CHADBOURNE
& PARKE LLP

PROJECT FINANCE
NewsWire

February 2014

Cost of Capital: 2014 Outlook

A group of industry veterans talked in late January about the current cost of capital in the tax equity, bank debt, term loan B and project bond markets and what they foresee in 2014.

The panelists are John Eber, managing director and head of energy investments at JPMorgan Capital Corporation, Lance Markowitz, senior vice president and head of leasing and asset finance for Union Bank, Thomas Emmons, managing director and head of renewable energy finance for the Americas at Dutch bank Rabobank, Raya Prabhu, managing director and head of power and midstream financing at Goldman Sachs, Richard Randall, executive director for North American debt investments for IFM Investors, an Australian-based fund with $48 billion under management, and formerly head of power and project finance for RBS Global Banking, James Finch, managing director and co-head of US loan capital markets for Credit Suisse, and Ray Wood, managing director and head of US power and renewables for Bank of America Merrill Lynch. The moderator is Keith Martin with Chadbourne in Washington.

MR. MARTIN: Tax equity volume in the renewable energy sector hit $6.5 billion in 2013, which is up about $1 billion over 2012. There was roughly an even split between wind and solar. John Eber, can you break it down further: how many wind or solar deals were there?

Tax Equity

MR. EBER: We saw 21 wind deals come to the market and receive commitments in 2013. There were 13 different sponsors for 23 projects and about 3,000 / continued page 2

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START OF CONSTRUCTION issues will take time to sort out.

The Internal Revenue Service is still feeling its way on complicated fact patterns.

Many wind companies rushed to start physical work on projects at year end 2013 to qualify for federal tax credits on the projects. The American Wind Energy Association reported that 10,900 megawatts of new wind farms were under construction at year end.

The rush to start physical work at year end left issues around turbine pad excavations, roads, substations and transformers. Work must have started in 2013 on a significant task. It does not need to have been completed in 2013. The IRS does not have a threshold / continued page 3

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megawatts of capacity. In the large-ticket solar market, we saw 27 deals from 18 different sponsors. Of those deals, 10 each were in residential and utility, and about seven in the distributed generation market. In total, it was almost 1,800 megawatts of solar.

MR. MARTIN: What volume are you projecting for 2014?

MR. EBER: I am not in the projection business. Let's just say we see a sizable pipeline of opportunities in both solar and wind. If you go to the American Wind Energy Association database and look at all the power purchase agreements, you will see the potential to double the amount of megawatts that we saw last year.

MR. MARTIN: Is it your sense that the supply of tax equity is elastic enough to meet whatever the demand will be this year?

MR. EBER: There will be enough tax equity. The market continues to expand in terms of number of investors. The active investors continue to increase the amount of tax equity they are prepared to invest.

Tax equity volume in renewables was $6.5 billion in 2013, up $1 billion from the year before.

MR. MARTIN: Lance Markowitz, yields have remained remarkably stable over the last three years. Where are they currently for wind, utility-scale solar and rooftop solar?

MR. MARKOWITZ: The concept of flip yield is misleading, but you are correct that they have been fairly stable in the wind market. They range between 50 basis points above or below 8% after tax on unlevered transactions.

We have seen a lot of diversity in utility-scale solar. They have been the most aggressively bid transactions, so yields in that market are a little lower than for the benchmark wind deals. Utility-scale solar has an investment tax credit as opposed to wind and production tax credits. People bid those differently. As for rooftop solar, yields tend to be higher than for wind, but no more than 50 basis points higher. We have seen really strong rooftop deals whose yields are well above wind.

MR. MARTIN: So rooftop solar is around 9%?

MR. MARKOWITZ: We have not done a ton of rooftop solar, but we have seen many different pricing files. Pricing depends on what the parties are trying to accomplish. We have seen ranges of a couple hundred basis points due solely to the way the transaction is structured.

MR. MARTIN: John Eber, how many active tax equity investors are there currently? Do you have a breakdown between wind and solar?

MR. EBER: There are roughly 25 active investors between the two markets. Of the 25, 13 invested last year in wind. There were more than 20 investors in the large-ticket end of the solar market.

MR. MARTIN: How far forward will tax equity commit?

MR. EBER: Most equity investors will make a forward commitment of no more than a year. That seems to work for the market. Last year, it was a little different in the wind market with the rule that wind farms had to be under construction by year end to qualify for tax credits. There were more sponsors looking for longer forward commitments than we had seen in a while, so there were a number of us that provided commitments longer than a year, but that is atypical. A year seems to work for the residential solar space. Many of our residential solar clients are looking to raise tax equity within a six- to 12-month time frame.

MR. MARTIN: Is the wind market purely a production tax credit market at this stage due to increasing turbine efficiency?

MR. MARKOWITZ: Yes. I am certain there are a few anomalies, but pretty much everything we see today involves production tax credits.

MR. MARTIN: Pay-go structures appear to have made a comeback. In a pay-go structure, the tax equity investor puts in its tax equity over time as the tax credits are earned. Why the revival? Is tax equity provided through a pay-go structure more expensive than where the entire tax equity investment is made at inception?

MR. EBER: Pay-go structures have always been popular. We have been using the structure since we started investing. They work well for deals where the financing is already in place, but the sponsor wants to monetize the remaining production tax credits. They work well for deals that are more risky than average; the pay-go feature can help reduce the risk to the tax equity investor, allowing the investor to commit tax equity to a deal he might not otherwise do. The IRS partnership flip guidelines allow up to 25% of the tax equity investment to be paid in over time as a percentage of output or production tax credits.

The tax equity costs the same. The pay-go feature brings the risk of the investment more in line with a traditional deal. Once you get it risk adjusted using the pay-go feature, then you don't need to seek additional yield.

MR. MARTIN: As solar projects get larger, they are more likely to need debt as well as tax equity. Yet, tax equity investors doing partnership flip transactions have not been keen on having lenders at the partnership level. Is this changing?

MR. MARKOWITZ: The preference to avoid partnership-level debt is not changing, but, that said, some leveraged flip deals are getting done. Looking at our own portfolio, we were involved in six deals in the last 18 months that required more than $400 million in tax equity, and none of them had leverage.

MR. MARTIN: Is JPMorgan more willing today to do leveraged flip deals?

MR. EBER: We have done some in the past. Fewer than 10% of the deals we have done over the last decade had any debt at the project or partnership level.

MR. MARTIN: Is there anything special about investment credit deals, which is what the solar market is, that makes it harder to do a partnership flip transaction or to combine tax equity with debt?

MR. EBER: No. They are just a very different type of deal, so they will appeal to different investors. The majority of the tax benefit comes at inception rather than being spread over 10 years as it is in a deal with production tax credits. ITC deals have a different income pattern and a much faster payback. They require a lot more tax capacity immediately for a comparable amount of equipment value from the investor, as compared to being able to spread the tax capacity over 10 years.

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dollar amount for the value of physical work that had to be done in 2013, although a miniscule effort like $100 of work on a large project would call into question whether work really started.

Unless the work completed in 2013 is itself a significant task, the contractor should continue working into 2014 on the task until it is completed.

The view of the senior technical reviewer in Washington who will review disputes on audit is that turbine excavations alone are not enough. Tax counsel holding a contrary view point to a statement in IRS guidelines on starting construction that "physical work a significant nature begins with the beginning of the excavation for the foundation. . . ."

There are two ways to have started construction in 2013. One is to have started physical work of a significant nature, and the other is to have "incurred" at least 5% of the total project cost in 2013.

Projects that relied on the physical work test must complete the projects by 2015 or be able to show "continuous construction" after 2013 on the project. This may be hard to do for wind farms on land.

Developers who incurred at least 5% of the project cost by 2013 must show "continuous efforts" on any project that will not be completed until after 2015. This may be possible to do. The "continuous efforts" requirement contemplates that a project may still be under development. However, there is a misconception in the market that it is enough to do one task a month. This view is not shared by IRS officials in Washington. The IRS may also have a problem with artificially stretching out or "slow walking" the development process.

In general, the development team should ask every Monday what can be done to advance the project that week and keep logs showing what was done on a week-by-week basis. Delays are acceptable if due to events that are outside the developer's control. For example, a developer may back up from when the interconnecting utility will be ready to start accepting power from the project to determine / continued page 5

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We like both types of investments, but there are some investors who are more comfortable with one or the other because of their particular tax positions.

MR. MARTIN: One of the difficult issues when you combine debt with tax equity is that tax equity investors want the lenders to agree to forebear from taking the assets after a debt default until the tax equity can reach its yield. The lenders can step in and replace the sponsor in the meantime. There used to be a "market" approach to forbearance, but that seems to have collapsed lately. There are deals that have not gone forward because of forbearance issues. Is it your sense that whatever market consensus there was has now disappeared?

MR. MARKOWITZ: Yes, although I don't know whether there was ever really a consensus. Over the years, the transactions that took the longest to close were the ones that bogged down over debt and equity issues.

MR. EBER: The consensus was that there were one or two banks that understood the issue and were willing to agree to forbearance. There was never a broad market consensus regarding forbearance, which is why the tax equity market remains dominated by deals that do not have debt at the project or partnership level.

MR. MARTIN: How much is the current yield premium when there is project- or partnership-level debt?

MR. MARKOWITZ: The yield will move up to the low teens to mid-teens, depending on the transaction.

MR. MARTIN: The federal bank regulators came out in late December with a definition of "covered funds" under the Volcker rule. National banks cannot invest in covered funds. Have you been advised by your bank regulatory counsel that the Volcker rule, as the federal bank regulators have now implemented it, will affect your ability to continue making tax equity investments?

MR. MARKOWITZ: I have not. We continue to make such investments and expect to be able to continue doing so.

MR. MARTIN: Wind, landfill gas, biomass, and geothermal projects had to be under construction by December 2013 to qualify for federal tax credits. There are two ways to start construction. One was for the sponsor to "incur" at least 5% of the project cost by the end of 2013. The other was for the sponsor to have started physical work of a significant nature on the project. It does not appear that much physical work was required in 2013. Are you willing to rely at this point on the physical work test?

MR. EBER: We expect to be able to do that. That said, we have not seen many examples of it yet, so we are still feeling our way about where to draw lines. Hopefully when clients bring deals to us, the physical work will be well documented and will be significant enough to fit within the parameters we think the Treasury and the IRS will use to draw lines.

MR. MARTIN: What do you think is the minimum physical work required?

MR. EBER: That's a hard question to answer. It will come down to facts and circumstances. We will make decisions based on what IRS guidance has been issued to date.

MR. MARTIN: In late December, the IRS released new guidelines on tax equity transactions involving tax credits for rehabilitating buildings. Has this so-called Historic Boardwalk guidance had an effect on how you are structuring deals in the renewable energy sector?

MR. MARKOWITZ: No, but I understand that there are a few general principles behind that guidance that people will at least pause to think about when doing future deals.

Bank Debt

MR. MARTIN: Tom Emmons, was the big story in 2013 that the banks are back as project finance lenders? The North American project finance bank market was $40 billion in 2011 and roughly only $24 to $25 billion in 2012. Do you have a figure yet for 2013?

MR. EMMONS: That number is hard to pin down, because there are several databases, they don't have standard criteria and some tallies have not been published yet. I think the consensus is that 2013 was up over 2012. Some of the databases suggest it was up around 20%.

What is more interesting is to look at the sub-sectors within project finance. Oil and gas and conventional power seem to be up. Renewable energy seems to be flat or down.

MR. MARTIN: How many active banks were there in 2013? How many do you expect in 2014?

MR. EMMONS: There were around 40 or 50 in 2012. I expect the final tallies to show roughly 10 more in 2013. There should be even a few more in 2014. We are seeing some US regional banks, smaller Canadian banks and even some northern European and Nordic banks coming in.

MR. MARTIN: Rich Randall, one would think a large number of returning banks would mean downward pressure on margins. Was there? What is the current spread above LIBOR for interest rates? Where do you see it headed in 2014?

MR. RANDALL: For bank deals, the average is probably around 200 basis points over LIBOR. I think there is a lot of downward pressure. We are starting to see some pricing go below 200 on some new deals. With the additional liquidity coming into the market, the downward pressure will continue.

MR. EMMONS: There is a large range in pricing. Pricing has softened over the last year, but I think most of that softening is with large straightforward deals with strong sponsors. The pricing on smaller complex deals has not moved as much.

MR. FINCH: The commercial bank market is the one market where a relationship matters, so unlike all the capital markets, if there is a strong relationship between the sponsor and bank, then the loan will be priced at a discount, regardless of the cost.

MR. WOOD: What we are talking about is deals within a narrow band of risk. There is an implied strong to mid-BB rating, if not higher. While the high-yield market, the institutional term loan market and the commercial bank market are much more liquid than they have been in years, they are still interested only in the low-risk deals.

MR. MARTIN: Current yields are 200 basis points over LIBOR, with some downward pressure. Is there a LIBOR floor tied to the cost of funding and, if so, what is it?

MR. RANDALL: Not in the bank deals. The bank market does not require a floor. However, we are seeing LIBOR floors in the institutional loan market of around 1%.

MR. FINCH: The reason for the LIBOR floor was that when rates were falling, institutional investors were trying to preserve some yield, and so they set a minimum rate to which the spread was added. That is a bit of a legacy that will disappear rapidly in a market where interest rates overall are expected to rise.

MR. MARTIN: What does 200 basis points over LIBOR translate into as a coupon rate?

MR. EMMONS: The six-month swapped LIBOR is around 3.25%, so you add 2% to that. There are often step ups over time for longer deals, but the rate is well under 6%.

MR. MARTIN: How much would you expect the rate to step up ultimately for a 10-year deal?

MR. EMMONS: It goes up typically by an eighth or a quarter percent every three or four years.

MR. MARTIN: What are current upfront fees?

MR. EMMONS: They vary with tenor and other factors, but they are often the same as the starting margin, so in the low 2% range. / continued page 6

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when to mobilize the construction crew on the site. This assumes the developer did not wait until 2015 to sign the interconnection agreement. It should work diligently in the meantime to put the project in a position to start work at the site.

The US Tax Court said in a case called *Caltex Oil Services* in early 2013 that costs for services are not "incurred" until the full service contract has been performed. The case involved a drilling contractor who signed a contract to drill wells. The costs of the wells were not considered incurred until the drilling contract was completed.

The IRS released a "field service advice" to an IRS agent in January that went in the other direction. The agent was auditing a company that claimed a 50% depreciation bonus on parts of a casino, hotel, restaurant and convention center project. A bonus could not be claimed if the developer "incurred" more than 10% of the project cost before 2008. The developer argued that none of the cost was incurred until the project was completed because the contractor it hired built the project under a turnkey contract where the contractor is responsible for turning over the project in ready-to-use condition. The IRS disagreed. The contract was not a turnkey contract, the IRS said, and costs were incurred as the developer made progress payments to the contractor. The contract said that title to the work in progress passed to the developer as such payments were made. The memo is Field Service Advice 20140202F.

Tax equity investors and lenders had shown a clear preference last year for projects that start work under the 5% test. However, they now appear willing to rely on the physical work test in cases with strong facts.

The IRS is willing to issue private letter rulings about construction-start issues, but only on purely legal questions. It has at least two ruling requests pending, and a third is expected to be filed in mid-February.

Grandfather rights to tax credits carry over where a developer sells a project on which it started construction in / continued page 7

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MR. MARTIN: We have read a lot recently about manipulation of LIBOR by banks and potential criminal prosecutions. Is the market moving away from LIBOR as a benchmark or is it just adjusting how LIBOR is calculated?

MR. FINCH: LIBOR remains the benchmark.

MR. MARTIN: Bank loans seemed to shorten in 2012 to seven to 10 years with mini-perm features. Where are they today?

MR. RANDALL: Seven to 10 years is still the norm. Institutions like ours have the ability to go longer, and that is where we are trying to fit into the market. We see a subset of banks, particularly the Japanese, that are willing to go as long as 15 to 18 years.

Bank spreads are 200 basis points over LIBOR, trending down as more banks return to the market.

MR. WOOD: I think the commercial banks have wanted to keep it shorter for return-on-capital reasons. There has been a big institutional bid for the longer-dated piece. We have seen banks come in jointly with pension funds or other institutional investors so that the sponsor can get the duration it wants by leaning on banks for the shorter piece and institutional money for the longer piece.

MR. MARTIN: Tom Emmons, last year on this call you said, "The shortening of tenors is creating opportunities for institutional lenders and they have been stepping up. I think it is a permanent shift." Do you still stand by that view?

MR. EMMONS: Yes. As mentioned, I think banks still want to keep their legal maturities under 10 years so borrowers are given the choice of doing a mini-perm with a commercial bank or going long-term fixed in the institutional market. Many borrowers are electing to go long-term fixed. The numbers in the institutional debt market were up last year as well.

MR. MARTIN: What are debt service coverage ratios currently for contracted wind and solar projects?

MR. EMMONS: Wind may be mid-1.40x, and solar is mid-1.30x.

MR. MARTIN: What about new gas-fired power plants?

MR. WOOD: There are not too many of those that come with the same long-term offtake contracts, so it is difficult to say. You tend to have amortization over the contract period, and you are really solving for the merchant loan-to-value. That is how the rating agencies and institutional investors evaluate how much debt gas-fired projects can support.

MR. FINCH: Ultimately, you can get coverage ratios for gas-fired power plants down to 1.0x through the offtake contract period, if the market believes that the project is truly contracted with a creditworthy offtaker. However, the devil is in the details at the maturity of the loan. Does the merchant component of the power plant provide sufficient coverage to merit the investment? That coverage will be higher than 1.0x.

MR. WOOD: A lot of gas deals will have a percentage cash sweep of all available cash flow, anywhere from 50% to 100%. There is a coverage ratio for the mandatory amortization, which tends to be pretty light, and then there is a cash sweep.

Merchant Deals

MR. MARTIN: Every plant has a merchant tail after a power contract runs out. Does the debt need to be shorter than the power contract?

MR. FINCH: No. Merchant is defined regionally. Merchant in ERCOT is different than merchant in PJM.

MR. MARTIN: What would a coverage ratio be for a merchant plant with a power hedge in ERCOT?

MR. FINCH: It depends on how long the tail is when the loan matures, but the power hedge usually lasts longer than the debt is expected to remain outstanding.

MR. PRABHU: One other factor to keep in mind as you get to the maturity of a term loan B is the loan-to-value. One of the other metrics investors have been using is the out-year value that would be assigned by the M&A market and trying to understand what kind of loan-to-value you have in the base case and downside scenarios.

MR. WOOD: Lenders are assuming a value well below the total capital cost of a new build. This is yet another reason why we are not seeing a lot of new construction. We have seen some in ERCOT and in other places where people have long-term contracts. There is a firm bid for merchant generation, but at a sizable discount to new entry capital costs.

MR. MARTIN: What percentage of project costs can be financed under a construction loan in the bank market?

MR. EMMONS: It depends on the bridgeable capital inflows coming in at the end of construction, and it also depends on each lender's policy for debt ratios, but it could be as high as 80% to 90%.

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

MR. EMMONS: In renewable energy, they are mostly club deals. The deals are pretty straightforward, and the borrowers do not require underwriting.

MR. RANDALL: On other transactions, we tend to use institutional markets interchangeably with commercial bank markets. Although it is the same product, there is a different risk appetite among lenders in the two markets.

For the larger deals that need underwriting, to the extent that there is sufficient relationship pull through the sponsor, banks are more than happy to provide significant underwritings to those transactions.

MR. WOOD: The liquidity in these markets lets the relationship banks make an underwriting commitment and have a high degree of comfort that there will be a decent takeout, even if the primary form of takeout falls away. There are so many other secondary forms of takeout with more institutions willing to step in. We have seen some one-off transactions where one bank acted as a bridge lender where time was of the essence and earned an exceptional return for the takeout risk, but it is not the norm.

MR. MARTIN: We talked a little about merchant projects. They were another big story in 2013. Gas-fired power plants and some wind deals were financed on a merchant basis in PJM and ERCOT. Were all these deals done in the term loan B market? Are banks getting more comfortable with merchant deals?

MR. RANDALL: It depends on the market. PJM is where most of the activity occurs. It is the most mature and transparent market, and the easiest in which to get a deal done. The supply-demand economics work well.

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time to another developer. It is not clear they carry over where a developer with 2013 equipment buys a project in 2014 from another developer who did not start construction in time and uses the 2013 equipment in the project. Until the IRS rules on this fact pattern, the best approach in such cases is for the two developers to form a joint venture to own the project. Each would have an interest in the joint venture commensurate with the value it brings to the joint venture.

A SINGLE CLEAN ENERGY TAX CREDIT would be created by combining eight existing tax credits for generating electricity under a draft bill that the Senate tax-writing committee staff released in December.

The proposal is one of several discussion drafts that the staff released late last year to show what the committee was considering including in a revamped corporate income tax code. Its future is unclear. In January, the committee chairman, Max Baucus (D-Montana), was named US ambassador to China. Baucus left in February to take up the post in Beijing. Corporate tax reform seems dead this year. However, there were rumors in Washington as the *NewsWire* went to print that the House tax-writing committee chairman, Dave Camp (R-Michigan), plans to press forward by releasing the full text of a comprehensive corporate tax reform bill by early spring.

The bill would combine all existing tax credits for generating electricity into a single clean energy credit that could be taken as production tax credits of 2.3¢ a kWh over 10 years on the electricity output or as a 20% investment tax credit in the year a project is completed. The credit would apply to new projects put in service after 2016. The production tax credit amount would be adjusted for inflation after 2013.

The full credits could only be claimed on projects with zero carbon dioxide emissions. Projects that emit between 1 and 372 grams of CO_2 equivalent per kWh would qualify for reduced credits. The credit amount would be reduced linearly across

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MR. MARTIN: Will banks get comfortable with merchant deals?

MR. EMMONS: I prefer to call deals either contracted or uncontracted. Contracted can mean a power purchase agreement or a hedge with a strong counterparty. Commercial banks typically lend against contracted cash flow, whether under a PPA or a hedge with a strong counterparty. There is no magic minimum number of years for a hedge, but shorter hedges support less debt, and the balance has to come from equity or junior debt.

MR. WOOD: All but possibly one "merchant" deal over the last 12 to 18 months has involved a power hedge. A counterparty agrees to a fixed-price offtake for 10 to 12 years off of a P90 wind resource scenario. It may even be a lighter production estimate than in the peak summer months, given the volatility in ERCOT.

Most such merchant wind deals have been in ERCOT. The load-serving entities have little interest in signing long-term contracts. There are anywhere from 2,000 to 4,000 megawatts under construction or being planned. Most of the projects have power hedges, the banks are coming in for construction debt, and tax equity has been available. A handful of players are providing the hedges. It will be interesting to see how the current discussions in Washington among the federal bank regulatory agencies about the extent to which banks should be allowed to trade commodities will affect Wall Street's ability to continue providing those hedges.

The same type of coverage ratios apply to deals with power hedges. The banks plan to be taken out with the tax equity or back leverage at the end of construction.

MR. MARTIN: Raya Prabhu, Goldman Sachs led many of the most prominent recent financings of merchant gas-fired power plants in the term loan B market. Do you see merchant gas as an expanding market?

MR. PRABHU: The bulk of the activity will remain in PJM and ERCOT. That is largely driven by the fact that these are mature markets with very strong underlying power fundamentals. Other drivers have been the low cost of natural gas and the expected coal retirements over the next few years.

We led most of the projects in the term loan B market this past year. We found a great reception to them from a wide range of investors. A lot of that was driven by tightening yields and spreads for operating assets. People who are looking for total return are moving to riskier asset classes, like project financings.

Term Loan B

MR. MARTIN: Term loan B debt is papered like bank debt, but it is sold to institutional investors looking for yield. It tends to be used to finance projects riskier than one might be able to finance in the regular bank market. Any idea what the term loan B volume was last year?

MR. FINCH: Rather than being papered like bank debt, I would say it is bank debt. You are simply selling it to different investor groups. Whether the buyer is a commercial bank or an institutional investor, it is still a bank loan. It is particularly attractive in a rising interest rate environment.

Last year, there were about $455 billion of B loan issuances, and that was an all-time record. The previous record was in 2007 at $387 billion. Money continues to flow into the term loan B market to the tune of about $750 million to $1 billion a week. As you see a lack of new M&A-driven issuances, investors are looking for new places to invest money. Project financing is becoming more and more attractive to them as they become more familiar with the construct and the risks they are being asked to take.

MR. MARTIN: Last year, this panel estimated that the combined term loan B and project bond market for North American project finance in the power sector was about $4 to $5 billion. Is there a comparable breakdown for 2013?

MR. PRABHU: Focusing strictly on the term loan B market for greenfield projects, I would venture to say that in 2013, between the various ERCOT and PJM financings and other deals, the figure was probably in the $2 to $3 billion range. We have not seen a lot of greenfield project financings in this subsector of the market. Most deals have been quasi-merchant.

MR. WOOD: One thing that hurts the project bond market is that banks are so comfortable with solar and wind projects that benefit from the 12- to 20-year PPAs that the loan-to-value, spread above LIBOR and the flexibility of being able to call at par is of greater value to sponsors than going to a non-call, long-duration project bond that has to be rated by both rating agencies and that locks them into a fixed yield.

Sponsors are more likely to move to project bonds if they are concerned about rising interest rates. That said, the fact that all the other markets are so wide open and relatively aggressive on pricing has made for less volume in the project bond market.

MR. MARTIN: B loans price off LIBOR, just like bank debt. How do margins compare for B loans to bank debt?

MR. PRABHU: It depends on the credit quality of the underlying asset. We have seen yields in the term loan B market price for strong BBs and higher as high as 275 basis points above LIBOR, with a 1% LIBOR floor and one point of original issue discount.

That is at the tight end of what we have seen. On the wide end as you move further down the credit quality spectrum and into single B territory, you see deals price as wide as 500 to 550 basis points over.

MR. MARTIN: What about upfront fees, tenors and coverage ratios? Are they the same as in the bank market?

MR. PRABHU: On tenors, we have seen a pretty stable market that has gravitated toward seven years as the maximum tenor.

In terms of upfront fees, we have seen a compression as the year has progressed. That is due largely to demand exceeding supply. We continue to expect that pressure in 2014, but I would say in 2013 you had anywhere from half a point to a point of upfront fees.

In terms of coverage ratios, the market is focused on both debt-to-EBITDA as a metric for initial financings and a debt service coverage ratio over the life of the asset. We have seen debt service coverage ratios close to 2.0x at closing of a financing, and then obviously increasing as the debt gets swept over the life of the loan.

MR. MARTIN: The B loan market does not like construction risk. It does not allow for delayed draws, so you end up with negative arbitrage during construction. Are there other differences between the B loan and bank markets?

MR. FINCH: These are all loans, so you consult an institutional or a commercial bank. Commercial banks tend to operate within a very narrowly defined low-risk area. Based on that and the relationship that they have with the sponsor, the first priority is the cost of capital. If it is a club deal, then the bank is focused on booking the asset on its balance sheet. It does not account for the loan on a mark-to-market basis, so it just needs to be earning a basic spread.

The B market tends to price risk across the spectrum from a high-risk project to a low-risk project. It also factors in where the pricing is in the secondary market. The secondary market is on mark-to-market accounting.

The result is that the spread can vary tremendously for any given quantum of risk based on where / *continued page 10*

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the CO_2 range in 1¢ increments for production tax credits and 1% increments for investment credits.

Wind, solar, nuclear, landfill gas and hydroelectric projects would qualify for full credits. Geothermal projects would probably qualify for production tax credits of 2.2¢ a kWh and a 19% investment credit. A typical wood-fired power plant might qualify for PTCs of 2¢ a kWh and a 17% ITC, while a power plant running on 60% digester gas and 40% natural gas might qualify for PTCs of 1.5¢ a kWh and a 13% ITC.

If the actual emissions prove worse than the anticipated emissions used to calculate the credit, then any investment credit claimed would be subject to partial recapture. The basis on which depreciation claimed would have to be reduced by the full investment credit claimed, according to a write up by the Joint Tax Committee staff.

Any CO_2 captured and sequestered would not be considered emitted. CO_2 emissions for biomass projects would be the net emissions.

The credit would phase out over three years starting the year after the Environmental Protection Agency advises that the annual average greenhouse gas emissions rate for electricity production in the United States is 372 grams or less of CO_2 per kWh. Projects placed in service in the first year of the phase out would qualify for tax credits at 75% of the original level, 50% for projects placed in service the next year, and 25% if placed in service in the third year. Projects that were in service before the phase out would still be able to claim 10 years of PTCs at the full level.

An investment tax credit could be claimed on the cost of carbon sequestration equipment added to power plants that went into service before 2017. However, there would have to be at least a 50% reduction in CO_2 emissions, and the CO_2 would have to be disposed in secure geological storage.

Residential solar credits for homeowners who buy solar systems for generating electricity or producing hot water / *continued page 11*

Cost of Capital

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the risk is being priced in the secondary market. Sometimes the pricing is below the commercial bank cost of that risk, because the market is so hot and there is a lot of liquidity, and sometimes it is above the commercial bank pricing for comparable risk.

The B market does not generally do delayed draws. The B market is a funded market. The investors have raised capital and are sitting on it.

The commercial bank market is a regulated market where a regulator says, based on a commitment, you can put some fraction of your capital against that and, as a result, a commitment is a very efficient way to finance a project and get banks a return on the commitment, because they are not having to put dollar-for-dollar capital against the commitment.

The B market developed because of this. Initially the pro rata market was a revolver term loan A that was sold to commercial banks to deal with the delayed draw aspect. The B market was a funded market that had a longer maturity and no hard amortization, which picked up the riskier part of the commitment.

Project Bonds

MR. MARTIN: Is there more talk of deals in the project bond market this year? Last year, there seemed to be a lot of talk, but not many deals.

MR. WOOD: They are still effectively museum pieces for the reasons we have already articulated. The debt markets are wide open. They are looking for product. Project bonds, high-yield bonds and investment-grade bonds will be there. The project bond market remains open, but we are not projecting as much volume as we are in the term loan B market and commercial bank markets.

MR. MARTIN: Project bonds and tenors can run as long as the power contract, and there are no upfront fees. The economics tend to be fully baked into the spread. Ratings may be required for widely syndicated deals. Make-whole payments will be required if the bonds are repaid ahead of schedule with the make-whole calculated as the remaining payments due under the debt instrument discounted at the current Treasury rate, plus 50 basis points. The project bond market will take construction risk, but charge a commitment fee on undrawn capital.

Do you see other differences besides these between the bank and B loan market versus project bonds?

MR. WOOD: Project bonds are fixed-rate loans versus floating-rate loans in the bank and B loan markets. Just as with the B loan market, you need to pay the rating agencies, and there is a gross spread or an underwriting fee upfront to the extent the issue is not directly placed.

MR. MARTIN: We heard last year that there were 20 to 25 institutions in 2012 willing to buy project bonds. Do you think it will be the same number in 2014?

MR. FINCH: It will be significantly greater. You will see a lot more institutional investors prepared to play in the project bond market because there are not enough other places to put the money.

MR. MARTIN: Project bonds are priced off Treasury bonds. What is the current spread above Treasuries? What does this translate into as a coupon rate?

MR. PRABHU: A lot of these project bonds are being done for investment-grade projects, so BBB-minus or better, and at that end of the spectrum, we have seen all-in rates of about 5.5% to 6%.

There have been a few deals that have been done sub-investment grade, but even those I would qualify as being strong BB if not better. They have a premium attached to them. It is tough to give a spread, as it depends on the interpolated Treasury rate and the weighted average life of the underlying project bonds.

We have not really seen rates creep much below 5.5%. Depending on the credit quality, the rate could be north of 6%. ◎

Changes Ahead For California Residential Solar

by Laura Norin, Heather Mehta and Julia Getchell with MRW & Associates, LLC, in Oakland

Two looming regulatory developments in California will have a significant effect on the residential solar market.

The state is rewriting the rules for net metering, where homeowners who use solar to generate their own electricity can sell any excess electricity to the grid. The rewrite is expected to scale back the benefits of net metering for solar customers.

The current multi-tiered residential rate structure used by investor-owned utilities in the state, which has been an important driver of the economics of solar for high-usage customers, is being re-evaluated and is likely to undergo substantial change or to be superseded by a new structure entirely.

These developments are likely to make California a tougher market for rooftop solar companies. However, the market should still remain viable, and there could even be new opportunities.

Net Metering

California has long supported behind-the-meter residential solar electric generation through net metering, which allows customers to sell surplus solar power back to the utility at the full retail value of the electricity. Net metering was instituted in California in 1996 and has been expanded several times over the years to allow for wider participation and greater benefits.

Under the existing net metering program, the amount of net-metered capacity that can be added for each investor-owned utility is capped at 5% of the utility's aggregate customer peak demand, which is defined as the sum of the maximum peak demands for each customer rather than the maximum demand for the utility as a whole.

When the cap is reached, there will be approximately 5,570 megawatts of installed solar capacity across the systems of the three California investor-owned utilities. At the end of September 2013, Pacific Gas and Electric reported that it had 902 megawatts of net-metered capacity connected to its system, which is the equivalent of 1.87% of the utility's aggregate customer peak demand. */ continued page 12*

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would be allowed to expire. This would give a boost to solar rooftop companies that retain ownership of systems and lease them or sell electricity from them to homeowners.

The draft bill would also eliminate investment tax credits for solar heating and cooling systems put to business use.

Wind and other projects that qualify for tax credits under current law because they were under construction by December 2013 would be given a deadline to complete the projects. There is none currently. The deadline would be the end of 2016.

PRIVATE EQUITY FUND MONITORING FEES come under fire.

Gregg Polsky, a law professor at the University of North Carolina, took aim at monitoring fees paid to private equity funds by their portfolio companies in an article in *Tax Notes* magazine in early February.

Polsky is representing a whistleblower who has called some such fees to the IRS' attention. The fees are paid under ongoing consulting agreements.

Polsky says either no work is done or the fees exceed what a third party would charge for the same services or they are a percentage of earnings or are paid out to more than one owner in proportion to the ownership interests. The last two features suggest the fees are dividends. Polsky says he and associates examined 229 portfolio companies owned by private equity funds and identified $3.9 billion in questionable monitoring fees paid from 2008 to 2012.

Polsky wrote another article in 2009 criticizing waivers of management fees that he said some private equity funds use to convert ordinary income into capital gains. The IRS is looking into the practice.

A LIKE-KIND EXCHANGE is being litigated.

A predecessor company of Exelon reinvested the proceeds */ continued page 13*

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San Diego Gas and Electric and Southern California Edison had net-metered capacity of 1.67% and 1.46% of aggregate customer peak demand, respectively.

California's net metering program allows a customer who installs a solar photovoltaic system of one megawatt or less to receive a financial credit for power generated by his or her system and delivered to the utility grid. A typical solar customer will generate more solar power than needed during some parts of the day and less than needed, or none at all, during other parts of the day and throughout the night. The same pattern can arise seasonally, often with the generation of more power than needed during the summer and less than needed during the winter.

Under net metering, customers can send excess power to the grid and use this power as a credit to offset purchases of power from the grid that are made in the same 12-month period.

For a customer whose rates are wholly volumetric, meaning that the customer is charged for the kilowatt hours of usage without any fixed charges or demand charges, as is the case for customers of PG&E and SDG&E, this allows the customer to sell power back to the utility at the full retail rate for the power, including all generation, transmission and distribution cost components. Aside from small minimum charges, which are binding only for customers with extremely low net usage, these customers can avoid having to pay electric bills by selling back enough solar power to offset all grid purchases.

Customers who generate enough solar power to more than offset all grid purchases can also receive net surplus compensation payments, but at the wholesale rate — rather than retail rate — for the surplus power generation.

Impact of Rates

Net metering has worked hand in hand with residential rate design structures to make solar PV economical for many customers, particularly high-usage customers. Most of California's residential customers have inclining block rates, with prices increasing over two, three or four tiers of rates as usage increases. Net metering is particularly valuable for high-usage customers because it allows them to avoid being pushed into higher tiers and rates.

For example, the January 2014 rates under PG&E's default residential rate schedule were 13¢ per kWh for "baseline" usage, 15¢ per kWh for 100% to 130% of the baseline amount, and more than 32¢ per kWh for usage greater than 130% of baseline amount. In other words, rates for highest levels of energy usage are about two and a half times the rate for the baseline level of usage. (The amount of energy in each tier is linked to the customer's "baseline" usage amount, which is set at 50% to 70% of the average residential electricity usage in the customer's climate zone.)

Two looming regulatory developments in California will affect the residential solar market.

The steeply inclining block structure greatly increases the value of net metering for high-usage customers, and these customers have represented a significant portion of the market for residential solar in California. Under the January 2014 rates, a high-usage PG&E customer whose solar system reduces electricity consumption from 200% of baseline to 130% of baseline has effectively sold power to the utility at a rate of 32¢ per kWh. By contrast, a low-usage customer whose energy usage without solar PV is at 130% of baseline would sell power to the utility at just 13¢ to 15¢ per kWh.

Customers also have the option to select a time-of-use rate schedule, under which rates are higher during peak periods of the day and during the summer months and lower at night and during other low-usage periods. These rate schedules are usually tiered, meaning that rates vary both by time of consumption and by level of consumption. For customers on time-of-use rate schedules, net metering credits are assigned a value based on the retail cost of power in place at the time of the power generation.

As a result, solar power generated during a summer late afternoon may offset two to three times that amount of winter or nighttime power consumption. For example, under January 2014 rates, one kWh of solar power sent to the PG&E grid between 1 p.m. and 7 p.m. on a summer weekday would earn a credit of 28.7¢, which is the summer peak-period residential time-of-use charge for one kWh of baseline usage. During the summer months between 9 p.m. and 10 a.m., this credit would offset 2.85 kWh of power, since the baseline cost of power is just 10.1¢ per kWh during this interval.

Concerns that the net metering program was shifting costs to customers who do not have solar on their roofs led to legislation requiring a study of net metering's costs and benefits for all ratepayers. AB 2514, enacted in 2012, directed the California Public Utilities Commission to undertake a study "to determine who benefits from, and who bears the economic burden, if any, of, the net energy metering program."

The study was completed in October 2013 by an outside consultant, Energy and Environmental Economics, Inc.

The study found that the level of the net metering subsidy is highly linked to the rate structure and that the utilities' current residential rate structures, with steeply inclining block rates and little or no fixed charges, yield a subsidy of 20¢ per kWh of solar generation.

Critics of the study claim the study does not account for the full benefits that solar PV provides to the grid and overstates the cost-shifting impacts. Despite the criticism, the study is being used to support proposals for changes in the residential rate structures of the three main California utilities.

New Direction

In the fall 2013, the state legislature enacted another bill, AB 327, that will end the current net metering structure in mid-2017 or, if earlier, when net-metered systems reach 5% of a utility's aggregate customer peak demand. AB 327 requires the California Public Utilities Commission to develop a new "standard contract or tariff, which may include net metering" for solar customers, to replace each utility's current net metering structure when the current program expires.

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from sales of two power plants in Illinois in three other power plants in Texas and Georgia in what the company treated as a "like-kind exchange."

The IRS disagreed, and the issues are now in front of the US Tax Court. Exelon filed a petition in January. The IRS says the company owes $517.4 million on the transaction, plus another $6.6 million for the next tax year after the sale.

Ordinarily, anyone selling a project can defer taxes on the gain from sale by using a bank as a "qualified intermediary" to reinvest the sales proceeds in similar property. The proceeds are paid to the bank. The seller then has 45 days to let the bank know where it wants the money reinvested. The reinvestment must be completed within 180 days or, if earlier, the due date for the tax return for the year in which the original projects were sold (including extensions).

The replacement power plant can be a new power plant that the seller is building.

An Exelon subsidiary, Commonwealth Edison, agreed in March 1999 to sell Edison Mission Energy seven base-load power plants and five peaking units as part of utility deregulation in Illinois. Commonwealth Edison was a subsidiary at the time of Unicorn Corporation. Exelon was formed in a merger of Unicorn and PECO Energy Company in October 2000.

Two of the plants were ultimately sold to Edison Mission Energy on December 15, 1999 in a deferred like-kind exchange using State Street Bank as the qualified intermediary. The two plants were Powerton and Collins.

Powerton is a 1,538-megawatt coal-fired power plant in Pekin, Illinois. It sold for $930 million. Collins was 2,698 megawatts and had a dual capacity to run on gas or oil. Mission paid $830 million for it. (The Collins plant shut down in 2004.)

Exelon told State Street on January 28, 2000 where it wanted the sales proceeds reinvested. It directed the bank to reinvest $725 million in unit 1 of the J.K. Spruce power station in San Antonio, Texas. The plant was / continued page 15

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Unlike the current structure, the new net metering structure would not have any cap on participation. However, the new net metering program must ensure that no costs are shifted to non-participating customers. Current net metering customers would be grandfathered under the current system for a period of time that has not yet been determined.

The practical effect of the law is that there will soon be two or possibly three distinct sets of net metering customers: one set that will remain under the current program for an indeterminate period of time, another set that will be put under the new program, and a third set that did not have solar when AB 327 was enacted but installs it before the current net metering program ends and that may be under a different set of grandfathering regulations than pre-AB 327 net metering customers.

To implement AB 327, the California Public Utilities Commission must first determine a schedule to transition from the current net metering program to the future uncapped program as well as the rules for grandfathering existing net-metering customers. The CPUC received a range of proposals for how to structure a transition period and the grandfathering rules.

PG&E and SDG&E both proposed that existing net metering customers with solar systems installed before April 2014 be allowed to remain on the current program through the end of 2023. Net metering customers with systems installed between April 2014 and December 2015 would be allowed to remain on the current program through the end of 2020. Net metering customers with systems installed between January 2016 and June 2017 would be transitioned to a new net metering program that would take effect on July 1, 2017.

SCE proposed that customers who participate in the existing net metering program before July 2017 would be grandfathered in the program through the end of 2023.

The California Solar Energy Industries Association recommended a more extensive grandfathering program that would allow customers who participate in the net metering program before July 2017 to remain under the current program for a minimum of 30 years.

The CPUC is expected to issue a decision on grandfathering rules by March 2014.

The commission has until the end of 2015 to develop the new structure for net metering. AB 327 gives the CPUC wide latitude to determine what should replace the current program. Possibilities include a feed-in tariff that allows customers to sell solar power to the utility at a fixed price or a new net metering program that reduces the amount of power that can be sold back to the utility or reduces the financial credit associated with that power.

In all likelihood, the structure of the new program will depend on the default residential rate structure in place when the program rules are adopted. The commission has a rulemaking underway to re-evaluate the current rate structure.

AB 327 gave the CPUC authority to make radical changes to residential rate design, including reducing the number of rate tiers to two through 2018, eliminating the inclining block rate structure entirely thereafter, and imposing fixed monthly charges of up to $10 per month for non-low-income customers beginning in 2015, with inflation adjustments thereafter.

A CPUC staff proposal released in January 2014 recommends that default residential rates shift from inclining block rates to non-tiered time-of-use rates beginning in 2018, and that until then the CPUC reassess the appropriate time-of-use period definitions — for example, what hours and months should be included in the summer peak rate period — and the rate differentials between time-of-use periods — for example, how much higher the summer peak-period rate should be than the summer off-peak-period rate. The proposal also recommends gradually reducing the number of tiers to two between 2014 and 2018, and greatly reducing the rate differentials between the tiers to just 20% by 2018, at which time the tiered rates would be an optional alternative to the default time-of-use rates. Finally, the staff recommends phasing in a fixed charge that would start at $5 a month and increase to $10 a month by 2018 with future inflation adjustments. The staff proposal does not recommend using minimum bills (instead of fixed charges), but if the CPUC were to adopt minimum bills, it recommends that they should start at $10 per month in 2015 and increase with inflation.

These potentially substantial changes to the residential rate design structure create many unknowns for residential solar developers, as the implications of the changes for the market will depend on the details of the new rate structures.

Potential Effects

There are three areas in which changes in residential rate design could alter the market for residential solar.

One is time-of-use rates or inclining block rates. A shift to non-tiered time-of-use rates (from the current default inclining block rates and optional tiered time-of-use rates) may improve the economics of solar PV for moderate usage residential customers with relatively high shares of energy consumption during peak periods. The extent to which this will be the case will depend on the rate differentials between the peak and non-peak periods and on how much overlap the new time-of-use period definitions retain between the peak time-of-use period and the period of maximum solar generation. These structural time-of-use definitions are likely to differ from those in place in the optional time-of-use rates that are currently available, and how they are structured could significantly support or debilitate the market for residential solar.

For example, the current on-peak period for customers on SDG&E's optional residential time-of-use rate is weekdays from noon to 6 p.m., a period that captures about 35% of the output from solar PV systems in the San Diego area. In January 2014, SDG&E proposed to shift the on-peak period in the winter to weekdays from 5 p.m. to 9 p.m., a period when little solar generation can be expected and, in the summer, to weekdays from 2 p.m. to 9 p.m. These new time-of-use periods would lead to a significant reduction in solar PV generation during the peak periods: less than 10% of the output from solar PV systems would occur in the peak period under SDG&E's proposal instead of about 35% under the current definitions, with the remaining output occurring in the semi-peak period.

If large differentials are maintained between on-peak and semi-peak rates, then this shift could undermine solar PV economics for customers on time-of-use rates. However, changes to time-of-use period definitions may not be quite so detrimental to solar PV economics. For example, the CPUC staff report raised an idea of a split on-peak period that would include both morning hours and late afternoon or evening hours. This structure would offset a portion of the loss of mid-afternoon on-peak hours with the addition of morning on-peak hours, which could include hours of high solar generation.

Another area where change could have an effect is a reduction in the rate differentials for inclining block rates. A reduction in the rate differences between tiers would eliminate the very high upper-tier rates that have been a cornerstone of residential solar economics.

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owned by the local municipal utility, the City Public Service Board known as "CPS," and it entered commercial service in December 1992. The transaction closed on June 2, within the 180-day period.

Exelon directed the bank to spend another $870 million to purchase a 15.1% undivided interest in units 1 and 2 of the Wansley power station and a 30.2% undivided interest in units 1 and 2 of the four-unit Scherer power station from the Municipal Electric Authority of Georgia or "MEAG." The Wansley units were completed in 1976 and 1978. All four Scherer units were completed between 1982 and 1986. The Georgia sales closed on June 9.

Both the Texas and Georgia transactions were structured as SILOs. The IRS does not view SILOs as real purchases. Congress effectively shut down their use (as well as cross-border leases called LILOs) in 2004. The IRS issued a notice in 2005 indicating that it considers SILOs a form of tax shelter called a "listed transaction." It had listed LILOs earlier. The government has won all six litigated LILO and SILO cases to date. A seventh case had a 10-day trial before the US Court of Federal Claims, but the court has not yet released a decision. The facts of the Exelon case may differ materially from those in the other cases.

Rather than buy interests in the power plants outright, an Exelon subsidiary entered into sale-leasebacks with the two municipal utilities. The subsidiary was the lessor. CPS leased back its project for 31.75 years and has an option to repurchase the project at the end of the lease for 101.2% of the amount Exelon paid for the plant. If CPS fails to purchase, then Exelon can require it to find a power contract or a tolling agreement for Exelon with a third party for a term of 9.58 years. CPS paid the Exelon lessor 76.9% of the purchase price for the plant as advance rent six months after the lease started. The advance rent is being treated as a "section 467 loan" and reported by Exelon as income over the lease term.

MEAG leased back the Wansley units for 27.75 years and the

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However, reductions to the upper-tier rates would be done concomitantly with increases in the lower-tier rates, potentially making residential solar economic for lower-usage customers whose rates were too low earlier for the investments to pencil out.

The retail electricity rate structure and the benefits from net metering are expected to change.

Finally, another area where change would have an effect is the introduction of fixed charges or higher minimum bills. Fixed monthly charges make residential solar less economic because these charges cannot be avoided through net metering. However, the extent of the impact depends on the level of the charge. Furthermore, if a higher minimum monthly bill is used in place of a fixed monthly charge, then the impact is likely to be less significant, particularly for those customers who offset most, but not all, of their electric bills with solar generation and continue to purchase a small amount of power from the utility. Under a fixed charge, these customers would pay the fixed charge in addition to their volumetric charges. Under a minimum bill, the volumetric charges would be credited against the minimum bill amount.

How the net metering program is restructured will also have a significant effect on the long-run viability of residential solar in California. The restructured program is likely to be less generous than the current program. These very important residential rate design and net metering program details have yet to be worked out.

That said, the California Public Utilities Commission has a goal of maintaining a viable and growing residential solar market in California. It is a daunting task, given the competing interests.

Residential rate structures must be designed to balance a number of equity and efficiency concerns that have implications both for solar and non-solar customers. The grandfathering provisions for customers who installed solar before AB 327 became law must be sufficient to provide confidence to customers who are evaluating new solar installations that their investments will not be undermined through future rate design or net metering changes while also satisfying concerns about cost-shifting. The design of time-of-use periods must be done carefully to provide the proper price signals to consumers while at the same time being sensitive to the potentially significant implications for commercial and industrial customers that have structured operations and entered into investments based on the current time-of-use periods. The restructured net metering program must support the residential solar market without increasing rates for non-solar customers.

Given these challenges and complexities, some amount of market disruption is inevitable.

However, there is also opportunity in that new segments of the residential population may be open to solar for the first time with the shift to non-tiered time-of-use pricing. ◎

Tax Equity Market Weighs New IRS Guidelines

by Keith Martin and John Marciano, in Washington

New guidelines that the Internal Revenue Service issued for tax equity transactions in late December apply only to transactions involving tax credits for rehabilitating buildings, but they are having an effect on refined coal and fixed-flip partnership transactions and eliciting discussion about inverted leases.

The new guidelines reflect three general principles, according to a Treasury source.

The tax equity investor must have entrepreneurial upside potential and downside risk.

There must be variability in the tax equity investor's potential return.

Things should happen consistently with what would happen in a transaction without significant tax benefits — for example, developer and management fees should be the same amounts that would be paid in a non-tax equity deal.

Blurred Photograph

The new guidelines are in Rev. Proc. 2014-12. They are a reaction to a tax equity transaction that a US appeals court set aside in August 2012 in a case called *Historic Boardwalk*. (For earlier coverage, see September 2012 *NewsWire* starting on page 7.)

The new guidelines do not apply to renewable energy or refined coal transactions. The initial reaction of many tax counsel has been that the new rules are so specific to tax credits for rehabilitating buildings that they are unlikely to have much effect on the broader tax equity market. The Treasury and IRS team that wrote them largely agrees, but believes the market cannot help but reflect on some new lines the IRS has drawn.

The guidelines are a mix of bright lines and general principles. The effect of mixing in general principles is like a photograph whose image is clear in the middle of the frame but blurred as one moves away from the center.

Until now, the IRS has had two sets of guidelines for tax equity transactions: a "safe harbor" for partnership flip transactions involving wind farms in Rev. Proc. 2007-65 and advance ruling guidelines for anyone who wants a private letter ruling that a leveraged lease of equipment is / continued page 18

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Scherer units for 30.25 years. It has purchase options to buy back Wansley for 83.4% and Scherer for 88.8% of the original purchase price. If it fails to repurchase, then Exelon can require it to find third parties willing to enter into power contracts or tolling agreements for another 8.1 (Wansley) or 8.7 (Scherer) years. MEAG made an advance rent payment six months after the lease started of 77.7% of the original purchase price for Wansley and 111.1% of the original purchase price for Scherer.

New cases filed with the US Tax Court usually take 23 to 50 months to reach a decision.

SEPARATE HOLDING COMPANIES for key assets like intellectual property or real estate were dealt a blow by an Arizona court.

Home Depot set up a subsidiary in 1999 to hold its trademarks and other brands. The subsidiary then collected royalties from Home Depot for use of the brands. The effect is to shift income to the subsidiary. Such subsidiaries are usually put in lower-tax jurisdictions.

The royalties in this case started at 1.5% of gross sales under a 10-year licensing agreement between the subsidiary and Home Depot, and then increased to 4% of gross sales when the licensing agreement was renewed for another 10 years two years before the original agreement was scheduled to expire.

Home Depot is headquartered in Atlanta, but has stores across the country, including in Arizona.

The Arizona tax authorities said the licensing subsidiary should join with the parent in filing a combined tax return in the state reporting income from the Arizona stores. The state requires affiliated companies with a connection to the state to join in a combined return as a "unitary business" with any company directly doing business in the state.

An Arizona appeals court agreed with the state tax department in a decision in December. The court said unitary treatment is appropriate where there is a "substantial interdependence of basic operations among / continued page 19

Tax Equity

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a "true lease" in Rev. Proc. 2001-28.

The market has generally complied with the wind partnership flip safe harbor.

It has strayed over time from IRS true lease guidelines after deciding that a number of the guidelines are more conservative than what the courts require.

Early indications are that the market may stray from the new Historic Boardwalk guidelines, if only because the photograph is still a little too blurred outside the center. The real test will be over time as the photograph comes more clearly into view.

Dos and Don'ts

Here are the new guidelines and what the Treasury and IRS team that wrote them have said about particular rules.

The tax equity investor must invest at least 20% of its anticipated total investment at inception. Inception means before the building is placed in service. The investor cannot put in less than 20% and then wait to invest the rest until it sees whether the building has been properly renovated. The guidelines do not address situations where a tax equity investor has committed to invest in multiple buildings over time.

New IRS guidelines for tax equity deals are affecting how tax counsel look at some deal structures.

At least 75% of the investor's expected total investment must be fixed in amount. Only 25% can be contingent on future events. The investor must be expected to be able to meet the fixed portion of its funding obligations as they arise. The Treasury and IRS team said this is not a net worth test. It is an intention test.

The sponsor must have at least a 1% interest in income, losses and tax credits. This refers solely to the partnership claiming tax credits. There are two forms of inverted lease in use in the solar rooftop market. In the more conservative form, the sponsor has no interest in the lessee. Since the lessee is not a partnership, such transactions are outside the scope of the new guidelines. The new guidelines are focused on use of partnerships to transfer tax credits.

The investor's partnership interest must have "a reasonably anticipated value commensurate with the Investor's overall percentage interest" apart from tax benefits. Another way of saying this is the sponsor cannot have stripped out the economics, leaving the investor largely with tax benefits and an interest in the remaining economics that is inconsistent with the investor's sharing ratio. For example, suppose the tax equity investor has a 99% interest until a flip date, and 5% thereafter. After stripping out the tax benefits, the investor's interest must have a value commensurate with what someone who cannot use the tax benefits would assign to an interest with those sharing percentages. This is not a pre-tax yield test. The project does not have to be economic absent the tax benefits. It is a general statement that the government does not want to see cash stripped out through developer, management and other fees that are above what a third party would be paid for the same services in a non-tax credit deal or through lease terms in an inverted lease, leaving the investor with little else besides tax benefits and certainly less than what someone with a 99% interest initially and 5% interest later in the business would expect to receive.

The sponsor cannot be distributed a disproportionate amount of cash — for example, it cannot receive all the cash above preferred cash distributions to the tax equity investor. There was a view within the IRS that sharing ratios should be straight up, meaning the partners should share in all income, loss, cash and tax credits in the same ratio before the flip, but that group lost. The position was considered "too constrictive." It is clear that the investor cannot be left with annual cash distributions equal to

2% of the initial capital it contributed. It is clear that a straight-up deal works. Anything beyond that is in the blurred part of the photograph.

If the tax equity investor leases assets in an inverted lease, then it cannot turn around and sublease them to someone else unless the term is shorter than the inverted lease. Some tax counsel have felt uncomfortable with inverted lease deals unless the customer agreements are shorter than the head lease because they want the tax equity investor to have merchant exposure for a period before the head lease ends. They take this position as part of the analysis whether the head lease is a true lease. The new guidelines say the sublease must be shorter than the head lease, but without setting a minimum period for the merchant exposure. It appears the IRS wants the tax equity partner to have some downside risk after the customer agreement ends as part of its analysis whether the tax equity investor is a real partner, but the failure to set a minimum period is peculiar.

A Treasury source cautioned against trying to apply the new guidelines to inverted leases in the solar rooftop market. The Treasury and IRS team did not spend any time thinking about application of the principles in the new guidelines beyond the rehabilitation tax credit fact patterns in which the team was immersed. The team is not familiar enough with the energy world to know whether importing the new guidelines to that world makes sense.

Does that mean that if he were a solar company tax counsel, he would not lose any sleep over the new guidelines? He would not necessarily go that far. It would be useful to test any structure against the three general principles at the start of this article.

Risk Allocation

The sponsor can take some traditional business risks. It can promise to do things that are required for the partnership to be entitled to tax credits and to avoid recapture. It can provide completion guarantees, operating deficit guarantees, environmental indemnities and make financial covenants. However, these guarantees cannot be "funded," meaning the sponsor cannot set aside money or property to ensure payment on the guarantees. Requiring the guarantor to have a minimum net worth is considered funding a guarantee. The sponsor can fund a reserve to cover up to 12 months of reasonably projected partnership operating expenses. However, the sponsor cannot set aside other money or property to / *continued page 20*

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the various affiliates or branches of the business."

It said such treatment is appropriate in this case because the brands are integral to the appeal of Home Depot products. The subsidiary licenses use of the brands only to Home Depot.

Home Depot reported income of $3.8 billion over the three tax years at issue. The licensing subsidiary earned $4.7 billion during the same period. It had only four employees: a lawyer, paralegal and two secretaries. The case is Home Depot U.S.A., Inc. v. Arizona Department of Revenue.

THE VOLCKER RULE does not appear to prevent national banks from supplying tax equity to renewable energy projects structured as partnership flip transactions after federal bank regulators issued final rules on the subject in December.

However, the bank should invest directly in the project company that owns the project or in a holding company one tier up from the project company.

An investment in an entity more than one tier up from the project company could be a problem.

The Volcker rule was enacted in July 2010 as part of the Dodd-Frank Act. It prevents banks with federally-insured deposits and their affiliates from engaging in "proprietary trading" — defined as trading in securities for the bank's own account to benefit from short-term price movements — and from investing in any "covered fund" — which the bank regulators have defined as a subset of entities that would be considered "investment companies" by the US Securities and Exchange Commission. While it is not always clear whether an entity is an "investment company," a company that is engaged directly in an active business or as a holding company whose sole assets are shares or other ownership interests in an active business company is generally not an investment company.

Banks have until July 21, 2015 to restructure or sell any investments that are not permitted under the Volcker rule. / *continued page 21*

Tax Equity

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secure its obligation to pay the guarantee. A parent guarantee is okay. Related parties are treated as the same entity, so the parent guarantee disappears in the analysis.

The sponsor cannot indemnify the tax equity investor against loss of tax credits or guarantee the "cash equivalent of tax credits" if the IRS challenges the transaction structure. The sponsor can enter into a tax indemnity agreement that puts risks on the sponsor that are within the sponsor's control, like when the building is put in service. However, other risks must be borne by the tax equity investor. The sponsor cannot agree to make ongoing capital contributions to the partnership to ensure the partnership will have enough cash to make cash distributions to the tax equity partner. The sponsor cannot pay the tax equity investor's "costs" or indemnify its "costs" if the IRS challenges the tax credits the investor claimed. "Costs" means legal fees and other costs of defending against an IRS challenge. It does not mean the underlying tax liability, penalties or interest.

Neither the sponsor nor the partnership can have a call option to repurchase the investor's interest in the future. The IRS believes that call options have the effect of shaving the investor's residual interest. The investor has a minority partnership interest, so the value will be discounted. The IRS does not want to get into arguments about appropriate discount rates.

The investor can have a "put" to force the sponsor or the partnership to repurchase the interest, as long as the put price is not above fair market value when the put is exercised. The price can be the lesser of a fixed amount and fair market value at time of exercise.

This position on options is such a break with established tax law precedent that it is unlikely to make sponsors forego call options, but it will put pressure on tax counsel to allow puts. ◎

A Lifeline For Cellulosic Ethanol Projects in California?

by Todd Alexander and David Lamb, in New York

A low carbon fuel standard in California should create opportunities for cellulosic ethanol producers, even as the federal government moves to reduce the amount of renewable fuels that must be used nationwide in motor vehicles.

The California program could be copied in other states.

The US Environmental Protection Agency proposed in November to reduce the amount of renewable fuels that must be blended into the US transportation fuel supply in 2014 from 18.15 billion gallons to 15.21 billion gallons. It proposed reducing the amount of cellulosic biofuels that must be blended from 1.75 billion gallons to a meager 17 million gallons.

This proposal has created significant doubt about the federal government's long-term commitment to renewable fuels and has also spurred significant criticism and negative reaction from the renewable fuels industry, including existing ethanol producers and developers of advanced biofuels. Existing producers and developers of new projects rely heavily on the federal mandates to provide a guaranteed demand for their products and assure investors of the future viability of their businesses.

A final decision on the 2014 federal mandates is expected soon.

Regardless of the outcome, producers of cellulosic and other advanced biofuels have been provided a lifeline by California. The low carbon fuel standard in California and proposed similar programs in other states will provide ample demand for advanced biofuels in the near future.

California Standard

The California standard — called "LCFS" for low carbon fuel standard as opposed to the federal "RFS" for renewable fuel standard — requires a 10% reduction in the carbon intensity of transportation fuels used in the state by 2020. California Governor Arnold Schwarzenegger imposed the standard in 2007 in Executive Order S-01-07.

Carbon intensity is measured as the average emissions produced over the life cycle of a fuel based on the amount of energy that is produced. The life cycle of the fuel starts upon extraction of the fuel, whether it is from a well or farm, and runs through consumption of the fuel to power a vehicle. The life cycle is often referred to as "seed-to-wheels" or "well-to-wheels." The process that the fuel source goes through from extraction to consumption is called the "pathway" of that fuel. The LCFS program is regulated in California by the California Air Resource Board or CARB.

In order to achieve a 10% carbon intensity reduction by 2020, the LCFS requires a gradually increasing percentage reduction in the carbon intensity of gasoline each year as illustrated in Table 1.

Table 1

Gasoline and Fuels Used as a Substitute for Gasoline

Year	Average Carbon Intensity	% Reduction
2010	REPORTING ONLY	N/A
2011	95.61	0.25%
2012	95.37	0.5%
2013	94.89	1.0%
2014	94.41	1.5%
2015	93.45	2.5%
2016	92.50	3.5%
2017	91.06	5.0%
2018	89.62	6.5%
2019	88.18	8.0%
2020 & Beyond	86.27	10.0%

The LCFS is a "market-based" policy. The focus is on "regulated parties," who are required to produce fuel that meets the carbon-intensity level of that particular year.

Regulated parties are the importers and producers of transportation fuels, fuel blendstocks and substitutes. Producers of electricity, hydrogen, hydrogen blends, compressed natural gas, biogas CNG, and biogas LNG are eligible to opt in as regulated parties. Opt-in regulated parties do not have to comply with the LCFS but may choose to opt into the LCFS program to generate credits that can be traded in the marketplace.

Regulated parties generate credits by producing fuel that is below the required carbon-intensity level and deficits by producing fuel that is above the required level. Regulated parties must have a net zero balance for credits and deficits annually. A regulated party can balance any deficits by purchasing credits in the market.

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The Volcker rule, named after former Federal Reserve Board Chairman Paul Volcker, is supposed to keep banks out of risky investments that might cause a bank to collapse and draw on federal insurance for bank deposits. Volcker wrote out his original idea in a page and a half. The preamble and text implementing it now run to more than 900 pages.

The Volcker rule does not apply to tax equity transactions that benefit the "public welfare," meaning bring housing, services or jobs to low-income communities, and in transactions involving tax credits for rehabilitating old buildings. It also does not apply where the federal bank regulators view the bank's role as essentially that of a lender, even though the transaction is set up in form to make the bank look like a partner.

The US Comptroller of the Currency, which regulates national banks, declined last fall to make a blanket determination that all renewable energy projects are public welfare investments, but suggested that many utility-scale projects qualify because they are in rural areas.

The Comptroller characterized participation by a bank in November in what may be a partnership flip financing of a US solar project near the border with Mexico as "substantially identical to a loan transaction." The characterization is in Interpretative Letter 1139.

The letter said the bank had to limit the dollar amount of this and similar transactions to no more than 3% of its capital and surplus.

The bank said it would have approximately a 70% interest in a limited liability company that owns the project. It said it would use the same credit evaluation of the project before deciding to invest that it would do for making a loan, and that it would not place "undue reliance" in the credit evaluation on any residual value after the tax benefits have run.

National banks may not take equity positions in real property. The letter said the solar project itself should not be considered real property, relying in part on its */ continued page 23*

Cellulosic Ethanol

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The LCFS was designed to be a flexible market-based policy. The flexibility in the LCFS comes from allowing regulated parties to determine the most market-efficient pathways to achieve compliance. In California, regulated parties must report the carbon intensities of the fuel they provide to the market by using a "lookup table" provided by CARB. The lookup table consists of pre-approved fuel pathways and sub-pathways. Additionally, any entity, whether a regulated party or not, may petition for approval of new pathways or sub-pathways. If approved, any new pathways or sub-pathways will be added to the lookup table and, thus, become available to any regulated party for reporting standards going forward. The structure of the program allows regulated parties to achieve compliance by creating more carbon-efficient pathways for standard fuels or by blending larger volumes of low-carbon intensity biofuels into the fuel supply.

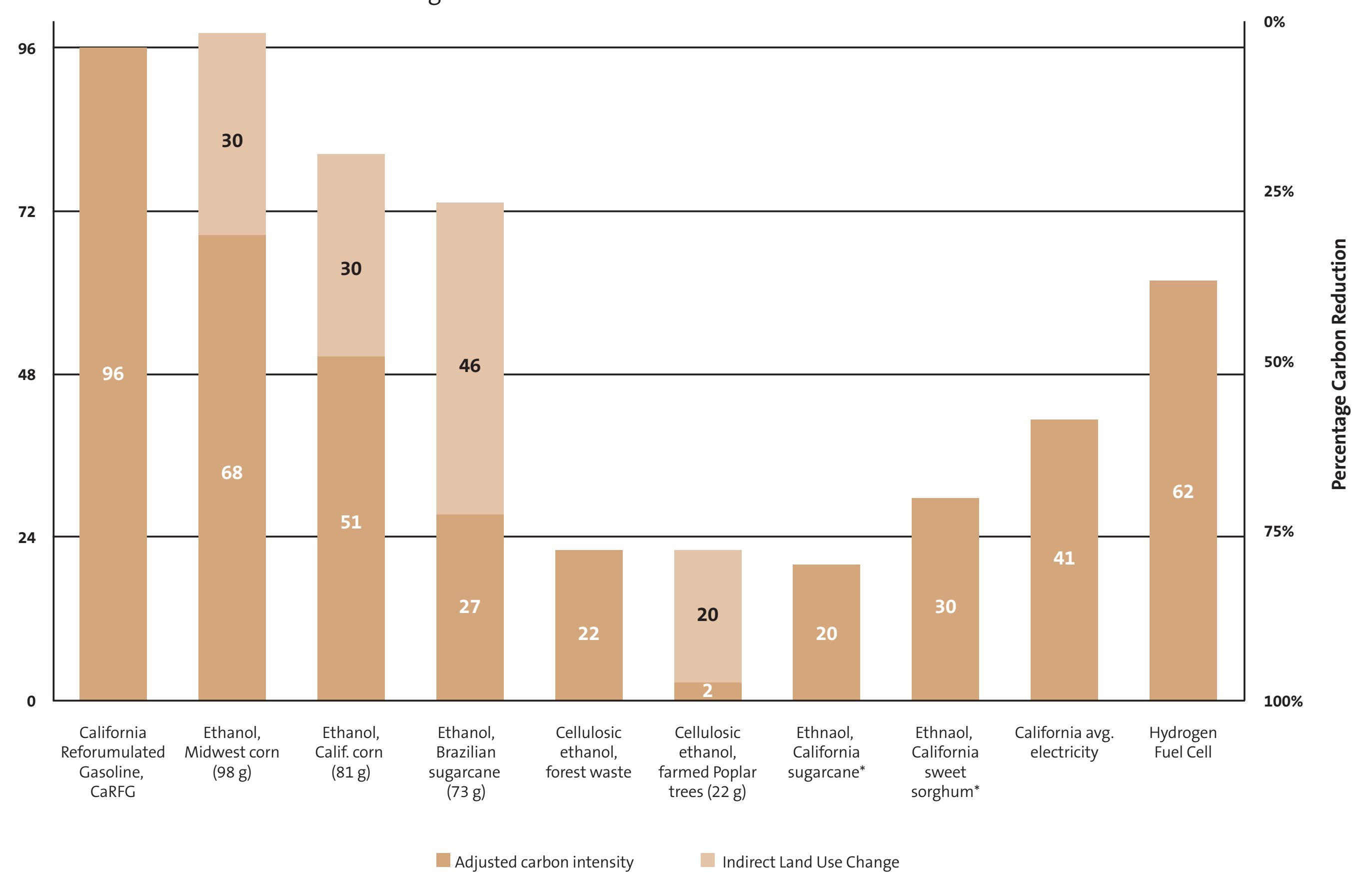
The carbon intensity of fuels can vary depending on the location and sources of the particular fuel sources. While the carbon-intensity levels announced by CARB may vary due to the different pathways associated with each individual producer, the general carbon-intensity levels associated with gasoline and its substitute products can be seen in Table 2.

Opportunity for Producers

As Table 2 illustrates, sugarcane ethanol and cellulosic ethanol have far lower carbon intensities than petroleum and conventional corn ethanol. Therefore, the increasingly stringent standards under the California LCFS will incentivize regulated parties to blend increasing levels of advanced low-carbon biofuels into the fuel supply in the near future. California uses 11% of the nation's transportation fuel supply. The effect on

Table 2. Carbon Intensity for Gasoline & Substitues, g CO2 e/MJ

(grams CO2 emitted per unit of energy adjusted for energy economy ratio [EER])
*staff estimate and indirect land use change not available



Source: CARB website (http://www.energy.ca.gov/ab118/documents/2009-04-09_meeting/2009-04-09_Carbon_Emission_Graphs.pdf) demand for advanced biofuels could be significant.

When first imposed, the California LCFS, like the federal RFS, was based on an aggressive assumption about the amount of cellulosic ethanol that would be available in the California market over the course of the program. In reality, cellulosic ethanol has fallen far short of these estimated levels despite a viable national market. For example, in 2012, only 20,269 gallons of cellulosic ethanol were produced for sale nationwide in the United States even though there was a federal mandate requiring 8.65 million gallons to be mixed into the national fuel supply.

The current lack of cellulosic ethanol supply means that, in the short run, there will continue to be a strong market for sugarcane ethanol in California. The main producer of sugarcane ethanol is Brazil. The shortfall in demand leaves a large potential opening for several cellulosic ethanol projects currently under development.

Other States

Thirteen US states, including 11 in the Northeast and mid-Atlantic region and Oregon and Washington in the Pacific Northwest, are studying or considering implementing LCFS programs.

States have been hesitant to move forward because of the risk that an LCFS could increase the price of fuel for consumers and because California has faced significant litigation from both the ethanol and petroleum industries. The California program seems to have withstood the most serious legal challenge after a favorable decision recently in the 9th circuit US court of appeals. Many states appear to be waiting to see where gasoline prices move as the LCFS ratchets up in California. The most significant step cellulosic ethanol producers could take to help themselves in other states is to make sure there is an ample supply of cellulosic biofuel in California as the state requires ever larger quantities to be mixed in California motor fuels. ◎

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understanding that the US tax authorities do not consider it real property, and any interest the bank would hold through the project company in a site lease for the project was merely "incidental to the financing." The bank suggested it was not assigning value to the site lease in its credit evaluation.

The letter made it a condition to the approval that the project developer had to have a call option to buy out the bank for the fair market value of the bank's interest after the bank reached its target return and the bank had also to clear the transaction with its bank examiner.

MORE CHINESE SOLAR PANELS could become subject to US import duties.

Duties could also be imposed on panels imported from Taiwan. The importers of record of affected products will have to post security for the estimated duties when importing the products once a preliminary determination is made by the US Department of Commerce that a duty should be imposed. Any such determination could come as early as late March.

Under US tariff law, if the foreign manufacturer reimburses its customer for the duty, then the reimbursement is itself collected as an additional duty.

The affected products are Chinese and Taiwanese solar modules made with cells "completed or partially manufactured" outside the country where the module is completed. The focus is on cells that use ingots or wafers manufactured in China or Taiwan or whose manufacture otherwise began in China or Taiwan.

The affected products do not include solar cells or modules that are already subject to US import duties. The US already collects countervailing and anti-dumping duties of 23.75% to 254.66% on imported Chinese solar cells. The affected products also do not include thin film.

The US subsidiary of German solar panel manufacturer SolarWorld petitioned the US government in late / continued page 25

The Outlook For Electricity Demand

James Turnure, director of the office of energy consumption and efficiency analysis in the US Energy Information Administration, spoke to Keith Martin of Chadbourne at the Infocast projects & money conference in New Orleans in January about the outlook for electricity demand and wholesale electricity prices in the United States. Before joining the US government, Turnure worked for Xcel Energy and Pacific Gas and Electric. The following is an edited transcript.

MR. MARTIN: I have often thought how much easier life would be if we worked in an industry where there is rapid growth in demand for the product we produce. That has not been true recently about electricity demand in the United States. At what annual rate is demand for electricity increasing?

MR. TURNURE: It used to increase at a faster annual rate than the rate of economic growth. However, our current long-term forecast is that electricity demand will grow by 0.9% a year while the economy will grow at around 2.4%.

MR. MARTIN: Yet that is up from the annual growth rate over the last decade, which was only 0.7%. Is the higher growth going forward — 0.9% a year — entirely due to expected economic growth?

MR. TURNURE: By and large, yes. Our macro-economic forecast comes from external providers. We interact with them, and we have a macro-economic group, but we don't try ourselves to forecast business cycles or external shocks. We are more focused on trends.

There is a general trend of industrial growth fueled by shale gas.

MR. MARTIN: How does US growth compare to growth in other countries?

MR. TURNURE: Table 1 shows growth rates outside the US. Japan, Europe and the United States have the lowest growth among OECD countries. The areas with fastest growth are China, India and Latin America.

Table 1

Projected Increase in Central Station Generating Capacity

	2005-2013	Through 2025
US	0.2%	13.5%
Canada	1.3%	25.3%
Mexico/Chile	24.8%	56.6%
Other Latin America	29.2%	28.3%
Europe	7.9%	13.7%
Japan	-1.1%	10.8%
China	82.4%	75.0%
India	42.0%	58.6%
Middle East	37.0%	34.9%
Africa	12.9%	46.9%

Source: International Energy Agency

MR. MARTIN: I should point out that these are not the US government's numbers, but data that we pulled from the International Energy Agency in Paris. Developers looking at the chart and trying to decide where is the best place to put dollars should take into account the small scale of some of these markets.

MR. TURNURE: There is an overwhelming urbanization trend in most of the world, but especially in Asia. The developing markets are starting to become reasonably large, but unless it is China or India, the market will take a while to reach scale. We are going to see a lot more cities of 10 to 20 million people in the developing world.

MR. MARTIN: I read that the entire demand growth for electricity in the United States the last three years will be offset by the shift to more efficient light bulbs. True or false?

MR. TURNURE: Close to true. If you took demand growth in normal years, it would be false. If you look at the last three years when the economy was struggling, then yes.

Key Assumptions

MR. MARTIN: What are the most important assumptions behind the forecast of 0.9% annual demand growth?

MR. TURNURE: The rate of macro-economic growth is first. Employment plays a really vital role in energy demand in general. The data series on employment tend not to exhibit gentle changes. There are a lot of cliffs in those data series up and down. We are currently in a very flat employment period. That is ahistorical.

MR. MARTIN: Say again what you are assuming for annual GDP growth?

MR. TURNURE: 2.4%.

MR. MARTIN: What is the second most important assumption?

MR. TURNURE: Number two is the pace of investment in technologies that go into these more dispersed demand sectors. That is very hard to analyze. You have to think about the rate of R&D that goes into appliances, HVAC and lighting being the dominant residential applications, but also things like supermarket refrigeration and some of the bigger commercial applications. Industrial energy efficiency has been an after-burner item, but it is starting to show results. These are more sources of uncertainty than they are likely to cause big upward or downward adjustments in the demand forecast. The end users are widely dispersed so that you can have a breakthrough in an area and it would only affect a small portion of the demand.

MR. MARTIN: Many people think there could be a surge in demand as the public switches to electric cars. What does the US government think?

MR. TURNURE: We are an independent agency, so our view is not necessarily that of the current administration. At this point, we have a fair amount of electrification in autos, but it is almost all hybrids. We expect eventually to see less than half of new vehicle sales made up of cars that use conventional gasoline. However, very few vehicles currently in use are dedicated electrics. There is actually more activity in natural gas vehicles than in electric vehicles. Long-haul trucking companies have started using LNG, and it is the first time that an alternative fuel has made it into our reference case in simple economic terms. In the transport sector fuel mix, we see gasoline peaking and then declining. That is a significant break with past trends.

MR. MARTIN: The growth of rooftop solar changes how homeowners get their electricity. How much growth do you expect in this sector?

MR. TURNURE: We expect dramatic growth in the next few years. Utility-scale solar continues short-term growth thanks to state renewable portfolio standards and then flattens out until 2035 when more capacity is added. Rooftop PV will have a large growth spurt until the investment tax credit expires at the end of 2016. This demonstrates that while we do not consider rooftop solar to be economic at / continued page 26

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December to investigate whether duties should be imposed on the latest products. The company charges that Chinese solar panel manufacturers are circumventing the existing duties by using cells made in Taiwan. Reports suggest that as many as 70% of Chinese solar panel manufacturers that export panels to the US are using cells made in Taiwan. The existing duties do not cover Chinese modules made with non-Chinese cells.

SolarWorld says the affected products from China are being sold at 165.04% below their price in other markets. It says the dumping margin on the affected products from Taiwan is 75.68%.

The US International Trade Commission said on February 14 there is evidence that sales of the products in the US are causing "material injury" to US competitors.

The US Department of Commerce has until March 28 to make a preliminary determination about any improper Chinese government subsidy to assist with the sales of the affected products in the US market. SolarWorld says there is at least a 2% subsidy by the Chinese — but not the Taiwanese — government. Commerce will have until June 11 to calculate the separate dumping margin on a preliminary basis. After the preliminary determinations, importers will have to start posting security.

A final decision whether to impose duties is not expected until October 16 at the earliest.

The Chinese government said in January that it has "serious concern" about the investigation and will "resolutely defend" its interests. China said in late January that imports of polysilicon from the United States will be subject to combined anti-subsidy and anti-dumping duties of 59.1%.

CFIUS reported to Congress in December that 19.3% of the 114 proposed acquisitions of US companies that were submitted for review in 2012 were later withdrawn.

About half were later resubmitted with revised terms. / continued page 27

Electricity Demand

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typical installation costs today, it is close enough that the investment credit makes a huge difference.

MR. MARTIN: If the government believes that the rooftop solar sector will basically flatline after 2016 when the investment tax credit expires, then isn't that a strong argument for extending the investment credit?

MR. TURNURE: The investment credit was a pretty special idea. There had been the earlier annual production tax credit taken against each kilowatt hour of electricity produced. To replace it with a tax credit that the owner of a project takes up front and as a percentage of the capital cost of the project was a onetime experiment. Congress will have to evaluate where to go with that. If we were talking about the production tax credit, you would say, based on history, that it has always been renewed, but the investment credit has not had that history yet. We cannot assume an extension in our forecast.

MR. MARTIN: Your forecast in Table 2 shows rooftop solar growing at a rapid pace though 2016 and then not growing at all again until 2035. What do you expect to happen in 2035?

MR. TURNURE: Mostly technological changes that bring down the cost. However, two other factors that will lead to more growth are state RPS targets in the long run, and we will also reach a point where demand growth by itself starts to pull some additional kilowatt hours.

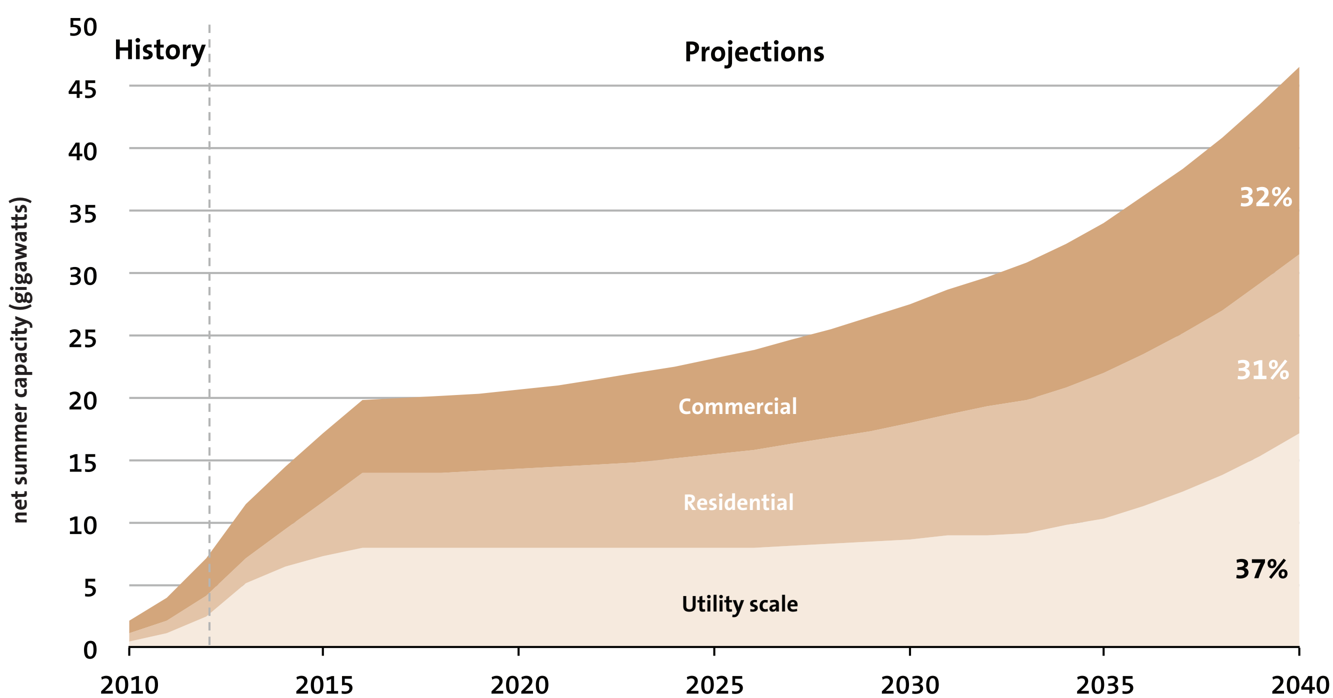
MR. MARTIN: Low natural gas prices are leading to growth in industries that depend heavily on natural gas. Could that help with electricity demand?

MR. TURNURE: It definitely helps with demand. However, it is important to understand that the shale gas boom will boost domestic industrial competitiveness, but we see this as a short-run story that is less important over the longer term because that competitiveness eventually gets washed away again. In our baseline forecast, the industrial sector growth is higher this year than it was last year. It drags quite a bit of electric power growth with it.

MR. MARTIN: Project developers have been watching planned retirements of coal-fired power plants, figuring they could fill in that capacity. What retirements are you expecting and when?

MR. TURNURE: We increased the number of retirements we expect in the near term in our latest forecast in Table 3. We

Table 2. Total PV capacity grows at an average rate of 7% per year; growth occurs in all sectors



Source: Annual Energy Outlook 2014 Reference Case

US electricity demand grew over the last decade at an average annual rate of 0.7%.

think the air regulatory picture will be clarified somewhat for the owners. The next time any of these owners has to make a major investment for compliance reasons or because the aging plant needs work is when the plant shuts down. The need for such spending tends to pull retirements forward in time. Instead of a small investment being a bump in the road, it becomes the end of the line.

MR. MARTIN: Your 2014 forecast shows fewer retirements this year than you expected even a year ago.

MR. TURNURE: This is more a consequence of how we think the market is responding to nearly level demand. Some aging plants will be retained for reserve margin purposes. Are you really going to build new capacity in a period of weak demand growth? That depends on the specifics in the regional market in which you are operating.

MR. MARTIN: Where do you expect the need for additional generating capacity to be greatest?

MR. TURNURE: Every summer, the National Electric Reliability Council estimates what will happen to reserve margins in the different regions. New York, Texas, the Midwest and California all have pretty tight reserve margins. If you lose any plants in those areas, you are going to have to replace them.

Gas and Power Prices

MR. MARTIN: Natural gas prices are a big factor in the US generating mix. What is the government projecting for gas prices, at least for the power sector?

MR. TURNURE: The shale gas story is important, but the big question is the long-run cost for shale gas development. Given how small scale and relatively new a sector it is, the cost is hard to predict. Historical trends suggest we are moving toward $7 or $8 an mcf over an extended period. A lot of people would have thought a few

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CFIUS — short for the Committee on Foreign Investment in the United States — is an inter-agency committee of 16 federal agencies, headed by the Treasury Department, 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 report lists as potential areas of 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.

The committee makes recommendations. The President has ultimate authority to block a transaction.

One transaction was blocked in 2012. President Obama ordered Chinese-backed Ralls Corp. to divest four wind farms that the company bought in Oregon at which it hoped to deploy turbines made by its affiliate, the Sany Electric Co. One of the wind farms is close to a US Navy base that provides training for drone aircraft. The company lost a suit in federal court to have the order set aside on grounds that it is an unconstitutional taking of private property without due process. The case is now before an appeals court. (For earlier coverage, see the December 2013 *NewsWire* starting at page 33.)

CFIUS reports annually to Congress. Its latest report, covering the period through December 2012, discloses that the committee reviewed 538 proposed transactions in the five years from 2008 through 2012. A little over a third of filings moved to investigations. In 2012, the figure was 39%. Of the 2012 filings, 12 were proposed acquisitions in the utility sector.

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years ago that you would never have gotten under $7 or $8 for a significant period of time. There was a time around 2005 when the Energy Information Administration would have needed to assume in our forecasting both LNG imports and an Alaska pipeline even to maintain prices around the $8 level. Now, without either one of those things, we have prices staying under $8 for the next 20 years.

The ratio of coal to gas is an important indicator of competitiveness. Last spring, we saw more gas generation than coal in the US markets for the first time ever. Despite this, coal should recover a little bit of its edge back in the mid- to longer term. That is one reason why the coal-fired power plants that do not retire in our forecast are heavily used.

MR. MARTIN: Given the government's interest in reducing greenhouse gas emissions, will it allow coal to come back as a fuel? Is this a realistic forecast?

MR. TURNURE: That is a big uncertainty. The full forecast we release in the spring 2014 will include a lot more scenarios. It will include some carbon tax scenarios. Some policies assumed in the forecasts are directly targeted incentives and penalties to reduce emissions which, if they were comprehensive, would look somewhat like a carbon tax. In the meantime, some coal-fired power plants will retire, but the remaining plants will generate more. So we have an essentially level coal share of the market going forward.

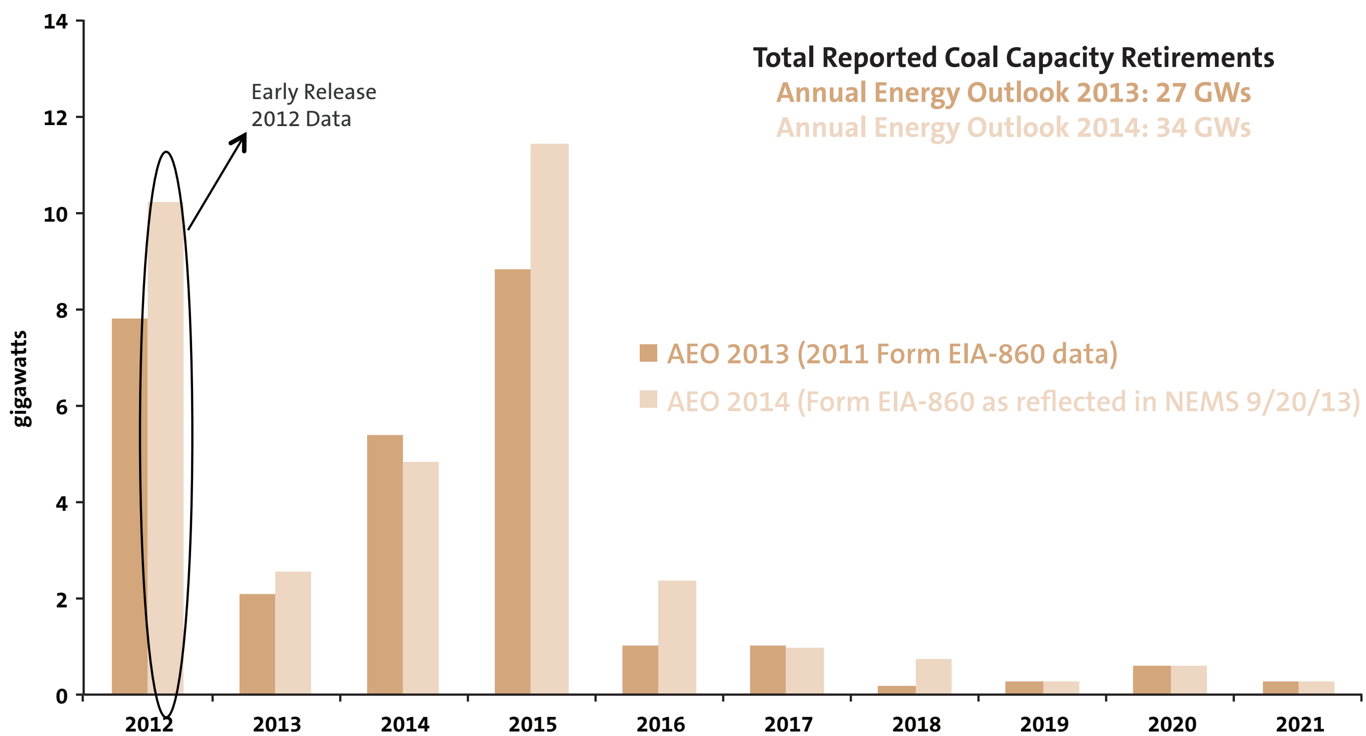
The flatter the demand growth gets, the less you need renewables because most state RPS standards are volumetric. If you build fewer renewables, then there is more room for natural gas to eat that remaining market share.

MR. MARTIN: US capacity additions in October 2013, the most recent month for which we have data, were 72% solar. Do you think solar will be able to put up these kinds of numbers through 2016 when the investment tax credit expires?

MR. TURNURE: I find that pretty unlikely. Maybe they did not correct for capacity utilization.

MR. MARTIN: You expect biomass to take off along with

Table 3. Reported Coal Retirements By Year



Source: EIA

solar. For the last two decades, government officials in this country and Europe have been saying that they expect biomass to be the next big thing. It never happens. Why not and why believe it will happen this time?

MR. TURNURE: Biomass can serve as a base-load resource. When people are doing policy and forecasting, there is a big interest in getting beyond the intermittent resources in wind and solar and looking at base-load resources. That is why hydroelectric has been the dominant renewable resource for all these years. Biomass is the second largest source of renewable power and has been for a long time because of its role in the pulp and paper industry and in other associated industries. Beyond that, it has been a question of how people run their state RPS standards and eligibility. Biomass has a pretty heavy upfront capital requirement, and the power plants tend to be larger-sized systems. The research and development is also quite expensive. You can build a prototype wind turbine for $1 or $2 million, but a biomass plant might cost $250 million for just a half-size demonstration unit.

MR. MARTIN: What do expect for wholesale power prices over the next few years?

MR. TURNURE: Many retail customers ask why their retail rates are not falling in line with natural gas prices. The reason is that even in competitive markets like the PJM system in the mid-Atlantic region, the utilities let out the energy portion for load in chunks; so those tranches take a while to pick up lower gas prices. Lower gas prices will eventually be reflected in rates, but it takes time to see the effects. The energy component of rates is not that big anyway. People forget that the transmission and distribution portion of end-use rates is pretty stable, if not increasing, because every time there is a big storm or something falls apart, the regulators have to increase rates to rebuild the transmission and distribution system. That's why we continue to see an upward trend in power prices overall.

Wholesale prices tend to move in the same direction as retail prices.

MR. MARTIN: Your 2014 forecast is for a rise of 1% a year in US electricity prices, but a little higher in the areas you said need more power: New York, New England, Texas. Wholesale prices tend to follow natural gas prices which are projected to rise in the forecast by 3% a year. Electricity prices are rising, but they tend to lag natural gas.

MR. TURNURE: We have pretty level demand, but a bit more money will flow through the system year on year. ◎

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The largest number of filings in 2012 were for in-bound US investments from China. The top 10 countries for which filings were made in 2012 and the numbers are China (23), United Kingdom (17), Canada (13), Japan (9), France (8), The Netherlands (6), Switzerland (5), Germany (4), India (4) and Israel (4). However, most of the utilities sector filings were from Canada and China.

THE TREASURY INSPECTOR GENERAL said in a report released in late January that an IRS "compliance initiative project" under which the agency is reviewing tax returns filed by companies that received grants found 50% of 16 large companies and 61% of 83 small companies had "significant issues" on their tax returns, possibly including in some cases claiming tax credits on projects on which they received grants. The grant program is called payments "in lieu of" tax credits. The IRS is expected to continue the compliance reviews through June 2015.

RELOCATION PAYMENTS did not have to be reported as income.

The IRS confirmed in a private ruling made public in January that a taxpayer did not have to pay income taxes on relocation payments from a state agency that used eminent domain to require him to move his business. A special federal statute makes clear that relocation payments by state agencies implementing federally-assisted programs do not have to be reported as income. The same rule applies to direct payments by federal agencies under federal programs.

The statute is 42 USC § 4636.

The ruling is Private Letter Ruling 201401001. The IRS said the taxpayer could not deduct the reimbursed moving costs and could not claim "basis" in any replacement equipment or other assets purchased with the relocation payments.

REAL ESTATE INVESTMENT TRUSTS may be easier for corporations to create through tax-free spinoffs of real estate */ continued page 31*

Is the Power Industry Business Model at a Tipping Point?

The Edison Electric Institute released a report last year warning that regulated utilities are facing a serious long-term threat from distributed generation and demand-side management programs. The traditional utility model relied on central station power plants. Customers are moving to generate their own electricity and are no longer sharing fully in the fixed costs of the grid. The report warned that this could put upward pressure on rates and could even affect utility credit ratings in the longer term. A panel talked about where the power industry is headed at the Infocast projects & money conference in New Orleans in January. The following is an edited transcript.

The panelists are Robert Hutchinson, managing director of the Rocky Mountain Institute, Jeffrey Goltz, former chairman and current commissioner of the Washington Utilities and Transportation Commission, Brian Daly, managing director of Babson Capital Management, an investment fund management group that manages more than $188 billion in assets, Drew Murphy, senior managing director of Macquarie Infrastructure and Real Assets and, before that, head of strategy and M&A for giant independent power producer NRG and president of the Northeast region for NRG, Jan Smutny-Jones, head of the California Independent Energy Producers Association, and John Shelk, president of the national Electric Power Supply Association. The moderator is Keith Martin with Chadbourne in Washington.

MR. MARTIN: There is no industry today whose business model is immune to disruptive technologies. The power industry is no different. Jeffrey Goltz, are we on the verge of a major upheaval in the electric power industry?

Major Shift?

MR. GOLTZ: It is geographic specific. Utilities in Arizona, Hawaii and California are being affected by a large build out of distributed solar. In the state of Washington, we do not have as much distributed generation, but we have the same pressure on utilities in the long run because of the increased emphasis on energy efficiency, which has made for relatively flat load growth in the Pacific Northwest.

MR. DALY: I think we are on the verge of a major shift.

MR. MURPHY: The biggest source of pressure on the utility business model is low demand growth. We forecast low and, in some cases, negative demand growth both in customer count and volume. That said, in states where distributed solar has taken off, it is an important part of the business model. It is just not the biggest pressure point across the entire US at the moment.

MR. HUTCHINSON: There is a very significant shift going on, but we are not near a tipping point where the business model collapses to be replaced by something else. It has regional flavors. The phrase "demand destruction" is absolutely real. Even places in the South like Louisiana have now officially endorsed efficiency programs for the first time.

MR. MARTIN: Are the regulated utilities most seriously affected or is the biggest effect on the independent power companies who are competing directly with newer sources of supply like rooftop solar?

MR. DALY: The distributed solar industry is taking advantage of current rate structures and tax credits. One wonders how long that will last. My first job at Long Island Lighting in the 1980s was to design rate structures to defeat small cogeneration units. There was a great piece out last week on why Mexico is a tremendous opportunity for solar even though there are no subsidies. The second rate tier in Mexico is 22¢ a kilowatt hour. It is pretty easy to compete against that. I think what we will see is a change in the rate structures to disincentivize net metering and large-scale deployment of commercial and residential solar.

MR. GOLTZ: There is a lot of pressure in a number of states. There will be a big push in that direction. That is not the only way to address the issue of load loss due to an increased number of net-metering customers, but it is one of the ways that public utility commissions will have to consider.

MR. MARTIN: Drew Murphy, you sat on the inside council of a very large and successful independent power company. Do you see this pressure on the business model we have been discussing as a greater concern to the independent power producers or the regulated utilities?

MR. MURPHY: Both are affected. The independent power producers have a different concern. I am not sure the pressure on them is any greater.

Independent power producers are looking forward and are trying to move into distributed generation because they realize it is another source of generating capacity that they can own or in which they can invest.

The issues on the regulated side are what will happen with rate structures and additional fees for access.

The bigger threat for the competitive power generators like NRG and others is the price of natural gas and the ability to find a place to make money from building new generation. Distributed generation is not a big threat because independents are trying to participate in that whole boom as distributed generators.

MR. MARTIN: Do you see energy efficiency companies as a major threat to the power sector?

MR. HUTCHINSON: We believe so. The efficiency movement is not aimed solely at reducing the overall amount of electricity used, but it is also starting to focus on the times of day when electricity is most valuable. We are starting to see more de-peaking type of activities. Our building design practice is seeing people using latent thermo-characteristics of buildings to design control systems that can shift peaks to different time periods. At the end of the day, this is about economics. It isn't just a matter of counting kilowatt hours.

MR. MARTIN: You said once that the trouble the efficiency guys have is that it is hard to make a good ad that sells making do with less. How do you see the efficiency companies getting past this?

MR. HUTCHINSON: Efficiency gets mischaracterized. You can talk efficiency all you want, but let's be clear: we are talking about waste. The message is that there is a cheaper way to consume electricity. We spend a lot of time with Fortune 1000 companies. The scaling of major programs around efficiency is coming back again. I have been working lately with Walmart on its program, and it is just scary how many things even Walmart has not done. We are going to see some serious demand destruction in utility systems where larger-scale or more sophisticated commercial and industrial customers are a big part of the load.

Building codes are changing rapidly. Seven states adopted higher-grade building codes recently. There are now nine cities with very clear labeling laws on commercial buildings. One city has started to move to residential. We are starting to see information come in on the side of efficiency, so maybe you cannot effectively market the whole concept, but you can market pieces of it and those are starting to be visible.

Empire Strikes Back?

MR. MARTIN: To what extent will the utilities strike back by taking over energy efficiency, rooftop solar / *continued page 32*

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assets than thought earlier.

William Alexander, IRS associate chief counsel for corporate issues, suggested at an American Bar Association tax section meeting in Phoenix in late January that a corporation can do a tax-free spinoff of real estate assets without showing any business purpose other than the advantages of raising capital in the public markets against that segment of the corporation's business. A tax-free spinoff normally requires a business purpose.

"If you are doing this with the intention that the REIT access the capital market, then I think that you would meet the test," Alexander said. He added that the analysis would not be the same for a private REIT that will not raise money in the equity capital markets.

REITs can raise capital more cheaply than regular corporations because a REIT is not taxed on the share of its earnings that it distributes to shareholders. Several REITs have been formed to invest in renewable energy projects, but their efforts have been hampered by reluctance by the IRS in Washington to classify solar panels and wind turbines as real property for REIT purposes. Machinery is not real property. The White House has been urging the Treasury to issue a revenue ruling classifying significant parts of solar and possibly wind projects as real property for REIT purposes. Any decision to classify such assets as real property could create other complications.

Meanwhile, data centers, casinos and others are spinning off buildings and land into REITs and leasing them back from the REIT as a way to monetize assets. The IRS released the first private letter ruling approving a tax-free spinoff of a standalone REIT by a corporation in September 2013. The ruling is Private Letter Ruling 201337007. It appears to have been issued to casino owner Penn National Gaming, Inc., which did a tax-free spinoff of its casino facilities into a REIT in November 2013.

PARTNERSHIPS that require the sponsor to fund operating deficits / *continued page 33*

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and other forms of distributed generation? They have access to cheaper capital than the rooftop solar and energy efficiency companies.

MR. DALY: The utilities have ratepayers, not customers, and I think there is a very big difference. Independents handle customer care a lot better. A regulated utility might buy a rooftop solar company, but the lower cost to capital is not going to move the needle for them.

MR. GOLTZ: I hear utilities say that there is a lot of pressure to become more like energy services companies as opposed just to providers of electrons. Electric companies, as mandated by state law, are in the energy conservation business. If a utility is providing electrons and also insulating your roof, maybe it can put solar panels on the roof as well. The utility could be like a general contractor. It is a daunting task for a homeowner to figure out how to manage his or her energy consumption. There might be a market for utilities who can serve as a one-stop shop for electrons, conservation assistance and rooftop solar.

MR. DALY: PURPA was about getting the utilities out of the business of building and owning large power plants. We did not do a particularly good job of that. Utilities are not going to give the customers a low cost experience of installing rooftop solar.

The US government expects solar installations to grow at a healthy rate until 2016 when the federal tax credit expires.

MR. GOLTZ: We will see a variety of responses from the utilities over the next five to 10 years. Some are more involved in the customer service area than others and see themselves as having some of those core skills. They need to be the party that ensures the entire system works. That is what good regulated utilities that provide transmission and distribution service do. We are talking about trying to get the management to see itself as essentially going on the other side of the meter to make sure it all ties together.

MR. HUTCHINSON: Look at the Nest thermostat. Yes, it is neat, but I really don't care about it. I would rather it just worked. I don't want to come home and have a little icon pop up that says "rebooting." I am afraid that is what we will end up with if we let the technology companies be the guys who own the thermostats in our houses. We will end up with a situation where none of the pieces fits together. It is okay for the TV. It is even tolerable for my cell phone, but it is not okay if turning on the lights trips the thermostat. There is a real role for the local utility to play.

There is a need for a more concrete set of standards on multiple levels at the distribution edge. That is one of the barriers to experimentation with business models. Progress is being held up today by such issues as how to measure efficiency gains, what are the real costs and what costs are avoided. PG&E, which probably has one of the better measurement systems, has a factor of five between its average and highest marginal cost of putting in new capacity to serve particular locations.

MR. MARTIN: Arizona Public Service wanted to charge customers who generate their own electricity using solar panels $50 to $100 a month as a backup charge for the right to draw electricity at any time from the grid. It also wanted to credit customers who send excess electricity back to the grid through net metering at the wholesale power rate and not the retail rate. APS argues that all users of the grid should help pay for the grid. Does APS have a point?

MR. GOLTZ: It has a point about the need for some sort of mechanism to recover the cost of the grid. There is a debate about the right level of backup charge and how best to structure it. Minnesota is offering utilities an alternative to the net metering system. The Minnesota Public Utility Commission has been charged with assigning a value to solar through a very complex formula. A customer installing rooftop solar would still buy its electricity from the grid, and then be paid for the value of the energy it produces. Calculating the value of the solar energy is hard. It may be that it is larger than people think. There are environmental benefits and reliability issues to factor into the equation.

MR. MARTIN: Is there a counter argument that solar customers should not have to pay any backup charge?

MR. MURPHY: The argument is that a customer should only have to pay for the grid to the extent he uses it.

A small backup charge is easier to swallow, but the day is coming where it will be too large to ignore. This debate will continue, and there is going to have to be a balance. Neither side will get everything it wants. We will need to recognize that the grid has to be sized to accommodate customers who may want power on a backup basis, but these customers are on average only sometime users of the grid, and that too must be taken into account in determining the proper amount of fee to charge. Someone who uses the grid infrequently because he is generating his own electricity should not have to pay a huge charge for what is essentially insurance.

MR. GOLTZ: A downside of the Arizona battle is the bad blood it is creating. One thing we are doing in Washington state is to open a docket and try to approach the issue in a more collaborative way without coming to a solution right away.

I am on the advisory committee of the Critical Consumer Issues Forum that is a group of utility representatives, ratepayer advocates and regulators. It is designed to bring these groups together and reach consensus on a number of principles. In the last year, we spent a lot of time worrying about distributed generation, and we were able to reach a consensus about some general principles. It is better to have the luxury of time to approach this in a methodical manner than trying to address it through litigation and adjudicated proceedings.

MR. MARTIN: Has any fresh thinking come out of these discussions or are we left with just the two variables that Arizona Public Service put in play — a monthly backup charge and the price paid for net-metered electricity? Are there other ways to tackle the issues?

MR. GOLTZ: There are many different things that you could do with rate structures. The "value of solar" rate pioneered in Austin is one. There are a number of other rate structures. There are also the moves towards different utility business models or portfolios of business models within a utility framework.

MR. MARTIN: Will the utilities make their own situations worse by charging a high backup fee? Won't the largest customers withdraw from the grid entirely to avoid the charge?

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without any promise of repayment or capital account credit risk having to report the funding for deficits as taxable income.

The IRS said that a partnership that earned state tax credits for renovating two historic hotels in downtown St. Louis should have reported income both from sale of the tax credits and from clawing back part of a developer fee to the developer to cover operating deficits.

An experienced developer, Historic Restoration, Inc., formed a partnership with tax equity investors led by Kimberly-Clark Corp. to own two hotels: the Statler and Lennox. The developer did the renovations on behalf of the partnership.

Missouri offers a tax credit for 25% of the amount spent on such projects. The credits are freely transferable, but do not become available until the project is completed. The developer borrowed $18.455 million as a bridge loan at 9.5% interest against the future value of the tax credits and contributed the amount to the partnership to help fund the renovations. The developer then signed an agreement with Firstar Community Development Corp., an affiliate of US Bancorp, to sell it the credits at completion for 82¢ or 83¢ per dollar of tax credit.

The Lennox renovation was completed in 2002, and the tax credits were sold to Firstar.

The Statler renovation cost more than expected and, therefore, the tax credits were greater than expected. The state awarded tax credits of $17.6 million for the Statler job on December 30, 2002, and the credits were immediately sold to Firstar. This was $4.2 million more than originally expected in tax credits.

An accounting firm for the partnership notified the state on January 8, 2003 that the partnership had incorrectly calculated the amount of tax credits to which it was entitled. It asked the state to void the original Statler award and award $16.3 million in tax credits instead. The state did so.

The IRS said that the partnership should have reported income in / continued page 35

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MR. GOLTZ: I can't imagine that we will move back to a world of micro grids. We are better off in this together. Electricity is becoming a more valuable commodity than it ever has been. When electricity first came into general use in the early part of the last century, it was used for light, manufacturing and heat. Now it is essential to our communications network. Without electricity, we cannot communicate with each other. It is replacing the post office and, with more electric vehicles, it may become essential to the transportation system.

MR. MURPHY: While some large consumers are trying to take control of some of their energy supply, I expect that almost everyone will want to remain connected to the grid as insurance. We count on reliable electricity more than ever. It is woven into the fabric of all of our businesses and lives.

Opportunities?

MR. MARTIN: If there are pressures on the power industry business model, perhaps it is a pivot point and an opportunity for profit. Where do you see the opportunities in this shifting business environment?

MR. DALY: The most capital is going to be deployed in large-scale generation, transmission and distribution, and that trend will continue. For all of the energy and buzz around distributed generation, it is a few percentage points of the entire business.

As an energy efficiency engineer, I once had a wonderful conversation trying to convince a commercial customer to sign up for a demand-side management program. I explained how he could reduce his energy bill by 75% if he would just turn off three days during the summer, and he looked at me and explained how much money he made processing credit card receivables and he would never shut off.

MR. MURPHY: We certainly look at and want to do more in the renewables space. We would love even to get into some of the distributed technologies on a portfolio basis, but the real money will continue to go into the transmission and distribution systems and utility generation. I don't see that changing in the medium term.

MR. MARTIN: So, Brian Daly believes this is an epic battle, but he would still put his money in the old business model. Drew Murphy, you agree with Brian that the big money will still go into utility-scale facilities, but you are also prepared to bet on the disruptive technologies?

MR. MURPHY: There is opportunity there. The bigger money is, as Brian said, in the bigger old-style projects like transmission, distribution and utility generation, but we have to be looking at both.

MR. HUTCHINSON: My money is on distributed, not because I don't think there are good deals in the utility-scale market, but I would argue that the market is changing quickly. Distributed consists of small pieces, but our ability to create portfolios is changing terrifically if we can break some of these barriers. If I want to be in an exciting growth business, that place is on the distributed side.

MR. MARTIN: Let's bring our two trade association heads into the discussion. John Shelk, the law plays a big role in how the power industry is structured. You do not have to look very far back to see how changes in law created the independent power industry. Law decides the structure of the regulated utility business. Is the surge in distributed generation likely to be more disruptive for your members, the independent power companies, than for the regulated utilities? Do the distributed generation companies threaten to meet the entire growth in electricity demand? Seventy-two percent of it was met by solar in October.

MR. SHELK: The short answer is no. Many of our members are also engaged in the distributed business.

It is useful to differentiate between demand for electricity in the aggregate and demand from the grid. The impact of distributed generation is greater on the distribution utilities because it affects load growth and the need for additional investments in equipment that add to rate base. We have seen a number of reports from Wall Street analysts saying that there will be very little load growth. They are expecting flat demand for on-grid power. To the extent that there is growth, it will be largely met by renewables because of the RPS standards.

MR. MARTIN: Jan Smutny-Jones, you told me when we were preparing for this panel that the California Public Utilities Commission staff has said there is about a $1 billion shift in the burden of paying for utility plant and equipment from customers who install rooftop solar to those who don't. How do you see the battle between the rooftop solar companies and the regulated utilities unfolding in California?

MR. SMUTNY-JONES: This is an area where there is going to be a lot of fighting over the next year or so. There was a staff report that came out last October that had that number in it.

The commission is looking at the retail electricity rate structure and the way that net metering has worked in California. I expect this to be hotly litigated.

MR. MARTIN: The state legislature enacted a bill, AB 327, last fall that addressed the issues, but did not settle them. Which side came out ahead?

MR. SMUTNY-JONES: It was a draw that will be played out next before the California Public Utilities Commission. After the California energy crisis in 2001, the legislature concocted a fairly complex rate system in which the top two tiers of utility customers were paying about 54% higher rates than less heavy users of the grid. This has created a ready market for the solar rooftop companies. AB 327 was originally intended to undo that rate structure and put it back in the hands of the CPUC to figure out how to set rates. However, as all politics work, on the way to that conclusion, the rooftop solar guys showed up and were able to persuade the legislature to lift a cap on the amount of net metering that the three investor-owned utilities are required to permit. As I said, the argument now moves to the CPUC.

I live in the Sacramento Municipal Utility District, SMUD, which is a very progressive utility and does a lot of renewables, energy efficiency and demand response. It is adjusting its rate structure and phasing in a demand charge. The base charge for anyone connected to the grid is $20 a month and then there will be time-of-use rates on top of that. You may see something similar coming out of our commission. I can't predict what the number will be, but I think the idea that the utilities need to recover something for maintaining the infrastructure is not absurd. The question is what is the appropriate demand charge.

MR. MARTIN: California is predicting that by March 2020, 13,000 megawatts of electricity will drop off the grid at sundown each day. How large is the total capacity in California?

MR. SMUTNY-JONES: On a peak day, it is about 60,000 megawatts. You have this surge of solar, and as the sun goes down and the peak demand goes up, about 13,000 megawatts of capacity falls off the system. We see this as an opportunity, but the challenge is that a large portion of the existing gas fleet is combined cycle gas turbines that operate well but at a midrange. They are not designed to be peakers. The state is trying to figure out how to retool to meet this challenge.

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2002 from the original sale of $17.6 million in tax credits — and taken an adjustment in 2003 — because it was too late to rescind the original transaction. A rescission must occur in the same tax year. The US Tax Court agreed.

The developer reported the income from the tax credit sales. The IRS said the *partnership* should have reported the income, since the tax credits were awarded to it. The partnership allocated its income 99% to Kimberly-Clark.

The Tax Court disagreed. It was willing to honor the form of the transaction as a sale of tax credits by the developer directly to Firstar, but said that the sale of $2.9 million in excess credits above what Firstar agreed to buy from the developer should have been treated as a sale by the partnership to Firstar directly.

The developer agreed in the partnership agreement to fund any operating cost deficits. The partnership agreement said that any payments by the developer to cover deficits would not be treated as capital contributions or loans and the sharing ratios would not be affected. The partnership had a deficit from the start in 2003.

The partnership had agreed to pay the developer a developer fee of $9.3 million, or about 8.5% of the cost of the renovations. This fee was to be paid in three installments. The amounts for the last two installments were put into a deferred developer fee fund and could be diverted by the partnership to cover operating costs. The partnership tapped $3.1 million from the deferred developer fee fund to cover the deficit in 2003.

The IRS said the partnership had to report the amount as income. The court disagreed. It said that if the partnership had paid the developer the amount as a developer fee and then the developer made good on its promise to cover operating deficits, the partnership would have had income, but that is not what happened in this case. Here, the partnership effectively had a right to reduce the developer fee to the extent it needed the money to pay for operations.

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Changing Laws

MR. MARTIN: John Shelk, one of the things we have been talking about is energy efficiency. It is potentially as big a threat to load growth as distributed solar. Is the federal government about to give energy efficiency a bigger push?

MR. SHELK: Yes. The Department of Energy has authority to do such things as impose appliance efficiency standards, and it has been moving aggressively in this area. The government itself is a large buyer of electricity, and there have been initiatives through the General Services Administration and the Pentagon. Legislation on the matter will be difficult, if not impossible, to put through the current Congress. This Congress can't agree on the day of the week, but last year, the Senate did start to take up the legislation introduced by Senators Rob Portman (R-Ohio) and Jeanne Shaheen (D-New Hampshire) that would have made a stronger push for both government and private sector energy efficiency measures.

Rooftop solar and other forms of distributed generation are putting pressure on the traditional utility business model.

MR. SMUTNY-JONES: I have lived and prospered in a world of demand destruction for the last two decades. In California, load growth has basically been at 1% to 1.5% a year for the last 30 years. That is basically one large power plant per year. Despite that, California has built about 16,000 megawatts of gas-fired power plants since 2000. In the last 14 years, we have had a fairly substantial change due to retirements. I don't see a hugely negative impact on the independent power industry in the long term.

MR. MARTIN: Utilities in California invest $1 billion every year in energy efficiency efforts. They pay their customers to make energy efficiency improvements, and they put the payments into rate base and earn a profit on the payments. How quickly are the payments recovered or backed out of rate base?

MR. SMUTNY-JONES: It is fairly quick, but I don't know the period.

MR. MARTIN: John Shelk, one of the more significant legal changes in the offing is that the federal bank regulators are considering whether to bar banks from owning physical assets and also trading commodities like electricity. The banks account for a large share of the wholesale power market in places like Texas. The Senate Banking Committee recently held a hearing on this. What are the bank regulators doing in this area? Are banks likely to be told they can no longer trade commodities? What is your trade association's position?

MR. SHELK: We will hear the head of enforcement at the Federal Energy Regulatory Commission and representatives from the Securities and Exchange Commission and the Federal Reserve Board talk about the recent enforcement cases involving banks at a Senate hearing later this morning. The Senate Banking Committee hearing was originally scheduled last fall. The Federal Reserve posted an advance notice of proposed rulemaking yesterday. It did not decide the issue, but rather asked for public comment by March 15 on what it ought to do. Banks were allowed a decade ago to start trading commodities. The bank regulators are having second thoughts.

We wrote the regulators in September to urge them not to bar banks from trading in electricity. We need creditworthy counterparties and their liquidity to hedge electricity prices.

The Fed will be under pressure to do something by the end of the year.

MR. MARTIN: Are there other changes in law under discussion in Washington or at the state level that could have a major effect on the power industry business model?

MR. SMUTNY-JONES: The principal driver in California is the climate change policy of the state. California wants to reduce greenhouse gas emissions to 1990 levels by 2020 and to 80% of the 1990 levels by 2050. The path to 2020 is pretty well understood. No one has a clue on how we get to an 80% level by 2050.

The utilities, in response to a growing interest by our state legislature on clean energy procurements, are countering with something called a greenhouse gas standard. The details are a little unclear. We are going to have some interesting public policy discussions.

MR. SHELK: I don't see Congress passing any new statutes like the Public Utility Regulatory Policies Act of 1978 that created the independent power industry. The Environmental Protection Agency will move forward on greenhouse gas regulations for new and existing power plants that will have a big impact. The Federal Energy Regulatory Commission has opened dockets about how to encourage needed capacity additions in places like the Northeast. We and others have filed comments arguing that this issue of flat demand about which we have been talking this morning is one of a list of a half dozen new realities that fundamentally change the landscape from what it was when FERC approved the initial regional transmission organization market design. We will have a new FERC chairman and a new commissioner at some point. FERC will end up at the center of a lot of activity this coming year.

Next Job

MR. MARTIN: My last question is for each of you on this panel. If you were to leave your current job and start a company that is in some aspect of the power business, where would you go?

MR. MURPHY: Not a rooftop solar company. I would want to join a company that focuses on how to put together and finance portfolios of distributed generation projects: somebody who can crack the code of how to bring down the cost of capital for distributed generation much like the Canadian pension funds do by pooling long-term money. There is a huge opportunity there.

MR. HUTCHINSON: Drew took my answer. I would go where the spreads are. There is a huge potential gain to be had by reducing the average cost of capital for distributed generation to 6%.

MR. GOLTZ: Transmission and distribution efficiency such as smart grids.

MR. DALY: Having had some time to think about this the last few years, I would focus on LNG distribution for over-the-road trucks and then do biomass on remote tropical islands.

MR. SMUTNY-JONES: First, if we are retiring all these coal-fired power plants, we have to come */ continued page 38*

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The case is Gateway Hotel Partners, LLC v. Commissioner. *The Tax Court released its decision in January. The case shows the danger of a sponsor agreeing to cover operating deficits without anything in return.*

BIODIESEL BLENDERS who claim excise tax credits for mixing biodiesel into diesel fuel can only deduct the net excise taxes they pay on the blended fuel after the credits, the IRS said.

The IRS made the statement in an internal legal memo it sent the IRS field in Houston in late January. The memo is Chief Counsel Advice 201406001.

The IRS compared this to the situation where someone claims a state income tax credit. "For example, in the analogous situation where a state provides a credit against state income tax liability, the Service has ruled that the state tax credit is not includible in gross income but rather reduces the taxpayer's state income tax deduction for federal income tax purposes."

The IRS branch chief who signed the memo said some people argue that the tax credit was meant as a subsidy and should be viewed as separate from the excise taxes the blender is paying. The IRS does not share that view.

The US government encourages biodiesel to be mixed into diesel fuel to produce a blend for use in trucks. Refineries and distributors doing the blending have a choice of claiming an income tax credit of 50¢ a gallon of biodiesel used ($1 for "renewable biodiesel" from agricultural sources) or alternatively of claiming a tax credit of $1 per gallon of biodiesel against the federal excise taxes on the blended fuel. The excise taxes are 24.3¢ a gallon.

Any excess excise tax credits are refundable. The latest IRS memo supplements an earlier memo the IRS national office wrote last October (Chief Counsel Advice 201342010) that said biodiesel blenders do not have to report refunds of excess excise tax credits as income.

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up with something to replace them, so I see opportunity in gas-fired generation. Second, I think the real big niche market is integration. The more solar we put on, the less value it has because it all comes on in the middle of the day. What you do in the middle of the night becomes very important. Third, the Mary Kay Cosmetics franchisees are having a big meeting here in New Orleans at the same time we are all sitting in this casino. I am starting to believe the best opportunities are in cosmetics. ◎

Opportunities: Renewable Energy Projects Near Mines

by Brian Greene and Valentina Castillo, in Washington

Renewable energy developers are set to strike gold in the next decade with inside-the-fence facilities at mines.

Mine owners are expected to invest $20 billion in new renewable energy facilities by 2020. Financial and energy security concerns are behind the investments. For project developers, this is good news. However, there are unique challenges when doing a project adjacent to a mine.

Mining operations, especially those that are located in remote off-grid locations or in developing countries with poor infrastructure, tend to rely heavily on diesel-fired generators for electricity.

Diesel oil prices have nearly doubled in the last decade. To make matters worse, mines today often extract lower-grade ores that take more power to reach. Thus, mines are using increasing amounts of energy to produce the same amount of output, which weakens the bottom line. Mines today spend 30% of operating costs on energy compared to 23% to 25% a few years ago.

The rigors of moving diesel to remote areas and grid instability in developing nations add to the challenges of running a profitable mining operation. Mines operate 24 hours a day, seven days a week, and they require a constant fuel supply. Extreme weather, poor infrastructure and frequent strikes delay diesel shipments. Grids in parts of Latin America, Africa and Asia are subject to frequent blackouts. To avoid shutdowns, mine owners spend large sums of money on transportation security and back-up generation.

These cost and security issues make mine owners ready to listen to proposals from independent power producers to supply electricity. Renewable energy is not expected to replace diesel as the primary energy source for mines, but there is ample room for it to be used in combination with diesel and other conventional energy sources as a means to reduce costs and mitigate transportation risk.

The intermittent nature of renewable energy and the present lack of economical energy storage options limit the extent to which mines can rely currently on wind and solar for their power needs. However, the potential cost savings are too great to ignore. Electricity from diesel generators costs 28¢ to 32¢ a kWh currently. Solar costs around 17¢ a kWh. The figure for wind is 14¢ a kWh.

One example of a successful hybrid solution is at the Thaba chrome ore mine in the Limpopo province of South Africa, where Cronimet Mining Power Solutions operates a 1-megawatt photovoltaic-diesel hybrid electric plant that currently supplies 60% of the energy requirements of the mine by combining solar panels with a diesel generator. The solar plant generates electricity during the day, and the generator supplies energy at night. By using solar energy, the mine is able to save on 450,000 liters of diesel fuel a year.

Challenges

There are several unique technological and financial considerations when trying to do a project near a mine.

The main financial challenge is finding a structure that allows financial participation by the mining company. Such companies prefer off-balance sheet financing that preserves their debt-to-equity ratios. The primary financial obstacle in structuring a renewable energy project with a mining company is managing returns based on the projected life of the mine, which can take 10 years to develop and then operate anywhere from 10 to 50 years, compared to a 20- to 25-year expected life for a solar or wind project.

Another obstacle is that mine owners are accustomed to modeling energy costs as ongoing diesel fuel costs rather than upfront construction costs for a power plant. One way to bridge this is for the independent power company to retain the power plant and sell electricity to the extent local law allows.

Choosing an energy source to supplement diesel requires balancing financial considerations such as what energy will best deliver the lowest-cost energy and closest to a fixed price, how long it will take to develop the project and the variability of the electricity output. All these factors affect how soon a mining company can reap the financial benefits of a renewable energy project and how consistently those benefits will be produced. There are important tradeoffs. While a solar plant can be developed in 18 months and its price can be predicted with a great degree of certainty, its energy production is highly variable. A wind project can take 36 months to develop. Furthermore, it can be difficult to predict its costs and it, too, generates a variable amount of energy. In contrast, while a geothermal plant might produce a constant amount of energy, it requires 48 to 60 months to develop, how much capacity the geothermal field can support is hard to predict, and there are higher operating costs.

Mines are usually in remote areas like far northern Canada, the African desert or tropical forests or mountains in South America. These areas are subject to extreme weather conditions such as dust, humidity, heat, snow and little to no access to water. Equipment must be designed to deal with these challenges. For example, wind blades in cold weather need de-icing and solar panels in very dry areas must be able to produce energy despite extreme dust. Repair and upkeep are difficult in remote sites and can drive up costs.

Several Project Structures

Three main ownership structures have been used for projects at mines.

Each structure requires a creditworthy offtaker or hedge counterparty (in cases where a contract for differences or synthetic power purchase agreement is used) in order to tap financing from banks or multi-lateral lending agencies.

In one structure, the mining company is the offtaker. The mining operator merely contracts to buy energy from (or enters into a hedge with) a renewable energy project, and thus avoids putting any of its capital at risk. An example of such a project is the Pampa Elvira thermosolar plant in Chile developed by Energía Llaima and Sunmark. The $26 million plant supplies electricity to Codelco's Energía Llaima copper mine in the Atacama desert under a fixed-price and fixed-quantity power purchase agreement. Codelco expects to save the equivalent of two months of diesel oil / continued page 40

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A PARTNER did not have to report a share of partnership income until his partnership interest "vested."

The president of Crescent Resources, a real estate development business belonging to Duke Energy, was given a 2% partnership interest under a new employment agreement in September 2007 when the business was dropped into a partnership with several real estate investment funds managed by Morgan Stanley.

The interest was not transferable for three years and would be forfeited if the president terminated his employment within three years.

Crescent Resources filed for bankruptcy less than two years later in early June 2009. The president resigned shortly before the bankruptcy filing.

The partnership sent the president US tax forms called K-1s at the end of 2007 and again after 2008 indicating that he should report a 2% share of the partnership's income. He disagreed each time, but reported the income. After the 2008 K-1, the board agreed to pay him additional money to make him whole and to make an advance against his tax liabilities for 2009. When the company went bankrupt, the lawyers handling the bankruptcy sent a demand letter asking for the additional compensation to be returned.

The US Tax Court said in December that the president should not have had to report a share of partnership income until his interest vested. The court said this was a question of first impression for any court. It said the income share allocated to the president should have been reported by the other partners: Duke and the Morgan Stanley funds.

Anyone receiving a "capital interest" — as opposed to a bare "profits interest" — in a partnership as part of his compensation for services must report the value when the interest vests. However, he can make an election under section 83 of the US tax code to report the value upon receipt when the value might be lower. No such election was filed in this case.

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each year under the arrangement.

The 100-megawatt CAP Amanecer project developed by SunEdison, also in the Atacama desert in Chile, is a variation on the same theme in that the project will sell its energy into the spot market with the project company entering into a 20-year contract for differences with a subsidiary of the Chilean mining company Compañia de Acero del Pacifico S.A or "CAP," effectively allowing the project company to receive a fixed price for the energy it produces. CAP has the downside risk if energy prices drop below the contract price, but receives any revenue from selling energy for more than the contract price.

The contract-for-differences model may be of particular interest to large mining companies that have more than one mine connected to the grid in a particular area and that are looking to hedge their exposure to fluctuating energy prices.

Another structure is to make the mining company a co-investor model. It enters into a partnership, joint venture or other co-investment structure with the developer. Under this structure, the mining company benefits from the developer's experience and the two parties share the financial risk. Depending on the structure, the mining company may be able to depreciate its investment for tax purposes. A co-investment could be structured as a lease or sale-leaseback.

An example of such a structure is a project undertaken by Xstrata Copper and Origin Energy Limited in Chile. Origin purchased a 51% stake in Energía Austral, which owns the development rights to three proposed hydroelectric plants with an expected capacity of approximately 1000 megawatts, from Xstrata Copper in 2012. The copper company retains the other 49% interest. Origin brings both a known hydroelectric track record and a substantial amount of capital. Origin is investing $75 million initially to complete a project feasibility study. Should the project pass the feasibility study, Origin will invest another $75 million.

The co-investment by Brazilian mining giant Vale SA and Australian renewable developer Pacific Hydro in two wind projects in the state of Rio Grande do Norte is another example of the partnership model and follows a more basic structure. Vale and Pacific Hydro will each own 50% of the projects, which are expected to be constructed in 2014 and will have a combined capacity of 140 megawatts and produce renewable energy for at least 20 years.

A third common structure is for the mining company to take the lead role in developing a renewable energy project. The independent power company act as the EPC contractor, operator or equipment supplier. Variations on this structure might be a build-own-transfer or build-own-operator-transfer model that has been used in the past for large power projects in emerging markets.

The mining company may already have many of the engineering, design and construction skills required successfully to complete a project. For example, Rio Tinto, a mining company, used its own resources to build a wind farm with four 2.3-megawatt wind turbines to support its Diavik diamond mine in the Northwest Territories in Canada. Most of the wind turbine installation was designed in-house, and the company used its own communications protocol and design rather than the turbine supplier's SCADA communications system. It also relied on its own crews and mining equipment to build roads, blast foundations, mix and pour concrete and tie into overhead power lines.

The key drawback to such a structure from the perspective of the mining company is the high upfront capital cost.

Many more power projects at mines are on the drawing board. Other structures may emerge. ◎

Opportunities: Southern California Power Needs

California faces serious challenges maintaining reliable electric service to more than six million people who live in the area from San Diego to Los Angeles after Southern California Edison decided to close the San Onofre nuclear power plant permanently in the summer 2013. The plant was 2,246 megawatts. Another 5,068 megawatts of coastal power plants that use seawater for cooling will also have to close over the period 2017 through 2021. The state is trying simultaneously to reduce greenhouse gas emissions to 1990 levels by 2020. Demand for electricity in southern California is growing by about 400 megawatts a year.

Robert Weisenmiller, chairman of the California Energy Commission, the agency charging with planning, talked about *what he sees ahead during an Infocast webinar in January. The moderator was Keith Martin with Chadbourne in Washington.*

MR. MARTIN: What role does the California Energy Commission play in the power sector in California?

DR. WEISENMILLER: The CEC was established 40 years ago. One of the many things we do is power plant siting for any thermal facility in California that is over 50 megawatts. We also are responsible for determining what qualifies as renewable energy in addition to verifying eligible generation and reviewing what the municipal utilities are doing for renewable procurement. We are the premier planning agency for the state, so we have a long history in demand forecasting. We also handle energy efficiency, which includes building and appliance standards. These standards are part of the reason why California's energy use is relatively low. We also do research and development for both gas and electricity, and we are responsible for helping to develop clean vehicles and alternative fuels. Finally, we do contingency and emergency planning for energy.

I first met Governor Jerry Brown during the Arab oil embargo in the 1970's during an earlier tour as head of policy development at the commission. We were trying to figure out what the situation was going to be at the gasoline pumps the next day.

MR. MARTIN: Suppose you decide, as part of your contingency planning for the power sector, that more capacity is needed? How are your recommendations implemented?

DR. WEISENMILLER: Most of the new power would have to come from utility solicitations. The procurement process is directed by the California Public Utilities Commission. In the past, we have sometimes also used executive orders requiring an expedited signing process. The more conventional approach is to ask the CPUC to move forward with procurement.

MR. MARTIN: The San Onofre nuclear generating station — SONGS for short — is midway between Los Angeles and San Diego.

DR. WEISENMILLER: It was 2,246 megawatts. It used to produce at a very high capacity factor, at 80% or 90%. That was a lot of energy relative to the rest of the system, and it also provided over 1,100 MVARs of reactive power support. It provided energy for 1.4 million homes.

MVAR is a measure of reactive power. It is like the pressure that pushes water through the water mains. SONGS was unique in that it helped not just with */ continued page 42*

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A capital interest is the claim a partner has on partnership assets if the partnership unwinds or liquidates. A bare profits interest is an interest solely in future partnership income and loss. One US appeals court has held that a bare profits interest does not have to be reported as income upon vesting because the value is too uncertain.

The case is Crescent Holdings, LLC v. Commissioner.

MINOR MEMOS. North Carolina ranked second in new solar capacity additions in 2013. The top four states were California, North Carolina, Arizona and New Jersey . . . . US carbon dioxide emissions from power plants and other energy sources were up 2% in 2013 compared to 2012, according to a preliminary estimate by the US Energy Information Administration. They are still down 10% from 2005 levels. The Obama administration has set a goal of reducing emissions by 17% from 2005 levels by 2020 . . . . The IRS audited 0.96% of individual tax returns in fiscal 2013, the lowest percentage since 2005.

— contributed by Keith Martin, Kelly Kogan, Sam Kwon and Amanda Forsythe in Washington

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generation, but also with the transmission system. You have to be able to move the power from power plants to people's houses. The southern California grid was built around the assumption that SONGS would remain in operation. We will need to replace the reactive power.

MR. MARTIN: What percentage of electricity in the LA Basin and San Diego did SONGS supply?

DR. WEISENMILLER: About 16%.

MR. MARTIN: SONGS had been largely idle for the two years before the decision to shut it down, and the region managed to get by without it. Why was the shutdown a big deal?

DR. WEISENMILLER: We were lucky the last two summers. We may not always be as lucky. The only generating units in Orange County are SONGS and a gas-fired power plant in Huntington Beach.

Huntington Beach has also had to be shut down as the pollution offsets that permitted it to remain in operation were retired. We had to work very hard with the California Air Resources Board and others to bring the Huntington Beach plant back up in that first summer to provide some reactive power in Orange County. Last year, since the pollution offsets had moved to an emissions project at Walnut Creek, we had to convert Huntington Beach into a synchronous condenser. That is like a motor that is providing reactive power, but it is pulling electricity into the grid as opposed to a turbine that combusts gas to push electricity to the grid. The synchronous condenser unit is still operating and is critical for the reactive power.

We also took the opportunity to rewire some of the transmission system. Southern California Edison has done a couple upgrades to enhance reliability, such as installing static VAR compensators at some of the major substations in Orange County, and we have had to resort to "flex alerts," where we run messages on TV and radio telling people to conserve electricity.

We have been lucky so far. The first summer without SONGS was relatively cool, although San Diego Gas & Electric came within about 50 megawatts of its peak. This year has been even milder. Northern California has more of a chance of hitting its peak, but in southern California, it has been more like a 1-in-2 year. When we are looking at contingency planning, we plan for a 1-in-10 year. We have been lucky not to have had an extended heat wave or fires near a transmission line. We have been working steadily in the meantime to enhance our capabilities.

Coastal Power Plants

MR. MARTIN: You have another 5,068 megawatts of power plants along the California coast that use seawater for once-through cooling and that are also expected to have to shut down. Over what time period will they close?

DR. WEISENMILLER: The next big unit we are looking at shutting down is a 946-megawatt facility in San Diego in 2017. A lot more will close in 2021. We may be forced to adjust the timetable.

MR. MARTIN: Will these shutdowns add to the difficulties in southern California or are most of the plants farther up the coast?

DR. WEISENMILLER: Some of the units are in the south and will certainly affect things. There is a proposal to repower and modernize Huntington Beach, which is a key facility for both power and voltage support. There are some in the LA Basin, and other potential retirements are all the way up the coast. The Los Angeles Department of Water and Power is in the process of repowering some units in the LA Basin. Unless repowered, all such plants will have to be shut down by 2021 under federal and California regulations.

MR. MARTIN: The figure 5,068 megawatts is somewhat illusory. Don't the plants operate for the most part at really low capacity factors?

DR. WEISENMILLER: The plants are old. Encino is a good example; the first units were built in 1959. The most recent units are from 1973. They tend to be steam boilers. They tend to have relatively long startup times of anywhere from 17 to 24 hours. That means that if you think you may need the power, you have to leave the unit running. They are relatively inefficient when you look at their heat rates, and they are dirty from an air quality perspective. There is a lot of logic in trying to repower to use more modern technology. They only really come in handy if it is midnight and you suddenly lose a transmission line, they can pick up the lost capacity within a half hour if they are left on and operating.

Reducing Emissions

MR. MARTIN: What percentage of California generation is from fossil fuels?

DR. WEISENMILLER: California has a rich resource mix. Without SONGS, we still have about 10% nuclear power between Diablo and Palo Verde. We have hydro, assuming that it is a wet year, of around 10%. We have around 22% renewables, and that is increasing. The remaining 58% is gas. If it is colder and wetter than expected, then the gas units operate less and, if it is drier or hotter, or if there is an outage of a major power plant, then they operate more.

MR. MARTIN: Are cap and trade and the renewable portfolio standard the principal levers California is using to reduce greenhouse gas emissions?

DR. WEISENMILLER: Our immediate goal is to return to a 1990 level of greenhouse gas emissions by 2020. The electric utility sector accounts for about 20% of total greenhouse gas emissions. We are using energy efficiency, renewables and cap and trade to reduce emissions.

MR. MARTIN: California has set a goal of 33% renewables by 2020. The state is at about 22% renewables currently. It is expected to reach 25% by 2016. Will it have any trouble, given current trends in natural gas prices, reaching 33% within the next seven years?

DR. WEISENMILLER: Not really.

One issue with renewables procurements is the percentage of projects that are awarded power contracts but never get built. The procurements to date put us on a track to hit the 33% target assuming a 40% failure rate.

The actual failure rate is well below 40%. One of the things my siting people do is look at the status of all projects in terms of how many have been permitted and what is under construction. Most of the permitted projects are being built.

MR. MARTIN: Do you know the actual failure rate?

DR. WEISENMILLER: It is probably in the 10% to 20% range, but exact number is hard to pin down, and it varies by technology. What we see is someone signs a power contract and eventually someone with much deeper pockets comes in, takes over the project company and does what it takes to complete the project. For example, a number of solar thermal projects have switched to photovoltaic. The projects and power contracts change hands. The renewable energy eventually gets delivered.

MR. MARTIN: You made the point at a conference in June that the state RPS target will be less significant to future renewable energy development in California than climate change.

DR. WEISENMILLER: Even without SONGS, we are pretty comfortable that we will reach the 2020 targets for both renewables and greenhouse gas emissions.

There are some executive orders from Governor Brown and Governor Schwarzenegger setting 2050 emissions targets, but our feeling is that 2050 is too far away to do accurate forecasting. It is more productive to focus on 2030, come up with a plan and make progress. We are counting on three trends to reduce emissions. One is a shift to electric vehicles. The governor wants to see 1.5 million electric vehicles in California by 2025. Transport accounts for 40% of our greenhouse gas emissions. We can't reach our goals by reducing emissions solely in the power sector.

The San Onofre nuclear plant that shut down permanently last summer supplied 16% of electricity in the LA Basin and San Diego.

It is also important to improve energy efficiency in existing buildings. We have very strict standards for new buildings, and we have another round taking effect in July that will be 25% lower than our previous standards.

MR. MARTIN: Does the 33% target for renewable energy by 2020 count output from rooftop solar or does it count output only from utility-scale facilities?

DR. WEISENMILLER: Rooftop is counted potentially both indirectly and directly. Rooftop solar reduces retail sales, which in turn lowers the amount of renewable energy credits needed to meet the renewable portfolio standard. Systems could aggregate and sell the credits to utilities to satisfy RPS targets; however, the sales will not earn as much for the sellers as credits from an in-state wholesale generator.

That said, our strategy is to use every possible lever to reduce greenhouse gas emissions. We are looking at energy efficiency, transportation and grid efficiency. We have wrung a lot of emissions out of the California system and are now starting to push the boundaries. We are looking */ continued page 44*

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next at electric rates and operational issues to achieve greater reductions.

MR. MARTIN: The governor's goal of 1.5 million electric cars by 2025 should increase electricity demand and mean that the state RPS target of 33% is 33% of a larger figure. Are there any projections of how much additional renewable capacity will be needed by 2025 as a consequence of the electric cars?

MR. WEISENMILLER: When we forecast demand, we project out for 12 years, so we include electric vehicles, distributed generation, the economy and the changing demographics in California. We have goals for zero-emissions vehicles. Some could be electric; some could be fuel cells or advanced biofuels. At this point, it seems like electric vehicles are winning, but 12 years from now, the field will probably be more wide open. Then you have to consider how much change in vehicle mix there will be in southern California versus northern California. The air quality issues in Los Angeles are so severe that air quality will force more rapid change in the south.

Electric vehicles are expected to add around 5,500 GWh of electricity use statewide in 2024, and that adds up to about 200 megawatts of additional capacity needed. You also have to take into account the capacity factor and whether people will charge during on-peak or off-peak hours. Until this year, we were really focused on trying to do off-peak charging. However, given that we have so much solar being built, we may need to encourage people to charge between noon and 3 p.m.

California will have to shut another 5,036 MWs of coastal power plants that use seawater for cooling by 2021.

Need for Additional Capacity

MR. MARTIN: The state as a whole is not short on capacity. It has a 20% reserve margin for a 1-in-10 weather event. The issue really is the transmission system in the LA Basin and in San Diego. The grid is not configured to import electricity to the area that was served by SONGS. You said the grid also needs to replace the voltage support that it received from SONGS.

DR. WEISENMILLER: Location really matters because you have a load pocket. We have a tendency to think of energy and capacity when we really need to look at other things as well. One is contingency response. We also need reactive power. It is not just how do we keep the lights on, but how we find power with the right characteristics.

We are very focused on Orange County and San Diego. Orange County was served by SONGS and Huntington Beach and, as you move away from those areas, the capabilities to provide support drop off. The California ISO does very detailed power flow modeling that allows us to ramp up certain facilities to best serve areas in need, but location will be a paramount consideration for new facilities. Any new project must really be in San Diego or Orange County.

MR. MARTIN: Besides the immediate need in Orange County, what other opportunities do you see for power development in the LA Basin and San Diego?

DR. WEISENMILLER: San Diego and the LA Basin have seen 400 megawatts a year in load growth at a time when we are expecting retirements. SONGS is gone. Some El Segundo units have been retired or repowered. Other units will retire either because of once-through cooling or their economics. We are losing about 12,000 megawatts in nameplate capacity, but we only need to replace about 7,600 megawatts. We do not need to replace all of the older units.

From a contingency planning basis, there are some pretty significant time points. The Encino project has to be retired or replaced in 2017, and that is 946 megawatts. Around 2021, another 3,800 megawatts in the LA Basin will be retired. We have talked to the water board about adjusting some of the deadlines if we have to, but these are very old and inefficient plants. We have a new transmission line, Sycamore-Peñasquitos, which we are hoping to bring on line in 2016.

The 7,600 megawatts are a combination of conventional and unconventional units, and some projects to replace them have already been authorized.

MR. MARTIN: That is 7,600 megawatts over what time period?

DR. WEISENMILLER: By 2022. We are also looking at transmission options. If we could find the right transmission option that could allow greater sharing between the LA Basin and San Diego, it would reduce the need for new generating capacity.

MR. MARTIN: There are three different estimates for the additional generating capacity needed to serve the LA Basin and San Diego. Yours is 7,600 megawatts over the next four years. That is a 5.5% increase in current generating capacity, but the California ISO has a different estimate, and SDG&E and Southern California Edison have yet another estimate. Why such a range in views, from 1,800 to 4,300 megawatts by the two utilities at the low end to your estimate of 7,600 megawatts?

DR. WEISENMILLER: It is good to put things in context. The figure 7,600 megawatts was a consensus figure among the staffs of three agencies, the California Public Utilities Commission, the California Energy Commission and the California ISO, with input from Edison and SDG&E. We took into account the potential effects of government policies, not just of our agencies but also the California Air Resources Board, the State Water Resources Control Board and the South Coast Air Quality Management District. We came up with a draft plan, but the next step is specific proceedings at each of the agencies, followed next summer by another look at the numbers.

In the meantime, the CPUC has been moving ahead with procurements. A number of bids came into Edison in December 2013 for providing power under a procurement the CPUC authorized when the assumption was still that SONGS would resume operating.

The CPUC took testimony recently from the CAISO and others about what the needs are without SONGS. We are saying about 3,000 megawatts in the short term. Edison and SDG&E have asked for at least another 500 megawatts each as part of the SONGS replacement. The CPUC draft decision might be out in the next month or two.

Meanwhile, the CAISO is in the midst of a transmission planning process. Transmission proposals will be submitted at the end of the month. They could conceivably reduce the 7,600 megawatts by 1,000 megawatts.

MR. MARTIN: The 500 megawatts each for Edison and SDG&E is capacity that the utilities would build and own themselves?

DR. WEISENMILLER: Each of the three investor-owned utilities will be asking for bids for a build-own-transfer project. Each will be asking for bids not only to build generating facilities, but also new transmission lines. Three or four bids have been submitted to build the Sycamore-Peñasquitos line. We expect proposals from Edison and SDG&E to build transmission, and we expect competing bids from independents. The utilities have also expressed interest in energy storage.

MR. MARTIN: The staffs of the three agencies recommended that half the 7,600 megawatts of additional capacity should come from preferred resources. Preferred resources are energy efficiency, demand response, renewable energy, combined heat and power and storage. The hierarchy after preferred resources is transmission and then conventional power plants. You said many of these megawatts are already in the works. The net additional capacity needed over the next four years, after backing out projects that are already in the works, is probably well under 6,000 megawatts, right?

DR. WEISENMILLER: Yes. A difficulty with the preferred resources on offer is they are not as targeted as needed. We really need to get retrofits in Orange County. The preferred resources need to provide not just energy or reduced demand, but also provide some of the other characteristics.

MR. MARTIN: The need could be a lot less if new transmission lines are built to allow additional electricity to be imported.

DR. WEISENMILLER: Edison and SDG&E were pretty creative at coming up with transmission options. The options are more illustrative of what is possible than of what will actually be built. If we can find a better way to shift power back and forth between the LA Basin and San Diego, we will reduce the amount of new generation needed. Building a high-voltage line through southern California is a daunting challenge. It would take at least eight years. One of the most interesting ideas is for an offshore cable. The undersea cable would be a way to do something more quickly.

SDG&E has proposed a high-voltage DC line from Imperial Valley to SONGS. It is trying to use the existing high-voltage infrastructure rather than build a new AC / continued page 46

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line. Edison has come up with some proposals that strengthen the grid within the Los Angeles area. There are a lot of proposals. Transmission lines will provide us a way to reduce the need for conventional generation, but they are very tough to site and permit. We are waiting next for a CAISO evaluation of the relative costs and benefits from some of these options.

Rooftop Solar

MR. MARTIN: Rooftop solar is very popular in California. I read that 72% of all new capacity added in the US in October was solar. California added 1,000 megawatts of rooftop solar in each of the last two years, and the pace is accelerating. How much of the capacity needs in the LA Basin and San Diego are expected to be met with rooftop solar?

DR. WEISENMILLER: Our forecast is that installed rooftop capacity will more or less triple in southern California by 2024. The rapid expansion is creating tension with the regulated utilities. The CPUC is starting proceedings to look at net metering and rate design issues. Rooftop solar does not yet provide some of the attributes we are looking for, so it is not the sole solution. One form of reactive power that we are trying to push is smart inverters that would help provide ancillary services. However, before announcing such a standard, we need to make sure California is relatively in sync with the rest of the country. We have well over 100,000 new solar applications. A lot of those are for distributed solar installations of less than 20 megawatts. We have an explosion of development on the photovoltaic side, and the economics have come down in a phenomenal fashion.

The state is trying at the same time to reduce greenhouse gas emissions to 1990 levels by 2020.

MR. MARTIN: Under California rules, out-of-state renewable energy suppliers are at a disadvantage. Why is that, and does the disadvantage extend more generally to all types of out-of-state supply?

DR. WEISENMILLER: When the legislature established the 33% RPS goal, it expressed a strong preference for relying on suppliers who are directly connected to a California balancing authority. Californians are willing to pay more for electricity from renewable sources, but they also want the economic benefits to inure to California. I am often approached by out-of-state suppliers who say they can help us reach the 33% target, but existing power contracts will already take us well past 33%.

The issue becomes how out-of-state generators fit into the next stage of expansion. The next stage will be driven by the need for emissions reductions. When it comes to emissions, more regional solutions are better.

MR. MARTIN: So the existing impediment for out-of-state suppliers does not apply to electricity from gas-fired power plants, just from renewables?

DR. WEISENMILLER: Right, and it is a complicated structure. There are some regional transactions, but the split for renewable procurement is around 70% in-state and 30% out-of-state, which is similar to the overall split between in-state and out-of-state generation.

MR. MARTIN: What effect is the need for capacity in the LA Basin and San Diego likely to have on wholesale power prices?

MR. WEISENMILLER: The US Energy Information Administration is expecting some increase in wholesale power prices in California. The drought had some impact and gas prices have ups and downs, but all else being equal, you would think that not having SONGS would tend to push prices up. However, the counterweight is that we have a lot of very new, very efficient combined-cycle plants running at around a 45% capacity factor. It is a very competitive market, and that forces everyone to figure out ways to keep costs low. Natural gas drives marginal electricity prices in California and, ignoring brief aberrations, gas prices have been remarkably low for a while. ◎

Kuwait: The BOT Market Reopens

by Sohail Barkatali and Derek Kirton, in Dubai

Global interest in undertaking development projects in Kuwait has never been greater. A significant milestone in the evolution of project finance in Kuwait was achieved in early January with the financial close of the Az-Zour North IWPP phase I project.

This article describes the legal framework in Kuwait for undertaking projects, examines the Az-Zour North IWPP phase I project and describes the upcoming opportunities.

Kuwait has undertaken few projects to date on a public-private partnership basis.

It used a build-operate-transfer or BOT model in 2002 to build the US$377 million Sulaibiya wastewater and reclamation project. The sponsors of that project were able to put together a 25-year regionally-funded debt package for a 27-year concession from the Ministry of Public Works. Since then, private infrastructure projects have been sparse, with the focus on tendering projects using the EPC procurement method; that is, until the Az-Zour North IWPP phase I project reached financial close.

Re-enter BOT projects.

The Az-Zour North IWPP phase I project was procured under a framework established by two pieces of legislation. The BOT law, passed in 2008, and the IWPP law, enacted in 2010 and amended in 2012.

For IWPP (independent water and power producer) projects, the IWPP law prevails over the BOT law. However, where the IWPP law is silent on any matter, then the BOT law applies. Therefore, Kuwaiti projects procured as public-private partnerships are undertaken within the framework established by the BOT law and, for certain projects, supplemented by additional legislation.

The BOT law is Law No. 7/2008. Regulations issued by the executive to implement it can be found in Law No. 256/2008. The two together provide the framework for PPP projects in Kuwait and the role of government institutions such as the Council of Ministers, the Higher Committee, Partnerships Technical Bureau, the State Audit Bureau, public entities and private investors. At the core is a steering committee that is responsible for studying and approving projects involving state-owned real estate and putting them out for public tender. Amendments to the BOT law are currently being considered by the government.

Key Agencies

The steering committee or "Higher Committee" goes by the formal name "High Committee for Projects on State-owned Real Estate." It is presided over by the Minister of Finance and also includes the Ministers of Municipality, Public Works and Commerce and Industry. Other members are the President of the Partnerships Technical Bureau, the Undersecretary of the Ministry of Electricity and Water, the Director-General of the Public Authority of the Environment and two experienced specialists named by the Council of Ministers from civil servants.

The Higher Committee is responsible for developing general policies and approving detailed documents for projects and initiatives (including unsolicited proposals) of strategic importance to the national economy of Kuwait. It refers projects to the Partnerships Technical Bureau for study so that decisions are taken in accordance with the BOT law. It selects the relevant public entity to participate in the project and sign the PPP contract and to monitor the project's implementation and operation. It also must authorize any termination of a PPP contract determined to be in the public interest.

No public entity or company is permitted to enter into a contract with any investor for a project that involves state-owned real estate under BOT or similar models until the project has been reviewed and approved by the Higher Committee.

While the Higher Committee has broad responsibilities, the Partnerships Technical Bureau handles the day-to-day administration and management of the procurement process and the monitoring of project implementation.

The Partnerships Technical Bureau reports to the Minister of Finance. Its duties include undertaking surveys to identify potential development projects, making a technical evaluation of projects and unsolicited proposals that are referred to it by the Higher Committee, developing a guidebook and forms of contracts for use in projects and following up on projects to ensure they are properly implemented.

The projects that are tendered by the Partnerships Technical Bureau follow a road map that tracks the Kuwaiti national development plan.

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National Development Plan

Kuwait has 10% of the world's oil reserves, giving it tremendous economic and development potential. Its GDP per capita is far higher than the OECD average, and it runs a trade and budget surplus that is 20% to 30% higher than the OECD average. Nevertheless, it has proven to be somewhat of a challenge for the country to translate its substantial wealth into domestic infrastructure. Kuwait ranks 52 in the infrastructure band of the global competitiveness index (2012 to 2013), which ranks investment by different countries in physical capital and infrastructure.

The framework for Kuwait's economic development is laid out in a four-year development plan that was approved by the Kuwaiti parliament in 2010. The plan sets a goal of turning Kuwait into a Middle Eastern trade and financial hub with approximately US$104 billion set aside for this purpose. Significant investment is intended to come through implementation of the PPP model and private-sector participation.

A goal of the PPP program is to attract private investors and capital to Kuwait by developing the capital market, writing a PPP guidebook based on international standards, guaranteeing impartial treatment of foreign and local investors, and promising an efficient licensing process where all required approvals are provided to the investor in a timely manner.

A total of eight priority non-oil sectors have been identified by the Partnerships Technical Bureau for private-sector participation, all within Kuwait's wider development objectives. These sectors are power, water and wastewater, communications, health care, education, real estate development, transport and solid waste management.

The PPP model has been tested and proven in several countries in the Gulf region, including Saudi Arabia and Abu Dhabi. Both managed to meet the strong growth in power and water demand through large IWPP and independent power projects that attracted international developers in addition to international banks that financed the bulk of these projects. For instance, Abu Dhabi IWPPs provide more than 10,600 megawatts of power and 750,000,000 gallons per day of desalinated water. Over the last five years, Abu Dhabi has added on average 900 megawatts per year of power generating capacity solely through IWPPs that have enabled the country to keep up with a demand growth exceeding 10% per year. Recent regional experiences show that once the market has closed on the first IWPP or IPP project in a country, then the implementation process for future projects was streamlined.

The closing on the financing for the Az-Zour North IWPP phase I project should have the same effect in Kuwait.

Lessons From Az-Zour North

The project has considerable history attached to it. There were several unsuccessful attempts made by Kuwait to develop the project using the EPC procurement method. During 2008 and 2009 there were plans to develop four phases at the Az-Zour North site, south of Kuwait City. Each phase was to be procured by the Ministry of Electricity and Water with costs for the development met through budget allocations from the Ministry of Finance.

A large water and power project that reached financial closing in January will be a template for future projects in Kuwait.

There are few vacant sites in Kuwait that can support a power generation and water desalination project. Finding a viable site is a challenge given the location of existing plants and other domestic and commercial infrastructure that is already in existence along the shoreline. As such land is scarce, it is not surprising that the Ministry of Electricity and Water requested the Partnerships Technical Bureau to run a competitive tender for the phase I project once it converted to a BOT project. This small but very significant step signaled the shift in procurement policy away from the traditional EPC model to the new but unchartered territory of IWPPs in Kuwait. Under the IWPP law, the government retains the right to tender renewable energy projects as EPC contracts, and EPC contracts for power plants with capacities of below five hundred megawatts may continue to be tendered by the Ministry of Electricity and Water, subject to the approval of the Council of Ministers.

The table below lists key features of Az-Zour North IWPP phase I.

Az-Zour North IWPP Phase I : Key Features	
Project	Development of a new combined independent power generation and seawater desalination station with a net dependable power capacity of at least 1,500 megawatts and a net dependable water capacity of between 102 and 107 million imperial gallons per day on a build-operate-transfer basis
Offtaker	Ministry of Electricity and Water of Kuwait
Term	40-year energy conversion and water purchase agreement
Shareholders in the Project Company	GDF-Suez, Sumitomo Corporation and Abdullah Hamad Al Sagar & Brothers Co (together, 40%) The Public Institution For Social Security (5%) Kuwait Investment Authority (5%) Partnerships Technical Bureau (50% shareholding on behalf of Kuwaiti citizens)
Project Cost	Approximately US$1.8 billion
Lenders	Commercial lenders are National Bank of Kuwait, Bank of Tokyo-Mitsubishi, Sumitomo Mitsui Banking Corporation and Standard Chartered Bank. Additional loans provided under Nippon Export and Investment Insurance (NEXI) cover and export credit agency funding provided by the Japan Bank for International Cooperation (JBIC)
Full Commercial Operation	Q4 2016

The request for proposals was issued in March 2011. For the first-ever IWPP project in a country with no history or track record in this sector, the result was impressive. The Partnerships Technical Bureau received bids from five strong consortia in September 2011. The consortia were led by ACWA Power International, GDF-Suez, Malakoff, Marubeni Corporation and Mitsui, with each bid supported by at least a 50% commitment of financing. This can be contrasted, for example, with the first-ever IPP project in Saudi Arabia that attracted only one bidder.

The consortium led by GDF-Suez was selected as the preferred bidder in February 2012. The project agreements were finalized and agreed in December 2012. The incorporation of the Kuwaiti holding company for the purpose of taking up shares in the project company was completed during early 2013, and the project company itself was established a few months later. The incorporation coincided with sweeping reforms to the commercial companies law that streamlined the process. The project agreements and financing agreements were signed in December 2013. Financial close was achieved in January 2014.

The main project agreement is an "Energy Conversion and Water Purchase Agreement" or "ECWPA" for the sale of capacity, electricity and water. As the use of "energy conversion" in the name implies, fuel is supplied by the Ministry of Electricity and Water and converted to electricity. The other project agreements include land lease agreements and a shareholders agreement. No sovereign or other form of payment guarantee was provided by the government.

The risk allocation in the ECWPA is largely consistent with regional precedent, but adjustments were made to ensure compliance with Kuwaiti law and general policies of Kuwait. The project agreements are governed by Kuwaiti law, but they provide for offshore dispute resolution in accordance with ICC rules.

A unique feature of the transaction is the shareholder arrangements and the issues that arise from the requirement of Kuwaiti law that the contract must be entered into by a public joint stock company. This requirement is a significant departure from regional precedent. Oman is the only jurisdiction in the region that requires an initial public offering of the shares in the project company, but it does not require the IPO to have occurred before entering into the project agreements. By contrast to the position in Oman, Kuwaiti law requires the IPO to have occurred before / continued page 50

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the project agreements are executed.

This raises a number of unique challenges, the main one being how to conduct an IPO for a greenfield project at its inception and manage a call on equity where a significant proportion of shares in the project company is held by Kuwaiti citizens.

As is typical for project finance, equity commitments were provided by all shareholders to the lenders. For those shares held by the government, the commitment came in the form of cash contributions.

Kuwait is teeing up another 20 new infrastructure projects for tender.

Shareholding Structure

Kuwaiti law is prescriptive as to the shareholding requirements. There is a clear public policy objective of ensuring participation in projects by Kuwaiti shareholders as a means of wealth sharing between the state and its citizens. Under the BOT law, for projects whose value is over KWD 250 million and for most projects whose value is over KWD 60 million, 50% of the shares in a project company must be placed for public subscription through an IPO. For projects between KWD 60 million and KWD 250 million, the Higher Committee can designate the project as being of a "special nature." Special nature projects do not require the formation of a public joint stock company and do not require an IPO. The new Physical Medicine Rehabilitation Hospital was designated a special interest project.

The IPO requirement before completion is unique to Kuwait's legal framework and has not been experienced in previous IWPP or IPP projects elsewhere in the region. Hence, there were developer and lender concerns over the risk. Completion of the IPO was a condition for the full incorporation of the project company. This meant the IPO process had to be undertaken in parallel with the negotiation and finalization of the project and financing documents with the preferred bidder and its lenders. This added a significant layer of complexity especially since investors and lenders prefer certainty as to the number of shares being subscribed for, the price of those shares and the timing of the subscription.

In the Az-Zour North IWPP phase I, a structure was developed to mitigate construction risk exposure for Kuwaiti nationals and for lenders. The amendments to the IWPP law subsequently enshrined this structure by permitting the Partnerships Technical Bureau to subscribe for the capital of the shares allocated for public subscription. The PTB will hold these shares until the project is operational at which time a distribution will occur during which Kuwaiti citizens will be invited to pay for subscriptions at the same price paid by the PTB. The Council of Ministers has reserved the right to exempt citizens from paying the subscription price.

The remaining shares are held by investors and Kuwaiti public entities.

Under the BOT law, 40% of the shares in the Kuwaiti public joint stock company that will serve as the project company must be offered by way of public auction to investors, with a further 10% offered to the successful bidder after award at a discount.

For IWPP and IPP projects to which the IWPP law applies, the share allocation can vary in that the sponsoring public entity is permitted to subscribe to shares not exceeding 24% with the investor subscribing to shares not less than 26% and with no change to the allocation for public subscription to Kuwaiti nationals. While 26% is a floor, investors are wary of investing in a company in which they only own 26% of the shares. Indeed, investors and lenders inevitably require control at the management and board level, and the application of Kuwaiti law can make this process challenging. For the Az-Zour North IWPP phase I, 40% of the shares in the project company were offered to investors with 10% taken by government sovereign wealth funds.

All shares whose capital is either not paid for within a prescribed period or that remain unsubscribed by the Kuwaiti nationals may, under the IWPP law, be transferred to the developer at the government's discretion within a period not exceeding one year from the date of distribution to Kuwaiti citizens. Alternatively, the government may choose to keep these shares within the percentage allocated to it, i.e., not more than 24%. The key issue for developers is the uncertainty of ascertaining the ultimate shareholding. Kuwait's record of implementing government-sponsored IPOs is so far very good and the proposed investment returns, together with the fact that the IPO is being implemented without construction risk attached, should ensure the distribution is a success.

Additional Key Features

The IWPP law specifies that the number of Kuwaitis employed by the project company must not be less than 70% of the total workforce, and their aggregate remuneration must not be less than 70% of the total remuneration of the workforce. These requirements seem high, but they are comparable with indigenous employment targets in the market.

The Partnerships Technical Bureau evaluates bids for PPP projects through a two-step process: a technical bid evaluation followed by financial bid evaluation. Under the BOT law, in evaluating financial bids, the highest score is awarded to the bidder providing the highest price for the proposed shares of the project company.

While this may be consistent in models where governments are trying to extract value for existing assets in a sales process, it does not sit comfortably for a greenfield project. In the context of a greenfield IWPP project, this requirement raises complex issues in terms of bidding process: bidding on a share price requires fixing the various components of power and water tariffs in the request for proposals that would constrain developers in optimizing project costs and could limit the competition. The bidder offering the highest share price is not necessarily the bidder with the best offer. This creates uncertainty in terms of bidding evaluation compared to international best practices and regional precedents. Fortunately, the IWPP law favors an evaluation methodology that balances the tariff and the share price bid by the investor.

Projects tendered under the BOT law and the IWPP law are subject to a multi-layered approvals process. Approvals at various steps in the procurement process are required from the government department for legal advice and legislation (Fatwa Tashrea), the State Audit Bureau and the Higher Committee.

Opportunities for Future Deals

The Partnerships Technical Bureau has commenced the feasibility process for around 20 projects. The following are the current active projects listed on the PTB website, with some more advanced than others:

Upcoming Projects		
Power	Az-Zour North IWPP phase 1	Financial close
Power	Az-Zour North IWPP phase 2	Pre-request for qualifications
Power	Al Khairan IWPP	Expressions of interest expected shortly
Power	Al Abdaliyah ISCC	Pre-expressions of interest
Water and Wastewater Management	Umm Al Hayman	Request for proposals expected shortly
Solid Waste Management	Municipal solid waste treatment facility – Al Kabd	Pre-request for qualification
Communications	Kuwait public post office	Request for qualifications (standstill)
Communications	Communications network and telecommunications services	Request for qualifications (standstill)
Real Estate Development	South Al-Jahra Labor City	Request for qualifications
Real Estate Development	Rest houses and Doha Chalet's service centers	Request for proposals
Real Estate Development	Kuwait Failaka Island development	Pre-expressions of interest
Real Estate Development	Commercial, education, cultural and entertainment center in Abdulla Alahmad Street	Expressions of interest
Real Estate Development	Expired contracts of properties established on state-owned real estate	Post-bid submission
Health	New Physical Medicine and Rehabilitation Hospital	Pre-request for proposals (standstill)
Education	Kuwait schools development program	Pre-expressions of interest

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The BOT law also allows the submission by a developer of an unsolicited proposal with respect to a project proposed to be developed in Kuwait under the PPP model. However, an unsolicited proposal cannot be submitted if a request for proposals has already been issued for a similar project. The advantage to the developer in submitting an unsolicited proposal is that, if the project is ultimately offered for public bidding or competition, the developer is entitled to a "preference margin" upon evaluation of the proposals submitted to the PTB, not exceeding 5% of the value of the lowest price proposal that fulfills all the terms and requirements of the request for proposals.

The Al-Abdaliyah integrated solar combined-cycle project is currently in the tendering phase and was initiated as an unsolicited proposal.

Kuwait has come a long way since Sulaibiya. There is now a new legal framework for undertaking projects. There is a now a banked and project-financed transaction. There is a long line of deals that are waiting to come to the market. There is an excitement about Kuwait. There is a buzz surrounding the potential that it represents for investors, developers and lenders. There is strong political determination for increased private-sector participation, for increasing technology transfer, for know-how, for creating investment opportunities and for employment and training of its citizens. Az-Zour North IWPP phase I has been described as the trailblazer. ◎

Evaluating European Infrastructure Bonds

by Partha Pal, in London

Infrastructure bonds are expected to be a growth market in 2014.

This past year was a significant year for the emerging European market in such bonds. Further developments are expected, given both the need for new sources of funding for infrastructure and, from the perspective of institutional investors, the need for investment products that allow them to meet their investment requirements.

European infrastructure bonds have traditionally been a monoline-wrapped product, with investors able to draw comfort from the claims payment ability of the monoline and the contractual validity of its wrap, while leaving the heavy lifting of assessing the transaction to the monoline. In the absence of monoline involvement and, unless using the services of an intermediary investment manager, institutional investors need to apply an analytical process that covers legal and structural risks, as well as commercial ones.

This article is an overview of some of the legal and structural matters that warrant consideration by institutional investors.

Infrastructure bonds are capital market debt instruments issued by special-purpose entities where interest is paid, and principal repaid, using the cash flow generated by one or more pieces of physical infrastructure owned by the issuer or by another entity to which the issuer makes a loan.

They are asset-backed bonds, as opposed to corporate or sovereign bonds, that rely on the ability of the issuer to pay interest and repay principal using all cash flow available to it, rather than any dedicated cash flow. As such, they are susceptible to focused analysis in terms of the robustness of the cash flow and its sufficiency for debt service purposes. The cash flow can be enhanced through various credit, liquidity, risk-management and operation-management features designed to ensure debt service is paid.

Required Analysis

It is helpful when analyzing infrastructure bonds to look at two key elements: the "asset side," meaning the infrastructure that generates the cash flow used to service the bond, and the "funding side," meaning the structural features that are used to enhance the cash flow from a credit, liquidity, risk-management and operation-management perspective.

Starting with the assets, the infrastructure has two manifestations.

Infrastructure bonds are expected to see wider use in Europe in 2014.

The first is the physical. Infrastructure assets are of various types and no categorization is fully comprehensive or satisfactory. However, a useful categorization is based on usage: utilities (such as electricity, gas, telecommunications and water), transport (such as roads, railways, airports, seaports and railway stations) and social (such as schools and universities, social housing, health care, recreational facilities and penal or correctional facilities). Clearly, without a physical asset there is no infrastructure and no cash flow. Creating and maintaining the physical assets is a necessary part of any transaction.

The second is non-physical. Infrastructure assets generate cash flow either pursuant to a regulatory framework (for example, the generation of electricity from renewable sources that is sold to a distributor at a price predetermined by a regulatory framework as opposed to through market forces or subject to a contract-for-differences framework) or pursuant to a contractual framework (for example, the payment of contractually-determined availability payments by a public authority in consideration for the provision of a road or a health care facility). In many cases, there will be both a regulatory aspect and a contractual aspect to how the cash flow arises.

Investors need an understanding of both the physical and the non-physical aspects. The non-physical aspect is self-evidently legal in nature because it is based on rules.

Diligence relating to the rules revolves around three key questions. How does the infrastructure generate cash flow? How might the cash flow be reduced? How might the cash flow be stopped?

While framing the questions in this way is straightforward, responding to them in a comprehensible manner requires sophisticated legal analysis, taking account of both regulatory and contractual matters, and an understanding of both the technology behind the infrastructure as well as the motivations of those who actually make payments, thus enabling the cash flow to be generated.

The physical aspect is less self-evidently legal in nature, because on its face, it is concerned with technical matters of complex engineering. However, both construction and maintenance of the physical assets will have contractual underpinnings. For example, if the physical assets are not constructed or operated to satisfactory standards, this may affect their ability to generate enough cash flow to service the debt, thus giving rise to the need to remedy the failure and to recover both the costs of remediation and other losses that flow from the failure of the responsible transaction participants.

Unlike other asset classes that back structured bonds such as residential mortgages, consumer loans or trade receivables, infrastructure assets are heterogeneous and require case-by-case assessment, both from the physical and non-physical perspective. This is certainly possible, but in order to be undertaken efficiently requires a systematic framework. It also requires a structured-finance mindset, meaning testing structural robustness by considering how the structure would respond after an insolvency event affecting each transaction participant.

Financial Architecture

While the asset side of an infrastructure bond is concerned with physical engineering, the funding side is where financial engineering becomes prominent. The funding side features of infrastructure bonds are similar to those that are found in conventional project financing.

Reserves are used either for specific asset-related purposes where there will be a need for expenditure */ continued page 54*

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or, more generally, to ensure debt service payments are made in a timely fashion. Hedging may be used to mitigate the possibility of variation in interest rates, currency exchange rates or possibly commodity prices that, if not mitigated, could have an impact on the cash flows available for debt service. Cash-flow control may be used to ensure that cash flow is collected and applied in a disciplined manner so that debt service payments are made. There may also be subordinated debt, in which case there is a need to ensure that the sponsors have enough economic interest in the continued functioning of the project and the continued generation of infrastructure cash flow.

Again, adopting a structured finance mindset is necessary, so that the implications of insolvency of the transaction participants can be assessed and provided for.

Where infrastructure bonds differ markedly from conventional project financing is the way in which the issuer, as the debtor, and the bondholders, as creditors, interact and how creditor rights are enforced in the event of financial distress.

In conventional project financing transactions where the creditors are banks, these functions will typically be undertaken through a facility agent. The agent will be able to interact as it considers appropriate, with mechanisms existing within the finance documents to allow lenders to exercise democratic rights. This approach works because, in the bank market, the identity of all lenders will at all times be known to the agent, allowing the necessary interaction to take place. In the context of capital markets, such a level of interaction is not so easy to facilitate because bondholder identity is both transitory and opaque (with bonds being held through clearing systems and custodian accounts).

There are basically three approaches to structuring interaction between the issuer and bondholders in infrastructure bond deals.

One is not to have any particular structural features. This is not as radical as it might first sound. Corporate and sovereign bonds do not have any such features. If there is distress, bondholders convene ad-hoc committees and deal with the situations that have arisen, with bondholders themselves determining the framework and decision-making lines. However, this approach is not consistent with the world of structured finance, nor with infrastructure as an asset class, where there is a greater need for interaction given the complex physical nature of the assets during both the construction and operating phases.

Another approach is to have a third party who acts for the benefit of all investors. This is the office holder described as a "servicer" or "special servicer" in the context of other asset classes. In theory, this is a good idea in that the issuer has a single point of contact and the bondholders have a single point of contact. In practice, this has proven harder to operate efficiently as servicers in other asset classes have faced various comments from investors about the discharge of their functions. Servicers have in any event been careful about owing duties directly to bondholders for fear of liability and conflicts of interest.

The third approach is to have an individual or collection of bondholders that takes the lead in interacting with the issuer. In theory, this could be an anchor investor or a collection of anchor investors, who constitute a creditor committee from the outset with stewardship responsibilities. However there can be no assurance that the anchor investor's interests will necessarily be the same as that of other investors. Nor can there be any assurance that the anchor investor will retain its holding during the entire term of the transaction.

Each approach has its advantages and disadvantages and it may take some time before any form of standardized approach emerges — the approach may vary to reflect how the asset side functions in connection with different types of infrastructure. However, a governance framework made up of all three elements, in different variants, could also be plausible with, for example, an office holder dealing with uncontroversial matters but relying on bondholder participation where greater complexity is involved and having a deciding voice if consensus cannot be reached.

Other Issues

Infrastructure bonds are complex and a proper review requires a thorough approach. For example, insurance requirements apply to the asset side of a transaction. A security package must be structured at the level of the issuer. The rating process is important, and institutional investors draw comfort from ratings. However, as the rating agencies have been at pains to point out following the onset of the financial crisis, a rating is only a statement of opinion and not a guarantee of performance; hence the importance of a rigorous, structured approach to diligence and assessment. ◎

Adjustments Needed in Some Partnership Terms

by Keith Martin, in Washington

New partnership regulations issued by the Internal Revenue Service in January may require changes in some arrangements used by partnerships.

The regulations are merely proposed at this stage, and the IRS is taking comments. They will apply prospectively once they are reissued in final form.

There are three main effects potentially for partnerships that own power and other infrastructure projects.

Return of Developer Costs

A developer forming a new partnership with a cash or tax equity investor sometimes has the investor make a capital contribution to the new partnership for an interest. The partnership then distributes part of the cash to the developer to reimburse him for his capital spending on the project.

Any such distribution can be received by the developer tax free as long as it reimburses for spending during the past two years. However, if the project is worth more than 120% of the "adjusted basis" the developer has in the project when the partnership is formed, then the amount that can be distributed tax free is limited to 20% of the fair market value of the project on the date the partnership is formed.

This ability of the developer to pull out money tax free is called the "pre-formation expense safe harbor." Otherwise, the IRS is inclined to view a developer who contributes a project to a new partnership and pulls out cash that the other partner contributed at formation as having made a disguised sale of the project to the new partnership. Any such sale would be taxable.

The IRS has proposed that the safe harbor be applied on a property-by-property basis. Thus, the cash distribution would have to be allocated among each separate "property" based on the spending over the last two years on that property, and a separate calculation would have to be done to determine whether each property is worth more than 120% of the adjusted basis the developer has in it. It is unclear whether a power plant would be considered a single property for this purpose.

In addition, if the developer borrowed money to fund some of its spending on the project and the partnership assumes the debt when it takes the project, then the partner cannot be reimbursed tax free for the capital spending paid for with this debt to the extent the debt is considered borne by the other partners. This situation arises where a project company that borrowed to build a project turns into a partnership because a cash or tax equity investor is brought in. Part of the debt is considered taken on by the new partner.

Partner Debt Guarantees

The next two potential effects of the new rules have to do with how partnership- or project-level debt is shared among the partners in "outside basis."

Each partner has both a capital account and an outside basis. These are two measures of what the partner put into the deal and what he is allow to take out. Once a partner runs out of outside basis, then the use of any further losses the partner is allocated by the partnership will be suspended until the partner is allocated income by the partnership against which he can use the losses. Any further cash the partner is distributed will be taxed as capital gains. (Partners are not taxed on cash distributions until they run out of outside basis.)

Thus, the more partnership- or project-level debt the partner can put in his outside basis, the more losses can he absorb and the more cash he can receive without having to pay taxes on the cash.

Any "recourse" debt at the partnership or project level for which the partner is liable ultimately goes into that partner's outside basis. In some deals, a partner may guarantee partnership- or project-level debt so that he can include the debt in his outside basis.

The IRS is proposing to take a harder line on this type of debt. It does not believe many of the guarantees are real. In the future, unless state law makes the partner liable for the debt, the guarantee would have to pass a number of tests.

The terms would have to be commercially reasonable and not designed solely to obtain tax benefits.

The partner must be good for the guarantee. The guarantee will be recognized only to the extent of the partner's net value. (This rule does not apply to individuals, but the IRS is asking whether it should.) The partner must also maintain at least the net worth that an outside lender would require to rely on the guarantee or be subject to restrictions on asset transfers for less than full value.

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The guarantee should be for the full principal amount of the debt. (The IRS is considering whether it also needs to cover all the interest that will accrue on the debt over time.)

"Bottom-dollar" guarantees do not work. An example of a bottom-dollar guarantee is where a partner guarantees $800 of a $1,000 debt, but only after the lender has collected at least $200 from the partnership. An example in the proposed regulations also makes clear that a guarantee will not work where a partner in a partnership of three equal partners guarantees 25% of the debt. However, it would work if each of the partners is "jointly and severally" liable for the full debt, but they have an agreement among themselves that each will contribute its share if any of them is called on to pay the full amount.

New IRS regulations may require changes in some arrangements used by partnerships. The regulations are prospective.

The partner should be paid the same amount a third party would require for providing the guarantee.

The guarantee should not require the partnership to hold cash or other liquid assets above its reasonable needs to fund operations, as this would make the partner guarantee less likely to be called.

The partner must provide the partnership and lender periodically with documentation about its financial condition.

The IRS will reduce the amount of debt a partner is considered to have guaranteed by the amount he would be reimbursed by any other person, including other partners, the partnership or third parties, if the partner's guarantee is called.

Nonrecourse Debt

Debt in the project finance market tends to be nonrecourse debt: the lender looks solely to the project for repayment. Assuming it remains nonrecourse debt — meaning no partner has guaranteed repayment of the debt — then the debt is shared among the outside bases of the partners according to a waterfall.

An amount of the debt is put first in each partner's outside basis in the amount of phantom income — called "minimum gain" — that the partner will have to report as the debt principal is repaid. Partners claim depreciation on the project. To the extent the project cost was paid by borrowing from lenders, then that share of depreciation gets reversed later as the debt is repaid. That's because repayments of principal are not deductible by the partnership. The partnership will have earnings from electricity or other product sales, but no cash to pay the taxes since the cash will have gone to pay debt service.

Next, if when the partnership was formed, the developer was treated as contributing project assets to the partnership and was credited with contributing more value than he spent on the contributed assets, then the assets have a "built-in gain." The developer will eventually have to report that gain when the assets are resold by the partnership or else the obligation by the developer to report this gain will be worked off by shifting depreciation to which the developer would otherwise have been allocated to the other partners. An amount of debt equal to the remaining built-in gain is put next in the developer's outside basis.

Finally, the remaining debt is put in partners' outside bases in the same ratio they share in income or profits. Current IRS regulations allow the parties essentially to set a percentage for sharing the remaining nonrecourse debt in outside basis. The IRS is proposing to eliminate this ability to set a percentage.

In the future, if the partnership does not want to allocate the remaining debt by profits shares, then its only other choice would be to allocate it to partners based on the ratio in which partnership assets would be shared when the partnership liquidates. This ratio would be fixed when the partnership is formed, but then would have to be recalculated each time new capital contributions are made, a partner withdraws, a partner is issued an interest for services or the partnership grants a non-compensatory option to someone to acquire a partnership interest. The recalculations could be burdensome.

Effective Date

These new proposals will not apply until after the IRS reissues them in final form. That could take a year or more. Once adopted, they will apply to borrowings and guarantees entered into after they take effect. Partnerships will have the option to apply them retroactively. A significant modification in the terms of an existing loan or guarantee after the proposals take effect could bring the new rules into play.

The proposed new rules are being printed in the *Federal Register* as Reg. 119305-11.

The IRS issued separate proposed regulations in mid-December to address some other technical issues with partnership- or project-level debt. Among the issues they address is what happens if multiple partners have given guarantees in an effort to turn partnership- or project-level debt into "recourse" debt that they can put in their outside bases, and the guarantees add up to more than the total debt.

The IRS said the answer is to allow each partner providing a guarantee a fraction of the debt in its outside basis equal to his guarantee times the sum of all the guarantees. ◎

Mexico Opens its Energy Markets

by Raquel Bierzwinsky, in New York and Mexico City

The Mexican Congress has until the end of April to pass implementing legislation after amending the Constitution on December 20 to allow sweeping changes in the oil and gas and power sectors.

The Constitution has been amended to allow private-sector participation in activities that, since the 1960s, were deemed the exclusive preserve of the Mexican state. Private companies should now be allowed to participate in oil exploration, production, refining, processing, storage, transportation and first-hand sale of oil, gas, basic petrochemicals and refined products and to participate in the competitive generation and sale of electricity.

Oil and Gas

Until now, all hydrocarbons (either in solid, liquid or gas form) have belonged to the Mexican state. The Mexican state also has had the exclusive right and authority to undertake all upstream activities, that is, the exploration, production and development of hydrocarbons, with an express prohibition on the granting of contracts and concessions. Other midstream and downstream activities, including refining, processing, transportation, storage and first-hand sales of oil have also been reserved to the Mexican state, with the private sector only permitted to participate in limited activities, such as transportation, distribution and storage of natural gas and the provision of services through service contracts.

With the energy reforms, ownership of all underground hydrocarbons will remain with the Mexican state, but the private sector will now be permitted to participate, in addition to service contracts, through profit-sharing agreements, production-sharing agreements and licenses in the following activities: exploration, production, refining, processing, transportation, storage and first-hand sales of hydrocarbons, oil, gas, basic petrochemicals and refined products.

The inclusion of licenses in the reform is a well-received development. While the authors of the amendments (including the President and his advisors) were reluctant to use the word "concession," the licenses will act in many ways as such, where the private companies will be able to control oil and pay royalties and taxes to the government. This could be the vehicle used by the government to tap Mexico's vast shale gas reserves.

Another significant development is that the reforms will allow private companies to book reserves for accounting and financial purposes, while noting that the reserves, as long as they remain underground, continue to be the property of the Mexican state and thus cannot be traded.

Power Sector

While the power sector reforms are not as expansive and detailed as the oil and gas sector reforms, they do expand the activities in which the private sector can participate.

Until now, the private sector has only been allowed to participate in the generation and transmission of electricity that is not intended for sale at retail or through select generation schemes for which permits must be obtained from the Energy Regulatory Commission (Comisión Reguladora de Energía or CRE): independent power producer, */ continued page 58*

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self-supply (autoabastecimiento), cogeneration, small production (under 30 megawatts), import for self-consumption and export. All wheeling and distribution activities has been reserved until now exclusively for the Mexican state through the Comisión Federal de Electricidad (CFE).

The reforms allow broader private-sector participation in the generation and sale of electricity, but reserve operation of the national grid, as well as transmission and distribution activities, for the Mexican state, but allowing the state to hire private entities to construct and operate transmission and distribution facilities. The reforms direct the Mexican Congress to determine through implementing legislation the contract types available to the private sector for financing, installation, maintenance, management, operation and expansion of the infrastructure necessary for transmission and distribution of retail electricity.

In addition, with respect to the generation and sale of energy, the expected amendments to the existing secondary laws that regulate the power sector will provide the types of schemes and contracts that private companies will be allowed to enter into, but it will not be until their enactment that we will be able to find out the real meat of the reforms.

Additional Provisions

The Constitutional reforms also include a series of additional provisions affecting the government agencies and entities in charge of the oil and gas and power sectors or that are active participants in these sectors. The state oil company, Petróleos Mexicanos or PEMEX, and the CFE will remain key players. However, they will become "state productive enterprises" that will compete head-to-head with the private sector.

Once the implementing legislation has been enacted, PEMEX will be able to decide which projects it wishes to keep and which others will be opened to private investment. With respect to the latter, the National Hydrocarbons Commission (Comisión Nacional de Hidrocarburos) will run the bidding processes for projects it has decided to open to private investment, with PEMEX allowed to bid.

The CRE will remain the agency in charge of granting permits for storage, transportation and distribution of petroleum products, natural gas and basic petrochemicals, as well as regulating access to pipeline transportation and storage of hydrocarbons, as well as first-hand sales.

Finally, the reforms require the executive branch to create two new independent entities — the National Energy Control Center to manage the national grid (a task that is currently performed by CFE) and the National Natural Gas Control Center to manage operation of the national gas pipeline and storage system — within 12 months after Congress enacts implementing legislation to put the new reforms in place.

The reforms are a major development and, if properly implemented, they should dramatically boost oil and gas production, including from Mexico's shale gas reserves, significantly decrease power tariffs over time and spark a new wave of multi-billion dollar investments in infrastructure to modernize facilities and expand Mexico's power grid and pipeline system. But there is work to be done and, as always, the devil is in the detail. It will be in the implementing legislation that we will be able to appreciate fully the extent of the reforms and their true implications for investors and for Mexico's growth. ◎

The Mexican Congress has until April to pass legislation to implement sweeping new changes in the energy sector.

Environmental Update

Regulation of air emissions from power plants is in a state of flux in 2014, with particular uncertainty as to how regulators can and will tackle cross-state air pollution and the degree to which new and existing power plants will have to curb emissions of greenhouse gases. The US Environmental Protection Agency is scheduled to propose limits on greenhouse gas emissions for existing power plants by June.

Cross-State Air Pollution

The US Supreme Court heard arguments in December about rules the Environmental Protection Agency issued to hold upwind states responsible for cross-border air pollution that harms downwind states. A US appeals court had rejected the rules. The "cross-state air pollution rule," or "CSAPR," was originally scheduled to take effect on January 1, 2012, but implementation has been delayed pending resolution of pending legal challenges.

The US appeals court said in a case called *EME Homer City Generation v. EPA* in 2012 that EPA had gone beyond its authority under the Clean Air Act in the way it apportioned the required emissions reductions among affected upwind states. EPA proposed in CSAPR to allow the market to decide where pollution should be reduced by setting a limit on total pollution and allowing credits or allowances to be traded. The court suggested that the agency should have apportioned emissions reductions by state based on the amount of pollution each upwind state causes. The appeals court also overturned CSAPR on the ground that EPA imposed a federal solution, rather than letting the states amend their state implementation plans in order to comply. The appeals court ordered EPA to continue administering the "clean air interstate rule" in the meantime, CSAPR's less-stringent regulatory predecessor, until the appeal to the US Supreme Court is decided in the government's favor or the agency promulgates a valid replacement.

Downwind states complain that upwind states can be in compliance with air quality requirements within their borders while sending some of their air pollution to neighboring states, thereby preventing the neighboring states from meeting regulatory obligations. The downwind states who want the issue addressed are largely in the Northeast and the mid-Atlantic, with the upwind states located mainly in the Midwest and the South. To decide the case, the justices will have to determine the meaning of a good neighbor clause in the Clean Air Act that prohibits pollution sources in a particular state from emitting pollution in "amounts that contribute significantly to nonattainment" in another state.

A decision by the US Supreme Court is expected by June, with the possibility of a 4-to-4 tie because Justice Samuel A. Alito, Jr. disqualified himself. A tie would leave rejection of CSAPR by the lower court in place.

Contingency Planning

The Environmental Protection Agency is working on a new cross-state transport policy that it could implement if the Supreme Court rules against it, possibly as soon as late 2014.

The fallback policy is expected to define each state's regulated contributions to downwind nonattainment on a proportionality basis, rather than through a straight market mechanism designed to capture the cheapest reductions. EPA would probably also allow states to revise their state implementation plans to reduce their shares of cross-state pollution rather than impose a federal plan.

Even if EPA wins and CSAPR is upheld, adjustments to the CSAPR implementation schedule will be needed because some compliance deadlines already passed.

Downwind States Take Action

In the meantime, some downwind states have taken steps under the Clean Air Act to force EPA to address cross-state transport of pollution.

In December, eight downwind states petitioned EPA under section 176A of the Clean Air Act to add nine upwind states — Illinois, Indiana, Kentucky, Michigan, North Carolina, Ohio, Tennessee, Virginia and West Virginia — to an "ozone transport region." If added, this would require the upwind states to amend their state implementation plans to step up vehicle inspection and maintenance programs for major metropolitan areas and implement certain volatile organic compound and NOx emission control technology requirements for major factories and power plants.

EPA may add a state to the transport region if air pollutants from it contribute significantly to failure by a downwind state to comply with a national

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Environmental Update

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ambient air quality standard. The petition says that cross-state pollution from the upwind states contributes significantly to violations of ozone standards in the ozone transport region as a whole — the downwind states are already included in the transport region — and asks EPA to require the upwind states to take steps to reduce their emissions.

EPA must act on the petition within 18 months, but the agency has broad discretion to approve or disapprove the petition. Whether EPA decides to expand the transport region may depend in part on whether CSAPR survives review by the Supreme Court.

In addition to the effort under section 176A, some states and cities have begun taking a more targeted approach to cross-state pollution by filing petitions under section 126 of the Clean Air Act. These petitions ask EPA to find that a particular stationary pollution source or group of such sources emits in violation of the good neighbor provision of the Clean Air Act. If EPA so finds, then the source has just three months to reduce its emissions or shut down.

Greenhouse Gas

The US Supreme Court will also hear arguments in a separate dispute over whether the fact that EPA is required to regulate greenhouse gas emissions from motor vehicles also obligates the agency to regulate such emissions from stationary sources like power plants.

If EPA loses, it could be forced to curb or withdraw current and planned rules imposing limits on greenhouse gas emissions from new and existing power plants and other industry sources, especially coal-fired power plants.

The lawsuit claims that EPA has no authority under the Clean Air Act to require major stationary sources to obtain permits for their greenhouse gas emissions. The Supreme Court let stand earlier a finding by EPA that greenhouse gases like carbon are pollutants that pose a potential threat to human health and the environment and, thus, the agency has the power to act. However, the latest case will test whether the agency only has authority to regulate carbon emissions from motor vehicles or can regulate them more broadly.

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00-100 | 14-02 PF NewsWire February 2014