solar deals was an ITC deal; they were Treasury cash grant deals, and those are mostly out of the picture now.

MR. EBER: If there were a wind deal, then you would want 10-year forbearance because that is the PTC period. That would be an even a bigger lift.

MR. MARTIN: John Eber, you said there were 19 active tax equity investors in the wind sector last year. Do you have a feel for how many there were in the solar sector?

MR. EBER: We counted 25 in solar. We are seeing somewhere around 28 to 30 between both sectors. Many play in both markets. A limited number will only participate in one or the other. In addition to the 28 to 30 active tax equity investors,

Downward pressure remains on interest rates, with 94 active banks chasing deals.

others are looking at entering the market. This is what one would expect as the economy improves. More companies start paying taxes and look to come back into the market.

MR. MARTIN: Do you see the solar rooftop market moving more in the direction of inverted leases, rather than partnership flips and sale leasebacks, and, if so, what do you think is driving that shift?

MR. CARGAS: We know that some market participants have a preference for inverted leases for solar, but we are not sure we have seen a huge shift. To the extent that there has been some movement in that direction, it may stem partly from new guidelines the IRS issued for transactions involving tax credits for renovating historic buildings in early 2014. Those guidelines suggested the IRS is okay with the inverted lease structure, at least in historic tax credit deals. Some players have concluded that that is *de facto* guidance for solar.

We maintain a preference in our shop for partnerships and regular leases.

MR. EBER: I generally agree with Jack. Many of the sponsors to whom we are talking have a preference for the partnership flip. That seems the more prevalent structure from our observations, although there are a number of solar investors who will only do inverted leases.

MR. MARTIN: How comfortable is the tax equity market with wind projects that relied on physical work at the project site or a factory to be under construction in time to qualify for tax credits?

MR. EBER: I think most of the market has become comfortable with physical work cases given that we have now had three rounds of guidance from the IRS. We think the accumulated guidance is fairly comprehensive.

MR. MARTIN: Let me drill down a bit briefly. Some developers dug several holes for turbine foundations before year end, and then went back to basic development work on their projects. Some developers ordered a transformer and there was limited physical work at the factory before year end. Are you okay with those cases?

MR. EBER: It will turn on the facts in each case. Let's just say that I think the sponsors have been very responsible in trying to establish clearly that they began physical work, and there is a range of fact patterns on offer in the market. The more work that was done, the better chance you have of attracting a broad spectrum of tax equity to a transaction. The closer you are to the low end of the requirements, the more challenging it will be to raise tax equity.

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The fund in this case engaged in a steady stream of US transactions.

The fund argued that it was shielded from being viewed as engaged in a US trade or business by two trading "safe harbors."

One shields foreigners who are merely "trading in stock or securities through a resident broker, commission agent, custodian, or other independent agent." The foreign person cannot effect the trades through an office in the US.

The IRS said this safe harbor does not apply because the fund is engaged in a banking business rather than "trading." Trading is purchasing and selling in secondary markets in order to profit from changes in value of the traded securities, the IRS said. A trader does not earn fees or a price markup in exchange for services.

The IRS said it also thinks the fund is acting through a US office. An independent agent's office is not usually treated as belonging to someone who hires the agent, but the IRS said this agent is not "independent" because it has been delegated too much discretionary authority to run the deals.

The other "safe harbor" shields foreigners who are merely trading stocks and securities for their own accounts. It does not matter whether such a taxpayer trades directly or through an agent. It does not matter how much discretionary authority the agent has to make decisions, and it does not matter whether the foreign person trades through an office in the US. However, a "dealer" in stocks or securities cannot use this safe harbor, as he is considered to be engaging in a business rather than merely investing for his own account. Under IRS rules, a foreign person is not a "dealer" if he underwrites securities by placing them solely with foreign purchasers or if the agent is merely investing funds belonging to a particular customer, such as where a foreign bank engages as US agent to invest funds of a particular customer in the US.

The IRS said this fund is a "dealer" and is not merely investing for its own account. Moreover, it resells the underwritten

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MR. MARTIN: How comfortable is the market with projects that were under construction in time because the developer incurred at least 5% of the expected cost, but that will not be completed until after 2016?

MR. CARGAS: That's a tough question. We are not fully ready to address 2017 because we are still concerned about 2016. We want to see clear guidance from the IRS that the extension of the construction-start deadline to the end of 2014 also had the effect of giving developers through the end of 2016 to complete projects without having to prove that they worked continuously on the projects.

Some participants appear to be assuming that there was already such a back-end extension, but we would like to see it in writing from the IRS and, until that happens, we are not even thinking yet about 2017.

MR. EBER: That is a very good summary. We are anxiously awaiting confirmation from the IRS as is the rest of the market.

Bank Debt

MR. MARTIN: Turning from tax equity to bank debt, Tom Emmons, what was the North American project finance bank market in 2014 compared to 2013?

MR. EMMONS: Volumes were up significantly in 2014 compared to 2013: 45% from a $28 billion market in 2013 to $41 billion in 2014. I am drawing on data compiled by *Infrastructure Journal*. The US was dominant, comprising about 80% of the North American project finance market, Canada about 15%, and Mexico the balance. In terms of sectors, oil and gas was just under half of the market, conventional power was about a quarter and renewables were just under a quarter.

MR. MARTIN: How many active banks were there in 2014, and how many do you expect in 2015?

MR. EMMONS: In 2014, 94 banks played some role in project finance. That is up 20% from 72 in the previous year. Of course, that is the whole universe, including a lot of banks who had low levels of activity. A better measure is the number of major lenders. In 2014, 49 banks committed more than $200 million in aggregate each, and that is up about 20% from 2013. Not only is the market growing in total participants, but the big guys are also putting out more money.

Predictions about the year ahead are always difficult. There will no doubt be new entrants, but we are nearing 100 banks and already have plenty of players. I think what will happen is that the current lenders will step up with additional capacity to meet the demand because those banks still have capacity.

Bank margins can be as low as 150 basis points over LIBOR, with most of the market sticking to tenors under 10 years.

MR. MARTIN: When you say step up to meet the demand, it sounds like you are suggesting that demand for capital to fund new projects in North America is increasing?

MR. EMMONS: There was increasing demand in the last two years, and the banks stepped up. The bank market is adequately liquid, and there are enough players that the bank market can adapt to additional market demand. We remain in a situation where there are plenty of banks and plenty of liquidity. If there is more demand in 2015, the banks will be able to handle it.

MR. MARTIN: It is always a question who has the edge in negotiations. The big story last year was there were so many banks chasing product that there was downward pressure on rates. Is demand increasing faster than supply, or will we remain in an oversupply situation?

MR. EMMONS: We remain in an oversupply situation. There is still downward pressure on rates. As I mentioned, there are more lenders, the market is liquid, the market is competitive, banks have lower funding costs, and there are more short-term facilities. The banks are not being asked to do the heavy lifting of long-term loans.

However, I think most of the rate reduction is behind us. Banks now are often bidding at the minimums in their return models. When you look at this from the perspective of cycles, we are now at margins that are roughly where they were in 2008. It is hard to see how they can fall a lot farther. That said, there is liquidity and there still is downward pressure. The bottom line is it remains a borrower's market.

MR. GREENWALD: A lot of the increase in the size of the market came from just a handful of mega transactions that took place in the oil and gas space, notably Sasol and the Freeport transactions in the last quarter of last year. We should see some more mega transactions this year.

MR. EMMONS: If you look at subsectors, apart from oil and gas, some interesting trends emerge. US solar doubled to $2.5 billion and lending to wind projects declined by about 40%, dropping from $3 billion to $1.8 billion. Conventional power was about flat.

MR. MARTIN: What is the current spread above LIBOR for interest rates?

MR. EMMONS: There is a wide range, particularly because different projects present different risks, but to summarize, at the low end, for clean, short-term, large, well-sponsored deals, margins can begin as low as 150 basis points above LIBOR, and sometimes even lower in unusual cases. In the middle, for a typical moderately-complex medium-sized term loan, somewhere around 200 basis points, plus or minus. At the upper end, complex and aggressive deals, and back-leveraged debt, can be in the high twos, maybe even approaching three. In very special cases, we are looking at something now, about which probably a lot of people on the call know, that is large, complex and very unusual, and the pricing for it could even go higher if there is a need to bring in a lot of lenders.

MR. MARTIN: Is the up-front fee the same as the LIBOR spread? If the spread is 150 basis points over, the up-front fee is 100 basis points?

MR. EMMONS: Yes. Typically fees are equal to starting margins. There can be exceptions.

MR. MARTIN: Steve Greenwald, is it still the case that there is no LIBOR floor in the bank market?

MR. GREENWALD: That is correct. You still see a LIBOR floor in the term loan B market, but not in the bank market.

MR. MARTIN: How much movement do you expect in interest rates this year? Do you think they will remain where they are for the whole year?

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securities to both US and foreign buyers.

Most offshore funds try to avoid a US trade or business for their lending by acquiring loans in the secondary market and by engaging in "season-and-sell" strategies where securities are held for a period of time before reselling.

TREASURY CASH GRANT litigation has started moving.

The US government won the first of a number of lawsuits against the US Treasury by renewable energy companies that feel they should have received larger cash grants under the section 1603 program. There are another 20 lawsuits pending. Several raise significant issues of interest to the larger project finance community, including whether part of the purchase price paid for a power project must be allocated to the power purchase agreement in situations where the contracted electricity price is above what can be earned in the current market.

The oldest lawsuit has been pending since July 2012. All are pending in the US Court of Federal Claims. The court decided the first case in mid-January within weeks after hearing oral arguments. The others should start to move this year.

The decided case involved a new power plant in Lewiston, North Carolina that used biomass to produce steam and electricity that were sold to an adjacent Perdue chicken rendering plant. Congress directed the US Treasury, starting in 2009, to pay owners of new facilities that use renewable energy to generate electricity 30% of the eligible cost in cash as an alternative to tax credits during a period when there were concerns that the tax equity market had collapsed.

The owner of the biomass power plant applied for a cash grant of $2,711,311. The Treasury only paid $943,754. It allocated the project cost between the parts of the project that produce steam and electricity and paid a grant only on the part that produces electricity.

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MR. GREENWALD: I expect them to be pretty much where they are currently. I do not see anything that will move them a whole lot lower, and I do not see anything that will give banks the negotiating leverage to push them much higher.

MR. MARTIN: Tom Emmons, what are current loan tenors?

MR. EMMONS: Banks are trying to stay under 10 years for term loans. There are some exceptions where banks are willing to go to 18 years, but most of the market is under 10. A lot of deals today are short-term bridges to tax equity; we just talked about how tax equity volumes are increasing.

MR. MARTIN: What cash sweep should a borrower expect during the term of a bank loan?

MR. EMMONS: In a renewable energy deal, typically none, except there may be some special reason to sweep in a highly-structured deal, perhaps to achieve a particular metric such as a maturity date or some key ratio for a ratings purpose.

MR. GREENWALD: There are sweeps in some of the very largest deals, or perhaps not so much sweeps as dividend restrictions. For example, if you have a $2, $3 or $4 billion bank transaction, the banks will not want to let a lot of money go out the door to the equity while waiting for a deadline to be reached when a huge principal amount has to be refinanced. They will want incentives to encourage the borrower to complete some of the refinancing before any distributions can be made to the equity.

MR. MARTIN: What are current debt service coverage ratios for wind, solar and natural gas projects?

MR. EMMMONS: I can comment on the renewable piece of that. They are quite stable. Solar is 1.35x, and wind is 1.45x plus or minus, depending on the circumstances. Those are P50 coverage ratios.

MR. GREENWALD: On natural gas deals, the coverage ratio tends to be 1.35x at the low end.

MR. MARTIN: What are advance rates on construction debt in the current market: 85%, 80%, higher, lower?

MR. EMMONS: They can be up to 80% to 90% for renewables.

MR. GREENWALD: For other large industrial projects, they can be as low as in the 50% range, depending on the price risk that lenders are being asked to assume, all the way up to the mid- and sometimes high 70% range on the well-structured tolling arrangements where there is little-to-zero price risk being left to the lenders.

MR. MARTIN: Yesterday, the Swiss released the cap on the Swiss franc and let the franc float. It went up 39% in value against the US dollar. You both work for European banks. What effect, if any, will this have on the US project finance market?

MR. GREENWALD: I don't see it having much effect.

MR. MARTIN: Tom Emmons, agree?

MR. EMMONS: It should make the US business more valuable to European banks because the dollars of income coming back are more valuable. However, most banks that play in this territory are international and they have US dollar funding desks to match assets to liabilities, so I don't think it has much effect on how the European banks play in this market.

Term Loan B

MR. MARTIN: Let's move to the term loan B market. JP Boudrias, do you have data on the term loan B volume in the power sector in 2014 and how that volume compared to 2013?

MR. BOUDRIAS: In 2014, we saw about $9 billion of term loan B compared to $11 billion in 2013. The 2014 deals were almost entirely power. There were 16 transactions in 2014 compared to 22 in 2013.

MR. MARTIN: Of those 16 projects in 2014, what percentage were merchant gas-fired powered power plants with power hedges in PJM and ERCOT?

MR. BOUDRIAS: Seven out of 16 are in that category.

MR. MARTIN: And the balance was what?

MR. BOUDRIAS: The balance was a mix of transactions such as Atlantic Power and ExGen Renewables that were holdco rather than opco transactions and renewable deals that tended to have a bit more contracted revenue.

MR. MARTIN: Earlier this week, a panel I moderated in New Orleans expressed the view that merchant power plants will prove financeable in 2015 not only in PJM and ERCOT, but also in the New England ISO. Do you agree?

MR. BOUDRIAS: That makes sense. When you look at the evolution of how the market has gotten comfortable with quasi-merchant transactions, the first deals were done in ERCOT because of good visibility on pricing and then moved to PJM where there is similar visibility and merchant projects can qualify for capacity payments. Obviously, one of the things that has changed in New England in recent years is that capacity prices are in much better shape than they used to be just a few years ago.

MR. MARTIN: For those listening who may not know what a term loan B loan is, it is basically debt papered as bank debt but sold to the institutional market.

MR. BOUDRIAS: From a documentation standpoint, it looks similar to bank debt, but borrowers in the term loan B market tend to have fewer occasions when one needs to come back to the lenders for approvals. It is not quite bond documentation as there are still financial covenants, but a B loan is written so that there will not have to be a lot future interaction between the holders of the term loan and the borrower.

From an execution standpoint, these are truly capital markets transactions. They will be driven by momentum and what is going on in the broader market, including the ability to place the paper in the secondary market.

MR. MARTIN: What do you foresee in the term loan B market in 2015?

MR. BOUDRIAS: It is interesting. When you look at the progression, 2013 saw a lot of refinancing volume. Obviously we entered 2014 with a lot of the refinancing that had to occur already out of the way. When we look at margins over the course of 2013 and 2014, the trend has generally been up. All of this suggests less refinancing activity in 2015. Deal supply will be entirely driven by either new assets that are being brought to market like transactions that had been financing in the bank market, but the sponsors are looking for more leverage or want to take a dividend. New construction and M&A may add to deal volume.

To sum up, in 2015 we expect largely similar volumes to what we saw in 2014. We do not expect significant growth in volume.

MR. MARTIN: Pricing for strong double B credits at this time last year seemed to be about 275 basis points above LIBOR with a 1% LIBOR floor and 1 point of original issue discount. For single B, I think the deals were pricing as much as 500 to 550 basis points over. What is the current pricing as we head into 2015?

MR. BOUDRIAS: It is comparable. Double B is probably around 350 over with the same 1% floor and issued at 99. Not all single Bs are created equal, but they are probably circling around 500 basis points over. This pricing is 75 basis points wide of where we saw levels at the end of 2013.

MR. MARTIN: So it is the opposite of the bank market where there has been consistent downward pressure on rates. What accounts for the increasing spreads?

MR. BOUDRIAS: One trend that we saw throughout 2013, but that was reversed in 2014, was the institutional bank mutual funds saw inflows for most of 2013. They went for 95 weeks in a row with positive inflows. Then in 2014, the trend went the other way. But interestingly, in 2014, we saw record formation of new collateralized loan obligation */ continued page 10*

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The court gave "considerable weight" to the Treasury's view "as a reasonable interpretation of the statute." However, it stopped short of giving the Treasury total discretion because "there is no indication that Congress explicitly or implicitly delegated broad interpretative authority to the agency." There was no formal rulemaking process by Treasury when it released guidelines explaining how it plans to pay grants.

The biomass plant owner said the Treasury already paid it a full grant on another, similar facility. The government lawyers told the court the earlier payment was a mistake. The judge said the Treasury is not bound by a mistake to make full payments on other plants. The case is *W.E. Partners II, LLC v. United States*.

Another suit filed in late December raises the same issue as the one that the court decided in January. That suit — called *GUSC Energy, Inc. v. United States,* involves a new power plant that GUSC Energy put in service in November 2013 at an industrial park in Rome, New York that uses wood chips to produce steam and electricity. The owner applied for a grant of $5,469,028 and was paid only $316,609. (The payment would have been $341,174 but for a 7.2% haircut due to budget sequestration.) The Treasury paid a grant solely on the equipment used to generate electricity, and it also removed costs related to site cleanup, landscaping, ornamental iron work and paving.

There is a six-year statute of limitations for companies who received grants to file suit. Any government losses in the remaining cases could lead to more lawsuits.

Meanwhile, Congress fixed a technical error in the original grant statute. Grants do not have to be reported by recipients as taxable income. The original program made this clear for companies that pay regular corporate income taxes, but not for companies that pay alternative minimum taxes. The US has two corporate income taxes. A company computes its taxes under both and pays essentially whichever amount is higher.

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funds that, by and large, are the largest players in the market, probably accounting for 60% of demand in the institutional debt market.

The difference between the two is that mutual funds have no real cost of funds, since they are not raising funding to invest, whereas CLOs have a cost of funds and will take that into consideration in pricing.

So as the mix of investors moves from largely price-insensitive institutional investors to investors who have a bit of a floor, you would expect that would put upward pressure on margins.

The term loan B market is 275 to 500 basis points over LIBOR.

Another thing to keep in mind is this is more capital markets driven. Obviously, there was a good amount of upheaval in late 2014 with falling oil and gas prices. About 20% of the leveraged finance market overall, including the bond market, is exposed to oil and gas borrowers. There has been a lot of selling pressure as the leveraged finance market has felt over exposed to energy; there is pressure to get out of that market and go someplace else.

As a point of reference, energy is about 10% of the S&P 500.

MR. MARTIN: Is a power hedge essential to financing a merchant power project and, if so, how long a term must it have in relation to the loan tenor?

MR. BOUDRIAS: We have not really seen a lot of pure merchant transactions. What we see are transactions where there is some form of price hedge. Probably somewhere around three to four years makes sense. If I tell you any shorter than that, the hedge would not provide any real benefit. It has been important to have a hedge at least in the early years to reduce price risk.

Project Bonds

MR. MARTIN: Let's move to project bonds. Jerry Hanrahan, the project bond market does not do well during periods when the bank and B loan markets are wide open and looking for product. Was that the story in 2014, and what do you see ahead for 2015?

MR. HANRAHAN: I think that's right. There is lots of liquidity in the bank and other markets, and that has traditionally been where most of the project finance deals have gone. Those markets have dominated. There were no large syndicated deals to the private placement market in 2014, but people like ourselves were able to do a few transactions on a more direct and relationship basis.

That said, the project bond market remains very deep. There are probably more than 25 active players.

MR. MARTIN: Primarily insurance companies?

MR. HANRAHAN: That's right. The project bond market can handle large transactions on the order of $500 million, maybe even up to $1 billion of capacity for a well-structured deal.

It is hard to say how much volume there will be in project bonds in 2015. We are not hearing a lot of chatter about deals in the pipeline, apart from one fairly significant deal that is in the market today.

MR. MARTIN: You need a spark like a fear that interest rates will rise. Project bonds are fixed-rate long-term debt, unlike floating-rate bank and term loan B loans.

MR. HANRAHAN: That's right. Many banks are limited in terms of how long they can go, although there are some players that will go fairly long. The project bond market does not have any real constraints on tenor other than the underlying creditworthiness of the borrower and the contract that is the source of cash flows.

MR. MARTIN: Let me run down a list of what seem to be the main differences between bank and term loan B debt, on the one hand, and project bonds on the other. Tell me if any of these items is wrong.

Tenor: you said you do not have a limit on tenor, but the loan tenor can usually run as long as the power contract or perhaps one year short of the PPA term.

MR. HANRAHAN: The tenor generally matches the power contract. It used to be more common to have the loan run just short of the power contract term, but these days, the term of the debt and the PPA term generally match.

MR. MARTIN: There are no up-front fees because the economics are fully baked into the spread. The spread is priced to Treasury bonds rather than LIBOR. Ratings may be required for widely-syndicated deals, but not for the private or direct placement deals that you have been discussing. Another key differences is make-whole payments are required if the bonds are repaid ahead of schedule. Such payments are not required in the bank market. The project bond market takes construction risk, but will charge a commitment fee on undrawn capital.

MR. MARTIN: Are there other differences besides the ones I mentioned?

MR. HANRAHAN: Adding to what you said, ratings are not required, but the project bond market is investment grade-driven. You might see some small high-yield issuances, but the market is overwhelmingly investment grade, and that is a big distinction between ourselves and the bank and term loan B markets as the bank market tends to be more double B, and the term loan B market can do things that are even lower rated.

The main differences are the need for an investment-grade credit and the ability to add tenor to the debt profile.

MR. MARTIN: What is the current spread above Treasuries for project bonds, and what does it translate into as a coupon?

MR. HANRAHAN: I think the current market is probably somewhere around the mid-200 to 300 basis points over average-life Treasuries. There has not been a lot of product to test that, but that is my sense for a well-structured deal. The price can go up significantly if the borrower is a tougher credit.

Given where we are with Treasury yields, we are at a multi-year low. That translates into a coupon of around 4.5% currently.

MR. MARTIN: For what may be 20-year fixed-rate debt.

MR. HANRAHAN: Correct. It would not surprise me if the multi-year low that we see today in the Treasury market ends up forcing some investors to impose minimum coupons over and above whatever their spread requirements are, but I think you will generally get to the range I mentioned.

IN OTHER NEWS

The IRS was starting to lose patience by last fall after waiting five years for Congress to fix the error and was starting to collect taxes from companies that received grants while they were on the alternative minimum tax. A tax extenders bill that cleared Congress in December fixed the error.

A MASTER LIMITED PARTNERSHIP set up to own solar and wind projects postponed a public offering in early February.

The company said it will operate for now using private capital.

Master limited partnerships are partnerships whose units are traded on a stock exchange or secondary market. Partnerships are not subject to federal income taxes; rather, each partner is taxed directly on his share of the partnership's income. Under US tax law, any partnership whose units are publicly traded is taxed like a corporation. A master limited partnership, or MLP, is a partnership that is able to retain its status as a partnership, despite public trading, under a special rule in section 7704 of the US tax code that preserves partnership status as long as at least 90% of the partnership's income each year comes from passive sources — like interest and dividends — or is income from producing, processing, refining, transporting or marketing minerals or natural resources. Wind and sunlight are not considered natural resources because they are inexhaustible.

The company — Sol-Wind Renewable Power, LP — planned to use a "self-help" MLP structure used by Fortress and Blackstone. (For a more detailed discussion about the structure, see "A New Structure for MLP Roll-Ups" in the January 2007 *NewsWire* starting on page 12.) Sol-Wind said it would have an initial portfolio of 185.6 megawatts of contracted solar projects and one contracted wind farm. All of the projects are in the US, with the exception of 5.9 megawatts of solar in Puerto Rico and 2.9 megawatts of solar in / continued page 13

Yield Cos: State Of Play

Six yield cos have been formed to date by large renewable energy developers in the United States. Many people are curious about how much yield cos reduce the cost of capital for the development companies that have formed them, what discount rates they use to acquire assets, how much room there is for additional yield cos, what it takes to be able to form one, and similar questions.

The following is an edited transcript from a well-attended roundtable discussion about yield cos at the Infocast projects & money conference in New Orleans in January. The panelists are Andy Redinger, managing director and group head of utilities, power and renewable energy at Keybanc Capital Markets and who contributed to the early buzz about yield cos by being one of the first investment bankers to write about them, Carl Weatherley-White, president of LightBeam Electric Company, former head of project finance at Lehman Brothers and Barclays Capital and another early proponent of yield cos, Alejandro Burgaleta, chief financial officer of Gestamp Wind, a Spanish wind developer with a global footprint that is considering forming a yield co, Hunter Armistead, executive vice president of Pattern Energy, a prominent US wind company that has reorganized itself as a yield co, and David McIlhenny managing director of project finance of SunPower Corporation, a prominent solar developer that has been debating whether to form a yield co. The moderator is Keith Martin with Chadbourne in Washington.

MR. MARTIN: David McIlhenny, what is a yield co?

MR. MCILHENNY: A yield co is a synthetic master limited partnership with equity investors who are looking for regular dividends and expect the dividend to grow significantly over time. One way to maximize how much cash flow is available for dividend payments is to minimize how much taxes the yield co pays by having the yield co hold projects that throw off as much in tax shelter as the taxable income they generate.

MR. MARTIN: That is a fairly sophisticated answer. Carl Weatherley-White, do you want to add to it?

MR. WEATHERLEY-WHITE: A yield co is a company with stable operating cash flows from long-term contracted assets, that expects dividends per share to grow over time and that taps into the public equity market to raise capital at a high multiple to earnings.

MR. MARTIN: Let me offer another definition. A yield co is a simple concept. A development company separates its operating projects from its development pipeline. It puts the operating projects in a separate corporation that lists on a stock exchange and is able to raise capital more cheaply because its projects are de-risked; they have operating histories.

Hunter Armistead, you take issue with these definitions. What is the problem with what all three of us said?

MR. ARMISTEAD: Anything that starts with the word synthetic makes me nervous. There are different flavors of yield cos. Is a yield co a separate company or is it a financing vehicle? Each of the yield cos that has been formed to date has had a strong sponsor standing behind the yield co with a healthy development pipeline that the yield co can buy as a path to future growth. However, Pattern is a different flavor of yield co than NRG Yield is. I do not believe all yield cos are the same.

MR. MARTIN: You asked whether a yield co is a company or a form of financing. By asking this, you are implying, I think, that there is not much more room in the market for yield cos that are merely roll ups of assets acquired from third parties; you need a real developer with a big pipeline of development assets to support a yield co. Is that what you meant to say?

MR. ARMISTEAD: Is this a negotiation? [Laughter.] Good lawyers put the question in a way that comes close to answering it. I think that the investor base that has been attracted to the existing yield cos has put a premium on strong sponsorship, a strong pipeline that allows for growth, stability and a track record running the operations side of the business. If those variables are there, then I think there is more room in the market.

Yield cos are vacuuming up operating assets at high prices.

Maybe someone who cannot check off all these boxes will find another group of investors that is looking for something different.

MR. MARTIN: Andy Redinger, is there much room in the market for more yield cos?

MR. REDINGER: Absolutely. There is a lot of room. I think a yield co is a real estate company. It is an opportunity to invest in an asset class that looks a lot like real estate with characteristics that are much better than what is in existing REITs today. There is a huge volume of potential yield cos coming to market in 2015. Look at the REIT market. REITs have been around for more than 25 years and have a current market capitalization of more than $400 billion. I challenge anybody to compare REIT assets to yield co assets, and I will tell you all day long that yield cos are a better asset class.

MR. MARTIN: So you see a lot of pent-up demand for yield cos in 2015. How many more do you foresee, and will the next round of yield cos be roll ups of assets from third parties as opposed to the Pattern or NRG Yield model?

MR. REDINGER: Hunter Armistead is absolutely right. We will see a different type of yield co in 2015. The yield cos we have seen to date have all had strong sponsors backing them. It will be interesting to see whether the market differentiates between sponsor-backed yield cos versus the two of us getting together, going out and buying assets and saying we are a yield co.

MR. MARTIN: Can we do that?

MR. REDINGER: We absolutely can.

MR. MARTIN: So roll ups work.

MR. REDINGER: Well, I am not calling it a roll up. Otherwise, you would have to call the entire REIT industry a roll up. Yield cos are similar to what is already done in the REIT space.

MR. MARTIN: I did not hear a number of how many more yield cos will come to market in 2015. Can you give us a number?

MR. REDINGER: It is more than a dozen.

MR. MARTIN: Carl Weatherley-White, do roll ups work?

MR. WEATHERLEY-WHITE: Absolutely.

MR. MARTIN: Isn't future growth less certain for a roll up? Yield cos are like vacuum cleaners. With so many yield cos competing for assets, eventually you run out of things to vacuum up.

MR. WEATHERLEY-WHITE: That's a great question. I think the emergence of more yield cos is not only possible, but really required for this market to develop. Investors are looking for more opportunities to participate in the space. Depending on how you define "yield co," there are five or six companies today. The market capitalization of the existing yield */ continued page 14*

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Canada. All of the projects were built in the last five years. Sol-Wind focuses on middle-market assets: solar ranging from 100 kilowatts to five megawatts and wind between from one and 10 megawatts in size.

The company said it would put all the projects under two corporate subsidiaries: one for US projects and the other for projects in other countries. It planned to raise $174 million from the public by listing on the New York Stock Exchange and $248.1 million from its sponsor, 40 North Investments, and use the money to buy the initial portfolio. The sponsor planned to retain 56.6% of the ownership interests through a mix of common and subordinated units. The sponsor would also have incentive distribution rights entitling the sponsor to as much as 50% of the excess cash flow after distributions of at least 37.38¢ per unit have been made each quarter on all the other units.

Sol-Wind said it has a pipeline of another 1,098.6 megawatts of solar and wind projects that it has entered into memoranda of understanding or holds rights of first refusal to acquire through the end of 2017. Some of the pipeline projects are in Japan, Mexico, the United Kingdom and Puerto Rico. The rest are on the US mainland.

The company planned to inject the money raised into the corporate subsidiaries that own the projects partly as equity and partly as debt. This would allow the company to "strip" earnings from the corporate subsidiaries as deductible interest on the debt, thereby subjecting the stripped earnings to only one level of tax at the level of the MLP partners. The remaining earnings would come up to the MLP as dividends. Sol-Wind said it expects "almost all" of its income to be dividends or interest. It said it does not expect the corporate subsidiaries to have "significant" taxable income for 15 or more years.

Interest in the MLP market could increase as an alternative to yield cos. The six existing yield cos have a combined market capitalization of $12 billion. There are 120 MLPs */ continued page 15*

Yield Cos

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cos is about $12 billion. The market capitalization of the existing master limited partnerships is about $600 billion.

More than 50 times as much capital is looking for opportunities like yield cos than is invested in the existing yield cos.

The question is whether there are enough assets to support that type of growth, and I think there are. Many new energy and other infrastructure projects are being built worldwide.

Necessary Predicates

MR. MARTIN: Andy Redinger, what are the necessary predicates before you can have a yield co? For example, how much asset volume do you need to start?

MR. REDINGER: Two years ago, you needed at least $1 billion in equity value. Today, $500 million is probably the minimum with at least $30 million a year in distributable cash flow. Can you do something smaller? Sure, but I do not think it will trade as well. You will see all kinds of yield cos coming to market this year. I think you need a development pipeline. You need to show an ability to grow, and you need to show some geographic diversity.

MR. MARTIN: So the yield co must have at least $500 million asset value. How much capital must it come to market hoping to raise against that much asset value? At least $100 million?

MR. REDINGER: You usually see 30% to 40% of the company sold in the initial public offering, so that would be $150 to $200 million as the initial capital raise. The objective is to take as little public as possible out of the box, but enough to ensure good execution. This will let the sponsor benefit from any upward price appreciation on its remaining ownership percentage after the IPO. You come to market as small as the market will allow and leave a lot in the development pipeline to show the potential for growth.

MR. MARTIN: Hunter Armistead, you have been through the process. Do those numbers sound right?

MR. ARMISTEAD: They are the right numbers for when Pattern went to market. One of the real challenges today is asset valuations have stepped up. Delivering growth is not just a matter of adding new assets, but it is also growing dividends per share. Depending on the yield co's cost of capital, that could be hard to do, given the sky-high asset valuations, unless the yield co has a strong development pipeline from an affiliated sponsor.

MR. MARTIN: This is where I was trying to pin you down before! So a yield co needs a sponsor with a healthy development pipeline?

MR. ARMISTEAD: There are two different kinds of yield cos.

MR. MARTIN: Let's move to cash flow. Some assets put into yield cos are subject to debt or tax equity. What percentage of the operating cash flow should be available for distribution to shareholders, or put differently, what percentage of it can be used for debt service or be distributed to tax equity? 65%? Less?

MR. REDINGER: Roughly a third of the revenue should be available for distribution. However, the trend today is to de-lever the assets going into yield cos or to have an amortization profile that is better suited for a yield co, for example, by having less amortization early on and maybe more later or there may be no amortization.

MR. MARTIN: So you front load the cash available for distribution?

MR. REDINGER: Yes. Yield co investors tend to be more focused on the short term. Yield cos tend to be valued based on next year's cash flows.

MR. MARTIN: Why would anyone be fooled by that? [Laughter.]

MR. WEATHERLEY-WHITE: It is important for management teams and bankers involved to have a strong handle on the cash flow projections. To miss a dividend and to fail to grow the dividend will lead to a failed company. Therefore, to value something based on first-year cash flow that trails off is setting the company up for a huge problem. The fancy vehicles, as Andy said, are designed to produce steady cash flows, less leverage, tax equity with less dramatic flips: those sort of things.

MR. MARTIN: Maybe one lesson for anyone doing tax equity is not to give 99% of the cash to the tax equity investor, but to work out a different sharing ratio, and not to have cash flow sweeps to pay indemnities. What cash sharing ratio should a sponsor aspire to if he wants to preserve the option to move a project later into a yield co?

MR. WEATHERLEY-WHITE: Just try for a fixed sharing ratio that leaves a significant amount of cash each year for the sponsor.

MR. MARTIN: I hope John Eber [head of tax equity investments for JPMorgan Capital Corporation], who is sitting in front of me, is listening to this.

MR. ARMISTEAD: John stuck me on his panel, so maybe this is my opportunity. It is an unnatural state when the tax equity is earning a higher return than the sponsors. [Laughter.]

MR. MARTIN: John asks, "What wrong with that?" [Laughter.]

MR. ARMISTEAD: The wind business has reached a stage of maturity where performance is much more reliable. This has

allowed the cash sharing ratios in tax equity structures to move today to a better split that makes projects more suitable for yield cos.

MR. BURGALETA: You must send a message to your investors that you will not fool around with cash flow, and you have to be very careful about what you announce because you will have to keep to that every quarter.

MR. MARTIN: So you must be careful about the dividend you announce because you create an expectation.

How much should one expect to spend to put a yield co in place, and how long does the process take?

MR. ARMISTEAD: This is an interesting thing. We have a banker who loves every yield co.

MR. MARTIN: Andy Redinger, that is smack talk. Are you going to let that go unanswered? [Laughter.]

MR. REDINGER: The question is how costly, how hard and what does it mean when you get there?

MR. MARTIN: Give me some numbers.

MR. REDINGER: I don't like to share them because somehow they will end up all going to you, Keith, as a lawyer . . . . [Laughter and talking over each other.] Four to $5 million in costs and nine months to a year to complete the offering.

MR. MARTIN: . . . which is not bad. Two data storage companies that converted recently to REITs said it cost them as much as $145 to $155 million in conversion costs.

MR. ARMISTEAD: I don't think they included underwriter fees in that. Actually, I am certain of that. [Laughter and talking over each other.] Andy does it *pro bono*.

Cost of Capital

MR. MARTIN: Yield cos pay low dividends on the order of 3%, 4%, 6% and yet most of the shares are held by institutional investors who have other places they can put their money that earn returns in the teens. The shareholders are looking for growth on top of dividends. What is the true cost of capital to yield cos in the current market?

MR. MCILHENNY: A rule of the thumb is that if you can project 15% dividend growth, then you can pay a current dividend yield of 3%.

MR. MARTIN: To what does that translate as a cost of capital?

MR. MCILHENNY: You can figure it out mathematically. The perception of growth is key to value. That perception can lower the cost of capital for the initial public offering. A high growth rate can lower the cost of capital for drop-down assets. Higher than expected growth can increase the */ continued page 16*

IN OTHER NEWS

with a market capitalization of close to $600 billion. In 2013, MLPs raised $43 billion in initial public offerings, almost 17% of the entire US equity market. Almost 60% of MLPs are fewer than five years old. As many as another 25 MLPs are expected to come to market this year.

MLPs have expanded in recent years into new asset classes such as container ships, offshore oil services and wood pellets. At least one paper company is rumored to have a ruling request pending at the IRS to move part of its operations under an MLP.

The IRS put a hold in 2014 on any further rulings about qualification of entities as MLPs while it sorts out a "hamburger stand" issue. A third of MLP rulings in the year before the hold involved companies that provide services in connection with hydraulic fracturing of oil and gas. The IRS has been concerned about rulings creep as services become farther and farther removed from actual oil or gas production. For example, is owning hamburger stands at fracking sites to feed workers closely enough related to oil and gas production to qualify?

The IRS is expected to release the hold in the "not too distant future," Erik Corwin, IRS deputy chief counsel (technical), said in early January.

In early February, President Obama called in his budget message to Congress to repeal "the exemption from the corporate income tax for publicly-traded partnerships with qualifying income and gains from activities relating to fossil fuels." He proposed a January 1, 2021 effective date for the change.

Dave Camp (R-Michigan), who led the House tax-writing committee, but retired from Congress at the end of 2014, proposed in a comprehensive corporate tax reform bill last year to tax master limited partnerships, except for minerals and natural resources businesses, like corporations, effective after 2016. The Camp tax reform bill may serve as a starting point for any corporate tax reform discussions later this year.

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Yield Cos

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value of the sponsor's incentive distribution rights.

Growth is key, and that is a different metric for financing through a yield co than the project finance market traditionally looks at things. Project financiers look at the long-term cash flow and tax benefits and come up with an internal rate of return that they need on their investment. In contrast, a yield co investor looks for a current dividend yield, some years of comfort that the yield will be maintained, and a dream that it will be there for a long, long time. The quality of the yield co assets affects whether the dream will come true.

Discount rates in some yield co bids are mid-6% to 7%.

The bottom line is it is hard to say what the cost of capital is for a yield co. The cost is affected by a number of factors.

MR. MARTIN: Is it as simple as to add a 3% dividend yield to a 15% growth expectation, which equals 18%?

MR. MCILHENNY: No.

MR. MARTIN: So you solve for the internal rate of return that sets the present value of the dividend stream, starting at 3% and growing at 15% a year, equal to your investment.

Hunter Armistead, is a yield co a form of financing for a development company?

MR. ARMISTEAD: It is an interesting question that we faced when we were evaluating the right vehicle. Keith told us to keep the answers short and controversial. That was his only guidance, so I need to shorten it up. [Laughter.]

MR. MARTIN: We also need the controversial.

MR. ARMISTEAD: I am trying to avoid that. It is cost-effective capital. The cost is not stratospheric compared to what we would be looking for from a pension fund. The numbers that we saw when we valued our assets in anticipation of forming a yield co were not that different than when we ultimately did our trade on the public exchange. The reason for going public had nothing to do with monetization. It was funding our growth. If you are just buying current short-term dividend growth or capital yield, with a low IRR, then that will turn on you in the future. You have to keep an eye on both.

MR. MARTIN: Carl Weatherley-White, I was looking at the dividend yields for three yield cos. They are 4.87% for Pattern, 3.6% for TerraForm, 2.91% for NRG Yield. What accounts for the differences in dividend yields? Is it just growth expectations?

MR. WEATHERLEY-WHITE: The market is evolving. There is a differentiation among business models. Investors assign different values to different models. This is a natural evolution. As more companies come to the market, there will be more differentiation and ways for sponsors to play it.

MR. MARTIN: David McIlhenny, you are nodding.

MR. MCILHENNY: I was just going to ask Carl a question. Why is NextEra's yield so low compared to Pattern's yield?

MR. WEATHERLEY-WHITE: NextEra has an enormous inventory of assets that it owns and operates, so investors can be more confident about the potential for growth. Pattern has an outstanding development team and a proven track record, and it will grow as well. You are seeing differentiation in yield, which I think is a function of growth expectation.

Growth

MR. MARTIN: Fair enough. Let's focus on how yield cos grow. They distribute almost all their operating net cash flow. So in order to have cash to make acquisitions, they must either borrow or raise more equity, thereby diluting the existing shareholders. Why isn't

this a zero sum game? How does one get growth out of such a process? Alex Burgaleta.

MR. BURGALETA: The sponsor must drop down or contribute assets in an accretive way for the existing shareholders.

MR. MARTIN: What does it mean to contribute assets in an accretive way?

MR. BURGALETA: When you dilute the existing shareholders by issuing new shares, the amount of cash that the shareholders will be distributed per share is higher than before.

MR. MARTIN: Are there any other ways of expressing this?

MR. WEATHERLEY-WHITE: It is the same model that has existed in the REIT and MLP sectors for many years. Alex said it well. There must be a difference between the value at which assets are brought into the yield co and the cost of capital.

MR. MARTIN: You basically raise money at a higher price-to-earnings ratio and reinvest at a lower one. What are current spreads in the yield co market? Are they narrowing or widening? Andy Redinger.

MR. REDINGER: The spreads are definitely narrowing as the demand for assets heats up. We are seeing other players coming into the market and competing with yield cos for assets. Pension funds and infrastructure funds are two examples of other sources of capital that have become more aggressive recently.

MR. MARTIN: Spreads are tightening. Does that suggest a shortage of product? Hunter Armistead.

MR. ARMISTEAD: I think you are getting to one of the core challenges if your growth model is acquisitions. As the spread narrows, it becomes harder to do more acquisitions on an economic basis. If you can't do any more deals, then you can't grow. That is where it helps to have a deep development pipeline to have a captive group of assets that provides that accretive growth as opposed to having to rely on the spread.

MR. MARTIN: Hunter Armistead, your company has said that the market has become too frothy. Asset values are inflated — you are wincing as I say this — so you will focus on your own pipeline probably to the exclusion of buying assets from third parties.

MR. ARMISTEAD: We continue to evaluate third-party acquisitions, but at the core, we maintain a deep, strong development pipeline that can feed the growth. To the extent we can augment that with acquisitions from third parties, we will do it, but we don't feel like we have to do it.

MR. REDINGER: These ebbs and flows are natural in the marketplace. The tightening will force yield cos to look other places for assets: international, residential / *continued page 18*

IN OTHER NEWS

MORE CREBS may be issued.

CREBs are a form of tax-exempt bond on which the lenders receive tax credits from the federal government in place of interest. The tax credits must be reported as income. The acronym stands for "clean renewable energy bond."

The bonds can be used to finance wind, solar, geothermal, biomass, landfill gas, incremental hydroelectric and ocean energy projects that are owned by municipal utilities, government agencies, Indian tribes, electric cooperatives and US possessions. Anyone proposing to issue CREBs must apply to the IRS for an allocation. Congress authorized up to $2.4 billion in such bonds.

The IRS announced in early February that it will allocate approximately $1.4 billion in remaining bond authority. Anyone given an allocation must issue the bonds within three years or else the authority reverts to the IRS and will be re-awarded to someone else.

Public power providers (municipal utilities) must apply by June 3, 2015 and will share up to $516,565,691.35 in remaining bond authority. The bond authority for public power providers will be allocated using a pro rata method. If the total amount applied for exceeds the amount available, then the volume cap will be split pro rata among all the eligible projects. Thus, for example, if the $516 million is two times oversubscribed, then each public power provider will receive authority to issue bonds covering half its project cost.

Governmental bodies and electric cooperatives must apply by March 5, 2015. There is $597,134,963.60 in volume cap remaining for governmental bodies and $280,778,469 for electric cooperatives. Volume cap for these two categories will be handed out on a first-come, first-served basis. However, no applicant may be awarded more than $40 million or, if greater, 20% of the total amount available for award in its category (governmental bodies or electric cooperatives).

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Yield Cos

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solar. What ebbs today will flow again later. Smart companies are already thinking about this. You will see a broader mix of assets put into yield cos.

MR. WEATHERLEY-WHITE: That's a great point. There is a natural evolution. I am also interested in what Hunter Armistead said because he is a developer. I see this as a search for a lower cost of capital that can then be applied to the ownership of assets, which then results in a more competitive electricity price. When we talk to developers about the opportunities of yield cos, they are working backwards from what electricity price works.

MR. ARMISTEAD: Hit me with the question again.

MR. WEATHERLEY-WHITE: When you think about what returns are necessary to support a power contract bid, you think about your cost of capital and do you consider yield co capital as giving you a competitive advantage?

MR. MARTIN: You are setting him up, because you are asking Hunter to admit that his yield co is a form of a financing. [Laughter.]

MR. ARMISTEAD: Thank you! [Laughter.]

MR. MARTIN: I'm a lawyer.

MR. ARMISTEAD: I think the answer to your question is yes. We were originally funded by Riverstone when Pattern was first formed. That's a private equity fund. The returns we were searching for, which included some yield compression, were materially higher than what we see would deliver very solid growth to our public vehicle. So, yes, the yield co allows us to be more aggressive when bidding for power contracts.

MR. MARTIN: Alex Burgaleta, do you want to add to that?

MR. BURGALETA: We have to look at the cost of capital of yield cos as something that is not as steady. The cost depends on the rate at which the yield co will acquire assets and the market prices at which it will do so. You cannot look at the yield co on a stand-alone basis; it is a more dynamic process.

MR. MARTIN: Your cost of capital may be harder to predict.

MR. BURGALETA: Yes. A yield co has a window in time when it may be most efficient and aggressive. But you have to be careful because you have to deliver the growth, and then we will discuss how you do so. Do you already have the assets? Do you develop the assets? Do you buy the assets? How much value are you bringing to the shareholders by contributing those assets? These different paths to growth are not equal.

Discount Rates

MR. MARTIN: There are many strategics that felt, when yield cos first appeared, that yield cos would have the lowest cost of capital and would win all the auctions for assets. Has that in fact happened?

MR. ARMISTEAD: As a loser of a bunch of options, no. There have been some big transactions that were transformative for a couple of the other companies that pay dividends like us; you can see I am moving away from the term "yield co." In our experience, the most aggressive bidders are buyers who want to form a new yield co and are trying to get to a critical mass of assets. We have seen bidders pay materially more than we thought justified. We feel like we have a good growth engine and do not have to stretch to grow.

MR. MARTIN: What discount rate do you think yield cos are using to win assets in the current market?

MR. REDINGER: I think 9% to 10% levered would get you right in the middle of the bell curve.

MR. MARTIN: What about unlevered?

MR. REDINGER: Three hundred basis points below that, so somewhere mid-6% to 7% unlevered may win you the deal, or at least get you into the second round.

MR. MARTIN: I would have thought 8% was enough to get you in.

MR. REDINGER: That is the tightening that we talked about earlier.

MR. ARMISTEAD: One of my favorite things is that it is not just about the return, it is also about the assumptions. What will it really cost to operate an asset? How well will it perform? Maybe you will not hit the flip points on schedule in the tax equity partnership and that changes the entire game and the internal rate of return. You may think you bought at 9% but you did not get it at 9%.

MR. MARTIN: I didn't follow that.

MR. ARMISTEAD: The banker for the seller sends you a *pro forma* that was prepared by the sponsor. If you bid based on the *pro forma* numbers, sure you bid at 9%, but when you actually realize that production is different, the operating costs are higher, and you have to add more workers at the local site, things get a lot more tight.

MR. BURGALETA: You also have to consider the profile of the cash flow as it changes dramatically from one market to the next. We are looking at projects in Brazil, South Africa and other places with high inflation rates, where cash flows are growing by 6% or

7% a year. Compare that with markets like the US and Canada with really flat cash flows or cash flows that decrease over time.

MR. MARTIN: Yield cos are usually built around a renewables base, but does it work to have solely renewables? Don't you need some tax capacity in the yield co itself? Andy Redinger, you are shaking your head no.

MR. REDINGER: No, because yield cos are vehicles that need tax credits and depreciation to shelter the income going forward. It is true that the yield co is not using the tax benefits efficiently, but the ability to roll the tax benefits forward and use them to shelter future income is what gives yield cos access to cheaper equity capital.

MR. MARTIN: If the yield co has a tax base, doesn't it have a valuable asset that can be used to earn an additional return in the renewable energy market?

MR. REDINGER: That is another story entirely. One of the things we are always tracking closely is what is our carryforward. Yield cos like to be able to project enough tax shelter far enough into the future so that they do not have to worry about taxes reducing the cash available for distribution.

MR. MARTIN: You like to be able to say to the investors that you expect to operate tax-free for nine or 10 years based on the existing asset portfolio.

MR. REDINGER: Correct. At the same time, we are trying to figure out how to make more efficient use of tax equity.

Sensible to Form?

MR. MARTIN: David McIlhenny, what are some pros and cons that a company that is already in business thinks about when deciding whether to form a yield co?

MR. MCILHENNY: On the pro side, the company should be able to reduce its cost of capital. A yield co is a form of financing future cash flows. It is also a way for a developer to retain long-term exposure to the value of the project rather than just selling it off, or doing some other type of financing where the upside is given to some other party. The long-term value is captured through retaining incentive distribution rights.

The cons are the yield co will divert management attention. It will make you think more like a finance company and less like a solar company or developer.

MR. MARTIN: Alex Burgaleta, do you want to add to that?

MR. BURGALETA: Yield cos are good examples of sensible risk and return allocation. Forming a yield co forces you to change the way you handle your business because / *continued page 20*

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NETWORK UPGRADE payments had to be reported as income by utilities, the IRS said.

A municipal utility needed more electricity to supply local residents. Transmission was a problem. It entered into negotiations with a private transmission company to build a transmission line that would bring the additional electricity. The line was a bridge between two regional grids. The transmission company will own the new line. The municipal utility subscribed for a percentage of the transmission capacity on the new line.

The administrator of one of the two regional grids required three neighboring utilities to upgrade their transmission systems so that the additional power flows over the regional grid on account of the new transmission line will not be impeded by congestion or bottlenecks on neighboring systems.

The transmission company building the new line agreed to reimburse the three neighboring utilities for the cost of the network upgrades to their systems. The municipal utility agreed, in turn, to reimburse the full cost even though it was subscribing for only a portion of the new transmission capacity.

The utilities asked the IRS whether they have to report the cost reimbursements as income. The IRS said yes in two "adverse" rulings the agency released in December and January. The rulings are Private Letter Rulings 201451007 and 201503001.

It is rare to see an adverse ruling. Companies requesting rulings usually withdraw the requests if they are told the IRS will not rule favorably.

The IRS said the utilities could avoid reporting the cost reimbursements as income only if they can show the company reimbursing them is acting solely for the public benefit and not for any private benefit it might receive.

The IRS is walking back from its past positions in this area. The agency said in three notices and one revenue procedure from 1988 through 2005 that payments a utility receives from an independent / *continued page 21*

Yield Cos

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the business is different. We have development companies that are also listed and are feeding yield cos. That changes how we think about the development business. If yield cos do a good job maintaining asset quality and see their dividend payments grow, then we will see even more yield cos as they offer something of value: access to cheaper capital.

MR. MARTIN: David McIlhenny, some people say that yield cos do not work for the solar rooftop business because there is so little development risk. You are not getting much of a pop in moving to a yield co. Make sense?

MR. MCILHENNY: Residential assets have not been part of yield cos so far because yield cos are evolving, and they started off with the best assets, which are big utility-scale projects with long-term power contracts with creditworthy offtakers and little technology risk. As the yield co market has evolved, every new yield co has done something different: incentive distribution rights, distributed generation, projects that actually are not in service but count as IPO projects, foreign assets. Residential solar is an asset class that can be part of yield co, but it just has not been done yet.

Other Issues

MR. MARTIN: As an investor, are you better off investing in the development company or in the yield co?

MR. BURGALETA: What kind of car do you have? Do you have a Prius or a Corvette? [Laughter.]

MR. MARTIN: I'm the one asking the questions here! You don't think it matters?

MR. ARMISTEAD: When you invest in a developer, you can lose everything or the investment can pay big dividends. A yield co should be a less risky investment.

MR. MARTIN: What happens when the market shifts and developers find a cheaper way to raise capital or they find other buyers willing to pay more for assets? What happens to the yield co at that point? Andy Redinger.

MR. REDINGER: They all get bought out or merged.

MR. MARTIN: Hunter Armistead, you were one of the early adopters of yield cos. What issues have come up in the first year and half of operation that you perhaps did not foresee?

MR. ARMISTEAD: We had a lot to learn. We have successfully managed and developed assets, but we have never managed a public company. Dealing with all of the reporting requirements and setting up the infrastructure so you can close your financials; if you are a private company and are a few days late on your financials, you call Riverstone and say, "We are a few days late." There is no leeway with a yield co.

We went into the yield co with our eyes open and we assumed it was going to be tough, but it was tougher. Then there is the pressure to keep growing at the same time.

Another thing is Andy Redinger said it is $5 to $7 million dollars to stand up a yield co. It was more for us. Maybe we were not efficient at it the first time, but it is expensive to do. The infrastructure to support it is significant. If you start going into new jurisdictions, you have a lot more rules to master, like the need to close the books at the right time. It sounds really cool to do a deal in Chile, but you end up creating more stress at every turn with additional regulatory requirements. We have had to hire more people than we thought we were going to have to hire.

MR. MARTIN: That is a good bridge to my next question. What complications are created when the yield cos run out of assets to vacuum up in the US and start looking more widely overseas? You mentioned one. Does anything else come to mind? Andy Redinger.

MR. REDINGER: Currency risk. Obviously, there are also repatriation risk and the tax consequences of bringing the money back into the US.

Sol-Wind brought a renewable energy MLP to market, but then postponed the offering.

MR. MARTIN: Alex Burgaleta, you deal with this all the time as your company operates in multiple countries.

MR. BURGALETA: I was going to say, if you are worried about Chile, wait for Brazil. [Laughter.]

MR. MARTIN: Energy Capital Partners packaged a group of gas-fired power plants and put them in a public vehicle. Compare that play to a yield co.

MR. MCILHENNY: Fossil fuel plants have fewer tax benefits, so the public company will be paying taxes, and there will be less cash for dividends.

MR. MARTIN: Where do you see the growth in that sort of play?

MR. MCILHENNY: Buying up old assets, I would think.

MR. WEATHERLEY-WHITE: But will those be contracted? That is a really interesting point because not all assets meet what you are trying to do here. Five- and 10-year contracts are tricky.

MR. REDINGER: The boundaries of yield cos are expanding so, as time goes by, unless there is a misstep, yield cos will push the bounds with shorter PPA terms, uncreditworthy offtakers and merchant opportunities. When there is a problem, things will stop. Until there is a problem, the market will keep pushing the boundaries.

MR. WEATHERLEY-WHITE: Look at the acquisition of First Wind by TerraForm. There was a lot of discussion about the shorter PPAs, I think 10 years on average, than what we were accustomed to seeing until then in yield cos, and TerraForm talked about re-contracting and the value of that. We are already starting to see movement in the market.

MR. MARTIN: A lot of intellectual capital will be required going forward and perhaps higher returns as riskier assets land in yield cos.

MR. BURGALETA: There is a huge opportunity for yield cos overseas. In many overseas markets, the demand for electricity is actually growing, unlike the United States. The combination of growing demand and a way to reduce the cost of capital will prove very enticing.

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generator who is not a customer of the utility to reimburse for network upgrades do not have to be reported as income. The IRS issued four private letter rulings from 1991 through 1995 that confirmed the same policy applies to cost reimbursements a utility receives from another utility for network upgrades when a new transmission line is installed.

The current position of the IRS branch handling these issues is that it will not extend the logic to other fact patterns besides those addressed in the existing notices.

The IRS and Treasury lawyers who worked on the first two notices in 1988 and 1990 had no difficulty using the logic behind them to analyze other fact patterns that were not known when the original notices were written. The reason there are three notices and one revenue procedure is the IRS has periodically updated its guidance to address new fact patterns as the power industry has evolved over time.

SOLAR TAX CREDITS can be claimed on special membranes put on roofs underneath solar panels, but only on the incremental cost above what replacing the roof would cost, the IRS said.

The IRS made the statement in a private letter ruling that it made public in December. The ruling is Private Letter Ruling 201450013.

A company asked the IRS whether it could claim an investment tax credit on a solar commercial rooftop system that it purchased. The system uses bi-facial solar panels that absorb sunlight on both sides of the panels. A special membrane is put on the roof to reflect sunlight to the backside of the panels. The panels are up to 40% more efficient than regular panels. The membrane covers 96% of the roof.

The IRS confirmed the membrane is considered part of the solar system, but said the company had to back out the cost of putting a new roof on the building without the reflective feature.

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Egypt's Feed-In Tariff Program: Ready, Set...

by Richard Keenan and Marc Norman, in Dubai, and Ahmed El Sharkawy, Mohamed Nabil and Ahmad Farghal, with the Sharkawy & Sarhan law firm in Cairo

Egypt recently released a shortlist of 110 qualified applicants for solar photovoltaic and wind projects for the first regulatory period of its new feed-in tariff scheme.

The first regulatory period runs from 2015 to 2017. During this time, the Egyptian government aims to procure 4,300 megawatts of renewable energy capacity, including 2,000 megawatts of medium-to-large-scale solar photovoltaic facilities and 2,000 megawatts of wind facilities.

The 110 qualified applications include 13 small-to-medium-scale solar photovoltaic facilities (i.e., up to 20 megawatts), 69 large-scale solar photovoltaic facilities (i.e., from 20 megawatts to 50 megawatts) and 28 wind facilities ranging from 20 megawatts to 50 megawatts.

Although certain known market participants are likely dissimulated behind special-purpose vehicles, many of the usual suspects are included in the shortlist.

A number of companies bid for more than one renewable energy source or solar photovoltaic facility size. Some renewable energy developers are also rumored to be negotiating independent deals directly with the government — most probably for larger-scale projects given the 50-megawatt cap on facilities procured under the feed-in tariff program.

The aggregate capacity of the large-scale solar projects that the 69 qualified bidding consortia have applied to develop under the feed-in tariff scheme exceeds the government's target of 2,000 megawatts by around 50%. This means that a certain number of qualified bidding consortia will miss out, at least for the first regulatory period.

The aggregate capacity of the wind projects that the 28 qualified bidding consortia have applied to develop falls below the government's target of 2,000 megawatts. This means that a further request for qualification for wind projects will be issued by the government during the first regulatory period.

The priority for all qualified bidders — and particularly for solar project bidders — must now be to position themselves to join the top of the queue for site allocation and thereby project award. The extent to which project award will ultimately come down to speed of company incorporation and grid connection downpayment remains to be seen; other technical and project viability criteria will surely play a role. However, one thing that has become very clear is that it is in the interest of all qualified bidders to organize themselves as quickly as possible to make sure that they are at the top of the queue and do not end up on a waiting list.

We understand that the government will provide 36 plots of land to qualified bidders for large-scale solar projects on a first-come, first-served basis.

Qualified bidders who are not allocated one of these sites will also be free to source their own sites. However, sites provided by the government have the advantage of being fully permitted. Developers who source their own land will have to provide to the government evidence of ownership or satisfactory usufruct rights.

How do qualified bidders position themselves to be eligible for a government-allocated site?

There are two requirements that must be satisfied as soon as possible. First, the applicant must establish a special-purpose vehicle for the project. Second, the applicant must make a downpayment to cover grid connection costs. In early February, qualified bidders were officially notified of the downpayment amount.

Egypt wants 4,300 megawatts of new wind and solar capacity by 2017.

Establishment of SPE

Qualified bidders should incorporate an Egyptian company under the investment law number 8 of 1997. Qualified bidders may choose between incorporating a limited liability company or a joint stock company.

Incorporation in Egypt takes one week from the date of completion of all the required documents. It is very difficult to transfer an LLC to a joint stock company.

It is not a practical option to acquire an existing shelf company. Shelf companies are not known under Egyptian law. The only way to acquire a joint stock company is through a share transfer. Share transfers require a lot of notarized and consularized declarations and documents in addition to appointing a stock broker to effect the transfer on the Egyptian Stock Exchange.

Joint stock companies offer some advantages that are not available in LLCs, such as the ability to list the company on the stock exchange and to offer shares, bonds and other securities to the public. There is a minimum capital requirement for joint stock companies, but only 10% of the share capital must be paid up upon incorporation and another 15% must be paid up within three months and the remainder within five years after incorporation. Joint stock companies are more appealing to banks when financing a project because it is possible for banks to obtain pledges over the shares as security; the enforceability of pledges over partnership interests in LLCs is unclear under Egyptian law.

More details about the differences between LLCs and joint stock companies are in a sidebar with this article.

Grid Connection Downpayment

Each developer is responsible for its share of grid interconnection costs. We understand from government briefings and recent feedback from developers that interconnection costs will be split among developers sharing the same substation.

Each qualified bidder will be required to make a grid connection downpayment. In early February, qualified bidders were officially notified of the downpayment amount.

Government sources have confirmed that this downpayment can only be made through the provision of a check or cash.

PPA and Government Guarantee

We understand from government briefings that draft project documentation (including the power purchase agreement and usufruct agreement) have been prepared. Developers and financiers are expecting these documents to be broadly consistent with Egypt's IPP template.

Egypt's IPP template originates from the Sidi Krir IPP (a 682.5-megawatt gas-fired steam power plant initially developed by InterGen that went into commercial operation in late 2001), the Port Said IPP (a 683-megawatt gas-fired power plant initially developed by EDF that commenced / *continued page 24*

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A MINING COMPANY leased rather than sold its interest in a mine to a third party, the IRS decided on audit.

The decision affects how much and when income must be reported from the transaction. It is interesting because it suggests a tax planning tool that might be used to avoid triggering a sale.

The mining company owned an interest in the mine in a joint venture with other companies, but the owners elected for US tax purposes to treat each owner as if it owned an undivided interest in the mine directly. Each reported its share of revenue and costs directly.

The mining company transferred its fractional interest in the mine to a third party. It was paid cash up front for the interest and was promised another lump-sum "bonus payment" in the future if the mineral reserves increase by at least X tons. It will also receive ongoing "production royalties" that are a percentage of revenue from sales of output, but these payments do not start until output sales from the mine pass a threshold.

The IRS addressed what label to put on the transaction in a "technical advice memorandum," or a ruling by the national office to settle a dispute between a taxpayer and an IRS agent. The ruling is Technical Advice Memorandum 201448002. The IRS made it public in December.

The IRS said whether the transfer of an interest in a mine is a lease or a sale turns on what sort of interest, if any, the seller retains. If the owner retains no interest, then the transfer is a sale. It is also a sale if the owner transfers a non-operating interest and retains an operating interest. For example, the owner retains the right for a period of time or for a fixed tonnage to remove minerals, but transfers everything else. It is a *lease* if the owner retains an "economic interest." An economic interest is a right to ongoing payments that are tied to production.

The IRS pointed to a 1972 US Tax Court decision in a case called *Ridley v. Commissioner* where a mine owner received an upfront payment at closing and no / *continued page 25*

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commercial operation in 2003) and the Gulf of Suez IPP (a 683-megawatt gas-fired power plant initially developed by EDF that reached commercial operation in 2003). This precedent has since been further developed in connection with the Dairut IPP and other projects such as the Gulf of Suez wind IPP.

The draft project documentation is currently being reviewed from a bankability perspective by leading financial institutions based on discussions with the New and Renewable Energy Authority about the required terms. The project documentation is expected to be amended to address any bankability concerns raised by the relevant financial institutions and then issued to successful bidders. Given the program's ambitious timetable, the New and Renewable Energy Authority and Egyptian Electricity and Transmission Company will have to provide developers with a bankable form of power purchase agreement as soon as possible. As with any new IPP program, the development of standard-form templates can be a time-consuming process. We expect that developers may have some reservations about making upfront financial commitments without any visibility on the form of PPA and proposed risk allocation.

The power purchase agreement tariff for large-scale projects will be denominated in US dollars, but be payable in Egyptian pounds. This is significant given that the Egyptian pound has not been pegged to the US dollar since 2003. Fifteen percent of each invoice amount will be converted at a fixed rate of 7.15 pounds to dollars, and the remaining 85% will be converted at the prevailing rate. This means that the Egyptian government will more or less assume exchange risk. A key question for financiers of these projects will be the extent to which the government will also assume the risk that that Egyptian pounds can actually be converted to US dollars. Depending on the extent to which the Egyptian government assumes convertibility risk, the preferred creditor status of multilaterals in the financings of these projects could prove to be critical.

Projects with a capacity above 500 kilowatts will benefit from a government guarantee issued by the Ministry of Finance.

The extent to which an equity sponsor may participate in multiple consortia is unclear. Government sources previously indicated that an equity sponsor could participate in multiple consortia, so long as it acts as a lead developer in no more than one consortium. However, we understand that the government may be reassessing this position.

The Feed-in Tariff Program

Last year saw Egypt launch an ambitious program to procure 12,000 megawatts of renewable energy capacity by 2020, the largest renewable energy target in the Middle East and North Africa region, after Saudi Arabia.

Any seasoned Middle Eastern renewable energy stakeholder would be forgiven for treating target announcements with some skepticism. However, recent developments suggest there is cause for excitement.

On October 20, 2014, the Egyptian government issued a request for qualification to participate in the initial procurement round of its freshly-issued feed-in tariff program for renewable energy. The deadline to submit qualification requests was November 26, 2014. The Egyptian Electricity Transmission Company, Egypt's renewable energy procurement arm, is reported to have received 177 submissions. In the first week of January 2015, Egypt surprised market participants by releasing its shortlist of 110 qualified applicants.

Since the release of the shortlist, the Egyptian government has made it abundantly clear to all stakeholders that it wants to move fast with the roll out of its feed-in tariff program.

For many years, Egypt has faced a major challenge in providing enough electricity to its citizens. Power blackouts, a daily occurrence for many

It is offering feed-in tariffs of 9.57¢ to 14.34¢ a KWh to attract developers.

Egyptians, stand out as one of the most explosive socio-political issues in the Arab world's most populous country; they were a key factor in deepening discontent with President Mohamed Morsi, who faced mass protests before Abdel Fattah al-Sisi, then army chief, ousted him in 2013.

In early September 2014, the country experienced one of its most severe blackouts in decades. The outages knocked TV stations off the air and halted parts of the Cairo subway, a major embarrassment for a government that sought to provide stability after protracted turmoil. As officials struggled to address the public outcry, President Abdel Fattah al-Sisi addressed the country in a candid television address saying that power blackouts were the result of years of underinvestment. Tackling blackouts stands as a key government priority; however, there is no immediate solution, he said. The President said the country needs to add 12,000 megawatts to its grid over the next five years at a capital cost of around US$12 billion.

Beyond the desperate need to increase generating capacity, the country also faces a challenge to diversify its energy sources.

Oil and natural gas currently contribute 95% of the total energy resources needed to generate electricity in Egypt. However, according to the Egyptian energy strategy for 2030 together with its update until 2035, Egypt is expected to become a net importer of oil and natural gas between 2030 and 2040.

As the cash-strapped country strives to meet other pressing challenges such as water treatment and education needs, reducing dependence on oil and natural gas via energy-source diversification is viewed as critical.

Egyptian authorities see the procurement of solar photovoltaic and wind facilities as an effective way to deploy additional power generation capacity rapidly — conventional facilities take considerably more time to bring on line — and to reach their diversification goal.

Egypt's feed-in tariff program was approved by the Cabinet of Ministers on September 17, 2014, weeks after the major blackouts.

The deployment of the program is spread out in a series of "regulatory periods." The first regulatory period runs from 2015 to 2017.

During the first regulatory period, Egypt aims to procure 4,300 megawatts of solar photovoltaic and wind capacity. (The explicit references to photovoltaic technology imply that solar thermal technologies are currently excluded from the feed-in tariff program.) On the solar side, the plan is to procure 300 megawatts of small-scale facilities (i.e., below / *continued page 27*

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further payments until about 42% of the ore reserves had been extracted. Thereafter, the mine owner was paid a royalty on output. The Tax Court said no sale occurred.

The transfer in this case was a lease, the IRS said. The possible bonus payment was not an "economic interest" because it was not tied to the mine output, but the production royalty is an economic interest.

SUCCESSOR LIABILITY can be a problem in acquisitions, but not in this case.

The US Department of Justice told a US consumer goods company in November that it would not be prosecuted for bribes that another consumer goods company it is acquiring paid to foreign government officials should it close on the acquisition.

The US Foreign Corrupt Practices Act makes it a crime for a US company or US person to give anything of value to an official of a foreign government, international organization or foreign political party in an effort to win or retain business or secure an improper advantage. Foreign companies raising funds in US capital markets can also be prosecuted.

A US company is acquiring a foreign consumer goods company in a foreign country from a foreign seller. The US company did extensive diligence. Among other things, it had its accounting firm review around 1,300 transactions with a value of $12.9 million. The accounting firm identified $100,000 in payments that raised questions. Most of the payments were to foreign government officials to obtain permits and licenses. There were also some gifts and cash donations to government officials, and there were significant problems with how the target company recorded these payments. Expenses were inaccurately identified on the target company's books.

The American company revealed what it had found to the US Department of Justice and asked for an assurance that the US government would not bring criminal charges or impose

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Comparing Egyptian Limited Liability Companies to Joint Stock Companies

	Joint Stock Company	LLC
Minimum required capital	EGP 250,000 (approximately US$ 34,000)	No minimum capital
Timing of capital contributions	10% of the issued capital must be paid upon incorporation. Another 15% must be paid within three months after incorporation. The rest of the issued capital is paid within five years after incorporation. The issued capital of the company can be denominated in a foreign currency. However, bidders in the feed-in tariff program must pay the entire issued capital upon incorporation.	Must be fully paid upon incorporation
Liability	The capital is divided into equal shares. The liability of each shareholder is limited to its shares.	The capital is divided into equal portions. The liability of each partner is limited to its portion.
Minimum number of owners	A minimum of three shareholders at all times	A minimum of two partners and a maximum of 50 partners.
Management	A minimum of three managers. There is no nationality restriction.	A minimum of one manager. At least one of the managers must be Egyptian.
Transfers of shares	Founding shares and shares issued for contributions in kind may not be transferred before publication of the company's financial statements for the first two full fiscal years without prior consent of the regulator (GAFI). In addition, the shares cannot be transferred until at least 25% of the company's issued capital has been paid.	Partners wishing to transfer their interests to third parties must first offer them to existing partners, who have a pre-emption period of one month within which to purchase the interests on a pro rata basis. The pre-emption right may be waived by the shareholders before the end of the one-month pre-emption period.
Lock-in periods for feed-in tariff SPEs	The majority shareholder of the SPE cannot transfer more than 70% of its shares before commercial operation without obtaining the approval of the Egyptian Electric Utility and Consumer Protection Regulatory Agency.	
Object of SPE	The object of the SPV must include "generation and sale of electricity from new and renewable sources and construction, management, operation and maintenance of electricity generation plants."	
Changing the type of the SPE	N/A	It is very difficult to convert an LLC into a joint stock company.
Listing	The shares can be listed on the stock exchange after fulfilling certain requirements. A joint stock company can issue securities by way of public offering.	LLC interests cannot be listed on the stock exchange. An LLC cannot issue securities by way of public offering.
Financing	The pledge of shares and enforcement of the pledge are regulated by Egyptian law. This makes joint stock companies more appealing in terms of bankability. LLC interests cannot be in the form of transferrable securities, and an LLC cannot issue any kind of securities. Accordingly, lenders cannot safely have a pledge over LLC interests.	Usually when a pledge is obtained by lenders, it is coupled with an obligation to convert the company into a joint stock company and reinstate the pledge over the shares after conversion.

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500 kilowatts) and 2,000 megawatts of medium-scale facilities (i.e., between 500 kilowatts and 20 megawatts) and large-scale facilities (i.e., between 20 megawatts and 50 megawatts). The wind target is 2,000 megawatts with project sizes ranging from 20 megawatts to 50 megawatts.

The initial plan was to issue a request for qualification every three months during each regulatory period, allowing one month for clarification requests, another for qualification submissions and another for the issuance of results. However, based on our understanding that the solar photovoltaic track is 50% oversubscribed, there should not be any further requests for qualification in the first regulatory period. We expect further requests for qualification for wind, but delays are to be expected.

There is no need for a developer that qualified under the first request for qualification to submit a qualification application under a subsequent request for qualification that is included in the same regulatory period, unless the developer's status changes.

The Egyptian Electricity Transmission Company or distribution companies (depending on project sizes) are committed to purchase the electricity produced from renewable energy facilities via power purchase agreements lasting 25 years for photovoltaic facilities and 20 years for wind facilities at the last prices announced by the Cabinet of Ministers.

The last prices announced by the Cabinet of Ministers for solar photovoltaic facilities are as follows:

Installed Capacity	Tariff (per kilowatt-hour in US¢)
Residential	11.86
Less than 200 kilowatts (other than residential)	12.6
200 kilowatts to 500 kilowatts	13.6
500 kilowatts to 20 megawatts	13.6
20 megawatts to 50 megawatts	14.34

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criminal penalties against the company after the acquisition.

The department said in a formal opinion released in November that it "does not presently intend to take any enforcement action." While it is "a basic principle of corporate law that a company assumes certain liabilities when merging with or acquiring another foreign company," Justice said, "[s]uccessor liability does not . . . create liability where none existed before." The target company's actions would not have been prosecuted by Justice because the target was not a US company.

An acquisition cannot create liability retroactively where there was none before.

The opinion is No. 14-02. The US government took six months to issue the opinion.

THE CHILEAN GOVERNMENT wants to stop signing new tax stability contracts with foreign investors.

The contracts guarantee foreign companies undertaking new projects in Chile that the taxes that will apply to the projects will not change. The Pinochet regime introduced the concept 40 years ago at a time when foreign investors were skittish about investing in Chile. The government says such assurances are no longer needed.

The proposal will have to be debated in Congress.

The government is proposing a four-year transition after 2015 during which contracts would still be signed, but guaranteeing a tax rate of no more than 44.45%, the new rate introduced in last year's tax overhaul, compared to the previous rate of 42%.

STATE TAX RATES are lower this year for corporations in seven states and the District of Columbia. Arizona reduced its corporate income tax rate from 6.5% in 2014 to 6.0% in 2015. Automatic rate reductions were set in motion in 2011 that will lead eventually to a 4.9% corporate tax rate in 2017.

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Egypt

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The last prices announced by the Cabinet of Ministers for wind facilities are as follows:

Hours of operation	First five contract years (US¢)	Remaining 15 contract years (US¢)
2,500	11.48	11.48
2,600		10.56
2,700		9.71
2,800		8.93
2,900		8.19
3,000		7.51
3,100	9.57	8.93
3,200		8.33
3,300		7.76
3,400		7.23
3,500		6.73
3,600		6.26
3,700		5.81
3,800		5.39
3,900		4.98
4,000		4.6

The above values are based on an exchange rate of US$ = 7.15 EGP, which was the reference rate used by the Egyptian Electricity Transmission Company in the first request for qualification.

The Egyptian government has the right to reassess the tariff either when the regulatory period lapses or when the capacity target for the regulatory period has been met, whichever is earlier. The reassessed tariff would only apply to new contracts; tariffs under existing contracts remain fixed for the power purchase agreement term.

Regional Perspective

To put Egypt's feed-in tariff values into perspective, the Jordanian feed-in tariff stood at approximately US17¢ for solar photovoltaic facilities and US12¢ for wind facilities: more generous than the Egyptian regime.

Jordan was the first country in the Middle East and North Africa region to implement a feed-in tariff. The incentive scheme is viewed by many as the most important factor in kick-starting Jordan's renewable energy program, which arguably became a regional template. Jordan is the first country in the region to have successfully banked both wind and solar projects on an independent power producer basis.

However, the Jordanian feed-in tariff had limited application. It applied only to the first round of renewable energy procurements. This included 12 solar photovoltaic projects ranging from 10 to 20 megawatts (excluding one project of around 50 megawatts) and one 117-megawatt wind project. Also, all solar photovoltaic projects procured under Jordan's first renewable energy procurement round were subject to an electricity production cap.

However, as Jordan moved on to its second renewable energy procurement round, it dispensed with the feed-in tariff model opting instead for a ceiling-tariff model. This model prohibits developers from bidding over a certain tariff and incentivizes bidders to tender the lowest possible tariff. The ceiling tariff is currently set at US14¢ for solar photovoltaic facilities and US11¢ for wind facilities, very close to where Egypt has set its tariff.

In late 2014, the local utility in Dubai, the Dubai Electricity & Water Authority (DEWA), tendered a 100-megawatt solar photovoltaic independent power project, the largest privately-financed solar photovoltaic project to be tendered in the region. On January 15, 2015, DEWA announced the appointment of ACWA Power as preferred bidder and said that it had accepted the Saudi developer's alternative bid to provide a facility with a capacity of 200 megawatts (on an alternating current basis) with a startling tariff of US5.84869¢ per kilowatt hour over 25 years, the lowest tariff ever witnessed anywhere in the world for a privately-financed solar photovoltaic project. It will be interesting to see whether this project sets a regional pricing benchmark for solar photovoltaic projects or is viewed by the market as an extraordinary result driven by intense competition and an IPP model that provides for significant government support.

Time will tell how Egypt fine tunes its renewable energy procurement policy. In the meantime, as Egypt gets back on its feet after several years of unrest, investors from all over the world are flocking in to get a foothold into what is fast becoming a renewable energy hotspot. ◎

Community Solar Models and Risks

by Jake Seligman, in Washington

Community solar projects are emerging as a new asset class, distinct from residential, commercial, industrial and utility-scale projects. It is still early, but lenders and tax equity investors are beginning to invest.

Like any new asset class, community solar projects have new risks to understand and allocate. This article explains some of the risks and how community solar works in a typical program, recognizing that community solar programs differ by state and utility.

Community solar programs are cropping up around the country. Eight states plus the District of Columbia have enabling legislation in place. Colorado and Massachusetts lead in installations. Minnesota has also had significant activity. A handful of other states are working on community solar legislation.

Enabling legislation is not always necessary. A study by the Solar Electric Power Association counted 58 programs in 22 states, including those initiated by utilities and third parties in partnership with utilities.

What is Community Solar?

A community solar project is a solar photovoltaic array, typically around one megawatt in size, to which customers buy in or subscribe. Projects are either ground mounted or located on large roofs, like a commercial or industrial building.

A customer owns or subscribes to a portion of the project. Customers can be residential, municipal, commercial or industrial customers.

There are two main models. In a "subscription model," the customer pays the developer for its share of the output, usually a fixed price per kilowatt hour per month or a fixed lease payment, escalating with inflation. The customer can also prepay the developer for all of the expected output from the customer's share of the project. In a "purchase model," the customer makes an upfront payment to buy a panel or series of panels.

The electricity from the project is delivered to the local utility. The utility then credits each customer for that customer's share of the electricity output. The customer pays its normal bill to the utility, reduced by the credit.

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The District of Columbia reduced its corporate income tax rate from 9.975% in 2014 to 9.4% in 2015.

In Indiana, the rate went from 7.5% to 7% and will fall to 6.5% after June 30. The rate will be reduced by 0.5% a year through 2016, and then fall by another 0.25% a year until it reaches 4.9%.

The corporate income tax rate in North Carolina fell a full percentage point, from 6% in 2014 to 5% in 2015. Future reductions are expected, but will depend on general fund tax collections the year before.

Rhode Island reduced its corporate income tax rate from 9% to 7%.

In New Mexico, the rate fell from 7.3% to 6.9%. The rate will continue to fall by 0.3% to 0.4% a year until it settles at 5.9% in 2018.

The Texas margin tax for retail and wholesale entities fell from 0.5% to 0.475%. The rate for other entities fell from 1% to 0.95%.

BUILDINGS can be in service before they open for business, a federal district said in late January.

A company that owns retail outlets that sell home building materials and supplies completed two new buildings in Louisiana in December 2008 that it intended to outfit as stores. Both stores had received certificates of occupancy that allowed them to receive and install equipment, shelving, racks and merchandize. The stores were not yet open for business, and the certificates did not allow the public to enter yet.

Louisiana was still recovering at the time from Hurricane Katrina. The US government allowed companies putting new assets in service in Louisiana to write off 50% of the cost immediately as a stimulus under so-called GO Zone legislation to encourage rebuilding. The special depreciation allowance only applied to assets put in service during the period August 26, 2005 through December 31, 2008.

The company claimed the special depreciation allowance on the buildings. The IRS disallowed the deductions. It said the buildings were not in service until they */ continued page 31*

Community Solar

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Before building a community solar project, the developer will sign subscription agreements with customers. Subscription agreements are similar to power purchase agreements in commercial projects. A typical term is 20 years from commercial operation. The customer agrees to pay for all the electricity produced by its portion of the project. Unlike a power purchase agreement, the customer does not receive electricity from the project. Rather, the customer is credited for the output to which it subscribes.

Customers sometimes also sign reservation agreements, if the project will not be built for some time. A reservation agreement simply reserves the customer's spot (typically for a deposit) for a period of time. The customer signs a subscription agreement before the project begins producing electricity.

A key element of the subscription agreement is the accounting and billing arrangement. The developer reports each customer's share of the electricity output to the utility. The utility credits the customer's bill at a price set out in the state or utility's community solar program guidelines, similar to a net metering arrangement. In the subscription model, the developer retains the environmental attributes, which it can sell to the utility in a separate agreement. The developer also retains the tax benefits.

Community solar is gaining ground with the 80% of utility customers who are not candidates for rooftop solar.

The utility and developer have a separate arrangement for interconnection and electricity offtake. Many programs require the utility to purchase unsubscribed electricity. For example, if the developer cannot find enough subscribers to take output from the whole project, then the utility will pay for the unsubscribed amount.

The amount the utility would pay in event of undersubscription is not as much as a subscribing customer would pay, but it is a helpful backup. The utility usually pays a rate set in the program guidelines equal to its avoided cost.

In the subscription model, subscriptions are transferable. If a subscriber moves within the utility's service territory, it can keep its subscription. If a subscriber moves outside the service territory, it can transfer its subscription. Developers maintain waiting lists, so new customers can join in place of customers who have moved.

Why the Growth?

Community solar projects are growing as an asset class because customers, developers and utilities all benefit from them.

Utilities benefit from community solar because they can recover their fixed costs, while promoting growth of renewable energy to meet state mandates. Community solar does not necessarily contribute to any utility death spiral by picking off utility customers and leaving utilities with stranded costs to maintain the grid without the customer base to support it. The customers remain with the utility, and the utility usually is able to continue recovering its costs in the fixed portion of a customer's bill.

Utilities can still charge customers fixed fees to recover the costs of transmission and distribution infrastructure. Compared to net metering, where a customer with solar can reduce the fixed-cost portion of its bill to zero, this arrangement is less scary to utilities. Rather than crediting customers the retail rate of electricity, as with solar net metering, the utility credits them at a lower rate, which is often decoupled from fixed charges the utility might otherwise not recover. Customers are typically allowed to offset 100% to 120% of their electricity demand.

Utilities are also the accountants in the community solar model. They bill customers and calculate the offset to each customer's electricity charge from the customer's portion of the

community solar project. Some developers, like Clean Energy Collective, offer proprietary software to facilitate this accounting.

Customers also benefit. Community solar projects are often compared to community gardens. They allow people who do not own their buildings or have a roof on which to put solar panels to subscribe to, or own, part of a community array.

Only about 20% of residential utility customers can host solar projects. The remaining 80% may be renters, own apartments or own homes with unsuitable roofs. Community solar programs are designed to reach this 80% and often try to reach low-income customers in particular.

Customers also do not have to worry about the complications that come from having solar panels on their roofs. Community solar avoids questions about roof repair, system maintenance and what happens if a customer sells his or her house.

If a customer moves, the customer can usually transfer the subscription to another customer that the developer finds (or that may be on the developer's waiting list). If the customer moves within the utility's service territory, he or she can keep the subscription.

Community solar is also good for developers. Projects are often in the one-megawatt range, but can be larger, depending on the program. This can give developers economies of scale, relative to residential solar. As First Solar's recent investment in Clean Energy Collective showed, panels that are most economic at larger scales can reach a market that includes residential, commercial and industrial customers.

Customer acquisition costs may also be lower. The pitch to customers of community solar is possible savings and environmental benefits without the on-site construction or maintenance required for rooftop solar.

Risks

There is interest from lenders, tax equity investors and even yield cos in financing and acquiring community solar projects, but the market is still feeling its way on risks.

Third-party ownership is a threshold requirement for domestic renewable energy projects seeking tax equity investment. In order to receive tax benefits from a project, a tax equity investor must own the project. There are three main forms of tax equity structures in use in the solar market. They may be hard to use in community solar projects using the purchase model where the customer owns the panels. Any tax equity investment would have to use a pooled structure like a master sale-leaseback with multiple customers as separate lessees. */ continued page 32*

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open for business, citing a matching principle that depreciation should not start to run until an asset has started earning revenue.

The federal district court disagreed. It said the matching argument was "totally without merit." Allowing a 50% depreciation deduction "inherently offends the matching principle. It is a tax subsidy purposely created to increase business investments and stimulate the economy."

The court said buildings are in service when they are "substantially complete." It does not matter whether the retail outlets are ready to receive customers.

The IRS cited a number of cases for the proposition that depreciation cannot start until a retail operation is open for business. The court distinguished all the cases as involving equipment (airplanes, power plants, an ethanol distillery, grocery display counter) rather than a building. The current case is Stine, LLC v. USA.

AN EARNINGS REPATRIATION strategy has come under fire.

The United States taxes US corporations on worldwide income, but foreign corporations are taxed only on income from US sources. This means that a US corporation can defer US taxes on earnings from its operations outside the United States by putting the operations under a subsidiary corporation in the Cayman Islands, Bermuda, Holland, Luxembourg or another country. The United States will look through the offshore subsidiary and tax any dividends, interest or other forms of passive income received by the subsidiary, but US taxes on income from active business operations can be deferred until the income is repatriated to the United States.

US multinational corporations look for ways to have the use of the money in the United States without formally repatriating it to avoid triggering taxes.

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Community Solar

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The purchase model is usually more favorable from a securities law perspective.

Community solar projects risk running afoul of state and federal securities laws if the sale of interests or subscriptions is considered a securities offering. Factors that bear on classification as a security include availability to the general public, the number of subscriptions offered and the characteristic of the subscriptions in the subscription agreement. Programs and projects where panels are sold to customers should have less risk of violating securities laws than those where a customer subscribes to an uncertain output. In the former case, the benefits to the customer rely less on the developer's future efforts.

If a subscription in a community solar project is a security, then the developer would either have to register the offering or find an exemption from registration. State legislators and market participants are still working through the securities law issues. In the meantime, agreements between developers and customers should be drafted to avoid potential securities law risk by, for example, excluding words like "share" and "investment" and by emphasizing the sale of electricity and the developer's administrative role rather than an active decision-making role that could affect the project's viability.

Cash flow to developers of community solar projects comes from customer payments. In the subscription model, developers may also have separate agreements with utilities to sell renewable energy credits or "RECs."

Customers are typically a mix of companies, municipalities and individuals. This mixture presents a more complicated risk analysis to credit committees than in single-offtaker projects. The market will eventually get used to it, but the first projects take more time for credit committees to evaluate.

Some community solar programs require that a certain percentage (e.g., 5% in Colorado) of the participants in each project be low-income residential utility customers. This requirement introduces a new type of customer to the risk analysis. Investors are used to residential projects whose hosts have FICO scores above 650 or 700.

The low-income component in some community solar programs complicates tax equity financing. A developer in a subscription arrangement can improve the creditworthiness of a community solar project by trying to have low-income customers prepay, instead of making monthly payments over 20 years.

Having the utility provide backup payments for unsubscribed amounts also is a form of credit enhancement. Credit committees can take comfort in knowing that if subscribers default, there is still a base level of revenue from the utility.

Part of what makes community solar appealing to customers is that if they move, they can either take their subscriptions with them or transfer them to other customers. Developers often have waiting lists for community solar projects, so they can transfer a customer's interest to a new customer with little delay. Requiring a customer to provide notice of an intention to transfer (e.g., 180 days) helps reduce risk.

There is more risk of an interruption in revenue in a project with a few large subscribers or panel owners than one with many small customers. It may be harder to replace a large customer, even with 180 days' notice.

Municipal customers require non-appropriation provisions in their long-term power purchase agreements, including community solar subscription agreements. Non-appropriation provisions allow a municipal customer to terminate its contract if the municipality fails to appropriate enough money to pay for the electricity. Although non-appropriation risk is hard to avoid with municipal customers, provisions can be added to reduce risk. For example, the municipality might agree not to sign a new power contract with a third party for a set time after a non-appropriation event. Another common provision is a requirement that the municipality use best efforts to re-appropriate funds after a non-appropriation event occurs.

Utilities often want to own and operate community solar projects directly. Recently, Xcel Energy, a leading utility in community solar efforts in Colorado and Minnesota, asked the Colorado Public Utilities Commission for permission to own its own community solar projects. The commission denied the request preliminarily. Similar attempts by other utilities are inevitable.

Crowdfunding: Good Way to Raise Capital?

A number of solar and cleantech companies have been raising money through the internet using an approach called crowdfunding. Some are doing this directly. Others are taking advantage of independent crowdfunding platforms that have matched varied developers with potential cleantech investors. Is this a good way to raise money? How does it work? What has been the experience of companies that have tried it?

A group talked about these and other questions during a roundtable discussion organized by Infocast in January. The following is an edited transcript. The speakers are Bruce Ledesma, chief operating officer of Solar Mosaic and former executive vice president and general counsel of SunPower Corporation, Tim Newell, vice president of financial products at SolarCity and, before that, founder and CEO of a financial technology company called Common Assets that was acquired by SolarCity, and Jon Norling, an advisor to GridShare, an internet funding portal for crowdfunding investments in cleantech and renewable energy. The moderator is Keith Martin with Chadbourne in Washington.

MR. MARTIN: Bruce Ledesma, what is crowdfunding?

MR. LEDESMA: Crowdfunding refers to the process of raising money over the internet for a new business or product.

It started with donations- or rewards-based crowdfunding, meaning that the people offering money get nothing in return — they make donations — or they receive a free product or gift — a reward. Kickstarter popularized this concept. The model has been enormously successful. Millions of dollars have been raised.

Our focus today is on something different. It is on what I would call equity- or debt-based crowdfunding. A company issues debt or equity securities to the public in exchange for money. This version comes in a few different flavors.

One flavor is a company may try to raise money for working capital. An example of a platform used for this purpose is Angel's List. Young companies can secure angel or series A-level financing from the public for their own balance sheet use.

Another flavor is what my company, Mosaic, does. We issue debt to the public and make the proceeds available to businesses or consumers who want to buy solar systems. Mosaic focused in the past on commercial projects but, last year, we pivoted to making loans to homeowners who want to */ continued page 34*

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Lending the offshore earnings to the US parent does not work unless the loan is for no more than 30 days. Up to two such short-term loans can be made. If a loan is made for a longer period, then the offshore subsidiary will be treated as having repatriated its undistributed earnings up to the amount of the loan.

A US company tried getting around this by having its offshore subsidiaries with large amounts of undistributed earnings make loans to lower-tier offshore subsidiaries with fewer earnings that then re-lent the money to the US parent.

The IRS said it would treat the subsidiaries that were the original source of the funds as the real lenders — and use their earnings to determine how much was repatriated — rather than focusing on the intermediate entities. It addressed the strategy in an internal legal memorandum that it made public in December. The memo is Chief Counsel Advice 201446020.

The IRS is planning to issue guidance soon on the treatment of loans by offshore subsidiaries to foreign partnerships with a US partner. The issue is when and how much of such a loan will be considered repatriation of earnings to the US partner.

WASTE HEAT engines moved closer to qualifying for US tax credits.

The Senate tax-writing committee voted February 11 to allow a 10% investment tax credit to be claimed on the cost of new equipment that uses waste heat to generate electricity. The heat would have to come from one of two sources: exhaust from an industrial process or a pressure drop in gas used in an industrial or commercial process. The equipment would have to be placed in service by December 2016. It could not have a generating capacity or more than 50 megawatts.

If the engine is integrated into the industrial process, then the tax credit could be claimed on only the incremental cost above what equipment to capture waste heat without converting it into electricity would cost. */ continued page 35*

Crowdfunding

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install solar. To the extent we are sourcing our capital for these homeowner loans from the crowd, we are engaged in what is known as "peer-to-peer lending." There are lots of high-profile companies in this space outside of solar. The Lending Club is probably the most prominent and was the largest initial public offering in California last year.

MR. NEWELL: Crowdfunding is not a new phenomenon.

I would define it as use of the internet to enable smaller investors to participate in investments that were only available in the past to large financial institutions. Its roots were in the 1980s and early 1990s with the emergence of on-line brokerages that gave smaller investors access to initial public offerings for the first time. Since then, there has been a steady progression of financial products that offer such investors direct access to everything from foreign exchange trading to mutual funds and ETFs. The story of the last 15 to 20 years has been steady removal of intermediaries through whom smaller investors had to go in favor of allowing direct investment.

At SolarCity, we issue bonds directly to investors using our own platform, but there are many other ways you can do it.

MR. MARTIN: So, Tim Newell, crowdfunding is a natural evolution. The internet is displacing brokers.

MR. NEWELL: Correct. A lot of the attention currently is on fixed-income and debt investments — that is what peer-to-peer and small business lending are about — with a smaller share of capital going to equity investments.

Back-to-Back Loans

MR. MARTIN: Bruce Ledesma, you said that Mosaic is using crowdfunding to engage in peer-to-peer lending, but I am confused about whether Mosaic borrows and relends or merely acts as a go-between to allow customers who want to buy rooftop solar systems to borrow the money to do so directly through crowdfunding.

MR. LEDESMA: We connect the borrowers to the crowd lenders, and we do that through our platform. Technically, Mosaic issues notes to the crowd, but the crowd is linked to specific, underlying borrowers.

MR. MARTIN: Back-to-back lending, but the crowd has a specific customer?

MR. LEDESMA: Exactly. The crowd lender has default risk associated with a particular project or individual homeowner or borrower. The payment obligations from Mosaic to the crowd are contingent upon the underlying linked borrower making its payments.

MR. MARTIN: How large are the loans?

MR. LEDESMA: We provide loans ranging between $10,000 and $100,000 to residential customers. The average loan is about $29,000.

MR. MARTIN: Is there also a commercial range?

MR. LEDESMA: We have moved away from the commercial business, but the loans we made in the past were between $250,000 and $2 to $3 million.

MR. MARTIN: How much have you borrowed in total today?

MR. LEDESMA: On the commercial side, we funded about $8.5 million during the two years that we ran that program. We just launched on the residential side and, in the last two quarters, we have signed agreements for just over $10 million. We have not crowdfunded those loans yet. They are in the queue, but we have also brought institutional capital into the mix to supplement the crowd. We are feeding the institutional demand for the time being while we ramp up our residential program and we see how those loans perform. We expect to start moving them over to the crowd later this year.

MR. MARTIN: Two more questions for you and then I have a series of questions for Tim Newell. How long does it take from the point you decide you want to borrow from the crowd to when the deal is struck? Is it a day, a week, a month?

MR. LEDESMA: The process should be continuous. We post residential opportunities and watch the uptake rates, but, in general, the loans should be

Mosaic uses crowdfunding to make long-term loans for customers to buy solar systems.

taken up almost immediately after posting. That was our experience with commercial loans.

MR. MARTIN: What interest rate, upfront fee and tenor does the homeowner get on these loans?

MR. LEDESMA: We have different loan products with different rates. Our flagship tenor is 20 years, and the rate is either 4.99% or 5.99%, but rates can vary depending on the creditworthiness of the borrower. We have another product that will be available soon that is a 12-year loan. We are still hammering out the details on the interest rate.

MR. MARTIN: That is the pricing on offer between Mosaic and the customer, correct?

MR. LEDESMA: Yes.

MR. MARTIN: This is a back-to-back borrowing. I imagine you borrow more cheaply from the crowd, and the difference is your margin?

MR. LEDESMA: Yes. We are paid an origination fee by the consumer like most consumer lenders receive, and then we provide a return to the crowd whose amount depends on the product and some other structuring considerations. The crowd return would be somewhere in the range of 4% to 11%. The higher returns are for loans to borrowers with lower FICO scores. The interest rates I quoted earlier are for the most creditworthy borrowers.

Solar Bonds

MR. MARTIN: Tim Newell, you are using crowdfunding to raise debt rather than equity for SolarCity. How much have you managed to raise to date?

MR. NEWELL: We are raising debt using our own crowdfunding platform, but we are doing something different than Mosaic in that we are issuing solar bonds to raise corporate-level debt for SolarCity directly rather than financing individual projects or individual homeowners. SolarCity uses the money to install solar systems that we own. We are aggregating tens of thousands of projects and issuing bonds whose interest payments come from SolarCity and the monthly solar payments we receive from our customers.

We launched our solar bonds platform in the fourth quarter of 2014. We have not said publicly yet how much capital we have raised through our direct platform, but what I can say is that we have had thousands of people register on the site and have issued millions of dollars in solar bonds.

MR. MARTIN: What is the term of the solar bonds? Twenty years?

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The outlook for the proposal is unclear. It must still clear the full Senate and House of Representatives. There is no larger tax or omnibus energy bill currently in sight to which it might be added as a rider. Small tax proposals like this do not pass Congress as standalone measures.

FOREIGN INVESTORS in the United States are hoping for modest relief from US taxes, perhaps as part of a bill to provide funding for US highway projects.

The highway trust fund runs out of funding at the end of May.

The United States does not usually tax foreigners on capital gains when they exit US investments. The US needs foreign investment to help fund US budget deficits. However, the Foreign Investment in Real Property Tax Act – called FIRPTA – requires that foreigners pay taxes on capital gains from investing in US land, buildings and other "real property." FIRPTA was enacted in 1980 at the urging of family farmers who were concerned that foreign demand for US farmland was making it difficult for young families to buy their own farms.

Advocates for relaxing FIRPTA are looking for two changes.

The Senate tax-writing committee approved one on February 11.

Any person buying US real property from a foreigner must generally withhold 10% from the gross sales proceeds and remit the amount to the IRS. A partnership or real estate investment trust must generally withhold 35% of cash distributions to foreigners to the extent the distributions are attributable to sales of US real property. The foreigner can ask the IRS for a refund if the amount withheld exceeds the taxes on the actual gain. For example, suppose a foreigner sells a US building for $100X, but at a profit or gain of only $5X. The taxes withheld by the buyer in that case will greatly exceed what the seller actually owes. Smart buyers always ask for proof that the seller is not a foreigner. A buyer */ continued page 37*

Crowdfunding

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MR. NEWELL: The initial bonds that we made available had varying tenors. We offered different series of bonds with one-, two-, three- and seven-year terms. The interest rates ranged from 2% to 4%.

MR. MARTIN: Why does SolarCity bother with this? Lyndon Rive, your CEO, told us last fall that SolarCity needs to raise $3 billion in 2015. This is just a drop in the bucket.

MR. NEWELL: It is a great question.

We have raised capital for some time now from a series of large institutional and corporate investors like Goldman Sachs, Google, Bank of America Merrill Lynch and others. We will continue doing that.

There are two reasons why we are also going to investors directly through our solar bonds platform.

First, the number of banks and other financial institutions that participate in renewable energy is growing rapidly, but it is still an emerging investment sector and is a very small percentage of the overall capital markets. When you are looking ahead to having to raise billions of dollars a year to finance solar installations, it is important to open the door to a wider range of investors. We established our own platform to bring in a broad range of investors – not only individuals, but also small and medium-sized institutional investors — to widen the market, to make our capital raising efforts more resilient over any kind of economic situation and, over time, to bring us the lowest cost of capital and the least risk in raising that capital.

The second reason is that, while solar energy has had huge growth, the transition from fossil fuel to clean energy will remain a bumpy process that will require continuing public policy support. The more people who feel they have a stake in the solar economy, the better.

MR. MARTIN: Did I understand each of you correctly? Bruce Ledesma, it sounded like each crowd loan is linked to a specific customer so that the crowd lender takes credit risk of that single customer. Tim Newell, it sounded like SolarCity is doing non-recourse borrowings through solar bonds, but putting a portfolio behind each bond. Is that correct?

MR. NEWELL: No, that's not correct on our part. We are issuing corporate debt. The payments on the debt are made out of the customer revenue we receive from large portfolios of solar systems, but the debt is backed by SolarCity.

MR. MARTIN: Okay. Bruce Ledesma, did I describe Mosaic's structure correctly?

MR. LEDESMA: Yes. An investor will often allocate its investment across more than one borrower by funding a percentage of each loan and diversify in that manner, but, yes, the loans are non-recourse and the lenders are taking the customer credit risk.

MR. MARTIN: And each of you is doing this directly and not going through an independent platform?

MR. LEDESMA: Correct for Mosaic.

MR. NEWELL: For SolarCity, we use our own solar bond platform.

MR. MARTIN: Jon Norling you are working with an internet funding portal, so I assume it is a platform for crowdfunding. You heard about the two models that SolarCity and Mosaic are pursuing. What other models have you seen used successfully to raise money for renewable energy or cleantech companies?

MR. NORLING: I don't think these companies have been getting a lot of traction to date raising true investments from the crowd. The market is still in its infancy and needs to be proven. Equity crowdfunding is allowed today only in a limited number of jurisdictions.

Going back to your first question, I see crowdfunding as a way to potentially to raise a lot of small investments from many people where the investment decisions are influenced by the crowd. People see others joining a crowdfunding campaign. This builds momentum, and that momentum helps the issuer reach its goal.

Five Paths to Market

MR. MARTIN: Let's focus on the legal underpinning for crowdfunding. First, are we talking about unaccredited investors or accredited investors or both? Is there a legal barrier to trying to raise money from both?

MR. LEDESMA: There are multiple paths to use of crowdfunding nationally. One path is to register the offering with the US Securities and Exchange Commission, which is what SolarCity has done, for example. It is an expensive and burdensome process to register a debt offering if you are not already a public company. It is really not a viable option, so everyone else needs to look for an exemption from the registration requirement and, today under the Jobs Act, there are three potential paths. Only one of these is in use, and two are still in the rulemaking process at the SEC.

The potential paths are title 2, title 3 and title 4 of the Jobs Act. Title 2 probably received the least amount of media attention,

but is active today and is the closest model to free-form, unregulated capitalism in that it allows companies to blast the airwaves and market offerings publicly with no maximum cap on the dollar amount raised. There is no prospectus to file with the SEC, but there is one major catch and that is that only accredited investors can qualify and there are some fairly intensive verification procedures required where you must check people's tax returns or paycheck stubs and make other intrusive inquiries.

MR. MARTIN: What is an accredited investor? How much income must he have?

MR. LEDESMA: He must have at least $200,000 annual income or $1 million in net worth. Accredited investors represent about 7% of the US population.

The other two titles require SEC rulemaking before they become available and the SEC does not seem overly excited about them.

Title 3 has received the most media attention. It would allow offerings to the general public and not just to accredited investors, and it allows general advertising, but it is limited to $1 million per 12-month period, so it is really aimed at young companies trying to get seed funding as opposed to project financing or peer-to-peer lending. It is not a viable path for Mosaic because of the $1 million cap per year.

Title 4 would also allow the general public to invest. It permits general advertising and it raises the cap to $50 million per 12 months. We are very interested in seeing how that one unfolds, but it has been taking some time and the rules are not final.

MR. MARTIN: Jon Norling, you are a lawyer also. Is there anything you want to add to what Bruce Ledesma just said?

MR. NORLING: We have been following the rulemakings closely and have been preparing for the title 3 equity crowdfunding rules to be finalized. It looks like they will be delayed for another year. Our offerings today are primarily Regulation D offerings to accredited investors.

MR. MARTIN: That is what Bruce Ledesma called title 2?

MR. NORLING: Yes.

MR. NORLING: The investors are limited. You are not getting the true crowd. Accredited investors have a lot of options for where to put their money, so it is tougher to get traction on a crowdfunding website if the audience is limited to accredited investors.

MR. MARTIN: Tim Newell, I assume SolarCity is also using what Bruce Ledesma called title 2.

MR. NEWELL: SolarCity is a public company, and the crowdfunding options that were talked about */ continued page 38*

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who fails to withhold will have to pay the seller's taxes.

Special rules apply to foreigners who hold interests in US real property through real estate investment trusts, or REITs. If the REIT is domestically controlled, meaning less than 50% of the shares are held by foreigners, then a foreigner can sell his shares in the REIT without being subject to tax under FIRPTA, even if the REIT's assets are entirely US real estate.

As already noted, when a REIT distributes cash to shareholders, it must normally withhold 35% of distributions to foreign shareholders to the extent a distribution is attributable to a sale of US real property. However, no withholding is required on distributions to foreign shareholders in publicly-traded REITs who own no more than 5% of the REIT shares. FIRPTA does not require that such shareholders pay tax on gains. Therefore, unless the distribution is considered a dividend, it would not be subject to any US tax.

The Senate tax-writing committee voted to increase the 5% to 10%. It also decided that shares in publicly-traded REITs owned by persons who own less than 5% of the shares will be treated as domestically held unless then REIT has actual knowledge that the shares are held by a foreigner.

President Obama called in his budget message to Congress in early February for a second change. He wants to exempt foreign pension funds from FIRPTA taxes on the theory that this would put such pension funds on an equal footing with US pension funds. US pension funds are generally exempted from US taxes. Advocates for the change want to make it easier for foreign pension funds to make badly-needed investments in US infrastructure.

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either are not appropriate for us as a public company or do not give us what we want in terms of offering investment opportunities to the broadest number of investors. That is why we took the path of using a fully-registered offering. If you are not going to take the path we chose, then you have basically five options. You could do a Regulation D offering like Bruce talked about or a Regulation A offering. Both of those are available today and . . . .

MR. MARTIN: Stop there for a second. I am not sure our audience is following this. Regulation D is an offering to accredited investors with no limit?

MR. NEWELL: Correct. There is no limit on the number of investors or the amount you can raise with a Regulation D offering as long as all the investors are accredited. The choice is whether you are going to limit yourself to private discussions or do a general solicitation.

MR. MARTIN: What is Regulation A?

MR. NEWELL: Regulation A offerings are a form of registered offering. Under Regulation A, you can approach any investor — not just accredited investors — but there is a limit currently of $5 million on the amount you can raise. That is what has been proposed to go to $50 million.

MR. MARTIN: So Regulation D is what Bruce Ledesma called title 2, and Regulation A is what he called title 3.

MR. NEWELL: There are three other ways you can do this as well. One is to go through a business development company. That is essentially putting together a public shell, raising capital and then using that capital to make investments. You can also go through a version of a venture capital firm. And, finally, you can make an intrastate offering where you are only taking investments from investors within the state and qualifying on the basis of a state's laws. Therefore, Regulation D, Regulation A, BDC's, venture funds and intrastate offerings are your choices if you are not going to do a fully-registered offering.

MR. MARTIN: Let me come back to the states. That is a good list. I take it then that SolarCity did not need the Jobs Act to do what it is doing with its solar bonds?

MR. NEWELL: The Jobs Act is an important step forward. It is just not relevant to us. We want as broad an offering as possible, and the restrictions that are inherent in the Jobs Act would not allow that.

MR. MARTIN: Is there a filing with the SEC that describes your solar bonds?

MR. NEWELL: Yes. We filed a shelf registration with the SEC last October for $200 million in debt, and we are currently issuing solar bonds under that registration. You can go to the SEC website and get all the details there. You can also find the prospectus on our solar bonds website.

MR. MARTIN: Let me ask one more legal question and then move to practical issues. The SEC delay has let 13 states adopt their own rules for crowdfunding by businesses in state from state residents. Jon Norling, in which states does investment-type crowdfunding have traction due to state rules?

MR. NORLING: Wisconsin, Michigan and Colorado have started some active crowdfunding campaigns, although they are limited to investors in those states. We have seen an interesting intersection in Michigan and Colorado between community solar and crowdfunding. For example, Colorado has community solar legislation, and the state crowdfunding rules present an opportunity to crowdfund community solar projects.

MR. MARTIN: So if I am a Colorado business, I can raise money through crowdfunding in Colorado from Colorado residents without the federal restrictions. What does it take to be a

The SEC is expected to open the door later this year to more forms of crowdfunding.

Colorado business? Must my business be headquartered in Colorado or is it enough to be doing projects in Colorado?

MR. NORLING: You need to be a state-registered business. All of the states require a resident to be authorized and organized to conduct business in the state. At least one state — I forget which — allows foreign registration of a limited liability company, and some require that at least 80% of the capital be used in that state.

MR. LEDESMA: Sticking with the general theme of different approaches to an offering, if you are a public company that has already gone through the arduous IPO process, as SolarCity has, then registering a solar bond offering is a simpler exercise on something called an S-3. The rest of us in the private company world trying to do crowdfunding must find another path. The Jobs Act only provides a path currently for offerings to accredited investors. Tim Newell mentioned a few other avenues. One is an intrastate offering.

Mosaic has decided to pursue such an offering in California; we are a California-based company. We have created a California-domiciled entity to issue notes to the crowd. We have secured a permit in California to crowdfund up to $100 million and it should work fine, but of course we have to stay within California.

Practical Considerations

MR. MARTIN: Let's move to some practical issues. How should a company that wants to use an outside platform select one? Platforms seem a little like Amazon for retailers; they offer a large audience.

MR. NORLING: Time to give a plug for GridShare. GridShare is a platform. We think the primary criteria for selecting platforms should be a broad base of potential investors who are registered with the site and who are excited about cleantech offerings, not only making venture-type investments but also investing in operating renewable energy projects either through debt or being part of the sponsor equity.

MR. MARTIN: Is there data that someone can look at to evaluate your platform?

MR. NORLING: It is www.gridshare.com. You will find various venture offerings on the site; for example, a company is looking to raise money to tap hydrogen from animal waste. Another wants to raise money to plant thousands and thousands of hectares of jatropha for making biofuels.

MR. MARTIN: If someone wants to use a particular platform, how can he determine how large an audience it has?

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CALIFORNIA may have to pay refunds to passive investors in limited liability companies that own projects in California after a state superior court judge held in November that such investors are not "doing business" in California.

The state Franchise Tax Board is expected to appeal.

The case is called *Swart Enterprises, Inc. v. California Franchise Tax Board*. Swart, a corporation formed in Iowa, operates a 60-acre farm in Kansas that feeds cattle for beef sales. Swart invested $50,000 for a 0.2% interest in a fund, called Cypress Equipment Fund XII LLC, that leases equipment to lessees in California. Swart has no other ties to California.

The state collects a minimum tax of $800 from members in LLCs doing business in the state. The Franchise Tax Board has been sending overdue tax notices to LLC members. The notices ask for $2,000 to $3,000 once penalties and interest are added.

Every corporation that is formed in California, qualified to do business there, or actually doing business in California must pay a minimum annual franchise tax of $800.

"Doing business" is defined as "actively engaging in any transaction for the purpose of financial or pecuniary gain or profit." Anyone holding an interest in an LLC that is a partnership for tax purposes is considered by the Franchise Tax Board to be doing business in California if the LLC is doing business in California. Partners are normally considered to do directly what the partnership does.

A state superior court judge in Fresno County ruled that holding a passive interest in an LLC is not doing business in the state.

Another state tax agency, the State Board of Equalization, takes the position that a limited partner in a limited partnership is not doing business in California solely by reason of holding the partnership interest. The Franchise Tax Board used to follow the same approach, but changed its position in a ruling / *continued page 41*

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MR. NORLING: I am not aware of any data on audience size. It is an interesting point, though, and one that we will try to figure out how to address on ours.

MR. LEDESMA: Let me add to what Jon Norling said about how to select a platform. I would focus on the track record: how long the platform has been around and whether there is a history of successfully-placed investments. That data should be displayed on the platform. There should also be a clear answer to what happens if the company that is managing the platform disappears. Typically, you would expect to see an arrangement with a backup servicing company that would continue to service the payment streams from the borrowers to the lenders. Information about it and any risks should be disclosed in the prospectus describing the platform.

MR. MARTIN: Tim Newell, you have been in this business for a while. If you were just starting out looking for a platform, what Google search would you do?

MR. NEWELL: I would not start with a Google search. I would first understand strategically what am I trying to achieve by using this method of raising capital: why use crowdfunding instead of other more traditional forms of financing? Many people think crowdfunding is a route to raising capital at lower cost or more quickly. I would be very careful about making either assumption.

Crowdfunding has the greatest potential for companies that have a strategic reason for doing it; for example, a company has a community-based project and wants to use this mechanism to bring in community investments.

Start there, and then ask yourself, "Is Regulation A right for me, where I reach general investors but in a smaller offering?" "Is Regulation D right for me where I focus solely on accredited investors?" No matter which platform you choose, you are still going to use one of these methods to reach an audience of potential investors. There are not that many choices.

MR. MARTIN: Those are excellent questions. Jon Norling, when someone uses your platform, has he in effect selected one of the routes that Tim Newell just mentioned and, if so, which one?

MR. NORLING: He has. It is either a Regulation A or Regulation D offering at this point, although we are now starting to get traction in some states that allow intrastate offerings.

MR. MARTIN: What percentage of money raised should one expect to pay in fees?

MR. NORLING: I know that the SEC just came out with a 15% figure all-in, with some of that being from the costs of audits and some of the other requirements for companies seeking to raise more than $500,000 in an offering. I think the fees ultimately will be in line with what you see for fees charged by investment banks and financial advisors, although we think, as an internet portal, that we can come in below that. You will still have transaction fees to paper the deal with lawyers. Our goal at GridShare is to have an all-in fee in the single digits that will include the accounting, the legal work and the costs for hosting the offering on the platform.

Thirteen states allow crowdfunding by local companies from state residents.

MR. MARTIN: Let me probe there. An investment bank does a lot of work. It does a road show. It prepares a lot of documents — a prospectus of some sort — and it digs deeply into the company when preparing the prospectus. What does a platform do aside from providing an audience?

MR. NORLING: Let's look at the SEC proposed regulations and what the platform is allowed to do. The platform can assist the issuer with the preparation of investment documents — the prospectus, a kind of pitch book — but the SEC was very clear that anything more than that in terms of doing due diligence and advising on risks is considered providing investment advice which crowdfunding portals are prohibited from doing unless the portal

is a registered broker-dealer. GridShare is not a registered broker-dealer, so it cannot provide investment advice. This has led to the use of third-party service providers who work on behalf of the issuer and provide some due diligence materials and some sort of ranking for the project to help guide investment decisions.

MR. MARTIN: Is there a stigma against companies using crowdfunding? I was at a roundtable discussion in Washington last fall. Two small solar and energy efficiency companies said that they will not use it for fear of such a stigma.

MR. LEDESMA: That sounds like what will eventually be antiquated thinking, certainly around Silicon Valley, which is an innovative, disruptive culture. I suspect the fear is companies that use crowdfunding will be viewed as having failed at securing venture money from their own angel network so now they are turning to strangers. If you are talking about the peer-to-peer lending space, there is absolutely no stigma. Lending Club moved $4 billion in loan volume last year and was the biggest IPO out of California. I think that speaks for itself. A number of successful companies are moving billions of dollars through peer-to-peer platforms that are wildly popular.

MR. NEWELL: The use of the internet to raise money is relatively new, and the negative perception that often accompanies anything new often has its roots in those participants in the marketplace who may have the most to lose by the development of a broader market. What you are seeing is the use of technology to broaden a marketplace by allowing investors to have direct access in ways they did not have before. It does not mean that there won't be institutional investors participating in these financings. In fact, if you look at models like Lending Club, the crowd includes individual investors, hedge funds and banks — including very large banks — as investors. That is how peer-to-peer platforms tend to develop. The choice is whether to invest with the crowd or along an institutional path. Many institutional investors want to do all of the above, and technology is now offering a way to do that. If this follows the same pattern as every other part of the financial sector, then all of the major financial players in the market will adopt this approach over time because it expands the market.

MR. MARTIN: Bruce Ledesma, you described three titles of the Jobs Act and said that the SEC has been slow to issue final regulations allowing two of them to be used. Until that happens, the use of crowdfunding is limited to raising money from accredited investors.

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while the *Swart* case was pending. Its current position is that each partner in a partnership – including an LLC treated as partnership – is considered to engage in whatever business the partnership does. The ruling is Legal Ruling 2014-01.

The court said there is "no legal authority for this conclusion."

The LLC in which Swart invested put sole control over the LLC in the hands of a manager rather than leaving management to the members. The Franchise Tax Board said Swart relinquished a more active role by agreeing to give the manager control. The court dismissed the suggestion; Swart invested two years after the LLC was formed.

The state could owe millions of dollars in tax refunds unless the decision is overturned on appeal.

A MICHIGAN court said in December that sales taxes must be paid on electricity sold to telephone companies.

Michigan collects a 6% sales tax on sales of "tangible personal property." Electricity is considered tangible personal property. However, no tax is owed if the buyer will use the article sold in "industrial processing," defined as "converting or conditioning tangible personal property for ultimate sale at retail or use in manufacturing of a product to be ultimately sold at retail." In other words, the buyer must use the electricity to produce another form of tangible personal property that will be sold to consumers.

AT&T argued that it converts electricity into telephone signals. The court said telephone signals are a service rather than a tangible product that one can hold or feel.

The decision came in a case called MidAmerican Energy Co. v. Department of Treasury *before the Michigan court of appeals. Detroit Edison, Consumers Energy and AT&T joined in the suit.*

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MR. LEDESMA: Or the intrastate exemption that we are using in California, for example, to reach a broad potential investor base, but composed entirely of California residents.

MR. MARTIN: The SEC final rules are expected when? Late 2015? Early 2016?

MR. LEDESMA: I believe late 2015.

MR. NORLING: The latest we have heard is October 2015.

MR. MARTIN: The SEC is proposing that anyone raising more than $500,000 must post audited financials. The SEC is concerned about fraud. Critics say compliance with the proposed SEC rules would add about 15% to the cost of any offering. Are the critics referring to other things besides audit costs when they complain about the burdensome proposed rules?

MR. LEDESMA: There are significant other costs involved with this Regulation A+ approach that might be viewed as a mini-IPO or S-1 type exercise. It is somewhere between a fully-exempt and relatively-inexpensive offering and a full-blown million dollar IPO process. Someone has to draft some version of a registration statement that entails legal costs. There are the audit costs. There are disclosure and risks and insurance that go with that package, so the costs add up. The countervailing point is that when you move to raise tens of millions of dollars from unsophisticated investors, there must be some level of regulated disclosure, and there is a cost associated with that path, albeit a lighter cost than a full registration. It is reasonable for the SEC to require some process, but if the process becomes too expensive, then it no longer is viable.

MR. MARTIN: Jon Norling, have any other equally burdensome things been proposed besides posting audited financials?

MR. NORLING: The SEC had a pretty detailed breakdown of what it views as the probable costs. The main items are audit costs, the transaction costs for lawyers to paper the transaction and the fees charged by the portal. The costs are expected to be 15% on average, but for smaller raises of under $100,000, the estimate was that as much as 25% of the funds would go to transaction costs, which I think would make small offerings under crowdfunding really untenable, even though, at that level, you would not have the audit costs.

It is unclear whether the auditor would have to be registered with the Public Company Accounting Oversight Board, the PCAOB, which can raise the costs of audits, or whether the auditor can be the company's local CPA. For a small start-up company, there is not much to audit.

It should be noted that the SEC requirement to audit is in sharp contrast to the 13 states that have adopted crowdfunding regulations. No audits are required in most states other than where a company is seeking to raise more than $1 million. Then audited financials are required. An audit is not triggered at the $500,000 level as in the SEC proposed regulations. Maybe the SEC will increase its own trigger to closer to $1 million.

Falling Oil Prices and Upstream Insolvency Risk

by Kevin Atkins and John Verrill, in London

Collapsing oil prices are affecting projects and companies in the oil and gas sector.

This article looks at how upstream joint ventures typically deal with the risk of partner insolvencies and, in particular, what rights host government and joint venture partners have upon an insolvency of a co-venturer.

Licensing Regimes

There are broadly speaking two main types of upstream licensing arrangements: concessions and production-sharing or service contracts. Aside from certain US states (such as Texas and New Mexico) where title to oil and gas vests with the landowner, host governments almost always have legislation vesting title to oil and gas with the government, whether onshore or offshore, up to the limits of the continental shelf. The licensing arrangement is the means by which the host government grants oil and gas companies the rights to search, drill and produce oil and gas. Without a licensing arrangement with the host government, no upstream oil and gas project can exist.

The concession structure is commonly used in Western Europe and the United States. Under such a structure, oil and gas companies take title to production, and the host government's revenue stream is then derived from fiscal terms (such as royalties and taxes) charged on production. However, under the

production-sharing and service contract structure, oil and gas companies do not take title to any of the oil and gas produced because title remains with the host government. The oil and gas companies only have an economic entitlement to a pre-determined share of the production or in the proceeds of sale.

Under the terms of any licensing arrangement (whether under the concession structure or the production-sharing and service contract structure), host governments will be entitled to terminate the license upon an insolvency event of the oil and gas company. However, where more than one oil and gas company is participating in the upstream project (as is almost always the case given the scale of financial commitments involved), the insolvency of one licensee does not always give rise to an automatic termination right over the entire project.

For example, certain production-sharing contracts in Africa do not give rise to termination rights in the event of the insolvency of fewer than all of the licensees if the project can still be funded and work programs fulfilled. In the United Kingdom, on the other hand, the insolvency of just one licensee, out of a number of other licensees of the same license area, triggers an automatic termination right. This makes the selection of joint venture partners in an upstream project, whether as part of a bidding round or as part of an approval of an entry of a third party into the joint venture, incredibly sensitive. In some cases, joint venture partner approval rights can hold up entire corporate sale transactions if those joint venture partners are concerned about the financial strength of the proposed incoming oil and gas company. As a matter of English law, even absent an express approval right, concerned joint venture partners have an effective *de facto* approval right if the sale transaction is conditioned on or otherwise requires novation documents to be signed by all concerned joint venture partners. Any failure or refusal to sign the transfer documents is tantamount to a separate approval right.

Joint Venture Arrangements

Pursuant to the terms and conditions of licensing arrangements, obligations of licensees are generally joint and several. Therefore, one of the key drivers behind upstream joint operating agreements is to allocate risk on a several basis between the oil and gas companies in the joint venture and to separate the joint liability regime under the licensing arrangement into percentage interest shares in the upstream project.

This severance of interests also means in the UK that each company is responsible for its own / *continued page 44*

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NEW JERSEY cannot require power companies to add back some taxes paid to other states when calculating their New Jersey incomes, the state tax court said in December.

Duke Energy sells crude oil, refined products, liquid petroleum gas, residual fuels and coal in New Jersey and, therefore, is subject to corporate income tax in New Jersey. The state starts with the net income a company reports for federal income tax purposes and then makes adjustments. A company must add back income taxes paid to other states.

Duke pays electric utility taxes in North Carolina that are based on gross receipts. It also pays a tax in South Carolina that is measured in part by the value of its real property in the state.

The New Jersey tax court said neither tax is an income tax that has to be added back. The decision is in a case called *Duke Energy Corporation v. Director, Division of Taxation*.

The same court held in October in a case called PPL Electric Utilities Corp. v. Division of Taxation *that the parent company of Pennsylvania Power & Light does not have to add back a gross receipts or capital stock tax that it pays in Pennsylvania.*

AN ABANDONMENT LOSS can be claimed on a power plant that was shut down, but not until an arbitration against the manufacturer and pending insurance claims have been resolved.

The IRS explained why in a private letter ruling in December. The ruling is Private Letter Ruling 201451014.

An electric utility owns interests in two large pressurized-water nuclear power plants. Two new steam generators were installed in each of the plants, but a steam leak developed in a heat transfer tube in one of the new generators. This led to discovery of excessive wear and tear in both plants after an inspection of all four steam generators and eventually caused the utility to decide to shut down both power plants permanently. The utility made a public announcement that it was retiring both / *continued page 45*

Oil Prices

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taxes since it lifts its own percentage share of oil and also has the benefit of tax losses from its proportionate share of costs.

The separation of obligations works between the oil and gas companies only and not against the host government that awarded the licensing arrangement, who remains free to pursue claims against any or all of the companies in the joint venture and will be most likely to take action against the companies that have the deepest pockets.

Project costs are funded by cash calls made by a joint venture party who is appointed to carry out the work, usually called the operator. Each joint venture party pays cost and lifts oil in proportion to its percentage interest share in the upstream project. Cash calls are usually made in order to fund the costs of work programs that have been agreed between the joint venture partners on the basis of a voting procedure set out in the operating agreement. This means that, to some extent, joint ventures can control the timing of expenditures by agreeing to work programs that are not especially onerous, provided, of course, that any commitments to the host government are satisfied. Typically, a cash-strapped joint venture party will want to slow down payment and will be reluctant to approve new work programs that it believes it may not be able to afford. However, during the initial exploration phase of an upstream project, mandatory minimum work commitments will be required that will obviously necessitate significant capital expenditure that cannot be avoided.

Any failure to pay a cash call will be treated by the operating agreement as a default. Where one party is in default, the other parties to the joint operating agreement will be required to pay the sums that are in default, each in the proportion that its percentage interest bears to the total of the non-defaulting parties' percentage interests. Any failure to pay these additional sums will itself be treated as a separate default. The defaulter will have his interest carried so that the project can continue, but default will also put additional strain on non-defaulting parties.

The consequences of a default usually escalate over time, with forfeiture being the ultimate and final remedy to the non-defaulters.

The default usually begins with the defaulting party having restricted rights under the joint operating agreement. For example, it will not receive joint venture information or be entitled to attend and vote at joint venture meetings or exercise any pre-emption rights or even take its share of petroleum. If the default continues for a further period of time, then the defaulting party may be obliged to forfeit its interest completely and transfer its interest to its co-venturers. This will obviously only apply to the particular project on which the default occurred and will not generally affect other projects that the defaulting party or its affiliates have interests in, provided that the party is not in default under those projects, too. However, there will almost always be cross-default provisions in the financing documents that will need careful scrutiny.

In addition, in some joint operating agreements, each joint venture party may be bound to grant a security interest to each other co-venturer over its percentage interest in the project, with the co-venturers being entitled to enforce that security, if a party defaults, and sell the percentage interest to realize the amount owed by the defaulting party. This is in addition to the lien on petroleum from which non-defaulters may recoup cash paid out on behalf of the defaulter. However, the nature and enforceability of such charges remains largely untested and, to date, we do not know of such a provision having been invoked in an international upstream project. In any event, as with any security interest, it is important that such security is perfected as a matter of law by the security holders registering particulars of the security in accordance with local laws.

Unlike licensing arrangements, joint operating agreements quite commonly do not include a specific termination right upon an insolvency of one

Insolvency scenarios at troubled drilling projects hurt by low oil prices vary by licensing and joint venture arrangement.

of the joint venture partners. This is because of the fundamental difference in bargaining power and purpose between a licensing arrangement and a joint operating agreement.

Under a licensing agreement, the bargaining strength is typically with the host government, which normally has a number of interested bidders for acreage in a licensing round. The focus of the licensing agreement is the extent and scope of duties and obligations on the oil and gas companies with a view to maximizing host government revenues and the tax take such that, if and when those things are at risk (for example, upon an insolvency of one of the joint venture partners), the host government can terminate the arrangement and seek new joint venture partners as licensee.

A joint operating agreement is more collaborative with the focus being on the integrity of the project in question and how to carry out operations and bear liabilities for the project with a view to a long-term and sustainable, successful and prosperous operation of the project; hence, parties are under an obligation to step in and remedy the defaults of others. Accordingly, insolvency is not itself a trigger to terminate a joint operating agreement. Additionally, in some jurisdictions ipso facto termination for insolvency is unlawful under insolvency laws, but not in the United Kingdom.

Insolvency Scenarios

Notwithstanding the contractual rights discussed earlier, in practice (in the UK at least), license revocation in the event of upstream oil and gas insolvencies is uncommon and, in the most recent insolvency in the North Sea, the UK government worked with the oil and gas company and the joint venture partners concerned to maintain the project as opposed to immediately looking to revoke the license. The political desire to pursue further development of the North Sea, and the awarding of tax reliefs in frontier areas (such as the West of Shetlands) and the issuance of new variants to the traditional licensing structure to facilitate continued development (such as frontier and promote licenses that lessen the burden on licensees during the initial exploration phase), also emphasize the desire to keep upstream projects alive. Consequently, prepackaged sale arrangements are generally preferred exits from formal insolvency proceedings as they ensure that the project continues in the hands of a viable third-party purchaser and, if done quickly, will reduce any administrator's risk of becoming personally liable for oil and gas operations.

In practice, even though joint venture / *continued page 46*

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plants and told the US Nuclear Regulatory Commission that the decommissioning process will take several decades. It laid off a substantial number of employees, got a reduction in its state property tax base to reflect the impairment, and wrote off its remaining investment in the plants on its books.

The utility then commenced an arbitration against the manufacturer of the defective steam generators and sent a notice of potential claims to its insurer. There are also ongoing proceedings before the state public utility commission to determine how the utility's unrecovered investment should be addressed in the rates it charges customers.

Section 165 of the US tax code allows a company abandoning assets to claim an abandonment loss to the extent the loss is "not compensated by insurance or otherwise." The taxpayer must intend irrevocably to discard an asset so that the asset will never be used again. However, no part of the loss can be claimed as long as there is a reasonable prospect of a recovery.

The IRS said in the ruling: "If a taxpayer's claim is not speculative or wholly without merit, and if the taxpayer believes that the chance of recovering the loss is sufficiently probable to warrant bringing a lawsuit and prosecuting it with reasonable diligence to a conclusion, [then] the deduction should be deferred until the conclusion of the lawsuit."

In this case, the IRS said the tax deduction should be deferred until the arbitration and insurance claims have been resolved. However, it saw no need to wait for the rate proceedings before the public utility commission since any increase in rates to compensate the utility will not cause the utility to be considered to have been "compensated for by insurance or otherwise."

The IRS also told the utility it can deduct the amounts it spends on decommissioning without waiting. Such spending is deductible under section 162 of the US tax code as an ordinary and necessary / *continued page 47*

Oil Prices

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partners have the right eventually to forfeit and effectively to take over a defaulting party's percentage interest in a project, the reality is that they will not force forfeiture unless there is a commercial rationale for doing so and they have the financial means to step in and fund the enhanced percentage interest share they will be assuming in the project.

One issue with the obligation on co-venturers to step in and remedy the default of a defaulting joint venture party is the funding parties will be unsecured creditors of the defaulting party who may also be insolvent or approaching insolvency. Therefore, funding co-venturers may seek to prioritize their claims over and above the claims of other creditors, but since the funding obligation is in the operating agreement from the outset, this is a desire not always achieved in practice. Why should the defaulter agree? Moreover, the defaulter's bankers will not want, at the time of most need, to see their security eroded. Indeed, most will have sought subordination of the joint operating agreement liens and other co-venturer protections as a condition for funding the project.

Host government consent may be needed for lenders to foreclose on security.

Falling Oil Prices

There are a number of reasons for the drop in the oil price. However, perhaps the biggest single reason is over-supply as the high prices of the last four to five years and the boom in shale gas have caused production to increase significantly and oil and gas to flood the market. The return of major oil players such as Libya, with its close to one million barrels per day, and Iraq has caused supply to outstrip demand and has given consumers a number of alternative sources of supply.

The dip in the Asian economy and the fall in Asian demand has also had a drastic effect on prices and contributed in large part to the over-supply problem. This is coupled with the stuttering European economy.

OPEC in-fighting is also rumored to be a cause of the price drop as members have, over the last few years, been fighting with each other to capitalize on the growing Asian demand and are now fighting to maintain their shares of that market and refusing to reign in production levels to alleviate the problem of over-supply. Politically, some of the cause for concern of the OPEC members may be driven by the US shale boom as US energy independence has removed a previously-buoyant sale market for OPEC crude, and some commentators have suggested that OPEC members are prepared for the oil price to drop as low as $35 to $40 a barrel for quite some time, which would drive competing producers out of the market, before taking steps to reduce production levels.

Effects of Oil Price Drop

Collapsing oil prices will bring upstream projects closer to their break-even points, with costly deep-water projects in pre-salt basins (such as offshore Brazil and Angola), in particular, being at significant risk.

This means that projects may no longer be economic as revenue streams from sales are no longer enough to offset funding obligations. Projects in emerging markets that adopt production-sharing contract arrangements will take longer to recover their capital expenditures from the proceeds of production, which will prolong when they are able to become cash positive. Host governments will also find that proposed licensing rounds are less active than previous rounds as oil and gas companies are unlikely to take on

new projects with heavy exploration commitments at a time of falling oil prices. This is already rumored to be the case in Mexico where onshore projects, which generally achieve production faster than deep-water projects, are looking less attractive as production will be monetized at current sales prices. This may mean that host governments consider either suspending or postponing licensing rounds or, if oil revenue is a core component of the local economy, offering more competitive license and fiscal terms to incentivize the continued development of upstream projects. At the very least, it is likely that oil and gas companies will re-assess their portfolios of projects and, where possible, seek to pursue less risky onshore projects as opposed to offshore drilling campaigns, as can be seen recently by a number of oil and gas majors, including BP, Chevron and Statoil, who have reduced their budgeted exploration capital expenditures for 2015.

The drop in price will cause lenders to think twice about offering credit lines to exploration-focused oil and gas companies as exploration risk will be compounded by the lower revenue stream if a discovery is even found. Additionally, existing loans will be stress tested as the ability of oil and gas companies to satisfy debt service covenants (in particular loan-life and project-life coverage ratios) will be scrutinized. Lenders may look to syndicate loan exposures to broaden the risk-sharing profile and reduce their shares of funding particular projects (although incoming lenders are unlikely to accept such risk without some quid pro quo from the syndicating lenders).

This may eventually lead to events of default and acceleration rights and enforcement of security under loan arrangements.

However, to the extent that asset-level enforcement is pursued, this will require the prior consent of the host government as enforcement over the shares or assets of an oil and gas company effectively constitutes a transfer of the interests in the project to an incoming third party, which is routinely subject to the prior consent of the host government. Host government consents for transfers of interests in oil and gas projects are, as a matter of local law, typically subject to the technical and financial competence of the incoming party. In the case of a lender enforcing a security interest over an asset, the lender will rarely be considered to have the appropriate technical competence to conduct an oil and gas project. Therefore, in practice the host government will likely work with the lender to locate a suitable third party buyer for the asset in order to facilitate a sale for the lender to realize the debt owed to it.

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IN OTHER NEWS

business expense. The possibility that the utility might recover some of these costs in the arbitration does not bar it from deducting amounts spent on decommissioning now. Any future recoveries for decommissioning costs should be reported as income.

MINOR MEMOS. US generating capacity increased by 15,500 megawatts in 2014, bringing total US capacity to 1,104,459 megawatts, according to SNL Financial. Of the 2014 capacity additions, 7,900 megawatts were natural gas, 3,800 were wind and 3,200 were solar . . . . Global demand for new wind turbines was just under 47,000 megawatts in 2014, compared to annual manufacturing capacity of 71,000 megawatts, according to Navigant Research . . . . The IRS issued 10% fewer private letter rulings in 2014 than the year before. Budget cuts imposed by Congress mean the agency has no ability to replace departing attorneys except for a handful of critical hires, Erik Corwin, deputy chief counsel (technical), said in January . . . . The fee the IRS charges to handle private letter ruling requests increased from $19,000 to $28,300 for ruling requests filed after February 1.

— contributed by Keith Martin in Washington

Oil Prices

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Where credit lines are squeezed and funding arrangements pulled, oil and gas companies will look to make their asset bases leaner and may look to corporate partners and potential joint venture arrangements to share the risk of capital-intensive operating expenditures. However, the buyer's market will be tight as not many investors will look to take a stake in a commitment-rich project that is in the exploration stage at a time when revenues are falling. This may mean marketing to specific buyers in the cash-rich Asian market (although Asian demand is falling and growth rates are slowing) or otherwise seeking partnerships with national oil companies that can manage relationships with host governments, although national oil companies are frequently funded during the exploration phase, meaning that they do not pay their percentage interest shares.

An alternative to debt finance is to seek equity capital from existing shareholders by way of a rights issue or from new investors by way of an offering. However, this will bring its own set of issues as each incoming shareholder will require specific veto rights and board seats and exit strategies that will affect the broader corporate strategy of the oil and gas group. This will also bring any shareholders with different investment profiles into direct conflict with each other and could lead to stalemates with board and shareholder decision-making leading to analysis of shareholder agreements to see how such issues are resolved.

The drilling rig and oilfield services markets may also suffer as assets are either under-worked or given up by joint ventures withdrawing from projects. The assets most likely to be discarded are those in the exploration stage where drilling commitments are mandatory and substantial financial sums are required. This will mean that drilling rigs and service operators are left under-utilized, and supply will exceed demand. This will, as a result, affect fleet prices and oilfield services charter party rates and could, in the long term, have an adverse effect on new ship building projects in the Far East. This will also have a consequential effect on oil-dependent projects such as refineries and associated infrastructure that will be postponed as project economics cannot be supported.

Falling oil prices could also re-energize the debate about delinking the natural gas price from the oil price as shale gas players will not want a fall in oil revenues to cause a similar fall in gas prices, especially as the steadily-increasing supply of gas in the global market has resulted in natural regional hub pricing. However, unlike offshore deep-water crude oil projects and the heavy sour crude oil projects that require a large refinery expense, a vast majority of onshore US domestic shale projects can still remain cash positive and above the break-even line despite the fall in process, although a sustained drop to a sub-$50-a-barrel figure would test the economics of even those shale projects.

A long-term drop in the oil price will have a devastating effect on resource-rich economies, a number of whom are OPEC members, and may lead to widespread redundancies by major oil and gas companies. For example, certain oil and gas companies active in the UK North Sea are already talking about mass layoffs in 2015, and a number of North Sea investors are whispering about the imminent collapse of North Sea prospects.

However, broader global geopolitical concerns may be relevant, too. For example, the Russian economy is heavily supported by oil and gas prices, and the lower oil price is having a disproportionate effect in Russia and is compounding the effects of the existing US and European Union sanctions that restrict, among other things, capital raising and oil and gas exploration and production activities and sent the Russian ruble into a freefall against the US dollar. This may mean that the drop in oil price is not seen as that bad a price to pay by the US as it imposes extra pressure on the Russian economy.

On a longer-term basis, the US 2016 election cycle will start in earnest in 2015. If the oil price continues to drop (or even if it just stays at below the $65 mark), unemployment will rise in a number of key electoral college states with active shale gas projects (such as Texas and the notorious swing states of Ohio and Pennsylvania). Accordingly, the US may put pressure on OPEC to cut production and let the price normalize as each party seeks to give its presidential candidate the best possible chance of success and push responsibility for the low price on the other party. Whatever happens, 2015 will be a very interesting year as the oil and gas industry and world leaders respond to the market.

An Expanding US P3 Market

by Doug Fried, in New York, and Jake Falk, in Washington

A consensus is emerging in Congress that something must be done about crumbling US infrastructure, but consensus remains elusive about how to pay for it. Public-private partnerships may end up being part of the solution.

This report provides an overview of the current US P3 market, including information about the pipeline of projects in procurement, deal structures, market participants and public sector programs.

It analyzes the trends and developments that are shaping the US P3 market, how the market has matured in recent years and where it may be heading in the future.

Chadbourne initially surveyed private involvement in US roads on a P3 basis in 2004. While few deals had been done at that time, a market for US P3s was emerging in the transportation sector. Industry participants were encouraged by the Chicago Skyway and Indiana toll road P3s in 2005 and 2006, respectively, and were hopeful that a wave of US P3s was on the horizon. However, political concerns and the financial downturn put off or delayed some US projects, including some very high-profile P3s that the industry had been pursuing. Nevertheless, the US P3 market has continued to grow over the last 10 years.

During this time, P3 structures have matured, and P3 opportunities have diversified and increased. States have been procuring more greenfield P3s and using availability payment structures for some projects. Certain states are developing more predictable procurement processes, and the pipeline of projects in procurement has generally become more reliable. Global concession companies continue to set up US offices. P3s are spreading to new states and cities and to new sectors, including transit, social and water. A number of P3s are currently in procurement, and more P3s are expected to be developed for procurement in the future.

Growing US Pipeline

A number of new P3s are in procurement or being planned. More than twice as many P3s could reach financial close in 2015 than in 2014. Many are in the transportation sector.

P3s currently in procurement, a number of which may reach financial close in 2015, include the Long Beach Civic Center in California, the UC Merced Campus project in California, the Escambia County waste processing project in Florida, the Illiana corridor in Illinois (which was recently put on hold by the new governor), the Illiana corridor in Indiana, the Indianapolis court house, the University of Kansas campus project, the Purple Line light rail P3 in Montgomery county, Maryland, a waste-to-energy project in Prince Georges county, Maryland, the LaGuardia Airport terminal building in New York, a rapid bridge replacement project in Pennsylvania, a CNG fueling stations project in Pennsylvania, the Port of Ponce P3 in Puerto Rico, the Portsmouth Bypass in Ohio, State Highway 288 in Texas and the Houston justice complex.

Several factors are contributing to the growing use of P3s in the United States.

P3s can reduce project costs, including construction and long-term O&M costs, accelerate project delivery, allocate risks from the public to the private sector and encourage innovation in all phases of the project life-cycle.

Traditional federal grant funding available to states for transportation infrastructure is falling short, and the federal government is increasingly encouraging private investment in infrastructure with new and expanded infrastructure financing programs.

Significant amounts of private capital are available for investment in US P3s.

Infrastructure investment needs are clear in many cases based on the condition, age and performance of US infrastructure facilities and networks.

Sustainable, long-term sources of revenue are being approved at the state and local level, such as sales taxes that can be used to support project financings.

Public officials are becoming more familiar with P3s and are establishing P3 offices, including, for example, in Virginia, Ohio, Pennsylvania and Puerto Rico.

Early P3 projects are completing construction and opening for operation, including, for example, the Capital Beltway and I-95 HOT lanes in Virginia, the Long Beach court house in California and the I-595 managed lanes and Port of Miami tunnel in Florida.

The P3 delivery model is spreading to new states and also to new sectors, including transit, airports, social, water and, most recently, waste-processing infrastructure.

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P3 Market

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A number of states that have closed P3s over the last 10 years are leveraging their experience and developing more P3s. Some examples of P3s that these states have closed, are procuring or are planning are in the chart below.

A growing number of states have turned recently to P3s for the first time. Some examples of P3s that these states are procuring or are planning are in the second chart on the following page.

REPRESENTATIVE LIST OF TRANSPORTATION P3s IN SELECT STATES THAT HAVE BEEN INDUSTRY LEADERS (P3s ARE OPEN, UNDER CONSTRUCTION, IN PROCUREMENT OR BEING PLANNED)	
Texas	SH 130 Segments 5 & 6 – Open North Tarrant Express – Construction I-635 Managed Lanes – Construction North Tarrant Express 3A/3B – Construction SH 183 – Construction SH 288 – Procurement
Virginia	Pocahontas Parkway & Richmond Airport Connector – Open I-495 Capital Beltway HOT Lanes – Open Elizabeth River Crossings – Construction I-95 HOT Lanes – Open I-66 Corridor Improvements – Planning/Development
Indiana	Indiana Toll Road – Open East End Crossing – Construction I-69 Section 5 – Construction Illiana Corridor (Indiana Portion) – Procurement
Florida	I-595 Express Lanes – Open Port of Miami Tunnel – Open I-4 Ultimate Project – Construction

REPRESENTATIVE LIST OF TRANSPORTATION P3s IN SELECT STATES THAT ARE PROCURING THEIR FIRST P3s (P3s ARE IN PROCUREMENT OR PLANNED, AND IN ONE CASE UNDER CONSTRUCTION)	
Pennsylvania	Rapid Bridge Replacement Project – Preferred Proposer CNG Fueling Stations P3 – Procurement Keystone Corridor Rail Stations Project – Planning/Development
Colorado	US 36 Express Lanes – Construction I-70 East – Planning/Development
Ohio	Portsmouth Bypass – Preferred Proposer Brent Spence Bridge – Planning/Development
Illinois	Illiana Corridor (Illinois Portion) – Procurement South Suburban Airport – Planning/Development
Massachusetts	Cape Cod Canal Crossing – Planning/Development Route 3 South Express Toll Lanes – Planning/Development
Maryland	Purple Line Light Rail – Procurement
Alabama	Decatur Toll Bridge – Planning/Development

In some cases, the states identified in the chart are procuring their first P3s, but cities or local agencies within these states have already closed a number of P3s. Examples are states like Illinois where P3s have been procured by the City of Chicago and Colorado where P3s have been procured by local agencies.

Highway, bridge and tunnel projects continue to predominate in the US P3 market, but other infrastructure sectors are seeing more P3s.

Transit: The first major transit P3 in the US, the Eagle light rail P3 in Denver, Colorado, is in full construction and is expected to open in 2016. The Purple Line light rail P3 in Maryland is now in procurement. In addition to light rail, possible transit P3s could include high-speed rail, commuter rail, bus rapid transit, streetcar and intermodal station projects, including, for example, the proposed Keystone corridor rail stations project in Pennsylvania.

Social: The Long Beach court house P3 in California opened in 2013, and there are currently five major social P3s in procurement in the United States: the Long Beach Civic Center (preferred proposer), the Indianapolis court house (preferred proposer), the Houston justice complex (shortlisted proponents), the UC Merced campus project (shortlist issued) and the University of Kansas campus project (request for qualifications).

Water: A handful of major water P3s have reached financial close in recent years, including projects in Rialto, California and Bayonne, New Jersey, and P3s are being considered for a water treatment facility in Miami-Dade county, Florida and other projects. Congress recently created a pilot P3 program and a new "WIFIA" loan program to support water P3s that is based on the Transportation Infrastructure Finance and Innovation Act (TIFIA) loan program.

Airport: The Luis Munoz Marin airport P3 in Puerto Rico reached financial close in 2012. The central terminal building project at LaGuardia airport in New York is being procured as a P3, the Denver airport great hall

project is being procured as a P3, and Illinois is considering a P3 for development of the new South Suburban airport.

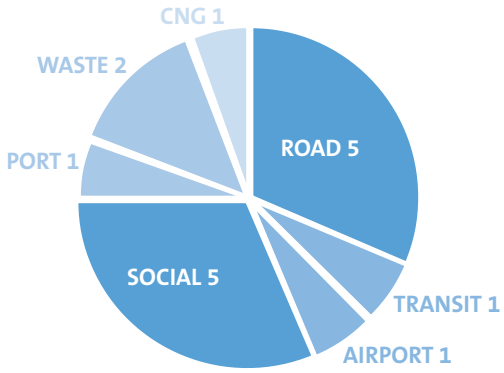
Other: A handful of parking P3s closed in recent years, including Ohio State University's parking P3 and Chicago's parking meters P3, although no parking projects are currently in procurement. There have also been P3s for port facilities, including some active procurements. These and other infrastructure sectors, including waste-to-energy (there are currently two projects in early stages of procurement), may see more P3 activity in the years ahead as the P3 delivery model becomes more familiar and spreads to new parts of the country with their own infrastructure needs.

There are also various US P3s in planning or development stages that should support continued growth of the market in the years ahead. This list includes the following possible P3s for which requests for qualifications may be issued in the first part of 2015: the I-70 East corridor project in Colorado, the Decatur toll bridge project in Alabama, the SR 156 West corridor project in California and the I-66 corridor improvements project in Virginia. Additional P3s for which there may be RFQs in 2015 include, among others, the Cape Cod canal crossing and Route 3 South managed lanes P3s in Massachusetts and the Keystone corridor rail stations P3 in Pennsylvania.

Of note, the November 2014 elections brought new leadership to some of the states that have been actively pursuing P3s, which could potentially alter the landscape for P3 activity in 2015 and 2016. The impact of the elections will not be fully known until the new leaders begin making decisions about infrastructure projects during 2015.

The number of public-private partnerships reaching closing to build out new US infrastructure could double in 2015 compared to 2014.

SECTORS OF REPRESENTATIVE P3s IN PROCUREMENT AS OF DECEMBER 2014



Evolving P3 Structures

Deal structures for US P3s have matured and diversified over the last decade. The US P3 market has evolved from an initial focus on long-term leases of existing facilities and is now increasingly focused on new projects.

There also seems to be a shift toward more availability payments and shorter concession periods.

Greenfield P3s: Since 2008, there have been more "greenfield" P3s for development of new projects than "brownfield" P3s, or leases of existing facilities. This shift coincided with the failure of two high-profile brownfield P3s (the proposed Pennsylvania Turnpike and Chicago Midway airport P3s), but also reflects the growing familiarity of states with the P3 approach for developing and delivering new infrastructure.

Availability Payments: Florida helped pioneer the use of availability payments for greenfield P3s with the Port of Miami tunnel and I-595 managed lanes P3s that each closed in 2009. Indiana and California have also used availability payments. Many of the states procuring their first P3s are using availability payments, such as Pennsylvania, Ohio, Illinois and Maryland.

Toll Roads & Managed Lanes: Since 2008, many of the toll-backed P3 projects in the United States have been for development of new managed lanes, with / *continued page 52*

P3 Market

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certain exceptions, such as the brownfield P3 for PR 22 in Puerto Rico and the Elizabeth River crossings P3 in Virginia. The managed lanes projects often include high-occupancy toll lanes, dynamic pricing to manage congestion, mass transit and other strategies to provide drivers increased reliability and choice. The limited number of real toll road projects reflects, in part, federal regulations that restrict tolling on interstate highways, which the Obama Administration proposed loosening earlier in 2014.

Bundling P3s: Pennsylvania is packaging the replacement of several hundred bridges into one major P3 for its rapid bridge replacement project, and it reached commercial close with a consortium of Plenary, Walsh and Granite on January 9, 2015. This P3 could pave the way for additional bundling projects that come with their own set of risks and unique procurement issues that have to be structured appropriately.

Market Participants

The diversity of companies participating in US P3s continues to increase as a growing number of US and global companies are being named as preferred proponents for US P3s. For example, Plenary (US 36 express lanes in Colorado) and Isolux (I-69 section 5 in Indiana) reached financial close on their first major US transportation P3s in 2014, and Walsh, Vinci and Bilfinger Berger (East End crossing in Indiana and Kentucky) did the same in 2013.

Developers and Equity Funds: A snapshot of six major US highway and transit P3s that were in the request-for-proposal stage in the summer of 2014 shows the growing diversity of bidders for these P3s. The six projects are the Illiana corridor in Illinois, the Illiana corridor in Indiana, Maryland's Purple Line, Pennsylvania's rapid bridge replacement project (the Plenary Walsh Keystone Partners team consisting of the Plenary Group, the Walsh Group, Granite Construction Company and HDR Engineering reached commercial close for this project on January 9, 2015), Ohio's Portsmouth bypass (the Portsmouth Gateway Group consisting of ACS Infrastructure Development, Inc., Infrared Capital Partners Limited, Star America Fund GP and Dragados, USA, Inc. reached commercial close for this project on December 5, 2014) and SH-288 in Texas.

More companies are participating in the US P3 market, including major engineering and construction companies, local and regional design and construction firms and companies focused on other types of infrastructure. However, the six P3s in this snapshot are representative of recent US highway and transit P3s and provide a good sense of the growing interest in this segment of the market.

Sixteen major US and global developers participated or are participating on bid teams for these six P3s (including ACS/Dragados, Alstom, Cintra/Ferrovial, Edgemoor, Fluor, Granite, Isolux, Kiewit, Lane, OHL, Parsons, Plenary, Shikun & Binui, Skanska, Vinci, Walsh).

Six equity funds participated or are participating on bid teams for these six P3s (Fengate, InfraRed, John Laing, Macquarie, Meridiam, Star America).

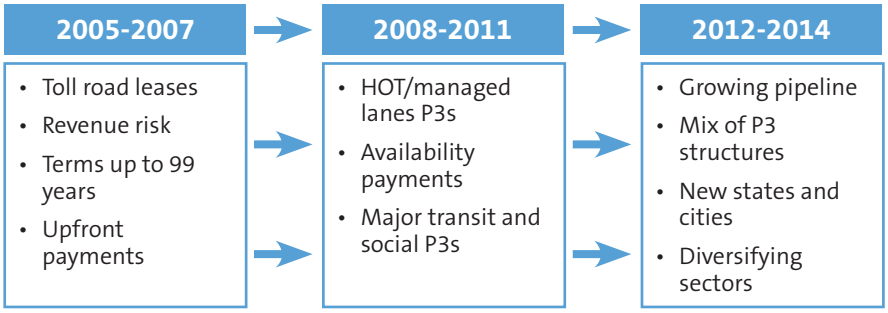
One US developer (Walsh) participated or is participating on bid teams for five of the six P3s and another (Fluor) participated or is participating on bid teams for three of the P3s.

Two foreign developers (ACS and Cintra) participated or are participating on bid teams for four of the six P3s, and another (Plenary) participated or is participating on bid teams for three of the P3s.

Two of the equity funds (Meridiam and InfraRed) were or are on bid teams for four of the P3s, and the other equity funds were or are on bid teams for two of the P3s.

A number of the foreign developers and equity funds included in this snapshot have set up offices in the US to facilitate their involvement in these and other P3s, including some that opened US offices in the last 12 to 24 months.

EVOLVING P3 STRUCTURES



NCSL LIST OF STATES WITH P3 ENABLING LEGISLATION (FEBRUARY 2014)			
States With Broad Legislation	1. Arizona 2. Alabama 3. California 4. Colorado 5. Delaware 6. Georgia 7. Florida 8. Illinois	9. Louisiana 10. Maine 11. Maryland 12. Massachusetts 13. Mississippi 14. North Dakota 15. Ohio 16. Oregon	17. Puerto Rico 18. South Carolina 19. Utah 20. Washington 21. West Virginia 22. Wisconsin 23. Virginia
States With Limited or Project-Specific Legislation	1. Alaska 2. Arkansas 3. Connecticut 4. Indiana	5. Minnesota 6. Missouri 7. Nevada 8. North Carolina	9. Pennsylvania 10. Tennessee 11. Texas
States With No Legislation Enabling P3s	1. Hawaii 2. Idaho 3. Iowa 4. Kansas 5. Kentucky 6. Michigan	7. Montana 8. Nebraska 9. New Hampshire 10. New Jersey 11. New Mexico 12. New York	13. Oklahoma 14. Rhode Island 15. South Dakota 16. Vermont 17. Wyoming

Lenders: Project sponsors in the United States obtain financing to close P3s through tax-exempt private activity bonds, bank loans and federal loan programs, in addition to equity and public contributions. Other sources of financing might also be available for US P3s, such as taxable bonds and institutional debt, but have not typically been used thus far to close P3s. While banks participated in most of the early P3s in the United States, they have not been involved in many of the P3s, particularly the greenfield P3s, that reached financial close after the market downturn in 2008. This may be changing. For example, banks are providing senior debt for Florida's $2.3 billion I-4 ultimate project that reached financial close on September 5, 2014.

The primary federal credit assistance programs used for P3s are tax-exempt bonds and the TIFIA loan program, which remains critical to the financing of some transportation P3s. Tax-exempt bonds and TIFIA are discussed below.

Pension Funds & Institutional Investors: The US P3 market has seen only a relatively limited amount of direct equity investment by pension funds and other institutional investors thus far, despite the apparent alignment of their investment objectives with infrastructure's long-range returns. While the Dallas Police and Fire Pension System invested in two P3s in Texas alongside Cintra and Meridiam, and TIAA-CREF acquired an interest in the I-595 managed lanes P3 in Florida during construction, these types of investments are currently not that common for US P3s.

State Activity

Thirty-three states and Puerto Rico have legislation allowing P3s for highway and bridge projects, according to the National Council of State Legislatures.

Some of this legislation is broad, allowing P3s for a variety of projects across multiple sectors without further approvals, while other legislation is more limited, and may require additional legislative approval of P3s or limit the number or type of P3s that state agencies may undertake.

Many of the states that are delivering P3s are developing more predictable procurement processes that work. States that are procuring their first P3s are learning from states that preceded them. (One of the Obama administration's P3 goals is to share best practices among states.)

More states have been considering P3s in recent years than previously, although not all of the states with enabling legislation are currently pursuing P3s. States that are considering or procuring their first P3s include Alabama, Illinois, Maryland, Massachusetts, Ohio and Pennsylvania.

An emerging hallmark for success is the creation of state-level P3 offices or dedicated personnel that can coordinate public P3 requirements and keep projects on track. States that have created P3 offices or dedicated personnel in recent years to implement P3 programs include Virginia, Ohio, Pennsylvania, Indiana and Puerto Rico.

Some states accept unsolicited proposals for P3s, but the majority of the P3s that have advanced through the procurement process have been solicited. */ continued page 54*

P3 Market

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A few procurements have been cancelled after state agencies shortlisted bidders. Most recently, Nevada elected to deliver the I-15 expansion (Project Neon) as a design-build project rather than a P3 after shortlisting three teams.

Federal Financing Support

Federal programs have played a significant role in financing US transportation P3s. Of the 17 most recent major highway and transit P3s to reach financial close in the United States identified below, 14 used a direct loan from the TIFIA program, 11 used tax-exempt private activity bonds authorized by the US Department of Transportation, and nine used both a TIFIA loan and tax-exempt bonds.

The 17 most recent major US highway and transit P3s include the I-4 Ultimate project in Florida, I-69 in Indiana, US 36 express lanes in Colorado, Goethals bridge in New York and New Jersey, North Tarrant express 3A and 3B in Texas, East End crossing in Indiana and Kentucky, I-95 HOT lanes in Virginia, Presidio Parkway in California, Elizabeth River crossings in Virginia, PR 22 in Puerto Rico, Eagle light rail P3 in Colorado, I-635 managed lanes in Texas, North Tarrant express in Texas, Port of Miami tunnel in Florida, I-595 managed lanes in Florida, SH 130 segments 5 and 6 in Texas, and Capital Beltway HOT lanes in Virginia.

TIFIA: TIFIA provides low-cost, flexible loans for eligible transportation projects, which include both P3s and publicly-financed projects. In 2012, Congress substantially increased the amount of money TIFIA can lend from approximately $1 billion a year to approximately $7.5 billion in 2013 and $10 billion in 2014. Also in 2012, Congress increased the portion of a project's total costs that a TIFIA loan can cover from 33% to 49%, but the government has continued limiting loans to 33%.

More publicly-financed projects are advancing under the expanded TIFIA program than P3s. Of the 44 letters of interest, submitted for TIFIA assistance since the program's lending capacity was increased in 2012, 33 have been for publicly-financed projects and 11 have been for P3s. The large number of publicly-financed projects is not likely to crowd out P3s as long as Congress continues to provide sufficient budget authority for TIFIA to make loans to all of the projects that are requesting assistance.

Private Activity Bonds: Private activity bonds are tax-exempt debt instruments issued by public agencies on behalf of private developers. Authority to use the bonds is granted by the US Department of Transportation for eligible highway and transit projects. Congress established a national limit of $15 billion on the use of such bonds when it created the program in 2005. As of November 12, 2014, $10.2 billion of the $15 billion cap had been allocated to eligible projects, and $4.8 billion of bonds had been issued. As the amount of allocations begins to approach the $15 billion cap, Congress would have to authorize a higher limit for the program to remain viable. Tax-exempt bonds are also available for certain water, waste and other types of infrastructure projects that may be financed through P3s.

TIFIA and private activity bonds have featured so prominently in US highway and transit P3s because they help reduce financing costs. TIFIA has also been particularly helpful for toll road P3s because TIFIA's flexible repayment provisions can better match projected cash flows.

The market is shifting from privatization of existing facilities to new construction.

WIFIA: The federal government recently created a Water Infrastructure Finance and Innovation Act program called "WIFIA" that is modeled on TIFIA. The program allows each of the

US Environmental Protection Agency and the US Army Corps of Engineers to make flexible, low-interest loans for water projects, including P3s. Various types of water and wastewater projects are eligible.

National Infrastructure Bank: Since 2007, many proposals have been offered in Congress for a new national infrastructure bank, but none has passed. The failure of these proposals is attributable, in part, to the difficulty of passing substantial new spending measures during an economic downturn and to a polarized Congress. The failure may also be due to the success of sector-specific programs like TIFIA that provide many of the benefits that an infrastructure bank would provide at a low cost to the taxpayer.

Traditional Public Funding

Federal Transportation Funding: Public officials are turning to P3s for transportation, in part, because traditional federal highway and transit spending is falling short. Federal transportation spending has relied on revenue from motor fuel taxes since 1956. These revenues have supported a federal Highway Trust Fund that provides grants to state and local governments to pay for highway and transit projects with currently-available funds rather than borrowing. However, Americans are consuming less fuel, and federal motor fuel tax rates have not been raised since 1993, leaving the Highway Trust Fund short of funds.

According to a June 2014 report from the Congressional Budget Office,

> The federal government spends more than $50 billion per year on surface transportation programs . . . [but in] the past 10 years, outlays from the Highway Trust Fund have exceeded revenues by more than $52 billion, and outlays will exceed revenues by an estimated $167 billion over the 2015–2024 period [at current spending and tax rates].

Since 2008, the federal government has addressed these shortfalls by making transfers from the US Treasury general fund to the Highway Trust Fund. The 2012, the federal highway and transit bill known as "MAP-21" did not provide any significant new revenues for transportation programs to address the shortfalls. Congress had until September 30, 2014 to reauthorize MAP-21 before the programs expired, but pushed off the deadline to May 31, 2015, largely because it could not solve the funding problem. President Obama proposed a $302 billion reauthorization of MAP-21, but this is more spending than the Highway Trust Fund can support.

The federal shortfalls over the last several years have helped push federal policymakers to consider new approaches for funding and delivering infrastructure, including P3s. Both Congress and the Obama administration have launched initiatives to explore the possibility of expanding P3s.

House P3 Panel: The House Transportation and Infrastructure Committee created a special panel in January 2014 to focus on P3s across various types of infrastructure. The panel produced a report on September 17, 2014, and the panel's work may lead Congress to encourage broader use of private-sector investment and P3s when Congress considers new infrastructure legislation.

Build America Initiative: In July 2014, the Obama administration launched a "Build America Investment Initiative" to encourage broader public and private sector collaboration and expand opportunities for P3s. The initiative includes a new Build America center at the US Department of Transportation to serve as a "one-stop shop for cities and states seeking to use innovative financing and partnerships with the private sector to support transportation infrastructure." The administration also created an inter-agency working group to focus on P3s with more than a dozen agencies and offices participating. The group will review ideas and make recommendations to promote broader use of P3s for US infrastructure.

State and Local Funding: With federal grant programs for transportation facing shortfalls, state and local governments have been creating new, dedicated sources of revenue for transportation infrastructure. Some of these sources of revenue are being leveraged to support infrastructure investment using innovative financing approaches, including P3s. Using new sources of revenue and innovative financing approaches allows cities and states to advance major projects in the near-term without waiting for new federal funding.

Some of the most significant local efforts to raise revenue are referenda that allow local voters to approve new sales and use taxes and dedicate the revenue to specific projects. One of the most substantial voter-approved sales taxes in recent years was the half-cent "Measure R" sales tax approved by voters in Los Angeles in 2008. Measure R revenues will be used to fund a number of transportation projects to be */ continued page 56*

P3 Market

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delivered by the Los Angeles county Metropolitan Transportation Authority, including possible P3s. Local sales taxes also fund the Denver Regional Transportation District's projects, including the Eagle light rail P3.

Some states have also recently been supplementing state motor fuel excise taxes with other long-term taxes that can be dedicated to transportation. These include increased motor fuel taxes, dedicated sales taxes and increased fuel taxes at the wholesale level.

Thirty-three states and Puerto Rico now have legislation allowing use of P3s for highway and bridge projects.

Tolling and Pricing: One significant reform that the federal government could make to help states raise revenue for transportation projects would be to relax the current restrictions on tolling interstate highways. By creating a dedicated source of revenue that can be used by private entities to pay debt service and receive a return on equity or to allow states to make availability payments, tolling would facilitate more P3s. Some states have expressed interest in tolling interstates in recent years to make critical improvements and replace aging and, in some cases, inadequate infrastructure. In 2014, the US Department of Transportation proposed that Congress provide more flexibility for states and cities to charge tolls on interstates. This proposal was in the draft highway and transit bill that President Obama sent Congress to replace MAP-21.

Opportunities

The US P3 market is growing and will continue to do so due to shortfalls in federal grant funds, the need to invest in aging and inadequate infrastructure, availability of private capital and public sector efforts to improve the financing and delivery of projects. The growth is also aided by the growing familiarity of public officials with P3s, the completion of early P3s and the effectiveness of the P3 delivery model.

There are currently several P3s in procurement or being planned. Some of the upcoming opportunities for the private sector to invest in US P3s include the following potential P3s currently in procurement or expected to move there:

I-70 East corridor project (CO) — An approximately 11-mile, $1.5 billion project to add capacity and managed lanes on I-70 East from downtown Denver toward Denver International airport. A request for qualifications is expected in early 2015.

CNG fueling stations P3 project for transit (PA) — An approximately $50 to $100 million project to install CNG fueling stations at up to 37 transit facilities across Pennsylvania. The shortlisted bidders were announced on January 16, 2015.

Decatur toll bridge (AL) – An approximately $250 million toll bridge P3 proposed for northern Alabama connecting Morgan and Limestone counties over the Tennessee River in Decatur. A request for qualifications is possible in 2015.

I-66 corridor improvements (VA) — An approximately 28-mile managed-lanes project on I-66 from Haymarket in Prince William county west of Washington to the Capital Beltway. A request for qualifications is expected for this P3 in early 2015.

Port of Ponce (PR) — A port operations P3 at the Port of Ponce in Puerto Rico with opportunities for additional improvements. A request for proposals was issued for this P3 in October 2014 describing the shortlisting and bidding process.

Prince George's county waste processing and alternative energy facility (MD) — A P3 to construct a new waste processing and conversion facility for Prince George's county. A request for qualifications was issued in October 2014.

South Miami Heights water treatment plant (FL) — A P3 to construct a new water treatment facility for Miami-Dade county. A draft request for qualifications was issued, and a final RFQ is expected in 2015.

SR-156 West corridor (CA) — An approximately $268 million project to construct a new highway parallel to Highway 156 in Monterey county. A pre-development agreement could be awarded in 2015 following an RFQ-RFP process.

University of Kansas Central District development project (KS) — A P3 for the planning, design, construction, financing and potentially operations and maintenance of the Central District development project. Responses to the request for qualifications were received on January 15, 2015.

Emerald Coast/Escambia county waste processing facility (FL) – A P3 for the design, permitting, financing, construction and long-term operation of a waste processing facility. The short-listed bidders were announced on January 7, 2015.

More solicitations are expected later in the year. ◎

Current Trends: Industry Chatter

A panel of power industry veterans had a wide-ranging discussion in New Orleans at the Infocast projects & money conference in January about the impact of falling oil prices on the US power sector, whether the basic power industry business model is being turned upside down by cheap natural gas and distributed solar and, if so, what emerges as a new business model, whether distributed solar is a good place to invest capital and other topics.

The panelists are Nazar Massoud, a principal with Energy Capital Partners and a former Goldman Sachs managing director, Todd Carter, senior partner and founding president of Panda Power Funds, Joe Kerecman, director of government and regulatory affairs at Calpine, Scott Taylor, chief financial officer of Moxie Energy and a former managing director in the wind and solar groups at AES Corporation, and Grant Davis, managing director of Tenaska Capital Management. The moderator is Keith Martin with Chadbourne in Washington.

MR. MARTIN: The power industry business model appears to be undergoing as significant a transformation as after the Arab oil embargo in the 1970's when the independent power industry was born. In 1978, the US Congress ordered utilities to buy electricity from independent generators. This led to deregulation of the generation side of the business in many states. Now it seems like we are reinventing things again and are entering another period of significant change in the basic power industry business model. Nazar Massouh, do you agree?

MR. MASSOUH: I agree that we are going through a big transformation. Some of it is driven by forces within the power industry itself. Some of it is driven by the Environmental Protection Agency. Some of it is driven by forces in the oil and gas industry. I have had the pleasure of working across industries, and I would say that the latter probably has had the biggest impact on the power industry by lowering natural gas prices from where they were in 2008. In preparing for this panel, I looked at where gas prices were in the 1990s and, surprisingly, they were about the same as they are today.

MR. MARTIN: So as transformational a period today as after the Arab oil embargo. Todd Carter, do you agree?

MR. CARTER: I completely disagree. [Laughter.] We are an independent generator building power / *continued page 58*

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projects in different parts of the country. We have not seen much change in how we do business. Low gas prices are creating opportunities for us to build more power plants, but the basic business model is the same as in the past.

MR. MARTIN: One yes. One no. Joe Kerecman, major transformation or not?

MR. KERECMAN: My frame of reference is PJM. There were 797,000 gigawatt hours of energy produced in PJM in 2013. Of that, about 1,948 gigawatt hours came from oil, so oil-fired generation is practically non-existent. Solar was only 355 gigawatt hours in 2013. Wind was 15,000 gigawatt hours. The story in PJM today is about how nuclear is suffering, coal is in transition, and gas is picking up market share because of low natural gas prices. There is a lot of opportunity for independent generators not only because of low gas prices, but also because PJM is changing its capacity market design with higher performance expectations on which some of the intermittent resources will not be able to deliver.

MR. MARTIN: Does that mean transformation in the basic business model or is it just more of the same with independent power producers seeing some new opportunity in PJM?

MR. KERECMAN: There is a greater opportunity to develop in PJM.

MR. MARTIN: Scott Taylor, are we in a transformational period as significant as the late 1970s?

MR. TAYLOR: I agree with Todd Carter. I think this is just an extension of the existing business model and not a period of transformational change. It is consistent with what was intended to occur in 1978 with enactment of the Public Utility Regulatory Policies Act and its mandate to utilities to buy from independent generators. Our industry has seen changes in the generating mix over the last 35 years. Think about some of the rice hull projects that we financed in the early years. Geothermal was big. There has been a gradual shift in the generating mix, but even the growth in renewables, some of which, like rooftop solar, involves significantly disruptive technologies, is still playing out against a backdrop of the same basic business model.

MR. MARTIN: Grant Davis, same business model?

MR. DAVIS: I disagree with Todd Carter. We are in a transformational period. I don't know whether it will take five years or 10 years to play out fully, but the power industry is in the midst of some fundamental changes in how it has operated over the last 20 years.

Major Transformation?

MR. MARTIN: Nazar Massouh, you think we are in a period of transformational change. What emerges at the end of this period?

MR. MASSOUH: The oil and gas industry is having a big impact on our sector, perhaps not for the reasons that are obvious because we no longer use oil to produce electricity, but we do use natural gas. Gas was $13 an mmBtu before prices collapsed. Prices would have come right back up, just like they did for oil, except they never recovered because of unconventional techniques for producing gas. Furthermore, close to half of our natural gas produced unconventionally is actually associated gas. It comes out of oil wells and is associated with oil production. The reduction in oil prices could lead to a reduction not only in oil output, but also output of associated gas. That could put upward pressure on the price of natural gas.

Low gas prices are what has allowed us to do a lot of things in the last five or six years.

I feel sorry for people in the renewable energy space because low gas prices are making life

Merchant power plants are expected to become financeable in New England.

difficult. If gas prices were still $13, we would have a lot more renewables, and we would have coal plants that would be retrofitted instead of being shut down. I don't know whether the coal generating capacity that will be shut down will reach 100,000 megawatts, but it should be close to that number.

I started with an independent power producer in the mid-1990s, and the first thing I learned was the stack works: you dispatch hydro, nuclear, coal and gas in that order. What is happening is transformational because the traditional stack no longer holds.

MR. MARTIN: What is the current stack?

MR. MASSOUH: Hydro and nuclear are still there, but natural gas is by far the cheapest source of production outside of the renewable energy producers who do not have to buy fuel.

MR. MARTIN: So the transformation is not so much in the business model as a shift in who supplies electricity?

MR. MASSOUH: More in what energy sources are used to generate our electricity rather than who generates it.

MR. MARTIN: Grant Davis, you believe we are in a transformational period. What emerges at the end of it?

MR. DAVIS: That is a good question. If I had the answer, I might have earned enough to retire by now. I think 10 years from now, we will look back and see some fundamental changes. The mix of generating assets or the stack is an obvious one. I think we will see changes in the regulatory environment relative to renewables, relative to demand-side management and the utility model. There is pressure to move away from sole concentration on large generating stations to more of a distributed generation model.

More of the Same?

MR. MARTIN: The rest of our panel believes it will be more of the same. Todd Carter, is it easier or harder today to get a power contract with a utility?

MR. CARTER: The changes that the gentlemen are talking about are not driven by falling oil prices. We are in a transformational period in the power business.

MR. MARTIN: Transformation to what?

MR. CARTER: We are building power projects that use natural gas. Gas has been the biggest game changer of all the trends that are visible today in the market. Low gas prices put pressure on renewables. They put pressure on coal. They will lead to a reduction in carbon emissions as gas replaces coal. The reduction will not be the result of government regulation, but economics.

I agree with Grant Davis about utilities and distributed generation. It is a different business today than it was 35 years ago. Everything is different. You have to stay on top of the changes and be at the forefront of the transformation.

MR. MARTIN: It is a harder business today because you do not have long-term power contracts for your projects. You are building gas-fired power plants that sell on a merchant basis into PJM and ERCOT.

MR. CARTER: No doubt it is a tougher business for independent generators. There are people in our business who are waiting for a 30-year power contract, they are waiting for a 20-year contract, they are waiting for a 15-year contract. Guess what? That model and that business shut down more than 10 years ago. There are still some long-term power contracts to be had, but they are few and far between, so we look to build in markets where the additional electricity is needed. Texas is a fast-growing market. It is a different place than PJM with its older asset base, but we like the transparency of both markets.

MR. MARTIN: Scott Taylor, you think it is more of the same.

MR. TAYLOR: I should clarify that. I agree with the comments just made. I am not suggesting that there are not big changes going on with coal going away and gas replacing it. I was more responding to the suggestion by NRG CEO David Crane that the market will turn upside down: IPPs and utilities will go the way of the dinosaur and consumers will turn to distributed generation. I am not suggesting that distributed generation will not have an impact on our industry, but that impact will be a lot smaller than many predict and, at the end of the day, we will still have a healthy IPP business and a healthy utility business.

Each of us must adapt to the changes, but the basic business model will remain. Utility-scale projects will still be needed to serve demand. I am not saying that renewables and distributed generation will not benefit from some of that growth, but the distributed generators are not going to turn the market upside down in the same way that gas has turned the market upside down by slowing the adoption of renewables and replacing coal. The industry is in a slow evolution of the sort that Congress set in motion in the late 1970's; nothing more.

Falling Oil Prices

MR. MARTIN: Let's drill down into several factors that affect the market, starting with oil prices. They have been dropping dramatically. Oil is under $50 a barrel today. Some people think the price will fall as low as $30 a barrel / *continued page 60*

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before turning around. What are the effects of the falling oil prices on the independent power market?

MR. DAVIS: I think there is very little impact. We will end up with less associated gas as oil wells are shut down. That could affect whether gas prices keep falling. There are some impacts of falling oil prices in some of the regional markets in terms of a reduction in electricity demand due to a slowdown in drilling, but that is on the margin and not a fundamental impact.

MR. MARTIN: So no real impact. Scott Taylor?

MR. TAYLOR: I agree with Grant Davis. I don't see any major impacts from falling oil prices. Within our industry overall, oil is not a major player. Some of the LNG export terminals that are planned may suffer, as they may find it harder to find buyers willing to lock in prices under long-term contracts. Demand for electric vehicles may suffer.

MR. MARTIN: What about in New England where fuel oil is used more heavily than in other parts of the country?

MR. TAYLOR: I don't know the New England market well, but I believe oil is only on the margin in New England in January and February, so consumers will benefit a little bit, but low oil prices should not have a big effect on the shape of the power market in New England.

MR. MARTIN: Joe Kerecman, you are nodding yes. You agree with Scott Taylor.

MR. KERECMAN: PJM and New England are moving to capacity markets that reward performance. There are severe consequences if you do not perform. What we are doing at Calpine is relying on dual fuels. We have some oil peakers in PJM, but the rest are combined-cycle gas-fired power plants with oil as a backup fuel. Lower oil prices reduce the cost of the backup fuel, but it is not a big effect because we not talking about the cost of our primary fuel. We use oil as a backup to reduce performance risk.

MR. MARTIN: Todd Carter, any effects?

MR. CARTER: I agree with what has already been said. The only other effect I would add is the slowdown in new oil drilling is freeing up workers who can help build our projects.

MR. MARTIN: Nazar Massouh?

MR. MASSOUH: Not surprisingly, I am a bit of an outlier in this group. I believe low oil prices will have an impact. Whether it will be severe, time will tell, as it depends on how long oil prices stay at $46 a barrel.

There are two primary areas where I see an effect.

One is on overall gas supplies. If oil prices remain as low as they are today, I get a little concerned about a possible tightening of gas supplies because of the loss of associated gas.

The second effect is on electricity demand. A lot of the growth in ERCOT, for example, has been driven by the oil and gas industry and new drilling. Fortunately, Texas is a low-cost oil producer, so perhaps we will not see as much of an impact in Texas. In places like Oklahoma, Colorado and North Dakota, we can see a greater effect. We live in a world with less than 1% annual growth in demand for electricity. In such a world, a reduction in demand growth to 0.5% is huge. I can see some impact on power demand, particularly if the slump in oil prices persists for a while. On the other hand, falling oil prices have led to lower gasoline prices at the pump, putting more money in consumers' pockets and helping the national economy to grow, so declining electricity demand in some areas could be offset by additional demand in others.

Close to 100,000 megawatts of coal-fired power plants are expected to be retired in the US.

MR. MARTIN: Does anybody in the audience see collapsing oil prices having an effect on the independent power market? [Pause.]

Nothing? [Pause.] That's news in itself.

MR. CARTER: I think that we in our industry tend to focus solely on our industry and not think enough about the external factors. Let's go back to 2007. What changed our industry is not that we created a new, more efficient turbine or we were able to build a natural gas-fired power plant more cheaply. What changed us is the fact that the oil and gas industry figured out a way to produce natural gas for a lot less.

I look at the renewables industry, and the same is true. What introduced renewables into the world of power generation is the technology improved so significantly that it brought down the cost of utility-scale solar from $230 a megawatt hour to maybe $80 today. That is huge improvement. I would like to challenge all of us to think more outside our industry for trends that affect us. Anyone building a power plant must think at least 10 or 15 years out. We have to because a power plant is a 30-year asset, and some of these changes could have a significant impact on the economics.

MR. MARTIN: Let me ask a quick question as a bridge to something else. Grant Davis, Nazar Massouh, you guys have money; you invest in things. You three guys in the middle are developers focusing on power projects that use natural gas. Are you two guys with the money putting your money into gas-fired generation?

MR. MASSOUH: The answer is absolutely.

MR. DAVIS: Yes and, in fact, Tenaska is on both sides of that equation. We have money, and we are also developers.

Market Shares

MR. MARTIN: Next question. The independent power industry seems to have peaked in terms of market share at about 42% of US generating capacity; it hit that about 2003 and its market share has not moved since then; the utilities are the rest. Many people thought the utilities would start reclaiming market share. Now the distributed generation companies come on the scene and are asking for a share of the market. Who cedes market share to them: the independent generators or the utilities?

MR. CARTER: There are more people on this panel that have capital than what you just mentioned.

MR. MARTIN: Panda Power Funds! [Laughter.]

MR. CARTER: It depends. Somebody had data earlier today showing that there will be a ton of distributed generation. If that were a profitable business, I promise you we would invest in it. I promise you Calpine and everyone else on this panel would invest in it. We always look at new technologies.

MR. MARTIN: Let's drill down on that. You have companies like SolarCity and Vivint growing at a 100% annual growth rates. Some of the smaller companies are growing at 200% a year. Why isn't that a good place to invest?

MR. CARTER: Listen, I like solar; we built a very large solar project in New Jersey of all places. Why did we build it? We built it because there are state regulations that give us an incentive to build it. I am glad those companies are growing. We don't see that as a big investment from our perspective, but we look at things a little differently than they do.

MR. MARTIN: If the rest of you were starting over today or you were just figuring out where to deploy capital, would you put your capital into rooftop solar?

MR. MASSOUH: I am on the board of one of these companies, Sungevity, and we made an investment. The investment was backed by 20-year contracted cash flow from their existing customers. We are not taking the risk that the solar rooftop industry will continue to grow. Most of the rooftop companies remain funded largely by venture capital. None of us is a venture capitalist. None of us is paid by our investors to take venture capital types of risks, so that is why none of us on this panel would invest in these businesses. Will they make an impact? Yes, but Scott Taylor said it well earlier which is that they will make an impact up to a point. They will not replace conventional independent generators. I have a lot of respect for David Crane, but I disagree with his predictions about the long-term direction of the industry.

MR. KERECMAN: There are three critical ingredients for rooftop solar. One is a high retail electricity rate. Another is a sort of regulatory cram down of the net metering rules. The third is sunlight.

You almost have to consider California separately from the rest of the market. California is not representative of the larger US. Is the distributed generation model taking hold outside California? I'm not so sure. Obviously New Jersey has a lot of solar penetration, but solar insolation is not as good in New Jersey as in California. To the extent distributed generation has taken hold in New Jersey, it is really through force */ continued page 62*

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feeding of a business model. Returning to PJM data for 2013, solar accounted for just 355 gigawatt hours out of 797,000 gigawatt hours in total.

MR. MARTIN: You are director of government and regulatory affairs and tend to see through that lens. You don't think that distributed generation works without government support. Todd Carter, you appear to believe the same thing. You built a solar project in New Jersey, but only because of the strong government support. Is there anybody on this panel who thinks that distributed solar is where you would put your money if you were starting over today. Scott Taylor nods no.

MR. DAVIS: Our affiliate has done utility-scale solar. It is a challenging market for a private equity investor. There is another player at the table.

MR. MARTIN: Who is the other player at the table?

MR. TAYLOR: The tax equity.

MR. MARTIN: So too many moving pieces; government is a big part of it.

MR. TAYLOR: The returns are too low relative to private equity expectations.

A wave of utility mergers is not expected. State utility commissions try to extract concessions.

MR. MARTIN: Then let's move in a different direction. Tom Fanning, CEO of Southern Company, sees a silver lining in that demand for electricity will increase as the market moves to electric cars. Will the collapse in oil prices put an end to that dream?

MR. TAYLOR: I do not understand how electric cars were going to be the cure for demand growth, even before oil prices collapsed. Even if electric cars reached 20% of the US auto market, that would lead to only a 5% increase in demand. It is not a substantial enough number.

MR. MARTIN: Isn't that a substantial number given how little electricity demand is increasing currently: about .9% a year?

MR. TAYLOR: Over time. What is total US generating capacity: about a million megawatts?

MR. MARTIN: A little over.

MR. TAYLOR: So that's 50,000 megawatts. That is a big number, but it is not a game changer.

Utility Death Spiral?

MR. MARTIN: Next question. EEI, the trade association for the regulated utilities, put out a paper a couple years ago that used the words "death spiral." The author saw the distributed generators picking off utility customers, not just any customers, but the most creditworthy customers. Then rates have to go up for the remaining customers to support the grid. Higher rates push more people to distributed generation. Do any of you worry about a decline in the creditworthiness of the electric utilities? After all, as independent generators, they are your customers.

MR. KERECMAN: At some point, the cost of reliability has to be assumed by somebody. You cannot put your solar panels on the roof and expect the utility still to be there if something goes wrong. The fundamental system has to come up with an answer.

MR. MARTIN: The regulators will have to step in; solar customers will have to pay more despite not using the grid as much? Nazar Massouh?

MR. MASSOUH: What we do not spend a lot of time talking about is that rooftop solar is a peak shaving tool, and that is pretty valuable to the utilities. Granted, the generation is intermittent and unpredictable, but I think the utilities tend to exaggerate the impact on them. If you look at the history of operation even in California, which probably has the highest penetration, utilities are getting used to distributed generation because rooftop solar is generally there most of the time and probably easier to predict than it is to predict wind generation. Look, utilities are not going away, and they definitely

will have to continue to provide generation of last resort directly or by buying from independent generators.

MR. MARTIN: When utilities need more power, they may go to independent generators for power. The distributed generators sit on one side of the utilities picking off utility customers. The independent generators sit on the other side looking to supply those same customers through the utilities. The distributed generators are growing rapidly. Isn't all the new load growth being filled by the distributed generators? Todd Carter.

MR. CARTER: We do not see that much growth in distributed generation. We pay attention to it of course, but we do not see it. But, listen, we are not in every market either. We like PJM, and we like ERCOT. We do not see as much distributed generation in those markets as what you just described.

MR. MARTIN: You will find additional market share out of the coal retirements or, if not, what else is creating opportunity?

MR. CARTER: I have never seen gas-fired power plants beat coal plants so significantly as I see now. The reality is we are putting some coal plants out of business. I am sorry for the coal guys. I think they have more issues than the bare economics, but that is part of life. You have to get more efficient in how you do things.

MR. MASSOUH: Let me put some numbers around what Todd just said. The reason we do not see the distributed generators is when we got involved with Sungevity several years ago, it was advertising it would double its installations from the year before. It was going to double installations from nine megawatts to 17 or 18 megawatts. To your point, displacing a 1,000- or 2,000-megawatt coal plant makes a difference. The growth rates for distributed generation are very high in percentage terms, but distributed generation is still having a very minor impact on the industry.

Other Opportunities

MR. MARTIN: If you were starting over today, would a good place to invest be conversions of coal-fired power plants to run on gas? The last time I checked, coal accounted for about 38% of US generating capacity. Retirements are expected to accelerate.

MR. KERECMAN: That may make some sense where the coal plants are close to the gas supply. Conversion does not require a huge investment. The coal plants probably also have a high heat rate. Of course, you have to de-rate the plant when you make the conversion, so it is probably more about a capacity play and then, from a capacity standpoint, like I said earlier, the rules are changing, so the converted plant needs to be pretty reliable. These coal plants are 40 to 50 years old. They were installed as base-load resources. They have not been operating as base-load resources, so they have been basically having to cycle. That makes them even more unreliable. It is an interesting question, but, from an efficiency standpoint, I wonder whether it is a great use of gas.

MR. MARTIN: Not much opportunity. Scott Taylor, agree?

MR. TAYLOR: I have a view, but it is probably self-serving, so I think I will pass.

MR. KERECMAN: It probably makes sense for some of the regulated utilities. The investment goes into rate base. It is fairly easy to switch, but the plants are on the margin and these plants are not made to operate as peakers, so the only value they really provide is reliability in a capacity play.

MR. MARTIN: A number of years ago there were several European utilities looking at a play in the US market at coal-fired power plants. Do you see any merit to such a play today?

MR. TAYLOR: No. It is good to swim against the current sometimes and pick the contrarian view, but that is one play that I would never think about tackling.

MR. KERECMAN: Are you asking about developing a coal plant?

MR. MARTIN: Just buying existing coal plants.

MR. KERECMAN: If you buy them very, very cheaply and have a very short horizon in terms of how long you can use them, then maybe.

MR. TAYLOR: I agree with that.

MR. MARTIN: Next question. Many people predicted, after the Public Utility Holding Company Act was repealed in 2005, that we would see a waive of utility consolidations. We have not seen much, but recently Exelon bought Constellation and is planning to buy Pepco. NextEra is buying Hawaiian Electric. Are we about to see more consolidations?

MR. MASSOUH: That is a tough one to predict.

MR. CARTER: Apologies to my utility friends, but I think utilities are a lot alike; they can be herds of sheep. If you start to see a few acquisitions, then a lot more may be on the way.

MR. MARTIN: Larry Eisenstat, this is your area of expertise. Are we about to see a wave of utility consolidations and, if so, why now and not earlier?

MR. EISENSTAT: I do not foresee a wave of utility consolidations. There are significant regulatory hurdles. For one thing, the local public utility commissions will try to extract whatever consideration they can.

MR. KERECMAN: Mergers are hard to do.

MR. MARTIN: Next topic: energy storage. Many people think energy storage will be a game changer, */ continued page 62*

Current Trends

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but no one has figured out how to make the economics work, at least as a standalone storage unit or by adding additional capital cost to an existing utility-scale renewable energy project. What do you think is the future for utility-scale storage and, if it is a bright future, what is the path forward?

MR. CARTER: Judging from the fact that a lot of people in the audience just headed for the exit when you mentioned that, it kind of gives you an idea what most people think about storage. [Laughter.] Listen, if it worked, we would love it. We have lots of wind in Texas that does not blow when you need it. It would be great if we could store the electricity. The technology is not yet competitive.

MR. MARTIN: Does anyone see a path forward for storage? Nazar Massouh?

MR. MASSOUH: Batteries and energy storage are probably where distributed generation was about 10 years ago, so maybe at some point, but not in our investment horizons.

Trends

MR. MARTIN: What are the most significant current trends in today's market? Let's start with Grant Davis and then move across the panel.

MR. DAVIS: The merchant generation model will probably dominate things for the next two to three years.

MR. MARTIN: Many of us are old enough to remember the last rush to do merchant power projects that ended badly around 2000 or 2001. Many of the bankers who financed the last wave of merchant plants are no longer working in the industry. Why is this a different merchant phase than we experienced before?

MR. CARTER: Today is completely different than the last round. For one thing, capital is not easy to come by. We have done $5 billion worth of projects, but not many banks were involved.

MR. MARTIN: Why is it a different marketplace?

MR. CARTER: We are in the midst of a transition in terms of market exit. The number of coal and nuclear power plant retirements is creating an opportunity to build highly-efficient new power plants that burn cheap natural gas.

MR. MARTIN: Grant Davis, why do you think the current rush to finance merchant power plants will end differently this time than it did before?

MR. DAVIS: I am not convinced that it does end differently, quite honestly.

Our industry has a tendency to overshoot, and we cannot necessarily rely on the capital markets to be our discipline. Just because someone will make money available to us does not necessarily mean we should build. I worry about repeating the same mistakes as in the past.

MR. CARTER: Grant, I am sorry, but I disagree with you. The only projects we are financing are ones where it is clear the debt can be repaid. We have sold power forward and expect capacity payments over time that make us feel pretty good about being able pay debt service. That is different than what happened the last time. Not many quasi-merchant plants are being built this time around.

MR. MASSOUH: I tend to agree. I think three things are very different than they were back in the late 1990s. First, there are a lot fewer developers and fewer capital providers. The independent power producers who drove the growth and the overbuild in the late 1990s are hardly building. What remains

Energy storage is where distributed generation was 10 years ago.

are private equity-backed developers who tend to be a lot more disciplined. Second, all these projects have a lot more equity in them. Third, hedging is being used to reduce risk. All of these projects are structured so that if you get the merchant-for-gas wrong, you are not immediately in default and turning the keys over.

MR. TAYLOR: The market is a lot more disciplined than before. I was around then, but I was not involved in any merchant projects, so I cannot do an actual comparison, but I do know that you have to satisfy three parties today — equity, debt and hedge providers —- before a project can be financed. All three are sophisticated, well aware of what happened the last time and determined not to see the experience repeated. A lot of due diligence is done. A large cushion is built into the economics.

MR. MARTIN: Bob Simmons of Panda, do you want to add anything? You are on the front line raising money for some of these projects.

MR. SIMMONS: The industry had a "Field of Dreams" model before 2000: build it, and they will come. Developers could raise 80% debt. They did not have to persuade other constituent parties, like hedge providers, to participate. We have financed three quasi-merchant power plants to date with roughly 50% equity and 50% debt. It is pretty difficult to raise that kind of equity and very difficult to raise that much debt on a merchant or quasi-merchant basis. We have been able to improve on the leverage, but only slightly and certainly not to the point where we were 15 years ago.

MR. MARTIN: Grant Davis, can merchant plants be financed anywhere besides in ERCOT and PJM?

MR. DAVIS: I would say no.

MR. MARTIN: Todd Carter, do you agree?

MR. CARTER: No. [Laughter.]

MR. MARTIN: Where else can you do them?

MR. CARTER: We are focused today on PJM, so I am being a little tongue and cheek with Grant. ERCOT and PJM are clearly the best markets.

MR. KERECMAN: I would add New England.

MR. MARTIN: The entire New England ISO area?

MR. KERECMAN: New England has come a long way. There has been a lot of improvement in the market construct. New York is a different story because of the amount of state intervention.

MR. MARTIN: So merchant plants work in New England. Scott Taylor, what is another important current trend in the market?

MR. TAYLOR: This is not a current trend because it might take another five years, but there will be a resurgence of long-term power contracts or ISOs modifying their capacity programs to be more than just one-year capacity markets. This will lead to development of large-scale gas plants that are needed to satisfy the projected demand over the next 20 years.

MR. MARTIN: Joe Kerecman, an important current trend?

MR. KERECMAN: I agree with Scott Taylor to a degree. In vertically-integrated areas like MISO, large-scale retirements of existing coal-fired and nuclear power plants will hopefully cause states to order utilities to enter into competitive-process PPAs to acquire capacity rather than simply allowing them to self-build.

MR. MARTIN: Todd Carter?

MR. CARTER: I think we are living the dream right now. We are building projects in places where the rates of return are high enough to justify new construction. Cheap natural gas is changing certain markets more quickly than others. We are going in with our eyes open and with lots of diligence around risks and the projected returns.

MR. MARTIN: Nazar Massouh?

MR. MASSOUH: I agree with what was said earlier about retirements, but with a slightly different angle. I think we are learning how to live with a lot less coal and, in some cases, less fossil fuel-fired generation as is the case in NEPOOL. Reserve margins are shrinking. It is possible to build again in NEPOOL, but most new construction to date has been backed by contracts. It is not possible to build in New York. Then I go all the way across the country to California, which is its own animal. With all the renewable energy there and the retirements of nuclear generation, California must figure out how to attract our capital because, without private capital, California will be in for a shock over reliability of the power supply, among other things.

MR. MARTIN: Various people have said that the independent power market is a boom-and-bust business. Each individual generator has an incentive to maximize output, but if all generators do that, then the entire sector is eventually impoverished. It is a little like the agricultural sector before the 1930s when target prices and crop set-asides were adopted. Where are we on the boom-and-bust continuum? We appear to be in a growth phase. How much longer will it last?

MR. DAVIS: Another five to six years.

MR. MARTIN: Scott Taylor, do you agree with the premise? Is this an industry that faces boom-and-bust cycles?

MR. TAYLOR: There are definitely ups and downs. However, there is a lot more discipline in the market than the last time, which will temper future ups and downs.

Environmental Update

The US Environmental Protection Agency missed a January 2015 deadline to finalize a rule to control carbon dioxide emissions from new power plants. It announced, at the same time, that it would also miss a June deadline to finalize a corresponding "Clean Power Plan" rule to reduce emissions from existing or modified power plants.

Although the two rules have been subject to different comment periods and will be based on different provisions of the Clean Air Act — section 111(b) for new plants and section 111(d) for existing and modified plants — EPA intends to defer completion of both to an unspecified date in "mid-summer."

EPA said that it will also simultaneously issue a model implementation plan that it is developing for states to follow as a guide to drafting their own state implementation plans for existing and modified plants. EPA could impose the model plan on any states that fail to come up with their own plans to meet CO2 emissions targets.

The agency said the delay is needed because new issues have been identified that will have to be addressed by better coordinating the rules covering new, existing and modified plants.

EPA extended the comment period earlier for the proposed rule governing existing and modified plants to December 1, 2015 and received more than two million comments. The proposal would require states to reduce carbon dioxide emissions from existing plants by 30% from 2005 levels by 2030. The delay may allow EPA to address a number of predictable consequences in a more coordinated fashion, including potential system reliability issues. However, the move also appears designed to delay efforts by Republicans in Congress to block the initiative.

Opponents argued that the rules will accelerate closures of older, dirtier coal-fired power plants and essentially prohibit new coal facilities from being built due to the need for expensive carbon-capture technology to meet the expected standards. A number of states and industry groups have already sued EPA over the proposals and other suits are expected. A three-judge panel in the US Court of Appeals for the District of Columbia will hear oral arguments on April 16 in several lawsuits challenging whether EPA has authority to regulate carbon dioxide emissions from existing power plants under section 111(d) of the Clean Air Act that been consolidated under the names I*n re Murray Energy Corp. and Murray Energy Corp. v. EPA*.

Congress is also expected to get into the act. The Senate majority leader, Mitch McConnell (R-Kentucky), tried procedural moves to derail the existing plant rule in 2014 when it was first proposed, but the effort was considered premature because the proposed rule was not final. Congress could try to bar use of federal funds to implement the final rule in a "must pass" spending bill that may be hard for President Obama to veto without shutting down part of the government.

California Cap-and-Trade

The California Air Resources Board — CARB, for short — decided in November that 88,955 offset credits in the state cap-and-trade program are invalid. Each credit allows the holder to emit one ton of carbon dioxide equivalent. The regulated entities that hold the invalid credits will have to buy new credits or reduce emissions.

Utilities and other entities that are subject to the California cap-and-trade program may use offset credits to meet up to 8% of annual compliance requirements. CARB has adopted offset protocols for urban forest projects, livestock methane digester projects as well as projects that destroy ozone-depleting substances and capture methane from mines. Offset credits may be generated by these types of projects.

In May 2014, CARB notified holders of 231,154 offset credits that it was investigating whether the credits are valid. The credits were transferred into a special CARB account pending the results of the investigation. They could not be sold or transferred in the meantime.

The offset credits were generated by two separate offset projects to destroy ozone-depleting substances at the Clean Harbors incineration facility in El Dorado, Arkansas. CARB regulations allow invalidation of offsets if the "offset project activity and implementation of the offset project was not in accordance with all local, state, or national environmental and health and safety regulations during the Reporting Period for which the [CARB] offset credit was issued."

CARB did not question whether the offsets were real, quantified or verified. Instead, it invalidated the 89,955 credits associated with one of the two destruction projects because the El Dorado facility was alleged to be in non-compliance with the federal Resource Recovery and Conservation Act. CARB determined that the other 142,199 offsets were created during destruction of ozone-depleting substances that were generated after the alleged violation was cured.

CARB said Clean Harbors failed to dispose of the waste after destroying ozone-depleting substances as a hazardous waste in violation of the law. Clean Harbors was not in compliance for two days in early February 2012. Clean Harbors entered into a consent agreement with EPA in April 2014 that settled these as well as other alleged violations at the facility.

Future purchasers of credits should weigh the risk of invalidation when negotiating to purchase credits and consider obtaining insurance to cover the risk.

Northern Long-Eared Bats

The US Fish and Wildlife Service said in January that it is considering listing the northern long-eared bat as "threatened" — rather than "endangered" — under section 4(d) of the Endangered Species Act.

The Fish and Wildlife Service first proposed listing the bat as endangered in October 2013 after finding there has been a severe decline in the species due to white-nose syndrome, a fungal disease affecting cave-hibernating bats. The bat is found in 37 states, from Maine to North Carolina on East Coast, west to Oklahoma and north into the Dakotas, Montana and Wyoming. White-nose syndrome is found in most areas where the bats live, but is particularly severe in the northeast.

The Endangered Species Act prohibits any "take," including harming, harassing or killing, of endangered and threatened species, unless a permit has been granted.

An endangered listing indicates that the species is in danger of extinction in a significant part of the area where it lives, while a threatened designation indicates the species is likely to become endangered in the foreseeable future. If a species is listed as threatened, the Fish and Wildlife Service may order protective measures deemed necessary and advisable for conservation of the species without unduly burdening persons with regulations that do not further its conservation.

In areas of the country affected by white-nose syndrome, companies would still be allowed to engage in forest management practices, maintenance and limited expansion of transportation and utility rights-of-way, removal of trees and brush to maintain prairie habitat, and limited tree removal projects if these activities protect bat maternity roosts and hibernacula. The strongest restrictions would apply during the two-month pup-rearing season in June and July when the bats occupy their hibernacula and are most vulnerable. Incidental takes of bats would be allowed, without the need for permits, in parts of the country that are not affected white-nose syndrome.

Various energy and timber groups argue that an endangerment listing would severely harm their industries and have been pressing for the less severe "threatened" listing. However, the proposed rule may offer only limited relief compared to an "endangered" listing because it would not exempt

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EPA is expected to release a model implementation plan this summer for states to reduce carbon emissions from power plants.

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incidental takes associated with wind, solar, mining, construction, agricultural and oil and gas activities.

The Fish and Wildlife Service has extended the time to April 2, 2015 to make a final decision about how imperiled the bats are currently. The latest proposal appeared in the Federal Register on January 16, 2015. The public comment period runs through March 17, 2015.

— contributed by Andrew Skroback in Washington

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