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Cost of Capital: 2013 Outlook

A group of industry veterans talked in early January about the current cost of capital in the tax equity, commercial bank, term loan B and mezzanine debt and project bond markets and what they foresee in 2013.

The panelists are John Eber, managing director and head of energy investments for JPMorgan Capital Corporation, Thomas Emmons, managing director and head of renewable energy finance for the Americas at Dutch bank Rabobank, Gerald Hanrahan, senior managing director of the power and infrastructure team at John Hancock Financial Services, Richard Randall, managing director and head of power and project finance at RBS Global Banking & Markets, and Jerry Smith, managing director and head of the tax equity desk at Credit Suisse. The moderator is Keith Martin with Chadbourne in Washington.

Tax Equity

MR. MARTIN: John Eber, what volume of tax equity transactions did the market do last year and how does that compare to 2011?

MR. EBER: We saw approximately $5.3 billion in tax equity last year in the US renewable energy market. About $2.5 billion of that was invested in wind deals and about $2.8 billion in solar. That is down from about $6 billion the year before, although the solar market was up and the wind market was down. It does not surprise me that the wind market was down. It does not surprise me that the wind market was down because of the uncertainty surrounding the production tax credit. Although Congress extended the credit in January, there was a risk it would not do so, with the result that projects that were at risk of not making it into service by year end / continued page 2

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WIND, GEOTHERMAL, BIOMASS, landfill gas, incremental hydroelectric and ocean energy projects in the United States will qualify for tax credits if they are under construction by year end under a bill that cleared Congress on January 1.

This is expected to lead to a rush to start construction of projects later this year.

The owners of such projects will have a choice between two tax credits: production tax credits of 2.2¢ a kilowatt hour on the electricity output for 10 years for wind and geothermal and 1.1¢ for other projects or an investment tax credit for 30% of the project cost. The production tax credit is adjusted each year for inflation. Any investment tax credit is taken / continued page 3

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were not built.

MR. MARTIN: What volume are you projecting for 2013?

MR. EBER: I am not really in the projection business, but solar should remain strong at the same or an even faster pace than in 2012. Wind will be a more difficult story. The delay in extending production tax credits means that it will take time for the deal pipeline to refill.

MR. MARTIN: In 2011, 55% of tax equity transactions in the wind market involved production tax credits. That was interesting because developers had the option of forgoing tax credits and taking the cash value from the US Treasury instead. The majority of the transactions did not take it. What percentage of wind deals in 2012 involved production tax credits rather than Treasury cash grants?

US renewable energy developers raised $5.3 billion in tax equity in 2012, down from $6 billion the year before.

MR. EBER: We think 12 of the 16 deals we tracked in wind, or 75%, took production tax credits. That actually represented about 85% of the tax equity dollars raised in the wind market.

MR. MARTIN: And the reason for that was that given a choice between a tax subsidy tied to output and one tied to cost, people opted for output because wind turbines are becoming more efficient and their prices are falling?

MR. EBER: Yes, both. The cost of turbines is down. Most of the equipment we saw coming to market last year had increased capacity factors due to taller towers, longer blades and improved electronics. The efficiency of the equipment has been improving year over year, and we saw that quite noticeably in 2012.

MR. MARTIN: How many active tax equity investors would you say there are currently?

MR. EBER: We think 20 actively participated in deals last year. Of that number, 15 put money into solar and 10 into wind, so there was an overlap between the two.

MR. MARTIN: Jerry Smith, is that number of active tax equity investors consistent with what you saw last year?

MR. SMITH: Yes. There are probably different levels of activity within that range. Probably seven to 10 companies did multiple deals. Some of the others are relatively new or are returning to the market.

MR. MARTIN: John Eber, do you foresee more or fewer tax equity investors next year? For example, will the transition from Treasury cash grants to tax credits affect the number of tax equity investors?

MR. EBER: I do not think the transition will reduce the number of tax equity investors. A few investors will drop out as the grant disappears, but we have seen new investors return to the market each year as more companies find they have tax capacity. I expect that trend to continue.

MR. SMITH: I agree with that, but with one qualification. Although the number of participants and the total dollars they are willing to spend may be the same, those dollars will not cover as many transactions as we move from Treasury cash grant deals to deals that rely on tax credits. The dollars will not go nearly as far.

MR. MARTIN: So some investors will drop out during the year?

MR. SMITH: Correct. They will exhaust their capacity earlier in the year than they might have done if the Treasury were still paying cash grants.

MR. MARTIN: What are current yields? How much does tax equity cost?

MR. SMITH: Yields have been relatively stable over the past few years. In an unlevered transaction, yields are somewhere in the high single digits, maybe 7% to 10%, and then probably about mid-teens if there is debt at the project or partnership level.

MR. MARTIN: How much is the premium the project will have to pay for having leverage? It sounds like 500 to 700 basis points.

MR. SMITH: Anywhere from 500 and 800 basis points, depending on the deal.

MR. MARTIN: Eight hundred would be a larger spread than last year.

MR. SMITH: Don't read too much into that. It might be a different person saying what the spread is. The spread has not changed in the last year.

MR. MARTIN: John Eber, it has seemed for the last couple years like the cost of tax equity for benchmark wind deals — projects developed by large, balance-sheet wind developers — has hovered around 8%. Would you say that is where it remains as we start 2013?

MR. EBER: We have not seen a lot a lot of change, and nothing has happened to suggest significant changes in the near term.

MR. MARTIN: Many people expect interest rates to increase this year — at least the bond market is signaling that already. Are interest rates a factor in the yields?

MR. SMITH: Tax equity yields are driven by demand and supply for tax equity rather than interest rates. However, they can be a cap on tax equity yields, since tax equity is competing with other sources of capital as a source of financing.

MR. MARTIN: Is there a difference in the cost of tax equity for the following types of facilities and, if so, how wide are the bands? Where does utility-scale solar PV price in relation to wind?

MR. EBER: For quality projects, we do not see a significant difference between the cost of tax equity for wind and solar.

MR. MARTIN: When you say "solar," are you referring just to utility-scale PV or also residential and commercial rooftop installations?

MR. EBER: Residential is a different market than utility scale and is priced differently. That may change over time as the market becomes more comfortable with residential solar.

MR. SMITH: Utility-scale wind and solar have been around for a while. Residential has a different credit profile.

MR. MARTIN: How does tax equity for geothermal compare in cost to wind?

MR. EBER: It is difficult to say. Too little geothermal is getting done to say what is market.

MR. MARTIN: What about biomass?

MR. EBER: We are not seeing much activity in the biomass market, so that is a difficult one as well.

MR. MARTIN: What evolution if any do you foresee in deal structures this year?

MR. SMITH: There are three main tax equity structures in use today in the market. The traditional / continued page 4

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fully in the year a project is completed, with the exception that it can be taken on contractor payments during construction for projects that are expected to take at least two years to build.

There is no deadline to complete the projects.

It will be up to the Internal Revenue Service to decide what it means for a project to be under construction.

Congressional sources say the intention was for the IRS to follow the same rules as under the Treasury cash grant program for renewable energy projects. Under that program, a project is under construction when the developer has either started "physical work of a significant nature" or "incurred" more than 5% of the project cost.

IRS and Treasury sources confirm that use of the Treasury cash grant definition is likely, but caution that no final decision has been made.

Guidance is expected to take several months.

A meeting among Treasury and IRS and Hill staff is expected shortly to make sure everyone is on the same page.

The IRS will have to decide whether to test when construction has started at wind farms on a turbine-by-turbine basis or by looking at the entire project. The IRS treats each wind turbine, pad and tower as a separate "facility" for production tax credit purposes. Under the Treasury cash grant program, a developer could choose to treat multiple units of property on a single site that will be operated as a larger unit as a single unit of property for testing when construction started, making it easier to treat an entire project as under construction.

The same bill that extended tax credits also extended a 50% depreciation bonus for another year for all new equipment placed in service in 2013. Thus, solar and fuel cell projects would also qualify. The bonus is the ability to deduct 50% of the equipment cost immediately. The other 50% is depreciated normally.

Assets like thermal power plants and transmission lines that would normally be depreciated over 15 or 20 years will have an extra year through 2014 to be completed and / continued page 5

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partnership flip is used primarily in the wind space, but can be used in solar as well. The solar market also uses sale leasebacks and lease passthroughs or, as some people call them, inverted leases. The three structures are pretty well developed and are flexible enough to be applied in most situations. There might be some evolution around the edges of the existing structures, but I do not see a need to move to a different structure.

MR. EBER: The only difference in the market going forward is we will not see many more renewable energy deals involving Treasury cash grants.

Bank Debt

MR. MARTIN: Moving to bank debt and starting with Tom Emmons, the North American project finance market was a $40 billion market in 2011 and predictions were that it would end up at only $20 billion in 2012. Any idea where it finished?

MR. EMMONS: The databases vary, but the ones on which we rely show $24 to $25 billion in project debt in 2012. The breakdown was somewhere around $20 billion for bank debt and $4 to $5 billion for bonds.

MR. MARTIN: Rich Randall, same numbers?

MR. RANDALL: We came out around $23 to 24 billion with the same breakdown.

MR. MARTIN: How many active banks were there in 2012, and how many do you expect in 2013?

MR. EMMONS: It is hard to calculate. All in, there are probably 70 banks who are involved in project finance, but some of them are small players. In 2011, probably 50 banks committed more than $100 million and maybe 40 banks committed more than $200 million. In 2012, those numbers were somewhat lower, but then the volumes were down by 40% so you would expect that.

MR. MARTIN: That is still a pretty healthy market. Richard Randall, same numbers?

MR. RANDALL: We see things a little differently. We only saw about 25 active banks in 2012. I concur with Tom Emmons about the 2011 figures.

We saw a lot of banks last year either exit permanently or go on hold because of the European capital adequacy issues. We are now seeing banks return to the market. We put out a syndication strategy for a client last week on a deal. There are 40 banks that we see open for business in 2013 to which we might syndicate.

MR. MARTIN: Yesterday, the European regulators took a more generous approach to what qualifies as liquid capital for Basel III. Do you see that helping to bring more European banks back into the market or will euro troubles continue to drag them down?

MR. RANDALL: Our initial take on the ruling is that it will affect investment grade liquidity facilities at the corporate level. Project finance lending will still have to adapt to Basel III. The rules for risk-weighted assets and the capital that will have to be applied toward project finance loans appear set in stone. Such loans will become a bit heavier for banks to carry.

MR. MARTIN: Tom Emmons, I heard you say at midyear last year that loan volume was down across the board for all project finance banks, except the Japanese and Canadian banks. By lending at the same volume as before, they gained market share. Did that remain true through year end?

MR. EMMONS: Yes. The movements are gradual. Basically the Europeans lost market share. That was picked up by the Japanese, the Canadians and some regional and super-regional American banks.

MR. MARTIN: Rich Randall, what is a term loan B transaction?

MR. RANDALL: It is essentially a bank loan in structure, but with an institutional lender. The interest rate floats. The structure, terms and conditions are very similar to bank debt, except for the buyers of the debt who are usually private equity funds, insurance companies and other institutions.

Tax equity investors chose production tax credits rather than Treasury cash grants in 75% of wind transactions in 2012.

B loans have been sub-investment grade issuances of debt. The credit is in the B to BB level. Investors in B loans are looking for yield.

The tenors are about seven years. The scheduled amortization is very light initially — usually only about 1% annually — and then there is a cash sweep, but most of the principal is not due until a balloon payment at maturity.

B loans emerged basically as a leveraged buyout instrument and that is still the primary use of the term loan B market. The market operates in conjunction with the high-yield bond market.

MR. MARTIN: So it is a way to finance a more risky project than one might be able to finance in the bank market.

MR. RANDALL: Correct. B loans were used in the project finance market mainly for merchant assets. The product evolved after Enron went bankrupt and merchant deals ran into trouble in the period 2000 though 2002. Banks exited that market. It was too risky. Money was lost in bankruptcies. The B loan market picked up to fill that liquidity gap.

MR. MARTIN: If the North American project finance market last year was $20 billion and there was another $4 to $5 billion in bonds, was part of the $4 to $5 billion made up of B loans?

MR. RANDALL: I don't have that off the top of my head, but I assume it was. There were probably $3 to $4 billion in B loans.

MR. MARTIN: Tom Emmons, in 2012, base interest rates on bank debt were 225 to 275 basis points over LIBOR, trending up toward 300. Upfront fees were on average 275 basis points. Are these accurate numbers for 2012? Where do you see them headed in 2013?

MR. EMMONS: Yes. The margins and fees have been stable over the last couple years. I expect them to remain flat or to rise slightly in 2013. It depends on the demand. Rates are a function of supply and demand, but with a floor. Let me come back to the floor.

High demand could come from wind if wind comes alive again, and there are lots of developers who have had projects on hold that they are bringing back to market. There could also be greater demand in 2013 for upstream oil and gas projects. Shale gas development is creating more demand. Some new combined-cycle gas-fired power plants will be built to replace coal with cheaper gas.

All of this could mean higher demand, in which case margins and total compensation could go up.

The supply is pretty elastic. It is not immediate, but it matches over time. I think there is a */ continued page 6*

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qualify for the bonus. However, the bonus can only be claimed on the share of depreciable basis built up through December 2013.

Among other changes, the bill allows projects on Indian reservations to be depreciated more rapidly — for example, for wind and solar facilities over three years instead of five years — for projects placed in service by December 2013.

It authorizes the Treasury to allocate another $3.5 billion in new markets tax credits for each of 2012 and 2013. New markets tax credits are credits of 39% claimed over seven years on investments in low-income areas.

Companies do not have to pay corporate income taxes on 9% of income from their manufacturing operations in the United States. Generating electricity is considered manufacturing. This has the effect of reducing the corporate income tax rate on income from such manufacturing to slightly less than 32%. Companies manufacturing in Puerto Rico qualified for the exclusion through 2011. The bill extends the exclusion for Puerto Rican manufacturing for another two years through 2013.

The bill gives electric utilities another year to sell transmission assets to independent transmission companies and receive an 8-year "spread" on the gain. A utility would normally be taxed fully on the gain in the year of sale. A special rule allows the gain to be reported over eight years. The special rule expired for asset sales after 2011. The bill extends it through December 2013. Congress wants to encourage regulated utilities to divest their transmission assets.

Wind and geothermal lobbyists say they will try to extend production tax credits again as part of any corporate tax reform bill that is taken up in 2013 or 2014 by Congress.

The American Wind Energy Association told Congress in December that it can accept a phase out of production tax credits for wind farms over six years. Under its proposed phase out, projects put in service in 2014 would qualify for 90% of the normal credit, in 2015 for 80%, in 2016 for 70%, in 2017 or 2018 for */ continued page 7*

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floor. At the current tenors, this pricing probably just passes the hurdle rates for the European banks based on their costs of capital and liquidity.

MR. MARTIN: Rich Randall, any sense where B loans price?

MR. RANDALL: For BB plants with some merchant risk, they are probably LIBOR plus 400 and above. That would be in a market where bank debt is pricing at LIBOR plus 250 for a more traditional project with a power purchase agreement.

We see quite a bit of appetite from banks and institutional investors. The two compete with each other on price.

The North American project finance market fell from $40 billion in 2011 to around $24 billion in 2012.

Banks are returning to the market this year. We will see the number of active banks increase to around 40. I think we will see pressure on margins from the increasing supply of available capital both in the bank market as well as the private placement market.

I agree with Tom — there is probably a 250-basis-point floor tied to the cost of funding — but I think the private placement market will continue to provide downward pressure on pricing.

MR. MARTIN: Does the fact that there is a healthy term loan B market suggest that it is possible today to finance purely merchant plants?

MR. RANDALL: Not purely merchant. The electricity price must be hedged to guarantee that interest and some level of principal amortization will be paid. The interesting thing about the B loan market is that it does not love construction risk. The banks are much more efficient at financing construction risk. The B loan market does not allow for delayed draws, so you have some negative arbitrage with which a construction borrower would have to deal.

That makes for a disconnected market. For that reason, we are toying with whether one can create hybrid structures where you have banks and B loans combining in order to eliminate the negative arbitrage during construction. It is unclear right now whether that can be done because banks are more conservative in the structures and the balloon payments that they can live with compared to the terms with which the B loan market can live.

MR. MARTIN: How long a hedge is required to finance a merchant plant?

MR. RANDALL: The market seems to be at around five years post construction, so that is essentially a 7-year hedge. We are just starting to see rumblings of maybe 10 years in certain markets. Electricity is fairly illiquid. Seven years all in will accommodate a construction loan plus a 4 1/2- or 5-year term loan.

MR. MARTIN: Tom Emmons, bank loan tenors seemed to shorten last year to seven to 10 years with mini-perm features. Where do you see them headed this year?

MR. EMMONS: The shortening really was a sea change as a consequence of the re-pricing of capital and liquidity problems, particularly among European banks. Borrowers have accepted mini-perm features. The shortening of tenors is creating opportunities for institutional lenders, and they have been stepping up. I think it is a permanent shift.

MR. MARTIN: How are debt service coverage ratios set, and what are they currently for contracted wind and solar projects?

MR. EMMONS: They are based on a judgment about the stability of cash flow available for debt service. They are typically 1.45 times debt service for wind. They are probably 1.35 for solar.

MR. MARTIN: Rich Randall, what are they for new natural gas-fired power plants?

MR. RANDALL: They are 1.4 if you are talking about a traditionally amortizing loan done in the bank market. B loans use a different structure since they essentially require payments of interest only. Those coverage ratios are 2 to 2.5 times debt service, and you have a sweep of excess cash flow for principal amortization.

MR. MARTIN: You mentioned the possibility that banks will team up with institutional lenders to do a combined bank and B loan financing. What structural issues does that create?

MR. RANDALL: It has not really been done yet, but such deals are coming. There will be inter-creditor issues. The debt would be pari passu. The banks would provide the delay draw feature to permit some construction financing. There will be debt sizing issues since the traditional B loan investor is going to allow for higher leverage. The banks will press for lower leverage. Trying to find that equilibrium will be a challenge.

MR. MARTIN: Are banks back to underwriting or are the larger transactions still being done strictly as club deals?

MR. EMMONS: We have not seen much underwriting. The retail market is still questionable, and there is still a lot of volatility in the bank market. We see mostly clubbing.

MR. RANDALL: We see a move to club underwriting where maybe banks lead a range or will underwrite a portion of the transaction, but it certainly would not be a fully underwritten deal.

Mezzanine Debt

MR. MARTIN: David Albert, the Carlyle Group, Energy Capital Partners and others have formed mezzanine debt funds. Do you sense a greater interest in mezzanine debt than before among borrowers and, if so, what is driving that interest?

MR. ALBERT: There are a couple drivers. The European debt crisis has caused some of the European project finance banks to pull back. Some are coming back into the market, but compared to pre-crisis levels, there is a smaller supply of bank capital available and a more conservative approach by banks to lending than in the past.

The other driver is that developers are looking for capital that is not as dilutive as traditional private equity. We see a greater desire by developers to retain as much ownership as possible and not have to give away control and 80% of the profits, if you will, in order to raise private equity.

Our capital is more expensive than bank debt, but it is flexible and less expensive than private equity, and we are not seeking control or governance rights.

MR. MARTIN: What is the spread typically between senior bank debt and mezzanine debt?

MR. ALBERT: It is hard to give a simple answer because mezzanine debt is not a standardized product like bank debt or even a project bond. Most of the deals that we have done to date have had a unit tranche where senior debt and mezzanine debt are drawn together. The cost of debt on an all-in basis in these transactions is somewhere in the low double digits.

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60%, and there would be no tax credits for projects completed after that.

Projects that start construction by 2013 would not be affected.

Senator Charles Grassley (R-Iowa), one of the original authors of the production tax credit statute, responded that the credits should phase out over three years.

SEQUESTRATION will take a bite out of Treasury cash grants paid on renewable energy projects on or after March 1, 2013, unless Congress delays the start further.

Automatic spending cuts of $984 billion over nine years were scheduled to take effect on January 2. On January 1, Congress delayed the start by two months and agreed to $24 billion in specific spending cuts and tax increases to pay for the delay.

The US Office of Management and Budget said last September that Treasury cash grants will be subject to a 7.6% haircut if sequestration goes into effect.

The haircuts will not apply to any grant considered an "obligated balance" before sequestration starts. Based on past precedent, a grant would become an "obligated balance" only when a letter or email is sent by Treasury informing a company that its grant has been approved for payment.

Developers complain that it is unfair for the government to have held out a carrot for companies to engage in economic activity during the period 2009 through 2011 when projects had to be under construction to qualify for grants, and then reduce the size of the carrot after companies have already done what the government wanted.

Wind companies are urging the Office of Management and Budget to exempt projects that were in service before sequestration from the cuts. This would remove delays at Treasury in processing grant applications as a factor in where the cuts fall.

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However, mezzanine debt can also be used at the corporate level. How that is structured can vary widely. For example, we can take a high coupon with very little equity kicker, or we can take a single-digit fixed-coupon return with much more of an equity kicker.

The transaction terms run the gamut, and that is also true for fees and everything else. The pricing is more holistic and tied ultimately to the risk profile.

MR. MARTIN: Tom Emmons, you said bank debt is pricing at maybe 225 to 300 basis points above LIBOR. What is that as an interest rate? Six percent? Lower?

MR. EMMONS: You would have to swap LIBOR, so that adds to cost, but somewhere in the low 5% range stepping up over time to a little above 6%.

MR. MARTIN: So David Albert, you are in the high single digits as a combined cost of senior debt and mezzanine debt, or in the same range for standalone mezzanine debt at a fixed rate and with an equity kicker, correct?

MR. ALBERT: It depends on the risk profile. We are willing to take construction risk. We are willing to be subordinated. We are willing to take on more challenging risk profiles.

There could be a management team that has its own skin in the game. It is putting in some capital, but there is still a large hole in the capital structure, and maybe the team can only get a certain amount of bank debt or cannot get any bank debt. We are willing to come into situations like that and, in those situations, our all-in return is obviously going to be much higher, and it will be a higher mix of equity.

We have been an anchor investor in some term loan B deals where we have taken a very low double-digit fixed return with no equity upside.

The point is that mezzanine debt is a flexible product with a wide range of potential risk and return profiles associated with it.

MR. MARTIN: Mezzanine debt displaces equity, and it is cheaper than equity. You said there is often an equity kicker. How is the equity kicker structured?

MR. ALBERT: If we are talking about oil and gas assets, it is structured as either a net profits interest or an overriding royalty interest. If we are talking about a power project, it usually takes the form of warrants that can either be struck as penny warrants or have a higher strike price. Again, there is a fair amount of flexibility in how we structure such mechanisms.

MR. MARTIN: Are there upfront fees and, if so, how much?

MR. ALBERT: You can either structure upfront fees or advance less than the full amount of the loan so that the fee takes the form of original issue discount of a couple points. It is not dissimilar to what you see in the bank market or the term loan B market.

The range can be anywhere from a point and a half to three points. It depends on the transaction.

MR. MARTIN: For how long a term do you lend?

MR. ALBERT: The tenor on mezzanine debt will usually be longer than for the more senior debt in the capital structure. The senior lenders will usually require it.

That said, the range of our debt can be anywhere from shorter dated meaning a couple of years to longer than the term loan B market. The key adjective is flexibility in terms of how we structure our investments.

MR. MARTIN: I can see a pattern here. I was going to ask what other differences are there between mezzanine debt and senior bank debt, but it all comes back to flexibility. Are there specific differences that are worth flagging?

MR. ALBERT: We are a source of capital that can provide significantly more leverage than the banks or the term loan B market. Because of that, not surprisingly, our cost is greater, but for borrowers who are looking for capital without the highly dilutive impact giving up control to a private equity fund, we fill a need.

We feel very much like commercial bank debt, only the leverage will be a little greater than what you would see in a commercial bank deal. Or we can play a role where we are much more equity like and charge higher interest with the interest paid in kind rather than in cash. We are taking on a different risk profile than the senior lenders. Our return profile is also different.

MR. MARTIN: How should one calculate how much mezzanine debt a project can support? Are there debt service coverage ratios and, if so, what are they currently?

MR. ALBERT: There are, but again, we are willing to provide construction financing and there is a great deal of flexibility in general to how our product is structured. One of the prior speakers talked about 2 to 2.5 times the interest payments in the term loan B market because there is no principal amortization.

Most of our deals do not have fixed amortization schedules. They tend to have a cash sweep.

The debt service coverage ratio is a function of the underlying asset that we are financing. For example, with an oil and gas loan, especially upstream, you are dealing with an asset that depletes over time as you lift those hydrocarbons from the ground.

The profile and the coverage on an asset like that will be different than a power plant with a 35-year life.

The difference will be even more dramatic when you are comparing that to a power plant with a long-term offtake agreement. Then you can get much closer to what you see in a commercial bank loan in the 1.5 times debt service range.

It all comes down to how risky are the cash flows? We are willing to finance merchant risk on the power plant side. The debt service coverage ratio will be higher in a situation like that than it would be for a contracted asset.

Project Bonds

MR. MARTIN: Jerry Hanrahan, you heard from Tom Emmons and Rich Randall that bank participation was down slightly from 2011 to 2012. Many people expect to see the project bond market fill the gap. We heard that the volume of institutional debt in 2012 was $4 billion to $5 billion.

Do you agree with those numbers? What volume do you expect in 2013?

MR. HANRAHAN: A lot of that may be term loan B debt. The project bond market has really been fairly shallow in the project finance area.

In 2011, a lot of the European banks that were having difficulty talked to us about 2012 being the year of the project bond and said we would see a lot of deals as the bank market lost its appetite. That did not really come to pass.

The reduction in European bank lending was filled primarily by Asian and Canadian and some US regional banks. It is interesting to hear the predictions about this year.

Some people are saying that with Basel III kicking in, that will move more lending to the project bond market and to people like us. I hope that is the case, but we have not seen it yet. Last year, we saw very little volume in project bonds. Topaz was the only significant deal, and that was a large solar transaction brought to market by Mid-American Energy Holdings. Otherwise, it was a fairly slack year for project bonds.

We did a few direct deals, but there were not many widely syndicated or 144A-type transactions.

MR. MARTIN: Your colleague, John Anderson, told me in mid-2012 that he thought there were 15 active / *continued page 10*

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A CFIUS REPORT to Congress in December suggests that all proposed foreign investments in US energy projects or companies should be submitted to the government for review before the transactions close.

The report by the Committee on Foreign Investment in the United States — CFIUS for short — lists areas of potential national security concern with foreign investments in US companies and projects. It is an annual report on activities during 2011. For the first time, the report lists as areas of potential concern investments in US companies or projects that "involve various aspects of energy production, including extraction, generation, transmission, and distribution" and projects that are near US military bases or other sensitive US government facilities.

CFIUS was formed by President Gerald Ford in 1975. It is an inter-agency committee, headed by the Treasury Department, on which 16 agencies sit that reviews potential foreign investments in US companies for national security concerns. Submission of proposed deals is voluntary. However, the committee has authority to set aside transactions after the fact that were not submitted for review.

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

The committee makes recommendations. The President has ultimate authority to block a transaction. Only two transactions have been formally rejected by the President. Transactions that run into trouble are usually withdrawn before they reach the need for a presidential decision.

Before 2006, at most one or two transactions a year were withdrawn. During the period 2006 through 2009, 64 transactions were withdrawn, or roughly 14% of the 469 transactions submitted to CFIUS for review during that period. From 2009 through 2011, the period covered by the latest report, 9% of transactions were withdrawn.

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institutions in the project bond market. I am not sure how one would get to that number if there was one deal. How many institutions do you see ready and willing to buy project bonds?

MR. HANRAHAN: The number is probably a little higher, probably 20 to 25, but it is a tiered market. You have probably eight or nine larger institutional investors like us, who tend to be the anchor investors. Then you have another tier of mid-range and smaller players, probably 15 to 20, who fill out deals.

Interest rates on project finance bank debt are expected to remain flat.

MR. MARTIN: Project bonds are priced off of 10-year Treasury bonds, I believe. What is the current spread? Where do you see both Treasury bond yields and spreads headed in 2013?

MR. HANRAHAN: Since 2010, Treasury rates and spreads have been moving in concert with each other and largely offsetting each other, with the result that we have had relatively constant yields.

We have been guiding people to focus less on the spread per se and more on the coupon. We end up with coupons in the 5 1/2% range for a project with a solid investment grade, things like gas-fired power plants or transmission deals. We end up with more of a premium heading up toward a 6% coupon for the riskier or weaker deals, maybe some of the renewables.

That is the current pricing range, and I expect it to continue.

We priced a couple of renewable deals recently in that range. That translates into spreads to Treasuries anywhere from the low 300 to maybe around 400 basis points, depending on the riskiness of the deal.

MR. MARTIN: The tenors are much longer than bank debt. A rule of thumb used to be that a project bond could be issued for a term as long as one year shy of the term of the power purchase agreement. Is that still true?

MR. HANRAHAN: In most cases, we see deals where the tenor of the debt matches the tenor of the underlying contract. Sometimes we see a tail on the power contract of one or two years, but the market has reached the point where the two tenors — the debt and the underlying contract — typically match each other.

MR. MARTIN: An upfront payment is required on a bank loan of perhaps 275 basis points. There is none on a project bond, but there is an upfront payment in effect in the form of original issue discount, correct?

MR. HANRAHAN: Not necessarily. The deals to which you are referring are the widely syndicated deals brought to us by arrangers or sometimes in the 144A market. Those usually do not require upfront fees and you are not getting original issue discount. We pay par. All of the economics are contained in the spread. Sometimes there are fees in some of the smaller direct deals we do, but not when they come syndicated.

MR. MARTIN: Project bonds require two rating agencies to rate the debt. Is that correct?

MR. HANRAHAN: Not really. That is if you are doing a 144A transaction. Those have rating requirements, but there are no ratings requirements for a deal done as a direct placement.

We get that question a lot from arrangers and issuers, asking what our rating requirements are. At least for us, we do not require an external rating. Many issuers and arrangers will get one even for a private placement because it helps ease the syndication process. It does not have to be two. One is fine.

MR. MARTIN: Another significant difference between project bonds and bank debt is the make-whole payments that are required if the project bonds are repaid ahead of schedule. What is a make-whole payment, and how is it calculated?

MR. HANRAHAN: It is calculated based off of spread to current Treasuries at the time of the prepayment. We are putting up debt at a fixed rate. We have matching liabilities to fund the debt. The make-whole payment is protection for prepayment risk against our liabilities. The remaining payments that would have been made on the debt are discounted back at the then-current Treasury rate plus a spread, typically 50 basis points.

MR. MARTIN: Are project bonds available for both construction debt and term debt?

MR. HANRAHAN: Yes. A frequent misconception about the bond market is that it does not take construction risk. It does, although it does not have the depth or the flexibility of the bank market when it comes to construction lending. There have been many large-scale construction deals done in the project bond market with construction periods of up to 24 to 30 months. A recent example is the Neptune undersea transmission cable.

MR. MARTIN: When you provide construction debt, are there construction draws or does the money have to be taken down all at once?

MR. HANRAHAN: There can be draws. There are typically draws every two to three months and, in those cases, there will be fees. You basically get a commitment fee on undrawn capital.

Electric Aggregation: The Next Boost for Renewables?

by Jake Seligman, in Washington

Chicago and San Francisco have become leaders of an emerging movement, called "electric aggregation," where cities buy cheap bulk electricity for the benefit of their citizens.

Electric aggregation enables cities to lower energy costs, which Chicago has done, and to dictate how electricity is supplied, which San Francisco and Chicago have both done.

Under electric aggregation, a municipality, usually a city or suburb, enters into a long-term power purchase agreement with an electricity supplier on behalf of its citizens. By negotiating a new price for all of its residents under one contract, a municipality can use its bargaining power to lower electricity rates and demand certain types of supply.

The local incumbent utility continues to operate and maintain its transmission and distribution network. A new electricity supplier, chosen by a municipality through a competitive bidding process, enters into supply agreements with electricity generators and sells that power to customers.

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transactions withdrawn are later resubmitted. For example, there were 111 CFIUS filings in 2011. Of that number, 40, or 36%, took another 45 days beyond the initial 30 for an investigation. In eight, or 20% of the cases that went to investigation, the parties agreed to mitigation measures to address government concerns with the transactions. Because working out a mitigation agreement takes time, it can lead to withdrawal and later resubmission once the mitigation measures have been agreed.

The latest report is interesting for the large number of transactions that were submitted involving investments by long-standing US allies. The largest numbers of filings in 2011 by far were for in-bound US investments from the United Kingdom. The top 10 countries for which filings were made in 2011 and the numbers are United Kingdom (68), Canada (27), France (27), China (20), Israel (18), Japan (18), Holland (14), Sweden (14), Australia (8) and Spain (7).

Another interesting development is the report says for the first time that the US intelligence community believes with "moderate confidence" that one or more foreign governments have directed companies to acquire critical American technologies in a "coordinated strategy." There were no details in the public report, but the details were shared with Congress. This adds a layer of complexity to evaluating proposed investments by Chinese companies.

In September, President Obama ordered Chinese-backed Ralls Corp. to divest a wind farm that the company bought in Oregon at which it hoped to deploy turbines by its affiliate, the Sany Electric Co. The wind farm is close to a US Navy base that provides training for drone aircraft. The company filed suit in federal district court in Washington in an effort to have the order set aside on grounds that it is an unconstitutional taking of private property without due process.

In the only other presidential action, the first President Bush */ continued page 13*

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Though they may seem similar, electric aggregation programs are different from having the city take back the concession from the local utility and vesting it in a new municipal utility. Municipally-owned utilities, like investor-owned utilities, maintain transmission and distribution lines, provide customer service and purchase (or generate) electricity for customers.

By implementing an electric aggregation program, a municipality only assumes a purchasing function and only within the political boundaries of that municipality. The transmission and distribution lines, as well as billing and customer service, remain the province of the incumbent utility.

Chicago Program

Last November, Chicago voters approved their city's plans to create such an electric aggregation program. All of Chicago's residents will begin receiving electricity under the new program in March. Rather than replacing the functions of the incumbent utility, the city government's role was to design its aggregation program and then negotiate a supply contract with its new electricity supplier.

The Chicago City Council selected Integrys Energy Services as its new electricity supplier for a term of two years, replacing Commonwealth Edison, an Exelon subsidiary. The electric aggregation supply agreement between Integrys and the city of Chicago is the largest in United States history, worth an estimated $300 million. Under the program, Integrys will sell electricity to more than 900,000 customers. When the contract term ends in May 2015, Chicago will be free to choose a new supplier.

Chicago residents will see their electricity rates drop from 8.319¢ per kilowatt hour to 5.424¢ per kilowatt hour. With non-electricity charges included, residents will typically see their bills lowered by 20%. Those savings relative to Commonwealth Edison's electricity prices will shrink when Commonwealth Edison begins delivering electricity under new, cheaper supply contracts, which it will sign in June, but savings are still expected to be between $130 and $150 per customer over the next two years.

The Chicago electric aggregation plan requires that Integrys' rates stay below Commonwealth Edison's. After May 2014, Chicago has an option to switch providers if Integrys cannot or does not beat Commonwealth Edison's rates. The city's option is particularly significant when Commonwealth Edison sheds the supply contracts it signed in 2008, which are expensive relative to prices in today's electricity markets.

Chicago has also banned coal-based electricity from its new contract with Integrys. Currently, coal provides roughly 40% of Chicago's electricity. Under the new contract, electricity will mostly be generated by natural gas plants. Integrys has already entered into an agreement with NextEra Energy Resources to supply much of that natural gas generation.

The ban on coal points to another reason why municipalities opt for electric aggregation: to control the source of their electricity. The ban demonstrates that electric aggregation can be used as a way to promote clean energy. In some cities, San Francisco being the largest, electric aggregation is also being used to spur new renewable energy development.

By choosing electric aggregation, Chicago is bringing it national attention and proving that, for the moment, a city's goals of lower prices and cleaner electricity need not be mutually exclusive.

Moves by some cities to act as bulk electricity purchasers for their residents are expected to create additional demand for renewable energy.

Enabling Electric Aggregation

Electric aggregation requires state authorizing legislation. Six states have passed enabling legislation giving municipalities the power to aggregate electric loads.

Massachusetts was the first state to enable electric aggregation, doing so in 1997. Ohio followed in 1999. Rhode Island and

California authorized electric aggregation in 2002, and New Jersey passed its own legislation in 2003. Illinois passed enabling legislation in 2009 and, since then, more than 200 communities within Illinois have approved electric aggregation. Chicago voters added Chicago to those ranks in November when they approved a ballot referendum authorizing the City Council to move forward with aggregation.

The details of electric aggregation programs vary. The type of electricity that programs offer depends on local goals. The price of electricity also varies, as do the customer classes for which the program is available. Residential customers are the most common participants.

Electric aggregation programs also differ in how they enroll customers, which is often a point of contention. Programs can either include opt-out provisions, where customers are automatically enrolled, or opt-in provisions, where customers have to choose to be a part of the electric aggregation. Not surprisingly, opt-out programs have far higher participation levels than opt-in programs.

Most municipalities moving to electric aggregation do so to reduce electricity prices.

However, some are as interested in promoting clean energy. For example, San Francisco, Marin County, California, and Cape Cod, Massachusetts have all used electric aggregation as a way to promote renewable energy. All three areas have or will have 100% green power options, and the same is true for Cincinnati. Programs in these areas may offer as much incentive to renewable energy developers as state renewable portfolio standards.

Oak Park, Illinois, a suburb of Chicago, offers a local wind option to roughly 20,000 accounts at a cheaper price than the standard incumbent utility rate. Evanston, Illinois, another Chicago suburb, has similarly favorable pricing for renewable energy options.

The advantage of renewable energy options over incumbent supply in Illinois communities may be short lived. Like in Chicago, as incumbent utilities shed expensive long-term supply contracts in favor of new, cheaper agreements, the spread between electric aggregation prices and those offered by incumbent utilities will shrink.

A Tale of Two Approaches

Chicago and San Francisco are the two largest cities in the United States to have adopted electric aggregation, though they did so under different political circumstances and to different effects. In particular, the two cities' / continued page 14

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rejected a proposed acquisition of MEMCO Manufacturing Inc., a supplier to Boeing, by the China National Aero-Technology Import and Export Corporation in 1990.

A proposed $257 million purchase of nearly all the assets of bankrupt US battery maker A123 by Chinese-backed Wanxiang American Corp. is also before CFIUS. The purchase was approved by the bankruptcy court of December 11. It is undergoing a 45-day investigation by CFIUS. The company said in a blog posting in late January that it expects to close on the purchase on February 1.

The defense part of the A123 business was sold to Navitas Systems LLC in Illinois. Wanxiang received approval from CFIUS last year for a $420 million investment for a minority stake in GreatPoint Energy near Boston. GreatPoint and China Wanxiang Holdings have entered into a joint venture to build a $1.25 billion plant in western China for converting coal into cleaner-burning synthetic natural gas. Wanxiang has more than 3,000 employees in the United States.

Several members of Congress have criticized the sale. Johnson Controls Inc., which lost the bid for the commercial assets, has hired a prominent Washington law firm to lobby against the sale. A123 received a $250 million loan guarantee from the US Department of Energy.

An assistant US Treasury secretary, Marisa Lago, made a trip to Beijing in November to assure the Chinese that there is no general US policy against Chinese acquisitions of US companies.

IRAN TRADE SANCTIONS are getting tougher.

Non-US companies that thought they understood US trade sanctions for engaging in energy-related transactions with Iran must now revisit them.

A new sanctions measure passed by Congress on January 1 and signed by President Obama the next day puts the energy, shipping and shipbuilding sectors generally off limits. US companies are already / continued page 15

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programs will have different long-term impacts on electricity prices and generation mixes, with San Francisco planning to encourage more renewable energy development.

The Chicago electric aggregation program focuses primarily on lowering short-term electricity costs for customers. Chicago also banned coal from its generation mix under the contract with Integrys, recognizing that it could do so in the process of lowering prices.

Chicago's electric aggregation program will probably also include energy efficiency and renewable incentives for customers, though the details of those programs are as yet unclear. The city is also trying to buy part of an Illinois wind farm to ensure some supply from local renewable energy projects.

In contrast, San Francisco is promoting renewable energy as its primary goal. The San Francisco program, called CleanPowerSF, has the potential to spur hundreds of megawatts of new renewable energy project development in California. It will offer customers 100% green power with an opt-out choice for customers who do not want to pay more for renewable energy.

Starting in mid-2013, 90,000 San Francisco residential customers will be enrolled with CleanPowerSF. Most likely beginning in the following year, half of all eligible residential customers in the city will be automatically enrolled with CleanPowerSF, with the other half able to opt in.

The San Francisco Board of Supervisors chose Shell Energy North America as its electricity supplier. Most of the electricity will come initially from regional wind farms. To satisfy the 100% renewable requirement, Shell Energy will also purchase renewable energy certificates, which, though not the electrons themselves, ensure that a unit of electricity associated with the certificate was generated by a qualified renewable energy project. The additional demand could help the state REC market.

As CleanPowerSF matures, San Francisco should encourage development of new renewable energy projects and even fund some of them with special purpose municipal bonds.

In 2001, San Francisco created a class of bonds, called H-bonds, to finance renewable energy and energy efficiency projects. Because CleanPowerSF will bill customers for electricity directly, the city will have a dedicated revenue source with which to pay debt service on the bonds. The bonds allow borrowing at a reduced interest rate.

Two other municipalities — Cape Cod and Marin County — also included new renewable energy development as part of their electric aggregation programs, building or planning to build 18.2 megawatts and 31 megawatts of solar, respectively.

Electric aggregation can be controversial. Three out of 11 San Francisco City Council members opposed the scheme, as did the mayor, worrying that automatic enrollment might confuse residents while leaving them with higher bills. The Pacific Gas and Electric Company, the incumbent utility, resisted electric aggregation, as it had in Marin County.

Chicago's was a smoother process since its electric aggregation was a relatively easy sell to consumer advocates. Electricity prices will drop immediately for Chicago customers, but not for San Francisco customers.

Looking Ahead

It is unclear how many other states will pass enabling legislation in the coming years.

Aggregating electric load has the potential to fall out of favor as incumbent utilities face declining load growth and cheap natural gas, which is driving down wholesale and retail electricity prices. New wholesale supply contracts utilities sign to buy electricity from independent generators will often be cheaper than the contracts they replace.

At the same time, some municipalities that favor renewable energy may find electric aggregation appealing in states that are close to meeting their renewable portfolio standards. Electric aggregation is a way to continue ratcheting up the percentage of clean energy. For the moment, Chicago, San Francisco and other aggregated municipalities have the potential to change the way that cities think about their citizens' electricity. ◎

The Next Generation of Solar Project Finance

A group of solar industry veterans talked at an Infocast distributed solar conference in San Diego in November about the need for solar rooftop companies to move over time to a new business model, growth rates in the US residential and commercial rooftop markets, possible pivot points that could cause dramatic *shifts in the market, how the costs of installed solar systems break down among equipment, labor, customer acquisition and capital, and current returns for developers and financial players.*

The panelists are Channing Chen, vice president of project finance and general manager of the small systems group at SunEdison, Ed Feo, managing director of USRG Renewable Finance, Ori Franco, senior director for finance at Sunrun, Inc., David Loomis, West Coast sales manager for ReneSola, and Chase Weir, CEO of Distributed Sun. The panel was moderated by Keith Martin from the Chadbourne Washington office.

MR. MARTIN: The business model that has gained the most traction in the US solar rooftop market is the offer to customers to have solar panels on their roofs for no upfront payment. The solar company retains ownership of the panels. The customer signs an agreement to buy electricity or lease the panels for 18 to 20 years for monthly payments that are something like 85% of what the customer is paying currently for electricity from the local utility. What other successful business models have you seen?

MR. LOOMIS: The models that have been successful and will continue to be successful are low- or no-down-payment products where the customer can see that he or she is saving money from the start.

MR. WEIR: Most of the innovations are in the models with third-party ownership. It is probably not widely known yet, but BMW is in the process of implementing a long-term strategy to provide the automobile as a service. It proposes to move away from the model where people own their cars. The solar rooftop market has been moving in the same direction.

MR. FRANCO: We may lease systems in form to our customers, but in substance we are providing a service. Our customers are busy people who do not want to decide which installation company to use or what technology to use. They worry about the risks and burdens of ownership. Many customers have the money to purchase solar systems themselves, but they choose instead to go with Sunrun or one of our competitors because they want a service rather than the equipment.

MR. MARTIN: The benefit of this model is that customers do not have to pay up front, but some customers choose to prepay the full rent they would have to pay over an 18- or 20-year agreement. Why?

MR. FRANCO: Service. As a professional owner of the equipment, we can do a better job than the homeowner in monitoring, maintaining and ensuring that the / continued page 16

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barred from trading with Iran. Thus, the new sanctions are aimed at companies outside the United States. Non-US companies that violate the sanctions and financial institutions that facilitate trading risk being locked out of the US economy.

Turkey complained that 20% of its natural gas comes from Iran, so that any sanctions against trade in natural gas would fall disproportionately on Turkish consumers. The new sanctions allow trade in Iranian natural gas to continue, but the money owed Iran would have to be credited to an account in a bank headquartered in the customer country.

The new sanctions apply to sales of Iranian oil and petroleum products, but only during periods when there is a large enough supply of oil and other such products available in global markets at prices that allow substitution for Iranian oil without undue hardship.

The new sanctions also bar trade with Iran in coal, precious metals, graphite, raw or semi-finished metals such as aluminum and steel, and computer software for integrating industrial processes.

They will not take effect until July 1, 2013, giving companies time to wind down existing trade.

They come on top of other measures the US enacted last August that will require public companies to disclose in filings with the US Securities and Exchange Commission, starting February 6, 2013, any business activities that they or their affiliates have knowingly engaged in with Iran. The SEC does not have a clear definition of affiliate.

Also beginning February 6, buyers of Iranian oil will no longer be able to pay for the oil in cash. A "buy-local" provision requires that any money Iran is owed will have to be locked up inside an account in a bank in the customer country and used by Iran in that country to buy goods from the local economy. Most countries that buy Iranian oil are running trade deficits with Iran. The new measures should help reverse the deficits.

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equipment performs.

MR. MARTIN: How much of a discount does the homeowner get for paying up front?

MR. FRANCO: We have seen a discount of 5% to 10% compared to the cash purchase price.

MR. MARTIN: One unsuccessful business model was the PACE programs. Please explain what those are and whether they have a future.

MR. FEO: In PACE programs, a municipality advances a local homeowner or business the money to install a solar system or energy efficiency improvements. The property owner agrees to a property tax lien as the means for repaying the funds advanced.

The issue with residential PACE is that the Federal Housing Finance Authority said it would not allow a volitional tax lien to have a higher priority claim than the mortgage on the house to which the financed equipment is attached. The commercial PACE programs do not have this problem because the mortgages on commercial properties are not federally insured.

One of the companies I am involved with is a group called Clean Fund. It just did the first commercial PACE deal in San Francisco on the ProLogis building on Pier 1. The deal has first-party ownership of the asset, with the financing coming through a senior secured tax lien. The tax lien payments are monetized in the capital markets, which leads to a very high level of leverage at a relatively low rate.

MR. MARTIN: This is a PACE program aimed at commercial properties? Is the loan repaid through property tax bills?

MR. FEO: Yes. This is commercial PACE. The agency that runs the program issues municipal bonds at low interest rates and advances the proceeds to the property owner for the purpose of paying for the energy efficiency or the solar system. The property owner agrees to an additional property tax, which becomes the source of repayment.

A PACE program does not preclude third-party ownership, so you could take the proceeds received under a PACE funding and use them to prepay a lease or power contract and combine low-cost debt with the benefits of third-party ownership of the asset itself.

MR. MARTIN: Is it worth it to combine such debt with third-party ownership? Are the systems too small to justify such a complicated financing structure?

MR. FEO: The structures are essentially levered tax equity deals. The cost of capital is lower if you can put tax equity and debt together. Since these structures are just getting out of the gate, I think that it is fair to say the transaction costs, on a deal-by-deal basis, are relatively high, but will get lower.

Community Solar

MR. MARTIN: What about the community utility-scale solar installations where people who live in apartments or condos buy individual panels in a utility-scale solar facility that sells its electricity to the local utility. The panel owners get a credit for the electricity sold that they can use against their utility bills. What is the future of that model?

MR. FEO: It is an awesome model.

MR. FRANCO: I agree. I am personally and professionally excited about deploying solar, and that is certainly one way to do it. There are still kinks to work out. Administratively, you need to worry about virtual net metering and ensuring that the local utility can charge the customer the appropriate amount, so there is a regulatory change that needs to occur, but it is a great way to deploy solar.

MR. CHEN: SunEdison is looking at that model, and we are excited about it, but we probably have not moved as far as others actually to deploy it.

MR. MARTIN: Have any municipalities enacted the ordinances necessary to allow the credit mechanism?

MR. WEIR: It is happening in states across the country: Arizona, California, Colorado, Connecticut, Delaware, Maine and Maryland. It is too bad that California's SB 843 did not pass, but maybe it will get some new life in 2013. At the end of the day, it is about equity. Ratepayers and taxpayers are already financing solar. It is also about meeting the targets in renewable portfolio standards. When community solar takes hold in four or five states is when solar will become a significant part of our generation mix.

MR. FEO: The model has the potential to permit solar to be provided to people who may not otherwise be qualified to buy a system or to sign a long-term lease or power purchase agreement. It allows for different tenors. Right now, the available solar financing is a pretty inflexible tool, with very long tenor contracts. A long-term power contract or lease is great for customers who qualify and who do not expect to move. I think the future of the business is going to be around bringing other customers in and getting closer to a model where you are offering customers something which is more of a service. It can have flexibility in terms of not just rate, but also contract term.

MR. MARTIN: What about other business models?

MR. LOOMIS: I like to think that the next evolution in solar will be when a department store installs 1.5 megawatts on the roof even though it only needs one megawatt of capacity for its own use. The other 500 kilowatts could serve the community or be used to provide discounts to employees on their utility bills.

Moving to a Service Model

MR. MARTIN: Ed Feo, you said the future of this business is really finding a way to have more flexibility. It is not locking people into 20-year contracts, but giving them options. I have always thought this business had more in common with the cable television business. Is your vision one of moving truly to a cable company? No one is locked into a cable contract for more than a month at a time.

MR. FEO: My view is that that the industry should adopt a theme of flexibility, where different terms are on offer, and the customer obligation is less about an equipment acquisition and financing and more about the terms of the service. For that to happen will require moving away from a model where the only place you can offer solar is to a customer with a roof. Community solar is one way to break the current model.

It is more of a regulatory challenge initially. Ultimately, flexible terms are what the solar industry must offer. Am I interested in a long-term contract from one of the solar finance companies? Well, I can go to a utility today and it costs me very little to hook up, and if I want to move, I tell the utility that I am leaving and I get back my deposit minus some nominal amount. What the utility offers is an incredibly flexible product. Today the solar industry is offering to sell equipment for cash or long-term financing that is relatively expensive. The average homeowner moves every seven years. That tells you something about that market. Non-homeowners cycle every 18 months. In order to capture more of the retail market, we have to offer something other than a long-term contract for a piece of equipment.

MR. FRANCO: That is absolutely right. Many customers do move every seven to 10 years. You need to ensure that the reassignment happens smoothly. You make sure that the new homeowner has an incentive to take over the contract by making that process easy. We have been through quite a few reassignments and have had very positive experiences with those reassignments because the new homeowner sees it as a no brainer. Why wouldn't he or she sign / continued page 18

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A NEW US TAX ON INVESTMENT INCOME should be factored into the economics of some transactions.

US individuals are subject to a new 3.8% tax on "net investment income" as of January 1.

The tax applies to anyone earning more than $250,000 a year in adjusted gross income for married couples filing joint returns. The threshold is $200,000 for single persons. The income levels are not adjusted for inflation, so more people will become subject to the tax over time.

The tax applies to interest, dividends, capital gains, rents, royalties and income from two types of businesses. The businesses are trading in financial instruments and commodities and any business in which the individual is considered a passive investor.

"Trading" means seeking to profit from short-term movements in prices. Electricity may be considered a commodity, but generating electricity for sale is not "trading" in electricity.

An individual owning an interest in a power project through a limited liability company or partnership may find his income subject to the tax because he is considered a passive investor. Unless he is engaged personally in the LLC or partnership business for a material number of hours each year, his role is normally considered passive. "Material" usually means more than 500 hours a year, but can be as few as more than 100 hours if his personal involvement in the business is not less than that of any other person.

The tax is on "net" investment income. Some directly-connected expenses can be deducted. An example is a fee that must be paid to a broker for arranging a sale that produced a capital gain.

A taxpayer who has net investment income but is over the income threshold at which the tax kicks in by a smaller amount than his net investment income is taxed only on the lower amount. For example, suppose a single person has adjusted gross income of $270,000 of which $90,000 is net investment income. He is only $70,000 over the threshold at which the tax starts to apply. The tax must be paid on only $70,000. / continued page 19

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up to save 15% versus the local utility bill and not have to worry about maintaining the system?

MR. MARTIN: How do you incentivize a new buyer to take over the house if the contract has had a 4% escalator running since inception?

MR. FRANCO: We do not have a 4% escalator in any of our contracts. Ours is at most 2.9% and in markets like the east coast, the escalator is closer to 1.5%. We have two products in order to mitigate the price risk to the homeowner. One is that we are willing to sell you power at a rate close to your current utility rate that will remain the same fixed rate for 20 years without any escalator. The other product is we are willing to sell you power at a lower rate initially that escalates at less than 3% a year, but with a cap that ensures your rate will always be below the local utility rate.

Growth Rates

MR. MARTIN: What are the annual growth rates for the US market leaders in this sector?

MR. WEIR: Greentech Media said this year it is 71%. Q1 year-over-year growth was 100%, but it will probably end up for 2012 as a whole at 71%. That is growth in capacity.

MR. FEO: That includes utility-scale solar. Looking just at residential and commercial and industrial or C&I, it is a different story. C&I is down significantly, and residential is up modestly at 5%.

MR. WEIR: In seven of the last 10 quarters, C&I has been the largest segment. It was the largest segment in Q1 and Q2, but not in Q3. There have been a lot of utility-scale projects in the pipeline. Earlier this year, commercial was around three times the size of residential, but it has slowed down a bit this quarter. We do not see that as a sustained slowing.

MR. MARTIN: Does 44 million roofs sound like the potential market in the US?

MR. CHEN: I think that is about right. However, once you look at the technical constraints — whether the house is owner occupied and other factors — the viable market is closer to 30% to 35% of those 44 million roofs.

MR. FRANCO: In the current states in which we operate, there are about 29 million single-family homes. Roughly 15 million are owner occupied. From there, some percentage will not be viable solar candidates due to structure, shade and other causes.

There are about 300,000 residential solar facilities installed in the United States. We are seeing an acceleration in growth in the residential market. It took us four years to get to 10,000 customers and then 11 months to get to 20,000 customers.

MR. MARTIN: So there is a lot of room still for growth in the residential market.

MR. WEIR: The National Renewable Energy Laboratory estimated that commercial rooftops have 100 gigawatts of potential. We have analyzed a lot of nationwide portfolios, companies that own buildings across the country, and we see the potential for solar with the current technology in less than 10% of sites.

Rooftop solar companies will have to move eventually to another business model where customers do not have to lock into 20-year contracts.

Potential Pivot Points

MR. MARTIN: Investors watch for potential pivot points in markets. These are things like changes in law, shifts in technology, inflation spikes, and changes in culture and weather that could cause the market to turn up or down. What are the potential pivot points in the next three to five years?

MR. CHEN: Technology will play a big role. There is a lot of effort to drag down the cost of polysilicon and increase the cell efficiency at a cost point that will make solar more attractive to homeowners to purchase systems.

MR. MARTIN: What will that do to the third-party business model?

MR. CHEN: I think for the next couple years, the third-party model will still drive the growth, but it remains to be seen what happens in 2016 when the 30% investment tax credit expires. I think it will be a very different world. Maybe that is when the more local or regional banks get involved with their solar loan products or securitization takes hold.

MR. MARTIN: What are other potential pivot points?

MR. WEIR: One pivot is when sustained commercial prices fall below $2 a watt. Installed cost is a big pivot point. Another pivot point will be when you see solar competing with conventional generation at 18¢ a kilowatt hour. The major pivot point is the technology. There are new technologies emerging that will radically expand how many roofs are accessible. We are a big proponent of the third-party ownership model, but we now view our business as services that lead to transactions that then lead to ownership. If we own the system, that is fine. If our partner, client or customer owns it, that is also fine. It is about delivering value to the marketplace. For us, the focus is the commercial and industrial sector.

We are beginning to see that the key to getting traction at scale is learning how to deal with the different channels within commercial solar. How you deal with REITs is radically different than the way you deal with a food distribution company. We are pursuing national account strategies, and the only way to do that is to be flexible. If you require that they take your form of power purchase agreement, then there is a lot of business you are not going to do. Flexibility is key.

MR. LOOMIS: All the third-party financing is driven by the current tax incentives: investment tax credits and MACRS depreciation. That is why we have customer agreements that run seven to 10 or 20 years. As the cost of systems falls and the tax credits expire, you will see 2- and 3-year contracts like cell phone contracts. That is the future. That is when you will get mass adoption.

MR. CHEN: We have a lot of internal efforts to drive down the cost of polysilicon and increase cell efficiency. My dream is to have a SunPower-like module at Chinese-level pricing.

Another potential pivot point is when we see solar offered as an add-on product to an existing business infrastructure. Vivint leveraged its home security business to get into solar. I think we will see more of these traditional consumer business companies enter the US market with home automation-type products and solutions. Xfinity is another example. The next product could be a solar-type partnership. Solar is energy, which is a low engagement category. You can / continued page 20

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Partnerships will have to send more complicated forms to partners — so-called K-1s — each year breaking down the type of income the partners are allocated by the partnership.

Interest, dividends, rents and royalties retain their character when they pass through the partnership, but they will not count as investment income if received by a partnership in the ordinary course of its trade or business. Thus, for example, a partnership in the business of leasing solar panels to homeowners receives rent and interest on late rental payments. These amounts are not investment income to the partnership. Therefore, they are not investment income when they pass through to partners. However, any partner who is considered merely a passive investor would have to report all the income he is allocated by the partnership as investment income.

A partner selling his partnership interest at a gain must treat the gain as investment income. Capital gains from the sale of property held in a trade or business are not investment income. However, the Internal Revenue Service suggested in proposed regulations to implement the new tax in December that a partner generally is not considered to hold his partnership interest in a trade or business.

The proposed IRS regulations will require complicated calculations to determine the share of gain any partner has when selling his partnership interest that will be subject to the 3.8% tax. The calculations are supposed to put the selling partner in the same position as if he had sold his share of the partnership assets directly. The partnership may have a different "basis" in its assets than the partner has in his partnership interest. The adjustments are intended to calculate his gain as if the partnership made a deemed sale of its assets and allocated the partner his share of gain immediately before the partner sold his partnership interest.

The tax is in section 1411 of the US tax code.

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only talk about the kilowatt so much at a cocktail party before people start talking about other subjects. It complements existing businesses. I see a lot of potential for these traditional consumer-based companies, the Vivints, HVAC and cable companies of the world, to come in and have the same people who sell HVAC, security systems or cable TV service also offer solar.

MR. MARTIN: What does that do to the SunEdisons of the world? There are very low barriers to entry in this market. What does it do to the incumbents?

MR. CHEN: I believe we at SunEdison have the ability to continue to drive down installation costs and, at the end of the day, this is really just a cost game. We are hoping to drive down the cost of capital because we have done close to $4 billion in institutional financing over the last eight years with many of the big banks. We have proven underwriting capability on a solar asset.

Cost of capital is roughly 25% of the cost to install a rooftop solar system.

We have a technology angle as well. If you can drive down the cost of capital, you can drive down the cost of products, and I think you will be okay.

We will survive based on cost and our ability to partner. We have the ability to partner with smaller developers and new entrants from more traditional consumer-based businesses.

MR. MARTIN: What is the relevance of state renewable portfolio standards and net metering programs to the current business models?

MR. FEO: Net metering is highly relevant. RPS programs are largely irrelevant.

MR. WEIR: You could not do solar without net metering. We are using the grid as a battery. There is another potential pivot point, and that is the coming wider use of energy storage and the growing unpredictability of the electricity supply. Many of you may not have been affected by Hurricane Sandy, but I can assure you there are millions of people today who are thinking very differently about the reliability of the local utility. There are people who were without power for several weeks after the hurricane. We saw hospitals that thought they had backup power, but were shut down for days. Those are key pivots. When you can store the solar energy on site, you do not need to use the grid as a backup. Until wider adoption of storage, you have a misalignment between the generation of the solar facility and the consumption at the site.

Cost Analysis

MR. MARTIN: What percentage of the cost of an installed system is currently capital, labor and equipment?

MR. FRANCO: In commercial solar, equipment is probably half. On the residential side, I think equipment is 20% or 25%. Labor is very little. Most of the cost is in customer acquisition and permitting or overhead on the residential side.

MR. MARTIN: What is the overhead related to customer acquisition: marketing to potential customers and getting them to sign contracts?

MR FRANCO: Yes. It includes signing the contract, originating the customer, dealing with canceled customers and designing the system. There are a lot of technological efficiencies that can be gained in system design. All of that is overhead, and this is an area where solar companies are working hard to reduce costs over time.

MR. MARTIN: What percentage of the cost is capital?

MR. WEIR: If I am installing at $4 a watt today and paying the current cost for capital, if I was able to pay 0% instead for capital, I could do install at $3 a watt. By that translation, the current cost of capital is $1 a watt for residential. Commercial is about 25% more.

MR. LOOMIS: It used to be that the equipment was 50% to 60% of the cost of the system. Now it is down about 20% to 25%.

MR. MARTIN: Channing Chen, if the equipment cost is 25%, capital is 25% and customer acquisition is 50%, what does this do to your supposition that SunEdison has staying power because it can chip away at the cost of capital?

MR. CHEN: Cost of capital is just one part of the equation. In the residential solar sector, we are also looking to customer acquisition as a place to reduce costs. If you can create competition among financing providers, you can drive the capital costs down. You cannot enter into a single negotiation with a financing party and expect to get the best pricing. The key is managing a process around competition for financing.

MR. MARTIN: Many people think that with the two cheapest sources of capital being pulled away — the Treasury cash grants and government loan guarantees — the cost of capital is bound to go up. Ed Feo, do you see it that way?

MR. FEO: I think that is what will happen in the near term. That said, I have been impressed that the pricing has not been crazy. Costs of capital are not increasing as much as I thought they would. That may be a function of investors getting their own return expectations in line with where investment opportunities are in the rest of the market.

Securitizations

MR. MARTIN: Some of you mentioned securitization as a future source of financing for solar rooftop companies. There has been talk about real estate investment trusts or REITs. Are these ideas, particularly securitization, for use after the tax equity market is gone or are they financing options that solar companies will begin to tap more quickly?

MR. CHEN: I hope they become financing options more quickly. I know SunEdison and SolarCity are actively looking at potential securitizations. The barrier may be the market getting comfortable with sparse historical data. We do not have more than six or seven years of data. We have talked with the investment banks to get a better feel for how the markets are looking at this asset class. I think we will see the first securitization close within the next two to three years.

MR. MARTIN: Ori Franco, will we see Sunrun do a securitization in 2013?

MR. FRANCO: I do not want to make a prediction about timing, but at least for the residential sector, the securitization market is a very deep pool of capital to finance consumer credit. Securitization investors or lenders understand consumer credit a lot better than tax investors do.

MR. MARTIN: Are tax equity and securitization mutually exclusive?

MR. FRANCO: No. / *continued page 22*

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FIXED-PRICE PURCHASE OPTIONS could spell trouble in some equipment leases.

A US appeals court in Washington suggested in January that it is a problem to give a lessee an option to purchase equipment at the end of the lease term if exercise of the option is "reasonably expected." The court said the lessee will be considered the tax owner of the equipment from inception.

This is a different standard than the market has been using.

Nearly all tax counsel have viewed purchase options as a problem only if exercise by the lessee is "reasonably certain": for example, because the exercise price is expected to be below the equipment value at the time or because other facts will compel the lessee to exercise.

The decision may spell trouble for leases with fixed-price purchase options in transactions that would be reviewed by the US appeals court for the federal circuit. The United States is divided into 11 geographic circuits, one District of Columbia circuit and one federal circuit. Cases heard first in the US claims court are appealed to the federal circuit.

The case involved Consolidated Edison in New York. The company entered into a complicated cross-border lease transaction called a LILO in 1997 with Dutch electric utility EZH. The utility leased a 47.47% undivided interest in a gas-fired combined-cycle power plant to Con Ed for 43.2 years and then subleased it back for 20.1 years. Con Ed paid $120 million in rent under the head lease at inception. It agreed to pay another $831.5 million in rent on the last day of the term if EZH had not exercised an option before then to buy out the Con Ed leasehold interest.

EZH had an option to purchase the leasehold interest at the end of the 20.1-year sublease for $215 million.

Con Ed had an appraisal from Deloitte that concluded there was no economic compulsion on EZH to exercise because the leasehold interest was expected to be worth less at the end of the sublease than the option / *continued page 23*

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MR. WEIR: They do not get along very well, though. Having the investment tax credit in the capital stack makes securitization more challenging. I think we will see securitizations within the next few years, but before we get there, we will need to have an industry-wide rule set and standardized contracts. Residential is virtually securitized right now. It is repeatable and standardized. The homeowner is not negotiating a deal. That is not what happens in the commercial and industrial sectors.

Developer and Financial Yields

MR. MARTIN: What are current yields for developers?

MR. WEIR: They vary. We were talking about the cable television model. In residential, direct marketing is an easy notion; having a phone bank is a really good strategy. In commercial, you are seeing a move away from origination for a number of players into platforms where you have members and partners that originate for you. Companies like that have a much higher margin. A multi-megawatt commercial project can take 12 to 24 months to develop. That is a big acquisition cost.

MR. MARTIN: What are current returns for developers? I've heard at other conferences that they are in the 7% to 8% range.

MR. WEIR: If you are relying on Treasury cash grants or investment tax credits, they are hovering around 7% to 8%. If you are higher than that, you are above average.

MR. FRANCO: In the residential sector, we compete with retail rates that are generally much higher than industrial and commercial rates. Returns are healthy enough to drive our business.

MR. LOOMIS: I have seen margins anywhere from 8% to 25%. This is hard on the independent installers. They have been in the business for a while, and they are used to a 30% margin, and now they are being challenged by larger, more sophisticated businesses coming in with greater marketing prowess. Peterson Dean is a prime example of a roofing company that sold solar as an add-on, but that is now being challenged. The good news is there is still plenty of business for everybody.

MR. MARTIN: What are current tax equity yields? How much does tax equity cost currently for rooftop solar?

MR. FRANCO: We have seen deals from 8% to the low teens, unleveraged, on an after-tax basis. It depends on the structure and how fast you want to close.

MR. MARTIN: What is the cost of debt for rooftop solar?

MR. FEO: There are not many players interested in small systems. The range is between 6% and 12%, depending on the lender, the credit and the seniority of the debt.

MR. MARTIN: Where do you think securitization will come in? Will securitized debt be less expensive than tax equity and straight debt and, if so, by how much?

MR. FEO: Definitely. A typical REIT return is 4.5% to 5%, so that tells you something about where the base line is. On pricing for securitized debt, if you have the good fortune to get to investment grade, you are at 4.5%.

MR. MARTIN: We heard today that 25% of the cost of an installed system is the cost of capital. Are there any other innovations you see over the next three to five years besides securitization that will bring down the cost of capital?

MR. WEIR: Crowd funding is coming. It is still very early. There are a few companies in a quiet period. The US Securities and Exchange Commission is about to make a ruling. That definitely brings down the cost of capital.

MR. MARTIN: Solar Mosaic is an example of a company planning to use crowd funding to raise equity. It plans to raise money in $25 increments over the internet. ◎

Opportunity to Buy Operating Wind Farms?

by Paul Kaufman, in Los Angeles

Private equity funds and pension trusts that are unable to use the large tax subsidies on US wind farms may have an opportunity shortly to acquire operating projects.

A significant number of US wind farms will have been in operation for at least 10 years by the end of 2013. These wind farms qualified for 10 years of production tax credits on their electricity output. The credits are 2.2¢ a kilowatt hour. The fact that the United States subsidizes construction of new renewable energy facilities through tax subsidies has made it difficult for anyone without a US tax base to invest in such projects. Most projects have been financed to date in the tax equity market. There are roughly 20 active tax equity investors.

The United States had an installed wind capacity of 6,350 megawatts at the end of 2003, according to data collected by the US Department of Energy. Those projects will be at least 10 years old by the end of this year.

Will the developers who still own them be interested in selling?

Developers sell projects for various reasons. A developer may need to rebalance its balance sheet or generate cash to develop other projects. Exhaustion of production tax credits may be an opportunity for the developer to exit as the value of the project at that point will be limited to the project's cash flow. The developer may have an added interest in selling if the project has underperformed, since the cash needs of the project for maintenance may be a strain for the developer or the project may need additional capital improvements.

Reliable Revenue Stream?

Purchasing a project that has been in operation for 10 years raises a number of due diligence questions. Knowing where to probe will save time.

One of the first places to focus is the status of the power purchase agreement under which electricity, renewable energy credits and other attributes from the project are being sold.

The first step in evaluating the power contract is to gather all of the documents that govern performance by the parties. Many utilities buying electricity from independent generators under long-term contracts use "administrative guides" or "operating committees" to administer such contracts. A review of the administrative guide or the minutes or records of the operating committee is advisable.

If the electricity is being sold to a regulated utility, another key document is the order by the state public utility commission authorizing the utility to pass through the electricity price under the contract to its ratepayers. Be sure to check whether the public utility commission imposed any conditions. Some state commissions require periodic review of the rate order.

Check whether the offtaker, or agency that regulates its rates, has developed buyer's remorse. While someone buying a wind farm may see it as a plus that the power contract requires the local utility to pay above-market prices for the electricity from the project, the utility and its regulators may not see it the same way. How great a risk is there that the utility will want at some point to try to get out of the contract? Will it be encouraged to do so by its regulators? Check whether the utility's consent is required to a sale of the project company, as that may give the utility leverage to insist on lower electricity prices.

More recent power purchase */ continued page 24*

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price. However, the court was not persuaded because EZH was expected to have slightly more than the $215 million option price available to it by then in two defeasance accounts into which the initial rent payment was deposited, "rendering the option effectively costless to EZH." The court said the appraiser also failed to address the consequences to EZH of not exercising the option.

The court said the question is whether exercise is "highly probable" — whether someone in Con Ed's position would have "reasonably expected that outcome."

It pointed to statements by Con Ed to its accountants, Price Waterhouse, when the transaction closed that exercise was "reasonably assured" and by the outside financial advisers in a transaction structure memo when the deal was being put together that "it is reasonable to assume . . . that [EZH] will exercise the purchase option."

The case is an example of how bad facts make bad law.

Nevertheless, it may make some tax equity investors more wary of fixed-price purchase options.

It is a reminder to insist on careful analyses in appraisals.

It should not affect transactions with options to purchase at fair market value determined when the option is exercised. It may affect the choice of venue when litigating tax cases in tax equity transactions.

CALIFORNIA said a property tax exemption for new solar facilities applies not only to solar panels mounted on rooftops, but also to large-scale solar projects.

New solar systems in California enjoy a one-time exemption from property tax assessment. An assessment will be triggered if the project is later resold or there is a change in control of the company owning the project. Property taxes vary by county. They can be as high as 2% of assessed value, and must be paid annually. */ continued page 23*

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agreements or PPAs demand a higher level of performance from wind developers and give the utility greater operational flexibility than what was found in older PPAs. Older PPAs may have had a mechanical availability guarantee, but were unlikely to include performance guarantees. An availability guarantee requires the project to be available a minimum percentage of the time to generate energy. A performance guarantee requires the project not only to be available, but also requires the wind to blow.

Older PPAs usually made the utility responsible for any curtailments beyond the point of delivery (which was generally the project busbar). The utility had to keep paying for the electricity that was curtailed. Newer PPAs generally require the project to shoulder some portion of the risk of curtailment beyond the busbar.

Be sure to check how the project has performed. Did it breach any availability or performance guarantees? Has the project paid any liquidated damages to the utility or received any notices of noncompliance or default? Have any disputes, formal or informal, been initiated by either party? Has the project company met all of its reporting obligations under the PPA?

Have there been any uncompensated curtailments or have all curtailments been compensated by the utility? If the project went uncompensated, has the cause for the curtailment been mitigated or eliminated?

Finally, focus on the market in which the utility is located. What other options are there for selling electricity if the utility defaults? Evaluating the financial strength of the utility is a critical issue. Has the utility maintained its credit rating? Has there been a substantial change in the utility's load or customer base?

Fully De-Risked Project?

There are a number of other due diligence issues to consider. On the positive side, the performance of the project will be well understood. Wind projections will have been verified or vilified.

Further, to some extent, major equipment problems are likely to have surfaced after 10 years of operation. The break-in period for the project will have been enjoyed or suffered by the original owner.

Nevertheless, the buyer should determine whether the project is "broken" or just "broken in."

For example, due diligence should include a review of the project's past operating history, project availability, outages and maintenance records, and a review of the turbine manufacturer's performance across other operating projects. A careful review of the owner's capital investments and expenses for operation and maintenance will be helpful to determine whether maintenance or repairs were deferred.

If possible, the buyer should consider whether the type of equipment in use at the project has met performance expectations at other projects. For example, has the turbine manufacturer been subject to any serial defect claims that might affect the project's turbines?

There may be an opportunity soon for pension funds and other cash investors to buy more than 6,300 megawatts of US operating wind farms.

While warranty periods in turbine supply agreements of the 2002 and 2003 vintage generally lapsed after two years, a purchaser should nonetheless be concerned with the turbine supplier's ability to continue to provide spare parts or be sure that substitutable parts are available from other suppliers. Review how well any outside contractor to whom the project has hired out operation and maintenance has performed.

Does a project stay "developed" once it is fully developed? If a project has been operating for 10 years, is it reasonable to assume that site control (land and title), permitting and community support are free from issues?

While the project may have been scrubbed for development flaws when it was financed, and development flaws will tend to reveal themselves with the passage of time, it is best not to assume that the project is free of development issues. The passage of time is not always kind to developed projects. The buyer should consider whether the owner has maintained site control as well as the priority of its claim over the site in the chain of title. A new phase I environmental assessment should be ordered to ensure that the site remains in an acceptable environmental condition. Consider asking for a new survey to check for any new crossings, easements or other uses of the land, such as mining or gas drilling, since the project was originally financed.

Wind farms operate under permits that may have conditions on continued operation. Check that the project has complied with all permitting conditions, including any requirement for post-operation reports and studies. Check whether any endangered or threatened species have moved closer to the site since the project was built. Did the project take on any study or reporting requirements with respect to flora or fauna and, if so, are there any open-ended mitigation obligations that spring from the reports?

Unfortunately, regulatory requirements are not frozen in time once a project has been built. Check for any new compliance obligations. For example, in 2002 wind projects were not regulated by the National Electricity Reliability Council and its regional reliability councils (such as the Western Electricity Coordinating Council). However, it is now clear that wind projects are subject to reliability regulation and, accordingly, every project needs a compliance plan.

Joint Venture Owner?

If the project is owned in a joint venture and less than all the joint venture interests are being purchased, be sure to understand the rights and obligations of the joint venture partners by reading the operating agreement. Most joint ventures are limited liability companies. There are a number of issues to consider.

For example, the other joint venture partners may have a right of first offer or an option over the interests being sold on the same terms as the proposed sale. There may be a waiting period before the sale can close. Even if there is no right by the other members to buy, their consent may be required to a sale. Joint venture agreements vary on how far up the ownership chain the restrictions on sale apply.

In joint ventures between a developer and a financial party, the developer usually has day-to-day control over operation of the project. A list of major decisions / continued page 26

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The State Board of Equalization rejected a suggestion by Inyo and Riverside counties in November that the exemption does not apply to utility-scale projects.

In December, the board released a set of final guidelines for local property tax assessors about the solar tax exemption.

The exemption grew out of a ballot initiative called Proposition 7 that the California voters passed in 1980 and that was later implemented by the state legislature as section 73 of the state tax code. It has had to be periodically renewed by the legislature and will expire at the end of 2016 unless renewed again.

The exemption applies only to "active solar systems" that are assessed locally. California assesses power plants that are 50 megawatts or larger in size and are owned by "electric corporations" at the state level. Other projects, including solar projects that are "qualifying facilities" for federal regulatory purposes (which covers most solar projects of up to 80 megawatts in size) are assessed locally.

According to the guidelines, if a builder completes a new house with a solar system on the roof and has not sold the house by the lien date when real property is assessed, then the builder will use up the one-time solar exemption, and anyone buying the house later will have to pay annual property taxes on the system.

Tax equity transactions to finance solar systems in the state should not be treated as a change in ownership that triggers an assessment. However, there are limits.

A sale-leaseback of a system within three months after the system was originally put in service is okay. However, an assessment will be triggered when the lessee exercises any purchase option. Partnership flip transactions, including the later flip down in the tax equity investor's ownership interest, do not trigger an assessment. However, if the solar company or a third party later acquires more than a 50% interest in partnership profits and capital — other than the flip that occurs / continued page 27

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requires consent by the financial investor. If buying out the financial investor's position, be sure to check, if possible, whether the parties had a good working relationship.

A buyer should understand the status of each party's capital accounts. Each partner in a joint venture has a capital account that is his claim on the project assets if the joint venture liquidates. If there is still outstanding debt at the project or joint venture level and the person selling claimed tax depreciation on the project, then there may be "phantom" income that the owner of that position will have to report in the future as the remaining debt principal is repaid. The project will have income from future electricity sales on which taxes will have to be paid by the partners, but the cash will go to pay debt service. The "phantom" income tied to principal repayment must be allocated to partners in the same ratio they claimed tax depreciation on the project.

Check how the joint venture agreement addresses deadlocks between the partners. Is there is a fair and manageable process for dispute resolution? Some operating agreements provide for a "shotgun" resolution of disputes. Under this mechanism, a partner disputing the decision of another partner offers a price at which he must either sell his interest or buy the other partner's interest.

Check the mechanisms for budgeting and calls for additional capital. Many operating agreements provide for dilution of a non-contributing partner's interest in the event of an unfulfilled capital call.

While uncommon, projects that reached commercial operation in 2003 may be owned by a "flip" partnership. A flip partnership is a joint venture between a developer and a tax equity investor.

In a partnership flip, the joint venture usually allocates 99% of income, tax losses and tax credits, and distributes 99% of cash, to the tax equity investor until it reaches a target yield, after which the interest of the tax equity investor drops to 5% and the developer has an option to buy the tax equity investor's interest.

If buying the tax equity investor's interest, be sure to check whether the tax equity investor has a negative capital account. Some tax equity investors agreed to "deficit restoration obligations" in order to absorb more tax benefits. The holder of the interest would have to contribute capital to the joint venture upon liquidation in the amount of any capital account deficit.

Most operating agreements also bar a transfer of a joint venture interest if the transfer would cause the joint venture to "terminate" for tax purposes. It terminates if 50% or more of the profits and capital interests in the joint venture are transferred within a 12-month period. Termination could have an economic cost, although it is not likely to have much of one for a 10-year-old project. Federal Energy Regulatory Commission approval will also be required to transfer an interest in the project. Such approvals usually take 45 days. State approval may also be required.

Improving the Value Proposition

Are there ways for a buyer to squeeze more value out of the project?

For example, is it possible to add or improve turbines under the existing PPA and the permit and land rights for the site?

Wind technology has improved substantially since the turbines were installed at 2003 and earlier projects. Are these improvements substantial enough to justify the capital investment required to install additional turbines or retrofit existing turbines?

Can the purchaser capture other intrinsic or extrinsic value? For example, is there spare capacity under the interconnection agreement and interconnection facilities that would allow a thermal or solar resource to be added to the existing wind resource?

Another factor that will improve the value proposition is the resetting of depreciation. The purchase price can be recovered through depreciation.

A carefully planned due diligence effort is required before buying any operating plant. That is the only way to prove the value proposition with any certainty. While the opportunity to buy older projects is real, proof as they say "is in the pudding."

Investing in Negawatts

by James Berger, in New York

Many financial institutions are trying to figure out ways to invest significant amounts of capital in energy efficiency as government incentives expire for renewable energy. Because it is often less expensive to avoid consuming a megawatt of energy by increasing efficiency than to build the generating capacity necessary to produce the same megawatt, energy efficiency investments promise attractive financial returns.

Obstacles

However, there are several obstacles to such investments.

One obstacle is the high upfront capital costs. More efficient equipment is often more expensive than less efficient equipment. Retrofitting a building can be prohibitively expensive for the building's owner. Many homeowners or building owners are reluctant to make investments that can take years to show a return or else they have higher priority uses for their capital.

Another obstacle is uncertainty about the amount of savings. While it is easy to calculate how much energy a piece of equipment or a building uses, it is much more difficult to calculate how much energy has been saved as a result of an energy efficiency upgrade. Standardizing protocols and models for accurately predicting and measuring the energy savings of different energy efficiency investments is important to create accurate financial models.

Another obstacle is most energy efficiency investments are illiquid. The lack of an easy or quick exit prevents many would-be investors from participating in this market. Tradable financial assets backed by energy efficiency improvements might be able to find a more ready market than direct investments in the underlying energy efficiency improvements.

Another challenge is scale. Upgrading the energy efficiency of a whole commercial building will always be a smaller investment than building a utility-scale wind or solar project. The low-hanging fruit of energy efficiency could provide billions of dollars of investment opportunities and very attractive returns, but it will require taking a page out of the books of residential solar companies that package portfolios of small rooftop solar installations to finance in master financing facilities in order to lower transaction costs and reduce risk through diversification.

Several different strategies for financing portfolios of energy efficiency investments have emerged.

PACE

Residential PACE (or property assessed clean energy) financing is used to install renewable energy systems such as solar panels on a residential roof and make energy efficiency improvements in a home.

Pursuant to special legislation, a local municipality borrows money in the capital market by issuing bonds. The municipality

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automatically under the partnership agreement — then an assessment will be triggered.

In a utility-scale plant, the solar "facility" that escapes property taxes is all the equipment through the step-up transformer.

Parking lot canopies qualify for the exemption as part of the solar system if they are built mainly to provide a mounting surface for solar panels while only incidentally providing shade for autos.

Leasing a solar system to a customer does not trigger an assessment. Neither does a change in the customer to whom the system is leased. The average homeowner in California remains in his house only seven years. A sale of the house to a new owner who assumes the lease will not subject the solar system to property taxes. However, the guidelines say that a buyout payment by the original customer to terminate the lease would trigger assessment. It is hard to understand the logic, since ownership of the system has not changed.

Contributing a solar system to a legal entity will trigger an assessment, unless each owner retains the same ownership percentage interest in the system after the contribution as before.

A change in control of an entity that owns the solar system will trigger assessment. The exemption will also be lost if the entity's "original co-owners" cumulatively transfer more than 50% of their ownership interests in the legal entity.

Solar companies sometimes have an easement to put their systems on customer roofs in cases where the customer is merely leasing a system or buying electricity. The guidelines warn that the solar company may have a taxable possessory interest in the roof that is not covered from the property tax exemption for the solar equipment.

TREASURY CASH GRANTS are at issue in two more lawsuits.

W.E. Partners, LLC sued the US Treasury in the US claims court on January 22 in connection with the so-called

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then lends the proceeds of the bond offering to homeowners who want to install renewable energy equipment or make efficiency improvements. In some cities, water conservation measures can also be funded. The homeowner repays the loan through a special property tax assessment that attaches to the property.

This addresses the problems of high upfront costs as a deterrent to make improvements. Loans to homeowners can run as long as 20 years. The loans are also on favorable terms because the municipality can borrow more cheaply than the homeowner can. The loan amount is based on the tax capacity of the property rather than the homeowner's credit.

The obligation to repay the loan transfers to a purchaser if the property is sold. This allows a homeowner to decide whether to make improvements without worrying whether they will pay off before selling the home.

PACE loans effectively subordinate all other lenders' security, because the PACE loan is repaid as part of the property tax assessment, which is superior to all other obligations. This means that mortgage lenders end up subordinated to the municipality.

In 2010, the Federal Housing Finance Agency, which regulates Fannie Mae and Freddie Mac, issued a statement indicating that it would not allow PACE loans to take priority over mortgages that are federally insured. Most PACE programs have had to be suspended as a result. Some states have subsequently passed legislation that removes the senior lien status and leaves PACE loans in a subordinated position to mortgage holders.

Currently 28 states and Washington, DC have passed legislation permitting PACE financing.

Commercial PACE programs have been implemented in California and Colorado. The structure of the commercial programs is similar to the residential programs: a municipality issues bonds and the proceeds are borrowed by building owners to install renewable energy systems or make energy efficiency upgrades. A key difference is that mortgage holder approval is required. In addition, the Federal Housing Finance Agency's stance on residential PACE programs does not apply to commercial PACE programs.

The financing potential for commercial PACE is huge, with an opportunity to invest $88 to $180 billion in improvements to large commercial buildings alone.

There are three types of bonds that can be issued under commercial PACE programs. A pooled bond is where applications are aggregated and a revenue bond is issued to fund proposed projects. A stand-alone bond can be used for very large projects. This is when a revenue bond is issued to fund an individual project or a small number of substantial projects. Finally, an owner-arranged bond is where an owner arranges project financing with a private lender and the lender accepts a PACE-like repayment arrangement.

Only a limited number of residential and commercial PACE bonds have been issued to date in California, Colorado, Minnesota and Ohio in amounts ranging from $40,000 to $9.75 million. Resolving the subordination issue and the Federal Housing Finance Agency's objections, as well as increasing awareness and the volume of issuances is important to this market. Commercial PACE can expand once more states pass the appropriate legislation.

Several strategies are emerging for financing portfolios of energy efficiency improvements.

Securitization

Despite securitization's bad reputation in the wake of the financial crisis in which securitized residential mortgages played a large role, many types of loans, such as auto and credit card loans, are still regularly securitized and sold to investors. There has been talk for months about the securitization of residential solar system leases and power purchase agreements.

Some investors are now looking at securitizing portfolios of energy efficiency loans, including PACE loans.

Securitization of such loans would work like any other traditional securitization. First, a bank or other financial institution would pool energy efficiency loans by purchasing them from lenders. Next, the bank would engage a loan servicer and segregate the pool of loans into discrete pools of assets that reflect differing categories of risk. Notes secured by the receivables from these pools of assets would then be marketed and sold to third-party investors. This model could give large investors a relatively safe investment that returns a specified interest rate while also giving the original lenders new capital with which they can make new loans.

Securitization of energy efficiency loans may remove some of the obstacles associated with investing in energy efficiency. First, securitization would make a fresh source of capital available to lenders. Second, it would provide a liquid market for investors, which could attract more capital to the market.

Determining the risk of default of the underlying loans is a hurdle that must be overcome. The risk associated with PACE loans is low in cases where the loans have a senior lien on the property associated with the loan. For non-PACE loans that do not have a senior lien, the risk of default would have to be based on the creditworthiness of the borrowers. There are not enough years of data on default rates.

Because securitized energy efficiency loans will be backed by the receivables of many different loans, creating standardized protocols and methods for determining the savings from certain energy efficiency investments is very important. The securitization model rests on being able to pool loans based on risk and return.

Some bankers expect that the first round of securitized energy efficiency loans will hit the market in 2013.

Fund Arrangements

Larger projects are needed in which to invest to provide the market with opportunities for scale. With fewer and larger projects, there will be lower transaction costs and, theoretically, a higher return.

Investment funds, which can aggregate tens or hundreds of millions of dollars of investable capital,

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section 1603 program under which owners of new renewable energy projects are paid 30% of the project cost by the Treasury in cash.

There are now five pending lawsuits under the program.

W.E. Partners built a small biomass-fired cogeneration facility to supply steam and electricity to a Perdue chicken rendering plant in North Carolina. The cogeneration facility cost $9 million and has the capacity to generate 495 kilowatts of electricity and 63,000 pounds per hour of steam.

The Treasury paid a grant of only $943,754 on the facility rather than the $2,711,331 the company was seeking.

The Treasury position in the past has been that the owner of a facility that uses biomass to generate both steam for industrial use and electricity is entitled to only a partial grant. The grant is a fraction of the full grant, with the fraction equal to the electricity as a percentage of total useful energy output. The legal basis for the position is unclear.

W.E. Partners argues that the steam should be ignored because all the steam passes first through the steam turbine to generate electricity before any of it is put to use by Perdue as steam.

Another developer, Nevada Controls LLC, sued the US Treasury in the US claims court on December 7.

Nevada Controls misread an email from the National Renewable Energy Laboratory, which reviews cash grant program applications under contract to the Treasury, in June 2010 to suggest that it did not have to file preliminary applications by September 30, 2012 for its remaining projects that were not yet in service.

The company submitted a preliminary grant application in early June 2010 for a small hydro project that the company said it expected to place in service the same month. Developers were obligated at the time to let the Treasury know of any remaining claims on the grant program by September 30, 2010. Projects put in service after

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Negawatts

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can make large energy efficiency investments using one of two similar arrangements.

One arrangement is an energy savings performance contract where an investment fund serves as an intermediary between a building owner and a service provider who installs and, to the extent necessary, operates and manages energy efficiency upgrades. The investment fund provides the financing for the improvements and owns them, usually through a special purpose entity used for a specific energy efficiency project. This only works for large projects.

The building owner agrees to pay the investment fund a regular service charge that will repay the investment as well as provide a return on the invested capital. The service charge is an amount per unit of avoided energy. This arrangement protects the building owner from ever paying more per month for energy than before the parties entered the contract.

The investment fund enters into an agreement with a service provider that will make the energy efficiency upgrades and be responsible for ongoing monitoring and maintenance. Continuous monitoring is needed to measure the energy savings. In some transactions, the agreements with service providers include a performance guarantee to ensure specified energy efficiency targets are met.

An alternative to pricing based on energy savings is to use a managed energy services agreement where the investment fund pays the building owner's on-going utility bills directly and charges the building owner a fixed monthly fee equal to the building's historical energy rates, adjusted for occupancy and weather-related variables, both of which must be negotiated and agreed upon prior to entering the transaction. Obviously, the fee charged must be less than what the building owner is paying currently for utilities for the arrangement to be attractive.

The investment fund generates revenue by capturing the difference between the building's old energy costs and its decreasing energy costs as the building is made more efficient over time.

An advantage of a managed energy services agreement is that it reduces diverging incentives in multi-tenant buildings where the building might have an incentive to pocket the savings from the efficiency improvements while charging tenants full cost for utilities. This will not maximize reductions in energy usage. In addition, because repayment in managed energy services agreements is tied through the utility bill, the risk of tenants or building owners failing to make a payment is reduced (when compared to energy savings performance contracts) because the tenant or building owner will have to pay the bill to keep the lights on or the hot water running.

Both types of arrangements typically provide an option for the building owner to purchase the equipment or other upgrades at the end of the contract with the investment fund. The owner of improvements can depreciate them, and many types of improvements also qualify for tax credits. The building owner cannot be expected at inception to exercise any purchase option or the investment fund will not be considered the tax owner of the improvements. The fund will also have a hard time claiming tax ownership of any improvements that cannot be removed and deployed economically at the end of the contract term. The contract must not be so long as to mean that the improvements have been dedicated to the building owner for substantially their entire economic life. Inability to claim tax ownership may not be fatal; it just affects the economics.

Both of the arrangements described earlier are new with only minimal track records. The kinds of investors that would invest in a typical investment fund may not be willing to invest in a fund that makes energy efficiency investments through these types of arrangements. Time will tell.

Additional Withholding on US Cross-Border Payments

by Kelly Kogan and John Marciano, in Washington

US companies will have to withhold 30% of payments to foreign companies from US sources under agreements signed after 2013, even in cases where there would not otherwise be any withholding tax.

This new withholding regime, called FATCA, is a stick designed to force foreign financial institutions that receive payments to provide information about their US account holders to the US tax authorities. The stick is also supposed to force other foreign business entities to disclose any significant US partners or shareholders.

Modifying an existing loan, lease, technology license or other agreement requiring payments after 2013 would also bring FATCA into play.

The Internal Revenue Service issued final regulations to implement the new regime in mid-January.

The foreign financial institutions affected by FATCA withholding are not only foreign banks, but also foreign hedge and private equity funds and insurance companies. Non-financial foreign entities are also affected if they have at least one 10% or greater US owner, but not if they are publicly traded or earn most of their income from an active business (rather than from investments).

There are a number of ways to avoid FATCA withholding, all of which are based on why FATCA was enacted. Unlike other withholding rules that apply to payments by US persons to foreigners, the goal of withholding under FATCA is not to collect taxes, but to compel foreign recipients of payments to provide the US tax authorities information about their US account holders or US owners. Thus, to the extent a foreign payee provides this information either to the IRS or to the payor (who must then forward it to the IRS), it can avoid withholding. FATCA withholding can also be avoided if the IRS considers the foreign payee to have a low risk of enabling tax avoidance by US persons. The IRS regulations have a list of 22 possible exemptions.

Anyone claiming an exemption from withholding must provide an IRS exemption form to the US person making the payment. Exemption forms must be updated every three years.

Debt

The most common situation where FATCA withholding will apply is where a US project company borrows from a foreign lender. A US branch of a foreign bank is treated as a foreign lender for this purpose, unless it enters into an agreement with the borrower under which the US branch takes responsibility for paying any FATCA tax directly to the IRS. Any FATCA withholding would be on the interest payments and not principal repayments.

Lenders usually require borrowers to "gross up" debt service payments for withholding taxes.

The typical withholding tax indemnity agreement absolves the borrower from having to gross up in situations where the lender has the ability to avoid withholding, for example, by giving the borrower an IRS form claiming an exemption from US withholding taxes under a US tax treaty or on grounds that it is using a US affiliate to make the loan. / continued page 32

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2010 qualified for grants only if they were under construction by December 2010.

Congress later extended these deadlines.

NREL wrote back that that there was no need to file a preliminary grant application for such a project. "Given the proximity in time between your application and the date you expect to place the property in service, a determination of whether you have met the begun construction requirements would not serve any purpose and could delay a final determination with respect to your property once it is placed in service." It asked the company to withdraw the application.

The company read the email to suggest it did not have to file preliminary applications for any of its projects.

It said it lost grants of $553,716 on four small wind turbines it placed in service in October 2012 and a small hydro project that it expects to complete in March 2013 due to the "US Treasury's direction not to file" preliminary applications. Preliminary applications had to be filed for these projects by September 30, 2011.

PREPAID POWER CONTRACTS OR LEASES may create complications when assets are sold.

Some wind and solar companies that sell electricity under long-term contracts are paid in advance by the offtakers or customers.

They do not report the advance payments immediately as income but rather report income over time as the electricity is delivered. If the assets used to supply the prepaid electricity are later sold — for example, in a tax equity transaction — it is unclear what tax basis the buyer should take in the assets, according to a paper the tax section of the New York State Bar Association sent the IRS and Treasury in January.

The bar association said there are two possible answers.

One, which it called an "assumption approach," is to treat the buyer as having assumed a contin- / continued page 33

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Most loans would have been structured in the first instance so that there is no withholding. Thus, the gross up is most likely to come into play when withholding is triggered by a change in US law.

However, historically lenders have usually agreed to provide exemption forms for withholding obligations only if they could produce them economically and without any negative consequences. When FATCA was enacted in 2010, lenders did not know how cumbersome and expensive compliance with the new regime would be. Because of this uncertainty, they were unwilling to bear the risk that debt service might be reduced if eventually there was FATCA withholding on the payment.

Now that the global financial community has been preparing for FATCA for over two years, and the new final rules provide more certainty about its implementation, more recent deal documents put the FATCA risk back on the lender. They do this by requiring that the lender provide a timely and valid FATCA exemption form to the borrower. The lender would have to check a box on the form indicating that it has an agreement in place with the IRS to turn over information about US account holders to the IRS.

Alternatively, the lender could check a box on the exemption form indicating that its home country has signed an agreement with the US Treasury Department. Currently, three countries have signed such agreements — the United Kingdom, Mexico and Denmark — and the US Treasury Department is in the process of negotiating agreements with more than 50 other countries. Under these agreements, a resident financial entity provides information about its US account holders to the local tax authorities, who then forward that information to the IRS.

US borrowers should insist in loan documents that lenders provide FATCA exemption forms beginning in 2014. The exemption form is an IRS form W-8. There are various types of W-8 forms. Each has a different suffix, like W-8BEN or W-8IMY whose use depends on the type of payment and whether the payee is the owner of the income or is acting as an intermediary.

Other Payments

While the focus in the trade press has been almost entirely on payments to foreign financial institutions, the new rules cover more than just interest payments. They also cover rents and royalties paid for the use of property in the United States, compensation for labor performed in the United States, and dividends paid by US companies to foreign shareholders.

This means that US payors should not forget to require FATCA exemption forms from foreign payees of these items beginning in 2014, and they should also consider whether they are obligated to "gross up" their payments if the payee fails to provide the form. Lenders are familiar with FATCA, but foreign payees of these other items probably are not.

Starting in 2017, the new rules will require a US company to withhold 30% of the full amount of any payment to a foreign person to redeem stock in the US company or debt of the US company.

Withholding will also be required on the gross purchase price by any buyer of stock in or debt of a US company from a foreign seller.

Withholding can be avoided in both situations if the foreign payee provides the US payor an IRS form providing a basis for an exemption: for example, that the foreign person is publicly-traded or that it earns most of its income from an active business.

US companies will have to withhold 30% of many types of payments to foreign lenders, investors or counterparties starting in 2014.

Blanket Exemptions

FATCA does not apply to payments for which the payee must itself report the payment on a US tax return and pay US income taxes, such as earnings from engaging directly or through a partnership or US branch in a US trade or business.

It also does not apply to foreign entities that are owned by a foreign government, such as an export credit agency.

In either case, the payee must claim the exemption by providing the payor with a W-8ECI or W-8EXP, respectively.

FATCA also does not apply to payments that do not have a source in the US, such as where the borrower is a Puerto Rico project company. There are complicated rules under US tax law for determining the "source" of a payment. For example, interest is considered to have its source where the borrower is located. Compensation has its source where the services are performed. No Form W-8 is needed to claim this exemption.

Practical Issues

From the standpoint of a US developer, the focus should be on trying to get a foreign lender or other payee to provide proof that it is exempted from FATCA withholding. This is best done by including in the deal documents a requirement that a payee provide an exemption form to the US developer before the first payment is due. This requirement must leave as little discretion as possible to the foreign payee.

Keep in mind that FATCA withholding obligations are ongoing, so the payee should be required to update any exemption form to the extent the facts change or the IRS requires that a new form be provided. Also, if at any point, the foreign payee is not able to provide the exemption form, consider who should be burdened with the FATCA withholding tax.

For its part, the foreign payee will need to confirm its eligibility for a FATCA exemption and be prepared to provide the US developer with the relevant form before the first payment.

If a US developer does not receive an exemption form from a payee exempting the payment from FATCA withholding in a timely manner, then the US developer must withhold the FATCA tax and forward it to the IRS. A US payor that fails to withhold the FATCA tax and remit it to the IRS becomes liable for it. ◎

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gent liability. For example, suppose a buyer pays $1.2 million for a solar project for whose electricity a customer has paid in advance, and the buyer is expected to have to spend $800,000 to deliver the electricity, but the actual amount the buyer will have to spend cannot be known with any certainty.

The buyer values the asset by subtracting this contingent liability. Therefore, were it not for the obligation to deliver the electricity without any further payments from the customer, he might pay $2 million for the project. Instead, he pays the net amount of $1.2 million and takes that as his basis in the project for depreciation. As he spends money in the future to deliver the prepaid electricity, he adds the amounts he spends to his basis in the assets. If he bought a project for $1.2 million in cash and assumed debt of $800,000 he would have a basis of $2 million. However, contingent liabilities do not go into basis until they are paid.

The bar association calls the other possible approach a "fragmentation approach." The buyer would be treated as having paid the seller $2 million, but then having received $800,000 from the seller to assume the contingent liability. The buyer would have a basis of $2 million for depreciation. He would have immediate income of $800,000.

The bar association urged the IRS and Treasury to issue guidance. It called the issue one of "longstanding uncertainty."

Its paper is called "Report on Treatment of 'Deferred Revenue' by the Buyer in Taxable Asset Acquisitions" and is dated January 7, 2013.

CHINA, which plans to install 10,000 megawatts of additional solar capacity this year and is on track to reach its current goal of 21,000 megawatts of solar generating capacity by 2015, may double the 2015 target to 40,000 megawatts, according China's official Xinhua news agency. Analysts say that the increase is not enough to soak up the global glut of manufacturing capacity for solar panels. / continued page 35

The US Army Goes In Search Of Electricity

Renewable energy developers are angling to supply up to $7 billion in electricity to the US Army under long-term power purchase agreements. The Army released a request for proposals last August. Developers who are interested in bidding had until October 2012 to submit their credentials and a maximum price for kilowatt hours at which they are prepared to sell electricity. Developers who make the first cut are expected to be awarded MATOCs or multiple award task order contracts. The developers will then be allowed to bid on specific projects as the projects are announced in the future.

The Army is not expected to announce the qualified bidders until the third quarter 2013. At least four projects at individual Army bases are expected to be put out for bid in the meantime.

The Army also asked for expressions of interest by late August 2012 from companies who are interested in entering into separate "energy savings performance contracts." The companies upgrade air conditioning and heating systems, lighting and boilers, improve windows, install solar panels and make other improvements and charge the Army a percentage of the energy savings over time.

The US Department of Defense has set a goal of relying on renewable energy for at least 25% of its total energy consumption by 2025.

Many larger renewable energy developers have hired specialists to focus on government contracting. A panel of them talked at a conference on November 30 in Washington about the Army solicitation. The following is an edited transcript.

The panelists are Nate Butler, manager of government programs at SunEdison, John Finnerty, government channel manager for Standard Solar, Robert Franson, a vice president of Energy Investors Funds, Kevin Johnson, manager of mergers and acquisitions and federal markets for Acciona Energy North America, David McGeown, a principal with McGeown Associates, a consultancy that is assisting the US Department of Defense, and Kevin Prince, project development manager for federal programs for SunPower Corporation. Many of the panelists had served in the US military or, in the case of David McGeown, in the Royal Air Force reserve in Britain. The moderator is Keith Martin with Chadbourne in Washington.

MR. MARTIN: More than 600 people showed up at a pre-proposal conference in late August hosted by the Army. That is a lot of people competing for a limited number of projects. If this were a utility solicitation, would you bother to bid in such a crowded field?

MR. JOHNSON: The solicitation is for multiple technologies. For Acciona, if it were a wind solicitation, yes, we absolutely would bid. We feel very competitive in the wind field. If it were solely a solar solicitation with 600 competitors, we probably would not bid. My guess is that the 600 respondents will probably whittle down to around 300 for wind and solar. The numbers for other technologies will be much smaller. The number of respondents for geothermal should be a handful. The number for biomass should be fewer than 25 to 50 bidders.

MR. BUTLER: The MATOC is structured in a way that compels people to team up where they might not have done so otherwise. Few companies can meet the experience requirements by themselves, especially if they want to go across multiple technologies. We expect solar to have the biggest field. It is worth it for a company like SunEdison to participate, notwithstanding the large field, because of the potential rewards at the other end. Ideally, we would have liked to have seen more culling of the field instead of letting everyone who walks in the door remain in the hunt.

Strategies

MR. MARTIN: One of the gripes that larger developers have had in the renewable energy sector as a whole is the two guys with an Avis card who underbid everybody else but then cannot deliver. How great a problem do you see this in such a crowded field?

MR. PRINCE: There are experience hurdles that must be met in the Army solicitation in terms of building, operating and financing systems, so the 600 will eventually turn into a smaller number. When the individual projects come out for bid, we will look at each project on its own merits. The three questions we ask first for any project are who is the offtaker, what does the interconnection look like and what is the site access status? We also look at the evaluation criteria and experience hurdles. We will be interested in whether bids are evaluated based on present value.

All of these factors are weighed as we assess whether to bid. If we identify risks, or if the Army is evaluating based on lowest initial cost or if no offtaker has been identified — for example, where the Army is merely allowing us of otherwise underutilized land to build a project — then we will not bid. Lack of an offtaker is a set up for a stranded project. The project will be awarded, but the developer will not be able to finance or build it.

The Defense Department needs to recognize that there are different levels of experience among developers in financing projects with long-term government offtake contracts. This is on top of differences in construction experience.

MR. MARTIN: Rob Franson, do you think a possible strategy is to try to pick up projects from winning bidders who are unable to perform? I don't know whether it is possible to take over a contract like that.

MR. FRANSON: In general, EIF would not want to step into a project that we had not fully negotiated or developed.

To answer your earlier question, look at the request for proposals that the Army released recently to supply power to Fort Detrick. I do not think that a firm like EIF would bid into a project with such a relatively small dollar amount knowing that we were going to be competing against 200 or more bidders.

MR. MARTIN: Are the other services besides the Army expected to come out with their own solicitations? If so, when, and are they expected to use the same process as the Army?

MR. MCGEOWN: The other half of my life is serving the US Department of Energy and you have now given me the opportunity to advertise that there was a draft large-scale renewable energy project development guide for federal agencies posted to the DOE website in the spring. We have spent two years listening to the community to put together a process that is repeatable and reliable, so that a 28-year-old analyst who works for you can look at one of these solicitations and say: "I know where to find the answer to that question. It is in section 173, paragraph 2." It would be wonderful if all of the Services use a process similar to that. The Army has adopted that and will be coming out with the Army version of it, and we are actively talking with the Air Force and Navy, but at the moment everybody has his or her own process.

Tempering Expectations

MR. MARTIN: There was an interesting quote in North American Windpower magazine about the Army RFP. It said, "Developers looking to bid on the Army's RFP should know that the process and requirements differ substantially from those of utility and commercial contracts, and working with the government presents both advantages and disadvantages." What are the main points senior management should know about this opportunity? Let's say you are drawing / continued page 36

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The country plans to increase its wind capacity by 30% in 2013.

Total electric generating capacity from all sources increased by 58% from 2007 to 2012 and is currently 1,140 gigawatts. This compares to total generating capacity in the United States at the end of 2011 of 1,018 gigawatts.

HYDROGEN ENERGY CALIFORNIA was awarded the right to claim an investment tax credit of up to $103,564,000 by the IRS in January.

The credit is 30% of the eligible cost of a hydrogen-fueled power plant that the company plans to build in Kern County, California. The hydrogen will be produced from non-potable water using coal and petroleum as fuel. The plant will produce a low carbon fertilizer in addition to electricity. The carbon dioxide emissions will be captured and used for enhanced oil recovery. The project cost will be paid in part with the help of a $408 million grant from the US Department of Energy.

The investment tax credit is a special credit under section 48A of the US tax code for advanced coal projects. The project must be placed in service within five years after award of the tax credit.

The company will probably have to do a sale-leaseback to get value for the tax credit. Alternatively, if it can find a strategic investor, it should be able to claim it on progress payments to contractors during construction.

CONDEMNATION PAYMENTS that an electric utility received from a highway authority to reimburse the utility for the cost of moving power lines and other utility equipment out of the path of a new turnpike did not have to be reported by the utility as income.

Amounts that a company receives in an "involuntary conversion" of its property to cash do not have to be reported as income as long as the amounts are reinvested within two years in similar property. The utility asked for a private ruling from the IRS / continued page 37

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up a few bullet points for senior management to temper expectations.

MR. FINNERTY: Everybody gets excited when he or she sees the headlines and the size of the opportunities, but the whole process takes a long time. The scope is for different types of renewable energy projects. Solar projects are just one of several categories. Each solar request for proposals will need to be evaluated independently. We are a growth company. We have to focus our resources and select an RFP that our team can close in a reasonable period of time. For some of the RFPs, our best strategy may be partnering with other key players. Focusing on our key strengths engineering, procurement, construction and operation and maintenance will deliver the best results for our partners and the Defense Department.

MR. MARTIN: Kevin Johnson, what is the main point on your list for senior management?

More than 600 people showed up at a pre-proposal meeting to bid on $7 billion in power contracts to sell electricity to the US Army.

MR. JOHNSON: Acciona competes globally. Our corporate headquarters are in Madrid, Spain. We are active in more than 30 countries on five continents. The main point for senior management is what it is reasonable to expect as a return on DoD projects. We are not going to see the 25% annual equity returns that are on offer in South Africa. The return is a function of the electricity price we will have to charge in order to win bids. Nevertheless, we feel the DoD procurements are a good opportunity for us to reach scale in the US market. Acciona has done very well working in government markets in infrastructure projects in Spain. We have a long-term view. The return, timing and pricing expectations are the key things that we talk about.

MR. MARTIN: What are your return expectations?

MR. JOHNSON: We expect a 10% return on equity invested.

MR. MARTIN: Kevin Prince, what is the main point you would make to senior management?

MR. PRINCE: The Army RFP has more in common with a utility development timeline than a commercial deal. You have to be comfortable, when undertaking a federal project, with the federal acquisition regulations for government contracts and the risks that are associated with the entire government contracting process. Everyone sees the headlines that the Army has underway a $7 billion procurement. I got so many emails from executives within the company asking, "Hey, are you aware of this?" The figure $7 billion makes people ask how much we can get. What the $7 billion actually means for solar projects is much smaller than $7 billion. We are all still learning what the Army wants. We have to manage expectations for the Army solicitation with our senior management.

MR. MARTIN: What do you think the amount is for solar?

MR. PRINCE: The figure $7 billion is the total PPA payments over 30 years across all technologies. Solar is somewhere between 60 and 150 megawatts in capacity.

MR. MARTIN: Do you agree with Kevin Johnson that a 10% discount rate to arrive at a value is probably the right figure?

MR. PRINCE: I think it depends on the project and the characteristics of the project. The federal government is the offtaker. It has the land. It pays high rates for electricity. Those are attractive features. The government is a strong credit and has strong site access and control. However, you are competing against commercial and utility deals for scarce capital to build. It depends on the deal, but the appropriate discount rate could be within range.

Potential Issues

MR. MARTIN: The Army received nearly 800 comments on its draft RFP. People raised a number of issues. Let's start with the expected term of the power contracts. How long are they expected to run?

MR. BUTLER: The Army has authority to enter into power contracts of up to 30 years. However, I do not expect a lot of contracts to be 30 years; 20 to maybe 25 years is more of a sweet spot for us both. A developer does not get much more benefit from taking the term out further.

MR. MARTIN: David McGeown, there was some speculation that the contracts might be limited to 10 years. Do you see that happening?

MR. MCGEOWN: No.

MR. MARTIN: What happens to the project when the power purchase agreement ends? Have you been given any indication you will be able to leave the project in place and sell electricity to the grid? Can you remove it? Who pays the cost to dismantle?

MR. BUTLER: We usually see a requirement to remove the project and restore the government's property at the end of the contract term. There are a lot factors that go into deciding what to do at the end of the term. What you say in the contract can affect not only how the government scores your bid, but it can also affect your ability to claim tax ownership of the project during the contract term and, therefore, your ability to finance the project if the contract requires the project be turned over ultimately to the government.

MR. MARTIN: Does anybody see any end-of-term issues with the contracts that are on offer?

MR. FRANSON: We would not usually finance a project that has a firm end date so that we are basically factoring in a dismantlement of the project. We develop projects with the intention of selling those projects to someone else at the end of the existing power purchase agreement. The assumption is that the project will sign a new contract to sell its output to someone else at a certain point. For example, EIF used to be the 100% owner of the Black River generation project at Fort Drum that was recently sold to a firm that is converting it into a biomass project. That project used to sell power to the Army and eventually came off contract. The project continued to sell power off base for probably 15 or 20 more years.

MR. MARTIN: The Army does not want to pay more than the retail rate it would pay the local utility for electricity. Renewable energy is more expensive to produce than electricity from fossil fuels. Does this retail rate cap leave enough room to operate in parts of the country where the retail rate is set by coal or natural gas?

MR. PRINCE: In order to make the economics of project work, we look at the three Rs: rates, resource and rebates. You don't need all three to make a project work, but you need a least two out of three. There are only a few installations where the economics work today. Over time as our cost reduction strategies kick in and the price of conventional power increases, we see that list expand. These assets have / continued page 38

IN OTHER NEWS

confirming there was no income in its case. The ruling is Private Letter Ruling 201252010. The IRS made it public in late December.

MINOR MEMO: The median price for a rooftop solar system installed in the United States in 2011 was $6.13 a watt for residential and small commercial systems of 10 kilowatts or less, and $4.87 a watt for commercial systems larger than 100 kilowatts, according to a report by the US Department of Energy in November. The average cost for utility-scale solar photovoltaic projects was $3.42 a watt. Prices are falling at an accelerating rate. Prices declined 5% to 7% a year from 1998 through 2011, but at an 11% to 14% rate in the last year of that period and may have fallen by as much as 25% to 29% if one compares Q4 2010 to Q4 2011 prices. According to the Department of Energy, analysts expect global average module prices to be almost 50% lower in 2013 than in 2011: 74¢ a watt compared to $1.37 a watt in 2011. The department said there are no analyst projections for the balance of system costs. The report is called "Photovoltaic (PV) Pricing Trends: Historical, Recent, and Near-Term Projections."

— contributed by Keith Martin in Washington

US Army

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useful lives well over 25 years. It is important to look at the net present value of savings over time and not just the initial cost.

MR. FINNERTY: The Army is no different than anyone else in wanting to pay less than the local grid rate for electricity. In addition to a low price, the Army needs nearly 100% reliability to support critical missions around the clock without interruption. The amount of electricity and the 100% reliability the Army requires are rapidly exceeding the ability of local utilities to deliver.

The focus on meeting a retail rate cap needs to be balanced with the added costs to deliver the required near 100% reliability and power security to a given base, even during grid failure events, that is being asked from renewables.

MR. MARTIN: How great a complication is it that the Army wants to keep any renewable energy credits or RECs? It wants a lower price but also to keep a subsidy that is supposed to help the generator be competitive.

MR. PRINCE: Life would be a lot easier if the developer could keep the RECs.

MR. FINNERTY: The Army has been clear that its goal is to purchase electrons at the best price. Solar developers have been able to deliver very competitive and sub-grid rates for many projects. RECs play a critical role in our ability to deliver competitive prices. Choosing to retain the RECs in service territories with low electricity prices and low or non-existent SREC markets can significantly complicate our ability to beat the local grid rate. Developer and finance teams are delivering innovative solutions. We need to match project innovation with contract innovation on the government side. There should be flexibility based on locality.

MR. MARTIN: The payments from the Army are expected to be subject to annual appropriations. How do you arrange long-term financing for a project with a non-appropriation clause in the power contract?

MR. BUTLER: If a homeowner gets in trouble, one of the last bills he or she will fail to pay is the utility bill. Similarly, if a military base gets into trouble, the base will not allow the electricity to be shut off. You have the benefit of the federal government being able to print more money to pay its bills. However, all of that said, non-appropriation is a risk, and we have to get our investors comfortable that the clause is very unlikely to be invoked because we are providing an essential service.

MR. PRINCE: Appropriation risk is something with which experienced federal contractors are used to dealing. Most government contracts have appropriations risks. There are several clauses in the federal regulations that are unique to federal procurement. Termination for convenience, Buy American and non-appropriation clauses are just a few examples.

Enhanced Use Leases

MR. MARTIN: Many of these projects are expected to be built on the base itself using underutilized government land under an EUL or enhanced use lease. The US military will reserve the right to terminate the lease for national security reasons. How great a complication is this?

MR. JOHNSON: It is definitely a risk. The risk can be mitigated by requiring the military to pay a termination value. The Fort Detrick RFP establishes a good precedent. Basically, we will need a termination value schedule in place before the project can be financed.

MR. MARTIN: The military has not been willing in the past to agree to a fixed termination value schedule if it takes the project for national security reasons. Have you had any indication this policy has changed?

MR. MCGEOWN: Yes. As a consultant, I cannot talk to policy. However, there has been a consistent theme with the last three questions. An anecdote comes into my head: I am a pilot and we get lots of automated weather stuff, but the rule is “look out the window.” I wonder if everybody in this business would look up from the Power Points and “look out of the window.” We are doing something that has never been done before. It is new to the federal government. Federal government acquisition is an extraordinarily complex and time-consuming process, and we have to make it fit into what the development community wants to do quickly.

When we get into the negotiation about RECs, we will have to see if the project will work the way the Army proposes to handle things. In the next year, we will begin negotiations and you will tell us the truth about what works and what does not work.

Government contracts have clauses about termination for convenience and equitable adjustments that utility and renewable developers generally don’t come across. The experts in the Department of Defense contracting offices know this stuff backwards and forward, and firms could probably make a few bucks on a white paper on what it means for financing. Our analysis suggests the banks will see how the federal government will compensate them in the event of a termination or pulling out prior to the end of the PPA. Banks will see that there is the ability within the rules for lenders to be satisfied that they can get out somewhat whole.

MR. MARTIN: How do lenders take possession after a default under the enhanced use lease?

MR. BUTLER: Ideally, they don't. We expect the lease to include a right for the lenders to step in and fix something if it goes wrong. Government contracts do not typically include such a right. However, we think it is doable within the federal acquisition regulations. The lender needs the right to replace the developer should the first one fail. If the lender does not have this right and the contract terminates, then everyone loses. The lender loses money, the developer is out and the government does not get the electricity it needs.

There is an extra set of risks to evaluate in contracts with the US military.

Excess Electricity

MR. MARTIN: Do you expect the Army to buy all the output or just what it needs? Do you expect to be able to sell any excess electricity to the grid? Do you expect to be able to build a larger project than the Army requires and earn additional revenue by generating electricity for export?

MR. FRANSON: If the base wants to take 100% of the output, that's great. If it does not want to take it, then we will need the ability to sell that power off-base to a utility. It would be even better if the base will allow us to build a bigger project and generate electricity from the start for export.

MR. PRINCE: It is the responsibility of the developer to look at the load data for the base and size of the system for the best economics or net present value. Utilities buying from larger scale projects generally do not want any excess electricity sold to someone else. There is usually a requirement from investors that 100% of the output be purchased whether or not the base consumes it. The issue of generating more electricity than the base needs might be resolved by establishing a baseline for consumption, calculated on historical usage, and if the purchase falls below that baseline, then there would be some sort of equitable adjustment.

MR. MARTIN: What happens if the project is curtailed? Will the Army pay for the electricity anyway?

MR. BUTLER: The contract should explain what happens if the project is curtailed. The answer will depend on who caused the curtailment and the reason that it happened. If it is a government-caused issue, then that might be a government liability. The contract will also have to allocate liability where the project is curtailed due to force majeure or a problem with the transmission grid. As long as you know what will happen, you can manage the risk. It is only where you do not know what will happen that the real problems begin.

MR. MARTIN: Some utility contracts increase the electricity price if the project misses deadlines to qualify for tax subsidies. Do you expect the Army to allow such adjustments?

MR. FINNERTY: It would be wonderful if they did, but we have not seen that flexibility.

MR. JOHNSON: We could also run up against the retail rate cap. What we are seeing is that the utility sets the price of electricity in a particular location.

Other Points

MR. MARTIN: What other issues do you see with the Army procurement?

MR. BUTLER: I would say to the Army that the cleaner the process, the better. If you can avoid it, do not add to the requirements as we go along. Have realistic expectations for the value of what you are bringing to the table, whether it is land, sunlight, biomass or wind. It makes it hard when we bid at one price and on one set of terms and then there are lots of things on which we also have to give. It makes it more difficult for a project to be successful.

Time is another big deal for us. You have incentives that are running out all the time. You have financing where rates come and go and if we can move quickly and get the best terms, the government benefits. Timing is a lot bigger issue than I think the government appreciates.

MR. PRINCE: The Army is operating under two types of authorities. It has section 2922a, which authorizes it to purchase electricity, or it has EUL authority, which allows it to lease underutilized land to earn revenue. It is usually an either-or situation. There is not enough value in the deal to get revenue from the land and also to get electricity savings. That is an important consideration.

MR. MARTIN: Are there other issues with the procurement?

MR. JOHNSON: There is a bit of a fatigue factor for those of us competing globally. There is a hurry-up-and-wait pattern to military procurements. It is hard to keep the management teams, both here and abroad, engaged and ready to react when we sit for a while and then, suddenly, an RFP comes out right before Thanksgiving or over the holidays.

MR. MCGEOWN: I have one that relates directly to each of the procurements, but is my big nightmare because I am often the one saying, "This is not going to work." It is a general comment that may not relate to my fellow panelists, but when we see 150 people come talk to the military brass about what they can do, we hear too much rubbish. Tell the truth. Equally, if you think what the Army is requesting is nonsense, tell the top brass. Tell them what it takes to get these deals done, and we will go and get some deals done.

MR. MARTIN: The North American Windpower article said there were both advantages and disadvantages to bidding into a DoD procurement compared to a utility RFP. What are the advantages?

MR. BUTLER: I think number one is marketing. The government pays up to $4 billion a year for electricity. That's a big payoff even if you can get a small part of that. I would say the barriers to entry are high, but once you clear those, it can be a less crowded field. The fact that the Army procurement has hundreds of applicants is not typical for a government or DoD procurement. Once you figure out how to work with the DoD, I think you can make a business of it.

MR. MARTIN: Rob Franson, you get the last word. What's the advantage of this?

MR. FRANSON: The main advantage is the potential for five to 10 years' worth of transactions using the same template. However, unfortunately there are still a lot of issues that need to be resolved before we can participate in this space. ◎

Non-Appropriation Risk in Government Contracts

by Amanda Forsythe and John Marciano, in Washington

A company with a contract to sell electricity, lease equipment or provide energy savings to a government entity should think carefully about the financeability of the contract.

Many jurisdictions place restrictions on contracts with government entities that straddle two or more fiscal years. The government must reserve the right in the contract not to make payments if the money for payments is not appropriated by the state legislature, county council or other legislative body. The reservation of rights is called a "non-appropriation" clause.

Such a clause can affect financeability. However, by taking a few simple steps, a developer can help protect his interests and ensure a successful financing.

Two main issues arise.

First, some jurisdictions prohibit government contracts that extend beyond the current fiscal year unless the contract obligations are covered by long-term bond authority. Often, there are exceptions for leases, power contracts and energy savings contracts that permit such contracts to run beyond the fiscal year. However, the permitted term still may be shorter than the parties want (for example, five or 10 years).

Second, in some cases, a contract may extend beyond the statutory limit if the contact has a non-appropriation clause allowing the government to get out of the contract or certain of its payment obligations if a future legislature fails to appropriate funds for the contract. One legislative body cannot bind a future legislature to spending.

Debt Limits

Many state constitutions and statutes restrict the ability of a state or local government to enter into a contractual obligation that is considered debt. Governments are usually limited in the amount of debt they can issue, and municipalities often require voter approval in order to issue debt.

The rules differ among jurisdictions. Some may restrict multi-year appropriations for leases but allow governments to guarantee funding for long-term power contracts or energy savings contracts (such as for LED lighting). Others permit leases, but not the other forms of agreements.

As an example, in New York, a municipal contract generally may not extend beyond one year unless it includes a non-appropriation clause. However, "second class cities" in New York may enter into lighting contracts for up to five years without having to include the clause.

It is not always possible to structure a deal to fit the type of long-term contract that is permitted.

If an obligation is determined to be debt and its issuance did not comply with state borrowing rules, then the counterparty runs the risk of non-payment or having to repay rent or other amounts previously paid to it by the municipality.

In an age of budget deficits and fiscal cliffs, governments can easily become overextended. They need access to utility services and equipment, but may have strained finances.

The power contract or lease is an effort to avoid running afoul of debt issuance laws. Rather than own a project itself and borrow money to build it, the government signs a long-term contract to buy electricity from a project built and owned by someone else. One form power contract with a federal agency requires the agency to terminate the agreement and pay a termination fee if sufficient funds are not appropriated to cover the government's obligations. Other contracts may simply require the contract to terminate without penalty.

Practical Steps

A government entity's ability to terminate its obligations raises several issues for a developer.

How does the developer best protect its interests? What duties can it impose on the government entity to limit the risk of non-appropriation? If the government fails to appropriate funds, what protections does the counterparty have with respect to the property leased or provided?

Several safeguards can be included in contracts with government entities.

One common safeguard is a "non-substitution clause." The government entity agrees not to sign a similar contract with a different counterparty for the same services or equipment if the agreement is terminated, at least for a specified period of time. The term of the clause varies from agreement to agreement but usually ranges from a few months to a year.

A non-substitution clause protects against a failure to appropriate funds to meet payment obligations under an existing contract simply because a better deal came along.

Although non-substitution clauses are generally standard provisions in government contracts, they are limited in scope and such a clause applies only to the extent permitted by law. There may be an issue as to enforceability because such a clause makes it harder to exercise rights under a non-appropriation clause, thereby calling into question whether the non-appropriation clause is effective to salvage the contract. Consideration should be given to enforceability in the relevant jurisdiction. The parties often include a non-substitution clause anyway, even if it is not enforceable, as a sign of good faith that the government intends to honor the contract for the full term.

The contract should require the government entity to covenant that it will take all steps necessary to seek appropriations, to the extent permitted by law, each year. Such contracts often require the entity to submit budget requests each year that are sufficient to cover the government entity's payment obligations for the following fiscal year.

Another protection is a statement or letter of "essential purpose." This is a letter acknowledging that the government entity needs the service or equipment for an essential purpose: for example, electricity to keep schools open or fire trucks or police cars to fight fires and protect the public.

Developers should consider the purpose for which the services or equipment will be used. Consider two power contracts. If a developer is providing electricity to a municipality to power a city hospital, then whether the services are essential is obvious. However, if the electricity will be supplied to a satellite office housing minimal staff, the government has less invested in the contract and may be more likely to let the contract lapse if it is forced to reduce its budget.

In an equipment lease, the lessor not only retains ownership of the assets but also takes a security interest in them to secure payment of rent and other obligations. This is another protection in cases where the lease is cut short due to non-appropriation of funds. The project owner will need access to the site to reclaim its property.

An obvious question is how much of a risk non-appropriation poses to a developer trying to finance a project. There is little good data on how often non-appropriation clauses have been invoked in practice. The Equipment Leasing & Finance Foundation is doing a survey. It hopes to have results by April. At the end of the day, most tax equity investors and lenders appear to take comfort in power projects that utility bills are usually among the last bills that struggling customers stop paying. Electricity is essential.

Environmental Update

The US Environmental Protection Agency toughened the annual national ambient air quality health standards in December by reducing the amount of fine particulate matter that can be in the air. A city or larger region will be considered out of compliance if it has 12 or more micrograms per cubic meter of air. The threshold had been 15 micrograms.

This could eventually require additional pollution control measures and other restrictions at power plants, refineries, factories and other industrial facilities in parts of the country that have trouble meeting the new standard. "Fine" particulate matter is particles of 2.5 micrometers or less in diameter.

Each area of the country has been designated as in attainment, not in attainment, or unclassifiable with respect to the ambient air quality standards for each criteria air pollutant, including particulate matter.

The change affects annual standards for fine particulate matter only, leaving untouched the current daily standards for fine particulate matter at 35 micrograms per cubic meter of air. EPA also left unchanged secondary air quality standards for fine particles, which are designed to protect the environment rather than health.

The new standards target attainment by 2020. Initially, EPA will determine whether particular areas meet the revised standard based on monitoring data from 2011 through 2013. After it receives input from the states in December 2013, EPA will designate certain areas as "non-attainment" in December 2014. States must then submit their implementation plans for reducing pollution by 2018, and then meet the standards by 2020.

Areas that cannot comply will have to take additional steps to reduce pollution, such as restricting permits for new facilities or requiring additional pollution controls or permitting obligations on existing faculties. However, EPA suggests that the vast majority of counties will meet the standards without additional emission reductions because a number of federal regulatory efforts already in place will reduce particle emissions in the coming years. These measures include recent vehicle and fuel standards, regional haze regulations, and air toxics standards for power plants and new boiler rules. Nevertheless, EPA estimates the annual cost of meeting the standard could be as much as $350 million. It says annual health benefits from reduced exposure to particulates may range from $4 billion to $9.1 billion a year.

The Clean Air Act requires EPA to review air quality standards every five years. During the last review in 2006, EPA left untouched the particulate standards that were set in 1997. The latest revision of the standard should resolve pending litigation over whether the prior annual fine particulate standard was tough enough to protect public health.

The final rule will become effective on March 18, 2013.

Boiler Emissions

EPA issued final rules in late December to restrict pollution from industrial, commercial and institutional boilers, solid waste incinerators and cement plants.

The rules limit emissions of a number of air toxics, including mercury, acid gases and particulate matter, from boilers and incinerators.

There are different standards for major source boilers and area source boilers.

Major source boilers, common to refineries and other industrial facilities, are larger and have the potential to emit more than 10 tons a year of a single air toxic or 25 tons a year of a combination of air toxics. Area source boilers, those with a potential to emit 10 or fewer tons a year of any single air toxic or 25 tons a year of a combination of air toxics, are commonly found in hospitals, schools and hotels.

The new rules create numerous boiler subcategories, applying numerical limits or work practice standards to particular boiler types. Only 14% of the largest boilers are expected to be subject to specific numeric emissions limits, while the other 86% will have merely to follow work practice standards to minimize toxic air emissions.

EPA says the boiler rules will cost industry at least $1.3 billion annually. At the same time, the rules are expected to prevent up to 8,100 premature deaths, 5,100 heart attacks and 52,000 asthma attacks each year once fully implemented.

In a concession to industry, EPA agreed to give additional time to comply with the new emissions standards. Major source boilers will have three years to comply, or until 2016. Area sources will have to comply by March 21, 2014, and incinerators must comply by 2018. Environmentalists are unhappy with the decision to delay the effective dates.

Tougher ambient air standards are expected to require additional pollution control in some parts of the United States.

The new rules also revised performance standards for certain industrial solid waste incinerators. They also ease some restrictions on burning tires, railroad ties and plastic bottles. By sticking to a narrow definition of what is considered solid waste, the rules allow boilers to avoid stricter pollution controls that apply to incinerators.

The new rules restrict air toxics emissions from cement plants. Cement plants must comply by September 2015.

As an indication of how hard it is in the United States to implement new environmental regulations, the boiler rules were originally supposed to take effect by 2000 and the cement rules by 1997. The rules will become effective 60 days after publication in the Federal Register in early 2013.

California Cap and Trade

The first auction under California's cap-and-trade program took place as expected in November despite a last-minute lawsuit filed on the eve of the auction by the California Chamber of Commerce. Although the lawsuit did not seek an injunction, it helped create uncertainty about the program's future.

All of the 2013 vintage allowances available for auction in November sold at a settlement price of $10.09 per metric ton as compared to the auction reserve price of $10. However, fewer than 2% of the available 2015 vintage allowances were sold (5,576,000 of the available 39,450,000) at the auction reserve price of $10 per metric ton.

The cap-and-trade program limits the amount of carbon dioxide or CO_2 and other greenhouse gases that power plants, refineries, chemical companies, cement plants and other affected emitters in California are allowed to release each year. Greenhouse gas emitters covered by the program are required to submit allowances for each metric ton of greenhouse gas emitted. The program is market based because anyone who can reduce his emissions more efficiently or less expensively can earn income by selling unneeded allowances to those whose emissions are harder or more expensive to control. As the cap on overall permitted emissions ratchets down over time, the value of the allowances is expected to rise, and the overall level of greenhouse gases entering the atmosphere should fall.

The program also creates a domestic offset market. Covered entities can meet, or "offset," up to 8% of their compliance obligations by surrendering valid greenhouse gas offset credits. An offset credit represents greenhouse gas emission reductions or sequestered carbon that meets certain regulatory criteria. Offset credits may only be obtained in three ways. First, certain "early action offset credits" generated between 2005 and 2014 pursuant to the protocols of the Climate Action Reserve may be converted into credits. Second, the state air board expects to issue its own offset protocols. Third, it expects to allow use of credits registered with some third-party offset project registries.

The cap-and-trade program covers only the power and manufacturing sectors initially (including refineries, but only for their "direct emissions"). By 2015, the program will expand to reach 85% of the California economy, including not only electricity generation and manufacturing, but also such sources as refineries, pipelines and fuel distributors.

The program will also have an effect beyond California by imposing compliance obligations on emissions associated with electricity, natural gas and other fuels imported from other states into California. This is the first regulatory program to regulate suppliers of power and fuels in other states who sell into the California market.

The new rules cover "first deliverers of electricity," who include not only in-state electricity generating facilities, but also "electricity importers." "Electricity */ continued page 44*

Environmental Update

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importers" are defined as "facilities physically located outside the state of California with the first point of interconnection to a California balancing authority's transmission and distribution system." Thus, even facilities located entirely outside California may be required to comply if their energy is sold in the state. California receives nearly a quarter of its power from out-of-state sources.

The program may also apply to out-of-state suppliers of natural gas and other fuels whose products sold in California reach an annual threshold of 25,000 metric tons or more of CO_2-equivalent from emissions from combustion or oxidation of the fuels.

The California Air Regulatory Board, called CARB, took steps to limit wild swings in allowance prices and increase market stability. To prevent prices from falling too low, the early auctions will have a price floor of $10 per allowance, adjusted over time. Unsold allowances are returned to the state's "auction holding account" and will be re-sold at later auctions, subject to the limitation that only 25% of an auction's total volume may include such re-auctioned allowances.

To prevent prices from rising too high too quickly, initially most allowances beyond the share reserved and sold at auction by CARB will be given to covered entities for free. Over time, as auctions account for greater distribution of allowances, there will be an allowance price containment reserve. This reserve acts as a soft price collar by offering allowances for sale six weeks after each auction at set price tiers ranging from $40 to $50 a ton at first, adjusted over time.

CARB announced in January that 57,628,254 2013 vintage allowances and 38,240,000 2016 vintage allowances will be offered in 2013 at an auction reserve price of $10.71. The first auction in 2013 will be held on February 19.

— contributed by Sue Cowell and Drew Skroback in Washington

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