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The Rush To Start Construction

by Keith Martin and John Marciano, in Washington

A lot of talk at recent renewable energy conferences in the United States is about how much of a rush there will be to start construction of new projects by year end.

Wind, geothermal, biomass, landfill gas, incremental hydroelectric and ocean energy projects must be under construction by December 2013 to qualify for federal tax credits. The credits are worth at least 30% of the capital cost of such projects.

Large wind company CEOs attending the Global Windpower 2013 convention in Chicago in May all said they hope to have at least one or two new wind farms under construction by year end. Equipment manufacturers have been focusing on what they can do to help developers satisfy tests in the US tax rules for what it means to be under construction. However, unlike past years, few developers seemed to be using the wind convention to close turbine deals. Any new turbine orders seem unlikely to be placed until the fall.

The Internal Revenue Service explained in April what a developer must do to be considered to have started construction of a project this year. The IRS guidance is in Notice 2013-29.

There are two ways to start construction.

One is by starting "physical work of a significant nature" at the site or at a factory that is making equipment for the project. However, any work done by a contractor at the site or the factory counts only if done under a binding contract that is in place before the work starts.

The other way is by showing that the developer "incurred" at least */ continued page 2*

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THE TAX EQUITY MARKET is awaiting new guidelines that could affect how some deals are structured.

The Internal Revenue Service is working on a revenue procedure that will explain what it wants to see in tax equity transactions involving tax credits for renovating historic buildings. The tax credits work like the investment tax credit in renewable energy projects. They are claimed in the year a project is completed. They are 20% of the amount spent on renovations. Developers form partnerships with tax equity investors and allocate the credits disproportionately to the tax equity investors.

The IRS feels that some such partnership transactions have become too aggressive. */ continued page 3*

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5% of the total project cost by year end. Costs are not usually "incurred" merely by spending money. The developer must ordinarily take delivery or title to services or equipment, but there are exceptions.

Projects that are under construction by December 2013 will qualify for 10 years of production tax credits on the electricity output or an investment tax credit upon project completion for 30% of the project cost.

The 5% test requires "continuous efforts," but contemplates that a project may still be merely under development, as long as the developer works diligently after 2013 on rounding up permits, negotiating contracts and moving the project along. It would be a good idea to keep a log.

There is no deadline to complete construction.

Some in the IRS view the continuous work requirement as a soft deadline. However, the IRS guidance itself suggests that it is more a tool the IRS can invoke to prevent abuse. The IRS said it "will closely scrutinize a facility, and *may* determine that construction has not begun . . . if a taxpayer does not maintain a continuous program of construction." (Emphasis added.)

Several types of renewable energy projects must be under construction by December to qualify for federal tax credits.

Developers have been asking a number of hard questions. One question is whether a project on which physical work starts in 2013 and that normally takes X months to build can qualify for tax credits if it takes three times that long to construct.

The answer is yes if the delays are due to factors beyond the control of the developer. The IRS published a list of examples of permitted delays. They are merely examples. There could be others. They include severe weather, natural disasters, licensing and permitting delays, inability to obtain specialized equipment due to limited availability and similar supply shortages and financing delays of less than six months.

What if there were no delays and the developer worked continuously, but at a much slower pace than normal? There is no clear answer.

What if there is a significant time lag between the start of work in 2013 and its later resumption that could have been avoided by not waiting as long to negotiate a key contract. For example, a developer relying on physical work in 2013 to start construction does not sign an interconnection agreement for the project until 2014 and there is an extended wait until the utility can have the intertie in place to allow electricity to reach the grid. The site work on the project is delayed to work backwards from when the intertie will be available. Such a project may have trouble qualifying under the physical work test, but seems to fit the pattern of a project still under development for which the 5% test is better suited.

The IRS had hoped not to publish any more guidance.

Continuous

Once construction starts, it must be continuous. This creates hindsight risk that a project that appeared under construction at the end of 2013 may not have been under construction after all.

Developers would do better to start under the 5% test rather than rely on physical work, although anyone who can should do both.

The problem with relying solely on physical work is that it will require proving later that there was "continuous construction." The US Treasury Department used the same two tests to administer a cash grant program for renewable energy projects that required projects to be under construction by 2011 to qualify. The Treasury came, over time, to feel that a project was not truly under construction based solely on a limited amount of physical work until it had all the permits and contracts in place to begin construction in earnest. Thus, for example, a developer who started work on roads or a foundation at the site, but who had no interconnection agreement, power contract, turbine supply agreement or balance-of-plant construction contract was not under construction even though another project with all the contracts that did the same road work would be viewed as underway. There is a risk that IRS agents auditing projects in the future will take the same position.

However, there is talk internally of possibly publishing examples to give the market a clearer indication of how the agency analyzes several common fact patterns. The talk is still at an early stage. Any such guidance would probably not be issued until the fall.

Physical Work

Physical work can be at the site or at a factory. It must be significant.

The IRS said examples of significant physical work at the site are "the beginning of the excavation for the foundation, the setting of anchor bolts in to the ground, or the pouring of the concrete pads of the foundation."

Preliminary activities like engineering, securing financing, doing environmental studies, negotiating contracts and obtaining permits are not physical work. Test drilling to determine soil conditions, "excavation to change the contour of the land (as distinguished from excavation for footings and foundations)" and tearing down existing turbines and towers are not yet significant physical work on the new facility. They precede the start of such work.

Test drilling at a geothermal field is not yet significant. Drilling is significant when it starts on production or reinjection wells.

An example in the IRS guidance deals with a wind farm that will have 50 turbines. Work starts in 2013 on 10 of the turbines. However, IRS and Treasury officials said there was no intention to suggest that at least 20% of the project had to be under construction in 2013. There is no minimum percentage threshold.

The work must start on the "facility" as defined for production tax credit purposes. For a wind farm, the "facility" includes any of the equipment through the point where the electricity moves into transmission. Electricity is not usually in transmission until it has been stepped up to transmission voltage. Thus, equipment through the step-up transformer is normally considered part of the facility, assuming the transformer is owned by the project, as are circuit breakers on the high side of the transformer whose function is to protect the transformer.

The IRS said that it will treat each wind farm as a single project so that work on any part of the project will qualify as the start of construction of the entire project when the facts point to one large project. This was good news for wind developers and was probably the largest open issue for that industry before April. The IRS has treated each turbine, pad and tower at a wind farm in the past as a separate power plant for production tax credit purposes. Facts that point to a single project are one company owns the entire project, / *continued page 4*

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A US appeals court struck down one such transaction in August 2012. The case, called *Historic Boardwalk LLC v. Commissioner,* involved renovation of a sports arena and exhibition hall in Atlantic City that was originally built in the 1920s and was the site of the Miss America pageant starting in 1933. The state of New Jersey, which did the renovation and had no use for the federal tax credits on the project, entered into a complicated transaction to transfer the tax credits to Pitney Bowes. The transaction had a number of features that apparently are common in the historic and affordable housing tax equity markets, but that would be viewed as aggressive in the renewable energy market. (See earlier coverage in the September 2012 *NewsWire* starting on page 7.)

An IRS associate area counsel in Detroit said in an internal memo made public in March 2013 that another transaction was nothing more than a "circular flow of contracts" with no real partnership formed. (See the April 2013 *NewsWire* starting on page 27.)

The court decision and IRS memo have caused some tax equity investors to defer making further investments in transactions involving historic tax credits until there is more guidance from the IRS.

Senior IRS officials say it is easy to structure transactions to transfer historic tax credits so that the transactions pass muster, but that the market appears to be walking too close to the line in some cases to bare sales of tax credits. Broker presentations that pitch the transactions as tax credit sales do not help the situation.

The guidance is on a "fast track," according to Craig Gerson, an attorney-adviser in the office of tax policy at the US Treasury.

The goal is to create a zone in which the deals can be done. The IRS is expected to say it wants a meaningful upfront investment by the tax equity investor. Many investors put in a small amount of money shortly before the end of the renovation project and then invest the rest after the project has been completed. The agency also wants to see / *continued page 5*

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all the electricity is sold under a single power contract, it moves to the grid through a single substation and intertie, the entire project is financed under a single loan agreement, all the turbines are on contiguous sites and they are being supplied under a single turbine supply agreement.

For a power plant that uses biomass as fuel, the "facility" includes all the equipment that is "necessary" for generating electricity. It does not include the fuel yard equipment. It does include integrated fuel handling equipment to move the fuel into the gasifier or boiler.

The IRS defines the "facility" at a geothermal project as including not only the power plant but also the geothermal wells and pipelines to bring steam to the site and return spent fluid for reinjection in the field.

There are two ways to start construction.

Roads that will be used at the site to move fuel or spare parts or other equipment needed during the operating phase are part of the facility. However, roads that provide access to the main highway or that will be used primarily by employees or visitors are not. Fences are not. Most buildings are not, but not all structures are considered buildings for tax purposes. A structure that is basically a shell over a boiler or turbine is part of the equipment.

The physical work does not have to be at the site; it can be at the factory. However, the work at the factory must be assembly of equipment that is being custom made for the project as opposed to components that the manufacturer normally holds in inventory.

5% Test

Alternatively, a developer can show construction started in time by "incurring" at least 5% of the total project cost by December 2013.

Costs are normally not incurred until the developer takes delivery or title to services or equipment. Chadbourne has never been comfortable relying solely on title transfer. It prefers to rely on delivery. During the cash grant program, developers would sometimes assert that title transferred to components like raw sheet metal that had to go back to the factory for further fabrication. It is hard to see how design services by a manufacturer are delivered before the product in which they are incorporated is delivered.

Delivery can be at the factory. However, the equipment should be segregated from other equipment belonging to the manufacturer. The developer should take risk of loss after delivery. It should buy insurance. It should pay any transfer taxes. An employee of the developer should inspect the equipment at the factory and sign an affidavit attesting to what he or she saw. Care should be taken to avoid provisions in the vendor contract that suggest that delivery did not really occur at the factory: for example, a provision that makes the vendor responsible for redelivering the equipment to the site and that leaves the vendor with legal title and control until such redelivery.

There are two exceptions where costs can be counted before delivery.

First, the developer can count spending in 2013 as a 2013 cost if the services or equipment are delivered within 3 1/2 months of the payment. This does not mean that an entire series of payments from September to December counts if delivery occurs by mid-April 2014. Only the last in the series of payments within 3 1/2 months before delivery counts potentially as a 2013 cost. For example, paying for turbine blades on December 31, 2013 counts if the blades are delivered by April 15. (The IRS requires that delivery be "reasonably expected" within 3 1/2 months. Therefore, the contract should make the deadline clear, but taking actual delivery in time avoids questions later about whether the missed deadline was realistic.) The payment should be for the particular equipment to be delivered as opposed to a general down payment or general milestone payment for performance of the entire contract.

The 3 1/2-month rule is a "method of accounting." If the developer has used a different approach in the past to determine when costs are incurred— for example, waiting until project acceptance to incur costs — then use of the 3 1/2-month rule would be considered a change in accounting method and require an IRS private ruling.

Second, the IRS made it easier than it appears at first glance to incur costs. The developer can "look through" any binding contract with a vendor or other contractor and count costs that the contractor incurs through December 2013 to perform the contract. Thus, for example, wages and benefits that the contractor accrues to its employees for work during 2013 to perform the contract count. An example is for design work on specially-ordered equipment. Costs incurred under binding purchase orders with subcontractors count if services or components are delivered to the contractor in 2013 (or, if the contractor is able to use the 3 1/2-month rule, within 3 1/2 months of a 2013 payment by the contractor to the subcontractor for them).

Any developer who plans to count costs incurred by a vendor directly or with its subcontractors should include a provision in the vendor contract requiring the vendor to deliver a certificate at year end, under penalties of perjury, attesting to the costs it incurred. The vendor should be required to help the developer respond to inquiries from the IRS.

The same costs cannot be counted twice.

The developer must incur at least 5% of the total project cost by December 2013. Put in both the numerator and the denominator of the fraction only costs that will be recovered through depreciation of the "facility." Thus, for example, legal fees to negotiate a power contract or interconnection agreement or the cost of land do not count. However, legal fees to negotiate a vendor contract or a construction loan and interest during construction do count (although a small portion of the construction loan legal fees and interest might not count due to partial allocation to buildings, fences, ineligible roads and similar items).

At the end of the day, most projects cost more than expected. Careful developers usually aim to incur at least 7% of the expected project cost to leave a safety margin. However, the IRS said that rather than disallow the entire project, where the project would normally be treated as multiple individual "facilities," like each turbine at a wind farm, tax credits can still be claimed on part of the project by shedding enough individual facilities to bring the costs incurred to at least 5% of the smaller project.

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"entrepreneurial downside risk" and a potential upside for the investor.

An historic tax credit coalition submitted eight fact patterns that it asked the IRS to be sure to address. Two of the fact patterns describe "fixed-flip" partnerships, where the tax equity investor takes a small share of the cash as preferred cash distributions and virtually all the tax benefits until a fixed date in the future, and "overlapping" inverted leases that strip tax credits by having the developer lease the project to a tax equity investor to whom the developer elects to pass through the tax credits and the tax equity investor also takes an interest in the lessor. The fact patterns do not mention some of the more aggressive features that are typical of such transaction structures. Another fact pattern asks the IRS for its view if the investor buys tax credit insurance from a third party.

The guidelines are expected to be patterned after guidelines the IRS issued in 2007 for partnership flip transactions involving wind farms. Any new rules for historic tax credit transactions will be read with interest by the broader tax equity community.

The US Supreme Court declined in late May to review the US appeals court decision in the Historic Boardwalk *case.*

CHUCK RAMSEY, chief of the IRS branch that deals with energy-related tax credits, is retiring in July. A replacement has not been named yet. The agency will lose an important part of its institutional memory when he retires.

A SOLAR ROOFTOP COMPANY that entered into a long-term contract to supply electricity to a city building in Dubuque, Iowa from solar panels it mounted on the roof is not making retail sales of electricity, an Iowa court said.

The decision could open a hole in retail sale restrictions that prevent rooftop solar companies from entering into power purchase agreements with customers in other states if the logic the Iowa court used were to */ continued page 7*

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Other Issues

Wind companies often enter into frame agreements to buy turbines for multiple projects. They may not know in 2013 where the turbines will be used.

IRS officials said that the turbines do not have to be designated in 2013 for use in a particular project. The intention is to follow the practice under the Treasury cash grant program of allowing the developer to contribute equipment whose costs were incurred in 2013 (or on which physical work started) later to an affiliated project company. The project company can count the same 2013 costs as incurred (or physical work as having started) on its project. The vendor should enter into a "daughter contract" with the project company that mirrors the terms in the master frame agreement as a way of assigning the contract rights for the turbines to the project company.

What if a turbine contract was signed by a project company but the project is later cancelled? Until the IRS confirms that equipment can be transferred in such a case to another project company within the same developer group, it would be safest to follow the pattern in the IRS guidance of signing contracts at a parent level, at least where the developer wants to retain flexibility to reassign the equipment later.

The IRS has not addressed when grandfather rights to tax credits will carry over in cases where a project is sold before the project is completed. Early drafts of the construction-start guidance had rules similar to the Treasury cash grant program. However, they had to be dropped after they caused the draft to bog down in the internal approval process. It is possible additional guidance will be issued later this year on the issue, but no decision has been made.

Physical work in 2013 by a vendor or other contractor counts only if done after a binding contract is in place. Also, costs can only be incurred under binding contracts. "Binding" is a term of art. The contract must be binding under state law; the developer should not have a right to cancel the contract and get its money back. It should not be able to walk away from the contract without compensating the contractor for its work to date. The contract can be silent about damages, but any cap on damages cannot be less than 5% of the total contract price.

The contract should identify the equipment to be purchased. A contract that is merely an option to choose among different types of equipment is not yet a binding contract. A contract for a range of quantities is binding only for the minimum quantity.

Many contracts require that a notice to proceed be given by the developer before the contractor is authorized to start work. Such a contract can be a binding contract as long as it is a question of when and not whether the notice will be given.

Work done under a limited notice to proceed counts toward the physical work or 5% test.

A contract between related parties cannot be binding. However, the most sensible approach in such cases is to analyze the work as if done by the developer directly. Thus, any contractor profit could not be counted toward the 5% test. ◎

How REITs Are Already Investing In Renewables

Renewable energy companies are looking at renewable energy investment trusts or REITs, among other vehicles, as ways to raise capital at lower cost. REITs must own largely real property. It is not clear how much beyond the land underneath wind farms and large solar projects or buildings underneath rooftop solar panels qualifies as real property for this purpose. Nevertheless, some REITs are already engaged in the renewable energy market. Several such REITs spoke at a meeting organized by Chadbourne in Washington in mid-May.

The panelists are Jeff Eckel, president and CEO of Hannon Armstrong Sustainable Infrastructure Capital, Bill Hilliard, CEO and co-founder of CleanREIT Partners, Arun Mittal, vice president of business development for Power REIT, Pavel Molchanov, senior vice president of investment bank Raymond James, Will Teichman, director of sustainability for Kimco Realty Corp., and Drew Torbin, vice president for renewable energy at Prologis. The panel was moderated by Scott Bank, a Chadbourne real estate counsel in New York, and Kelly Kogan, a Chadbourne tax lawyer in Washington.

MR. BANK: Where will dividend yields need to be for renewable REITS to be attractive to investors?

MR. HILLIARD: The percentages are hard to determine because when people talk about a percentage, they are often talking about an after-tax return or an internal rate of return on a specific project, and not the actual cash returned each year from that project or from the investment. The same project portfolio generating a 10% cash return for a 20-year period, for instance, will have a 12% internal rate of return if the cash flows are augmented by a 30% investment tax credit or an 8% internal rate of return if not. All three numbers — 8%, 10% and 12% — are accurate investor return descriptions. But they are not comparable.

We are going public in Canada because we believe there are good comparables in the Canadian market even where the listed entity is not a trust. For example, Brookfield is at the low end with a yield of about 4 1/2% to 5%. Others are at the higher end with a yield of about 6 1/2% to 7 1/2%.

Based on the information we have seen, we think that to go public in Canada, you need to be paying a 6.5% to 7% annual cash dividend to investors. That kind of arrangement begins to look like an interest-only 7% loan with no principal repayment.

MR. MITTAL: Power REIT is publicly traded and has been for a while. Power REIT is unique because it owns a railroad, but it is also transitioning into owning renewable energy properties. Its current dividend yield is just under 4%.

Renewable energy is a new market that is dependent on both the underlying assets and other attributes of the project. For example, to the extent you have better assets, you obviously are going to trade at a lower dividend yield, and vice versa. The type of leverage makes a difference, but so does the business plan. The size and structure of the project are also relevant. In short, the renewable energy market is highly differentiated.

MR. ECKEL: I can't talk about our yields because we are still in a quiet period, but I am not sure that being a renewable energy-focused company brings added market benefit. During our road show, we looked for investors interested in sustainability and renewable energy. We found that those kinds of investors are not big participants in IPOs. We might see them in the after market.

Ultimately, whether such specialized investors exist does not really matter. Investors in the capital markets have plenty of ways to generate yield. We met with 60 investors. Two of them scoffed at the sustainability theme. The others were quiet or politely dismissive of the idea. So while the people in this room may care a lot about sustainability and renewable energy like Hannon Armstrong does, I am not sure investors do.

Kimco and Prologis

MS. KOGAN: Some people will be surprised to learn that a few of the more traditional REITs are already involved in renewables. Will Teichman and Drew Torbin, could */ continued page 8*

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be adopted more widely. The court said the solar company is really in the business of making energy efficiency improvements that *reduce* the amount of electricity a customer takes from the grid rather than selling the customer electricity.

Many solar companies retain ownership of rooftop systems and lease them to customers. The customers pay rent that is roughly 85% of what they pay the local utility for power. However, it is not a good idea to lease a solar system to a government or tax-exempt entity because equipment leased to such an entity does not qualify for a 30% investment tax credit and accelerated depreciation. The only way to preserve the tax benefits is to enter into a power contract rather than a lease with such a customer. A special provision in the US tax code allows an agreement to be written in such a way that it is close to a lease in substance, but is still treated for tax purposes as a power contract. The key is to avoid four "foot faults" in how the agreement is drafted.

Eagle Point Solar signed a power contract to supply electricity to a city building in Dubuque. Interstate Power & Light Company, a regulated utility, has a monopoly to supply electricity to retail customers in the area. Eagle Point asked the Iowa Utilities Board for a declaratory order that it would not violate state law by entering into the arrangement. (Ironically, the power contract was drafted in a way that would have prevented Eagle Point from claiming any tax benefits on the solar system.)

The board said Eagle Point will become a public utility if it enters into the arrangement and will infringe on the IP&L monopoly as the sole authorized retail electricity supplier in the area.

Eagle Point filed for judicial review. An Iowa district court said Eagle Point would not be a utility. The key for the court was that Eagle Point was not selling electricity "to the public" as used in the state statute defining a "public utility."

The phrase "to the public" is not defined. The court relied in part on an */ continued page 9*

REITs

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you tell us how Kimco and Prologis are participating in that sector and the reasons —- financial or otherwise — for their participation?

MR. TEICHMAN: Kimco Realty is a REIT that owns approximately 900 shopping centers in 46 states and Puerto Rico. Kimco is also involved in the Canadian and Mexican markets through joint venture structures. Kimco's properties total 130 million square feet of single story buildings, which equates to 130 million square feet of roof space.

In 2009, we began to consider how to use that roof space. We also realized that many of Kimco's larger tenants were interested in solar electricity as a hedge against increasing energy costs and as a way to lock in lower electricity rates through a long-term power purchase agreement. We felt that the combination of these factors presented a business opportunity.

In deciding how to incorporate solar electricity into Kimco's portfolio, an important consideration was the ability to use the section 1603 Treasury cash grant. We learned that the grant was available to a taxable REIT subsidiary but not to the REIT directly. For this reason, we decided to use a wholly-owned taxable REIT subsidiary or TRS as the vehicle that would own, finance and develop Kimco's rooftop solar systems. The TRS partnered with a third-party developer on construction of the projects.

To date, Kimco's TRS has developed and owns about 3 megawatts of installed solar capacity on several shopping centers in New Jersey. Its TRS sells the power generated to several of its major tenants at those sites under long-term PPAs. The TRS manages all aspects of these facilities, including system operation, customer billing and contracts for sale of the solar renewable energy credits or SRECs.

MR. TORBIN: Prologis' reason for moving into renewables is similar to Kimco's. Prologis is an industrial REIT that owns warehouses and distribution centers with over 550 million square feet of rooftop space around the world. Its objective in participating in renewable energy is to create additional value for its existing assets.

Initially, Prologis started simply by limiting its involvement to leasing rooftop space on its distribution warehouses to third-party developers and project owners. Later, it moved into developing and constructing these projects through a taxable REIT subsidiary.

The two big differences between the way Prologis and Kimco operate are who owns the project and who buys the electricity. Prologis' TRS is involved in the development and construction of a project, but then the TRS sells its interest in the project to an investor or utility. Electricity generated by the project is retained by a utility owner or sold to a utility offtaker. After the sale of its interest in the project, Prologis' role is limited to acting as a construction contractor and leasing rooftop space to the project owner.

Currently, Prologis is host to about 100 megawatts of solar projects that its TRS developed and sold or developed with a partner. The majority of these projects are in southern California with others located across Europe and Japan.

MS. KOGAN: How do Kimco and Prologis meet the REIT income and asset tests taking into account the assets and income from these solar projects? At least 75% of the assets held by a REIT must be real property, and at least 75% of the income must be rent from real property or interest on mortgages secured by real property.

MR. TORBIN: Prologis' development activities are performed by its TRS. Prologis' long-term participation is limited to leasing rooftop space. The rental income from these leases is good REIT income. Prologis does not own the solar projects.

MR. TEICHMAN: Kimco's taxable REIT subsidiary leases rooftop space from individual property-owner landlord entities, it develops and owns the system, and eventually it earns taxable income from the sale of electricity and SRECs. Any impact that this structure would have on Kimco's income and assets tests is nominal due to the small scale of these projects relative to Kimco's total income and asset base.

Several REITs are engaged in renewable energy projects.

MS. KOGAN: Has Kimco's taxable REIT subsidiary distributed any of its after-tax income to Kimco?

MR. TEICHMAN: Yes, I believe it has.

Power REIT

MR. BANK: I would like to turn to Power REIT, which has an unusual history. I also understand that Power REIT made a decision to pursue properties that do not require a private letter ruling from the Internal Revenue Service. Arun Mittal, can you tell us about Power REIT's history and its no-PLR strategy?

MR. MITTAL: Power REIT's sole asset for most of its history has been the Pittsburgh and West Virginia railroad. How it came to own that asset is very interesting.

The railroad was assembled around 1900, but with the advent of the interstate highway system in the 1950's, it started to have problems. When the REIT rules were enacted in 1960, its owners saw an opportunity to reorganize its structure. The only thing they needed was confirmation from the IRS that railroad properties qualified as good REIT properties.

In 1967, the railroad received a private letter ruling from the IRS concluding that its property, including the trackage, roadbed, superstructure, buildings, bridges and tunnels, qualified as real property for REIT purposes. (Ed.: The IRS later converted that private ruling into a broader revenue ruling that applies to all taxpayers and has been cited extensively in later private letter rulings and revenue rulings.) Shortly after receiving the PLR, the railroad was transferred to Power REIT, a REIT traded on the then American Stock Exchange.

For more than 40 years, Power REIT did not do anything other than own the railroad and receive rent from a single lessee, the railroad operating company to whom the REIT leased its assets. Shares in Power REIT were similar to a bond that paid out a fixed rate of return to its shareholders. Power REIT was not interested in doing anything else.

When we stepped in a few years ago, we saw a real opportunity to capitalize on what we believed to be an innovative public platform that could provide capital to and monetize real estate-related assets owned by energy and infrastructure projects.

Initially, we considered applying for a private letter ruling. However, after talking to large asset owners and describing what we were doing, we decided that it did not make economic sense for us to incur the cost of obtaining a private letter ruling. Coupled with the fact that there are a number of other people hiring law firms to do exactly that, we decided to focus on acquiring properties that are clearly good REIT property under

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eight-factor test that an Arizona court developed in a natural gas case.

The court said it was important to look at what Eagle Point actually does. The company installs solar panels and also provides financing options to its customers in the form of leases or power purchase agreements. These "financing options" are incidental to the company's main business, the court said.

That business is installing solar panels on the customer side of the utility meter. The company is basically helping the customer reduce its electricity demand just like other energy efficiency installers. "[A] provider of behind-the-meter energy efficiency services in not subject to regulation as a public utility," the court said. Eagle Point "provides the customer with the same service [as energy efficiency companies that install better insulation, new windows and more efficient lighting, but it does so] by different means."

Eagle Point is not serving the broader public like a utility. Rather, each rooftop system is dedicated to a single customer on a single site. Rooftop solar companies are not natural monopolies and, as such, there is no policy reason to regulate them as utilities, the court said, particularly in view of the state's policy to encourage use of renewable energy.

The case is SZ Enterprises, LLC d/b/a/ Eagle Point Solar v. Iowa Utilities Board. *The court released its decision on March 29.*

THE US TREASURY is expecting to pay another $12.5 billion in grants on renewable energy projects before the section 1603 program ends.

It expects another 100,000 applications, almost exclusively for solar projects with the vast majority of them for smaller systems mounted on rooftops. The only projects that still qualify for grants are projects that were considered under construction by December 2011. Many solar developers are sitting on solar panels and other equipment stockpiled in 2011. Projects that use this equipment / continued page 11

the existing rules.

That said, we are certainly willing to consider properties in the grey area. We also have no aversion to jumping on the bandwagon if and when the IRS rules that a particular type of renewable energy property is good REIT property.

CleanREIT

MR. BANK: Bill Hilliard, your firm has a slightly different PLR-related history. CleanREIT actually started down the road to obtain a private letter ruling but then aborted the process. Can you take us through how far down the road you went toward getting a PLR, the decision to pull the plug, and what CleanREIT decided to do afterwards?

MR. HILLIARD: My partners and I have backgrounds in both tax credit investing and mortgage REITs. In 2009, the idea of starting a mortgage REIT did not seem very attractive, so we started thinking of other ways to combine our expertise in REITs and renewable energy. We came up with the idea of a renewable energy equity REIT.

After doing our homework and even hiring tax counsel, we put out feelers to the IRS about its views on the status of renewable energy property in general as good REIT property. We quickly learned that the IRS had significant reservations about whether many of the components of wind farms could qualify.

At this point we decided to focus exclusively on solar. We even got to the point of asking the IRS for a pre-submission conference, a meeting with the IRS to discuss our possible ruling request. We thought that if we could help the IRS get comfortable with the idea that solar is both inherently permanent and passive and that our proposed investment structure is also passive, then the IRS might be willing to issue a PLR confirming that solar assets are good REIT property. *(Ed.: Equipment and machinery do not qualify as good REIT property. Only real estate does. What looks at first glance like equipment can qualify as real property for REIT purposes if it is considered permanently affixed — "inherently permanent" — but not if it is machinery.)*

It quickly became clear that the IRS didn't really understand solar technology. For example, it did not understand that although solar PV assets perform the activity of generating electricity, they are not like more traditional electric generating assets. For example, they do not have moving parts and do not require fuel and on-site personnel to operate. They just sit passively.

About this time, we also started talking to bankers who specialized in REITs and other specialty finance companies. To our surprise, we learned that they viewed solar energy REITs as a niche REIT similar to REITs that owned things like vineyards, and that they had little interest in bringing such a vehicle to market.

At this point, two things happened. First, we began to reexamine our strategy of pursuing an IRS private letter ruling. We decided to put that strategy on hold at least until the markets caught up with us.

The IRS is letting active businesses put their real property into REITS and lease it back to the operating company.

Second, we were introduced to the concept of a Canadian income trust. This is a type of pass-through entity formed in Canada that generates high yields. Its units are traded on Canadian stock exchanges. It is used to raise money in the capital markets, which it pools for investments outside of Canada.

Because Canada does not impose any limits on the type of property an income trust can own other than that the property not be used in carrying on a business in Canada, Canadian income trusts are a good option for owning renewable energy assets in the United States. A second benefit is that there is plenty of information in the Canadian markets about how to price these investments. For these reasons, we were able to engage bankers for an IPO. We were also able to raise some initial capital to begin acquiring assets.

There are two additional comments I would like to make. The first is that the capital markets want to see a stream of cash flows. While the markets are interested in the presence of a development pipeline as a way to ensure future growth, the only assets they will value are an entity's operating assets that generate cash flow. For this reason, we are looking for post-COD solar assets that are either more than five years old or that are 1603 cash grant-financed (since we can acquire both kinds of assets without triggering recapture under our acquisition structure).

Second, because a solar project is a wasting asset more akin to an amortizing mortgage than a parcel of real estate that grows in value, we plan to adopt a strategy of limiting our payouts to about 80% of our cash flows. The remaining 20% will be used to reinvest in new properties. This is one way we hope to grow our asset base.

Hannon Armstrong

MS. KOGAN: Turning to Jeff Eckel, your company, Hannon Armstrong, received a private letter ruling from the IRS last fall. Because the PLR has not been made public yet, there has been tremendous speculation about what is in it. Many seem to think that it will open the floodgates to investments by REITs in renewable energy projects. Can you tell us about the PLR and whether that speculation is warranted?

MR. ECKEL: Sure, but first let me take a step back for a moment. Hannon Armstrong is a 32-year-old specialty finance company that provides debt and equity financing for sustainable infrastructure projects. We do equity transactions and we do mezzanine debt transactions, but we are best known as a senior lender.

We securitize many of our assets. Since 2000, we have arranged close to $3 billion of securitizations. Most of them are energy. Some are telecommunications. Some are water assets.

Because a lot of what we do is related to buildings and their structural components, we have always had the sense that our assets would be good REIT assets.

We have also wanted to broaden our investor base. Our historic investors have all been institutions. We have had private equity and personal equity, but it was not a broad investor base. With a REIT structure, we were able to generate significantly more capital that is economically priced.

In addition, under a REIT structure, our capital is permanent. We do not have to go back and ask a private equity firm for a little more capital. It also allows us to act with discretion, something we think we deserve given our history.

What we did not seek to do is to convert to REIT status in order to avoid taxes, and I have been rather alarmed by New York Times articles suggesting that is the case. It never occurred to us that there was a tax angle. We converted from an LLC, which is a pass-through entity, to a REIT, / continued page 12

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can still qualify given the right facts.

Total payments through May 10 under the program were $18.5 billion.

The largest single grant to date was a $542 million grant paid in May 2011 to E.On Climate & Renewables in connection with a 781.5-megawatt wind farm the company built in Roscoe, Texas. The grants are 30% of the eligible cost or fair market value of the project, depending on how the project was financed.

Grants approved for payment through September 30 this year are subject to an 8.7% haircut due to budget sequestration.

The haircut percentage is expected to drop to 7.3% for grants approved on or after October 1, according to the latest estimate by the Office of Management and Budget. OMB said it will issue an update in August. The actual haircut will depend on budget decisions made between now and the start of the US government's next fiscal year on October 1. Unless Congress turns it off, sequestration will remain in effect for another eight years after this year.

There has been continuing erosion in the "tax bases" that Treasury will accept for calculating grants. Treasury has been paring back the bases it will accept in some cases to the actual amount the developer can demonstrate a project cost to build. Many projects are financed in the tax equity market in a manner that lets tax benefits be calculated on the fair market value rather than cost. Treasury's view is that the market value should not exceed the replacement cost, or the amount someone would have to spend today to build the same project. With solar panel prices falling, this has meant projects built today using equipment purchased in 2011 may have a lower replacement cost than the actual cost to build. Treasury has accepted the actual cost in some cases, notwithstanding the lower replacement cost, but after knocking out developer fees or other markups achieved in tax equity transactions. In other cases, it has been willing to entertain a small markup above actual cost. In other cases, it has / continued page 13

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which is also a type of pass-through entity. There was zero tax-related motivation for our decision.

As for our decision to request a private letter ruling, that was really belt and suspenders. After we hired our very expensive IPO counsel but before we incurred significant legal fees, we wanted to make sure that the IRS would be comfortable with our REIT status.

The PLR was a way to do that. It is very narrowly focused on our balance sheet that we have built up over three decades. It is specific to our situation.

That said, we never felt that we needed the PLR to qualify as a REIT. We were confident that we could have closed the IPO without it. However, being a pretty conservative company, we like having the insurance policy that the PLR represents.

As for the future, we are very active in the renewable energy business. Our platform reflects our intention to invest in a lot more renewables: solar, wind, geothermal. We also have a bias toward assets that contribute to the reduction of carbon.

We also hope to migrate to additional investors who care about sustainability, but frankly we will always have to compete for capital like every other REIT. I do think we are in a good position to do that.

Buying Assets

MS. KOGAN: Arun Mittal, I understand you closed on one property acquisition earlier this year, and this month you announced that a term sheet had been signed for a second one. Please describe the types of property that Power REIT seeks to own and how you look for those properties. What attributes make them appealing to you?

MR. MITTAL: Power REIT's goal is to purchase good REIT properties without going to the IRS. This means that we are focused on acquiring land and certain other items that can be bundled with the land. The first transaction we did was the acquisition of the land under the largest solar farm in Massachusetts. We just announced a similar type of transaction in California.

We are looking at operating assets, like the one in Massachusetts. We are also looking at partnering with developers and asset owners in the late development or preconstruction stage. We believe this will provide several benefits.

First, it provides developer liquidity in cases where developers have contracted to buy land. Second, we think it provides a part of the capital stack that is not well suited for a tax-oriented investor.

As to how we find assets we are interested in purchasing, I would say we talk to a lot of people and come to programs like this. So if any of you has assets, come talk to me.

MS. KOGAN: Given that REITs are required to distribute 90% of their taxable income each year, how do you come up with the cash you need to buy these other assets?

MR. MITTAL: Most REITs are very aggressive capital raisers. Power REIT has a $100 million shelf offering in effect with the US Securities and Exchange Commission. We also have access to the capital of institutional and private investors who are interested in renewable energy and with whom we have been speaking for a number of years. We also use debt.

With access to these three sources of capital, we will be looking to capitalize transactions as they show up. We do not like to raise money and then have it sit on the balance sheet waiting to invest. Our goal is to capitalize as assets show up.

Foreign Assets

MS. KOGAN: Drew Torbin, you mentioned that Prologis has a lot of warehouses and other buildings outside the United States, and Will Teichman, you told me before the panel session that Kimco has some involvement in the Canadian and Mexican markets. One of the things this reflects is that good REIT property does not have to be located in the US. It can be outside the US. Can each of you comment on your experiences with developing and owning renewable-type assets outside the US? Are there opportunities for US developers, US equipment suppliers, etc. to help in those efforts outside the US?

MR. TORBIN: Solar is certainly a global industry. One of the bigger aha moments for us was when we were given vastly different prices on an installation in France, which at the time had a very attractive feed-in tariff, and an installation in the US. This happened even though the technologies were the same.

Obviously, people were pricing to the market. We have had face-to-face discussions with our suppliers letting them know that this is a global industry and that the real estate owner is the one that should be controlling the upside, whereas the supplier should be pricing on a cost-plus basis.

The other big lesson we learned with international development is that you have to have a local partner. An example of learning that lesson is an eight-megawatt project in Spain we completed with a US-based development partner. We tried twice to fit within the feed-in-tariff window. We sent in people from both our firm and our partner. We did not actually succeed, however, until we sent in local colleagues.

I think that is true in the US as well. I have had meetings in some parts of the US in which having a local person attend with you has been very helpful.

The biggest opportunity I see is in operations and maintenance. There is a huge O&M procurement gap in this industry. It is hard to find a large bankable, geographically-diverse O&M provider. For better or worse, investors have gotten used to accepting smaller O&M providers that are geographically oriented in one spot. It would be very nice to have somebody that is much larger, and with a much larger balance sheet, to perform that side of the business.

MR. TEICHMAN: Kimco does not have any solar projects yet outside the US, although we are in the process of exploring some opportunities through portfolio reviews. One possibility is the Mexican market. There are a lot of things going on in Mexico that potentially may open that market up for solar.

The other thing I can talk about is the portfolio review process itself. One thing we look for during that process is a good local partner. Having local boots on the ground is an important factor, which we learned through our experience in doing energy efficiency projects.

In terms of assessing locations, a very important consideration obviously is the prevailing rates and market for local power from the grid.

Another factor is the potential offtaker. In the US, Kimco sells power to its tenants. In Mexico, the situation is a little different. All of Kimco's Mexican shopping centers have enclosed common areas, which means that Kimco itself can consume a portion of any solar electricity it generates to electrify, heat and cool those common areas. The third factor, perhaps surprisingly, is the roof itself. One of the things that has continually surprised me is the number of potential projects that fall off the list as a result of the condition of the roof. This may be due to the fact that in the shopping center industry, buildings and their roofs tend to be a little bit older.

Also, the roofs of larger properties tend to vary in age in a patchwork fashion. It is unusual to replace an entire roof at one time. Instead, replacement is done in sections in order to manage the capital costs year-to-year.

So roofs are a big issue for Kimco, and they are one of the reasons that solar projects do not get done. It would be helpful if a structure could evolve that / continued page 14

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used the income method to arrive at basis, but using the tax equity investor's internal rate of return as the discount rate, unless the developer can produce a better market assessment of the riskiness of the customer revenue stream being discounted under the income method.

The Treasury is strictly enforcing a deadline to respond to any questions that its reviewers ask after looking at grant applications. Responses are due within 21 days. Grant applicants who need more time should be sure to ask for an extension before the deadline. At least one applicant who failed to respond in time has been told he is out of luck: the application has been treated as withdrawn and cannot be refiled.

There are currently five lawsuits pending against Treasury about the section 1603 program. A sixth suit was withdrawn by the solar company that filed it "with prejudice," after the government filed a counterclaim against the company charging it with fraud. The company claimed grants on bases as high as $45 a watt on solar systems mounted on flat-bed trucks.

In April, a biodiesel producer lost a round in one of the other pending suits. Clean Fuel, LLC filed suit against Treasury in February 2012 after being denied grants on new Cummins generators that it added to two existing biodiesel plants in Florida. The plants make biodiesel from waste soy, palm nuts and some waste animal fats. Clean Fuel bought them in early 2009 from the original owner and added the generators a year later to make electricity for use in the plants. Treasury appears to have denied grants on grounds that the company was asking for grants on used property. The government should have pointed out that the company would not have qualified for production tax credits on the electricity because there is no sale of the electricity to third parties. However, the Treasury does not appear to have raised this as a bar to a grant.

Clean Fuel sued not only for the grants it was denied but also for the net income it said it lost in 2011 as a result of not receiving grants. The company said its 2011 net / continued page 15

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would bundle some of the re-roofing costs into the overall scope of the solar project. That would make many more projects work for us. That is something we are trying to work our way through right now.

Potential for US REITs

MR. MOLCHANOV: I'd like to add a macro level observation. There is a reason why historically 90% of the world's solar installations have been outside the US, and that is because the US has the cheapest electricity of any industrialized country.

So, by definition, the economics of both rooftop and ground-mounted solar are better in any other OECD country than the US. In the US, we pay 8¢ to 12¢ per kilowatt hour for residential, with commercial rates less than that. Europe pays 50% more. Japan pays double. The US market is on the tail end of where the economics are.

MR. BANK: What are your thoughts about the various structures — not only REITs but also others like master limited partnerships and yield cos — that are being talked about in the industry? Do you think they ultimately will have the desired effect of reducing the cost of capital for renewable energy projects?

MR. MOLCHANOV: If they can pass legal muster in the case of REITs or political muster in the case of MLPs, then there would certainly be demand for them.

Let me put it this way. Ten years ago MLPs were in two categories. There were pipeline MLPs and there were timber MLPs, and that was it. Now there are MLPs that make fertilizer, MLPs that own refineries, MLPs that own gas stations and MLPs that own offshore drilling rigs.

If investors can gravitate to those assets, there is no reason why they would not gravitate to assets that, at a minimum, have less risk. Solar projects by definition do not have much operating and political risk. There are no oil spills to worry about and no need to obtain drilling permits. As we have tragically seen recently, fertilizer plants sometimes have accidents. Solar projects do not. For this reason, I absolutely think there would be investor appetite for these structures. The challenge is that they first have to get past the legal and political hurdles. ◎

Accelerating The (Commercial) PACE

by James Berger, in New York

PACE (or property assessed clean energy) financing is still in its infancy, but could be a huge growth market. It is a form of financing for energy efficiency improvements to buildings. It can also be used for water conservation measures.

In order for PACE financing to work, a state must first pass enabling legislation permitting PACE financing. Twenty-six states and the District of Columbia have passed such legislation. Under such legislation, local governments can establish or join a PACE district. Each PACE district has different guidelines with respect to the types of improvements that can be financed. Once a PACE district has been established, building owners evaluate potential projects and determine whether to seek PACE financing.

After a building owner decides to use PACE financing for an upgrade, then financing is arranged. Financing can be either public or private. If public financing is used, then the local municipality will typically borrow money in the capital markets by issuing bonds and then lend the proceeds to the building owner. If private financing is used, then the building owner will borrow money from an approved private source of capital, such as a bank or private equity fund.

After borrowing the money, the building owner accepts a property tax assessment on its property for up to 20 years and repays the loan through this special property tax assessment.

PACE loans effectively subordinate all other lenders' security, because the PACE loan is repaid as part of the property tax assessment, which is superior to all other obligations. This results in the PACE loan subordinating existing mortgages on the property.

Residential PACE has been at a virtual standstill since 2010, because the Federal Housing Finance Agency, which regulates Fannie Mae and Freddie Mac, issued a statement indicating that the senior lien status of most residential PACE programs could not take priority over a mortgage guaranteed by Fannie Mae or Freddie Mac.

Commercial PACE is not affected because commercial mortgages are not guaranteed by Fannie Mae or Freddie Mac. Commercial PACE is not currently as widespread as residential PACE was poised to be, but it is expanding steadily. The development of commercial PACE programs did not begin in earnest until 2011. Sixteen programs in seven states have been launched as of February 2013. A number of new programs have begun operating in the last several months, and some states are considering passing PACE enabling legislation.

Funding Models

There are four basic financing models that exist in commercial PACE programs. All four models use the property tax assessment as the repayment mechanism. The difference among the models is the way in which capital is provided.

The models are grouped into two categories: the municipal-bond-funded model and the privately-funded model, each of which has two variations.

The municipal-bond-funded model is often used to finance upgrades to smaller buildings and is often chosen by cities with more small buildings than large buildings.

The municipal-bond-funded model is where a municipal bond is funded and funds are available on demand to finance projects as soon as applications are processed. Once all the bond proceeds have been disbursed, new bonds can be issued to create a new reserve. The ability to receive funds on demand and immediately determine the interest rate that applies to a loan is advantageous for borrowers who want to fund a project quickly and want more certainty about the overall project cost after the financing is taken into account. An example of this model is the Sonoma County Energy Independence Program in Sonoma County, California that has financed nearly 60 projects.

An alternative municipal-bond-funded model is where the municipal bond sale is arranged after enough projects can be pooled for the bond issuance. The demand for funds must exceed a certain level (usually a minimum of at least $2 to $5 million) before the authority will issue the bonds. This structure can lead to lower interest rates because transaction costs are lower, but borrowers may have to wait until there are enough projects to meet the minimum level the authority needs to issue the bonds. This structure also leads to some uncertainty for borrowers because the interest rate will not be determined until the bonds are sold. The Toledo PACE Program (in Toledo, Ohio) follows this model and has financed more than 50 projects with $12 million in financing.

The privately-funded model is more advantageous for financing upgrades to larger buildings and is often chosen by cities with more large buildings than small buildings.

The privately-funded model is where */ continued page 16*

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income was down $8.977 million in the case of one of the two plants.

The government moved to dismiss the claim for lost profits — called "consequential damages."

The judge in the case agreed with the government. He said the claims court does not have the power to award consequential damages in a section 1603 case.

The Treasury has extended the deadline to apply for grants after projects are put in service. The deadline had been 90 days. It is now 180 days.

STATE INCOME TAXES may be owed in more cases than companies realize.

A survey by Bloomberg BNA found that 26 of the 50 US states believe a company has a sufficient "nexus" — or link to the state — to subject it to income taxes if the company leases space on a computer server in the state. Thirty-six states believe there is a sufficient nexus to tax if the company has an employee who works from home in the state and telecommutes.

Once a company has a sufficient nexus to tax, then the tax is on the share on the company's income that is considered to have been earned in the state. Such income has a "source" in the state. Most states use some variation of a three-factor formula to allocate the company's total income partly to the state by weighing the share of the company's total payroll, property and sales in the state. However, some states provide different weighting to the factors and some have moved to use of just one of the factors.

Foreign companies doing business in the US are most likely to run into problems. Most foreign companies are familiar with the federal tax system but less familiar with state taxes. They may run up significant liabilities before they realize they owe money. Foreign companies are usually not subject to regular income taxes at the federal level unless their activities are regular enough to create a "permanent establishment." Most states do not use the same concept. They look for a "nexus," which can be created with a much smaller level of activity. */ continued page 17*

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the projects are funded individually and the financing is either done in the open market (such as through a competitive bidding process) or through an owner-arranged program. This structure offers on-demand funding, but the transaction costs will vary and the interest rates will depend on negotiations between the borrower and the entity providing the financing. GreenFinanceSF, a program with a budget of $150 million in San Francisco, uses this structure.

An alternative privately-funded model uses a turnkey financing program with funding on demand. The program administrator will offer financing from one private entity. This model offers easy access to on-demand funding with negotiated interest rates. An example of this structure is Clean Energy Sacramento, a program that was launched in March 2013 in Sacramento, California.

PACE programs in seven states are being used to finance energy efficiency improvements to buildings.

Benefits of Commercial PACE

Unfortunately, there are various barriers to making improvements in existing buildings. The most significant barriers are lack of funding and an insufficient return on investment. Other barriers include uncertainty about the amount of savings that will be achieved and split incentives between landlords and tenants.

PACE financing is designed to overcome these barriers and is attractive to all interested parties, not just building owners, for a number of reasons.

PACE financing addresses the lack of funding because it can provide up to 100% upfront financing. Large projects can be undertaken with little or no money out of the owner's pocket.

The problem of insufficient return on investment can also be addressed through PACE because investments made with such financing can be cash-flow positive from day one: the loan is repaid over a longer period, often over a term of up to 20 years. This is compared to terms of 10 years for commercial property lending and five to seven years for general real estate lending. Building owners do not have to wait years to break even on an investment made with PACE financing.

The interest rates on PACE loans are relatively low, often in the 6% to 8% range. One bond issuance in the Toledo PACE Program had effective interest rates of 5% to 5.5%.

Payments can be passed through to tenants (who usually reap the immediate benefits of an upgrade in the form of lower utility bills) in a typical lease arrangement where tenants pay for their shares of utility bills and property taxes. For example, if the owner installs a new energy-efficient heating and cooling system that lowers heating and cooling costs, then the tenants will have lower utility bills. The cost of the upgrade, if financed with PACE, will lead to a higher property tax bill, which is also usually passed through to the tenants as an offset to the lower utility costs.

Because a PACE assessment stays with the property, a building owner does not need to worry about repaying the loan if the building is sold before the loan is fully repaid. The obligation to repay the PACE loan transfers to a new owner upon the sale of a building. A more efficient building can also command higher rents and, by extension, an increased long-term property value. By one account, buildings with a green rating command an effective rent that is 6% higher than less efficient buildings and sell at a 16% premium.

While the accounting treatment is still an open question, there is the possibility that projects financed with PACE will not be entered as a long-term liability because property assessments are only a one-year obligation. If the full investment can be treated as off-balance sheet, then a building owner's ability to take on additional debt for other projects is less likely to be affected.

Lenders like PACE loans (to the extent the privately-funded model is used) because they offer a low-risk investment opportunity. The lien securing repayment is senior in priority to mortgages and all other liens on the property (other than for taxes). The repayment mechanism (the loan is repaid when property taxes are paid) is secure.

Lenders holding the mortgage on a building receiving PACE financing also benefit from the PACE loan, despite the PACE lien having a higher priority than the mortgage. The upgrade financed with the PACE loan will usually reduce operating costs for the building, which increases the building's cash flow. The PACE loan will not have an acceleration feature. Finally, a building that is more efficient is more attractive to occupants, which increases the value to the owners (including higher rent) and lowers the risk of default.

Municipalities like PACE because making buildings more efficient is a form of economic development that leads to higher tax revenues and creates jobs. One study predicted that every $1 million in building energy-efficiency improvements leads to $2.5 million in economic output, about $250,000 in state and local taxes and approximately 15 new jobs. Professionals are needed to develop and administer local PACE programs, and construction and technical workers are needed to implement and maintain upgrades.

PACE financing is no burden on a county's or city's credit or general fund. Unlike a typical economic stimulus program, the government is not spending tax dollars.

Energy costs and usage for local businesses are reduced. Less money spent on energy is more money that can be spent on other goods and services in the local economy, and a clean environment creates a more desirable place to live.

Issues and Opportunities

Commercial PACE financing is not without issues.

Lender consent is often required. Fortunately, the Federal Housing Finance Agency does not guarantee commercial mortgages, but most commercial mortgages forbid a borrower from permitting a lien to be placed on the property with a higher priority than the currently existing mortgage. In order to have the PACE lien assessed without triggering a default under an existing mortgage, the borrower will need the current lender's consent. However, mortgage lenders generally consent to the PACE lien because of the other advantages from the energy-efficiency improvements to the building.

Another issue is the limited availability of PACE financing. While over half of all states have enacted PACE enabling legislation, only seven states have pro-

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MASTER LIMITED PARTNERSHIPS took a step closer in late April to use in the renewable energy market, but they remain a hard sell in Congress.

MLPs are large partnerships in which the partnership interests are traded on a stock exchange or over-the-counter market. Publicly-traded partnerships are taxed like corporations in the United States. Thus, their earnings are taxed at the partnership level and then again when distributed as "dividends" to partners. However, the US tax code makes an exception for partnerships that receive at least 90% of their gross income each year from dividends, interest, rents from real property or from an active mineral or natural resources business.

Senator Chris Coons (D.-Delaware) reintroduced a bill in late April that would allow MLPs to own renewable energy projects as well as a long list of other types of new assets they are not able to own currently. The expanded list includes fuel cells, combined-heat-and-power projects of up to 50 megawatts in size, electricity storage devices, renewable chemicals companies, installers of energy efficiency improvements, large industrial facilities that capture and store their carbon dioxide emissions and gasification projects that gasify coal, petroleum residue, biomass or other materials and that capture and store at least 75% of the carbon dioxide emissions.

The bill inadvertently would block some rooftop solar systems from being owned by MLPs. Under the bill, solar systems on which customers have signed power contracts to buy electricity could be put in MLPs, but solar systems that are leased to customers could not be.

Coons has done an excellent job of building support for the bill. However, it is unlikely to be taken up until Congress tackles broader corporate tax reform, at which time Congress will have to decide how many industries it is willing to allow to operate without having to pay corporate income taxes. The more industries added to the list, the harder it is to sell. The renewables companies argue for parity with fossil fuel companies.

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grams that are active. Even fewer have had a significant amount of activity. Most of the projects financed to date have been in California, especially Sonoma County and San Francisco. Outside of California, a number of projects have been financed in Toledo, Ohio, Edina, Minnesota and Boulder, Colorado. The other active, but recently launched, programs are in Connecticut, Washington, DC, Florida and Michigan.

For commercial PACE to grow significantly, two steps must be taken. First, more states need to pass enabling legislation. There should be little political opposition, because the typical partisan issues surrounding energy policy are not present with PACE financing. Second, local governments in states that have passed enabling legislation must establish (or join already established) PACE districts to allow PACE financing to occur.

Surprisingly, there may even be some help from Washington. Senators Jeanne Shaheen (D.-New Hampshire) and Rob Portman (R.-Ohio) are promoting a bill called The Energy Savings and Industrial Competitiveness Act that will encourage building retrofits. The bill passed the Senate Energy Committee in early May with strong bi-partisan support. It would provide grants to states to establish or expand programs that promote energy efficiency retrofits of commercial buildings, including PACE programs. It must still pass the House.

The market itself will also help expand PACE financing. Over time, more and more investors will be willing to participate in PACE financing. There is always a problem of persuading investors to be first movers. Large bond issuances will be possible over time as the pool of potential investors increases. Some market watchers believe that enough volume could exist in California within a few years to start bundling the currently privately-placed bonds to sell in the public market. The public market would offer lower interest rates and further increase access to capital.

Growth in PACE financings should lead to standardization in documentation and lower transaction costs.

Once the market is large enough, securitization of PACE loans could create a new asset class. The scale needed to make securitization work is probably in the $50 million to $100 million range. Once this occurs, loans could be bundled, sliced and sold to a variety of investors, including large institutional investors such as pension funds and insurance companies. These investors control very significant amounts of capital.

A larger pool of investors will lead to downward pressure on interest rates on PACE loans. This would further expand the PACE market by increasing the number of economically feasible projects.

Buildings in the United States consume more than 40% of the energy used and nearly 75% of the electricity used. Making these buildings more efficient represents an investment opportunity of nearly $280 billion. PACE financing is still in its infancy, but it could be the most efficient and promising way to enter this nearly untapped market. ◎

Sunny Days Ahead For Solar In Turkey

by Ayse Yüksel with Chadbourne and Deniz Şahbaz and Ekin İnal with Çiğdemtekin Şahbaz Avukatlık Ortaklığı, in Istanbul

Applications for the Turkey's first-ever solar energy licenses to build up to 600 megawatts of solar projects in 27 regions previously announced by the Ministry of Energy are due at the Energy Market Regulatory Authority in mid-June. The licenses are expected to be awarded in the first half of 2014.

The window may reopen for another round of applications thereafter.

Demand for electricity in Turkey has been growing at an annual rate of almost 8%, and Turkey is highly dependent on imports of oil, natural gas and coal to meet this increasing demand.

The government has been promoting renewable energy in an attempt to reduce the high import bill. Turkey has a vast solar energy potential with 2,640 hours of insolation per year and 380 terrawatt hours of output potential.

The license application process was launched in May 2012 sparking significant interest from the global industry. Notwithstanding a one-year solar radiation measurement requirement as a condition to the license applications, more than 600 interested parties reportedly applied to the Directorate of Meteorology to initiate the solar measurement process. The Directorate of Meteorology is responsible for the control and evaluation of measurement data and, in late March 2013, it shortened the evaluation process following the measurement period from 30 days to 10 days, which reportedly enabled some 200 more entities to apply for a license who would otherwise not be able to complete the one-year measurement requirement.

License applications must pertain to a specific site.

Generators must first get an authorization from the Directorate of Meteorology to set up a measurement station on the site and then submit to the Energy Market Regulatory Authority or EMRA measuring data of at least one year, including an on-site measurement conducted for at least six months. Once the on-site data has been secured by the applicant, the data pertaining to the remainder of the one-year period may be obtained from meteorology stations of the Directorate of Meteorology.

When EMRA announced the deadline for solar power license applications, it also set out some terms and conditions for licensing. For instance, agricultural lands have not been made available for solar power investments: a maximum of two hectares can be allocated for each one megawatt project, and the total annual solar radiation cannot be less than 1,620 kWh/m2. EMRA did not specify the technology to be used by the generators; therefore, license holders are free to choose the appropriate technology (photovoltaic or concentrating solar power). Applicants must also fulfill various general licensing preconditions.

Feed-In Tariff

Solar power generators can benefit from various advantages introduced by the Law No. 5346 on "Use of Renewable Energy Resources for Electricity Generation."

The renewable energy law was amended in early 2011 to provide for feed-in tariffs for renewable generators who opt into a renewable energy support mechanism. The renewable energy support mechanism offers various incentives, including a domestic component incentive.

Solar power plants are granted a feed-in tariff of US$133 per mWh.

With the domestic component incentive, the feed-in tariff can reach as high as US$200 per mWh in photovoltaic plants and US$225 per MWh in concentrating solar plants.

These incremental price incentives apply only to projects that commence operations before December 31, 2015 and opt into the renewable energy support mechanism. Incentives for using domestically-manufactured components are available for five years after a project commences operations. Generators that do not opt into the renewable energy support mechanism will sell the power to the national grid or through bilateral trading. Generators that do will sell it through the Market Financial Settlement Center operated by the state-owned electricity transmission company TEİAŞ (which will be taken over by the Energy Market Operation Co. or EPİAŞ, the new energy bourse expected to be opera- */ continued page 20*

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IMPROVEMENTS to power plants should be easier to distinguish from repairs in the future after an IRS revenue procedure in April that breaks power plants down into smaller "units of property" and "major components."

Power companies can deduct amounts spent on repairs immediately. They must capitalize amounts spent on improvements, meaning add them to basis in the power plant and recover them through depreciation of the power plant over time. It is usually preferable to claim something is a repair to get the faster tax deduction. However, in projects that qualify for investment tax credits, it may be better to treat the amount as an improvement so that an additional tax credit can be claimed.

The IRS said it will not challenge power companies that treat the cost of replacing a "unit of property" or "major component" as an improvement. The revenue procedure lists all the units of property and their major components at coal- and natural gas-fired and nuclear power plants. A coal-fired power plant can be broken into 27 units of property, and each unit of property has from zero to eight major components. Examples of units of property are boilers, turbines, scrubbers, cooling water systems, condensers and continuous emissions monitoring systems. A turbine, for example, has four major components: the shell and casing, the instrumentation and controls, the complete blade set and the shaft.

These classifications can only be used by companies in the business of selling electricity or steam. They do not apply to alternative energy facilities. The information is in Revenue Procedure 2013-24.

The trade association for the regulated utilities, the Edison Electric Institute, worked for years with the IRS on the classifications. Both sides hope it will reduce the number of disputes in tax audits.

A REPATRIATION STRATEGY that a US company used to bring back money parked in offshore holding companies for */ continued page 21*

Turkey

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tional within a few months).

The renewable energy law also provides other benefits, such as reduced costs in accessing and using state-owned land and priority in grid connection. Renewable generators are almost fully exempted from the license application fee and annual license fees.

A new law regulating the electricity market in Turkey came into effect at the end of March.

The new electricity market law introduced a number of changes, including a pre-licensing mechanism. Going forward, each generator will be issued a preliminary license during the pre-construction stage that will be replaced by a permanent license at the beginning of construction. During the pre-licensing period, the generator must obtain the required permits, approvals and licenses to start construction and also secure title to or the right to use the relevant land. The pre-licensing period is 24 months, unless there is a force majeure event (unavoidable and unforeseeable events beyond the reasonable control of the generator, including acts of God and war) or it is extended by EMRA (under certain circumstances), which cannot exceed an additional 12 months.

If the generator fails to secure the required permits, approvals or licenses within the pre-licensing term, then no permanent license will be issued. Direct or indirect changes in the shareholding structure of the generator are prohibited during this period and such changes will result in the revocation of the pre-license as will the failure of the generator to fulfill any requirements imposed by EMRA. The upcoming applications for solar power in June will be pre-license applications.

Licenses

Permanent (generation) licenses are granted for a minimum of 10 years and for a maximum of 49 years. Other than expiration of the term, licenses are terminated upon request by the generator or if the generator is declared bankrupt or no longer fulfills the licensing conditions.

As a general rule, licenses are not directly transferable; however it is possible to acquire a licensed project by acquiring the project company, subject to regulatory approvals. Also, a step-in right is granted to lenders in limited or non-recourse project financing, and they may request EMRA's approval for the transfer of the license to another legal entity provided that this entity assumes all the obligations of the related license holder. The pre-construction stage is now covered under the pre-licensing period, during which no direct or indirect shareholding change is allowed.

The electricity market law also changed the contest procedure in solar power applications. Under the previous regime, if there were multiple solar power license applications in the same substation, TEİAŞ would organize a tender through an underbidding procedure with respect to the feed-in rates. In other words, the applicant offering the lowest feed-in rate would be granted the license. However, under the new regime, bidders will bid to pay TEİAŞ an amount per megawatt of capacity for the license, and TEİAŞ will award the license to the bidder offering the highest price. The price offered by the successful bidder will be paid to TEİAŞ within three years (at the latest) after the plant goes operational. If there are no competing bids for the same area or substation, then applicants proceed with the licensing and interconnection formalities.

Although Turkey's renewable energy market has focused more on hydraulic and wind power to date, there is significant solar power potential that will remain untapped after the first round of bids. Solar companies criticize the measurement process due to its cost and argue that meteorological and satellite data should suffice for the applications, but the large number of interested parties indicates a genuine interest in Turkey's solar resources. The countrywide total 600-megawatt capacity is expected to increase to up to 3,000 megawatts by 2023,

Licenses to build up to 600 MWs of solar projects in Turkey are expected to be awarded in the first half of 2014.

which will mean a significant rise in the number of licensed generators.

Oman: Future Power and Water Needs

by Sohail Barkatali and Derek Kirton, in Dubai

Sustained growth and development is the key phrase. That is the future outlook for Oman's power and water sector according to a new seven-year outlook for the period 2013 to 2019 released in late May by the Oman Power and Water Procurement Company or OPWP.

While Oman's neighbors in the Persian Gulf have widely publicized their lofty ambitions in the power and water sectors, particularly in the renewables space, Oman continues to mature, presenting opportunities not only for development of new generation and desalination capacity but also in the secondary market through the sale of performing assets.

Every year OPWP, the single buyer in Oman and the procurer of new capacity, publishes a seven-year statement setting out its projections for the demand for electricity and desalinated water production capacity and output, as well as any new capacity required over this period.

According to its latest projections, peak power demand for Oman's central system (including the electricity production facilities at Ghubrah, Rusail, Manah, Wadi Al-Jizzi, Barka Phase I, Al Kamil, Sohar and Barka Phase II), known as the "main interconnected system," is expected to double from 4,293 megawatts in 2012 to 8,106 megawatts in 2019. This exceeds OPWP's previous forecasts.

Peak demand for the Salalah power system in southern Oman is expected to double from 389 megawatts in 2012 to 848 megawatts in 2019.

Peak water demand in Oman's northern region (the interconnected Sur and Ad Duqm zones) is expected to grow from 218 million m^3 in 2012 to 316 million m^3 in 2019.

Within the main interconnected system, OPWP expects to add 200 megawatts of solar power, subject to government approval.

Certain existing agreements providing 1,517 megawatts of purchased power (and related water) capacity are due to expire by the end of 2018.

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use in the United States ended up triggering US taxes, the US Tax Court said.

The Barnes Group manufactures and distributes precision metal parts and industrial supplies. The group has been in business since 1857. In the late 1990's, the group brought in new management with the aim of growing the company through acquisitions. It made three significant acquisitions in 1999 and 2000 for $197.1 million.

As a consequence of the acquisitions, by the end of 2000, the company had $230 million in outstanding long-term debt and a debt-to-equity ratio that was high enough to cause its borrowing costs to increase.

The company was paying 7.13% to 9.47% interest to borrow while earning roughly only 3% interest on $43.7 million cash held in offshore holding companies.

The company's tax director sought ideas from three of the big four accounting firms and eventually settled on a "reinvestment plan" suggested by PricewaterhouseCoopers. The plan came complete with an exit strategy to unwind the plan if Barnes wanted to return the funds to the offshore subsidiaries and a draft "business purpose" suggested by PwC.

The plan involved moving money held in a Singapore subsidiary to the US parent company, but through two new intermediate entities. Money was contributed to a new Bermuda company and then by the Bermuda company to a new Delaware company. The Delaware company then lent the money to Barnes in the US. Some of the money contributed as capital was the accumulated offshore cash. Some was money the Singapore subsidiary borrowed from a Japanese bank at a lower interest rate than the US parent could have borrowed because the Singapore subsidiary was generating significantly more cash than it needed.

PwC, which also acted as the auditors for Barnes, gave a tax opinion that repatriation done in this fashion would not trigger a tax in the United States. Earnings of a US-controlled foreign corporation become taxable in the

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Increased Demand

For the main interconnected system, the forecast of 8,106 megawatts for 2019 represents nearly 10% year-on-year growth in electricity production with the demand outlook for Salalah increasing at around 12% annually. With this forecasted demand anticipated to exceed contracted supply, a number of options are open to Oman to meet this capacity.

It could develop new power generation and water desalination plants. It could agree to contract extensions for generating units that are due to fall out of contract during 2013 and 2014. It could agree to contract extensions for independent power and water producer plants that have power and water purchase agreements that are due to expire in 2017 and 2018. It could add temporary generating capacity or request existing plants to increase their output. Finally, it could purchase capacity from interconnected power systems such as Abu Dhabi and the Gulf Cooperation Council Interconnection Agency.

The availability of gas may constrain Oman's procurement activities

Oman's fuel requirements remain a challenge. Within the main interconnected system, natural gas requirements are anticipated to grow at a rate of 6% per year with a projected increase from 6.7 billion Sm³ in 2012 to 9.8 billion Sm³ in 2019. In Salalah, natural gas requirements are anticipated to grow at a rate of 7% per year to reach 1.1 billion Sm³ in 2019. These growth rates are a substantial increase compared to past forecasts.

The seven-year statement also considers a high case scenario that forecasts a peak demand of 9,133 megawatts in 2019 for the main interconnected system and 936 megawatts for the Salalah system. If realized, Oman could face a gas allocation shortfall from 2014, and it may have to look to other fuel types or consider other options.

Historically though, Oman has been focused on gas-fired plants with fuel oil as back-up fuel. Fuel allocation issues are usually resolved operationally through a protocol among the Ministry of Gas, the Oman Electricity Transmission Company and OPWP to prioritize gas allocation to plants high up in the merit order. This provides the ability to prioritize natural gas for more efficient plants with the further option of reallocating gas from plants that are undergoing maintenance or *force majeure* shutdowns to those that are in operation.

A few years ago, OPWP considered developing a 1,000-megawatt plant at Duqm that would have been the first plant in the Persian Gulf to burn coal (a blend of imported and locally sourced coal). The project was not tendered but with a potential shortfall, if gas supplies are insufficient, Oman may be forced to consider alternative feedstock.

Solar power and other forms of renewable energy also continue to be options. The development of a 200-megawatt solar photovoltaic and concentrating solar power project is planned; however, the project remains subject to government approval.

Electricity demand in central Oman is expected to double in the next seven years.

The Year Ahead

A request for proposals is expected in the summer 2013 for the Salalah II IPP and Dhofar Power Company acquisition with eight developers having submitted statements of intention to qualify.

Later in the year, an RFP is expected for the Qurayyat IWP with expected new water desalination capacity of 40 MIGD.

In 2014, an RFP is expected for the Suwaiq IWP with expected new water desalination capacity of up to 50 MIGD.

In 2014, an RFP is expected

for the Suwaiq IPP with a power capacity in the range of 2,500 to 3,000 megawatts. It is probable that the IPP and IWP projects might be combined.

Oman's power and water purchase agreements are reaching maturity

In the Gulf, Oman is arguably the most mature market for IPP projects having kickstarted its program with the Al Manah project in 1998, which was the first IPP project to be developed in the Gulf region using the public-private partnership model. In 2000, Oman awarded the Al Kamil IPP and Barka Phase I IWPP projects, and it awarded the Sohar Phase I IWPP in 2004. In each case, the projects were tendered under the build-own-operate framework with no mechanism in the contracts for OPWP to repurchase the plant upon expiration of the contract.

Other than at Al Manah, which has a 20-year power purchase agreement, Oman's model PPA has a term of 15 years. The consequence of this is that the PPAs for Al Kamil and Barka Phase I will expire within the next seven years. With the build-own-operate framework, that potentially leaves open a number of options for OPWP and plant generators: they can agree on short- or long-term extensions of the PPAs or allow the PPAs to expire and further deregulate the sector and permit the creation of a competitive power generation market.

With the forecasted power demand and the fact that these plants will have considerable remaining useful lives, all three options remain viable. For Al Kamil, with the PPA expiring prior to the summer 2017, if not renewed, this will result in a reduction in capacity of 282 megawatts in 2017. For Barka Phase I, with the PPA expiring prior to the summer 2018, if not renewed, this will result in a reduction in capacity of 427 megawatts in 2018.

A strategic study is being undertaken within Oman to assess the options available to OPWP on the most economical approach to dealing with expiration of the contracts, whether renewal or the development of new capacity.

New Opportunities

With the maturing of Oman's power and water market, opportunities exist for new entrants. Eight plants are currently in operation with a further three under construction. With OPWP as a financially strong counterparty and stable payment history (currently rated as A- by Standard & Poor's) and the quality of the plants in operation, these factors, as well as Oman's market share restrictions, could also create opportunities for new entrants. The market will continue to be attractive to developers as well as to infrastructure funds / continued page 24

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United States if they are invested in US property. Shares in a Delaware corporation are normally such an investment. However, PwC relied on a 1974 revenue ruling that suggested the amount that should have become taxable in the US is the basis that the Bermuda company had in the Delaware company shares and that basis was zero in this case.

The US Tax Court invoked the step-transaction doctrine to treat the money as coming back to the US directly from Singapore. It said intermediate entities and complicated steps served no business purpose other than to avoid taxes, and the purported loans by the Delaware company were not real loans. There was no evidence that any interest or principal had been paid on loans in the company's general ledgers or bank statements.

The case is Barnes v. Commissioner. *The Tax Court released its decision in April. The courts have been showing less and less patience for complicated transactions intended to achieve a tax result based on a narrow technical reading of the law.*

SERIES LLCs are gaining ground, but slowly.

Nine US states, the District of Columbia and Puerto Rico have statutes that allow limited liability companies to create different pockets or cells of investments, each potentially with different owners, a different managing member and different assets. In at least three of the nine states, each series can have a separate right, in its own name, to sign contracts, hold title to assets and grant liens and security interests in the assets belonging to that series. The debts of a particular series may be enforceable only against the assets of that series.

The structure opens a number of possibilities. For example, wind companies that build out projects in 100- or 200-megawatt increments using a single interconnection agreement may have trouble getting consent from the utility to divide up the interconnection rights among separate project companies. If a series LLC were used, then the interconnection agreement could remain in the name of a / continued page 25

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looking for strong returns from a stable asset class.

Significant transactions to date include the divestment of the Barka Phase I plant from The AES Corporation to ACWA Power International, who subsequently divested a minority stake to the Bunyah Investment Fund managed by Instrata Capital. Since then, the Barka Phase I plant has seen an expansion and subsequent refinancing. More recently, the MENA Infrastructure Fund acquired a 20% stake in the Sohar Power Company (Sohar Phase I IWPP), adding to its current portfolio, which includes a stake in the United Power Company (Al Manah IPP). This trend is expected to continue.

Already, there are developers who are close to reaching the regulatory threshold of 25% of installed capacity or a majority of the generating licences. Oman could see certain developers who meet this criterion either refraining from bidding for future projects or, perhaps more likely, divesting part of their existing portfolios. However, any divestment would remain subject to satisfying the sector's regulatory requirements, such as the appropriate persons criteria prescribed by the regulator, The Authority for Electricity Regulation, Oman.

Oman is also focusing on the town of Ad Duqm and its surrounding areas, which are being promoted by the government for the development of a major industrial and economic city around the new seaport. The current electricity supply is provided by a 67-megawatt diesel-fired power plant operated by the Rural Areas Electricity Company; however, electricity demand is forecast to grow rapidly with current projections forecasting demand of around 100 to 150 megawatts by 2019. Among the options being considered by OPWP to meet this demand is the development of a power generation plant or an interconnection to the main interconnected system.

As with the Gulf region as a whole, Oman's forecast demand for power and water capacity is robust with an accelerated program to add significant new capacity over the next seven years. It remains a mature investment-grade jurisdiction with a strong offtaker, a long history of a sustainable IWPP and IWP programs and a solid regulatory track record that has differentiated itself from other markets in the region. ◎

US Public-Private Partnerships: A Few Steps Forward And One Possible Step Back

by Doug Fried and Chadron Edwards, in New York

There are currently more public-private partnership projects in the procurement phase in the United States than ever before.

Six major public-private partnership or "PPP" projects in the US have reached financial close in the last 14 months, and several more are currently at advanced procurement phases.

Three factors are expected to contribute to continued growth of the PPP market. One is increased federal government support for PPP transportation projects, notwithstanding the federal budget cutbacks in other areas. Another is adoption of a fast-track approval process for major infrastructure projects. The third factor is the possibility that Congress may authorize a national infrastructure bank or similar type of entity.

However, a recent court decision in Virginia has called into question when and how private parties can recover their investments in PPP projects through tolls collected from users of the assets.

Although the US PPP market has not yet experienced growth at the scale and speed as in some other countries like Canada, the United States is steadily building a good track record with such projects.

MAP-21 and TIFIA

Both federal and state governments are spending less on transportation projects due to general budget cutting. A primary source of funding for highways in the United States has been a highway trust fund that is funded by excise taxes on motor fuels. Motor fuel tax collections are down as Americans drive less and tax rates remain at early 1990s levels.

A major exception to this trend is funding at the federal level for financing of projects through the Transportation Infrastructure Finance and Innovation Act, a 1998 statute called TIFIA for short. TIFIA is administered by the US Department of Transportation and provides federal direct loans, loan guarantees and credit support for a wide variety of transportation projects, including highway and transit projects. TIFIA funding levels have increased.

Major (>$300M) US PPP Projects Reaching Financial Close in the Last 14 Months

Project	Asset	Amount	Type of Project and Funding Source
East End Crossing (Indiana)	Bridge	$759,000,000	Greenfield availability project. Private activity bonds.
Luis Munoz Marin International Airport (Puerto Rico)	Airport	$615,000,000	Brownfield revenue project with profit share. Private placement.
Ohio State University Parking	Parking	$535,000,000	Brownfield revenue project. Bank debt..
I-95 HOV/ HOT Lanes (Virginia)	Road	$918,800,000	Brownfield revenue project. Private activity bonds and TIFIA..
Presidio Parkway (California)	Road	$362,000,000	Brownfield availability project. Bank debt and TIFIA.
Midtown Tunnel Project (Virginia)	Tunnel	$2,100,000,000	Greenfield revenue project. Private activity bonds and TIFIA..

Federal legislation in July 2012 called Moving Ahead for Progress in the 21st Century — or MAP-21 — increased TIFIA's loan-making capacity from approximately $1 billion a year to approximately $7.5 billion in 2013 and $10 billion in 2014. Before MAP-21, the TIFIA program was being used (or considered for use) to support several projects, but would clearly not have sufficient funding to assist more than a few of them.

The combination of the additional support for innovative project delivery methods (such as PPPs) and the decreasing support for traditional means of project delivery makes PPPs a much more palatable option for states to finance some of their infrastructure needs.

Most TIFIA support for projects is through fixed-rate loans for a percentage of project costs with interest rates equivalent to Treasury rates. Loan guarantees and line-of-credit facilities are also possible, but are used less frequently.

MAP-21 also increased the percentage of total project costs that TIFIA may fund from 33% to 49%, but the Department of Transportation has indicated that TIFIA funds will generally remain limited to 33% of project costs absent spe- / continued page 26

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single LLC.

A big open issue is how each of the separate LLC subsidiaries is treated for tax purposes. The IRS proposed in 2010 to treat each subsidiary as a separate entity for tax purposes. Therefore, some could be treated as separate partnerships or disregarded entities at the same time that the parties might to choose to treat others as corporations.

The American Bar Association tax section surveyed all 50 states about their treatment of series LLCs. Thirty-one states had responded by May.

The survey found that series LLCs are gaining popularity, but the numbers are not staggering. In Delaware, 8,068 series LLCs have been formed and, in Illinois, 6,320. Twenty-two states said they would follow the federal lead and let each LLC subsidiary make its own income tax election. Six states were undecided. Texas will not follow the federal lead and will treat all the LLCs in the series as a single entity for purposes of the state's "margin" tax, which is effectively its corporate income tax.

The Uniform Law Commission is working on a uniform draft law for use by the states, but the draft will not be completed until 2015 at the earliest.

A WINDFALL PROFITS tax in the United Kingdom can be credited against US income taxes, the US Supreme Court said.

PPL Corporation, a US utility holding company, bought a 25% interest in a regional electric distribution company in Britain when the British government privatized all 12 of its regional distribution companies in 1990. The Labour party was opposed to the privatizations. After it regained control of parliament in 1997, it imposed a one-time windfall profits tax on the owners of the companies.

In form, the tax was 23% of the difference between what the Labour government felt the companies' flotation values should have been and the prices at which they were actually sold.

US companies / continued page 27

PPPs

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cial circumstances.

TIFIA loans were used in several PPP projects in 2011 and 2012. Twenty-nine applications were submitted from August 2012 through February 2013 for TIFIA funding on projects with total costs of $41 billion. Several of these applications have been identified as potential PPP transactions.

Detailed guidance from the Department of Transportation for TIFIA's revised program under MAP-21 is forthcoming, but the department has updated its application procedure in the meantime and now accepts applications for projects on a rolling basis. Applications are submitted by the procuring government agency, but loans are ultimately distributed to and repaid by the private concessionaire in PPP projects. Some projects in previous years have stalled after not receiving TIFIA funding. These projects may reapply, and several already have done so.

A court decision in Virginia raises questions about when tolls can be collected on privately-funded tunnels and roads.

Expedited Approval Process

The classic newspaper headline "Red Tape Holds Up New Bridge" is no laughing matter for those involved with projects that are stalled by problems with governmental approvals.

The Obama administration is attempting to address this problem through a series of executive orders, presidential memoranda and interagency reports, one outgrowth of which is a pilot program for streamlining the government approval process for major infrastructure projects. The goal of the pilot program is to come up with a list of lessons learned and best practices that can be applied to all projects.

The first of these presidential memoranda in August 2011 called for a listing of projects for an expedited review process. The initial list included 14 initial high-priority projects and eventually grew to 50 after adding "nationally or regionally significant projects." The projects include bridges, transit projects, railways, waterways, roads and renewable energy generating facilities.

Executive Order 13604 in March 2012 created and directed a steering committee on federal infrastructure permitting and review process improvement to present recommendations for how to expedite federal permitting reviews.

Identified techniques include expanding the use of advanced data analysis, more and earlier governmental coordination at all levels, assigning a coordinating agency responsibility for the overall permitting and review process for each project and undertaking concurrent (rather than consecutive) project review by various agencies.

The list of identified projects that are supposed to benefit from the expedited review process includes the high-profile replacement of the Tappan Zee Bridge in New York, which is under procurement as a design-build project and is in the process of procuring a TIFIA loan. While New York does not have PPP legislation currently that would allow the Tappan Zee Bridge to be procured as a PPP project, the state legislature is considering proposed PPP legislation that would allow the bridge reconstruction or an expansion of it to accommodate mass transit to be funded through a PPP. The Department of Transportation and White House say the expedited approval process "trimmed up to three years off the timeline" for the project.

Another presidential memorandum in May 2013 directs federal agencies to adopt these improved procedures on a wider basis.

The new procedures should help the PPP market because they will allow states to take proposed projects to market in a faster and more predictable manner.

National Infrastructure Bank

The Obama administration has not given up on the idea of creating a national infrastructure bank or fund. The President called for additional support for leveraging private financing for infrastructure in a speech in March in Miami to call attention to the Port of Miami tunnel project. Subsequent White House releases outlined some details of a proposed national infrastructure bank. The bank would be capitalized with an initial injection of $10 billion in capital and be structured as an independently-operated entity to prevent political interference. It would finance transportation, water and energy projects through direct lending or loan guarantees. Projects would have to be at least $100 million in size to qualify for funding. Federal loans would have tenors of up to 35 years, but would finance no more than 50% of total costs and would have to be backed by dedicated revenue streams. Several of these features mirror what is required currently under the TIFIA program. However, for TIFIA projects, cost limits are lower: $50 million in general or $25 million for rural infrastructure projects.

Congressman John Delaney (D.-Maryland) and 26 co-sponsors introduced a bill in May (H.R. 2084) to establish a government-owned corporation called the American Infrastructure Fund to guarantee repayment of project debt and make loans and equity investments to state and local governments and non-profit infrastructure companies. The bill has significant bipartisan support: the co-sponsors are split evenly between Democrats and Republicans.

The Delaney proposal would require at least 25% of the projects financed through the American Infrastructure Fund to be PPP projects for which at least 20% of a project's financing comes from the private sector. The fund would invest in transportation, energy, water, communications and education infrastructure and be funded by the sale of $50 billion worth of infrastructure bonds with terms of 50 years that would pay a fixed interest rate of 1%. US corporations would be incentivized to purchase the bonds by allowing them to repatriate a certain amount of their overseas earnings tax free for every $1 they invest in the bonds.

It is unclear exactly how funding for transportation projects through the proposed national infrastructure bank or the American Infrastructure Fund would overlap with the existing mandate of the Department of Transportation under the TIFIA program. However, a similar situation developed in the energy sector when the Department of Energy, under its loan guarantee and other programs, shared space with the Treasury cash grant, production tax credits and investment tax credit programs for renewable energy projects.

Outside of the transportation sector, a national infrastructure bank or fund could become a useful tool for filling investment gaps for water, environmental and social infrastructure projects, just as TIFIA has done for transportation projects.

While the current push for fiscal austerity in Washington is not ideal for enacting any such new / continued page 28

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can claim income taxes paid on foreign earnings to other countries as a credit against US income taxes on the earnings when the earnings are repatriated to the United States. However, foreign tax credits can only be claimed for taxes whose "predominant character" is that of an "income tax in a US sense."

The IRS argued that the taxes in this case were not income taxes because they were calculated on a hypothetical windfall for "underpaying" for shares in the privatization.

The Supreme Court analyzed the formula for calculating the tax and concluded that it was in fact a tax on actual income. What the formula did, the court said, was to calculate the amount by which a company's actual profits over the first four years after privatization were "excess" and impose a tax on it. The actual formula was 23% times the daily average profit during the initial post-privatization period of up to four years times 365 times 9 (the price-to-earnings ratio the Labour government thought should have been used to value the companies in the privatization). It then subtracted the actual flotation price.

However, the court said the formula was mathematically the same as a 51.71% tax on the company's actual profits over the first four years, minus what the government thought it was reasonable for the company to earn. The amount subtracted from actual earnings in the formula was mathematically equivalent to a fraction — the flotation price at which the company was sold in the privatization divided by 9 — multiplied by 4.0027. In other words, the tax was on the actual profits to the extent they exceeded an amount the government considered reasonable.

The court released its decision in late May. The case is PPL Corp. v. Commissioner. *Entergy, another US utility holding company that bought London Electricity, won a similar case at the appeals court level. The Supreme Court declined to review the decision in the Entergy case.*

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PPPs

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initiatives, the fact that Congress found a way to increase TIFIA funding, news reports about unsafe bridges and the bi-partisan support for the American Infrastructure Fund suggest a bank or fund is not out of the running.

Litigation in Virginia

In a potential step backward in the PPP market, a recent court decision, Danny Meeks v. Virginia Department of Transportation, may call into question the tolling regimes for certain projects in Virginia and possibly in other states as well.

The case, brought by citizens, businesses and a group called Citizens Against Unfair Tolls, focused on tolls that must be paid for use of the midtown tunnel project in Norfolk. The $2.1 billion project was arranged as a toll-revenue design-build-finance-operate-maintain project with a TIFIA loan and private activity bonds.

The project involved construction of a new tunnel parallel to the existing midtown tunnel under the Elizabeth River connecting Norfolk with Portsmouth, Virginia, as well as an extension of the nearby Martin Luther King Freeway and improvements to the existing nearby downtown tunnel.

The new and existing tubes for the midtown tunnel, the existing tubes for the downtown tunnel, and the highway extension were each planned to be tolled to pay for the project. The two existing tunnels had previously been tolled, but those tolls were lifted when their original construction financings were paid off.

Opponents argued that the proposed tolls would technically be taxes and that the procedures for imposing taxes in the Virginia constitution were not followed.

A state circuit court agreed. The court said the Virginia legislature violated the Virginia constitution by "ceding the setting of tolls rates and taxes in the circumstances of this case for the use of facilities that have been bundled solely for revenue-producing purposes" and by giving "unfettered power to the Virginia Department of Transportation to set toll rates without any real or meaningful parameters."

The defendants argued that the tolled facilities collectively form an integrated transportation network and that "motorists drive on the tolled segments for convenience, so the toll is a voluntary payment for a governmental service, not 'an enforced contribution'" as in the case of taxes. They also argued that the state's PPP legislation does not unlawfully delegate legislative powers.

Toll collection was scheduled to begin in February 2014. The court rejected a request for a stay of the ruling, which would have allowed toll collection to begin during the appeals process.

If not reversed on appeal, the potential impact of the case is not limited to the midtown tunnel project. It could affect other existing and proposed PPP projects in Virginia, particularly those with tolling structures rather than availability payments, and those with multiple components that are aggregated into a single project.

Outside of Virginia, while each state's law and project-specific facts and circumstances would control, the case may serve as a springboard for challenges to other projects. While rulings from courts in other states usually do not control, they can be persuasive, especially when facts and circumstances are similar.

Parties to existing concession agreements should confirm who bears the risk of this type of litigation. Documentation should be clear as to which parties assume this risk. ◎

The CHP Revival

by Paul Kaufman and John Frenkil, in Los Angeles

Low natural gas prices and the growing interest in distributed generation are causing power plant developers to refocus on combined heat and power or "CHP" projects.

Various programs at both the federal and state level are also encouraging the shift.

Portfolio financing models that were developed for the rooftop solar market can be readily adapted for use with CHP. CHP projects at state or other government facilities may be able to take advantage of tax-exempt bond financing.

Cogeneration

CHP refers to equipment that produces two useful forms of energy from a single fuel. The energy is usually in the form of electricity and either steam or mechanical power. The term CHP is often used synonymously with "cogeneration" (although the latter term is most often associated with programs implementing the Public Utilities Regulatory Policies Act of 1978 or PURPA). CHP fuels include biomass, biogas, natural gas, petroleum coke and municipal waste.

By concurrently producing electricity and useful heat or mechanical power from a single fuel source, CHP is more efficient than technologies that produce these outputs separately.

This efficiency reduces greenhouse gases from use of fossil fuel. A recent study by the Oak Ridge National Laboratory concluded that increasing the cogeneration share of electricity generating capacity would significantly reduce carbon dioxide emissions. CHP is also credited with additional benefits such as the reduction of other air pollutants including sulfur dioxide, improved local reliability (produced because CHP may be distributed) and a reduction in otherwise necessary investment in transmission infrastructure. Adding to its potential appeal is CHP's capacity to operate as a baseload facility, its use of technology that has been in use for some time and the potential in some states to displace higher-cost retail service from utilities.

PURPA and federal tax incentives helped to expand CHP installed capacity from about 12,000 megawatts in 1980 to more than 66,000 megawatts in 2000. Yet CHP remains an underused resource, representing approximately just 8% of US generating capacity, compared with over 30% in some northern European countries.

Federal Support for CHP

The federal government has adopted a number of programs to encourage CHP. These programs take various forms, including federal tax subsidies and directives to increase electricity self-sufficiency at federal installations such as military bases. Electric utilities also remain obligated by PURPA to buy electricity from cogeneration facilities in some parts of the country.

Owners of CHP projects can depreciate, or deduct, the cost of the projects on an accelerated basis, meaning the deductions are front loaded, over five to 20 years, depending on the fuel. The fastest depreciation is available on CHP facilities that use biomass as fuel. Projects put in service in 2013 or 2014 may qualify for a 50% depreciation "bonus," meaning the ability to deduct half the "tax basis" in the facility immediately. The other half is depreciated normally.

Some CHP projects also qualify for an investment tax credit. Unlike depreciation, which is deducted from income, a tax credit offsets directly taxes that the CHP owner would otherwise have to pay.

The tax credit may be 10% or 30%, again depending on the fuel.

CHP facilities that use biomass, landfill gas or municipal solid waste as fuel qualify potentially for a 30% investment tax credit. However, such facilities would have to be under construction by December 2013. There is no deadline to complete such facilities to qualify.

A 10% investment tax credit can be claimed on CHP facilities that have at least a 60% conversion / continued page 30

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A CARBON TAX remains in play.

Such a tax was included on a list of options that members of the Senate tax-writing committee were given by committee staff in April. Senators on the committee have been holding a series of closed-door meetings to talk about corporate tax reform. The options are merely a laundry list of all the possibilities and should not be viewed as having been endorsed by the staff that assembled them. However, the committee chairman, Senator Max Baucus (D.-Montana), said in late May that "everything is on the table, including a carbon tax. It's being considered, it is being discussed." The Congressional Budget Office estimated in 2011 that a tax of $20 a ton on the carbon content in fossil fuels would raise $1.2 trillion in revenue over 10 years from 2012 to 2021.

Interest in a carbon tax seemed to peak early in the year as a possible element of a grand bargain on the budget and then recede quickly after attracting strong opposition from Republicans and indifference from the Obama administration.

FOREIGN PARTNERS in partnerships engaged in business in the United States are subject to income taxes at regular corporate income tax rates when selling their partnership interests, the IRS says.

The Obama administration is asking Congress to codify the position. The IRS views the partners as owning directly a share of each partnership asset. Therefore, when a partner sells his partnership interest, he is treated as selling his share of the assets directly. Since the assets are used in a US trade or business, tax must be paid on the unrealized gain in each asset.

The IRS position is explained in Revenue Ruling 91-32. The agency is in the process of writing the position into its regulations, but the regulations are still at an early stage.

In the meantime, the Obama administration is asking Congress to write the same thing directly into the US tax code and to require anyone buying a partnership interest in / continued page 31

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efficiency ratio as fuel is converted into electricity. The credit is reduced to zero as the facility moves in size from 15 megawatts to 50 megawatts in capacity. At least 20% of the useful output must be in form of mechanical power or steam. Projects that use biomass as fuel do not have to meet the 60% efficiency requirement, but the credit is reduced proportionately to the extent the efficiency is less than 60. Projects must be completed by December 2016 to qualify for the 10% investment tax credit.

Low natural gas prices and interest in distributed generation are fueling growth in small cogeneration facilities.

Through a number of statutes, executive orders and directives from the Department of Defense, all branches of the military are engaged in processes to acquire renewable resources and move away from relying on local utilities. The US Army, in particular, has made a significant effort to procure renewables and CHP for the purposes of meeting a "net zero" goal. A "net zero" installation is one that produces as much energy on site as it uses on site over the course of any given year.

PURPA was enacted after the Arab oil embargo in the 1970s in part to encourage the more efficient generation of electricity and decrease reliance on foreign oil. PURPA formally recognized cogeneration by creating a class of power generators called qualifying facilities or "QFs." To be a QF, a project using fossil fuel must produce both steam and electricity, the stream must be put to use and the project must meet certain fuel efficiency requirements. For example, to satisfy the efficiency standard, a gas-fired cogenerator would have to show the useful power output plus half the useful steam output is at least 42.5% of the energy content of the natural gas used as fuel.

As long as a facility qualifies as a cogenerator, PURPA requires a utility to buy the electricity at the utility's "avoided cost" or what it would cost the utility to generate the same electricity. In 2005, Congress gave the Federal Energy Regulatory Commission authority to terminate the utility obligation to buy electricity from QFs in regional markets that are "workably competitive." While FERC has found large swathes of the country "workably competitive," utilities in some regions remain subject to the mandatory purchase obligation.

State Support for CHP

In terms of state support, a number of states have renewable portfolio standards that include CHP as a qualified resource. Some state RPS programs include a specific set aside, meaning a special target, for CHP. Some states also offer tax incentives to support CHP, as well as minimum pricing and a mandatory purchase program for renewable energy credits from CHP facilities. Finally, certain states have authorized the use of their bonding authority to pay for CHP facilities owned by state and local governments.

Of the 13 states that include CHP or waste energy recovery in their RPS targets, California is perhaps the most aggressive in providing a CHP set aside. The California program also provides form power contracts for use with CHP projects. California utilities have a mandatory procurement obligation of 3,000 megawatts of capacity from CHP facilities. PPAs offered under the CHP set aside have terms of up to seven years for existing CHP facilities and up to 12 years for new CHP facilities. The utilities are required to provide updates on their procurement of CHP. To qualify for the CHP set aside, facilities must qualify as cogeneration QFs under PURPA as well as satisfy other guidelines including greenhouse gas emission reduction targets.

There is a formal RFP process for utilities buying electricity from CHP projects, but the California Public Utilities Commission or CPUC also allows utilities to procure CHP through bilateral negotiation of PPAs. However, the bilateral process is limited in scope. The CPUC has separated CHP into categories based on size (20 megawatts or less and larger than 20 megawatts). There are additional efficiency requirements on large CHP projects to qualify for the procurement set aside.

The CPUC also adopted a program to encourage new behind-the-meter CHP facilities. Further, California law has directed the CPUC to establish a feed-in tariff for small CHP systems (less than 20 megawatts) that are new (meaning in operation after January 1, 2008) and highly efficient (operating at better than 62% efficiency).

Illinois offers grants for CHP. The grants cover 50% of a project's cost up to $225,000 for biogas CHP facilities and $500,000 for biomass CHP facilities located in the state. Eligibility is limited to the purchase and installation of generating equipment for the facility. The Energy Resources Center at the University of Illinois Chicago assists the state's Department of Commerce and Economic Opportunity in administering the incentive program, which expires December 15, 2015.

In New York, a CHP acceleration program is administered by the New York State Energy Research & Development Authority. The program, designed for relatively small CHP facilities of between 0.5 and 1.3 megawatts, provides incentives for installation of pre-qualified and conditionally qualified CHP systems by approved CHP system vendors. Incentive funds are allocated on a site-by-site, first-come-first-served basis. The maximum incentive per project is $1.5 million out of a total program budget of $20 million. The incentive commenced on February 15, 2013 and will expire on December 30, 2016.

Connecticut has a CHP set aside in its renewable portfolio standard. Under the state RPS, electricity suppliers were required to supply at least 4% of their retail loads by 2010 using distributed CHP systems at customer sites. As load grows, the electric suppliers in the state are required to maintain the 4% threshold. These facilities must have a minimum operating efficiency of 50% and must be installed at commercial or industrial facilities in Connecticut on or after January 1, 2006.

Connecticut also has a minimum price and purchase obligation for RECs produced by facilities that qualify based on their emissions and efficiency. Connecticut Light & Power and United Illuminating Company are subject to this requirement. The "LREC" program applies to RECs from projects with limited emissions that are no larger than two megawatts.

The Massachusetts renewable portfolio standard requires 3% of the state's electric load to be supplied from alternative energy sources by 2013. This mandate grows to 5% by 2020. "Alternative energy" includes CHP.

Massachusetts has also established a Renewable Energy Trust Fund that is funded by a non-bypassable surcharge of $0.0005 per kWh imposed on customers of all investor-owned electric utilities and competitive municipal utilities in Massachusetts. The fund provides grants, contracts, loans, equity investments, energy produc- / continued page 32

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a partnership engaged in business in the United States to withhold 10% of the gross purchase price unless the seller certifies that the seller is not a nonresident alien individual or foreign corporation. If the buyer fails to withhold the correct amount, then the partnership would be liable for the under-withholding. The partnership would satisfy the withholding obligation by withholding on future distributions that otherwise would go to the new partner.

The typical partnership agreement in the United States has an entire article that addresses when partners can transfer their interests. Careful draftsmen should make sure the agreement requires a partner who transfers his interest to include a clause in the sales document requiring the buyer of the interest to withhold if the seller cannot produce the required certificate.

COST REIMBURSEMENTS to partners are getting attention at the IRS.

The IRS is concerned about double dipping in partnerships as follows. A developer borrows to pay its costs to develop or build a project. The developer contributes the development rights or project to a partnership and a money partner is brought in as the other partner. The partnership assumes the debt. The money partner will be allocated most of the economics, leaving the developer with only a carried interest.

The developer is distributed cash to reimburse it for its spending on the project in the two years before the partnership was formed.

Under the US tax rules, the money partner gets to include the debt the partnership assumed in its "outside basis." Its outside basis is a way of measuring what the partner contributed to the partnership and what it is allowed to take out. The additional outside basis gives the money partner more room to claim depreciation and other tax losses and be distributed cash without having to pay taxes on the cash.

Meanwhile, the developer may be able to receive the cash distribution / continued page 33

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tion credits, bill credits and rebates to customers. The total fund size was $23 million starting in 2011. The fund is authorized to support CHP systems less than 60 kilowatts in size.

The New Jersey Board of Public Utilities has two incentive programs. Incentives for CHP systems with installed capacities of up to one megawatt and that produce useful waste heat and achieve annual system efficiencies of at least 60% range from $1 to $2 a watt. An additional incentive of 25¢ a watt is available and paid on a performance basis. The incentives available for small CHP systems are effectively capped at $2.25 million per project.

CHP facilities larger than one megawatt in size are subject to a different incentive program. After the incentives are approved by the Board of Public Utilities, they are paid by check in stages (20% upon purchase of the equipment, 60% after installation and the remaining 20% after the first year of operation).

Developers are using master financing facilities originally developed for the solar rooftop market.

Financing

As with other forms of distributed generation, CHP can be challenging to finance due to its small size. CHP technologies vary in design, size, fuel source and prime-mover technology. During the heyday of PURPA, cogeneration facilities were coal- or gas-fired, the projects were large and the prime-mover was a combustion turbine or boiler and steam turbine. Today's CHP can be biomass-fired, use reciprocating engines and be sized and designed for individual industrial and commercial customers.

To the extent the small size of each facility is an impediment to financing, there are parallels in the rooftop solar market. As is the case with rooftop solar, CHP can be aggregated into portfolios. The key to this approach is repeatability. CHP owners will find it easier to arrange financing if all their facilities have similar technical designs, use similar customer agreements and have similar warranty coverage.

Most rooftop solar facilities are financed in the tax equity market. The developer enters into a master financing facility with a tax equity investor. These facilities may take one of three forms: a partnership flip, sale-leaseback or inverted lease.

In a partnership flip, the developer forms a partnership with the tax equity investor. The partnership takes assignment of the customer agreements and hires the developer to install the systems. The partnership will own the systems, supply electricity under power contracts to customers or lease the systems to customers and collect rents. It receives the tax benefits and allocates them largely to the tax equity investor.

In a sale-leaseback, the developer sells the systems to a tax equity investor within three months after installation and leases them back. The lessor claims the tax benefits and shares them indirectly with the developer in the form of a reduced rent for use of the systems.

In an inverted lease, the developer leases the systems to the tax equity investor and assigns the tax equity investor the customer agreements. The tax equity investor claims the investment tax credits on the systems. The developer keeps the depreciation and receives most of the customer revenue as rent from the tax equity investor.

All three structures are "master" financing facilities in the sense that the terms are spelled out in a set of master financing documents. Each month, the developer brings a file folder with the new customer agreement it proposes to sign. As each additional batch of projects is added, an additional schedule is added to the back of the master financing documents.

The financing facilities usually run $50 to $100 million in size but can be smaller. The tax equity investor agrees to finance up to that amount in equipment or to finance all systems that are presented through a date 12 to 18 months in the future, whichever is reached first.

Some states offer programs to offset the costs of CHP and fund those programs with revenue bonds. However, a state's bonding authority may also be used to fund the capital costs of CHP. To the extent the bonds are tax-exempt, the project sponsor will have to fit within the rules for "private activity bonds" or other programs designed to assist with waste disposal.

Barriers to CHP

The US Environmental Protection Agency said in a recent presentation that the potential market for CHP at existing industrial facilities is just under 65,000 megawatts with roughly an equivalent potential market for CHP at commercial and institutional facilities. What are the barriers to the further development of CHP?

The value proposition for utilities is not entirely clear. From a utility's perspective, CHP is similar to distributed solar. Both technologies reduce and change the load shape of the utility's customers. This becomes a problem for the utility as it relies on electricity sales to those customers. The conundrum for regulators is how to encourage CHP, with its benefit to the environment and potential overall benefit to utility customers, while still allowing utilities to earn necessary revenues.

Regulators faced similar issues in the context of efforts to increase demand-side management and in the era of retail deregulation. Both of these policies led to smaller electricity sales by utilities.

CHP can require a substantial capital investment. In some states, CHP owners sell both electricity and steam or waste heat to an industrial or commercial host. If a CHP owner builds a project to serve a host, then the CHP owner will be relying on the financial strength of that host. Thus, from a practical perspective, the CHP owner will be subject to the same economic pressures that affect the host's business. Some hosts will not be willing to commit to the CHP owner for a long enough term to allow recovery of the CHP owner's costs and expected margin or, even if the commitment is there, the host at some point may not be able to fulfill its commitment.

In cases where CHP owners sell electricity to a utility and steam or waste heat to an industrial or commercial host, the overall concern with the host's financial strength is blunted but not eliminated. State programs encouraging CHP often come with requirements for fuel use efficiency. If the steam host is lost, then the CHP owner may also lose the incentives or other support that allowed the owner to make the CHP investment in the first place.

There are still retail sale restrictions in most states that limit how a distributed CHP project can be structured. Fifteen states allow customers to choose their electricity suppliers. In other states, only the local utility can sell electricity at retail in its monopoly service territory. In such */ continued page 32*

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to reimburse it for its spending on the project before the partnership was formed tax free under something called a "pre-formation expense safe harbor."

The IRS believes it is double dipping to let the developer receive this cash tax free and set up the money partner also to receive the same amount of cash tax free because the debt that funded the spending has now been moved to its outside basis.

The IRS is expected to deny use of the pre-formation expense safe harbor in such cases to the developer. The cost reimbursement to the developer would not be tax free. Instead, the developer would be treated as having made a "disguised sale" of the development rights or project to the partnership for the money it was distributed. This is expected to be addressed in regulations on disguised sales that the IRS hopes to release later this year.

MINOR MEMOS: It would cost the US government $24.7 billion over 10 years in lost tax revenue to make production tax credits for wind, geothermal, biomass, landfill gas, incremental hydroelectric and ocean energy projects permanent as the Obama administration has proposed, according to a Joint Committee on Taxation estimate in May. Some wind industry lobbyists believe that Congress will extend the tax credits again in 2014 if it has not taken up corporate tax reform by then .... The Defense Department is expected to announce another round of military base closures in 2015. This could complicate efforts by various bases to sign up long-term contracts to buy electricity from renewable energy suppliers .... The difficulty ahead for corporate tax reform can be seen in the fact that the corporate revenue raisers in the budget that the Obama administration delivered to Congress in early April would add up only to $94.6 billion over 10 years. A 1% reduction in the corporate tax rate would lose $100.6 billion in revenue over the same period, according to the Joint Committee on Taxation. Both political parties want */ continued page 35*

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states, the CHP owner will have to lease the system to the customer rather than sell the electricity. However, leases do not work when dealing with customers who are government or tax-exempt entities because most of the federal tax benefits will be lost. More creative thinking is required for projects with such customers.

There are other regulatory issues to be considered. CHP facilities, while reliable, will not operate to serve a host's load 100% of the time. CHP is also unlikely to be sized in a manner that matches a host's load on a time-of-day basis. This means that the host will have to rely, to some extent, on the local utility. The cost of providing "standby service" (service to the customer or the CHP facility when the facility is not operating) or "supplemental service" (service for load in excess of the electricity produced by the CHP facility) is subject to state regulation and the pressures regarding loss of utility load discussed earlier. There may be resistance from the local utility to providing such service.

Further, unless the CHP facility is disconnected entirely from the utility grid, there will be interconnection and power scheduling issues for the CHP owner to consider. Finally, CHP projects can have interesting local permitting issues.

For example, even in states where thermal generation is regulated at the state level, CHP may not meet the capacity threshold requirements to qualify for centralized state permitting and, as a result, CHP may be thrust into a confusing maze of state and local permitting requirements. In California, for instance, while permitting for thermal generation in excess of 50 megawatts is governed by the California Energy Commission, smaller thermal generation is permitted at the county level. CHP is a thermal resource that will have air emissions and may require discharge of cooling water. Thus, regardless of whether land use is regulated locally, CHP facilities will still have to meet state and federal emissions and, potentially, effluent requirements. ◎

Power Contracts With The US Military

The US Army has embarked on a program to enter into $7 billion worth of long-term contracts to buy renewable energy for US Army bases. The other service branches have their own similar programs. There are special challenges when trying to finance a power project that sells its output under long-term contract to the military, especially if it is on land that the US government has given the developer a right to use on a US military base. Several veterans of financing government revenue streams under energy savings performance contracts and utility energy services contracts talked about the challenges at an Infocast conference on defense microgrids in Washington in April.

The panelists are Jonathan Yellen, managing director of global capital markets at Morgan Stanley, Anita Molino, president of Bostonia Partners, Tracey Gunn Lowell, vice president of renewable investments for US Bank, Scott Foster, senior vice president and managing director for federal operations at Hannon Armstrong, and Andy Redinger, managing director and group head at KeyBanc Capital Markets.

MR. MARTIN: Have you looked at the proposed US Army power contract and, if so, are there any show stoppers in what you have seen so far?

MR. REDINGER: We financed a wind project that was being used to supply electricity to the US State Department last year. I believe the contracts are similar. That project was not on a military base, so we did not have to deal with the problem that the military insists on a right to terminate its contracts for convenience. I think there are ways to get around such termination rights. If the contract is terminated for convenience, then the military should make a payment that will make us whole as a lender.

MS. MOLINO: I can't say I have studied the contract in depth, but it is pretty much what we expected. There are a whole host of issues. Termination for convenience is just one.

The Army is proposing a yield maintenance solution, which may or may not work. There is a ton of capital waiting to be deployed in this sector. The question is whether this capital is so anxious that it is willing to adapt to how the government insists on doing business. The government cannot violate the Anti-Deficiency Act. Its commitment to pay for electricity has to be subject to appropriations. There are a lot of issues on both sides, and the challenge will be how they all come together. We saw it happen very successfully in military housing, but we are not there yet on power contracts. Everybody is willing and everybody wants to try to get there, but there is a lot of work still to be done.

MR. YELLEN: We looked at one service department's form power purchase agreement. It is based on one that successfully attracted third party capital. The service department reached out to us and others to review the contract with an eye to financeability. The contract was blessedly simple when compared to contracts we see with investor-owned utilities. Key definitions and the schedules were redacted, but we had discussions with the department about termination for convenience and found a workable approach. The surest test of financeability is when a financing is completed with commercial entities like the ones who were involved in the prior project. The workable approach is for the military to compensate both the lenders and equity investors when the contract is cut short for convenience.

MR. FOSTER: The contract should acknowledge that a third party has an interest and is providing financing.

Termination for convenience is a concern. There are contracting officers who refuse to put a termination liability amount in a schedule. A perfect example is the US Air Force Davis-Monthan contract. The contract was unfinanceable. The only reason the deal got done was the North American Development Bank ended up doing it. It is going to take some flexibility by both the capital markets and the government as we work to make deals bankable.

MS. GUNN: We have seen a couple deals where the military had a right to terminate for cause, but "cause" covered a long list of items. We are waiting to see more of the top developers engaged in helping work through these issues.

Financing Terms

MR. MARTIN: You have a federal government credit behind the electricity revenues. How does that affect the cost of debt and tax equity for such deals?

MR. YELLEN: The federal government is clearly a very strong credit; maybe not as good as it was a couple of years ago, but it is still better than the utilities and other entities who sign up to buy long term power. The government as counterparty is a very strong positive and probably one of the reasons that many of us have been looking so closely at this sector.

There is a perception that these projects should be able to raise capital at the same cost as a federal borrowing. The reality is that a least-common-denomi- / continued page 36

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to reduce the tax rate significantly as part of corporate tax reform. The Democrats want to reduce the rate to 28% from the current 35%, and the Republicans want to reduce it to 25%. . . . . Congressional insiders put the odds of corporate tax reform in a poll by the *National Journal* in May as follows: excellent 0-1%, good 5-8%, fair 33-39% and poor 56-58%.

— contributed by Keith Martin and Amanda Forsythe in Washington

Military PPAs

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nator approach is applied to the project credit analysis. While the offtaker's credit is very strong, we still have all the operating and construction risks associated with a power project that brings the overall risk of the asset down typically to a low investment grade level.

MR. MARTIN: What is the premium to Treasuries for debt in this type of transaction?

MR. YELLEN: For assets like these that are structured well with long-dated, fully-amortizing financing against the PPA, assuming one can get past the termination for convenience clause and the other issues, you would probably be able to borrow for 25+ years at somewhere around 5 1/2% fixed.

MR. MARTIN: What spread would a borrower get with a securitization compared to a bank financing?

MR. FOSTER: A securitization requires volume. Assuming volume, if you use energy savings performance contracts as a guide, the spread would probably be 150 basis points over average-life Treasuries. It would be very cheap money. It is a well-developed market. What must happen is we need more volume with a consistent set of terms and conditions from one deal to the next.

We are much more comfortable with a federal government contract, if we can get the right terms and conditions, than we are with a commercial contract. The government can contract for up to 30 years. We are comfortable that the government will be around in the long term or we will have bigger problems. We are willing to do 20- and 25-year contracts with the government when we would limit the contracts to 10 and 15 years in a commercial setting.

MR. MARTIN: We are talking about two types of projects. There are the small utility-scale projects of 10 to 20 megawatts and there are rooftop solar installations, for example, on military housing. What sort of coverage ratio would you need for the debt?

MR. YELLEN: We have seen the bank and bond markets converge to approximately 1.40x coverage.

MR. REDINGER: I think the coverage ratios are between 1.30x and 1.50x, depending on size of the project, using P50 numbers.

MR. MARTIN: We have several financing options represented at this table: debt, tax equity and securitizations that are a form of debt. Which type do you think this market will gravitate toward? I would have thought tax equity, because you have 56% of the cost of the project being paid by the federal government through tax subsidies. That's the reason for third-party ownership structures where a power company owns the project and the military merely buys the electricity.

Financing projects on US military bases can be challenging.

MR. REDINGER: The financing strategy depends on who owns the project. Somebody who has a tax appetite obviously does not need to access tax equity, so it will finance projects differently than another developer who lacks tax capacity. The more important question is whether the projects will be able to attract equity. Lenders and tax equity investors want to see real equity investors behind them in the capital structure. The returns on these projects do not look high enough for the equity market.

MR. MARTIN: What do you think the returns will be?

MR. REDINGER: It is really hard to say. Every project is different. I suspect equity returns will be in the high single digits.

MR. MARTIN: These are small projects. Returns are low for the equity, so why chase them? I assume because you guys are ahead of the equity in the capital structure?

MR. YELLEN: That could be one reason. We are also chasing them at times because we may have a relationship with the developer, and the developer is doing other things as well that could be of interest.

Non-Appropriation Risk

MR. MARTIN: Anita Molino, you mentioned non-appropriation risk. Any payment from the federal government is subject to annual appropriations. How do you arrange long-term financing in the face of that risk?

MS. MOLINO: Very carefully.

We have spent decades educating the institutional investor market about what the risk is and isn't. With proper due diligence, investors can get comfortable. They will extract a premium for the risk, but that is not a huge concern because we have been dealing with non-appropriation risk for so many years in many different types of securitizations with the federal government.

MR. REDINGER: I agree with that. Due diligence is obviously critical, but non-appropriation risk is something that has been placed successfully in the market for decades. Deal volume is an issue. The stronger the forward calendar of deals and the more dependent the government is on its ability to continue to finance these projects, the less likely it will be to do something that will harm its ability to continue to secure financing.

MR. YELLEN: The analogy is often made to the military housing program, which was an extremely successful program over a period for more than a decade. It raised tens of billions of dollars and is probably the most successful global example of public-private partnerships, and it was done by the service departments within the US military, so it is a great model to follow.

Base closure risk is another issue that those deals often faced. Some of the early deals had guarantees to address it. The services were willing to take that risk and not put it on investors. Over time, as people got more comfortable that the risk could be quantified through diligence, it became an issue that investors would take. They would assign a price to the risk. In some extreme examples where there was a greater risk of a base closure, the government had to provide a guarantee. The experience showed there are ways to deal with even the most difficult risks.

MR. MARTIN: Scott Foster, Hannon Armstrong has had experience dealing with government paper over many years. What has the default rate been on your securitizations?

MR. FOSTER: We have not had any defaults. The transactions have been primarily energy efficiency transactions, energy savings performance contracts and utility energy service contracts. We also finance submarine fiber optic cable and information technology in aircraft. We get comfortable that the risk of the agency funding being cut off is minimal. Where we have more risk is non-renewal. Non-renewal is very different from non-appropriation. It is the risk the agency will decide not to extend the arrangement.

MR. MARTIN: What's the difference between an ESPC, or energy savings performance contract, and a UESC, or utility energy services contract?

MR. FOSTER: A UESC is similar to an ESPC, but there is usually no performance guarantee, and a utility is allowed to be the sole source the base approached for a contract if the base is within the utility service territory. The government can contract directly with a utility for demand-side management. The big difference between the two forms of contracts is that the military procurement regulations state clearly that ESPCs can have terms of up to 25 years while the permitted term for UESCs is somewhat grey. The procurement regulations say the permitted term is 10 years, but that has been interpreted as a UESC contract awarded to a utility can be valid for 10 years and then renewed, and the Department of Defense can grant special approval for terms of up to 30 years. Civilian agencies are limited to 10 years.

If you want to do power contracts with civilian agencies, you have to start thinking outside the box of how are you going to deliver green power at brown power cost and work with a contract limit of 10 years. Congress is unlikely to change the law to facilitate financings as was done with military base housing. We have imaginative people in the market. Someone will figure out how to do this.

Sequestration

MR. MARTIN: An admiral testified before Congress in March about the North Korean threat, and he was asked about the effect of budget sequestration on the military's readiness. How big an issue is sequestration for this market?

MR. YELLEN: It is having a near-term impact. I attended a conference in San Diego, and the Department of Defense personnel were not able to attend. From what we understand, a lot of their activities are considered administrative costs and have been curtailed. The longer-term impact is tough to assess at this stage.

MR. FOSTER: At least on the energy efficiency side in small renewables, we have not been affected yet by sequestration. We have actually seen the opposite of more deals coming through the pipeline because these transactions are budget neutral. The military would like there to be no net cost to the government. It wants PPAs to look a lot like ESPCs or UESCs and try to have the green power be at the same price as brown power, or close to it.

MS. MOLINO: I think we have started

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Military PPAs

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to see a bit of an effect from sequestration. These renewable energy projects require a lot of due diligence on the services side in terms of figuring out what projects to pursue, and we are hearing talk of some layoffs of contractors who do these evaluations. The result may be a slowdown in the program.

Termination for Convenience

MR. MARTIN: Scott Foster, you mentioned Davis-Monthan Air Force base. Most of us saw the contracts with the Air Force and figured that it was impossible to get the Air Force to agree to a termination value schedule showing what the Air Force would pay in the event it terminates the contracts for convenience. Why do you think any other service branch will do so?

MR. FOSTER: I think each contracting officer has discretion. Some will agree to such a schedule. We see it all the time in ESPCs and UESCs. We did two biomass transactions under ESPCs — one at Oak Ridge and one at Savannah River — and at Oak Ridge, the government took fuel risk, and at Savannah River, it refused to do so, with the result that the cost went up for that reason. I wish I could tell you that every deal is going to be the same from the top down, but I think there will be a lot of negotiation with the local base and contracting officer.

MR. MARTIN: Can you finance a project without a termination value schedule showing what the military will pay if the deal is cut short?

MR. FOSTER: No one wins if the deal is cut short. We would still need to be comfortable that the base needs our electricity for the full duration of the contract.

MS. MOLINO: I do not think such a project is financeable, or at least we would not consider it prudent to finance. There is no reason for the military not to agree to such a schedule.

Collateral

MR. MARTIN: These projects are built on military land. There may be a default at some point. How do lenders realize on their collateral? What is the collateral?

MR. REDINGER: It is no different than with any other project that we finance. We want access to that collateral, whether it is on a military base or otherwise. I cannot think of a project with the government where we have not had some issue on third-party consents allowing the lender to step into the developer's shoes to gain access to the collateral for whatever reason, and if we do not have that, it is a deal stopper for us.

I have been wondering how the military will deal with that, because I am sure it will have heartburn about just having any Tom, Dick or Harry roll onto US military bases to collect his collateral. This will have to be worked out as we move forward.

MR. MARTIN: If you're dealing with a utility-scale project, is it satisfactory just to be able to come on to the base and remove the equipment?

MR. REDINGER: Is that realistic? No. It is just one of those things that lenders require to check a box. Going onto the base and removing that collateral is not something that we would do in practice. We would want the ability to leave the project in place and sell it to someone else.

MS. MOLINO: We financed a solar array under an ESPC for the Army at White Sands, and there we had to do it on the basis of a site license, and it cost us a lot of legal fees to figure out how to get the project done. It materially shrank the universe of interested lenders. Lenders want their rights. They want the access, and the fact that access can be denied to them eliminates a lot of lenders.

Electricity Price Cap

MR. MARTIN: The Army would like to pay less for electricity under these RFPs than it pays the local utility. But you are talking about technologies that cost more to generate electricity than gas, which the local utility might be using. In addition, the Army wants the renewable energy credits that are supposed to bridge that gap to the developer. Suppose you enter into a 20- or 30-year contract. The electricity price is below what the military base is paying the local utility for electricity, but over time, the contract price becomes higher than the local retail rate for electricity. Do you worry about the political risk that the contract will be cancelled?

MR. FOSTER: All you can do is try to end up with good terms and conditions from the perspectives of both parties so that the power contract can withstand that type of test. ◎

Shale Gas In China: How Far From Dream To Reality?

by Edwin Lee, in Beijing

Shale gas has become one of the hottest topics in the Chinese energy market since the country's first round tender for shale gas exploration in June 2011.

At the end of 2011, the State Council decided to regulate shale gas as an independent mineral from other oil and gas.

The sector has attracted interest from state-owned enterprises, especially those in traditional oil and gas, the coal mining and power industries as well as from private companies and foreign investors. The sector feels on the verge of a boom.

The Chinese government has been watching the shale gas boom in the United States and does not want to be left behind. It has been holding out incentives to shale gas producers in the form of tax benefits, grants and easy access to cheap credit. This has created great interest in the sector, but many of the companies crowding in have no technologies and little experience with shale gas.

Large Potential Reserves

According to a 2011 report by the US Energy Information Agency called "World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States," China has 107 trillion cubic feet of proven natural gas reserves and is one of only five countries with proven natural gas reserves of more than 100 trillion cubic feet. The other four countries are the United States, Australia, Algeria and Venezuela. The amount of technically-recoverable shale gas in China is 1,275 trillion cubic feet, 50% more than the 862 trillion cubic feet in the United States.

Chinese official figures differ from the US estimates. A paper by the CNPC Economics and Technology Research Institute in July 2012 estimates that the recoverable shale gas in China is 36.0825 trillion cubic meters (equivalent to 1,275 trillion cubic feet), around 20% of the world total proven reserves of 187 trillion cubic meters (equivalent to 6,607.77 trillion cubic feet). The figure quoted in this report is similar to the EIA estimate.

However, in March 2012, the Ministry of Land and Resources (MLR) said in a report that the recoverable shale gas in China is only 25.1 trillion cubic meters (equivalent to 886.93 trillion cubic feet). This conservative estimate is still more than the reserve of 862 trillion cubic feet in the United States. The shale gas development plan (2011-2015) issued by MLR in the same month repeats this estimate.

By April 2012, 58 shale gas wells had been completed in China. The first well, Yuye Well 1, was drilled in Pengshui, Chongqing in 2009. By contrast, thousands of shale gas wells have been drilled in the United States. The few operating wells in China make the reserve estimate less reliable.

Most of the on-shore shale gas is in the following five areas: the Upper Yangzi, Dian, Qian and Gui region, the Middle and Down Yangzi and South-East region, the North China and North –East region, the North-West China region and Qing Zang region. The Upper Yangzi, Dian, Qian and Gui region and the North China and North-East China region have around 46% and 20% of the total shale gas reserves in China respectively. The national oil companies (CNPC, Sinopec and CNOOC) are holding large blocks with shale gas potential there.

In terms of provincial distribution, Sichuan, Xinjiang, Chongqing, Guizhou, Hubei, Hunan and Shaanxi provinces or municipalities are relatively rich in shale gas and have nearly 68.8% of the total resource in the country.

In the two rounds of public tenders for 26 shale gas blocks in 2011 and 2012, the MLR did not provide any geological information or surveys to bidders. The information does not exist yet.

Planning

The national shale gas development plan (2011-2015) establishes the following targets by 2015: a complete national survey of shale gas reserves, selection of 30 to 50 proven shale gas areas and 50 to 80 favorable target areas, and production by 2015 of 6.5 billion cubic meters (229.52 billion cubic feet).

The plan lists 19 shale gas areas for exploration: Changning, Weiyuan, Zhaotong, Fushun-Yongchuan, Er West and Yu East, Chuan West-Langzhong, Chuan North-East, Anshuan-Kaili, Jiyang, Yanan, Shenfu-Lingxing, Qinyuan, Shouyang, Wuhu, Hengshanbao, Nanchuan, Xieshan, Liao River North and Cengong-Songtao. The shale gas blocks for the coming third round public tender are expected to be mostly in those areas. The plan also commits to increase the investment in shale gas exploration in these areas during the period 2016 through 2020 if there has been a breakthrough in exploration technology. Shale gas production is expected to reach 60 to 100 billion cubic meters by 2020. Compared to the US target of 250 billion cubic meters by 2020, China's output is / *continued page 40*

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expected to be much smaller due to the late start and shortage of technologies.

Growing environmental concerns in China and scarcity of water are potentially limiting factors.

Some experts believe that the 2015 targets will be difficult to achieve. The main challenges are limited access to technologies, complex geological conditions (compared to the US), regulatory conflicts and weak infrastructure such as pipelines and liquefaction terminals.

On the other hand, the state-controlled oil companies are bullish. CNPC estimates that it will produce 1.5 billion cubic meters and Sinopec estimates 0.13 billion cubic meters. One local government, Chongqing, is planning to drill 150 to 200 shale gas wells by 2015 whose annual production will be 1.3 to 1.5 billion cubic meters. These plans could account for almost 50% of the national target of 6.5 billion cubic meters by 2015. The other local governments' plans are still works in progress. One official in the MLR said that the estimate of 6.5 billion cubic meters is conservative.

Even if the 2015 targets are reasonable, the 2020 targets seem more ambitious. Some experts think that production will reach around 11 billion cubic meters by 2020, less than coal-bed methane production of 17 billion cubic meters. Realization of the 2020 target will require drilling 20,000 wells and US$65 to $100 billion for drilling and other infrastructure.

Time to Jump into the Pool?

Both wholesale and retail natural gas prices are regulated by the National Development and Reform Commission (NDRC). The residential use natural gas price is three times higher than in the US. For example, in Beijing, the current residential use natural gas price is RMB2.28 (US37¢) per cubic meter compared to roughly US14¢ per cubic meter in the United States. Although gas producers and importers such as PetroChina are facing huge losses in the upstream business, the government is reluctant to let them raise the downstream price for fear of a public backlash.

Shale gas investors will need to predict the gas price level in the future when any gas they produce will be brought to market. The natural gas pricing system is expected to undergo reforms with the goal of raising the price. Some gas producers in China are exporting gas even though the domestic gas demand cannot be met, in order to press policymakers for a domestic price increase.

Due to geological differences, gas wells cost 10 times more to drill in China than in the US. The drilling cost per shale gas well in the United States is between $2.7 million and $3.7 million compared to $27 million to $37 million in China.

The funding requirement for 20,000 wells by 2020 will be RMB400 to 600 billion (approximately US$65 to 92 billion). Regulators are hoping to spread the licenses in order to attract funding from more sources. In the first round shale gas tender, PetroChina and Henan CBM [coal-bed methane] were awarded licenses in exchange for funding commitments of RMB800 million. In the second round, 16 winning bidders agreed to contribute RMB12.8 billion by 2015. The majority of the funds will be used for drilling wells and related exploration activities. The winning bidders in the first two rounds included only two private companies and the rest are national or local state-owned enterprises. The state-owned enterprises are not expected to face funding challenges because of their easy access to cheap loans from Chinese state-owned banks. In the longer term as more private and foreign investors engage in the sector, there will be more concern about their financial strength and willingness to endure since they will have high capital spending initially without making a profit in a short term.

Demand for natural gas is expected to grow rapidly in the coming years in China, and the gap between demand and supply will widen. Shale gas will be needed. The growing demand for gas is being driven by a number of factors. First, air pollution is becoming of greater concern; a shift to gas helps. Coal-fired power plants and community heating plants in urban areas are being converted to run on gas. In Beijing, 263 turbines at coal-fired power plants will be replaced by gas turbines by the end of 2014. In Zhengzhou, the capital of Henan province and around 680 kilometers south of Beijing, 145 such turbines will be replaced by gas turbines. Other cities, such as Lanzhou and Xian, are also formulating their conversion plans. Second, a continuing trend toward urbanization in China will increase the number of residential gas consumers. Third, the amount of gas used to run autos and factories will increase. Chinese natural gas consumption is roughly 165 billion cubic meters in 2013, but it is expected to reach 350 to 400 billion cubic meters in 2020 and 500 to 550 billion cubic meters in 2030.

Technology

The technologies used to extract shale gas in the United States may not work in China. The geological conditions differ in China.

Most Chinese shale gas is found at 1,500 to 4,000 meters below ground in Sichuan compared to 800 to 2,600 meters in the United States. New technologies may have to be found for use in China.

Horizontal well and fracking technologies used by American companies have been tried in China. Both technologies are controlled by foreign companies. PetroChina has cooperated with such companies as Shell, Chevron, Halliburton and Schlumberger, in different blocks, in order to learn about the technology.

Chinese companies seek any opportunity to acquire intellectual property from foreign partners. In 2012, three national oil companies completed major overseas acquisitions that were closely connected with shale gas. Sinopec acquired a 33.3% interest from Devon Energy in five shale oil and gas basins and said in March 2013 that it is looking for other overseas shale gas assets to acquire. CNOOC closed on a $15.1 billion takeover of Nexen, which holds shale gas assets in Canada. PetroChina acquired a 49.9% interest from Encana in the Duvernay shale gas project in Canada.

Shale gas recovery in China is about to expand rapidly.

Environment

Water consumption, wastewater treatment, greenhouse gas emissions and other environmental pollution are being raised by opponents of shale gas development.

Water consumption will be a challenge since China is a country badly lacking in water. According to a report by Accenture, a consultancy, drilling and fracking will consume around 19,000 tons of water per well. Except for the Sichuan and Jianghan Basins, all the other shale gas accumulation areas overlap with water shortage areas. For example, in north Western and northern China, underground water must be extracted first and then injected back into the shale gas wells. The polluted surface water is not useable. The vast amount of extraction of underground water will reduce the water table and could lead to salt-water encroachment.

Water pollution is another major concern. The water injected into shale gas wells is accompanied by around 700 kinds of additives and poisonous materials, such as lead. This could cause pollution of underground water. Even under the strictest and most advanced environmental regulation in the US, such pollution seems inevitable. Very tough environmental regulation is expected in China as China tries to learn from the US experience.

The "shale gas curse" is another headache for gas producers. In the United States, producers would like to flare the extracted gas during periods when low gas prices and high transportation costs make gas uneconomic to produce. This is an alternative to shutting in wells. Flaring will not be an option in China in the next five to 10 years. But potential gas producers in China may have no alternative if the infrastructure, such as pipelines and liquefaction terminals, are not ready when the gas wells come on line. PetroChina and Sinopec are concentrating on construction of pipelines in order to control a potential bottleneck for other producers. During the exploration period, some flaring of gas is inevitable. However, the air pollution from carbon dioxide and methane emissions during exploration have shocked investors and environmentalists.

Earthquakes are another potential nightmare for shale gas development. Some countries, such as France, Bulgaria and Switzerland, have held shale gas producers at bay due to concern about the potential for induced earthquakes. Even in the United States, the state of New Jersey still bans fracking for natural gas. In May 2008 and again in April 2013, earthquakes occurred in Sichuan which is believed to be the richest area of shale gas.

Regulations

Regulation of the shale gas industry is jointly undertaken by at least six authorities at ministerial level, including the National Development and Reform Commission (NDRC), Ministry of Land Resources (MLR), Ministry of Finance (MOF), Ministry of Environmental Protection (MEP), Ministry of Science and Technology (MOST) and the State Administration of Taxation (SAT).

The challenge will be how to get so many regulators on the same page.

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NDRC is responsible for shale gas industrial policies and planning, including targets, transportation, consumption and pricing. MLR is in charge of public tenders of shale gas blocks and the thresholds for entry. MOF and SAT work jointly on fiscal incentives, such as grants and preferential tax policies. MOST runs a program for improving and inventing technologies that work in Chinese geological conditions. MEP will also play a significant role because of its responsibility for underground and surface water protection, wastewater treatment and recycling, air pollution and protection of species of animals and plants.

The government will also have to address legal issues with overlapping of shale gas blocks with traditional oil and gas blocks. To date, China has issued only two or three rules about shale gas. Shale gas producers are looking for guidance otherwise to regulations on producing coal-bed methane. Coal-bed methane was an area of great interest to domestic and foreign investors from the 1990s until three or four years ago when investors decided the government would not solve the problem of overlapping rights to coal miners and coal-bed methane producers. Shale gas will have the same problem. The national oil companies hold the rights to most of the high potential oil and gas blocks, including some that overlap with shale gas blocks. It is one reason that they did not participate in the second round tender last year.

There is also uncertainty around a short-term grant program for shale gas. Chinese national and local government grants are only available for shale gas between 2012 and 2015. The national government offers cash grants of RMB0.4 (about US6.5¢) per cubic meter. Local governments may supplement the national grant. Blocks in the first two rounds of tenders will not be in production by the end of 2015.

Notwithstanding all of the issues, foreign investors are welcome in the shale gas sector. The third round public tender for shale gas is expected to be announced in the second half of 2013. The aggregate size of the blocks offered in round three may be more than the total size of 24,236.77 square kilometres in the first two rounds. Although no foreign investors were awarded blocks, directly or indirectly, in the first two rounds, the Chinese government has made the participation thresholds clear: participation by foreign investors must be through a sino-foreign equity joint venture in which a Chinese party holds a majority of the shares, with at least RMB300 million of registered capital, and the venture or the partners must have experience in oil or gas exploration.

Most major foreign oil and gas companies prefer to enter into product sharing agreements or PSAs. They have been using the PSA model for Chinese oil fields since coming to China years ago. A shale gas PSA between Shell and CNPC was approved by the Chinese government on March 27 this year for drilling in the Fushun-Yongchuan block in the Sichuan Basin. This is the first PSA approved for foreign involvement in the shale gas sector. Shell will contribute its technology and operating expertise in an effort to reduce the drilling cost per well from $12 million to $4 million. This block is viewed as the first commercial shale gas project in China. Shell committed to contribute $1 billion at a minimum each year of the joint venture to fund exploration. An advantage of the PSA model is that Shell can exit easily without having to go through a complicated approval procedure.

The other oil giants like Statoil, ConocoPhillips, BP, Chevron and Exxon Mobil have signed joint study agreements with Chinese national oil companies. Following Shell's PSA, these giants will probably pursue the PSA model by transforming their study agreements into PSAs.

Another approach to entry is to acquire or enter into a cooperation agreement with a local oil or gas field service provider. The well drilling and completion service market is expected to grow in the next five to 10 years from the current RMB100 billion to RMB180 billion in 2015 and RMB400 billion in 2020.

The Path Forward

The European Union has been proceeding cautiously to embrace shale gas, and Aleksey Miller, CEO of the Russian gas giant Gazprom, believes that shale gas is a "soap bubble" and will burst soon. The Russian government appears not want to follow the American "seducement." In contrast, China, the country with the largest energy consumption, is keenly interested in any brand new programs proposed by the US in sectors like coal-bed methane and shale gas. China wants energy supply security. Its weak innovation capability requires that it try to learn from what others are doing.

Shale gas is a great opportunity for investors, but it poses more challenges and risks for China. Fresh water, clean air and a healthy environment are becoming significant political issues in China. Before tumbling headlong into rapid development of shale gas, China needs to do more homework into the technology, environmental protection, incentive policies, shale gas licensing reform and infrastructure construction. It needs to avoid the same mistakes as in renewable energy, where a rapid expansion of the sector was followed by overcapacity. There is still a significant distance to go from dream to reality. ◎

More US Gas Exports Approved: What Next?

by Donna J. Bobbish, in Washington

The US Department of Energy signaled that it would proceed cautiously before approving any more applications to export US-produced liquefied natural gas after granting only the second export license in May.

The question of how much LNG should be exported has become a difficult political issue in the United States.

Advances in natural gas drilling techniques, principally hydraulic fracturing or "fracking" that allows production of natural gas from shale, have led to dramatic increases in US natural gas production. US natural gas production is increasing faster than US natural gas demand, causing natural gas prices to decrease. Because natural gas prices currently are higher outside the US, domestic natural gas producers and project developers are looking at projects to export domestically-produced LNG. Meanwhile, the US manufacturing sector and other natural gas users are hoping to benefit from low gas prices. Unresolved environmental issues also remain in play.

The Department of Energy granted the developers of a liquefaction and export facility planned at the existing Freeport LNG import terminal in Texas conditional authority on May 17 to export domestically-produced LNG on a long-term basis to countries with which the United States does not have free trade agreements requiring "national treatment" for trade in natural gas. "National treatment" for trade means treating an imported product the same as a locally-produced one once it enters a market.

This is only the second such order issued by DOE since 2011.

More than 20 other applications for export licenses are still pending.

DOE conditionally authorized the Freeport project to export LNG equivalent to up to 1.4 billion cubic feet of natural gas a day for 20 years.

The agency said Freeport had introduced substantial evidence projecting a future supply of domestic natural gas sufficient to support both the proposed export authorization and domestic natural gas demand with only a modest increase in the domestic market price for natural gas through 2035. DOE said Freeport had also shown that the exports would produce significant local and regional economic benefits in terms of employment and income.

DOE Role

Section 3 of the Natural Gas Act requires DOE approval before natural gas can be exported from the US.

Exports to countries with which the US has free trade agreements that require national treatment for trade in natural gas are considered automatically in the public interest, and applications for such exports must be approved without delay or modification.

The US had such free trade agreements with 18 countries as of the end of October 2012: Australia, Bahrain, Canada, Chile, Colombia, Dominican Republic, El Salvador, Guatemala, Honduras, Jordan, Mexico, Morocco, Nicaragua, Oman, Panama, Peru, South Korea and Singapore.

DOE granted Freeport authorization to export LNG to such countries in 2011.

Authorization to export LNG to countries without such free trade agreements requires DOE to find that the proposed exports are not inconsistent with the public interest. In making this determination, DOE considers the domestic need for the natural gas proposed to be exported, whether the proposed exports pose a threat to the security of domestic natural gas supplies and other factors bearing on the public interest.

DOE granted the Sabine Pass LNG export terminal in Louisiana conditional authority in May 2011 to export LNG equivalent to up to 2.2 billion cubic feet of natural gas a day for 20 years. The agency granted Sabine Pass final authority in August 2012 after an environmental review of the Sabine Pass project had been completed and the Federal Energy Regulatory Commission had granted the project developers authority to construct the project. DOE rejected a challenge to its final Sabine Pass order by the Sierra Club in January 2013.

The agency said in early in 2012 that it would not process the other pending applications for export authority until the second part of a DOE-commissioned LNG export study had been completed and fully reviewed. The study was completed in December 2012, and then there was a period through February 2013 for public comment, after which the agency said it would act on the pending applications based on the order they were received by DOE and the applicants had started the separate approval process at the Federal Energy Regulatory Commission for permission to construct. It published a list with the applications by name and where each sits in the queue.

The Freeport application was the next in line after Sabine Pass.

Freeport

Only the American Public Gas Association, */ continued page 44*

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whose members include publicly-owned gas distribution systems, public utility districts and other public agencies that purchase natural gas, objected to the Freeport application.

Much of the Freeport order focused on DOE's analyses of the LNG export study and of the comments filed in response to the study.

The first part of the study was done by the US Energy Information Administration, which is an independent agency within DOE, and it examined the potential impact of additional natural gas exports on US energy consumption, production and prices under several export scenarios. It said export of US LNG will lead to higher domestic natural gas prices, increased US natural gas production, reduced US natural gas consumption and increased natural gas imports from Canada via pipelines.

In the second part of the study, NERA Economic Consulting examined how LNG exports would affect the US economy. It said the net effect would be positive in that US gross domestic product would increase, but households and industries that use natural gas would have to pay more for gas.

DOE said, in granting the Freeport license, that it also considered the international consequences of its decision and the US commitment to free trade.

Freeport's authority to export is subject to several conditions, including that Freeport must begin exporting within seven years. The deadline is May 2020.

Freeport asked for authority to export for up to 25 years, but DOE said "caution recommends" limiting the conditional export authority to 20 years because the customer contracts Freeport submitted with its application were for 20 years and that is the same period that DOE authorized for Sabine Pass.

The Freeport export authority is conditional, pending satisfactory completion of environmental review of the project by FERC and DOE, after which DOE will issue a final order.

Freeport still must get authority from FERC to build and operate the gas liquefaction and export facility at the existing Freeport LNG import terminal on Quintana Island, Texas. It filed an application with FERC in August 2012.

Freeport also has pending before DOE a second application to export another 1.4 billion cubic feet of gas a day to countries with which the US does not have free trade agreements requiring national treatment for trade in natural gas. Freeport's second application is third in the DOE queue after applications by the Lake Charles and Dominion Cove projects.

Outlook?

After granting Freeport conditional authority to export, DOE "hastened to add" that it will take a "measured" approach in granting Freeport final approval and in reviewing the other pending applications to export.

DOE gave three reasons for taking a cautious approach to future export applications. First, the LNG export study, like any study based on assumptions and economic projections, is inherently limited in its predictive accuracy. Second, applications to export significant quantities of US-produced LNG are a new phenomena with uncertain impacts. Third, the natural gas market has experienced rapid reversals in the past and is again changing rapidly due to economic, technological and regulatory developments. DOE said it intends to monitor developments in natural gas markets that could undermine the public interest if it authorizes additional exports.

The US is working one at a time through more than 20 applications to export LNG.

DOE said that it will assess the "cumulative impacts" of each succeeding export application on US natural gas supply and demand. It said it would attach terms and conditions to future export authorizations to ensure that they are used in a timely manner and refrain from granting permission to export except in cases where the applicant can show that it will have the export terminal up and running within a reasonable time after the authority to export is granted.

Several people who filed formal comments on the LNG export study urged the government to phase in exports over time to minimize potential price impacts. DOE said that while it was not adopting a formal phase-in schedule, it would consider the comments in the course of reviewing future LNG export applications.

The new energy secretary, Ernest Moniz, who was sworn in May 21, said during his confirmation process that he would undertake his own review and analysis of the LNG export study with an eye to whether the data in the study is already outdated before moving forward with the other applications.

Bills have been introduced in both houses of Congress by members who favor allowing more gas exports to direct the Department of Energy to treat gas exports to a longer list of countries as automatically "consistent with the pubic interest."

One bill, S. 192 in the Senate, was introduced by 11 Senators from Alaska, Louisiana, North Dakota, Oklahoma, Texas, Wisconsin and Wyoming in January and would authorize exports to member countries of the North Atlantic Treaty Organization and Japan. It would also give discretion to the US secretaries of state and defense to add to the list.

No action has been taken on the bill in the Senate. A companion bill, H.R. 580, was introduced in the House. ◎

Commercial Microgrids: The Next Big Thing?

The trouble that utilities have had maintaining service during hurricanes and other major storms has led to a renewed interest in microgrids — small communities that can generate their own electricity and avoid blackouts during periods when the grid is down as well as save money by buying power during off-peak hours while generating their own electricity during peak hours. How widespread are microgrids? How great a threat are they to traditional utilities? A group of panelists talked about these and other issues at an Infocast conference on commercial microgrids in Washington in late April.

The panelists are Mark Crowdis, president of Think Energy Inc., Michael Kornitas, energy conservation manager for Rutgers University, Brian Patterson, chairman of Emerge Alliance, Jeff Seidel, director of capital expenditures for the Mohegan Tribal Gaming Community Authority, Dr. Mohammad Shahidehpour, professor and director of the Robert W. Galvin Center for Electricity Innovation at the Illinois Institute of Technology, and Phil Smith, director of federal project development for Honeywell Building Solutions. The moderator is Keith Martin with Chadbourne in Washington.

MR. MARTIN: Is there a difference between a "microgrid" and just generating your own power? Paper companies used to generate their own power.

DR. SHAHIDEHPOUR: Microgrids are nothing new. If you go to most villages in the third world, they have a diesel generator and it is not connected to any state grid. Microgrids were in existence for many years, but now people are using smart systems to manage the load more intelligently. Microgrids are different because now there are data and control systems that make microgrids a lot more efficient.

MR. MARTIN: Will we see more communities in the United States with their own grids and their own power supplies?

MR. CROWDIS: I have a client in Hawaii who is hopping mad with the local utility. It is entirely possible for small communities to disconnect from the grid in the higher-cost markets.

MR. MARTIN: Will those communities be regulated as utilities?

MR. CROWDIS: They would have to be. However, there is a size issue. One of our clients is Anguilla, which has a 10-megawatt average demand and 15-megawatt peak demand. On a small island like Anguilla, a community disconnecting from the grid would have too small a load to make it economic.

MR. KORNITAS: We are more likely to see a move to distributed generation on a massive scale that will give rise to individual homeowners as generators. It will follow the model of the internet. There will be some large entities and some small entities.

MR. PATTERSON: Distributed generation and the internet have the same characteristics. Your laptop manages its own power and can be on the grid or off the grid. It can run your USB light and all kinds of other things you can plug into it. The only thing that prevents you from doing that today with power is regulations about crossing rights of way and things like that. Without such regulations, when the solar system on your roof is not being used fully, you could sell the spare electricity to your neighbor.

DR. SHAHIDEHPOUR: We struggle with that issue in the Chicago area. The reason universities can do fancy things is because we own the grid. Everything is behind the meter. About 60 communities in the Chicago area over the last year have formed community choice operations. The struggle is that they do not own the grid. If they want to connect any item to the system, they have to have the utility's permission. That permission is going to be a very long time coming. They try to operate as virtual

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microgrids managing their loads without controlling the electrons, but it will be an uphill battle.

MR. MARTIN: What is a virtual microgrid?

DR. SHAHIDEHPOUR: A virtual microgrid is basically where you do not own the generation or the grid. You only own the load, and you manage the load.

A true microgrid must be able to be operated as an island. You have to own the generation and these entities do own generation, but in order to get the power to the load, they have to go through wires that they do not own. In many cases, the utility is in favor of letting them manage the wires.

MR. PATTERSON: That model is going to change because you have a lot of people who can climb utility poles today and are already well equipped to move low and even medium voltages. It all comes down to policy. We saw the same thing happen with telephones when the publicly-granted monopolies existed, and the incumbent telephone companies said you cannot use our telephone lines and you have to operate under our rules. There was a battle between the Federal Trade Commission and the Interstate Commerce Commission, and the Federal Communications Commission broke that deadlock. We might see a similar battle soon.

MR. KORNITAS: Even if a community is an island, it would still need to be connected to the grid in case the microgrid's power goes out so that it can pull power from somewhere else to keep equipment running.

Different Models

MR. MARTIN: I want to establish how many different models of microgrid there are. Princeton and Rutgers operate basically as islands and generate electricity for themselves. What other models are there?

DR. SHAHIDEHPOUR: Microgrids are either connected to the grid or not. If a microgrid is in the middle of nowhere, then it is obviously operated as an island. If it is in a metropolitan area, then it is often connected to the grid, even though it is run as an island. In our university's case, we only run our microgrid as an island for liability reasons. We do not operate the system as an island for economic reasons.

MR. MARTIN: Is there any place in the United States where a microgrid can operate today involving an entire community without being a municipal utility?

MR. PATTERSON: There are several if I am not mistaken. They are identified in the book Perfect Power. There are other experiments that are being managed by the Electric Power Research Institute that involve more than one building or campus.

Northern Power Systems created a system that uses wind, solar and diesel at the North Pole for a weather station. That little system ran on its own. To me, a microgrid is something that can work independently of the utility grid.

In most cases, you are not going to be able to connect to the grid as a whole community unless you are a municipal utility.

MR. MARTIN: Is anyone aware of a movement to try to relax the regulatory restrictions in any states to allow broader microgrids?

DR. SHAHIDEHPOUR: It is not going to happen soon because the appeal of the business model is too limited. You have to convince utilities that there is something in it for them to promote microgrids. Some utilities are proactive, but overall it will be difficult to convince utilities to facilitate taking a chunk of the load away from them.

MR. CROWDIS: Utilities might find microgrids appealing in cases where the utilities would otherwise have to make large repairs or upgrades to their transmission systems. A utility might embrace a microgrid if it can avoid having to invest additional dollars in the transmission system.

DR. SHAHIDEHPOUR: Many businesses in the Chicago area have backup power. If everybody has a backup generator, the marginal cost of operating that system is significantly more expensive than starting a microgrid where you have a coordinated way of controlling the electricity flow in the region. At some point utilities are going to see that it is to everyone's benefit to have microgrids, but it will be a while.

MR. CROWDIS: Economics will drive policy. There will come a day when utilities in the US will conclude it is uneconomic to serve certain areas. They will realize that re-stringing power lines every other year in problem areas is a costly pain so a microgrid might be better.

Existing Microgrids

MR. MARTIN: Jeff Seidel, do you already generate your own power for the Mohegan casinos?

MR. SEIDEL: We generate some electricity, but not a lot. We are looking at generating more. The issue is whether we can produce the power more cheaply then we can buy it. Our load maxes out at about 28 megawatts in the summer for our largest casino. We can only generate about eight megawatts from back-up generation and fuel cells today. We want to expand, but it has to make sense with the heating systems. If we expand, it will probably be with more cogeneration.

MR. MARTIN: Michael Kornitas, the load at Rutgers University is more than 20 megawatts?

MR. KORNITAS: We have a 13-megawatt cogeneration plant, and we just added a 1.4-megawatt solar facility and an 8.8-megawatt solar array that is over our parking lots. We produce a lot of our power, but we also buy power to cover the load. The solar covers 65% of one of our campuses and the cogeneration facility covers quite a bit of the other. We dispatch our energy based on economics. Sometimes it is cheaper for us to buy electricity from the grid than to generate it.

MR. MARTIN: We heard immediately before this panel that Princeton University is managing its purchases from the grid not only based on price but also based on its environmental goals. It tries to manage its power supplies to limit the amount carbon dioxide its electricity usage is responsible for emitting. Is Rutgers doing the same thing?

The trouble utilities have maintaining service during major storms is spurring interest in microgrids.

MR. KORNITAS: Yes. We have a memorandum of understanding with the US Environmental Protection Agency under which we agreed to send EPA our greenhouse gas data in six-month intervals. We monitor the effect our electricity usage has on emissions closely.

MR. MARTIN: Are you thinking of adding more generating capacity?

MR. KORNITAS: Yes. We are looking at this currently, but the key is whether it makes economic sense. We have to look at both environmental and economic factors. We are looking now at a natural gas fuel cell which is basically cogeneration on a different level. The fuel cell would not have variable output, but it could be part of the base generation.

MR. MARTIN: Do you own the solar systems on your campus? Or does a solar company own them and lease them to you or just sell you electricity under a long-term power purchase agreement?

MR. KORNITAS: We own the 1.4-megawatt solar facility. We lease the 8-megawatt solar array and the amount we get for the solar renewable energy credits covers the rent to the lessor.

MR. MARTIN: The SRECS cover the full rent despite the fact that they fluctuate in value over time? What are SRECs worth today in New Jersey?

MR. KORNITAS: About $110 a mWh.

MR. MARTIN: $110 now, but the long-term outlook is a little murky, right?

MR. KORNITAS: Yes, but we were very conservative with our numbers, so we feel we will be okay for the life of the facility.

MR. MARTIN: Dr. Shahidehpour, what is the total load for the Illinois Institute of Technology?

DR. SHAHIDEHPOUR: The total load is about 12 megawatts. The total generation is about 10 megawatts. We buy some power, and we do demand response and load control. Eight megawatts of the generation is gas, and the rest is from a mix of solar, batteries and wind.

We are looking into adding more storage. One issue is that in northern Illinois, the price of electricity at night is negative because of the local nuclear facilities. So it makes economic sense to have batteries available. You basically get paid to charge the batteries and then you get paid to discharge them. Right now we have a ZBB or zinc bromine battery on campus that we use to provide frequency regulation services to the PJM grid.

MR. MARTIN: So you provide ancillary services to the grid and you earn money.

DR. SHAHIDEHPOUR: We are looking at other generation options as well, like geothermal. There is a good chance we will add geothermal, but the option in which I am most interested is batteries.

MR. MARTIN: Philip Smith, I think of Honeywell as a contractor. Do you also generate your own electricity on some of your campuses?

MR. SMITH: Not too often. I mentioned earlier a project in which we are involved at the US Food and / *continued page 48*

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Drug Administration headquarters. Honeywell installed a cogeneration unit on the FDA campus and is paid a percentage of the energy savings each year under a long-term energy savings performance contract, which is our core business. It was a new campus development, and we were able to finance construction of the CHP plant by borrowing against the future energy savings performance payments.

We went from what was originally planned to be a thermal-only central plant to a cogeneration plant that distributes hot water for comfort heating. There is still a conventional chill water plant, although we introduced some absorption and chillers into the mix and then we provided for the backup power. The original driver was power reliability. We run in parallel with the grid. We are generally in a net export mode with the grid, but we do thermal load following in the economic model. We are now an energy-only resource on the PJM grid, so we get locational marginal pricing for what we put on the grid and it shows up as a credit on the federal government's overall utility bill for the area.

Relationship with the Grid

MR. MARTIN: Why would it make sense to disconnect from the grid? I did not hear any of you say you are disconnecting from the grid. Is anybody backing off the grid entirely?

DR. SHAHIDEHPOUR: We do it only for reliability reasons. If the area is in an outage, we can keep our lights on by disconnecting the campus and turning it on as a microgrid. We have divided the campus into seven loops, and each loop is connected to one of the substations. Each loop is equipped with S&C Vista switches that allow the campus to disconnect almost instantly after detecting a fault in power supply. Ever since we have done that, we have had no downtime on campus.

MR. MARTIN: Michael Kornitas, does Rutgers ever supply excess electricity to the grid?

MR. KORNITAS: No, we do not. We use all the electricity we produce on campus.

MR. PATTERSON: A microgrid allows you to articulate power in a different way than when you are connected or having to use the common denominator of an interconnected grid. To the extent that you are disconnected or isolated, you can set different quality parameters for the power you generate or store. For example, data centers require a different quality of power, and that is one of the reasons that data centers are largely isolated from the line-voltage power.

Opportunities

MR. MARTIN: In terms of opportunity in this sector, I heard there is an opportunity to add more storage and more generating capacity in the form of solar, fuel cells, geothermal heat pumps and CHP or cogeneration facilities. Are these the main opportunities in this sector?

MR. CROWDIS: I think solar, storage and wind are opportunities. We worked for about six years on microwind projects. I am not completely convinced that those things can work, but large wind projects on site will become more attractive over time if they can be combined with storage.

When we talk about microgrids here in the United States, disconnecting from the grid does not make sense because the utility is usually of high quality and the power supply is reliable. In certain markets, such as the Dominican Republic, it makes much more sense to have control over your own power supply.

MR. MARTIN: So control over your own power supply makes less sense in the United States?

MR. CROWDIS: There are two places where there might be power supply issues, making a microgrid practical. One is Alaska. There are very remote communities there. Some people have said that they can achieve payback with a solar photovoltaic array very quickly even with no sun for half the year. With the cost of storage coming down, some remote communities may do that. We also might see it in Hawaii.

MR. SMITH: We are focused primarily on reliability. We look at federal entities that have critical loads. We look at ways to serve them through some sort of viable economic model.

We do not separate from the grid. We run in parallel with the grid so that we have enhanced reliability, but during the course of the last couple years, we have disconnected 50 times. Some of that was proactive, and some was automatic. In the case of Hurricane Irene, we saw the storm coming so we went into island mode. In the case of the earthquake, we did not anticipate that so we disconnected automatically.

MR. MARTIN: Michael Kornitas, you must be pitched by cogenerators, solar companies and storage purveyors. Who else?

MR. KORNITAS: Fuel cells seem to be the big thing because of the state subsidies. We are looking at storage right now. It would be the greatest thing in the world if we could get storage at a price that makes sense to install it. We are looking at thermal storage right now.

MR. CROWDIS: We released a request for proposals, and we will get bids this week for a five-star hotel in the Virgin Islands. We have been contacted by virtually every company on the planet that is doing some kind of storage indoor microgrid work. Some of the pricing is very attractive.

MR. MARTIN: How much does storage cost per megawatt of capacity?

MR. CROWDIS: It depends on how big the application is. We had one deal that was three mWhs of storage for around $3 million. The deal was paired with renewables.

MR. MARTIN: You could also earn revenue from ancillary services. What percentage of the cost do you think can be covered by providing services to the grid?

MR. CROWDIS: None of the deals at which I am looking would provide that service.

MR. MARTIN: Jeff Seidel, who is pitching you at the moment?

MR. SEIDEL: Mostly solar and cogeneration companies.

MR. MARTIN: Brian Patterson, where do you see opportunities?

MR. PATTERSON: I do not think the goal is to be disconnected from the national grid. Microgrids are more about providing different levels of quality and reliability. In essence, they make the user share responsibility with the utility. The goal is not to replace the utility.

Shift in Basic Utility Model?

MR. MARTIN: Dr. Shahidehpour, do you think we are on the verge of a change in how electricity is supplied in this country? Should the regulated utilities be worried?

DR. SHAHIDEHPOUR: We are adding so much uncertainty to the electric power system today with intermittent sources of electricity like solar and wind. Electric cars are another element. The system is volatile. It is very difficult to assume one control center for a large utility where we would be able to manage all these uncertainties within the system. By localizing the control, we would improve the operation of the system from an economic and a reliability point of view.

It will be a while before we have system partitioning, but something has to happen because utilities do not have the answer to solar and wind adding uncertainty to projections of electricity output. By localizing, we are still connected to the grid but we make their lives much more manageable.

MR. CROWDIS: My view is that microgrids are only being pushed by the US military, islands and remote communities because they need the service. India and China are doing all kinds of things. I feel there will be more of a boomerang effect.

Let's look at the 900-pound gorilla. Natural gas is cheap. It will remain cheap for a while. I do not see a mass migration to microgrids. I do not think see it happening in the continental United States. We have great utility service at low prices.

AUDIENCE MEMBER: There has to be some sort of new regulatory compact to allow the utilities to move toward this different model. The utilities have huge investments in wires and generating facilities that they are recovering over time through rates. To the extent some customers disconnect from the utility grid, then the remaining customers are left having to the bear the stranded cost of a system that was built to serve a larger customer base. That does not work.

MR. CROWDIS: A hotel in Antigua decided recently to take its large reverse osmosis system off the grid and run it with solar. I think this idea that you can take things off the grid and run them independently is disruptive. What I am worried about in Antigua is that it is an impoverished place, and what happens to the rest of the ratepayers? I am concerned about equity and fairness.

MR. MARTIN: Is it true that if you install a rooftop solar system, you will be protecting yourself from utility outages? Can such a system operate when the grid is down?

MR. KORNITAS: We would have to shut it down. When the grid goes down, we are not allowed to produce solar.

MR. SMITH: The amount of PV that we have on the Food and Drug Administration campus is about 30 kilowatts out of 26 megawatts of capacity, so it is a tiny part of the overall generating capacity. Solar has played a critical role in Japan in the post-tsunami period. It plays a critical role when it is available in the post-restorative period because it can bridge a gap.

MR. CROWDIS: I have been talking to a number of investors who are getting comfortable with the idea of large microgrids in which they might invest. We are at the same stage on the learning curve as in the early days of distributed solar. ◎

Environmental Update

California sold 14,522,048 2013 vintage allowances for $14 a ton and 7,515,000 2016 vintage allowances for $10.71 a ton in an auction on May 16 under the state cap-and-trade program. Each allowance allows the holder to emit one metric ton of greenhouse gases. All of the 2013 vintage allowances offered for sale and roughly 79% of the 9,560,000 2016 vintage allowances offered were sold.

The settlement price of the 2013 vintage allowance was higher than the auction reserve price (the minimum price at which the state was prepared to sell) of $10.71, while the settlement price for the 2016 vintage allowances was the same as the auction reserve price, suggesting relatively weak demand for allowances whose use is still three years in the future.

The covered entities who must turn in such allowances include certain power and manufacturing companies.

If covered entities need additional allowances, then allowances may be purchased at auction or covered entities may use "compliance offset credits." Covered entities can meet up to 8% of their triennial obligations to surrender allowances by using compliance offset credits.

Compliance offset credits are created when projects reduce or remove greenhouse gas emissions and meet regulatory criteria set by the California Air Resources Board or CARB. Only CARB can issue offset credits for use in the cap-and-trade program. These credits represent verified reductions in greenhouse gases or removal enhancements from sources of greenhouse gas emissions that are not subject to a compliance obligation under the cap-and-trade program. The reductions must come from a project that was undertaken using a CARB-approved compliance offset protocol or the offset credits can be issued by another jurisdiction whose credits California recognizes, or be sector-based offset credits issued by an approved sector-based crediting program.

CARB is considering expanding the number of compliance offset protocols. New protocols could mean additional business opportunities for those that are willing to go through the process.

CARB has already approved four existing compliance offset protocols (US forest projects, urban forest projects, livestock projects and ozone depleting substances). CARB proposed rice cultivation and mine methane capture as potential additional compliance offset protocols in May. These protocols focus on reductions in methane, a powerful greenhouse gas.

CARB is considering the rice cultivation protocol to quantify reductions in methane emissions resulting from certain cultivation practices that could be used in major rice-growing areas of California and states in the middle South (Arkansas, Missouri, Mississippi, Louisiana and Texas). CARB is considering three rice cultivation practices for California: replacing wet seeding with dry seeding, early drainage at the end of a growing season and rice straw removal after a harvest. In the middle South, CARB is considering rewarding the following practices: early drainage at the end of a growing season, rice straw removal after harvest, intermittent flooding and staggered winter flooding.

CARB is also considering a protocol to quantify reductions in methane emissions from active underground mines, abandoned underground mines and active surface mines. Methane can be released from underground and surface mines from ventilation shafts and from drainage and gasification wells that remove methane associated with mining activities.

Equator Principles

Version three of the Equator Principles takes effect on June 4, 2013, although there is a transition period for certain projects.

The Equator Principles are a voluntary framework to help identify, assess and manage social and environmental risk. Since their inception 10 years ago, more than 75 lenders have adopted them. By doing so, the lenders have committed not to provide project or project-related finance to borrowers who will not or are unable to comply with the Equator Principles.

Version three contains the following notable changes from the previous version: expansion of the scope of the Equator Principles to include certain project-related corporate loans and bridge loans, a requirement for an analysis of less intensive greenhouse gas emitting alternatives for projects that will emit more than 100,000 metric tons of greenhouse gases per year (as measured in carbon dioxide equivalents) and additional information sharing and disclosure requirements.

Developers of projects that may be subject to the Equator Principles should make sure that these new requirements will be met to avoid delays with lenders.

The revisions add the following to the list of covered lending activities: project finance advisory services where total project capital costs are US$10 million or more, project finance with total project capital costs of US$10 million or more, project-related corporate loans meeting certain criteria and bridge loans of less than two years that are intended to be refinanced by a project finance loan or a covered project-related corporate loan.

Version three requires projects that will emit more than 100,000 metric tons of greenhouse gases per year (as measured in carbon dioxide equivalents) to evaluate alternative ways to reduce the emissions. The lenders will have to see an alternatives analysis of technically, financially-feasible and cost-effective measures to reduce greenhouse gas emissions during project design, construction and operation.

Wastewater Effluent Guidelines

The US Environmental Protection Agency proposed revisions in April to its wastewater effluent guidelines for power plants that make steam as an intermediate step to generate electricity. The revisions are required under a consent decree in *Defenders of Wildlife v. EPA*. It has been more than 30 years since these guidelines were last updated, a period during which air emissions limits for many other pollutants have been ratcheted down. Instead of being released into the air, these pollutants can end up being discharged in wastewater effluent.

EPA proposed eight different options to control the following types of waste streams: flue gas desulfurization, fly ash, bottom ash, flue gas mercury control, combustion residual leachate from landfills and surface impoundments, nonchemical metal cleaning wastes, and gasification of certain fuels. EPA indentified four preferred alternatives from these options and noted that the differences among the alternatives relate to the waste streams covered, size of the units controlled and stringency of the controls.

EPA will accept public comments for 60 days after it publishes the new rules in the *Federal Register* and has scheduled a public hearing on proposed pre-treatment standards on July 9 in Washington. The new guidelines had not been published by the time the *NewsWire* went to print.

New protocols in California for offsetting greenhouse gas emissions could create business opportunities.

According to EPA, "no coal plants are projected to close as a result of this rule." It estimates that fewer "than half of coal-fired power plants are estimated to incur costs under any of the proposed standards, because most power plants already have the technology and procedures in place to meet the proposed pollution control standards. For example, over 80% of coal power plants already have dry handling systems for fly ash that avoid wastewater discharge."

EPA did not comment on the projected impact on coal-fired power plants when the new rules are combined with other regulations that will affect such power plants like the mercury and air toxics and pending coal combustion residual rules.

Startup, Shutdown and Malfunction

EPA is expected to issue a final rule this fall requiring changes to how 35 states and the District of Columbia are required to regulate excess air emissions during periods of start up, shut down and malfunction — so-called SSM periods. The states will then have 18 months to submit revised state implementation plans.

In the meantime, states are left to ponder how they will revise state implementation plans, particularly with respect to those sources like peaker plants that may be disproportionately affected compared to baseload power plants.

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Environmental Update

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EPA issued a proposed rule in February with respect to how some states are handling sources of regulated non-hazardous air pollutants that, during short periods of time (particularly during planned start ups and shut downs) emit more of these air pollutants than during periods of normal operation. Some states currently allow defenses against enforcement for excess air emissions during periods of start up and shut down. Environmental groups have opposed these defenses. EPA issued the proposed rule in response to a petition by the Sierra Club.

Under the proposed rule, 35 states and the District of Columbia would be required to resubmit state implementation plans with respect to SSM periods. The 35 states are Alabama, Alaska, Arizona, Arkansas, Colorado, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maine, Michigan, Minnesota, Mississippi, Missouri, Montana, New Hampshire, New Jersey, New Mexico, North Carolina, North Dakota, Ohio, Oklahoma, Rhode Island, South Carolina, South Dakota, Tennessee, Virginia, Washington, West Virginia and Wyoming.

A state implementation plan describes how a state plans to achieve compliance with the national ambient air quality standards, also known by the acronym NAAQS. The NAAQS set allowable concentrations of six air pollutants in outdoor air (particulate matter, ozone, carbon monoxide, sulfur dioxide, nitrogen dioxide and lead). Each area of the country has been designated as either in attainment, not in attainment or unclassifiable with respect to the NAAQS for each of the six air pollutants.

— contributed by Sue Cowell in Washington

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