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US Partnerships Get A Makeover

by Keith Martin, in Washington

Partnership agreements will have to be revised in the wake of new partnership audit rules that the United States enacted in early November.

The new rules may also complicate future sales of interests in existing partnerships, loans where a partnership is the borrower, and the allocation of risk and tax contest provisions in tax equity deals.

The Internal Revenue Service is having a hard time auditing large partnerships. For example, master limited partnerships in the energy sector can have 10,000 or more partners. Since 1982, how a partnership is audited depends on its size. For most partnerships, any audit is at the partnership level. The IRS then goes after the partners for payment of any back taxes. However, small partnerships with up to 10 partners, each of whom is an individual or a C corporation, must choose to have this approach apply to them. Otherwise, the IRS audits the partnership and the individual partners separately. Large partnerships with 100 or more partners can choose to have any tax assessments flow through to the partners in the year the IRS assesses back taxes rather than the tax year under audit. Thus, current-year partners end up with the tax burden if the partnership chooses to handle the tax adjustment that way.

Congress replaced this approach with a new approach in early November as part of a budget deal to increase the federal borrowing limit. The new rules will apply starting with tax returns filed for 2018, but they may start affecting transactions involving partnerships that expect to be in business past 2017 immediately. / continued page 2

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STATE INCOME TAX REFUND CLAIMS are proliferating as states move to drop out or nullify parts of a multistate tax compact that companies are using to make refund claims.

Michigan is the latest state in the crosshairs. Taxpayers in 50 consolidated tax cases lost before the state court of appeals in September in a lawsuit against the state tax department. The issues may be headed ultimately to the state Supreme Court.

Each US state taxes income earned in the state. Because the states have different approaches to determining how much income a large company operating nationally earned in each, there is the potential for double taxation. A House subcommittee / continued page 3

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Under the new approach, the IRS would audit partnerships at the partnership level. If there is an adjustment, then the partnership would pay the tax and reduce cash distributions to partners in the year the tax is paid. Thus, current partners would bear the burden rather than the partners during the tax year under audit.

Effects on Transactions

This means anyone buying an interest in an existing partnership will have to factor in the risk that he may be hit with additional taxes that should have been paid in the past by the person selling him the partnership interest.

It also means that lenders to partnerships will have to factor in the possibility that the partnership will have to make a tax payment. Most lenders calculate debt-service coverage ratios by assuming that income taxes are paid by the partners directly and are not an expense at the partnership level.

It will also affect tax equity transactions in the renewable energy market. The tax equity investor in such transactions takes the risk that the structure works to transfer tax benefits. However, if the IRS adjusts the partnership allocations, for example, so that the tax equity investor is allocated a smaller percentage of the investment tax credit, then it would have the effect of shifting risk back to the partnership. The partnership agreement would have to be amended to require the tax equity investor to indemnify the partnership for the tax.

The IRS will assume that any tax assessed at the partnership level should be at the highest marginal income tax rates even though partners would not have had to pay taxes at that rate. The highest tax rate is the corporate tax rate — currently 35% — or the individual tax rate — currently 39.6% — whichever is higher. The partnership can provide evidence to the IRS that the taxes would have been lower if they were based on partner-level information for the tax year under audit. Examples are the status of the partners — for example, the partners may all be corporations rather than individuals or some may be tax-exempt entities — or the type of income involved — for example, the income may be capital gains or dividends on which the partners qualify for a reduced rate of tax. Congress assumed that there would be back and forth with the IRS agent about the appropriate tax rate to use while the partnership is under audit.

A peculiar feature of the new rules is that if the IRS finds fault with how the partnership allocated income, deductions or tax credits among the partners, then it will not net the shift in amounts. For example, suppose a partnership allocated $1 million in deductions to partner A that the IRS feels should have been allocated to partner B. It will assess the partnership for taxes at 39.6% of $1 million.

The partnership can reduce the taxes it has to pay by sending amended K-1 forms to each person who was a partner in the tax year under audit. This would leave the extra taxes with them, but require them to file amended tax returns for the year under audit. This would spare the partnership from having to pay the assessed taxes only to the extent each partner pays its share of the assessment within 270 days after the partnership received the notice of proposed adjustment from the IRS. The IRS likes this approach because the partnership, not the IRS, would have to do the work of dividing up the assessment and chasing partners.

A partnership with 100 or fewer partners can opt out, in which case the partnership and partners would be audited separately. Clifford Warren, a special counsel to the IRS associate chief counsel for partnerships, described this as going back to "prehistoric days" where "each partner can litigate separately and take its own position" at an American Bar Association tax section meeting in Philadelphia in early November. However, it would mean that any audit adjustments affect persons who were partners in the tax year when the additional taxes should have been paid. Partners would still be under a general obligation to report partnership results

New US tax rules will require rethinking transactions with partners and partnerships.

consistently with how the partnership is treating them or to alert the IRS to the inconsistency. A partnership choosing this approach would make an election under section 6221(b) of the US tax code.

Any such election would have to be made on each tax return the partnership files for 2018 and future years. If that is what the partners want, then the partnership agreement should require the managing partner to make such an election.

Opting out is not an option unless all the partners are individuals, S corporations or C corporations. The IRS will look through any S corporation and treat all of its shareholders as if they were partners directly for determining whether there are too many partners to make the election.

It is unclear whether the election will be available where one of the partners is itself a partnership. On its face, the statute does not allow an opt-out election, but it gives the IRS the authority to apply a look-through approach of treating all the partners in the upper-tier partnership as if they were partners in the main partnership directly. The IRS will have to think about the challenges of auditing partnerships that opt out in this situation when deciding whether to allow opt-out elections. Tax staff on Capitol Hill say it has authority to allow the elections.

As an alternative to making opt-out elections on each tax return, the partnership can wait until it receives notice from the IRS of a final partnership audit adjustment and then send K-1s to persons who were partners in the tax year under audit. Those partners will be allowed to include the additional taxes on their current-year tax returns rather than have to go to the trouble of filing amended returns. However, the partners will have to pay higher interest on the late payment. The partnership is relieved from having to pay any taxes at the partnership level. The partnership must notify the IRS within 45 days after receiving the final partnership audit adjustment from the IRS that intends to use this approach. In so doing, it makes an election under section 6226 of the US tax code.

Lenders

Lenders may insist in future loan agreements that any partnership to which they lend make opt-out elections under section 6221(b) or commit to use the procedure in section 6226 for shifting taxes back to the audit-year partners. They also may need to make sure, through borrower covenants and transfer restrictions, that all the partners remain individuals, S corporations or C corporations so that the partnership remains eligible to make an opt-out election.

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recommended in 1965 that Congress impose a uniform apportionment regime on the states. State tax administrators from nine states drafted a multistate tax compact in 1967 in an effort to avoid federal action. More states joined later. The multistate compact adopts a three-factor formula in which a company apportions income to the state based on the share of the company's total property, payroll and sales in the state. The three factors are given equal weight.

In 2008, Michigan shifted to a sales-only formula. The companies involved in the lawsuit argue they should still have been able to use the three-factor formula in the multistate tax compact to determine their Michigan incomes, at least until September 2014 when the state dropped out of the compact retroactively to January 1, 2008. The companies have large sales, but little payroll or property in Michigan.

The state is facing as much as $1.1 billion in refunds if it loses in the courts.

The case is *Gillette Commercial Operations North America v. Department of the Treasury*. Other companies joining in the suit include IBM, Dollar Tree, Anheuser-Busch, Michelin, Sonoco Products, Cargill, Goodyear, Fluor, T-Mobile and Hallmark.

The court of appeals said the state has a right to change its tax laws retroactively and doing so is not a denial of due process to taxpayers under either the federal or state constitution. Both federal and state courts have held that retroactive amendments to tax statutes do not offend due process as long as there is a legitimate business purpose that is furthered by rational means. It is not enough for taxpayers to show they did something in reliance on the tax law at the time. (For a discussion about when retroactive tax law changes go too far, see the November 2012 *Project Finance NewsWire* starting on page 11.)

The case may end up next before the Michigan Supreme Court. That court held in July 2014 that IBM was entitled to use the three-factor formula for calculating its taxes in 2008 after concluding there was no */ continued page 5*

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An opt-out election could cause contests in tax equity deals to be conducted at the partner rather than the partnership level. (Contests where the section 6226 procedure is chosen would remain at the partnership level.) The typical contest clause in a partnership flip tax equity transaction allows the sponsor to control any contest for losses for which the sponsor will have to indemnify the tax equity investor, but requires it to keep the tax equity investor informed. Some rethinking may be required of these contest provisions in opt-out situations. Most tax equity documents require the partners to try to push the contest back to the partnership level.

Another change is in who can be the "tax matters partner," or the partner designated to deal with the IRS on behalf of the partnership. Under current law, the tax matters partner must be a member-manager, if the partnership is a limited liability company. Starting with the 2018 tax year, the partnership can designate either a partner or a person who is not a partner with sole authority to act for the partnership in IRS audits and court proceedings.

A partnership may elect to have the new provisions apply immediately to tax years starting after it was enacted on November 2, 2015. Any partnership making such an election could not then opt out before the 2018 tax year. ◎

California's March to 50% Renewables

by David Howarth and Mark Fulmer, with MRW & Associates, LLC in Oakland, California

California Governor Jerry Brown signed a bill — SB 350 — in early October committing the state to generate 50% of its electricity from renewable energy by 2030.

There are so many moving pieces in California with energy efficiency and rooftop solar soaking up load growth, net metering and rate design proceedings before the California Public Utilities Commission potentially changing the calculus for distributed solar, solicitations by the three main electric utilities for large amounts of energy storage, and fears from independent power producers and the California grid operator, CAISO, about how the grid will be able to adjust to more renewables.

It can be hard for outsiders to unpack the new 50% renewables target. Is it as simple as it looks: another 17% in renewable energy generation will be needed?

The short answer is no.

SB 350 adds to the moving pieces for project developers trying to identify opportunities.

In addition to increasing the state renewable portfolio standard, SB 350 contains provisions calling for the state to double energy efficiency savings in electricity and natural gas use by 2030. Since the RPS is calculated as a percentage of sales, reductions in electricity consumption will offset the potential increase in renewable energy demand from the higher targets. The bill originally set a goal to reduce petroleum usage in the state by 50%, but that provision was removed just before the assembly vote at the end of the legislative session. However, as discussed below, SB 350 still promotes transportation electrification, which would increase demand for renewable electricity.

The 50% renewable portfolio target applies to utilities, community choice aggregators and electric service providers regulated by the California Public Utilities Commission, as well as independently-governed municipal utilities and irrigation districts.

The 17 percentage point increase in the state renewable portfolio standard is phased in over time, with the existing 33% RPS in 2020 increasing to 40% in 2025, 45% in 2027, and 50% in 2030. SB 350 requires that 65% of RPS procurement be from contracts of at least 10 years or supplied from eligible resources owned by the utility or other load-serving entity. Category 1 resources, which are delivered to points on the California grid, can be banked without limit beginning in 2021. (For background about how the different types of renewable electricity are classified under the state RPS program, see "California Rules Worry Out-of-State Generators" in the May 2012 *Project Finance NewsWire* starting at page 10.)

According to the most recent RPS report from the CPUC to the California legislature, the three major California investor-owned utilities anticipate meeting nearly 31% of their retail sales with qualifying renewables by 2016. Thus, the utilities are well positioned to begin the march to meeting a 50% target over the next 15 years.

Because the utilities are ahead of schedule for meeting the existing 33% target by 2020, and there are still mandates requiring utility purchases of smaller-scale renewables that also count towards the RPS, there will probably be a pause in RPS procurement in the near term. For example, PG&E has indicated it will not hold a 2015 RPS solicitation. SDG&E last held an RPS solicitation in 2013 and does not foresee holding another one in the next several years. However, thanks to SB 350, annual RPS solicitations should pick up again to meet the new targets within a few years.

Community Choice Aggregators

There has been a lot of interest recently in community choice aggregators. These are entities that buy power for local communities. For example, both Marin and Sonoma have community choice aggregators that were the offtakers for the 100-megawatt Mustang solar project whose financing closed in August. Many of these community choice aggregators have set their own goals to exceed 50% renewables in their communities. This growing market sector may help fill some of the slack in demand for new RPS procurement in the short term.

All of the San Francisco Bay area counties either have, or are seriously considering, forming community choice aggregators. (Serious consideration can be seen among the counties that have funded feasibility studies.) In southern California, Los Angeles County (outside of the City of Los Angeles, which is served by LADWP), San Diego County and the City of Santa Monica are also expected to form community choice aggregators.

Thus, renewable energy developers may have opportunities to respond to more, albeit smaller, renewable energy solicitations, from purchasers with little or no track-record of power purchasing or portfolio management.

In addition to SB 350, the California legislature also considered a companion bill (SB 32) during 2015 that would have set mid-term greenhouse gas targets and codified the state's 2050 goal of reducing carbon emissions to 80% below 1990 levels by 2050. Although SB 32 was ultimately withdrawn, SB 350 contains language reiterating the 2050 greenhouse gas goal, as well as setting a mid-term goal of reducing GHG emissions to 40% below 1990 levels by 2030.

SB 350 says that reaching the GHG goals will require "widespread transportation electrification" and directs the CPUC to require utilities to file applications for multi-year programs and investments to accelerate electrification of the transportation sector.

SB 350 also directs the California Public Utilities Commission to require utilities and other load-serving entities to file integrated resource plans to ensure that the entities meet the state's GHG and RPS targets while minimizing the effects on customer bills, maintaining reliability and satisfying other related goals.

Extensive modeling by the California grid operator, CAISO, and others suggests that increasing the / continued page 6

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evidence that the state legislature wanted to repeal the multistate compact provision allowing companies to elect use of the three-factor formula when it adopted a single-factor approach in 2008. The state legislature responded to the Supreme Court decision by quickly repealing the multistate compact retroactively the start of 2008.

Meanwhile, the California Supreme Court heard oral arguments in early October in a case in which Gillette and other companies are arguing they are entitled to use the multistate tax compact formula for calculating California source income.

California adopted the multistate compact in 1974. However, in 1993, its changed its law to require double weighting be given to the sales factor.

Gillette and five other companies sued the state for $34 million in refunds in 2010 arguing that they are entitled by law to use the multistate formula. A California appeals court agreed in a decision in 2012. (For earlier coverage, see the September 2012 *Project Finance NewsWire* starting on page 11.)

The state legislature voted, shortly before the appeals court released its decision, to withdraw from the multistate compact and to bar refund claims unless a company elected to use the apportionment formula in the multistate compact when it originally filed its tax return.

> *Similar battles are playing out in other states. Fourteen of the 20 states that belonged to the multistate compact had moved away from the three-factor formula by 2012. North Dakota replaced the three-factor formula in the compact with a single sales factor in April 2015.*

NORTH CAROLINA clarified in late September how to prove solar projects are far enough along by year end to qualify for a 35% state tax credit.

A project must ordinarily be in service by December 2015 to qualify. However, the state legislature granted an extra year to complete any solar project on which the / continued page 7

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supply of renewable energy much beyond current levels will present operational challenges and probably lead to higher levels of renewable curtailment without policy changes designed to address these challenges. (For background about the risk of increasing curtailments and negative prices for renewable electricity, see "Renewables Face Daytime Curtailments in California" in the November 2014 *Project Finance NewsWire* starting at page 13.)

SB 350 directs the CPUC, where feasible and cost effective, to authorize procurement that minimizes reliance on system power and fossil fuel for maintaining grid reliability and instead to focus on large- and small-scale energy storage, targeted energy efficiency, demand response and renewable resources.

Regional Grid?

One way to integrate higher levels of renewables is to make it easier to sell excess renewable electricity from California to its neighbors and to be able to do this on a sub-hourly basis, although perhaps at zero or negative prices.

The CAISO has established an energy imbalance market to allow multiple balancing areas to dispatch least-cost resources automatically on a five-minute basis, thereby sharing reserves and helping to respond to changes in renewable energy generation. PacifiCorp became the first participant in November 2014. NV Energy is set to join the energy imbalance market as soon as final authorization is received from the Federal Energy Regulatory Commission and could be participating as early as December 1. Puget Sound Energy and Arizona Public Service will join in October 2016, and other utilities in the west are also considering this option.

The CAISO is in the process of establishing a new five-member governing body for the energy imbalance market with independent, regional representation to oversee and approve EIM market rules before they are presented to the CAISO board of governors for approval.

Even with the benefits provided by the EIM, the challenge of integrating up to 50% renewable energy supply will require greater levels of regional coordination.

The CAISO and PacifiCorp entered into a memorandum of understanding in April 2015 to explore the feasibility, costs and benefits of PacifiCorp joining as a participating transmission owner. A regional independent system operator would allow for day-ahead and hour-ahead scheduling of generation and transmission resources, which provides much greater opportunity to benefit from regional diversity in the integration of intermittent renewable resources.

Becoming a regional organization would represent a significant change for the CAISO, which, as its name implies, has been strictly a California grid operator since its inception. In fact, the law allowing for the establishment of the CAISO specifically prohibits the CAISO from entering into a regional organization without approval from the state Electricity Oversight Board. The CAISO governing board is appointed by the California governor and confirmed by the California Senate.

California set a new 50% renewable energy target, but the opportunity for developers is not as simple as it looks.

SB 350 provides a process for lifting restrictions on the CAISO entering into agreements with grid operators in other states and transitioning to a governing structure that is not subject to the parochial selection and confirmation requirements of the current CAISO board. By providing a process for the CAISO to explore becoming a regional entity and to help develop more integrated electric and transmission markets throughout the west, SB 350 addresses one of the significant challenges of extending the RPS to higher and higher levels of renewable penetration.

The process involves the CAISO developing a revised governance structure and studying the impacts of a regional market on ratepayers, the California economy, the environment, disadvantaged communities, GHG emissions, reliability and integration of renewable energy resources. The governor must then submit the revised governance and studies to the legislature by December 31, 2017. The revised governance structure would not become effective until after the legislature enacts a statute implementing the changes. There are many moving pieces, but they have a way eventually of falling into place. ◎

Community Solar Gains Ground in New York

by Todd Alexander and Christopher Vale, in New York, and John Marciano III, in Washington

New community solar rules that took effect in New York in late October should help jump start community solar development in that state. The rules make it possible to build projects at utility-scale costs and sell electricity directly to customers at higher rates than utilities pay for utility-scale power.

New Playbook

The new rules provide incentives for projects with capacities of up to two megawatts and require participation by at least 10 customers in each project. Projects larger than two megawatts can be still be built, but only the first two megawatts are eligible for credits and incentives. Projects must serve customers located within the same utility service area and NY independent system operator load zone as the facility.

Projects generate net-metering credits based on the amount of net electricity generated. Customers whose electricity consumption is 25 kilowatts or more cannot as a group receive more than 40% of the net-metering credits generated by the project. An electrical load of 25 KW is usually the breakpoint between commercial and industrial customers versus residential customers. Thus, residential customers need to receive at least 60% of the net-metering credits generated by the project. The percentages refer to the facility's aggregate output allocated to each type of customer. Thus, an array that has one commercial customer receiving 40% of output and hundreds of residential customers receiving 60% of output would qualify.

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developer has "incurred" at least a minimum percentage of project costs and completed a minimum percentage of "physical work" by December. The percentage is 50% for projects with a DC capacity of 65 megawatts or more. It is 80% for smaller projects.

Developers had to notify the state tax department by October 1, 2015 of any potentially eligible 2016 projects by letting the department know each location, total cost estimate and project size.

Proof of the incurred costs and percentage completion must be submitted by March 1, 2016. The developer must certify in writing as to the costs and physical work completed, and it must submit notarized reports from a certified public accountant attesting to the costs and from an independent engineer about the percentage of physical work completed. Both the engineer and accountant must be licensed in North Carolina. The state may release forms in January to use for making these certifications.

The state released a series of frequently-asked questions and answers in late September.

Costs are not considered "incurred" for *federal* income tax purposes until delivery of equipment or services; it is not enough for the developer merely to have paid money.

The latest state guidance is ambiguous about what is required in North Carolina. However, an official with the state tax department confirmed by email that "economic performance" is not required and that accrual of costs is enough. Costs are considered accrued when the developer is legally obligated to pay and the amount is known. There is no deadline actually to have made the payment, although a long delay may call into question whether there was really a legal obligation to pay.

The state issued a table to guide engineers on how to measure the percentage of completion. According to the table, a solar project is considered 5% complete at the end of design, engineering and site preparation, another 20% complete after all the posts have been installed, another 15% complete when */ continued page 9*

Community Solar

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Each customer must be allocated at least 1,000 kilowatt hours annually of output, but a customer cannot be allocated more than its historic average annual consumption. The rules limit customers to receiving net-metering credits from a single source. Thus, a customer could not have an interest in output from more than one community solar array or have rooftop solar panels plus an interest in a community solar array. For master-metered customers, like co-op boards and apartment buildings, the rules look through to the underlying participants for customer minimums and demand sizing.

New rules released in late October should help community solar developers get traction in New York.

Community solar participants can be nominal members, meaning they do not have to own an interest in the array itself as opposed to the electricity.

The electricity generated by a community solar array is fed into the grid. The project sponsor holds a "host meter account" at the facility under a demand rate or non-demand rate classification. The sponsor determines each customer's generation every month and reports net-metering credit allocations to the utility. The utility then applies a net-metering credit directly to the customer's bill.

If the host meter account for the project is classified as a "non-demand host meter," then the utility applies volumetric crediting that essentially runs the customer's meter backwards to reduce the amount of electricity for which it is charged. It still takes its electricity from the utility. The customer pays for the net electricity it uses, after the credits, at the retail rate.

In contrast, if the host meter account is classified as a "demand host meter," then the utility bill sent to the customer each month will show the actual electricity it used, but also show monetary credit for the customer's share of electricity from community array. The credit will be subtracted from the final bill. The credit in this case will be calculated at the retail rate for the project. In the case where customer meter runs backwards, the credit is at the customer's — not the project's — retail rate.

If a customer defaults on its obligations to the project sponsor, then the net-metering credits may be temporarily held by the sponsor. The sponsor must distribute any such credits it is holding at year end to the other customers.

The New York Public Service Commission has been introducing community solar in phases.

During the introductory period or phase one, lasting through April 30, 2016, the most well-managed projects will proceed as test cases. Phase one is limited to areas identified by the utilities as "opportunity zones" and projects with a minimum of 20% of low-income customers. Phase two will open community solar to all locations and types of customers, but not until the state PSC has made decisions in a related "Reforming the Energy Vision" proceeding. Interconnection applications for community solar projects that do not qualify under phase one can be filed now, but the projects will not be interconnected until phase two.

Why Community Solar?

One of the most appealing aspects of community solar is the ability to realize economies of scale by building utility-scale solar arrays with lots of individual customers. Developers can essentially build at wholesale at significantly lower costs than for rooftop installations. Projects are classified as distributed energy resource providers under New York law, and the Public Service Commission regulatory body has confirmed that these providers will not be subject to the same rate regulation as utilities. These providers will still be subject to some form of quasi-regulation, including consumer protections.

Another positive aspect of community solar is ownership of the facility can remain with the project developer, free and clear of potential ownership issues associated with rooftop solar systems. Solar panels installed on customer roofs face unresolved issues with security interests, including whether the solar panels are attached to the real property. Most mortgages that homeowners take out to finance their homes have after-acquired property clauses that give the mortgage lender a security interest in anything attached to the house. Moreover, if a customer defaults on its obligations to the solar company, there is no need with a community solar array to spend money removing and reinstalling the solar panels somewhere else. Developers need only find another individual to replace the customer who defaulted, usually at only a modest cost.

Another benefit to community solar is the array can be put in a location with the best access to sunlight. Early adopters of community solar will find themselves in a prime position to select the best locations to reduce the levelized cost of energy.

Remote net metering regulations have existed in New York for years, but the new community solar rules open access to the untapped residential market, including customers behind master-metered accounts. Existing net-metering regulations did not permit residential customers effectively to participate in remote net-metering. Residential customers were only allowed to participate in remote net metering if the project account and residential account were held by the same customer.

One of the goals of the pending "Reforming the Energy Vision" proceeding before the New York PSC is to make renewables more accessible to the masses. The existing solar third-party ownership model focuses on customers with above-average credit scores to limit credit risk exposure and improve borrowing rates. Community solar projects are a form of pooling of customer revenue streams. The portfolio diversification can increase the creditworthiness of the project. Lenders will still focus on the risk that individual customers will default, but the fact that a customer can be replaced easily without great cost will help. The developer retains the ability to pursue payment from the individual customer even after the customer has been replaced. ◎

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all the racks have been mounted on posts, and another 20% complete when all the panels have been mounted.

If only part of a task has been completed, then the engineer should weight that percentage. For example, if only half the solar panels have been mounted, then only 10% completion — half of 20% — would be credited to toward that work stage.

The state said the "project" that must be at least 50% or 80% complete by year end is one or more solar installations on a contiguous land tract.

A developer can divide a large project into smaller projects so that a smaller project qualifies even though the larger project does not.

The company that notified the state tax department by October 1, 2015 that it has a 2016 project does not have to be the company that ends up claiming the tax credit. Ownership of the project can change hands.

If the final project ends up costing more than was expected at the end of 2015, so that the costs incurred through 2015 end up less than the 50% or 80% required, it does not matter. Eligibility for the 2016 deadline to complete the project is determined at year end 2015 based on the projected project cost at that time.

Developers are asking what happens if the local power company cannot connect the project to the grid by the completion deadline. The tax department said the developer is out of luck: the project is not considered in service.

INVESTMENT TAX CREDIT regulations that solar, geothermal, and other renewable energy companies use to determine whether, and how much of, their projects qualify for the tax credit are being rewritten. The regulations date to 1982.

The IRS asked in a notice in October for comments about a list of issues about which companies have been asking it in recent years. The request is in Notice 2015-70.

Comments are due by February 16.

The regulations are out of date. As it rewrites them, the IRS will be trying / continued page 11

Future of the Solar Residential Rooftop Business Model

Representatives of four companies who are active in the US solar residential rooftop market had a wide-ranging discussion at a conference hosted by Solar Media in New York in late October about the different business models in use in that market and how each will fare if the 30% federal tax credit for solar is not extended past 2016. The conversation covered current installation costs, typical capital stacks, the cost of capital, barriers to entry and the potential for margin compression.

The panelists are Sylvain Mansier, chief operating and financial officer of Sungage Financial, Albert Luu, vice president for structured finance at SolarCity, Jason Cavaliere, vice president for project finance at Sunrun, and Chris Hale, president of SunBlue Solar. The moderator is Keith Martin with Chadbourne in Washington.

MR. MARTIN: We have three or four different business models represented on this panel. Let's explore the differences. Sylvain Mansier, Sungage Financial provides financing to homeowners who want to install solar?

MR. MANSIER: Several years ago, while a couple of the other firms on this panel were growing rapidly, we decided that as much as the third-party ownership model was serving the market and helping to grow it, there was unserved demand for homeowners who want to own their own solar energy systems.

Studies show that consumers like to finance purchases over $7,000. We were looking for an opportunity to deliver a point-of-sale financing mechanism that made the transaction process easy and accessible to homeowners who want to buy.

Three years ago at these conferences, we were always relegated to a corner. Today, the market is moving in our direction. The trend today is for direct ownership, and some of the bigger players are starting to offer products that accommodate it.

MR. MARTIN: When you say you offer a point-of-sale mechanism, is it a website?

MR. MANSIER: Qualifying for financing takes two minutes to fill out an online application, and you get a decision in 20 seconds.

MR. MARTIN: Do you provide the financing? Do you make a loan that the homeowner uses to buy the solar system?

MR. MANSIER: Yes. It is a direct loan product to consumers. It is a purchase money loan structure, so we take a collateral position that is similar to what the third-party ownership companies take. Funds are disbursed directly to the installation company on behalf of the consumer.

It is not a retail installment contract. It is a direct consumer credit obligation.

MR. MARTIN: How long is the loan?

MR. MANSIER: We have four different terms for five, 10, 15 and 20 years. Interestingly, the 20-year product is not our number one selling product. Even though for solar leases or power contracts a 20-year term makes sense, some people would prefer to pay off their systems over five or 10 years.

MR. MARTIN: What do you take as security: a lien solely on the solar equipment or also on the house?

MR. MANSIER: This is not a real-property-lien product. It is a security interest solely in the equipment.

MR. MARTIN: What interest rate would I get if I come to you today looking for a 20-year loan?

MR. MANSIER: Somewhere around 7%.

MR. MARTIN: What about five years?

MR. MANSIER: Just 4 1/2%.

MR. MARTIN: Albert Luu, SolarCity is an integrated installer. It manufactures panels at this point?

MR. LUU: We have started to do so.

MR. MARTIN: It installs, owns and then sells the electricity or leases the system to the homeowner. How many systems do you install a year?

MR. LUU: To date, we have roughly 300,000 customers.

MR. MARTIN: Most of your customers sign power contracts or leases while you retain ownership. How much of your business today is direct sales?

MR. LUU: We have always sold systems on a cash basis to customers who prefer to own. Third-party ownership has been the dominant product, but about a year ago, we launched a loan product called MyPower. It is a 30-year loan to the consumer who owns the system and takes a federal tax credit for 30% of the system cost.

MR. MARTIN: Is MyPower an installment sale or a loan? Do you provide the equipment as well as the financing?

MR. LUU: We sell the system to the customer, and then we provide financing for it over a 30-year term.

MR. MARTIN: With the third-party ownership model, is your business proposition to the customer that he will pay 85% of what he pays his local utility for electricity?

MR. LUU: The customer proposition is we will sell you cleaner, cheaper power with a savings on your electricity bill of somewhere in the 15% to 20% range.

MR. MARTIN: Jason Cavaliere, Sunrun is a lot like SolarCity, except I do not think you manufacture panels and you probably do not have the big workforce to install. You contract out installation, correct?

MR. CAVALIERE: Sunrun started with a channel model where we subcontracted everything out to local installers. About two years ago, we bought our largest channel partner, REC Solar, and folded it into Sunrun. Today, we install about half our systems, and we use outside contractors for the other half.

MR. MARTIN: How much of your business is third-party ownership versus direct sales?

MR. CAVALIERE: We are way over 90% third-party ownership. We just started direct sales after the acquisition of REC Solar. We did not do any direct sales before that.

MR. MARTIN: Albert Luu, what percentage of SolarCity's business today is third-party ownership versus direct sales?

Customer defaults on rooftop solar PPAs and leases remain under 2% nine years into the business.

MR. LUU: Our MyPower product today is somewhere between 15% and 20% of our business on the residential side.

MR. MARTIN: Jason Cavaliere, how many customers does Sunrun have currently? We heard 300,000 from SolarCity.

MR. CAVALIERE: We just hit our 100,000th customer.

MR. MARTIN: SolarCity hopes to get to a million by 2018. Does Sunrun have a similar target?

MR. CAVALIERE: By 2018, we should be well over 500,000.

MR. MARTIN: Chris Hale, you are a local installer. Are your roots as a roofing company or did you start as a solar company?

MR. HALE: I worked in the legal industry doing electronic discovery. I took a couple classes at the Bronx Community College Center for Sustainable Energy. The more I / *continued page 12*

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to make clearer what parts of solar, geothermal, fuel cell, biomass, and other renewable energy projects qualify for the tax credit. The credit can only be claimed in most cases on the "facility" for generating electricity. The existing regulations treat that facility as including "storage devices, power conditioning equipment, [and] transfer equipment," but not equipment that is used to transmit the electricity.

The regulations also treat "dual-use property," meaning equipment that uses energy from both renewable and non-renewable sources, potentially as eligible, but only if at least 75% of the energy in the year the equipment is put in service is renewable energy, and then the tax credit allowed is whatever fraction is renewable energy. Thus, for example, if the first-year renewable percentage is 90%, then 90% of the investment tax credit can be claimed. If the percentage dips below 90% in any of the next four years, then there is partial recapture of the unvested tax credit. The tax credit vests ratably over five years. Thus, a dip to 80% in year two would lead to recapture of 1.8% of the 27% in original tax credit (30% x 90% = 27% x 80% x 10% = 1.8%). If the renewable energy percentage dips below 75% in any of these years, then the entire unvested credit is recaptured.

The US Treasury has been taking the position that, where a biomass power plant produces both steam and electricity, the cost must be allocated between the two functions, and a Treasury cash grant will be paid only on the part that produces electricity. It won a lawsuit over the issue in January 2015. (For earlier coverage, see the February 2015 *Project Finance NewsWire* starting on page 7.)

The Treasury lost a lawsuit in March 2015 involving fuel cells. It argued that equipment a fuel cell owner uses to clean methane gas from municipal wastewater treatment facilities before feeding the gas into two fuel cell assemblies is not part of each "fuel cell power plant." (For earlier coverage, see the May 2015 *Project Finance NewsWire* starting on page 5.)

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learned about the solar industry — this was in 2008 — the more I saw the opportunity. I quit my job and started SunBlue Energy in 2009.

MR. MARTIN: You focus solely on Westchester County in New York?

MR. HALE: Westchester, Bronx, Rockland, Orange and Putnam.

MR. MARTIN: What percentage of your business is residential?

MR. HALE: It is about 80% to 90% residential in terms of number of customers.

MR. MARTIN: How many customers do you have currently?

MR. HALE: We have installed more than 100 systems.

MR. MARTIN: Is all of it direct sales?

MR. HALE: All direct sales. We are not against third-party ownership. We are offering a solar PPA, but most of our customers take out a loan and buy the system.

MR. MARTIN: Sunrun does purely residential. SolarCity does both residential and commercial and industrial installations. Sungage is a consumer finance company. Its focus is residential. Are the only real business models at this point in the residential solar market third-party ownership, meaning solar PPAs and leases, and direct sales?

MR. CAVALIERE: I think those are the only two choices to put solar on your house. Companies may specialize in different aspects of the business. For example, we partner with people that just do construction.

MR. MARTIN: Let's talk next about the market potential. I read somewhere that there are 44 million roofs in the United States that are potential places to put solar. Is that number correct?

MR. LUU: I am not sure of the exact number, but the point is the market penetration rate for residential solar is still very low. In a market like California where there has been high adoption, it is still in the 2% to 3% range.

MR. MARTIN: Depending on whom you ask, anywhere between 49% and 80% of roofs are not suitable for solar installations because of shade or other reasons. This is creating a market for community solar arrays. What do you think is the correct percentage?

MR. LUU: A high number of homes get disqualified for many reasons, with the roof being one of them. Community solar is one of the more interesting new products that can address the roof issues.

Solar PPAs and Leases

MR. MARTIN: I want to drill down into the third-party ownership model. What is the current customer default rate under solar leases and PPAs?

MR. LUU: Less than 2% on a cumulative basis.

MR. MARTIN: That is over how many years?

MR. LUU: For us, about nine years.

MR. MARTIN: Jason Cavaliere, same question.

MR. CAVALIERE: Our cumulative default rate has been about 1.2% over eight years.

MR. MARTIN: There has been some discussion in the market about the number of solar PPAs and leases that are underwater. You start out offering the customer a 15% or 20% savings from retail rates, but the electricity price in the contract increases annually by a fixed inflation rate that can be anywhere from 0% to 3%. Over time, the price the customer is paying may be higher than the retail rate. What percentage of contracts is underwater currently?

MR. CAVALIERE: Very few of our contracts are underwater, and they are not underwater because of that escalator. They may be underwater because of some pricing snafu that may have happened five years ago and that has been rectified since then.

It really does not make sense for any of us to price a contract that will go underwater at any time in the future, because when we raise funds behind these contracts, the rating agencies and the banks that do their scenario tests assume that if any contract goes underwater, then the PPA rate will be lowered to give the customer the same percentage savings from its retail electricity rate. We will not get a cash advance on that number.

It is in both of our best interests to make sure the customer keeps saving money.

MR. MARTIN: How do you do that?

MR. CAVALIERE: We give the customer 15% to 20% savings upfront, sometimes with a zero escalator and sometimes with an escalator as high as 2.9%. If retail utility rates are increasing at 4% to 6% a year, you should never have a crossover point.

MR. MARTIN: Albert Luu, same question. What percentage of solar PPAs or leases are underwater? How do you avoid such a situation?

MR. LUU: Very few contracts are underwater. Our base pricing today is 15% to 20% lower that retail rates in every market. For example, in California our residential PPAs are 15¢ with an escalator capped at 2.9%. Tier one electricity rates in California are around 17¢, and our customers can be charged by the utility at rates as high as 33¢ for those in tier three.

MR. MARTIN: So there is a lot of room before a customer would have to pay more than the retail rate.

MR. LUU: Correct, and as Jason mentioned, the fundamental premise in residential solar is that customers save money. The rating agencies look at it, all our financiers do, and they all run stress-test scenarios to ensure that there is a cushion between utility rates and what customers pay.

But let's play it out and say that somebody is underwater. That doesn't necessarily mean that there is a contract default. And the worst-case scenario is you would end up renegotiating the rate to keep the customer in the money.

MR. MARTIN: Solar PPAs and leases have had terms for the most part of 20 years. Do you see any pressure to extend the term?

MR. LUU: One of the biggest hurdles in getting a customer to sign up for solar is the 20-year agreement. I think very few contracts are that long. It is a lot easier to refinance a 30-year mortgage than a 20-year lease or PPA. The push today is to look at other types of products that have shorter terms.

I would not be surprised to see a move to shorter-term contracts over the next few years as more financing tools become available to the solar companies.

Direct Sales

MR. MARTIN: Let's move to direct sales. One of the problems with the solar lease or solar PPA is the pricing is a function of retail electricity rates. Solar panel prices have been dropping while retail electricity rates have been increasing, and that seems to be driving a shift to direct sales. People would rather price based on the cost of the equipment. Do you have any sense of how powerful a shift is taking place? Albert Luu, you said as much as 20% of SolarCity's business currently is direct sales.

MR. LUU: They are different groups of customers. It is a different customer who signs up for a lease or PPA versus one who wants to own the system. One views it as an energy payment, and one views it as an asset or an improvement to his home.

MR. MARTIN: Sylvain Mansier, do you have any data on how strong a move there is to direct sales, if in fact such a move is occurring?

MR. MANSIER: Direct ownership is often sold as monthly energy savings, the same way that a solar lease or PPA is. A lot of our customers are saving 30% to 40% off their monthly energy bills, once they take into account the federal tax credit, which we bridge finance to help them do that. */ continued page 14*

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Treasury cash grants are supposed to mirror the investment tax credit.

Both decisions are being appealed.

The IRS wants comments about whether storage devices and power conditioning equipment should be considered part of the "facility" on which an investment credit can be claimed and how to calculate tax credits on dual-use property. It is also looking for help drawing lines around the eligible equipment at geothermal, fuel cell and distributed cogeneration units, called combined heat and power facilities. It is open to other suggestions about what should be addressed.

Chadbourne has met with IRS officials in Washington in recent years about a number of other issues that are ripe for clarification. They include how much of the cost of solar parking canopies qualifies for tax credits, whether a tax credit can be claimed on improvements to existing wind, solar, geothermal or other facilities on which a Treasury cash grant or investment credit was claimed, whether the "75% cliff" applies to batteries, and whether wells are part of a geothermal power plant for purposes of testing whether a repowered plant qualifies for a new tax credit.

STANDALONE ENERGY STORAGE facilities can be depreciated on an accelerated basis over five years, the IRS said.

A renewable energy developer and construction contractor owns a large battery that it uses to provide frequency regulation services to a utility. The device stores electricity when the grid frequency is above 60 hertz and then sends it back when the frequency dips below 60 hertz. The company, as battery owner, pays the utility for the electricity it takes at the wholesale power rate and then is paid the same rate when the electricity is returned to the grid. Thus, ownership of the electricity passes back and forth.

The company asked the IRS whether it can depreciate the battery over seven years. The IRS classifies assets by the industry in which they are used. All assets in a particular industry are depreciated the same way, with the exception of some types of equipment, like */ continued page 15*

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Chris Hale might be able to share sales practices of his team. The focus is generally on the size of the monthly payment.

MR. MARTIN: How does a consumer decide on ownership versus a solar lease or PPA? Albert said it is a question of whether the customer wants to buy energy or own assets.

Customer agreements will have shorter terms as more financing tools become available to rooftop solar companies.

MR. MANSIER: I am not sure that homeowners make a huge distinction about solar as a home improvement versus a discounted energy bill, although some homeowners would prefer not to have a third party owning assets bolted on their roofs. I think the purchase decision for many folks ends up being how much am I saving?

Intuition tells us you may be happy to have savings over 25-plus years, but that doesn't mean you want to finance the system over 25-plus years.

The value proposition is easily communicated in the form of monthly savings. Some customers care more about lifetime savings, however. They do not really care about how much they will save today. They just want to stop paying the utility as soon as they can, and if that means they pay off their solar panels in five years and then they will not have another bill for the next 20, then that is what some people want.

Our job as a consumer finance company is to meet consumer preferences. We try to match the financing options we offer to consumer preferences.

MR. MARTIN: Chris Hale, how do you find your customers?

MR. HALE: Mainly through word of mouth. Happy customers lead to more customers. They are very comfortable with us. We are the local guy. They know us.

Other than that, we do a lot of the same things as every other company. We have bought leads over the internet. We have been trying to become more visible in the community. I run to work every day. More of our employees work nearby. We become known in many different ways, but mainly by word of mouth.

MR. MARTIN: How do you compete with the big guys, the SolarCitys and Sunruns? They are out combing the same neighborhoods.

MR. HALE: Maybe we should ask them how they compete with us. [Laughter]

MR. MARTIN: Is it a hard competition for them?

MR. HALE: A customer makes a different decision when he or she decides to go with a SolarCity or Sunrun or with a local installer like us. They are selling you a 20-year service agreement. They will take care of the system on the roof, and you will save money.

With Sungage, the customer borrows and is looking to amortize the system cost over 12 or 15 years and to be in the black from day one.

Then you have customers who want to pay cash and see the long-term investment. They bought their houses. There is no reason to rent a system, so they decide to purchase a system and pay in cash. They are saving money from day one on electricity.

MR. MARTIN: Do you offer financing?

MR. HALE: Yes, we do.

MR. MARTIN: On what terms?

MR. HALE: We actually engaged with Sungage earlier this year because there is state-backed program called Green Jobs Green New York that allows homeowners to take 15-year loans and repay them through their utility bills. The program was expiring. We reached out to Sungage to carry on with the loans. Then the New York program got extended.

MR. MARTIN: Small companies always are strained for capital. Is it a struggle to get the capital you need to keep going?

MR. HALE: Yes.

MR. MARTIN: Are there pressures to consolidate? Do you get approached by larger companies to sell?

MR. HALE: No one has approached us.

Challenges Ahead

MR. MARTIN: Take note, Jason Cavaliere and Albert Luu. Let's move to another topic, which is the challenges ahead. The solar investment credit is currently 30%. It will drop to 10% in 2017 unless Congress extends it. Albert Luu, is the third-party ownership model viable after 2016 if the credit is not extended?

MR. LUU: Costs have to come down significantly in order for the current customer proposition still to make sense. We have laid out a cost target curve that will put us at $2.50 a watt as an all-in cost by the end of 2016 in order to have a viable business in 2017 with a 10% ITC. Unless you can get to that cost level, it will be very difficult to operate a business at scale.

MR. MARTIN: Jason Cavaliere, do you agree that $2.50 is key?

MR. CAVALIERE: I think we are scheduled to hit $2.49 by the end of 2016. [Laughter]

One of the interesting things about direct ownership versus third-party ownership is if the current law does not change, then the investment tax credit that supports the third-party ownership model goes from 30% to 10% while the residential solar credit that supports direct ownership goes from 30% to zero.

MR. MARTIN: So you think Chris Hale will not be in business at that point?

MR. CAVALIERE: Not in his current form or his market will shrink significantly. It is not that small installers cannot compete with us right now, but they will not be able to compete against a solar PPA that has a 10% subsidy from the investment credit plus an additional subsidy from depreciation from which their customers are not benefiting.

MR. MARTIN: Sylvain Mansier and Chris Hale, that's smack talk. Do you have an answer? [Laughter]

MR. MANSIER: I think everyone up here would agree that the greatest opportunity to reduce cost is in soft costs. Most of the soft costs are really sales and marketing costs. They are not the labor.

Let's dissect the sales and marketing costs. According to GTM Research, roughly half the marketing leads across the entire industry come from referrals. The other 50% come from direct marketing campaigns, marketing partnerships and other channels. Not every company sources customers the same way. They have a very different cost structures from a sales and marketing standpoint.

For a company like Chris Hale's that has mostly referral-based lead generation, the average cost of customer acquisition could be something like $250. The industry average is $3,000. That is a huge delta. The most expensive way to / continued page 16

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trucks, computers and autos, that are used across all industries. There is no specific asset class for assets used in an energy storage business. Assets without an asset class are depreciated over seven years.

The IRS suggested in this case that the taxpayer could use five years. It said the battery falls in asset class 57.0 for assets used in the wholesale and retail trade.

The agency made the statement in Private Letter Ruling 201543001. It made the ruling public in late October.

If standalone storage facilities are considered used in the wholesale or retail trade, then why not all power plants? The IRS branch chief whose branch issued the ruling said the branch views the battery in this case as being used to provide services. She said that would not be true of a power plant. Some power plants provide services under tolling agreements.

MASTER LIMITED PARTNERSHIP issues are expected to be resolved "relatively soon."

The agency made clearer in May where it plans to draw the line on the types of minerals and natural resource businesses that may operate as master limited partnerships.

Master limited partnerships, or MLPs, are large partnerships whose units are traded on a stock exchange or secondary market. The United States usually taxes publicly-traded companies as corporations. However, it makes an exception for partnerships that receive at least 90% of their gross income each year from passive sources, like interest or dividends, or from activities tied to minerals or natural resources. Such companies are able to operate without having to pay corporate income taxes. Their income is taxed to the owners directly.

The new rules are in the form of proposed regulations that are expected to be finalized soon.

The IRS set off a storm of protests from companies that had received private letter rulings from the agency telling / continued page 19

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acquire customers is direct marketing.

MR. MARTIN: That is $3,000 for what unit of measurement?

MR. MANSIER: $3,000 for an average six-kilowatt residential solar installation.

MR. MARTIN: The solar system costs how much: $40,000, $50,000?

MR. MANSIER: If you are at $3.50 a watt, then the all-in cost is roughly $25,000.

MR. MARTIN: That is $25,000 of which $3,000 is the cost for finding the customer. That seems low. Albert Luu, does that seem low to you?

MR. MANSIER: That is the average. This is the point, Keith. Some companies are way above average. Other companies are way below average. The main differentiating factor is how they get their leads.

MR. MARTIN: Albert Luu, what percentage of the cost of the average SolarCity system is customer acquisition?

MR. LUU: We publish our costs every quarter. Looking back two quarters, I think our all-in costs were in the $2.90 range with sales being about 50¢ a watt.

The thing to keep in mind is how people think about cost varies from one company to the next. I have seen customer acquisition costs counted in different ways, and many companies do not incorporate the full cost of acquiring the customer. They report only a portion of it. So 50¢ a watt is our all-in customer acquisition cost when you count every dollar that goes to acquiring the customer.

MR. MARTIN: Jason Cavaliere, I assume Sunrun's is 49¢?

MR. CAVALIERE: Fifty cents is a nice round number. That is our direct business. One of the benefits of the channel model is that we can take advantage of some of our channel partners that have local relationships. We have a management layer on top to run our business, but that management layer is maybe 10¢ to 12¢ cents a watt. Our channel partners have their own costs that we pay for, but their costs are usually lower than ours because they have local relationships.

MR. MARTIN: Where are your current installation costs all-in? Are they $2.90 a watt, a little higher, a little lower?

MR. CAVALIERE: We are a bit higher.

MR. MARTIN: Chris Hale, what is your all-in installation cost?

MR. HALE: We are charging the customer just under $4 a watt.

MR. MARTIN: What is your customer acquisition cost as a fraction of that.

MR. HALE: It is around 10%, including our marketing budgets and sales commissions.

I think I could have said more in response to your earlier question about whether we are strained for capital. I think the big question for all of us in this market is how does any residential solar business model become profitable?

When Profitable?

MR. MARTIN: Good question. What is the answer?

MR. HALE: I like the way my company operates. We have low overhead. We have a very solid team. We have one crew, and we are looking to expand to two crews. Once we get to two or three crews, then the business will be nicely profitable.

Many people think the future lies with the major companies with national brands. But, you know what? How many major national companies are installing HVAC systems on homes? It is a local guy. I see a transition to more local companies over the next few years.

MR. MARTIN: Interesting. We will come back to that. In terms of the ability to get the cost down, Albert Luu, you said the cost of an installed system needs to be at $2.50 a watt for residential to continue to thrive after 2016. Is that to thrive in all states or just a small handful of states?

MR. LUU: In all states in which we are currently operating.

MR. MARTIN: Which is 16 states?

MR. LUU: Nineteen plus Washington, DC.

MR. MARTIN: Where are the most likely additional cost savings?

MR. LUU: Partly in the solar panels. We are going to be manufacturing our own high-efficiency modules. We expect this to reduce the cost of modules to around 55¢ a watt, compared to 70¢ a watt where modules are today with the import tariffs. You get 15¢ in savings there.

A lot of the additional cost savings is just integration. We have our own racking company. We have our own installation crews. We had a crew recently do three installs in a day where, two years ago, a typical install took two days. We are getting a lot of efficiency there. Then it is the non-hardware costs: lowering customer acquisition costs over time and getting some other soft-cost reductions.

MR. MARTIN: Chris Hale posed the question, "How do we get this business model to be profitable?" I don't think SolarCity or

Sunrun has turned a profit yet. When will they move into the black?

MR. LUU: We have not turned a profit yet on a GAAP basis, but if you look at the equity value we have in our systems and discount that at 6%, we are creating a tremendous amount of value.

MR. MARTIN: What about cash flow?

MR. LUU: We are cash positive if you look at cash flow on an individual system.

Barriers to Entry

MR. MARTIN: Jason Cavaliere, how would you answer Chris Hale's question?

MR. CAVALIERE: Like he said, there are few, if any, large, national construction companies that have all their own employees in every state. They subcontract out the work. I think in the solar business, you either have to remain a small, local player or you have to work to become a national brand with a large footprint to benefit from economies of scale.

One of the things about residential solar that people do not realize is that there is a huge barrier to entry to become a national brand. You have to spend $200 to $400 million dollars on infrastructure to be able to maintain 100,000 or 300,000 customers, and that is just not an investment that the smaller guys can make.

That also means that we have more systems over which to amortize these costs, but because we made that investment, we can handle hundreds of thousands of customers. The marginal cost of additional customers is not very high. Costs come down. That money is amortized over a larger number, and you can become profitable.

MR. MARTIN: So you disagree with Chris Hale. He thinks the business will shift over time to more localized, smaller companies. You think it will consolidate.

MR. CAVALIERE: It will consolidate in a way that if he were to become a channel partner of Sunrun, he would take advantage of the infrastructure we have built.

MR. MARTIN: His best move would be to become a feeder for Sunrun in the future?

MR. CAVALIERE: Correct. He would still be doing installation. We could come up with the financing. He could use our systems. We have a very high bar to accepting channel partners, so I don't want to say anything out of line, but I am just saying. [Laughter] In some jurisdictions, people want to see the local guy they know. His product might be co-branded with Sunrun. Places like Hawaii want to see a local person. / *continued page 18*

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them their activities produce good income, but who now fall on the wrong side of the new line the IRS drew in May. At least 10 to 12 such rulings are at odds with the new rules. Senior members of Congress, including the new chairman of the House tax-writing committee, have also sent the IRS letters to complain.

Seventeen people testified at an IRS hearing in late October.

One area of controversy involves whether making olefins from natural gas liquids should qualify. Congress said, when enacting the MLP statute in 1987, that manufacturing plastics or similar petroleum derivatives should not qualify. Olefins are used to make a range of products. The proposed regulations appear to allow MLPs to earn income from some refinery-grade olefins, like ethylene, that are produced as an adjunct to making gasoline and other fuels, but not from natural gas liquids. Westlake Chemicals and Enterprise Products Partners, two chemical companies that received private letter rulings allowing them to operate as MLPs, urged the IRS at the hearing to focus on whether what goes into the process is a natural resource and not on what comes out.

IRS officials attending the hearing asked at what point something stops being a natural resource. They were also interested in whether small tweaks might be made in the proposed regulations to address the olefins issue. Curt Wilson, an IRS associate chief counsel, said the next day at a conference in New York that he does not know where the IRS will come out on olefins. Clifford Warren, a IRS special counsel, said at a tax conference in Chicago in early November that it is a "rather difficult discussion: when do refining and processing become manufacturing?" He said the engineers with whom the IRS is consulting have expressed a range of opinions.

Another company that testified is SunCoke Energy Partners LP, an MLP that makes coke by baking coal for producing steel. The company has seen its share price drop from $23.63 in early May to around $8 due to / *continued page 19*

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MR. MARTIN: Chris Hale, that may be the answer to your capital needs. Do you disagree with Jason Cavaliere that you might do better as a channel partner of Sunrun?

MR. HALE: That is a tough question. I threw out the gauntlet by saying the future is with local companies. I don't see how the large companies can keep their investors happy by running $50 million a year in losses over the long haul.

MR. MARTIN: What happens to your business model after the customers can no longer take a 30% residential tax credit?

MR. HALE: We are trying to transition a little more into commercial work by hiring a commercial sales representative. We think that the commercial side will be a good hedge for the residential business. The awareness of solar has grown incredibly since we started the company, thanks in part to Sunrun and SolarCity. The unknowns have really fallen away. People are much more comfortable with the technology and the economics of it. I think people are buying for more reasons than just electricity savings.

MR. MARTIN: So you are catering to the Prius owners for whom cost savings are not the top priority?

MR. HALE: Prius owners, but I think at some point we will have the fantasy football guys, too. We will hit a tipping point when it will be just plain practical for everyone to install solar. That said, there may be some upheaval after 2016 if there is no tax credit.

MR. MARTIN: Sylvain Mansier, make the case that the direct sale model will survive if the residential solar credit expires as scheduled after 2016.

MR. MANSIER: I certainly think it survives. The question is how big the market will be and how quickly it will continue to grow. The market will not disappear. No one believes it will disappear just because the tax credit expires. Fifty cents a watt for customer acquisition can be brought down dramatically if you rely solely on referrals.

Let me add to a couple things to what others have said.

One of the early insights from the founders of SolarCity and Sunrun was we have an immature value chain in residential solar. They are chasing cost savings through vertical integration. The value chain has matured dramatically over the last 10 years. For example, our company exists now. We are one link in the chain; we provide all the capital needed to finance installations for direct sellers. Another need within that market is working capital to support growth among the smaller players. We find opportunities to help facilitate that all the time.

My other point is that, yes, there are barriers to entry to become a national brand, but barriers can disappear or become less daunting as the value chain matures. For example, we are starting to see things like specialized small business software packages that help small installation companies run their businesses more efficiently and do a lot of the things for which the bigger folks have had to invest millions of dollars to be in a position to do. The analog is if you visit your doctor's office or a restaurant or an auto dealership, there is specialty small business software that runs each of these types of businesses. That has not existed for residential solar. The big guys have basically built their own software and spent a lot of money doing it. The small guys may not need to do so to catch up.

MR. MARTIN: You argue that there are actually low barriers to entry. Maturation of the value chain will ensure that remains so. Jason Cavaliere, does that lead to margin compression in the long term if the big guys cannot protect their market positions?

MR. CAVALIERE: We are spending a lot of money to get to scale and build that infrastructure. We make money on every system we put in today. A large customer base helps us to amortize the fixed costs over a larger number of systems. I don't see how smaller companies can compete with that over the long haul.

MR. MARTIN: The stock analysts in the last couple of days have noted how rapidly Sunrun and SolarCity are hiring people. You have lots of ads out to hire. At the same time, they look at the long term and worry about margin compression. It is simple economics: in any business where there is large value being created, others rush in and the competition depresses margins. If there are low barriers to entry, the compression comes more quickly. Albert Luu, what is your response to the analysts?

MR. LUU: The barriers are low to be a small installer. Think of coffee shops as an analogy. It is not hard to open a single coffee shop. It is difficult to manage 10. Starbucks thrives in a market where the barriers to opening one, two or three coffee shops are low. Starbucks does not have many large competitors. A lot of them have gone away. The barriers are very high to be a national company. We have more than 14,000 employees.

MR. MARTIN: In fact, SolarCity hired 500 in one day I read recently.

MR. LUU: Look at it this way. If some of our installation crews were standalone companies, they would be in the top five residential solar companies in terms of the number of installations they do.

Data Points

MR. MARTIN: I want to race through a series of remaining questions to get some useful data points. What is the average cost of capital today for a residential solar company using the third-party ownership model? Albert Luu, what is it for SolarCity?

MR. LUU: Our cost of capital is probably somewhere in the 6% to 7% range.

MR. MARTIN: What percentage of the capital stack is true equity, what percentage is tax equity, and what percentage is debt?

MR. LUU: Roughly 40% of project value is being monetized through tax equity, and then we monetize a portion of the cash flow stream to cover that remaining delta. Tax equity is somewhere in the 9% after-tax range. On a pre-tax basis, the cost is really 3% to 4%. Debt raised through securitizations costs around 4.5%.

MR. MARTIN: Tax equity is about 40% of the capital stack. Debt is how much?

MR. LUU: It is about 40% of the overall project value. Let's say our costs are in the $2.90 to $3.00 range per watt. We raise $1.75 to $1.85 in tax equity and then you monetize enough of the cash flows to cover the delta.

MR. MARTIN: The true equity is 10%? Higher? Lower?

MR. LUU: It is north of 10%.

MR. MARTIN: Jason Cavaliere, do those sound like the right figures for Sunrun, as well: 40% tax equity, 40% to 50% debt, and the balance true equity?

MR. CAVALIERE: Our financing arrangements are similar to SolarCity's.

MR. MARTIN: Sylvain Mansier, you simply borrow and relend, correct? That is your capital cost.

MR. MANSIER: We have a few different structures, but this is another place where I think scale benefits some of the larger players. We started offering our first product in 2013. We are seven years behind these guys. We are starting aggregating customer paper to buy optionality.

MR. MARTIN: To securitize the customer payment streams?

MR. MANSIER: That remains to be determined. There is a lot of opportunity for yield compression. Our cost of funds today is not that dissimilar from SolarCity's. We offer a plain vanilla product. The universe of potential investors in our kind of paper is probably much broader than for customer payment streams washed through more complicated tax equity vehicles.

MR. MARTIN: Chris Hale, I assume all of your capital is equity, correct? / continued page 20

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weakness in demand for steel and doubts about whether it qualifies to operate as an MLP. SunCoke went public in January 2013 based on a "will" opinion from its counsel that it qualifies to operate as an MLP. It describes coke as a purer form of coal.

Meanwhile, the IRS confirmed in a new private letter ruling that a partnership that owns an LNG regasification terminal and is in the process of expanding the terminal to liquefy US natural gas for export can operate as an MLP. The partnership earns fee income under contracts with suppliers whose LNG or gas it processes. The ruling is Private Letter Ruling 201537007. The IRS made it public in September.

MEXICO adopted its own version of master limited partnerships.

New regulations issued in mid-September by the Mexican tax authorities authorize use of an entity called a Fibra E to raise equity on the Mexican stock exchange. A Fibra E is a Mexican trust with a bank or broker-dealer acting as the trustee. The trust invests in shares of Mexican companies that are active in the Mexican energy or infrastructure sector.

The attraction is no income tax at the level of the Fibra E and a liquid market in the shares. The structure should make it possible to raise equity more cheaply.

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

The targeted sectors are electricity (generation, transmission, distribution), various types of private-private partnerships to undertake infrastructure implemented through concession agreements with terms of at least seven years (roads, highways, railways, bridges, inter-city transportation, ports, terminals, marinas, airports, prisons, potable water, drainage, sewage treatment plants, expansion of the main telecommunications network) / continued page 21

Rooftop Solar

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MR. HALE: That is correct.

MR. MARTIN: Albert Luu, people are trying to figure out how to combine PACE financing with the third-party ownership model. What is the benefit if one can figure out how to do it?

MR. LUU: People are trying. We will see where that goes. We are offering PACE for our small and medium-sized business customers. Those customers do not typically have a credit rating. We have not seen too many models around residential PACE yet. There are some concerns around lien priority and Fannie Mae and Freddie Mac.

The benefit of PACE, if somebody can figure it out, is the customer payment stream becomes a tax assessment. There is a higher likelihood that customers will pay their tax assessments, especially if the obligation to pay is secured by a lien over the house. This makes it possible to borrow against the future payment stream more cheaply.

MR. MANSIER: Here is a data point on PACE. The interest rate today is above 8% on a 20-year PACE deal. If the grand bargain that we are hearing about in Washington happens and you end up having effective subordinations through home sales, then I wonder what the interest rate will be. There may not be a lot of room to bring down the rate significantly.

We have always viewed PACE as an interesting idea, but our 20-year product already carries a lower interest rate. We wonder how PACE can work as long as there is uncertainty about the subordination issue.

MR. MARTIN: My last question is about net metering. Jason Cavaliere, what do you expect to come out of the California proceeding and how important is net metering for the third-party ownership model?

MR. CAVALIERE: Net metering is extremely important.

MR. MARTIN: Why?

MR. CAVALIERE: . . . and not just for third-party ownership, but also for any ownership, because it allows the customer effectively to use the grid for storage at retail rates during the sunniest part of the day. The push back we are getting in some states, like Hawaii in particular, will increase as solar penetration rates go higher, which will take some time, especially since they are so low currently.

Hawaii is an outlier, with at least 10% to 15% solar penetration. As solar penetration increases, regulators will be under more pressure to push back on net metering and what that will lead to is on-site storage, most likely with batteries. This is a short-term issue. It will eventually resolve itself as batteries become more widely available for on-site storage.

MR. MARTIN: Let me go across the panel quickly in case there is anything any of you wants to add that we failed to mention. Sylvain Mansier?

MR. MANSIER: There is a lot of uncertainty around the solar tax credits. That is the elephant in the room. Business models will have to change if the credits are not extended, and some people are already planning accordingly. Those people will do well. Moving beyond that, the upward trajectory for this business, beyond these blips, is clear. The market disruptions will be managed. Loss of the tax credits may cause short-term volatility, but the longer-term outlook is bright.

MR. LUU: Do not assume that the ITC will be extended. Plan your businesses around it not happening. There will be a big fallout in the industry. In some markets, like California, the solar industry employs more people than the investor-owned utilities. It will be a challenging environment in 2017 for any companies that cannot get their costs down in order to operate with a 10% ITC.

MR. CAVALIERE: Same comment. Plan for the worst, hope for the best on the ITC. Another thing that may happen that will separate the big players from the little players is if Congress changes the 2016 deadline to complete projects to qualify for the 30% investment credit to a deadline merely to start construction, we will spend hundreds of millions of dollars on equipment. I am sure SolarCity will, as well. The smaller companies probably do not have the capital to do that. This will enhance our ability to offer very competitive value propositions to customers with a continuing 30% tax credit.

MR. HALE: No one has mentioned the environment. A lot of people see the value in the financial aspect of solar, but the effect solar has on environment is what should be the real focus. If you factor in the real cost of gas drilling or coal mining, the health costs of pollution, and the costs imposed by increasingly erratic weather patterns, the price of solar is a steal every time. ◎

Mexico Tees Up PPA Auctions

by Raquel Bierzwinsky, in New York and Mexico City

Mexico will issue the first request for proposals and bidding guidelines on November 11 to bid on 15-year contracts to sell capacity and electricity from clean energy sources and on 20-year contracts for clean energy certificates, known as CELs.

The contracts will be awarded in an auction expected in the second quarter of 2016.

Clean energy sources are wind, solar, geothermal, hydro, and other forms of renewable energy plus nuclear, certain biofuels and efficient cogeneration, among others.

A separate request for proposals and bidding guidelines will follow in the third quarter of 2016 for an auction that will be open to all power suppliers to bid for three-year contracts to sell capacity and electricity from any sources.

Anyone interested in participating in the auctions will be required to post commitment guaranties, but will not need a permit to participate in the auctions and, in the case of a generator, it is not required to have built its power plant before the bid is submitted.

Anyone operating in the wholesale power market will have to post a separate performance guaranty.

New Market Rules

Mexico released long-awaited rules for operation of the new wholesale power market in September.

The new rules govern sales of electricity, capacity, ancillary services, financial transmission rights and clean energy certificates, among other products, and auctions will award medium- and long-term contracts.

There will be separate short-term markets for wholesale electricity, capacity, clean energy certificates and financial transmission rights.

Electricity may be sold wholesale initially into a day-ahead market (*mercado del día en adelanto*) or a real-time market (*mercado de tiempo real*). In the second phase of market evolution, an hour-ahead market (*mercado de hora en adelanto*) will be added.

Sales in the short-term market of energy and ancillary services will be based on locational marginal prices and ancillary services zonal prices. Virtual offers for power / continued page 22

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and downstream oil and natural gas (treatment, processing, refining, transportation, storage, distribution, but not exploration and production or retail sales).

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

It must distribute at least 95% of its income to shareholders each year by the following March 15. There is generally no income tax at the Fibra E level. Tax is collected from the shareholders through a 30% withholding tax on distributions. Mexican shareholders can claim credit for the tax withheld. Foreign shareholders can treat the withheld tax as their final tax. The trustee must pay tax on any income that is not distributed.

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

The first Fibra E could list as early as the second quarter of 2016. Pemex is expected to be an early adopter. The sponsors of the $13 billion new Mexico City airport are also reportedly studying the structure. Mexican pension funds may be early investors. The pension funds control $148 billion in capital.

Energy stocks are underrepresented on the Mexican stock exchange compared to the US. They are 1% of market valuation currently compared to 6% in the US. The only publicly-traded Mexican energy company currently is IEnova, a Sempra energy subsidiary. Its stock is up 88% over the initial launch price in 2013.

Meanwhile, the Mexican government submitted a series of tax proposals to the Mexican Congress in September that are expected to be enacted before year end and to take effect on January 1, 2016.

Companies that generate electricity from renewable energy or at cogeneration facilities will be able to pay dividends to shareholders free of the 10% withholding tax on dividends. The companies would keep special after-tax profit accounts from which to / continued page 23

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trading will not be permitted until the second phase of the market. Generating units assigned to the day-ahead market will not be subject to economic curtailment in its initial phase, but may be curtailed after the market moves into the second phase; however, they will be entitled to receive an income sufficiency guaranty.

Mexico will award 15-year contracts to supply capacity and electricity from clean energy sources in Q2 2016.

For projects located outside of Mexico selling power into the Mexican market, only cross-border energy import and export transactions with fixed programming will be accepted in the initial phase of the day-ahead market, but after the market moves into the second phase, cross-border energy import and export transactions with fixed or dispatchable programming will be accepted in both the day-ahead market and the hour-ahead market.

In terms of pricing, all charges in the initial phase of the real-time market will be based on hourly measurement data, while in the second phase, charges will be calculated and paid for based on each dispatch interval.

The short-term capacity market will be for sales of capacity in annual increments and will focus on transactions to allocate capacity that was not allocated to, or covered by, purchase agreements (*contratos de cobertura eléctrica*). The capacity market will match offtakers and any other entities acquiring power (*entidades responsables de carga*) that were unable to sign contracts for their actual capacity requirements in the previous year, as well as generators that did not satisfy their contractual obligations during the same period of time, with offtakers who came up short or with generators that have excess capacity.

The independent grid operator — CENACE — will operate a market for clean energy certificates where all offtakers can purchase CELs to satisfy their statutory purchase requirements. Briefly, Mexico is requiring certain market participants, including registered consumers with aggregate load points above a threshold set by the department of energy (two megawatts as of August 2015 and one megawatt as of August 2016), power suppliers and holders of grandfathered generation permits (that is, permits issued prior to publication of the new electric industry law) with load points with power consumption not entirely sourced from clean energy generators, to purchase, beginning on January 1, 2018, CELs representing at least 5% of their aggregate power consumption.

CENACE will also run auctions to allocate financial transmission rights, which are the marginal congestion component of locational marginal prices. These auctions will take place in the day-ahead market. Financial transmission rights do not grant a physical right to use the grid, but rather transfer the costs of congestion from one party to another. Basically, the holder of financial transmission rights is entitled to a portion of the income (or costs) resulting from the difference between marginal prices in the system. Financial transmission rights may be sold in the market for cash.

Upcoming Auctions

The main goal of the upcoming auction for 15-year contracts for energy and capacity and 20-year contracts for CELs, is for the state utility, CFE, to satisfy its requirements for any or all of the three products. Thus, most contracts awarded through the auction will be entered into with a CFE subsidiary as an offtaker.

After the first auction, participation will be broadened and private offtakers will also be permitted to participate, but the utility's requirements will always have priority.

While bidders will not have to have a generation permit in hand when bidding, the permit will be required before the bidder can perform any contract it is awarded. Power plants operating under legacy permits will not be permitted to participate in the auctions, except where the power to be offered in the auction is generated by expansion capacity under a new generation permit.

The 15- and 20-year contract terms are meant to help generators finance projects, especially renewable energy projects given that, other than these long-term contracts and the sale of CELs, there are basically no tax or other type of incentives in place for the development of renewable power projects.

A key issue will be what the contracts awarded in these auctions say. The forms of contracts will be part of the package of bidding guidelines. This remains an item of concern for lenders and developers alike. Several lenders have said that they would like to see terms similar to those included in the CFE legacy contracts for independent power projects (including lender step-in rights and payment by CFE of all due obligations upon a CFE default, among other provisions). Lenders are familiar with these provisions and have relied on them to finance projects for the past two decades.

Pricing under contracts for the sale of power from clean energy sources will be based on the zones — called "generation zones" — where the offering power plants are located, thus transferring to the buyers the risk of congestion. Contracts for intermittent power sources, like wind and solar, will include hourly adjustments to take into account the value of energy based on the time of the day and month of the year during which it is produced. CENACE is expected to issue a table as part of the bidding guidelines for the clean energy auction, with the projected hourly adjustments for a 24-hour period, for each month of each year of the 15-year contract term. These adjustments will take into account seasonality. The table, once issued, will not be modified going forward.

Existing participants in the Mexican market and new entrants have eagerly awaited the publication of the request for proposals for the long-term auctions.

Winning bidders who are awarded contracts will have to have their projects in commercial operation by January 1 of the third calendar year following the date of the RFP, except that if the bids were received in the calendar year following the RFP, then the commercial operations deadline will be two years after bids were submitted. For example, for an RFP issued in November 2015, if bids are received by December 31, 2015, then commercial operations must begin no later than January 1, 2018. However, if bids are received in 2016, then commercial operations start by the two-year anniversary of the bid date. The rules allow bidders to select a different date for starting / *continued page 24*

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pay dividends out of earnings from such electricity generation. In addition, debt borrowed to finance such projects will be exempted from thin-capitalization rules that limit the debt to no more than three times equity.

RESIDUAL VALUE INSURANCE was at issue in a case before the US Tax Court in late September.

This is insurance that an asset will be worth at least the insured value at the end of a lease term or some other period of time. The court included some interesting data about such insurance in its opinion.

The case involved a Bermuda-based insurer and looked at how the company reported its premium income on its 2006 tax return. Residual value insurance accounted for more than 97% of the company's business that year. The company accounted for the premiums it collected like an insurance company. Insurance companies are allowed by section 832 of the US tax code to spread out the premium income over the years that claims are expected to be paid. The IRS said the company is not an insurance company because residual value insurance is not "insurance" for US tax purposes.

The US Tax Court disagreed with the IRS in a decision in a case called *R.V.I. Guaranty Co., Ltd. v. Commissioner*. Even though RVI is based in Bermuda, the company elected under section 953(d) of the US tax code to be taxed like a US company. Its income was from US sources.

The US tax code does not define "insurance." The US Supreme Court said in a 1941 decision that "[h]istorically and commonly insurance involves risk shifting and risk distributing." Courts have also considered whether a transaction involves insurance "in its commonly-accepted sense" and whether the risk transferred is an "insurance risk."

The IRS analogized the residual value policies to "puts" that an investor might enter into to protect his downside case and said the policies were downside protection for customers against an investment loss rather / *continued page 25*

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commercial operations that may be up to one year prior to, or two years after, the statutory commercial operations date.

Long-term auctions will take place annually or more frequently should a need arise or should SENER (the energy department) or the CFE request an interim auction from CENACE.

There are prequalification requirements for all interested parties and minimum offer requirements for all bids. Capacity offers must be for a minimum 5% of the capacity demand in the auction or, if less, 10 megawatts. An offer for CELs must be for a minimum of 5% of the aggregate demand in the auction or, if less, 20,000 CELs per year. Offers may be for bundled services. Offers for clean energy must identify the power plant units that will generate the power and the percentage of total output from the plant.

Bidders must specify whether they wish for payments to be indexed in Mexican pesos or US dollars, in which case the new rules provide both inflation and currency exchange adjustment mechanisms, but all payments will be in Mexican pesos.

Moving to the follow-on auction in late 2016 for three-year contracts that will be open to all generators, the energy or capacity offered must be available starting January 1 of the year after the auction took place. Offers for energy will be based on the zones where the load points are located, thereby passing to the sellers the risk of congestion, and will be required to indicate whether the offer is for base, intermediate or peak energy blocks. Offers for capacity will have to indicate a fixed annual capacity offered in a particular zone where the power plant is located, called a "capacity zone."

The auctions for three-year contracts — called "medium-term auctions" — will take place annually or more frequently should a need arise or should SENER or the CFE request it from CENACE.

Guaranties

Anyone participating in any of the auctions must provide a commitment guaranty. For long-term auctions, the guaranty is a flat amount for all participants, plus a flat amount for each sale offer, plus an amount for each megawatt of capacity offered per year, plus an amount for each megawatt hour of clean energy offered per year, plus an amount for each CEL offered per year.

All amounts will be expressed as Mexican investment units or UDIs (*unidades de inversión*). The Mexican central bank publishes the UDI value in pesos for each day of the month in the official gazette. On the 10th day of each month, the central bank publishes the value of the UDI corresponding to days 11 through 25 of the relevant month and on the 25th day of each month, it publishes the value corresponding to the 26th day of that month through to the 10th day of the next month. The published value of the UDI for November 11, 2015 is 5.34 pesos.

If a power plant bidding in an auction is already in operation when the bid is submitted or has all the permits and equipment necessary for construction in time to meet the commercial operations deadline, then a smaller guaranty may be required. Commitment guaranties will be released after the auction or, if the bidder was a awarded a contract, once the contract is signed.

Wholesale market participants will also be required to post a performance guaranty in favor of CENACE to operate in the market. The amount of the performance guaranty will vary from one participant to the next. It will be based on the aggregate estimated potential liability of the participant in the market. The amounts will be updated by CENACE at least every 15 minutes. The government has released a "Market Manual for Performance Guaranties" that includes formulas for calculating the amounts. Market participants' operations will be suspended immediately if the estimated potential liability exceeds the guaranteed amount.

Since the enactment of the new electric industry law in August 2014 and the restructuring of the Mexican power market, one of the key questions has been the creditworthiness of the CFE subsidiaries that will become market participants, including the subsidiary that will be the sole supplier of basic electricity services and thus the main offtaker under contracts awarded through medium and long-term auctions. The new wholesale market rules allow these entities to provide a guaranty from their parent — the CFE — that will make the CFE jointly and severally liable for their obligations as market participants, and to deliver a surety from the federal government for obligations owed to CENACE.

Private market participants will be able to post stand-by letters of credit as guaranties. The LCs may be issued by financial institutions that are on an approved list drawn up by CENACE and that have an agreement in place with CENACE that will allow quick and efficient drawing of funds. Market participants will also be permitted to post cash or financial instruments issued by the Mexican government.

A market participant may reduce the amount of its performance guaranty after a year based on its creditworthiness and its track record of performing.

Financial Transmission Rights

Financial transmission rights — or FTRs — will be available under three different scenarios.

Grandfathered FTRs (*DFT legados*) will be directly assigned, at no cost, to parties to grandfathered interconnection contracts, parties to transmission rights agreements and basic service suppliers. Parties to grandfathered interconnection contracts will be assigned FTRs so long as they have elected to migrate to an interconnection agreement under the new regime. If a party to a grandfathered interconnection contract chooses not to migrate, then the FTRs it would have received will be assigned instead to a unit of CFE that will serve as an intermediary (*generador de intermediación*) that will manage the FTRs on behalf of the party to the contract. The amount and term of FTRs assigned will be determined on a case-by-case basis, but the term may not go beyond the year 2035.

After all the grandfathered FTRs have been assigned, CENACE will auction FTRs for the remaining transmission capacity. During the first phase of the market, FTRs will only be available through annual auctions and for a period of one year. During the second phase of the market, auctions will award FTRs for three-year periods based on seasonality. There will also be monthly auctions to assign FTRs for the immediately following month and the remainder of the year.

Finally, if a market participant or a party to a grandfathered interconnection contract pays to expand transmission or distribution networks that are not included in the government's expansion and modernization plans, then it will be entitled to FTRs that will be valid starting when the expanded network is put in service and for a period of 30 years. ◎

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than true insurance. Another strike against them, the IRS said, is the policies paid on a particular date — for example, the end of an equipment lease — rather than after some unpredictable occurrence, like a car crash.

The court disagreed.

It found the following important. RVI is regulated as an insurance company in every state in which it operates. The insurance regulators in the states view these policies as insurance. This is insurance in its most classic form in the sense that risk is being distributed among all the policyholders by collecting premiums from a wide pool of customers. There is a significant risk of loss to the insurance company.

The court recited a number of interesting facts about the residual value insurance business.

During 2006, RVI had 951 policies in force covering 754,532 autos, 2,097 buildings and 1,387,281 commercial equipment assets. The policies covered $16.2 billion in insured value.

RVI had a cumulative loss ratio through 2006, the tax year at issue, of 27.7% and through 2013, when the case went to trial, or 34%. The cumulative loss ratio is the share of premiums that had to be paid in claims. RVI paid more than $150 million in claims through 2013.

Premiums were low: the premiums rarely exceeded $4 per $100 of coverage and could be as low as 50¢ per $100.

The policyholder took the first loss. For example, if a residual value policy was written for a lessor of an auto that was expected to be worth $10,000 at the end of the lease term, and the insured value was $9,000, then the lessor suffered the first $1,000 in loss. The policy paid to the extent the residual value at the end of the lease term was less than $9,000.

A TAX PLANNING memo was privileged and did not have to be disclosed to the IRS, even though the company shared the memo with its lenders.

The memo, written by Ernst & Young, analyzed the tax consequences of a corporate restructuring and weighed / continued page 27

Wind Tax Equity Update

Two chief financial officers of major US wind companies and three leading tax equity investors talked in mid-October about how much tax equity can be raised on wind farms, current yields, the effect that low capacity factors and falling electricity prices are having on deals, the extent to which the tax equity market will finance projects that relied on modest physical work at the project site or a transformer factory to get under construction in late 2014, whether tax equity can be raised on 2017 projects, developer fees and other issues. The conversation took place at the American Wind Energy Association's annual finance conference in New York.

The panelists are Bernardo Goarmon, executive vice president and chief financial officer of EDP Renewables North America, Tom Festle, chief financial officer of E.On Climate & Renewables North America, Jack Cargas, a managing director at Bank of America Merrill Lynch, Yale Henderson, a managing director at JPMorgan Capital Corporation, and Kenji Ogawa, a managing director at MUFG Union Bank. The moderator is Keith Martin with Chadbourne in Washington.

MR. MARTIN: Bernardo Goarmon, CFOs can draw on various kinds of capital. There are loan guarantees, export credits and other forms of government-assisted debt, straight debt, tax equity, back-levered or subordinated debt and true equity. What share of the capital for the typical wind farm today comes from tax equity?

MR. GOARMON: For a project on which production tax credits will be claimed, probably between 55% on the low end to 75% on the high end for a project with high wind performance and, therefore, more tax credits.

MR. MARTIN: Tom Festle, same number?

MR. FESTLE: Yes, same range. We try to invest in high wind areas with competitive construction costs.

MR. MARTIN: Yale Henderson, the figures we have heard so far are the amount of tax equity that can be raised in a partnership flip transaction. What determines whether the transaction will raise 55% or 75% of the capital cost?

MR. HENDERSON: A number of factors. They are the wind regime, how many production tax credits are being generated, the asset cost and the amount of depreciation. Ultimately, the CFO is trying to optimize the structure by retaining as much cash as possible. Monetizing cash flow through the tax equity deal is not a goal of the CFO, and we are happy to accommodate him or her because it makes for a safer transaction from our perspective.

MR. MARTIN: The less cash the tax equity investor gets, the closer you are to the bottom end of the range. Bernardo said 55% at the low end.

MR. HENDERSON: For a PTC deal you never get below 50% because, if you do, then you will not be able to monetize the depreciation effectively. The low end of the range is probably 50% for a PTC deal and in the 40% range for an ITC deal.

MR. MARTIN: Kenji Ogawa, Tom Emmons from Rabobank said on the panel immediately before this one that he has not seen a leveraged partnership flip deal for a long time. Is that structure now extinct and, if so, why?

MR. OGAWA: I would not say that it is extinct, but it is selectively used. You really need scale to make the numbers work. In addition, there are probably only three or four tax equity investors who will consider doing a leveraged tax equity transaction. You need a large project with low risk and low variability in the wind regime.

MR. MARTIN: Jack Cargas, agree?

MR. CARGAS: I would call it extinct.

MR. MARTIN: Yale Henderson?

MR. HENDERSON: It's dead.

MR. MARTIN: Bernardo Goarmon, is anyone claiming an investment tax credit instead of production tax credits on new wind farms?

MR. GOARMON: Frankly, we do not see the economics working for investment credits. PTCs are a superior way of financing.

MR. MARTIN: Tom Festle, do you agree?

MR. FESTLE: We always look, and it never works. Our projects are too productive.

MR. MARTIN: Kenji Ogawa, have you seen any ITC deals recently in the wind market?

MR. OGAWA: I am aware of only one wind deal this year that was done on ITC basis.

MR. MARTIN: Why was it done that way?

MR. OGAWA: Cost.

MR. MARTIN: It was a very expensive project?

MR. HENDERSON: It was in a relatively weak wind regime in the northeast. There are a few that make sense on an ITC basis, but they are needles in a haystack.

MR. MARTIN: Tom Festle, in view of those answers, do we need to preserve the option for companies to claim the ITC when lobbying Congress?

MR. FESTLE: It is not a high priority for us.

MR. GOARMON: If we start adding large batteries to projects, then maybe the ITC will make more sense.

MR. MARTIN: I was going to go there next. Let's talk about batteries. Is EDP adding batteries to its wind farms and how will that change the equation? It makes the whole project more expensive without generating more electricity.

MR. GOARMON: We are not adding storage currently, but it is something we may do in the future. Storage tips the scale back toward ITCs if batteries are an integral part of the facility. The more expensive the project, the more advantageous it is to claim a tax benefit tied to cost. The greater the output, the better it is to claim a tax benefit tied to output.

MR. MARTIN: Tom Festle, is E.On adding batteries currently?

MR. FESTLE: It is something we are considering, but we have not done it yet. We are likely to do it at our solar projects before adding batteries to wind farms.

MR. OGAWA: Batteries are a reason to preserve the ITC. The ITC is not available for batteries on a standalone basis, but if you have a battery as part of a wind or solar project on which an ITC is claimed, then you may be able to claim an ITC on the entire project cost, including the battery. If you were to add a battery to a PTC project, then the battery would simply be a drag on cost and not qualify for an additional tax benefit.

MR. HENDERSON: I also assume that the only way offshore wind farms will be built is with investment tax credits.

Yields

MR. MARTIN: Kenji Ogawa, my impression is that tax equity yields have been trending down in the last six months. Do you agree?

MR. OGAWA: It depends on how you define slipping. I would say they have been relatively stable within a range. [Laughter]

MR. MARTIN: Yale Henderson, can you do better than that?

MR. HENDERSON: That was right and sweet. [Laughter]

MR. MARTIN: Jack Cargas, I am not going to ask you, unless . . . .

MR. CARGAS: Yes, they have been slipping.

MR. MARTIN: Bernardo Goarmon, where do you think tax equity yields are currently in flip deals?

MR. GOARMON: Still far too high! Let me just share the way I like to convey it to people overseas. Tax equity is a sophisticated product. Ironically, the pricing mechanism / continued page 28

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the strength of possible IRS challenges.

The US appeals court for the 2d circuit overruled a federal district court in November that had ordered the memo turned over to the IRS in a case called *Schaeffler v. United States*.

Georg F.W. Schaeffler owned 80% of a three-tier chain of companies headquartered in Germany that manufacture and distribute bearings and other automotive and industrial components.

The group made a tender offer for shares of Continental AG, another German auto and industrial parts supplier. It expected to acquire less than 50% of the shares, but ended up buying 89.9% at €70 to €75 a share for a total cost of €11 billion. The acquisition closed in July 2008. Over the next seven months, the share price plummeted to €11 a share. The acquisition was financed by a consortium of banks. The falling share price left the Schaeffler group close to insolvency and forced it to refinance the debt and restructure.

Schaeffler hired Dentons and Ernst & Young to help figure out a plan and advise on the tax consequences. The restructuring took place over the period 2009 to 2010. Ernst & Young wrote a long tax planning memo as part of the process.

Schaeffler received a favorable private letter ruling about the transaction from the IRS in August 2010. The favorable ruling did not stop the IRS from auditing the 2009 and 2010 tax years of the company in 2012. The IRS asked for all "tax opinions and tax analyses that discuss the US tax consequences of any or all of steps of the restructuring," and it issued a separate administrative summons to Ernst & Young directly for "all documents created by Ernst & Young" that relate to the refinancing and restructuring.

Both the company and Ernst & Young responded that the tax memo was privileged.

US tax law recognizes two types of privileges. One is for attorney-client communications about legal matters. Section 7525 of the US tax code extends this privilege to communications between a client and a "federally authorized tax practitioner." The other / continued page 29

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is as simple as it can get. It is supply and demand. The tax equity investors seem to be disciples of Adam Smith.

MR. MARTIN: Tom Festle, where do you think yields are currently?

MR. FESTLE: I heard somebody say on the last panel that they are between 7% and 8%. That range sounds reasonable. We are going out to market shortly, and we hope to see yields going down. They are still high compared to when we did our first deal in 2007.

MR. CARGAS: It is not clear that people measure the cost of tax equity appropriately. People talk about whatever the yield is. Tom Festle says 7% to 8%. We do not quote rates publicly, but call it somewhere in that range. That is the return to the tax equity, including tax benefits. These transactions are done by sponsors because they cannot use those tax benefits, so 7% to 8% is not a genuine cost. Part of the return to the tax equity comes from outside the transaction. It comes from the US government. I think the appropriate comparison ought to be to pre-tax internal rates of return, which is a better measure of the real cost to the sponsor.

MR. MARTIN: I am glad you brought that up. Now, let me press you on that. What do you need as a pre-tax yield?

MR. CARGAS: Sorry? [Laughter]

MR. MARTIN: Yale Henderson, what pre-tax yield does JPMorgan require: 2%? We heard from Invenergy on the previous panel that tax equity investors are requiring pre-tax yields of 1% to 2%.

MR. HENDERSON: Every tax attorney and every shop has his or its own benchmark, but 2% plus or minus is the right number. Of course, that is the pre-tax cash plus PTCs. If you look solely at the cash we are taking out of the project, we are making a negative internal rate of return. A lot of that flip IRR of 7% or 8% is tax savings from depreciation, which people have to understand produces no book earnings for us. The point is there are a lot of things that go into pricing when we look at a transaction.

MR. GOARMON: I agree with the up to 2% range for pre-tax yields. They are a proxy for long-term inflation. I disagree with Yale that there is a lot that goes into pricing. Pricing seems to be simple.

MR. MARTIN: Kenji Ogawa, what pre-tax yield does Union Bank require?

MR. OGAWA: The numbers that Yale quoted on the plus side are probably right.

MR. MARTIN: On the plus side. Tom Festle, are you seeing tax equity ask for a higher 20-year yield. Maybe 50 basis points higher?

MR. FESTLE: The last time we were in the market was at the end of last year. We will be back in soon. With that in mind, we do see some markup for a 20-year yield.

MR. GOARMON: We look at the period after the flip where we keep most of the value. Yes, there is a premium during this period for the tax equity investor, but it is a small premium. We like to measure it over 25 years.

MR. MARTIN: The yield premium is not 50 basis points?

MR. GOARMON: No, it is not; 25 basis points is more common from where we stand.

MR. OGAWA: One of the things you really need to look at is the profile of the project. The stronger the profile, the higher your back-end 5% is going to get you.

MR. MARTIN: The stronger the project, the higher the premium you will receive?

MR. HENDERSON We are not sitting there saying we need another 50 basis points above the flip IRR by year 20 or 25. The real driver is the pre-tax yield we are trying to hit. That will also drive what we end up with as an after-tax IRR. The additional yield at year 20 or 25 could be 25 to 50 basis points or even higher if you have a project with a merchant tail.

MR. CARGAS: I agree with that. We track those numbers, but most tax equity investors do not insert a minimum requirement or a minimum spread between the flip yield and the full-term yield.

MR. MARTIN: Kenji Ogawa, how common are structuring fees?

MR. OGAWA: They are a market-driven mechanism. The more complicated the structure, the more likely you are to see a structuring or commitment fee.

MR. MARTIN: Market-driven means that if you can get it, you ask for it? [Laughter]

MR. HENDERSON: I don't think they are structuring fees. I think they are commitment fees, and I think the market today is looking for longer-term commitments. The amount of regulatory capital and the cost of capital for those commitments have increased, so the market is taking that into account, particularly for parties who need commitments of six, nine or even 12 months before a project goes into commercial operation.

The larger US wind companies are raising 55% to 75% of the cost of their projects in the tax equity market.

Weather and Falling Prices

MR. MARTIN: Bernardo Goarmon, wind output has been below expectation this year in places like Texas, California and the Pacific Northwest. In Texas, an average capacity factor in the first half of 2015 was just below 30%, compared to 38% the year before. How has that affected your existing tax equity deals for projects in these locations?

MR. GOARMON: We have not seen such a significant gap in our portfolio. It is about half the gap you just described both in Texas and California. Other markets, like New York for instance, are slightly better than the long-term expectations. So far we have not seen any impact on our ability to arrange new tax equity transactions. We think that there are always good and bad years, and they average out. For example, 2012 was good, 2013 was good, and 2014 was a record first quarter. This is just the nature of the business.

MR. OGAWA: I think that most investors understand that the wind varies from one year to the next.

MR. HENDERSON: The partnership flip structure works well for projects with variable output because low performance one year does not lead to cash being trapped or payment defaults. We are not lenders. We are a form of preferred equity. We ride along with the ups and downs of the project.

MR. MARTIN: Jack Cargas, you are based in California. You see low capacity rates. Do they change how you will do deals going forward?

MR. CARGAS: They might. We are thinking hard about this. We hear our sponsors say that this is an anomaly that will be offset by better performance in other years, but we are tracking it closely. It has affected our portfolio. Certain transactions within our portfolio have been affected significantly. You asked how it will affect the deals we do in the future. / continued page 30

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privilege is a work-product privilege for documents prepared in anticipation of litigation.

Both privileges may be lost if documents are shared with third parties.

The bank consortium and Schaeffler entered into an "Attorney Client Privilege Agreement" during work on the transaction in which they expressed a desire to share confidential documents and analyses of the transaction without waiving privileges. The Ernst & Young memo was shared with the bank group.

The appeals court said the memo did not lose protection under the attorney-client privilege when it was shared with the lenders. The privilege is not waived by sharing it with others engaged in a "common legal enterprise." The enterprise in this case was avoiding a mutual financial disaster. The interests of the parties sharing the information do not have to be perfectly aligned. The parties do not have to be involved in litigation. The tax strategy was central to the restructuring. Information was shared pursuant to a confidential agreement.

Turning to the work-product privilege, the court said there are two ends of a spectrum. At one end is a document that is prepared because of the potential for litigation. At the other end are documents that are prepared in the ordinary course of business and that would have been prepared in largely the same form regardless of litigation.

The court said the memo in this case was "geared to an anticipated audit and subsequent litigation, which was on this record highly likely."

HAWAII voted to modify its net metering program.

Under net metering, utility customers with rooftop solar panels receive credit against their utility bills for any surplus electricity they feed into the grid.

The state Public Utilities Commission voted in October to reduce the price at which such electricity is credited to roughly half what it was before. Sales to the grid will / continued page 31

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For past transactions, it could push flip dates out. For new transactions, we are doing more sensitivity analyses. There is a decent chance that we will see larger haircuts in base case models.

MR. MARTIN: Are you pricing off P99 and applying a haircut to that?

MR. CARGAS: This is not something we have done yet. We are thinking about it. Right now, we are pricing off the expected case. We are starting to look at a larger range of possible outcomes. Exactly what we will do with that data is not yet clear.

MR. MARTIN: Power prices are falling. Thirteen power purchase agreements were signed last year for 1,768 megawatts of wind farms. The average price for the electricity was $23.50 a megawatt hour. The average cost to build wind farm was $1.71 million per installed megawatt. Do falling wholesale power prices affect how you will do deals going forward?

MR. FESTLE: The good news is that the capital cost to build a wind farm is falling at the same time. It just reinforces the need to optimize every transaction for wind and cost, both of which can vary significantly from one site to the next.

Corporate PPAs

MR. MARTIN: Yale Henderson, one of the big stories this year has been the number of corporate PPAs signed. Fifteen hundred megawatts had been signed by mid-year. We are expecting about 3,000 megawatts to have been signed by year end. Are you indifferent to whether the PPA is with a corporate offtaker or a utility? Does it come down simply to the creditworthiness of the offtaker when deciding whether you will do a tax equity deal?

MR. HENDERSON: Essentially, yes. Obviously, everybody likes a nice regulated utility backstopping the power pricing; it gives everybody comfort. But I think we are well-positioned, as a large bank, to evaluate the credit of corporate offtakers. We probably have a relationship with them already, so we are willing to roll up our sleeves and figure out what the credit is.

The bigger challenge is that a lot of those entities are not willing to use their balance sheets. They put these PPAs into standalone special-purpose subsidiaries and are offering little credit support, even when the parent is creditworthy. It is tougher to get comfortable with that. There is also a basis risk issue in corporate PPAs that is not present with utility PPAs because the electricity sold under corporate PPAs is often priced at a hub rather than the bus bar. We are able to get comfortable with the basis risk, but it is just another complication.

MR. GOARMON: We saw this train coming and prepared ourselves for it. We have a disciplined approach to negotiating PPAs. Our finance team is closely involved and on the lookout, among other things, for the quality of credit package and embedded derivatives for book purposes.

MR. MARTIN: Tax equity investors, would you do a deal with a virtual PPA? A lot of the corporate PPAs are essentially hedges or contracts for differences rather than physical trades.

MR. OGAWA: Yes. As Yale said, the biggest risk with corporate PPAs is the long-term creditworthiness of the offtaker, and then, secondarily, the basis risk on the settlement point of the contract.

MR. MARTIN: With a virtual PPA, there may also be risk that the electricity will find an outlet. The virtual PPA merely places a floor under the electricity price.

Construction-Start Issues

MR. MARTIN: Jack Cargas, are tax equity investors financing projects that started construction in 2014 under the physical work test?

MR. CARGAS: Yes.

MR. MARTIN: There are various ways a developer could have started physical work. Do you have a preference for roads, turbine excavations, transformers, substation foundations? How much work do you need to see?

MR. CARGAS: Clearly the more work, the better, but it is also clear that when the IRS provided additional guidance on this topic, it set a very low bar. A year ago, we were saying that a guy on site turning dirt with a shovel is not enough. We still say that, but three guys and a backhoe might be enough if they did the right work.

MR. MARTIN: Yale Henderson, how much physical work do you need to see, and do you have a preference for roads, transformers, turbine excavations, substation foundations? Are they all the same in your mind?

MR. HENDERSON: They are not all the same. We do not have a bright-line test. We evaluate each deal individually. We look hard at what work was done. Three guys and a backhoe? I am not sure we are there.

MR. MARTIN: A lot of developers will want to know this year, if they are given just two or three weeks to act, whether having a manufacturer do a small amount of work on a step-up transformer is enough. What do you think?

MR. HENDERSON: Spend real money, and you will be better off.

MR. MARTIN: Kenji Ogawa, is it enough to have started work on a transformer?

MR. OGAWA: I am with Yale on this one, too. There is no bright line. Depending on the size of the project, a transformer might be okay. I would defer to you and your esteemed colleagues on the tax side.

MR. MARTIN: Fair enough. Are there any issues with the physical work test that you think the IRS did not settle and needs urgently to address?

MR. OGAWA: If the IRS would make it a real bright-line test and not have it turn on facts and circumstances, that would be ideal.

MR. MARTIN: The bright line is called the 5% test.

The larger wind developers have bought turbine components in order to qualify their projects under the 5% test. Some of these projects will slip into 2017. Are tax equity investors willing to finance such 2017 projects? The developers must prove continuous efforts on the projects after 2014 to qualify for tax credits.

MR. CARGAS: We have not definitively answered this question frankly due to lack of time to analyze it. It is entirely possible we will get there, but we probably will not make this determination until sometime in 2016.

MR. MARTIN: Yale Henderson, same answer?

MR. HENDERSON: Pretty much. We have a lot of 2016 business to do first.

MR. MARTIN: Kenji Ogawa?

MR. OGAWA: Likewise.

MR. MARTIN: What happens if Congress does not extend the PTC?

MR. CARGAS: I have a view on this. There is a long history of structured asset finance in the United States that goes back at least 50 years. It will not be as dynamic a market, but to the extent there are depreciation-only transactions to be done, there will be sponsors who will take advantage of them.

MR. MARTIN: Yale Henderson, I assume the tax equity team at JPMorgan will need to find something to do. You will figure out how to continue doing tax equity deals, even with fewer tax benefits.

MR. HENDERSON: I started at First Chicago Leasing Corporation. The technology is there. The world has changed a lot since we did depreciation-only deals, both in terms of accounting and the willingness of banks to take 15- or 20-year risks, but, ultimately, like Jack said, we have figured / *continued page 32*

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be at the wholesale rather than the retail electricity rate. Wholesale rates range from 15¢ to 28¢ a kilowatt hour, which is about half the retail rate. Residential customers will also have to pay a minimum monthly fee to the utility of $25, and commercial customers will have to pay $50, to help defray the cost of the grid.

The Alliance for Solar Choice asked a court in late October for a preliminary injunction to block implementation of the new rules.

The new rules do not apply to anyone who had solar panels on his roof or applied to install them by October 12. Forty-four US states currently have some form of net metering.

FOREIGN CORRUPT PRACTICES ACT issues dog two projects in South Africa.

Japanese company Hitachi agreed to pay the US government a $19 million civil penalty to settle a complaint the US Securities and Exchange Commission filed against the company in court. The details are in a settlement that was filed with the court in late September.

Hitachi set up a company in South Africa in 2005 to bid on contracts to supply the boiler works for two coal-fired power plants: the Medupi and Kusile projects. Eskom, the South African utility, ultimately awarded Hitachi the contracts worth $5.6 billion. Eskom is owned by the South African government.

Hitachi sold 25% of the stock in its South African company to another company that the SEC said is a front for the African National Congress, the ruling political party in South Africa, and encouraged the front company to use its political influence to help secure the contracts. The chairman of the front company was married to a family member of the Eskom CEO. The front company had extensive ties with the ANC, according court documents.

Hitachi paid the front company a success fee of $1 million in 2008 that Hitachi recorded on its books as a "consulting fee." It paid another $1 million in 2010 that it recorded as a dividend on the 25% shareholding. / *continued page 33*

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out how to do such transactions in the past and we will figure this out again, if faced with the issue.

MR. MARTIN: Bernardo Goarmon, how common are developer fees in wind deals and at what level?

MR. GOARMON: Five percent is our typical. We see them more frequently in solar than in wind.

MR. MARTIN: Tom Festle?

MR. FESTLE: In some projects, we can add a lot of value as the developer and, in other ones, we add just a little value, so the fee varies.

MR. MARTIN: What is the range?

MR. FESTLE: It is hard to give a range.

MR. MARTIN: Some older flip deals are now getting to the point where they are about to flip or they have flipped. Lawyers and business people try to anticipate all the issues that might come up when drafting deal documents. Are there issues that have come up in the flip year that were not fully addressed in the standard partnership flip documents the market is using?

MR. FESTLE: We have not reached 10 years in any of our deals.

MR. GOARMON: We have had only one deal that flipped, so it is too early to speak.

MR. HENDERSON: We did our first deals in 2003 and have had some transactions reach the flip date. We have had a good experience with the deals that have flipped to date.

Yields for tax equity investors have been trending down.

Tax Risks

MR. MARTIN: Have you seen tax indemnity payments having to be paid in any of your deals, and if so, about what issue?

MR. GOARMON: No.

MR. HENDERSON: No.

MR. CARGAS: Not in wind.

MR. HENDERSON: Are you asking also about the Treasury cash grant program and indemnities paid on account of grant shortfalls?

MR. MARTIN: Yes, I am. So there have been indemnities in connection with shortfalls in Treasury cash grants. Kenji Ogawa?

MR. OGAWA: Same answer on the cash grant program for shortages.

MR. GOARMON: My answer is still no.

MR. MARTIN: Tax risk is allocated in flip deals through representations and a series of fixed tax assumptions. Have you seen any shift in the last year about how tax risk is shared?

MR. GOARMON: Attempt, yes; success, not yet.

MR. CARGAS: We have seen a shift. The depreciation methods and periods used to be a fixed tax assumption. They are no longer one in the current market. That risk has shifted from investor to sponsor.

MR. MARTIN: Almost all flip deals have absorption issues, meaning the tax equity investor has too little capital account to absorb the full tax benefits he is allocated. Yale Henderson said earlier that a flip deal must raise at least 50% of the capital cost for the tax equity to have a shot of absorbing a reasonable amount of the depreciation on a project. Is the absorption problem getting addressed still by having the tax equity investor agree to a deficit restoration obligation, and what is a typical percentage DRO in the current market? It seemed to be in the low 20% range a few years ago and to have fallen to the low single digits lately. These are percentages of the tax equity investment.

MR. CARGAS: I think the range is all the way from the low single digits to the high 20s, maybe even crossing 30%. It depends on the transaction. It depends on the sponsor. Even more important than the day one cap on the DRO is the capital account deficit profile over time, and how quickly the deficit is expected to be eliminated over time. Ideally, we would like to see the deficit eliminated before we flip.

MR. MARTIN: Is the principal factor how quickly the base case model shows the deficit reversing?

MR. OGAWA: It is an important factor given how PPAs are being structured today. It is harder to reverse a DRO if the project has a PPA with level pricing that does not escalate over time.

MR. MARTIN: Jack Cargas, some tax equity investors are offering a time-based flip where the tax equity investor gets essentially 2% of its investment in cash each year as a preferred distribution and not much other cash. Are you doing these deals?

MR. CARGAS: No.

MR. MARTIN: Why not?

MR. CARGAS: One other feature of these deals is that the sponsor has a call at year five to buy out the tax equity investor, and the tax equity investor has a withdrawal right at year six essentially to force a buyout if the sponsor call has not been exercised. One wonders in the wind arena how a transaction like that, which has a likely termination five or six years out, is useful to a sponsor who would like to see the transaction last for at least the 10-year PTC period. There may also be some concerns about whether the withdrawal right is a put that is likely to be exercised so that the tax equity is a fixed-term investment.

MR. MARTIN: Tom Festle, are these deals attractive to you as a wind company CFO?

MR. FESTLE: I agree with Jack that we are unlikely to consider them for a wind project because we do not want to have to finance the project twice. We would rather cover the whole PTC period right out of the box. Solar may be another story.

MR. GOARMON: Bernardo Goarmon, are these deals attractive to EDP?

MR. GOARMON: Not in wind.

MR. MARTIN: Yale Henderson, is JPMorgan doing them?

MR. HENDERSON: No.

MR. MARTIN: Kenji Ogawa?

MR. OGAWA: No.

Cash Strips

MR. MARTIN: Yale Henderson, coming back to you, JPMorgan tried for years to develop the secondary market for tax equity paper. Has such a market developed and, if so, how would you characterize it? / *continued page 34*

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The Foreign Corrupt Practices Act requires US and foreign companies that have to file reports with the Securities and Exchange Commission to keep books that accurately reflect what they are doing and also to have internal controls that will help them spot any bribes paid to foreign government officials or officials of foreign political parties.

Hitachi was an issuer of US securities. It had American depositary receipts, or ADRs, that were traded on the New York Stock Exchange at the time of the violations. It delisted the ADRs in 2013, but they continued to trade on over-the-counter markets.

The case was a collaboration between the SEC and the integrity and anti-corruption department of the African Development Bank. In recent years, the AfDB has vigorously enforced ethics violations, according to Keith Rosen, an FCPA expert with Chadbourne. “For example, on October 1, 2015, the AfDB settled claims against SNC-Lavalin Group Inc. alleging the company made illicit payments to public officials in order to secure contracts on two AfDB–financed projects, and in December 2014, the AfDB imposed a three-year debarment and an $18.86 million fine on China First Highway Engineering Co. Ltd. following the company’s admission of fraudulent and collusive practices in an AfDB-financed project,” Rosen said.

The SEC settled charges with Goodyear that led to a $16 million fine against the tire company in February 2015 related to bribes paid to obtain tire sales in Kenya and Angola. In September 2015, Hyperdynamics Corporation settled SEC charges that its subsidiary in Guinea failed accurately to record payments to two companies.

FOSSIL FUEL POWER PLANTS are running at lower capacities, making them more expensive to operate, according to a report by Bloomberg New Energy Finance in October.

The report said there is evidence of a “virtuous cycle.” As more renewable energy facilities are built, utilities cut back / *continued page 35*

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MR. HENDERSON: Yes. We have done a number of secondary market transactions selling the cash portion of our tax equity position to interested cash investors where the flip date has been delayed beyond the 10-year horizon. I think it is a growing market. We are aware of other tax equity investors who are looking into doing similar transactions. We will continue to actively manage our portfolio using this tool in the future.

MR. MARTIN: Why shed the cash portion of your tax equity position?

MR. HENDERSON: The impetus was the deals had not or were not expected to flip on schedule. We wanted to manage the tail risk and not have a large residual sitting there at year 10, so we decided to be a little more proactive in managing our portfolio. Those were very early partnership flip deals that we did during the period 2003 through 2006. I think we have gotten a lot smarter about how to predict wind output. Those tails on more recent deals will be a lot shorter. The impetus to do additional deals on new facilities will not be as great.

MR. MARTIN: I have two more questions. How receptive is the tax equity market to merchant wind deals? Can they be done on a standalone basis or only as part of a larger portfolio?

MR. HENDERSON: Merchant can get done on a standalone basis.

MR. MARTIN: Only with a 12-year hedge?

MR. HENDERSON: Without any hedge.

MR. MARTIN: Without any hedge at all. In what parts of the country?

MR. HENDERSON: Where you have a good merchant market.

MR. MARTIN: ERCOT and PJM. Anywhere else? New England?

MR. HENDERSON: Not in New England.

MR. CARGAS: I don't know what you mean by merchant. If you are talking about hedge transactions, we have been doing a lot of these deals, and they have a true merchant piece in that some percentage of the output is not, in fact, hedged. The hedge deals that we are doing at Bank of America use Merrill Lynch Commodities as the hedge counterparty. We are doing transactions like that. Pure merchant transactions? No. Are we doing transactions that have some percentage of the output unhedged and are, therefore, merchant? Yes.

MR. MARTIN: What percentage: 25%? Higher?

MR. CARGAS: It depends on what you are measuring. If you are measuring cash flow or PTCs, then yes: 20%, 25%, 30%.

MR. MARTIN: Yale Henderson, I understood you to say you can do a pure merchant deal without a hedge. Did I misunderstand?

MR. HENDERSON: No. We have done those in rare instances, but they have been done.

MR. MARTIN: Is that because another part of JPMorgan is taking the price risk, as Jack Cargas described for Bank of America?

MR. HENDERSON: No. There are deals structured so that the tax equity investor can reach its return, if necessary, largely on PTCs and depreciation and, therefore, the exposure to merchant price risk is small and over collateralized. With proper structuring, you can do a hedge deal with the right sponsor and the right project.

MR. FESTLE: Maybe we are that type of sponsor. When we make an investment decision on a site, we are willing to stand behind the wind assessment.

MR. GOARMON: We do not like merchant, it is not in our DNA, but when we do it, we fold the project into a portfolio so that it is financed as part of a larger portfolio that limits the exposure to the tax equity investors.

MR. MARTIN: Last question. With the benefit of hindsight, how successful was the Treasury cash grant program?

MR. CARGAS: It was very successful. It was not perfect and there was some difficulty in administration, but the use of that technique during a period when there was really low tax capacity on offer in the market was very important for advancing renewable energy in this country. We would not be as far along as we are today were it not for that program. It provided liquidity when the market would otherwise have lost momentum. ◎

FERC Incentives for New Transmission Lines May Help Secure Early Financing

by Bob Shapiro and Joseph Tierney, in Washington

The recent selection of independent transmission developers to construct new transmission lines as part of plans by grid operators to upgrade has opened opportunities for "non-incumbents" to finance early-stage development of independent transmission projects.

In the past, only the "incumbent" utilities that own the grid were being selected by the regional transmission organizations and independent system operators that manage the grid to construct the additional capacity.

However, recent decisions by the Federal Energy Regulatory Commission eliminated a long-standing right of first refusal for incumbent utilities to construct transmission in their own service territories under a regional transmission plan. This has created a more level playing field for independent developers to construct new transmission, and some independent developers have been selected in recent RTO solicitations.

Incentives

Congress amended the Federal Power Act in 2005 to direct FERC to establish rate-based incentives to promote new investment in electric transmission facilities.

FERC responded with orders that grant incentives in exchange for a showing of additional risks taken and a willingness to grant regional operational control over the new transmission facilities before project siting, permitting and construction have begun. The potential incentives currently available include an incentive-based return on equity, recovery of construction work in progress and pre-commercial expenses, use of a hypothetical capital structure for purposes of rate-of-return calculation, accelerated depreciation, recovery of costs of abandoned facilities, and deferred cost recovery.

The ability to recover the cost of abandoned facilities reduces the risk associated with non-routine projects. These are projects that must be abandoned for reasons beyond the developer's control. For projects approved by an RTO, an */ continued page 36*

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on the number of hours that power plants that burn fossil fuels operate. This pushes up the cost per unit of electricity, and helps accelerate reaching the crossover point when renewable energy is cheaper than electricity from coal or natural gas to generate.

Germany and the United Kingdom have reached the crossover point where wind is now the cheapest electricity, even without government subsidies. Bloomberg says wind is cheaper than fossil fuels in the US if government subsidies are taken into account. However, it expects another decade before the crossover point is reached without subsidies.

One consequence of the virtuous circle is returns from gas-fired power plants become harder to predict if one assumes the plants will be dispatched less and less frequently over time.

Ben Fowke, CEO of US utility Xcel, said his utility is receiving bids currently of $25 a megawatt hour for wind under 20-year power purchase agreements. He expects prices for electricity from gas-fired power plants to be closer to $32 a megawatt hour over the same period.

Meanwhile, the National Renewable Energy Laboratory reported in September that the median cost of utility-scale solar photovoltaic projects in the United States fell by more than 50% in real terms during the five to seven years through 2014. The cost figures in current dollars, meaning the dollars for the year in which spending occurred, are $6.30 a watt AC at the start of the period falling to $2.30 a watt by 2014.

NREL said that at least 44,600 megawatts of utility-scale projects were in US interconnection queues at the end of 2014. Not all the projects will be built, especially if the investment credit falls from 30% to 10% as scheduled after 2016.

A KEY COURT FOUND ECONOMIC SUBSTANCE LACKING in two transactions in September.

The IRS is free to deny tax benefits claimed in transactions that lack economic substance.

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independent developer would recover the costs through access charges that all users of a grid are required to pay.

Typically an applicant for incentive rates will file at FERC for approval of a cost-of-service tariff that would include one or more incentive features that are available under FERC policy.

To succeed, the applicant must meet a two-part test.

Recent FERC decisions will help independent developers looking to build new transmission lines.

Under the first part, referred to by FERC as the "section 219 test," an applicant must demonstrate that the transmission facilities for which it seeks incentives will improve reliability of the grid or else reduce the delivered cost of power by relieving congestion. FERC established a rebuttable presumption that this standard is met if one of two things is true. The applicant can prove that the transmission project is the product of a fair and open regional planning process that considered and evaluated projects for reliability or congestion. Alternatively, the applicant can show that the project already has construction approval from an appropriate state commission or state siting authority that considered whether the project improves reliability or reduces the cost of delivered power by reducing congestion.

Most applicants try to meet the section 219 test by submitting independent studies of a project's reliability and economic benefits.

When an applicant asks for incentives for a project that was not approved in a regional or state transmission plan, FERC has conditioned that approval on the project being included in a regional or state plan at a later date.

The second part of the two-part test is referred to by FERC as the "nexus test," and it requires a demonstration of a link between the incentive sought and the investment being made. Where authorization for multiple incentives is sought, an applicant must explain how the total package of requested incentives is tailored to address the demonstrable risks or challenges faced by the project. Applicants must provide enough evidence to allow FERC to evaluate each element of the package as well as the interrelationship of all elements of the package.

In evaluating whether requests to be able to recover costs if the project is abandoned have met the nexus test, FERC considers how great a risk there is the developer will have to abandon the project for reasons outside its control. FERC has found environmental, regulatory, siting and rights-of-way acquisition to be elements in specific projects that were beyond the reasonable control of the party seeking the incentive. In a notable recent decision, FERC authorized abandonment cost recovery for a minority owner in a planned transmission project on the grounds that, as a minority owner, the applicant had little control over abandonment decisions, and faced unique financing challenges. FERC has declined to authorize incentives where the applicants only cite risks that are not unique to the project, such as a risk that the project will not be approved in a regional plan, or where applicants fail to describe the risks in enough detail to tie them to the particular project.

If a request for incentives is denied, FERC usually allows the applicant to refile with updated information. Further, FERC has indicated a party may seek recovery of abandonment costs in a proceeding under section 205 of the Federal Power Act after a project is abandoned in fact even if the abandonment cost recovery incentive was not granted in advance.

Recovering Costs

Even if abandonment costs are approved for recovery in advance, this does not guarantee the amounts can be added to transmission rates. Following project abandonment, an applicant must demonstrate in a filing under section 205 of the

Federal Power Act that the abandonment was beyond its reasonable control and the costs were prudently incurred. It must also propose a reasonable rate and cost allocation method to recover the costs.

FERC generally defers to the business judgement of transmission developers in assessing whether project costs were prudently incurred. For larger abandoned projects or those presenting complex cost allocation issues or where there has been a significant protest or adverse intervention, FERC has set the matter for hearing.

The amortization periods approved by FERC for abandonment costs have been between one and three years.

Lacking customers is not a barrier to receiving authorization to recover costs if the project is abandoned. However, in the case of an independent developer, the question is how it can recover the authorized costs if the project was never built so that there is no service and, thus, there may be no customers from whom to recover the costs.

Some RTOs have taken steps to address how independent developers can recover the costs of abandoned projects within their systems. For example, the California Independent System Operator provides in its tariff that projects selected in the CAISO's transmission plan, but canceled prior to operation, can recover costs via a transmission access charge that is collected from all users of the system. PJM, the grid operator in the mid-Atlantic states, plans to file tariff revisions addressing abandonment costs by early 2016. In the absence of RTO tariff provisions addressing the abandonment cost allocation, a non-incumbent may propose a cost allocation method in a cost recovery proceeding following project abandonment, but that allocation method would be more open to challenge by stakeholders within the RTO.

Thus, if the transmission investment has been approved as part of a regional transmission plan, and the transmission owner agrees to transfer control over operation of the assets to the RTO, its FERC-approved incentive rates can be included as part of the regional transmission charge of the RTO. The charges would be allocated in some fashion to the users of the RTO or ISO grid. This approach to transmission cost recovery is also used by the ERCOT system in Texas, although it is not regulated by FERC. The extent and manner in which abandonment costs can be recovered may differ among RTOs.

A significant, unaddressed issue relates to abandonment cost recovery for interregional projects (across two planning regions). Because FERC has suggested that abandonment costs may not be recovered unless a transmission / continued page 38

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The US appeals court for the 2d circuit — considered one of the most influential by lawyers — found no economic substance in transactions that AIG and the Bank of New York Mellon Corp did more than a decade ago.

Congress has since written into the US tax code that transactions must have economic substance. The appeals court applied a version of the requirement that was developed over many years as common law.

The cases are *American Insurance Group v. United States* and Bank of *New York Company v. Commissioner.*

AIG Financial Products entered into six cross-border transactions between 1993 and 1997. The company essentially borrowed from foreign banks at rates below LIBOR and reinvested the funds at rates above LIBOR. In each transaction, AIG set up a special-purpose foreign subsidiary. The foreign lender advanced its funds to AIG in the form of a subscription in the AIG subsidiary for preferred shares. AIG committed to repurchase the preferred shares on a specific future date for the original share price.

AIG took the position for US tax purposes that it was the sole owner of each subsidiary. It claimed foreign taxes paid by each subsidiary as a foreign tax credit in the United States. It deducted the "dividends" paid to each lender as interest.

Meanwhile, each foreign bank treated its preferred shares as an equity investment for tax purposes in its home country and treated the payments to it as tax-exempt dividends rather than taxable interest. This allowed it to charge a lower interest rate on the loan.

AIG said the transactions had substance because they were expected to generate $168.8 million in pre-tax profit. It ignored the foreign and US taxes paid and foreign tax credits in its calculation.

It said in its brief that a court cannot deny it foreign tax credits for foreign taxes that were actually paid.

The appeals court disagreed. It said the economic substance / continued page 39

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project has transmission customers or unless cost recovery is provided for in a FERC-approved tariff, the abandonment incentive is effectively unavailable for most interregional projects, absent a cost allocation agreement between the planning regions. An exception may be participant-funded, cost-based projects. FERC has authorized that recovery of costs be allowed for such projects, but there is no precedent on how abandonment costs will be allocated if the project is abandoned.

Sufficient for Financing?

A number of developers that have been selected recently by RTOs to build transmission projects have been filing at FERC for transmission rate incentives, including abandonment cost recovery.

Developers have been trying to get lenders interested in providing very early stage development financing based on a FERC authorization to include abandonment cost recovery if the project is cancelled.

Since this project financing would occur at a stage that is earlier than when banks typically lend, it remains to be seen whether this incentive will be strong enough to attract bank debt. Authorization for abandonment cost recovery does not guarantee that abandonment costs can in fact be recovered since the developer would have to demonstrate its entitlement to cost recovery after the fact. As noted, FERC has generally deferred to the developer's business judgment on whether costs were prudently incurred. Even if the banks will not lend, equity investors may find the prospect of cost recovery enough of a draw, but at higher required returns.

As a final note, incentive rates do not apply to independent transmission developers that are using negotiated, or market-based, rates for their service, since they simply sign bilateral agreements under which FERC does not approve the specific charges. ◎

Energy Hedges: What To Look For

Chadbourne runs internal training sessions for its project finance lawyers. The following is an edited transcript from a session on energy hedges taught by Rob Eberhardt and Monika Szymanski in the Chadbourne New York office in late October.

MR. EBERHARDT: Our focus today is on energy hedges for natural gas-fired power plants. I will give a brief overview of recent trends in the market for natural gas-fired power plants. Energy hedges address a problem with such projects. I will describe this problem. Two types of energy hedges are common in recent deals: a heat rate call option and a revenue put. I will describe each of them and differences between them.

Monika Szymanski will talk about the issues that get negotiated in the ISDA documentation once one gets into the legal documents to implement a hedge.

Context

Hydraulic fracturing and directional drilling have led to an abundant supply of natural gas in North America. Prices of gas have fallen. This has led to heavier use of gas as a fuel for generating electricity. At the same time, the US government is moving to more stringent regulation of emissions from coal-fired power plants, causing many older coal-fired power plants to be permanently shut down. Even though electricity demand is flat, because gas is cheap and because the existing fleet is turning over, developers see opportunities to build new natural gas-fired power plants.

In the last two to three years, there have been at least 14 project financings of new merchant natural gas-fired power plants in the United States. The bulk of them are in the PJM market, which covers the mid-Atlantic states and parts of the Midwest. There also have been a few deals done in Texas, and one project has been financed in New York. Each of these projects has had an energy hedge as a critical element of the financing.

The projects have been financed in both the bank market and the term loan B market. They range in size, but the typical project cost is $800 million to $1 billion. There can be 12 to 15 banks in the lender syndicate. There may be both senior and mezzanine debt. There are multiple equity investors in some projects. These are big, complicated projects.

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They have been done with both revenue puts and heat rate call options. However, there appears to be a preference in the bank market for revenue puts. Panda has done several projects in the term loan B market with heat rate call options, but as far as we are aware, there has only been one bank deal with a heat rate call option.

Energy hedges are not the only driver for the financing, but they are a very important part. To understand why, one must go back in time.

Early in the life of the independent power industry, independent generators financed power plants based on long-term offtake contracts with utilities. Utilities paid the avoided cost that the utility would have to incur to generate the same electricity itself. Long-term offtake contracts remain the lynchpin of most project financings in the power sector.

However, by the late 1990s, after certain electricity markets were deregulated, a large number of combined-cycle gas-fired power plants were built on a merchant basis, without long-term offtake contracts. The market fundamentals ultimately deteriorated because too many people were chasing the same opportunities. Then natural gas prices went up.

Plants could still make money by operating, but they were not nearly as valuable. A large number of projects that were under development were cancelled. Developers lost money. Developers had to shed operating projects at steep discounts. Some bankers who had financed the projects lost their jobs. We then went through a decade in which the market soured on combined-cycle gas-fired power projects. There were a few deals done, but not many.

A generator that buys gas and turns it into electricity makes money if the spread between the gas and electricity prices is favorable and the cost associated with that process is low enough. If the cost of gas goes up or if the wholesale price for electricity goes down relative to one another, then the viability of the business can be affected significantly. It is not so much how much the gas costs or what price will be paid for the electricity in absolute terms. The key is the spread between the two and how efficiently you can convert gas into electricity.

The wholesale price for electricity can vary wildly. Gas prices also are volatile. Energy hedges guard the spread between gas and electric prices. In doing so, they protect a project against a deterioration in market conditions like what occurred previously. / continued page 40

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doctrine allows courts to take a "second look" at whether particular uses of tax benefits comply with Congressional purpose.

The court isolated the part of each transaction that generated the foreign tax credits for AIG in the United States and then applied a two-prong test to assess whether that leg of the transaction had substance.

There has to be an objective expectation of profit apart from tax benefits. The court said the foreign taxes paid should be treated as a cost in assessing whether there was a profit to be made, but, at the same time, the foreign tax credits claimed in the United States should be ignored as that is the benefit whose appropriateness the court is testing. Not all transactions have to show an expectation of profit. A profit is not required in cases where the tax benefit is supposed to induce companies to make investments — for example, in low-income housing — that would otherwise be uneconomic absent the tax subsidy.

The other prong is there must be a non-tax business reason for the transaction. The appeals court said that, while there was room for argument, there was enough evidence for the lower court to have decided this in favor of the government.

Turning to the Bank of New York case, the bank borrowed $1.5 billion from Barclays at LIBOR plus 20 basis points in late 2001. The Bank of New York booked the loan through a subsidiary in the Cayman Islands. However, the loan was set up as a transaction run on paper through a trust in the United Kingdom with an elaborate series of agreements a number of which involved circled cash. The main reason for interposing the trust and for some of the arrangements surrounding the trust was to trigger taxes in the United Kingdom on collateral held in a Delaware limited liability company that was a subsidiary of the trust over the term of the loan, which was expected to run through 2006, but to allow the Bank of New York to claim foreign tax credits for them in the United States. Barclays received tax benefits from the arrangement in the United Kingdom and shared half / continued page 41

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Revenue Puts

The way to think about revenue puts is they are a type of insurance. The project (the insured) pays an upfront premium to the hedge provider (the insurer), and if gas and electric prices move in the wrong direction, then the hedge provider will make a payment to help the project make up the loss in revenue.

The put is downside protection in exchange for an upfront payment. The project typically makes the payment at closing on the financing for the project, at the start of construction. The upfront payment is large. It can be in the range of $30 to $50 million for a five-year revenue put.

Revenue puts and heat rate call options are becoming more common in gas-fired power projects.

The put sets an assumed revenue floor for the project. If market conditions have changed so that the actual revenue in any year after the project starts operating is below the floor, then the hedge provider makes a payment that year to get the project to the floor. If market conditions are such that actual revenue in a year is above the floor, then no payment is made that year.

The risk that assumed revenue, based on market prices for electricity and gas, for any year will dip below the floor is borne by the hedge provider. The hedge provider is compensated upfront for taking that risk. The hedge provider of a revenue put takes a view on where the market is headed, but it also does offsetting trades to try to protect itself.

The project keeps the upside to the extent market prices turn in the project's favor. That is a key difference between a revenue put and a heat rate call option. In the latter case, the hedge provider keeps the upside.

The term of the hedge starts to run once the project is in service. They typically do not have terms longer than five years.

Payments under a revenue put are calculated on an annual basis. In cases where a project needs cash more frequently, the hedge may have interim quarterly settlements. If the project has been overpaid by the end of the year, then it has to give money back. The dollars back are usually small. Money runs primarily to the project.

The hedge protects against deterioration in market conditions — changes in gas or electricity prices — but not operational inefficiencies or technical problems or outside events that prevent operation of the project.

The hedge confirmation refers to something called the "net revenue amount." The net revenue amount is calculated and compared against the floor to determine whether the hedge provider is required to make a payment.

In a revenue put, at the end of the each quarter or year, depending on the settlement period, the net revenue amount is calculated based on assumptions about what the maximum revenue a hypothetical plant would have earned given actual gas and electricity prices. You make assumptions about the plant size. You make an assumption about its heat rate, i.e. how efficiently it operates. You make an assumption about how much it costs to start the plant. You make assumptions about how much it costs to run the plant, apart from fuel costs, and you assume how frequently the plant has to be restarted. For example, you might assume a maximum of 300 restarts in a year and that, once the plant has started, it must run for at least five hours.

The only revenue figures in the calculation are gas and electricity prices. These are set based on published market prices. How much would the project collect by selling electricity, and how much would it have to spend to run the plant in that hour? You do that calculation for each hour for the entire quarter or year. You sum up all the revenue in each hour and compare that to the floor amount that was set at closing. If the number for the settlement period is below the floor, then the hedge provider pays. If the number is above the floor, then no payment is made.

Heat Rate Call Options

Let's talk next about heat rate call options and focus on how they differ from revenue puts.

First, in a heat rate call option, you do not make a big upfront payment at financial closing. Second, there are payments potentially in both directions. If market conditions deteriorate, then the hedge provider makes a payment to the project. If market conditions improve, then the project makes a payment to the hedge provider.

Heat rate call options typically have a fixed revenue amount called the "option premium." This fixed amount is compared to the "cash settlement amount" to determine which party makes payments for the relevant settlement period.

The calculation of the cash settlement amount in a heat rate call option ultimately looks similar to the calculations that are made under a revenue put. Similar assumptions are made as in a revenue put to isolate the gas and electricity price risk.

However, while the calculations for a revenue put are done based on an optimal "exercise schedule" — an hour-by-hour schedule of whether or not the plant is assumed to run for purposes of the hedge — for a heat rate call option, the exercise schedule is set based on elections made by the hedge provider each day in advance. Each day on a day-ahead basis, the hedge provider — not the project owner — decides whether to consider the plant in operation solely for purposes of the hedge. The decision whether actually to run the plant is made by the project owner, but for purposes of determining whether a hedge payment will made, it is the option of the hedge provider to "call the hypothetical plant" from one hour to the next.

If the hedge provider decides not to call the hypothetical plant, then there is no revenue for that hour for purposes of calculating the cash settlement amount. If the hedge provider decides to call the hypothetical plant for hedge calculation purposes, then the revenue for that hour may be positive or negative, depending on actual market prices and assumptions about the plant's heat rate and operating costs.

The ultimate settlement amount will equal the option premium and will be paid to the project if the hedge provider elects not to call the hypothetical plant in any hour during the relevant settlement period. Doing so is in the hedge provider's interest if the spread between gas and electricity prices has deteriorated, because, the way the math works, the settlement amount payable to the project can actually exceed the option premium if the hedge provider calls the / *continued page 42*

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the benefit with the Bank of New York in the form of a reduced interest rate on the loan. The Bank of New York indemnified Barclays against the potential loss of half the UK tax benefits. Absent the tax benefits, the interest rate on the loan would have been LIBOR plus 30 basis points.

The US Tax Court denied the Bank of New York the foreign tax credits on economic substance grounds, but allowed it to deduct the interest paid on the loan. The appeals court agreed. It said the "circular cash flow demonstrates that Bank of New York, far from risking double taxation, used an extremely convoluted transaction structure to take maximum advantage of US and UK tax benefits." (For earlier coverage, see the April 2013 *Project Finance NewsWire* starting on page 31.)

The issues may be headed to the US Supreme Court. The US appeals courts are split on the key issues in the cases. BB&T, another unsuccessful bank in a transaction with Barclays like the one done by Bank of New York, asked the Supreme Court in late September to hear its case. (For earlier coverage of the BB&T case, see the July 2015 Project Finance NewsWire *starting on page 33.)*

CFIUS agreed to let Ralls Corporation sell the development rights to four wind farms in Oregon to investor Dr. Xieuxin Tang, the company said in a statement in early November.

Ralls has been engaged in a three-year battle with the US government over the projects. The company bought them from Greek company Terna Energy in March 2012. The US Navy expressed concerns soon after Ralls closed on the purchase about the location of the one of the projects that is near a US Navy base that trains pilots of drone aircraft. Ralls agreed to move it to a different site.

Ralls failed to notify CFIUS — short for the Committee on Foreign Investment in the United States — when it made the purchase. CFIUS is an interagency committee of 16 federal agencies that reviews foreign / *continued page 43*

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hypothetical plant during periods of unfavorable market prices.

When thinking about the potential payment amounts made to or from the project during a settlement period, the more favorable the spread between gas and electricity prices, the less the project receives under the hedge. At a certain point, market conditions are sufficiently favorable that the project must make payments under the hedge.

From the option premium (the maximum expected settlement amount payable to the project), the payment to the project reduces, and the net direction of payment ultimately switches from the project to the hedge provider as the cash settlement amount increases. The cash settlement amount increases for every hour in which the hedge provider has elected to run the hypothetical plant when there is a favorable spread between gas and electricity prices.

A revenue put is downside protection in exchange for an upfront payment.

For a financially-settled heat rate call option, as the amount paid under the hedge to the project decreases, and as the direction of payment ultimately switches from the project to the hedge provider, the assumption is that revenue associated with physical electricity sales will increase. The combination of hedge payments to or from the project and electricity revenue received by the project results, in theory, in a steady project revenue stream based on a fixed spread between gas and electricity prices.

Heat rate call options settle on a monthly basis, and there is a payment by the hedge provider to the project or vice versa.

Contrasts

Backing up to see the big picture, the hedge provider is usually not taking physical delivery of any electricity. Most hedges are financial instruments. That said, we have seen a few heat rate call options involve physical delivery.

Both products provide downside protection for project revenue. With a revenue put, the project has all the upside — the assumed excess revenue from physical sales — if market prices turn in the project's favor. With a heat rate call option, the upside goes to the hedge provider.

With a revenue put, there is little likelihood that the project will have to make significant payments to the hedge provider apart from the large upfront payment. With a heat rate call option, there may be ongoing payments to the hedge provider.

The hedge protects the project from market deterioration at hubs rather than the bus bar for the project or the actual delivery point for the gas the project is purchasing. The hedge provider wants to use hubs because gas and electricity are traded at the hubs. Hedge providers are comfortable taking a bet only at big, established trading hubs. The fact that pricing may differ at the hubs from where the gas and electricity actually change hands is called "basis risk" and is borne by the project. People spend a lot of time looking at historical data and projections in an effort to understand how likely actual prices are to match up the prices at the hubs.

Everything about the plant, other than gas and electricity prices, is the project's risk. If you have an assumed heat rate in the hedge and you are not operating efficiently enough to make it, then that is the project's problem. If the plant is down for whatever reason, then that is the project's problem. The hypothetical plant on which the hedge is based is considered to be running for hedge purposes from one hour to the next if it makes sense to run. If the property tax rate goes up, then that is the project's problem. The project will have less money to pay the hedge provider, and the project is not making as much money as it expected, but the hedge offers no protection. If water or

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any other variable charge is more expensive than expected, then that is the project's problem. The amount of each of these costs is assumed in the hedge.

Power plants in PJM are paid for capacity as well as energy or electricity. That is a separate revenue stream. There no protection for capacity payments under the hedge. Ancillary services, like frequency regulation to help balance the grid, are another, smaller revenue stream that also is not protected under the hedge.

The hedge provider does not look for much in the way of collateral from the project with a revenue put because there is no need to make significant ongoing payments to the hedge provider. Lenders like the simplicity. With a heat rate call option, there are significant ongoing payments to be made by the project to the hedge provider, and those payments are typically made as an operating expense ahead of debt service. The hedge provider will require significant collateral to secure payment. During construction, there is usually a large letter of credit. Sometimes, the hedge provider gets first or second liens. There are intercreditor issues to work out between the hedge provider and the term lenders. The complexity of the heat rate call option is one reason we do not see many of them in the bank market.

Documentation

MS. SZYMANSKI: Let's discuss how hedges are documented. There are three main documents: an ISDA master agreement, which is a pre-printed form that comes in a 1992 and a 2002 version and that has the common terms that apply to all hedges, a schedule that has modifications that the parties have agreed to make to the terms of the master agreement and a confirmation that has the economic terms of the transaction that are specific to the deal.

There are also standard ISDA definitions for transactions such as the 2006 ISDA definitions and the 2005 commodity derivatives definitions. For physically-settled power transactions, there is an ISDA North American power annex with additional definitions and provisions.

In addition, either or both parties to the hedge may have to post collateral, so there may be a credit support annex. There are several versions in use, but what we see most frequently is the 1994 New York law version.

The master agreement is where you have the set of standard representations, covenants and events of default that apply across the market. / *continued page 44*

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investments in US businesses for national security concerns. Ralls is Chinese backed. Submission of proposed deals is voluntary. However, the committee has authority to set aside transactions after the fact that were not submitted for review if the deals raise national security concerns.

After the Navy expressed concerns, CFIUS contacted Ralls and suggested it file a notice. It did so in June 2012. On September 28, 2012, President Obama issued an order requiring Ralls to remove everything from the sites within 14 days and divest the projects within 90 days. The order also blocked the future use of any turbines made by Sany — a Chinese manufacturer — to any third party for use at the project sites. The two individuals who own Ralls are also connected to Sany.

The order also blocked sale of the projects to any third party unless the buyer complies with the same conditions.

Ralls sued in federal court to have the order set aside. It lost the first round, but a US appeals court said in July 2014 that the company should have been shown all unclassified information that led to the government order and given a chance to respond. The court called the refusal by the US government to share any information with Ralls a "clear constitutional violation" of the company's right to due process.

The case has now been settled. Terms of the settlement have not been released, but Ralls said in a press release that it will be able to use Sany turbines in its other US projects. The company has projects in Colorado and Texas.

MINOR MEMOS. Utility-scale assets were selling for an average of roughly \$2.8 million a megawatt for solar and \$2 million for wind at the end of 2014, according to Bloomberg New Energy Finance . . . . Talen Energy Corp. agreed in October to sell a combined-cycle gas-fired power plant to TransCanada and two hydroelectric facilities to Brookfield. The gas plant is being sold for eight times EBITDA, while the / *continued page 45*

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There are some differences between the two forms of master agreement, such as the calculation of the termination amount if the hedge is terminated early. There are shorter cure periods for defaults in the 2002 form, which banks usually favor.

However, you cannot go into the master agreement and start revising provisions. If you want different or additional representations or covenants, or to negotiate other changes, you must do so in the schedule.

Focusing on the schedule, there tend to be negotiations around the events of default. For example, how long should a party have to cure a payment default? In the 2002 form of master agreement, the standard cure period after a failure to pay is one day. In the 1992 version, the standard is a three-day cure period. The parties might agree on two days and that gets put into the schedule.

The standard termination events are illegality, force majeure event, tax event, tax event upon merger, and credit event upon merger. However, you can negotiate additional termination events between the parties or remove or change certain standard events of default. For instance, we have seen the standard cross-default provision changed to cross acceleration, and we have seen certain events, such as a merger without assumption of the hedge, removed as events of default.

For energy hedges where there is collateral, additional termination events may include impairment of the collateral, a condemnation event or a casualty event with respect to the project or failure to reach financial closing by a certain date.

Other negotiated provisions are unique to energy hedge transactions. Covenants may be expanded because, in addition to the standard covenants under the master agreement, you may want specific project limitations, such as limitations on liens, debt, mergers, dispositions and maintenance of insurance. They may be the same ones as those negotiated in the credit agreement. You negotiate each of these individually.

We also see changes to the condition precedents in the master agreement. For example, the master agreement includes a provision that says, in order for you to make payments to the other party, the other party cannot be in default. In most swaps, this is good because payments are going back and forth between the parties, and parties keep the provision as is. However, with a revenue put, because the project company is making the payment upfront and has no on-going payment obligations, it should not matter if the company is in default . It would not make sense for the bank counterparty to be able to stop payments to the project company, so this gets negotiated.

Another commonly negotiated item is a provision where the bank counterparty can suspend payments if there are certain trigger events, such as the termination of the credit agreement or a casualty event that affects the project.

Shifting focus to the credit support annex, this is a separate collateral document in addition to the usual security arrangements under the financing documents. The credit support annex provides that you have a security interest in the posted collateral and what you would need to post depending on what the exposure is throughout the life of the trade. So what is important here, and what differs from interest rate hedges where you do not usually have the bank counterparty posting any collateral, is the bank counterparty may need to provide collateral.

The credit support annex is the preprinted form — like the master agreement — with a specific paragraph where you designate certain elections and provisions, including the types of collateral that you expect, whether it is cash, a letter of credit or other types of credit support. The credit support amount is the amount that a party needs to provide on a given day based on the exposure of the secured party. The annex provides the parameters for calculating the amount. ◎

Europe Moves to Bring More Private Capital Into Infrastructure

by Despina Doxaki, in London

The European Investment Bank estimates that the European Union will need to invest €2 trillion in infrastructure in the 28 member countries through 2020.

The sheer scale of the capital needed will require governments to find new ways to attract more private sector investment in public infrastructure.

The EU is considering forming a "capital markets union" as one way to do this. A consultation paper calling for formation of a capital markets union by 2019 was presented to the European Commission on September 30. Numerous bodies participated in writing the paper in an effort to find a suitable regulatory framework.

Project Bonds

The hope is that project bonds will play a bigger role in the future for financing infrastructure projects.

The bonds may be privately placed or listed on a stock exchange. Payment of interest and repayment of principal are made primarily from the cash flow generated by an infrastructure project. Project bonds are particularly attractive for institutional investors, such as life insurance companies and pension funds, because they can match long-term liabilities, such as obligations to pensioners, to long-term cash flows from projects. Maturities can extend 20 years or more.

The bonds themselves usually offer stable returns at higher rates than similarly-structured sovereign debt.

Wider use of project bonds is critical because other sources of debt are constrained. Punitive capital treatment of long-term bank debt under Basel III and the latest EU capital requirements directive, CRD IV, has largely eliminated banks as a major source of long-term debt to the sector. Loans from multilateral lending institutions have constraints. Export credit-backed financing is limited to specific sectors.

The goal of the capital markets union is to improve access to the public markets for start-up companies, small and medium-sized businesses, and long-term investments like infrastructure projects, to diversify the potential */ continued page 46*

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two hydroelectric facilities are being sold for 18 times EBITDA, UBS estimates. Both transactions are expected to close in the first quarter of 2016 . . . . Rates on term loan B debt continue to trend up. A $460 B loan to finance the Panda Hummel project, a 1,000-megawatt combined-cycle gas-fired power plant in Pennsylvania, closed in late October at 600 basis points over LIBOR with original issue discount of 96 and a 1% LIBOR floor, according to *Power Finance & Risk*. The deal closed on slightly worse terms than the 550 to 575 basis points on which it went to market. A senior bank debt tranche of $250 million closed as a 6.5-year loan priced at 375 basis points over LIBOR. The senior debt is rated BB- by Standard & Poor's . . . . A solar power plant owned by a utility and used to supply electricity to a federal agency, probably a military base, at negotiated rates under a long-term power purchase agreement is not "public utility property," the IRS said. Utilities cannot claim investment tax credits or accelerated depreciation on assets considered "public utility property" if their regulators require the benefits to be passed through immediately to ratepayers. The IRS analysis of the case is in Private Letter Ruling 201544018. The ruling was released in late October . . . . The IRS told another utility in a ruling released in September that it could claim five-year MACRS depreciation on a coal-fired power plant that the utility converted to run on biomass. Such depreciation can only be claimed on a power plant that is considered owned no more than 50% by a regulated utility within the meaning of the Public Utility Regulatory Policies Act as in effect in September 1986. The utility said it owns 100% for tax purposes, but it produced an opinion from the Federal Energy Regulatory Commission that it owns no more than 50% within the meaning of the utility statute. The ruling is Private Letter Ruling 201539024.

— contributed by Keith Martin in Washington

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funding sources, and to provide an easier and more efficient way for investors (bondholders) to connect with those seeking funding.

A new framework — called the Solvency II framework directive (Directive 2009/138) — will take effect on January 1, 2016 to regulate long-term investments by insurance companies.

Capital Charges

The EU imposed strict capital requirements until now on insurance companies that discourage them from making long-term investments. Solvency II introduces capital charges related to the risk an insurance company can undertake. A capital charge is an amount of cash the insurance company must hold against each long-term investment it makes.

Europe is hoping project bonds will play a bigger role financing the €2 trillion in new infrastructure investment needed by 2020.

The current framework imposes the same capital charge for all kinds of investments regardless of their structures or their risk profiles. As a result, insurance companies and pension funds have invested only €22 billion in infrastructure projects, representing less than 0.3% of their total assets. At the end of 2014, insurance companies had almost €9.9 trillion invested on behalf of their policyholders. In other words, institutional investment by insurance companies has been an underused source of capital so far. It is estimated that if insurance companies and pension funds were to increase their investments in infrastructure projects to even 0.5% of total assets, this would mean an extra €20 billion of investment. The decision by institutional investors when and where to invest can have a significant impact on the economy.

The European Commission decided to amend the rules under Solvency II to give insurance companies more incentive to invest in infrastructure projects. The commission sought technical advice from the European Insurance and Occupational Pensions Authority, or EIOPA, about how best to amend its existing capital requirements. EIOPA initiated a consultation in February 2015, and the outcome was a report identifying, measuring, categorizing and standardizing infrastructure investment risks. The final version of the EIOPA paper (EIOPA-BoS-15-223) was published in September 29. EIOPA proposed the adoption of less stringent capital charges for investments in infrastructure projects if certain criteria are met.

The existing framework has now been amended to introduce the notion of "qualifying infrastructure investments." The amendments can be found in the Delegated Regulation 2015/35, which supplements Solvency II.

Qualifying infrastructure investments are a new asset class of safer infrastructure projects under Solvency II. Therefore, the insurance companies may proceed with them while reserving lower capital charges of around 70% of the charges for other debt and equity investments.

A qualifying investment must meet a number of criteria that focus on providing for a high degree of protection and security for investors and predicable cash flows, documented and validated due diligence and ongoing risk management on the part of the insurance company. For investments in bonds or loans, the insurance company must also demonstrate that it is able to hold the investment to maturity. It is not necessary for an investment to be externally rated, but where it is unrated (or if the investment is in equity), then additional criteria must be met. Rated infrastructure debt investments must be investment grade to receive a reduced capital charge.

In order to qualify, the debt or equity must be issued by a special-purpose entity whose only asset is the infrastructure project, and the primary source of payments to bondholders and equity investors must be the income generated by the assets being financed.

These amendments to Solvency II allow insurance companies also to benefit from lower capital charges when investing in European long-term investment Funds (ELTIFs) and in equities traded through multilateral trading facilities (MTFs). This brings the capital charges in line with investments in European venture capital funds (EuVECA) and European social entrepreneurship funds (EuSEF), which benefit from the same equity capital charge as equities traded on regulated markets, lower than that for other equities. Also, a similarly favorable treatment is allowed for investments in closed-end, unleveraged alternative investment funds.

Investments in infrastructure project bonds are treated the same as corporate bonds, even when credit risk is divided up among different debt tranches, instead of being treated as securitizations.

A number of measures are being taken to make it easier for insurance companies to invest in unrated bonds and loans. First, insurance companies investing in unrated bonds and loans can use proxy ratings (for example, the rating of the issuer or of other debt instruments that are part of the same or similar issuing programs). Second, where unrated debt instruments are backed by collateral, the risk-mitigating effect of the collateral on spread risk is recognized. Third, where debt instruments are fully guaranteed by a multilateral development institution, such as the European Investment Bank or the European Investment Fund, they are exempted from any capital requirement for spread and concentration. The thought is that the due diligence and credit enhancement provided by EIB and EIF considerably reduce the riskiness of such investments.

Insurance companies and pension funds have already shown greater interest in investing in infrastructure projects, even before the new capital charge provisions take effect.

Some notable recent investments are a £100 million investment by Prudential in the Swansea Bay tidal lagoon project, a £6.3bn investment by Legal & General in UK property and infrastructure to date as part of an overall commitment of £15 billion and an investment by Allianz, as part of a £4.2 billion consortium, in the Thames Tideway tunnel.

The European Parliament and the European Council have up to three months to object to the relaxation of insurance company capital charges, with the possibility to extend this period for another three months. Thereafter, the new capital charge provisions will be published in the Official Journal of the EU and will enter into force the next day. ◎

Concession Agreements and CFIUS

by Amanda Rosenberg, in Washington

A little known committee within the US Treasury Department could have a big impact on deals involving concession agreements over US infrastructure with foreign contractors or investors.

The Committee on Foreign Investment in the United States — CFIUS — reviews transactions in which a foreign person acquires control over a US company or facility and there are potential national security concerns.

Certain concession agreements for owning or building out US infrastructure may raise national security concerns.

State and local governments in the United States are in need of innovative solutions to budget shortfalls. Public infrastructure is aged and inadequate. The public strongly resists tax increases to pay for rebuilding roads, bridges, tunnels, ports and other basic infrastructure.

One way state and local governments are dealing with the problem is by selling, or privatizing, existing facilities to raise money. The state or local government enters into a concession agreement leasing an existing facility to a private party and granting it the right to provide basic services using the facility and to earn fees for doing so. The private party may be required to rebuild the existing facility. It is required to operate and maintain it. The concession agreement runs long enough for the contractor to recover its costs and earn a return.

The private party makes a large upfront payment for the concession, thereby providing cash for the state or local government that can be used to pay off debt, fund other programs and create reserves. The contractor may be able to deliver any needed upgrades more quickly and operate and maintain the facility more cheaply than the government could. Risks are also shifted from the public to the private sector.

The concession agreement can last as long as 99 years, although, in recent years, the trend has been for concessions that are in the 30- to 50-year range. At the end of the contract, the facility reverts to the state or local government.

Many private parties who take on these concessions are based outside the United States. For example, in 2005, the City of Chicago leased a stretch of elevated highway called the Chicago Skyway to foreign investors for / *continued page 48*

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99 years. Chicago received a $1.83 billion upfront payment. In 2006, Indiana leased the Indiana toll road to foreign investors for $3.8 billion. Last year, Gulftainer, a wholly-owned subsidiary of a company based in the United Arab Emirates, entered into a 35-year concession agreement with Port Canaveral in Florida to upgrade and operate its container and multi-purpose cargo terminal.

Must a foreign company that merely enters into a concession agreement — instead of buying a US company or facility — clear the transaction with CFIUS?

CFIUS is charged with reviewing transactions in which a foreign person acquires control over a US company or facility, so-called "covered transactions." It reviews such transactions for national security concerns.

Some foreign companies entering into public-private partnerships to build US infrastructure should submit their plans to CFIUS.

Notifying CFIUS of a transaction is voluntary; however, failure to do may lead to the deal being unwound later if CFIUS decides there were national security issues. CFIUS does not have the authority to review deals that are not covered transactions.

State and local governments sometimes require a legal opinion that the concession agreement will not be a covered transaction subject to CFIUS review or a more general opinion that the concessionaire has obtained all required approvals. In some circumstances, the government may go one step further and require that the parties notify CFIUS of the transaction and get CFIUS sign off. Thus, it is important for foreign investors bidding on concession agreements to think about the CFIUS risks and find out at an early stage whether the government will require a CFIUS filing. CFIUS review can take up to three months after filing. The filing itself typically takes one to two months to assemble, depending on the complexity of the deal and the US business or assets involved.

Is a concession agreement potentially a "covered transaction"?

It must first be a transaction. The CFIUS regulations say that certain long-term leases are "transactions." A long-term lease is a transaction if the "lessee makes substantially all business decisions concerning the operation of a leased entity, as if it were the owner." The regulations provide the following example with respect to long-term leases:

"Corporation A, a foreign person, signs a concession agreement to operate the toll road business of Corporation B, a U.S. business, for 99 years. Corporation B, however, is required under the agreement to perform safety and security functions with respect to the business and to monitor compliance by Corporation A with the operating requirements of the agreement on an ongoing basis. Corporation B may terminate the agreement or impose other penalties for breach of these operating requirements. Assuming no other relevant facts, this is not a transaction."

The regulations do not draw a line between what is a long-term versus short-term lease. There is no official guidance on this issue. The parties must make a judgment call. A 50- or 99-year concession agreement seems certainly to be the former. A 35-year lease likely also is considered long-term, while a 10- to 20-year lease probably is not. Short-term leases are not transactions subject to CFIUS review.

Similarly, there are no bright-line rules to determine whether the lessee is acting as if it is the owner of the leased property. It is determined based on the specific facts and circumstances of a concession. The regulations tell us that "the more significant the substantive responsibilities retained by the lessor over the leased property, the likelier that the lease would not be viewed as a transaction." The example recited above suggests that, if a lessor retains responsibility for major functions such as safety and security measures, which is common in concession agreements, then the lessee will not be viewed as making substantially all of the business decisions for the leased entity. In addition, some degree of oversight by the lessor of the lessee's operation of the property, including termination or step-in rights, points to a concession not being a "transaction" for purposes of CFIUS.

A transaction is a "covered" transaction if it gives the private party "control" over a US trade or business. "Control" is very broadly defined in CFIUS regulations. The power to determine, direct, take, reach or cause decisions regarding the operations of a US trade or business are considered control. In a typical concession agreement in the US, the lessee controls the day-to-day operations of the assets, while the lessor remains responsible for major safety and security functions, including ensuring that the lessee complies with all safety and security requirements. The lessor also typically retains certain step-in rights to assume control of the asset or suspend lessee performance if the lessee fails to perform as expected or, in some cases, at the lessor's discretion.

For a concession to be both a transaction and a covered transaction, the lessor must pass on its safety and security responsibilities to the lessee and forgo oversight of the lessee's activities, which would be a departure from how concession agreements typically work.

Does a filing have to be made with CFIUS? A filing is required only if the granting of the concession to a foreign person potentially raises national security concerns.

A concession over critical infrastructure raises such concerns. An example is an interstate highway or a heavily-used bridge or tunnel in a major US city.

The regulations define critical infrastructure as "a system or asset, whether physical or virtual, so vital to the United States that the incapacity or destruction of the particular system or asset of the entity over which control is acquired pursuant to that covered transaction would have a debilitating impact on national security."

A concession may raise national security concerns based on the identity of the person granted the concession. For example, companies owned by foreign governments are subject to increased scrutiny. Generally, a 45-day investigation is mandatory if the person being granted the concession is controlled by a foreign government

Recent CFIUS actions also suggest proximity to sensitive US government installations or critical infrastructure is an important national security factor. The US government blocked a sale of wind farms by a Greek developer to a Chinese company. The wind farms were close to a US military facility used to train operators of drone aircraft.

The takeaway? A foreign bidder for a concession agreement should consider these issues as it readies its bid and be prepared for the state or local government to ask whether the bidder will have to make a CFIUS filing. The bidder may need to provide more than a mere oral assurance. ◎

Environmental Update

Recent moves by New York Attorney General Eric Schneiderman suggest there may be greater peril to companies in what they disclose, or fail to disclose, to investors about the potential effects of climate change than they may have previously thought.

The attorney general accused Peabody Energy, the largest publicly-traded coal company in the United States, of violating state laws by making misleading statements to investors and the public about the financial risks it faced from climate change and potential regulatory responses.

A two-year investigation led to charges that the company violated New York laws barring false and misleading conduct in statements to investors. Peabody said in filings with the US Securities and Exchange Commission that it is unable to predict the effects of environmental regulations, despite internal company projections that the regulations could reduce the value of its coal sales in the United States by 33% or more. After the investigation, Peabody agreed to file revised shareholder disclosures with the Securities and Exchange Commission that objectively present the risks.

In November, the New York attorney general subpoenaed extensive financial records, emails and other documents from another company — Exxon Mobil — to determine whether the company has made false statements to investors about climate change risks and the impact on its business.

The focus of the investigation appears to be whether the Exxon Mobil disclosures about climate risks as recently as this year are consistent with its own scientific research on the subject. Exxon Mobil denies that it suppressed any climate change research.

Clean Power Plan

A large number of lawsuits have been filed against the Clean Power Plan since the final plan was published in the Federal Register on October 23, 2015.

The Clean Power Plan requires a 32% reduction in carbon dioxide emissions from certain existing fossil fuel power plants by 2030. Initial reductions are not required until 2022, but states are required to submit initial compliance plans to the Environmental Protection Agency by September 6, 2016. States may then request a two-year extension to submit a final plan. EPA will impose a federal plan on states that fail to submit plans or failed to secure EPA approval of their plans.

There are political calculations on both sides. Opponents hope the lawsuits will stall implementation of the plan long enough to allow a Republican to be elected president and then to modify or set aside the plan. The Obama administration hopes that requiring states to have taken steps to draw up their own plans by September 2016 will create a constituency for moving forward with the plan. US voters will go to the polls to elect a new president in November 2016.

A number of states and mining interests tried persuading the federal courts to block EPA from issuing the final plan. Those efforts were rejected by the courts as premature. Thus, opponents of the plan were eagerly awaiting publication of the final plan to open a 60-day period during which petitions for review can be filed in the US court of appeals for the District of Columbia. Petitions for judicial review have now been filed by 27 states, coal mining interests, power companies, rural electric cooperatives and other businesses. Petitions have also been filed by advocates for the Clean Power Plan by various states, environmental organizations, public health interest groups, and renewable energy groups to intervene in the litigation.

The court is expected to announce a timetable for review as soon as late December.

A number of opponents have asked the court for an immediate stay in the meantime. A stay would delay implementation of the Clean Power Plan until the court reaches a final decision on the merits of the case. The court has consolidated the numerous stay requests and ordered that all briefs and responses be submitted by December 23, 2015. The plan opponents have asked the court to rule on the stay request by the spring 2016 before reaching the merits of the case. This schedule means the Obama administration will be able to participate in the international climate talks in Paris in December with the Clean Power Plan intact.

The statutory and constitutional arguments that have been raised thus far by opponents of the plan can be summarized as follows. First, Congress did not give EPA authority under section 111(d) of the Clean Air Act to compel states to restructure their electricity markets by forcing a shift away from coal in favor of natural gas and renewable generation. Second, EPA is barred from subjecting existing fossil-fuel fired power plants from additional regulation under section 111(d) because they are already regulated under section 112 of the Clean Air Act. Third, it is a violation of the 10th amendment to the US constitution for the federal government to regulate how electricity is generated in individual states. When the US constitution was written, the states gave only certain powers to the central government.

Opponents of the plan point to EPA predictions that a number of coal-fired power plants will be forced to shut down within the next year as evidence of irreparable harm if they are not granted a stay. They must show the potential for irreparable harm before the court will grant a stay. One challenge for opponents is that the plan itself delays implementation until 2022. Opponents respond that the states will have to begin overhauling the power sector immediately, including legislation to promote use of renewable energy and natural gas so that they will be on track to start showing reductions in carbon emissions in 2022.

The initial salvo of litigation over the Clean Power Plan is the first glimpse of the significant economic, legal and policy issues that will be vigorously debated as the US government tries to reduce US carbon emissions from the power sector.

Power Effluent Guidelines

Final effluent limitation guidelines took effect on November 3 that will affect wastewater discharges from roughly 1,100 power plants that use fossil fuel or nuclear energy to produce steam as an intermediate step to generating electricity.

The new guidelines will begin to be incorporated into power plant discharge permits beginning in 2018.

The guidelines do not apply to oil-fired power plants or to power plants that are smaller than 50 megawatts in size.

EPA estimates that about 12% of steam electric power plants will have to make new investments to comply with the new guidelines and that the annual compliance cost for all steam electric power plants will be about $480 million. Critics are expected to go to court to block implementation.

Steam electric power plants discharge large volumes of contaminated water. According to EPA, the discharges contribute approximately a third of all toxic pollutants discharged into surface waters by industrial sources in the United States. The pollutants include mercury, arsenic, lead, selenium and nitrogen compounds.

EPA did a detailed study of the steam electric industry in 2009 that found significantly increased levels of pollutants in wastewater discharges from power plants. The increased pollution is a byproduct of steps that power companies are taking to comply with stricter limits on air pollution.

The new guidelines are the first federal numeric limits on toxic metals in steam electric power plant discharges. They create uniform requirements based on demonstrated treatment technologies and processes. Until now, discharge limits were primarily based on the use of settling ponds that only removed suspended solids and were ineffective for removing dissolved metals.

Numeric discharge limits for arsenic, mercury, selenium and nitrogen will now apply to the following processes and byproducts associated with steam electric power generation: flue gas desulfurization, fly ash, bottom ash, flue gas mercury control, and gasification of fuels such as coal and petroleum coke. The guidelines encourage power companies to commit to meeting even more stringent limits by the end of 2023.

Climate Change

International officials have gathered at a United Nations meeting in Paris to try to reach a global agreement on greenhouse gas emissions. This is the 21st conference of the parties to the UN framework convention, or COP-21.

Before arriving in Paris, 146 countries and the European Union made pledges to shift away from fossil fuels and toward renewable energy, to improve land management and to increase energy efficiency .

However, the pledges fall significantly short of what many scientists suggest is required to keep global temperatures from rising above two degrees Celsius (3.6 Fahrenheit) since the preindustrial era. UN officials suggest that the actions pledged may limit the temperature rise to 2.7 degrees Celsius by 2100, rather than the warming of four or more degrees Celsius that is projected by many scientists.

A benchmark for assessing whether the talks are a success or failure will be whether the final agreement includes language to tighten each nation's emissions limits automatically every five or 10 years without reopening the entire agreement to renegotiation.

Key pledges include carbon pollution limits for power plants in the United States, expansion of solar and other renewable energy in India, expansion in emissions trading by the European Union and China, and nuclear expansion by seven countries.

Three quarters of developing nations submitted pledges, including major emitters such as Brazil, China, India, Indonesia and Mexico. Many developing nations */ continued page 52*

Environmental Update

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made offers to cut emissions with or without assistance from developed countries and pledged additional cuts if financial and technological assistance is provided. The remaining one quarter of the pledged emissions cuts turn on whether developing nations receive funding from developed nations.

The negotiations in Paris will focus on reaching a global agreement to reduce projected emissions increases by 2030, but not produce actual aggregate reductions from current levels. The pledges would reduce global average per-capita emissions over the next 15 years by as much as 9% in 2030.

Banks

A new report examining 61 of the world's largest banks on their management of climate-related risks concludes that few are taking a strategic approach. Investment manager Boston Common Asset Management reports that the world's largest banks are not prepared for the effects of climate change and argues that lenders are making an insufficient effort to support the transition to a low-carbon economy that is being discussed at COP-21 in Paris.

Banks have a critical role to play in funding the transition. The report concludes that most lenders do not have quantitative targets for increased financing of energy efficiency or renewable energy projects. The key criticism is that many banks fail adequately to assess the carbon risk of their lending and underwriting or to conduct climate-related stress tests.

Of the world's 10 largest banks, only Citigroup and Bank of China were among the top 10 ranked for climate management.

— contributed by Andrew Skroback and Richard Waddington in Washington

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