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PROJECT FINANCE
NewsWire

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New Financing Strategies

A wave of new strategies has started to appear in the US to drive down the cost of capital. Developers are turning to publicly-traded "yield cos," synthetic MLPs, self-help MLPs, REITs, foreign asset income trusts and securitizations as new financing tools or exit strategies to raise capital around operating projects. How easy are they to use? How much do they reduce capital costs? A panel discussed these and other questions at the 24th annual Chadbourne global energy and finance conference in June.

The panelists are Lyndon Rive, CEO of SolarCity, Bob Hemphill, CEO of Silver Ridge Power (formerly known as AES Solar), Jeff Eckel, CEO of Hannon Armstrong Sustainable Infrastructure, Ed Fenster, co-CEO of Sunrun, and Carl Weatherley-White, CFO of K Road Power. The moderator is Keith Martin with Chadbourne in Washington.

MR. MARTIN: Carl Weatherley-White, there has been a lot of talk about yield cos. What is a yield co?

Yield Cos

MR. WEATHERLEY-WHITE: It is not a fresh concept but there has been fresh thinking about it in the renewable energy industry. Yield cos have been around for many years in energy, real estate and other industries. A yield co is a publicly-traded company that is formed to own operating assets that produce cash flow. The cash is distributed to investors as dividends.

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MORE CONSTRUCTION-START ISSUES are likely to be addressed by the Internal Revenue Service this fall.

Wind, geothermal, biomass, landfill gas, incremental hydroelectric and ocean energy projects in the United States must be under construction by year end to qualify for federal tax credits. The IRS issued guidance in April about what it means to start construction, but many people still have questions.

The questions are mainly in two areas.

First, once a project is considered under construction, the remaining work must be continuous. It is not always clear what continuous means. For example, is it continuous where some work is */ continued page 3*

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MR. MARTIN: Many people think the best use of a yield co is to take operating assets that have been de-risked to produce a predictable cash flow stream and use it to raise capital at a low yield from retail investors. K Road does not have operating assets. Why does it make sense for you to be thinking about using a yield co?

MR. WEATHERLEY-WHITE: For a company like K Road that has developing assets, a yield co is a possible future way of financing our assets. Investors are willing to pay more for assets that have a proven history than for those that are merely under development. Separating the more volatile activities of development and construction from the more stable and less volatile cash flows of operating assets is a good choice. NRG recently filed an initial public offering for a portfolio of contracted assets in the hope of attracting capital at lower cost.

Yield cos are being used to raise capital more cheaply against operating projects.

MR. MARTIN: So you would put operating assets in the publicly traded vehicle and put the development pipeline in a separate entity. The publicly-traded vehicle would have an option to buy the development assets once they have reached construction?

MR. WEATHERLEY-WHITE: That is correct. There is a long history of a similar arrangement in master limit partnership deals for midstream and other energy-related assets where you have the operating assets held in the public company and development assets held in a parent or an affiliate with varied arrangements for eventually transferring the development assets into the public vehicle.

MR. MARTIN: Yield vehicles were hammered in the last week on rumors that the Federal Reserve Board will back away from its continuing monetary stimulus called quantitative easing. Yield investors looking for an intermediate yield vehicle that pays something a little above what a bond pays are finding that bond rates are rising enough that interest has dampened in yield vehicles, according to market watchers. How has this affected your move to a yield co, if at all?

MR. WEATHERLEY-WHITE: We looked at the correlation of how yield co, master limited partnership and real estate investment trust units perform against underlying interest rates. You can look at 10-year Treasury notes or BBB bonds as benchmarks. There are some indexes that track those different sectors. As one might expect, yields increase slightly as Treasury rates increase. There is a correlation, but it is not a one-for-one effect.

MR. MARTIN: Bob Hemphill, you attempted to do on the Canadian exchange exactly what Carl Weatherley-White described, putting your operating assets in a publicly-traded vehicle and the development assets in a separate vehicle. You had to pull back the offering. Why?

MR. HEMPHILL: We pulled for the same reason everybody pulls back an offering: we didn't get the kind of price and volume response that we had anticipated. That was disappointing.

MR. MARTIN: Why did you choose Canada rather than the US to do this?

MR. HEMPHILL: We were told that the Canadian market appreciated yield and energy projects, and there was plenty of money. The process was allegedly smoother, quicker and cheaper. It took us a year and $10 million, so I am not entirely convinced. [Laughter.]

MR. MARTIN: What is the fall back plan? Are you going to try it again after waiting a while?

MR. HEMPHILL: Take a vacation? [Laughter.] We are still going through the stages of grieving; we have not gotten to the stage yet of coming up with a new plan.

MR. MARTIN: First Wind put its operating projects in New England into a holding company and sold a 49% interest to Emera, a Canadian utility holding company. The development projects are in a separate entity. The company was able to raise capital at a pretty good rate. Why not do that rather than one of these publicly-traded vehicles?

MR. HEMPHILL: We have a solid business with 50 power plants operating and another big plant that is about 33%

complete in California, and we have real revenue. We generate $50 to $75 million a year. It is a nice solid business, and we do not have to do anything tomorrow. On the other hand, we have investors who would like to see some return on their money, and we have an obligation to get them that return, so we are reexamining everything at the moment and, hopefully, we will come up with a better choice than going back to Canada.

MR. MARTIN: Christopher Hunt, you own Pattern Energy, a wind company. I have read in the trade press that you are planning to take it public in Canada. Why?

MR. HUNT: I cannot comment on whether we are doing that, but Pattern is different from Silver Ridge Power in the sense that it has a sizable business in Canada.

REITs

MR. MARTIN: Jeff Eckel, two data processing companies, Iron Mountain and Equinix, announced in the last week that rulings they were expecting from the Internal Revenue Service to convert into REITs are being delayed while the IRS forms an internal working group on REITs. You have a ruling. You converted into a REIT. Have you heard anything about what the IRS might be doing?

MR. ECKEL: We have not.

MR. MARTIN: The Equinix ruling was that an operating company that owns data storage centers can sell the data centers to a REIT to raise capital and then lease them back. Your ruling addressed a different issue. Can you say anything about your ruling? It was a private ruling that has not been made public yet by the IRS.

MR. ECKEL: I am not sure why our ruling is not out yet. We received it last fall. We have converted our company into a real estate investment trust. A REIT must own mainly real property or loans secured by mortgages over real property. The assets that Hannon Armstrong owns are building components. They are real property, affixed to buildings, or there is a mortgage over such assets. We asked for confirmation that our assets are eligible assets for a REIT. It was not a contentious issue. Lighting, heating and cooling components are within the bounds of what has traditionally been considered good REIT assets.

MR. MARTIN: Before you converted into a REIT, did you consider other publicly-traded vehicles like a Canadian publicly-traded company, US yield co, synthetic MLP or Canadian income trust and, if so, why did you choose a REIT?

MR. ECKEL: We have REITable assets, so that is a good place to start, but then we did look at a private REIT as opposed to a publicly-traded one, MLPs and an initial / *continued page 4*

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done, but then stops until the local utility can catch up on building substation improvements or network upgrades that must be completed before the project can connect to the grid?

Second, it is not clear in what circumstances someone who buys a project, after this year, on which another developer started construction in 2013 can claim tax credits.

The IRS branch for these issues has been given a "tentative green light" to issue additional guidance. The guidance is "not that far along" yet, but, if issued, will come out in the fall.

On continuous work, there was talk earlier about releasing examples showing how the IRS views different fact patterns, but the agency has moved away from examples and is now focused on adding more detail to the guidance it already published.

On transfer issues, the US Treasury Department took the position under the section 1603 cash grant program that any project on which significant physical work started in time at the site or factory would remain "grandfathered" no matter how many times the project changes hands before completion. However, it was concerned about developers who started construction of projects by stockpiling wind turbines or solar panels that they then sprinkled among multiple projects in increments that amount to more than 5% of each project's cost. The Treasury did not want to encourage trafficking in stockpiled equipment as a way of conferring grandfather rights on future projects, so it required the original developer to retain more than a 20% interest in any project to which it contributes such equipment, unless the later sale of the project is a sale of a real project and not a project company that is mere wrapping paper for the stockpiled equipment. Tax equity transactions are not a problem.

The new guidance will probably allow retention of grandfather rights after most transfers.

The government believes that the requirement that there must be "continuous efforts" after this year on projects / *continued page 5*

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public offering as a regular corporation. Our desire was to get permanent capital after 32 years of operating. The question was which form. A REIT is friendlier to investors than an MLP. Investors get simple 1099 forms at year end with the amount of their dividends. They do not have to fuss with complicated K-1 forms reporting cash distributions, allocations of various kinds of income, capital accounts, outside bases and the like.

Our business fits very well into the REIT investor universe and has appeal to both classic green investors and specialty finance investors. This is also why we put "sustainable infrastructure" in our name. Sustainability is a defining issue for a new generation of investors, and it is also very important to us.

MR. MARTIN: How has converting to a REIT affected your cost of capital?

MR. ECKEL: Now that we have capital, it is actually worth the time required to figure out what it costs. [Laughter.] The REIT has given us another financing tool on top of our existing securitization and syndication broker dealer capabilities. It allows us to do a lot more than we could before. The three things together are a very powerful model for us. We are finding good deal flow and good things in which to invest.

MR. MARTIN: There are two types of REITs. There are equity REITs where the REIT owns the assets and then leases them to an operating company, and there are mortgage REITs where the REIT makes loans and takes back a mortgage over real property. In either case, at least 75% of what the REIT holds must be real property or mortgages over real property. You are largely a mortgage REIT. You are prepared to lend to renewable energy developers. Is there enough real property in a wind, solar or geothermal project to make a REIT potentially a significant source of debt for such a project?

MR. ECKEL: We think so. We are starting out with $1.6 billion in existing assets. That is not an enormous amount of money, but it is certainly enough to get some developers interested. We also have the ability to have up to 25% assets that are not real property through a taxable REIT subsidiary.

The 25% is calculated on a net basis rather than a gross basis, so when you subtract the leverage, we really have the ability to combine real property with other assets that are not real property on a one-to-one basis.

MR. MARTIN: What interest rate could a developer of large solar projects like Bob Hemphill expect to have to pay on a loan from the REIT?

MR. ECKEL: We could compete with the banks and term loan B market on these large utility-scale projects, but that market segment does not look terribly attractive at the moment.

MR. MARTIN: What is your hurdle rate?

MR. ECKEL: The renewable industry is hoping these vehicles will get them to a lower cost of capital. Our investors are really not that interested in giving capital away to support the renewable energy business. There is a middle ground between our cheaper capital and what we are able to offer.

IPOs

MR. MARTIN: Lyndon Rive, SolarCity went public in December. It was a highly anticipated and watched public offering, and was very successful. Stock values have quadrupled. What lessons did you take away from that experience?

MR. RIVE: When we went public, the climate for renewable energy was not good. The financial markets were rough. Unfortunately, it felt that we were lumped into the category of a generic manufacturing company during a period when the manufacturing industry was taking a significant beating.

We tried to explain that we were a different business model. It felt like we were swimming against a strong current, and it was more than just an investment decision for potential institutional investors; it was a situation where if they made the investment and it went negative, they would be fired.

Some investors understood the business model, but they had a hard time assigning a value. It is really complicated from looking solely at our current profit and loss statement to recognize the value. Revenue is expected under customer agreements with 20-year terms, but there are only a few years of operating history. Even where people recognized the value, there was skepticism. It was difficult to punch through. We had to take a significant haircut on valuation in the actual offering.

Then the market started to grasp the business. It began to see the long-term contracted cash flows and to appreciate that we are not a solar manufacturing business but a true energy company.

MR. MARTIN: The tax equity market is getting more and more comfortable with rooftop solar installations as an asset class. Is it helping you to raise tax equity now that potential tax equity investors see how the broader investment community has valued your company?

MR. RIVE: Absolutely. That combined with the aging of the assets creates very good asset quality. As the assets get older, you see more and more data associated with them. You see the default and recovery rates, and you compare them against the mortgage industry.

Our customers have three options: pay us, pay the utility more or don't have electricity. Given those three options, we are the winner. This is proving to be a very good asset class. The coverages are very conservative and, from an investor perspective, there is a favorable yield-to-risk ratio.

MR. MARTIN: How has your weighted average cost of capital been affected by going public?

MR. RIVE: The key things on which we are focused currently are monetizing cash flows and reducing the cost of debt. The first step has been to roll over short-term debt. We refinanced some of our assets at around 3 1/2%. That's short term for about two years. We are now in the process of going through the rating agencies with the aim of replacing short-term debt with longer-term borrowing. If that goes well, then there will be many different avenues we could take hopefully to get to something like a 6% weighted average cost of capital.

MR. MARTIN: Ed Fenster, is one of your goals to go public?

MR. FENSTER: We really have two businesses. We have an operating business with existing assets, and we have a development business. The costs of capital for the two are maybe 20 points different. The rate of return that corporate-level investors expect from us is very different than the rate of return that people are expecting investing directly in our projects. We need orders of magnitude more project capital than operating capital, and so we spend all of our time and attention in minimizing the cost of our subsidiary level of capital and maximizing the extent of that capital.

Because of this, we have not been as focused on taking the holding company public. We are still growing really rapidly. We will address it at an appropriate time.

Tax Equity

MR. MARTIN: Both you and Lyndon Rive have voracious appetites for capital. You are deploying rooftop solar systems at blinding speed. You have raised dozen tax equity funds, and Lyndon Rive has raised at least two dozen, if not more. Are you finding tax equity harder to raise or are there more tax equity investors today? What tax equity yields are you being offered?

MR. FENSTER: There are two forces — supply and demand. Our supply of projects is growing at a very fast rate. Also, the supply of tax equity is growing, so our perception of the tax equity market is colored by the ever increasing amount of projects that we are trying to finance. / continued page 6

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that start construction by incurring costs will protect against bare trafficking in stockpiled equipment.

THE SECTION 1603 PROGRAM is attracting more litigation.

Three new lawsuits have been filed in the last two months. Eight suits are now pending. All the cases have been filed in the US Court of Federal Claims.

A ninth lawsuit was withdrawn earlier this year "with prejudice" after the US Treasury filed a counter-claim charging the company that brought the suit with fraud.

The oldest pending suit has been pending since July 2012. No dates have been set for trials. The government has filed motions to dismiss four of the cases.

One of the new lawsuits involves the Alta I wind farm, a 150-megawatt project in Tehachapi, California. The developer, Terra-Gen Power, sold and leased back the project in December 2010 for $560 million, after running an auction two months earlier when it was considering an outright sale. The auction produced six bids from potential buyers, two of whom went to a second round of bidding. The second round bids were $550 million and $565 million.

The lessors claimed that $521 million of the $560 million they paid was basis in equipment that qualified for a grant. The Treasury accepted an eligible basis of only $400 million. It said the difference was basis that should have been allocated to the power contract or going concern value. The lessors submitted an appraisal from DAI to support the overall purchase price, and KPMG attested to the eligible basis of $521 million.

The suit charges that the expert reports should have been dispositive. According to the complaint, the power contract had no value in December 2010 when the sale-leaseback occurred because the electricity prices in it were no more favorable than other power contracts in 2008 when the contract / continued page 7

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We have seen the cost of capital for tax equity come down a little, but the rates appear fairly stable. Supply appears to be keeping up with demand.

MR. MARTIN: What does tax equity cost currently?

MR. FENSTER: It depends on how you structure the deal. I think the tax equity investor's internal rate of return is a terrible metric. We don't think in terms of tax equity IRR.

MR. RIVE: It is definitely a wide range. We have seen from 6 1/2% to 12%. The 12% is coming down quickly.

MR. MARTIN: What is your preferred structure?

MR. FENSTER: We prefer partnership flips or inverted leases.

MR. MARTIN: Bob Hemphill, you and I were at a White House meeting about a year ago and you mentioned on the way out that you were finding it hard to find tax equity for large utility-scale solar projects. Is that still the case?

MLPs may not offer renewable energy companies much incremental benefit beyond what such companies can do with a yield co.

MR. HEMPHILL: Yes, but I have a grand total of one data point. If you need to find a lot of money, it does not matter what type of money it is or who it is from. Finding a lot of money is hard. If you are going to finance 200 megawatts at a time, you are going to spend a lot of time trying to find a large amount of money.

MR. MARTIN: Jeff Eckel, you raised tax equity for a geothermal project, but it was unusual because you had a Treasury cash grant. The tax equity transaction was a way to monetize the depreciation. Many people wondered if it was possible to do such deals. You proved that it is. The money was expensive, but it was worthwhile. Why?

MR. ECKEL: The depreciation was of no use to the project or to its owners, so any amount raised for it was found money. It was a model transaction. We have a great partner in Chevron and that business.

Securitizations

MR. MARTIN: Lyndon Rive, your general counsel, Seth Weissman, has been at the center of a National Renewable Energy Laboratory effort to create a market for securitizations where solar rooftop companies could package together customer revenue streams from residential solar installations and borrow against them in the public markets. That effort is about to move into a mock transaction. By the fall, the rating agencies should be able to rate the mock deal. Suppose securitizations open up as an avenue for raising capital. Will you do them in place of tax equity? Do you think it's possible to marry securitized debt with tax equity?

MR. RIVE: We will need to find a way to combine the two. Traditionally, the industry is focused on project-based financing, and we are trying to move it toward cash flow financing. In the residential space, you have fairly high cash flow. Currently, you pay your tax equity investors, and then you can allocate the rest of your cash flows to a holding company.

A lot of the tax equity funds are not that big, and there are multiple funds, so marrying debt at the fund level with every single fund is very, very difficult to scale. So what you want to do is have all the cash flow up to one entity and then potentially take that to a different financing source.

MR. MARTIN: Ed Fenster, do you see securitization as something of interest to you before 2016 when the investment credit drops to 10%?

MR. FENSTER: Probably not. We spent a lot of time considering two different capital structures last year, one of which was securitization. We got initial ratings feedback from Standard & Poor's and came very close to closing a big warehouse facility. Ultimately, we found the weighted average cost of capital on a pre-tax basis to be higher in that approach.

The reason is, in a securitization, one might finance about 75% to 80% of the net present value of the cash flows. Therefore, you should be able to get a low cost of capital on that percentage. If you have a tax equity deal, you layer that capital cost with the pretax cost of tax equity, and the combination looks really attractive. But then there is the question of what to do with the remaining 25%? That 25% causes the total capital stack to be higher cost.

In the alternative, if you were to marry tax equity with a yield co-type structure, although you will end up paying more to the yield co investors than you would in the securitization market, the weighted average pre-tax cost of capital is lower. We anticipate doing that. Lyndon may be doing a securitization. I imagine it could be a boon to his common stock value just to announce it and have it be a standard that the industry has overcome.

Right now, securitization makes sense if your holding company's cost of capital is below 12% on an equity basis and if you are taxable. If a big utility gets into the market, maybe it will start thinking about securitization or about recapitalizing old tax equity deals. When you consider the transaction costs of dealing with the rating agencies, going through a public securities offering and negotiating intercreditor agreements, I do not expect it to be a winning capitalization structure for a long time.

MR. MARTIN: Lyndon Rive, do you see a role for securitization beyond the use as a form of back leverage that you described?

MR. RIVE: Regardless of where the capital comes from, the more sources, the better. When you look at MLPs, REITs and the other structures, this is all positive movement toward financing and bringing additional capital. It is nice to have the choice. Greater supply brings down cost. We can decide later how to use it.

MR. WEATHERLEY-WHITE: I will use one of my favorite terms that I learned a few years ago from Goldman Sachs — yield equalization. This is what happens when you get lots of different types of capital chasing a single asset. You get the capital more cheaply.

FAITs and MLPs

MR. MARTIN: Bob Hemphill, did you look at a foreign asset income trust as an alternative to listing on the Toronto Exchange?

MR. HEMPHILL: Yes. Both have real benefits in Canada, but significant disadvantages for investors in other countries. We decided that it was not appropriate.

MR. MARTIN: Jeff Eckel, there is an effort in Congress to allow renewable energy companies to restructure themselves as master limited partnerships. These are partnerships whose units trade on a stock exchange. If MLPs opened up, would you convert to an MLP from a REIT?

MR. ECKEL: No. I think we are in exactly the right spot. The MLP market is an interesting one, and I certainly hope Congress allows their use for renewable energy. There are questions whether traditional investors in MLPs will */ continued page 8*

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was originally signed, and the lessors could not have purchased any going concern value because the wind energy business remained with Terra-Gen as lessee. It also says that Treasury improperly failed to allow a "turnkey premium or developer profit" to Terra-Gen when Treasury added up the project costs to determine whether the $521 million claimed in equipment basis was reasonable in relation to what the project cost to build.

In another new lawsuit, Blue Heron Properties, LLC complained in late July that it was shortchanged on grants paid on two solar systems installed on the roofs of apartment buildings. This is the second suit involving a Dallas electrical contractor, RCIAC, that installs solar systems. Bret Heron, the managing member of the LLC that brought suit, paid RCIAC $10.50 a watt in 2010 for a solar system installed at an apartment complex and applied for a grant on the full amount, which Treasury paid the same year.

Heron then bought three more systems installed on other apartment buildings in 2011 at prices ranging from $9.52 to $10.50 a watt and applied for grants on them at the full prices after the systems went into service in the first half of 2012.

Treasury paid the full grant requested on the first system ($9.52 a watt), but accepted bases of only $5.56 and $5.43 a watt on the next two. The Treasury posted benchmarks on its website in late June 2011 suggesting that it thought the market value of systems put in service in the first quarter 2011 ranged from $4 to $7 a watt, depending on the size of the system. The two systems on which Heron feels shortchanged were 205 kilowatts and 294 kilowatts. The June 2011 benchmark for such systems was $5 a watt. Heron argues that Treasury had no discretion but to honor what he had in fact paid RCIAC for the systems.

In the most recent suit, filed in early August, Anaergia, a fuel cell */ continued page 9*

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be interested in renewables. The structure has been used mainly for oil and gas.

MR. FENSTER: It saddens me that the renewable energy industry has put so much effort into MLPs. It requires a big act of Congress, but it does not add much value. I wish the focus were on broadening access to tax credits. Being able to structure an MLP would be advantageous if you could relax the passive activity loss rules and eliminate investment credit recapture on changing ownership. Then you could create a publicly-tradable tax equity structure that would radically increase the size of that market.

Our perception is that as awesome as that would be, that is a very unlikely outcome. The after-tax benefit that you can achieve as a regular C corporation, never mind the REIT, is similar to an MLP. MLPs are an enormous amount of brain damage for not much improvement. As an industry, we only have so many opportunities to ask Congress for something. It feels to me like that was a bad choice.

I think the most significant single thing that Congress could do to lower the cost of capital for solar would be a refundable tax credit. That is the constraining point in the marketplace.

MR. WEATHERLEY-WHITE: I agree with Ed Fenster on that. There may be a marginal benefit to eliminating double taxation of earnings, but it is not nearly as helpful as finding ways to benefit fully from the existing tax subsidies.

MR. HEMPHILL: If someone gave me one for free, I would take it. The chance of Congress doing anything that basically counts as a tax expenditure is about as likely as the Easter Bunny and the Tooth Fairy getting together.

MR. RIVE: I am optimistic. It is a big lift, but if we can get the two things that Ed mentioned, the recapture and the passive activity loss rule changes, it would really open up the market. Without those changes, it is not much of a benefit. ◎

Powering Africa

by Kenneth W. Hansen and Rachel Rosenfeld, in Washington

It is a good time to sponsor an energy project in sub-Saharan Africa.

The Obama administration's Power Africa initiative is marshalling government resources to build out the sub-Saharan African energy sector. Success will depend on a similarly unprecedented response from the developer community, as well as cooperation from host governments, who will need to conduct procurement processes geared to attract public and private capital on appropriate terms. Whether these sectors will respond as the Power Africa initiative envisions remains to be seen.

Meanwhile, the US government is taking steps to improve the competitiveness of US equipment suppliers with those from China.

During his recent trip to Africa, President Obama announced plans to direct up to $7 billion in government resources to support US businesses building energy projects in sub-Saharan Africa. The goal is to double access to power in the region, focusing initially on six countries: Ethiopia, Ghana, Kenya, Liberia, Nigeria and Tanzania.

The $7 billion commitment was over-fulfilled with roughly $7.8 billion in funding commitments declared by five federal agencies. The participating US agencies will be keen to hear from developers with prospective generation, transmission and distribution projects in the region.

Eight private companies have committed alongside the US government to invest another $14 billion in power projects in the six target countries. The eight will be looking for suitable projects.

While no time period is attached to spending the dedicated funding, the declared goal is to double power generation in the target countries within five years.

The Africa Power initiative does not require action by Congress to implement.

10,000 MWs

Power Africa aims to add 10,000 megawatts of "cleaner, more efficient" electric generating, transmission and distribution capacity to bring electricity for the first time to an estimated 20 million homes and businesses and to ease what business leaders on the continent describe as their biggest problem: a lack of reliable electricity. The high cost of producing electricity as a result of outdated power plants and responding to blackouts with emergency power sources help to explain why African exporters still struggle to compete in international trade.

The public funding commitments are largely drawn from assorted existing federal loan, loan guarantee, political risk insurance and grant programs. These programs are variously aimed at financing energy projects, improving technical assistance, increasing energy reliability and sustainability, speeding up project implementation and enhancing risk mitigation.

In the numerical lead among the agency commitments are two US agencies that finance private projects: the Export-Import Bank of the United States and the Overseas Private Investment Corporation. Ex-Im Bank chairman, Fred Hochberg, declared that the bank would "make available $5 billion in support of US exports for the development of power projects" in sub-Saharan Africa. OPIC, which makes loans and guarantees loans from private lenders to projects typically with at least 25% US ownership and writes political risk insurance on project investments by US persons, has earmarked $1.5 billion.

The Millennium Challenge Corporation indicated that it is prepared to contribute up to $1 billion in new power generation, transmission and distribution projects. MCC will also invest in energy infrastructure, policy and regulatory reforms and host government capacity building.

The US Agency for International Development has pledged to contribute $285 million in technical assistance, grants and risk mitigation to advance private sector energy transactions by helping governments to adopt and implement policy, regulatory and other reforms necessary to attract private sector investment to the region's energy sector. The US view is that the legal and regulatory regimes need work.

OPIC and the US Trade and Development Agency jointly committed to make available up to $20 million in project preparation, feasibility study and technical assistance grants to support the development of renewable energy projects.

The US African Development Foundation is launching a $2 million Off-Grid Energy Challenge, offering grants of up to $100,000 to African-owned and operated enterprises to develop or expand the use of proven technologies for off-grid electricity benefitting rural and marginal populations.

The US Trade and Development Agency also signed a memorandum of understanding with the Development Bank of Southern Africa to enhance cooperation on project development. The two committed to leveraging / continued page 10

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company, complained that it was shortchanged on grants on two fuel cells that it installed at municipal wastewater treatment plants in Ontario and San Jose, California. Treasury paid $1.6 million less in total than the grants for which the company applied on the two fuel cells, mainly by excluding the cost of gas conditioning equipment. The fuel cells use methane gas that the municipalities produce by putting sewage sludge through anaerobic digesters, but the gas must be cleaned before use in the fuel cells. The Treasury's position is that only the fuel cell qualifies for a grant, and not equipment used in "the production or refining" of the gas.

The company argues that the fuel cells qualify independently for grants as "trash facilities" that use "municipal solid waste" to generate electricity. Treasury allows grants to be claimed on fuel processing equipment at the front end of such facilities. However, the Treasury cash grant rules are supposed to mimic what the IRS does for tax credits, and the IRS treats a power plant as a trash facility only if it uses municipal solid waste directly and not gas that an unrelated fuel supplier has made by running the waste through a digester.

There are rumors that another suit may be in the works challenging whether the US government has authority to reduce grants by the 8.7% sequestration percentage. Grants approved for payment on or after March 1 this year have been subject to a haircut of 8.7% under across-the-board spending cuts ordered by Congress. The percentage is expected to drop for grants approved after September 30. The Office of Management and Budget estimated in May that the new percentage will be 7.3%. However, it said it would update the estimate in August.

Treasury is allowing companies that are unhappy with the grants they were paid to pay back the money and claim tax credits instead. There does not appear to be a hard deadline to do so. / continued page 11

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their respective resources to accelerate the development, financing and implementation of priority clean energy infrastructure projects. The partnership will leverage private sector resources and expertise to deliver innovative development solutions and greater investment in sub-Saharan Africa.

US efforts to develop renewable energy projects will be supported and coordinated by an interagency joint venture among the US Export-Import Bank, OPIC and the US Trade and Development Agency called the US-Africa Clean Energy Development and Finance Center. The Center, which recently opened in Johannesburg, is supposed to provide a coordinated approach to clean energy project development in sub-Saharan Africa. It will offer both US and sub-Saharan African project developers a centralized means to identify and access potential US government support for their clean energy projects. The Center will also coordinate its efforts with those of the US private sector, multilateral development banks, local development banks, private banks, private equity firms, and foreign governments.

The US has committed $7 billion for projects that will bring more electricity to Africa.

The White House reported the following private sector investment commitments totaling nearly $14 billion. General Electric has promised 5,000 megawatts of new, affordable energy through provision of its technologies, expertise and capital in Tanzania and Ghana. Heirs Holdings, a pan-African proprietary investment company, has pledged $2.5 billion of investment meant to create 2,000 megawatts of new electric generating capacity over the next five years. Symbion Power has undertaken to raise $1.8 billion to invest in 1,500 megawatts of new energy projects in Power Africa countries over the next five years. The African Finance Corporation, an Africa-focused consultancy, will raise $250 million for investment in the power sectors in Ghana, Kenya and Nigeria. South Africa's Harith General Partners, the inaugural fund manager appointed to manage a Pan African Infrastructure Fund, pledged $500 million across the sub-Saharan African power sector, including $70 million for wind energy in Kenya. Standard Chartered Bank committed to finance $2 billion worth of energy projects. Other companies now working on specific energy projects in the region include Aldwych International, which is developing large-scale wind projects in Kenya and Tanzania, representing a projected $1.1 billion investment, and Husk Power Systems, which plans to install 200 decentralized biomass-based mini power plants in Tanzania.

Beyond these numbers are many other projects under consideration or active development by US and other developers that did not work their way into the Power Africa pronouncements.

Significance

No doubt the announced commitments depend on a number of factors. To borrow from *Moneyball*, it is not the money, but what the money says. In this case, the numbers mean that the Obama administration and its trade- and investment-promotion agencies are taking African energy projects seriously — both as responses to regional barriers to development that need to be addressed and as a source of tremendous opportunities for US businesses.

There is no question that the demand for power is there. In 2012, the International Monetary Fund forecast that seven of the 10 fastest growing countries in the world will be in Africa. The World Bank expects Africa to grow faster than the world average in coming years. Domestic investments and intra-African trade are emerging as significant drivers of Africa's new growth. All that growth will depend on access to reliable, sensibly priced power.

Arguably more important than the numbers announced, Power Africa, together with the complementary Trade Africa initiative to expand trade and economic ties with Africa, reflect the Obama Administration's adoption of a "trade-not-aid" strategy. That strategy aims for transparency, efficiency, standardization and reducing bottlenecks, roadblocks and corruption. Power Africa is also effectively an order to the participating agencies to concentrate more on finding and implementing energy projects in sub-Saharan Africa, an order that they should work hard to follow given its source.

While the goal of these initiatives, and US strategy more generally, will be sustainable business partnerships, conventional bilateral aid will continue to play a role. If the investment environments in African countries were reasonably adequate, then heroic initiatives would not be necessary to attract capital to their energy sectors. While great progress has been made in the region that has paved the way to the successful development of world class projects, such as the 250-megawatt Bujagali hydroelectric project in Uganda, the 84-megawatt Olkaria geothermal project in Kenya and a range of renewable energy projects under the REFIT program in South Africa, the region continues to be rife with barriers to entry and to ultimate success. The availability of funds to address regulatory and other legal reforms will continue to be an important part of the way forward.

Since 1999, the US Agency for International Development has spent an ever-increasing amount on foreign aid in Africa, including for trade and investment capacity building. For example, the US spent $16 million in 1999 on various infrastructure-related projects in Africa; it spent more than $435 million in 2011. Such aid has allowed countries to invest in streamlining regulations, limiting corruption and opening pathways for foreign-domestic cooperation. These efforts to improve the business environment have led to increased opportunities to invest in energy sector privatizations, with backing from the US Export-Import Bank, OPIC and the US Trade and Development Agency taking credit and country risks that exceed the appetites of commercial institutions.

Other countries have also recently pledged aid to support sub-Saharan African infrastructure. Japan has pledged $14 billion in aid to Africa over five years, and approximately half of the money will be targeted at infrastructure development, with Japan supporting its firms' desires to export transport systems and power grids. The United Kingdom has supported 437 transactions totaling $30.5 billion, while France has supported 141 transactions worth a similar amount.

Chinese Competition

The controversial partner in the investment rush in Africa is China, whose investments in Africa have grown by a factor of 30 since 2005, with over 2,000 firms being represented in 49 transactions totaling $20.8 billion.

Commentators question whether Power */ continued page 12*

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WIND FARMS accounted for 43% of new generating capacity built in the United States in 2012, but 2013 is expected to be a slow year while developers gear back up, according to a new report by Ryan Wiser and Mark Bolinger of the Lawrence Berkeley National Laboratory in early August.

The authors expect an uptick in projects that need financing in 2014 given the need to start construction of new projects by year end 2013 to qualify for federal tax credits. However, the outlook for 2015 and beyond is uncertain.

The US has 60,000 megawatts of installed wind capacity. Only 1.6 megawatts were added in the first quarter of 2013. Just 537 megawatts were under construction as of March 31 this year. The biggest gains in 2013 will be in natural gas and solar. The Solar Energy Industries Association reported that solar accounted for 49% of new electric generating capacity installed during the first quarter of 2013, and the fast-growing solar rooftop residential market grew by 53% year on year to the end of the first quarter.

Wind turbine prices are currently in the $950,000 to $1.3 million range per megawatt. The average installed cost per megawatt for wind farms completed in 2012 was $1.94 million. Merchant or quasi-merchant projects accounted for 19% of new wind capacity additions in 2012.

Electricity prices under long-term power contracts have fallen to the lowest levels since 2000 to 2005, but construction costs have increased since then, making the economics for wind projects more challenging. The average price for contracts signed in 2011 and 2012 was $40 a megawatt hour. The prices vary by region, with prices in the $50 to $90 range in the West, $20 to $40 in the interior of the country and $50 to $70 in the Great Lakes and Northeast.

Utilities in the Southwest and Texas signed another 1,500 megawatts of long-term contacts with wind companies in recent weeks at prices */ continued page 13*

Powering Africa

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Africa can compete effectively with China's non-interventionist investment model, expressing concerns that China's African investments are undercutting US efforts to increase efficiency and transparency in public policy and business practices. While US-supported investments take an active stance towards eliminating regulatory barriers and corruption, Chinese investment has taken a more hands-off approach for how host countries manage in-bound investments.

While China has pledged to provide African countries with $20 billion in loans, it has been criticized for the presumed, tacit tying of those loans to Chinese goods and services and even imported Chinese labor. Export financing by OECD members is also, of course, tied to national exports. However, the United States and the other OECD member nations, as well as numerous non-OECD members, have committed under the OECD Arrangement on Export Credits to regulate the terms on which they provide export financing, constraining the extent to which export credit terms can be discounted. This agreement avoids the cutthroat competition that had previously characterized dueling export credit agencies. Under the Arrangement, if a member wants to provide more substantially discounted terms, then those terms must become a grant, i.e., a gift, to comply with the Arrangement.

China has so far declined to join the Arrangement and openly ties not only its aid but also its export credits to the use of its own goods and services and provides that financing on terms that would violate the Arrangement. As a result, 40% of China's global foreign aid expenditures in recipient countries worldwide are for construction projects in which China provides some or all of the financing, services, materials and labor on financing terms with which countries adhering to the Arrangement cannot compete.

The US policy focus on a sustainable business environment promoting local development and long-term investment opportunities is also in contrast to China's non-interventionist approach of making substantial, even massive, investments in physical infrastructure, but without a similar level of regard to the regulatory, legal, political or other societal factors that may ultimately prove critical to the ultimate functioning of that infrastructure. Concerns have been raised that the Chinese model perpetuates circumstances that stand in the way of modernization and development of the host countries.

Life-Cycle Costing

One blunt accusation is that Chinese bidders often win procurements with the lowest bid, but deliver facilities with a correspondingly low quality, requiring high maintenance that is beyond the capacities of the host countries to provide. The all-in cost of keeping such facilities in operation undermines the advantage seen in the low original cost. The US Trade and Development Agency is attempting to address this issue head on by partnering with the George Washington University law school and collaborating with various multilateral development banks, in an initiative to promote "life-cycle costing" and "best value," rather than just lowest price, in bidding for public procurements. The life-cycle cost is the sum of all recurring and one-time (non-recurring) costs over the expected useful life of a project, including the costs to install, operate, maintain and upgrade and the remaining value at the end of its useful life.

US and European companies tend to believe that, while their equipment or construction may come at a higher initial price than that of Chinese and other low-cost competitors, the result will be a longer useful life with lower maintenance costs, yielding, in the long term, a better value for the purchasing country. Thus, a best value approach in bidding will benefit both US and European companies and, in the long run, their host country customers.

Another development outside of the Africa Power initiative that could have important consequences for how Africa Power develops is the US government's recent announcement that, going forward, it will not finance, insure or otherwise support coal-fired power projects unless carbon capture and sequestration are used, except in the absence of feasible alternatives for "the poorest of the poor." No one expects there to be any actual agency financing for coal-fired generation plants in Africa or elsewhere. Consequently, while Power Africa speaks of electrification broadly, the focus is likely to be on gas-fired or renewable energy projects.

For countries that lack access to natural gas, this may involve introducing more intermittent renewable energy sources into an already unstable grid, adding to the technical challenges that will need to be resolved.

Looking Forward

While it remains to be seen whether Power Africa will succeed in bringing governments, investors and financiers together to address the electricity infrastructure needs of the region, it should at least succeed in drawing serious attention from commercial parties and public institutions to opportunities in the region's energy sector.

Project developers will have a chance to explore those opportunities at various upcoming conferences. For instance, in 2014, OPIC and the US Agency for International Development plan to host jointly an African energy and infrastructure investment conference, bringing developers and other investors together with key US and African government officials to demonstrate the opportunities for investment and the tools and resources available from the US government and other partners to support those investments. Stay tuned. ◎

Going Merchant

The last time merchant power plants could be financed and developers were able to raise 100% of the project cost in the debt markets was shortly before Enron collapsed. Now such financings are back. Panda raised term loan B debt for a merchant gas-fired power plant at 600 basis points over LIBOR, and the transaction was "reverse flexed." Moxie Energy, Invenergy and others have been in the market with merchant financings. In what circumstances are such terms available? What does it say about the market? A panel discussed the subject at the 24th annual Chadbourne global energy and finance conference in June.

The panelists are Todd Carter, president of Panda Power Funds, Scott Taylor, CFO of Moxie Energy, Ray Spitzley, senior managing director at Morgan Stanley, Mike Pantelogianis, co-head of power at Investec Bank, and Andrew Rosenbaum, a director at Royal Bank of Canada. The moderator is Rohit Chaudhry with Chadbourne in Washington.

MR. CHAUDHRY: Is it a real trend toward merchant power or just a smattering of projects?

MR. ROSENBAUM: There is no trend *per se*. There are a lot of banks chasing a relatively small number of deals. Non-merchant deals are more prevalent than merchant opportunities.

Pricing is at very tight levels. There is a lot of private equity in the market. A number of funds have been raised and dedicated to this sector at a time when the opportunities have been harder to come by. Pension funds have also been drawn into the sector. There are broken price signals. Some lenders are willing to lend despite what the rest of the market is seeing in terms of inadequate capacity payments and

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ranging from $22 to $33 a megawatt hour.

Renewable portfolio standards that require utilities in 29 states and the District of Columbia to supply a certain percentage of their electricity from renewable energy are expected to require only another 3,000 to 5,000 megawatts of renewable generating capacity each year during the period 2013 through 2020. The industry is fighting efforts by conservative interest groups to roll back these standards in various states, but so far the line has held.

Wind accounts for 20% of more of electricity supply in three states: Iowa (25%), South Dakota (24%) and Kansas (20%). This compares to an average of 4.4% nationwide. The top four states for new wind construction in 2012 were Texas, California, Kansas and Oklahoma.

ARIZONA is the latest battleground for rooftop solar companies and utilities.

Arizona Public Service asked the Arizona Corporation Commission in July for permission to charge customers who install rooftop solar panels $50 to $100 more a month on their utility bills as compensation for the ability to draw electricity at any time from the grid. The additional charges would only apply to customers who install solar systems after October 15.

The utility has 18,000 solar customers in its service territory currently. It is receiving 200 new applications a week.

It also asked the commission for permission to reduce the amount it credits customers who produce more electricity than they need and feed the excess back into the grid. The utility credits these customers under its "net metering" program at the same retail rate the customers pay to buy electricity from the utility. (Under a net metering program, a customer's meter runs backwards as it feeds electricity into the grid.) The average solar customer pays 15.5¢ a kilowatt hour. The utility argues that it should not have to pay more than the market rate it can pay to buy

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projected demand-supply imbalances.

MR. PANTELOGIANIS: There are pockets within the broader US market where capacity is needed. We are starting to see activity in ERCOT and PJM where investors are comfortable that enough cash flow will be generated from merchant projects not only to cover debt service, but also to earn an equity return.

Refinancing or new construction are much more achievable today due to the factors that Andrew Rosenbaum mentioned plus the fact that capital is more widely available as a consequence of QE3. Is this sustainable? I think it is.

MR. SPITZLEY: If you look back over the long history of project finance, sound fundamentals are important. It is good for project sponsors that we have frothy debt and equity capital markets, but the fundamentals need to be there. We are one of four banks participating in LS Power's West Deptford project, which is a fully-merchant greenfield project. That four banks participated was not a capital markets phenomenon. It was wholly driven by the fundamentals of the project, its location and what we saw in the forward price curves and PJM. There is a skilled operator and sponsor behind the project. The healthier the markets, the better the pricing that will be on offer, but we need to have the fundamentals first.

ERCOT and PJM are the two markets where merchant power projects have the best chance of being financed.

Fully Merchant?

MR. CHAUDHRY: You said the project is "fully merchant." Does that mean there are no hedges or other supports to put a floor under the electricity price? Is it the only project being financed in the current market that is not quasi-merchant but purely merchant?

MR. SPITZLEY: That's right. We are aware of other projects that have synthetic revenue that helps to provide comfort in the early years. Those projects are in ERCOT where there is no spare generating capacity. The West Deptford deal is in PJM which has a forward-capacity market, so there is visibility with respect to contracted capacity from the regional transmission organization. You can debate whether that is fully merchant.

MR. TAYLOR: There are companies that are consciously pursuing merchant as a strategy, but there is no broad trend. Those companies have a positive view of certain markets and want to benefit from that.

There are projects that are being developed on a merchant or quasi-merchant basis that backed into it out of necessity. I will use our project as an example. We developed our project with the goal of having the fundamentals to support a purely merchant project. When we started, the concept of going merchant was pushing the envelope. We thought it made sense as a business matter, but we were trying to land a power contract at the same time. We thought we had a couple opportunities, but we were naïve and found out quickly that it is easy to get a long-term power contract if you take a price that does not work economically. Getting a PPA that actually makes sense is more difficult, and we were unsuccessful. Fortunately, because of our fundamentals, we then quickly shifted toward a merchant or quasi-merchant structure.

There are some other developers who had no intention of ending up in the merchant market who got a project developed in an attractive area and then backed into, "I need to find a way to get my project done." Deals ready to close do not get better with time.

Merchant projects still need to have the fundamentals to close on financing. The frothy debt market is not leading to crazy financing structures. It is driving down the spread, but not allowing deals that lack the fundamentals to get done.

MR. CHAUDHRY: What are the fundamentals that make these merchant projects work?

MR. CARTER: They depend on the opportunity. The forward market is broken in Texas. We had to figure out something that would work in that market, and we were able to get our first project off and, shortly thereafter, a second and a third. The three fastest growing cities in the country are Austin, Houston and Dallas.

Geography

MR. CHAUDHRY: Which markets in the US do you think are well suited for a merchant deal? Which markets have the fundamentals for getting a project done on a quasi-merchant basis?

MR. TAYLOR: We picked PJM for our two projects because of the liquid electricity market, but the real driver was the ability to put two projects right on top of the gas supply. This gives us a gas supply-basis benefit that we believe is sustainable because there is not enough takeaway capacity to support the volume of gas. If a gas producer wants to increase its takeaway volume, its only option is to pay transport charges on an incremental basis. We get a benefit by being right there and allowing gas suppliers to avoid incurring those transport charges.

The founder of our company focused on PJM because we have western hub energy pricing, a capacity market and the gas benefit. The energy and the gas benefit were the two big drivers. The capacity market is important, but it was not the driver.

MR. CARTER: The ERCOT market was attractive to us because the market fundamentals were right. Power was needed in Texas. There was no capacity market, and you could not get a long-term, forward heat-rate call or any kind of forward hedge. So we took a position on that particular marketplace.

We are focused on lots of different markets. We like the PJM market because it has a lot of strong fundamentals. We like the ERCOT market because it has growth, unlike PJM.

I know there has been a lot of discussion about PPAs. They are like the mythical unicorn — very difficult to find. When you do find one, you should be very proud. As a general rule, we would not put a project on the ground without a long-term PPA.

MR. CHAUDHRY: Which markets do you think are easily financeable for a merchant deal?

MR. ROSENBAUM: We have not seen any greenfield construction outside of PJM and ERCOT. There is no sign that merchant developers are exploring other markets. That goes back not only to the fundamentals, but also to the regulatory structure.

There is probably a need for some new development in California, but the regulatory risk in that state is such that you need a PPA. */ continued page 16*

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power from large power plants.

> *The proposals would significantly alter the economics of installing solar. Some utilities are facing steady erosion in their rate bases as solar rooftop, fuel cell and small cogeneration or CHP companies pick off customers. The same battles are or will soon be fought in other states.*

FIXED-PRICE PURCHASE OPTIONS may receive more attention after a decision by the US Tax Court in a case involving LILOs and SILOs.

The court said 27 lease transactions that John Hancock Life Insurance Company did during the period 1997 through 2001 were not true leases for tax purposes and denied tax deductions for rent and depreciation that the company claimed.

Some of the transactions were cross-border lease-sublease deals called LILOs (for lease-in-lease-out) where mainly European municipalities or companies leased infrastructure assets to Hancock that Hancock subleased back to them. The remaining transactions were sale-leasebacks called SILOs where, at the end of the lease, the lessee had either to buy the assets or enter into a power contract or other "service contract" to continue buying the output from the leased facility. The parties selected three LILOs and four SILOs to litigate as test cases.

The government has won all six litigated LILO cases to date. A seventh case had a 10-day trial before the US Court of Federal Claims, but that court has not yet released a decision.

The Tax Court said that all of the Hancock LILOs and one of the SILOs were "financial arrangements" rather than real leases. In the other three SILOs, it said Hancock bought only a future interest in the leased assets.

The case is *John Hancock Life Insurance Company v. Commissioner*. The Tax Court released its decision in the case in early August.

Starting with the LILOs, Hancock leased assets for 38 years and subleased them back for 18, but the court */ continued page 17*

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However, look at it from a different perspective. There is a healthy trade in existing power plants. Almost all sales of existing projects require the purchaser to take some form of back-end tail risk. The projects were financed originally on the basis of a PPA or heat-rate call option, but buyers are committing capital beyond the known revenues that they see in front of them. We see that happening in every market around the country, some more than others. The secondary market is taking merchant exposure in every region of the country.

MR. CHAUDHRY: Coming back to the PJM market, there was a recent capacity auction. What were the results and what impact will they have on developing projects in the PJM market.

MR. TAYLOR: We were disappointed by the $119-a-day clearing price. We had projected higher numbers. It is easy to take that price and quantify the one-year hit to capacity revenues, but we are driven by our energy price. The capacity price is important because it helps with financing — it helps provide some benchmark for covering fixed costs — but our long-term view is based on energy and locking in a spark spread because of cheap natural gas.

The results in the PJM market should be kept in perspective. We would not develop a project based on a one-year number, particularly if that one-year number is a relatively small percentage of your total revenues. Even though it knocked off some cash in the first year, the silver lining is that there are other projects that were behind us in the development queue and were planning to line up their deals for next year's auction that are probably now slowing down their efforts.

MR. CHAUDHRY: What percentage of your overall revenues are capacity payments?

MR. TAYLOR: Less than 10%.

It highlights, in an indirect way, the sophistication of what people are doing. The capacity market was supposed to provide a forward price signal to induce new construction. We are saying it is not really a factor at all. Developers really have to take a different and more sophisticated view of the market instead of relying on the same price signals that others may use.

MR. PANTELOGIANIS: Don't you also look at how many new projects other developers have announced they are pursuing in PJM? Take New Jersey, for example. As we look at the queue, we see projects that were supposed to be locked up and contracted, but because of disputes with the regulated utilities, the projects are now going to be constructed on a quasi-merchant basis, and they depend more heavily on capacity payments from PJM.

Leverage in merchant projects is a little over 50%.

The meltdown occurred 10 years ago because of a realization that more projects, many of them merchant, were under construction than the market could support.

New Jersey announced several more projects including the 800-megawatt CPV Shore project. EIF has teamed up with Hess and has started building a project entirely with equity. NRG won a contract, but I don't think the project will make the cut and be built. As I look around, I ask myself, if I am dependent on capacity revenue to help me cover my costs, then I need to get comfortable that the market will remain stable over the next five years.

MR. CHAUDHRY: Scott Taylor, you said people should not place too much weight on the auction results because capacity payments are a small percentage of your revenue stream and they are only one-year numbers.

MR. TAYLOR: It goes back to the fundamentals. If you have a project where the capacity price is a small percentage of total revenues, it must be a small percentage either because you have favorable energy prices or cheap gas. It depends on the project. If the developer views the capacity payments as the real long-term benefit, then the recent auction results will cause work on the project to slow down. Projects with good fundamentals will keep proceeding, and projects that are on the margin will be more inclined to slow down when they see these types of price signals.

MR. CHAUDHRY: So there are a lot of projects coming on line. You may have some that rely on capacity revenues for a larger percentage of overall revenue. Are these new additions already factored into the recent auction prices? Will they cause developers to worry more about more depressed prices in future capacity auctions?

MR. TAYLOR: The $119 price reflects the projects that bid into it. The $119 price does not reflect projects that might be bidding in next year.

Necessary Fundamentals

MR. CHAUDHRY: Todd Carter, you have done three projects in Texas. What are the fundamentals you rely on to make a successful merchant project?

MR. CARTER: They are location, location, location. You have to be able to get your electricity into the marketplace. Do you have a willing community that supports your project? Do you have access to the lower-cost gas?

Everything starts with the location. I cannot stress that enough. We look at this as a private equity shop. I cannot tell you how many projects we have looked at for which we would not pay two nickels. The interesting thing about Scott Taylor's projects is the gas price. The gas price is phenomenal. It is negative 30¢ in Henry Hub. In the old days, all the gas was being brought up from the field, and it was 15¢ to 75¢ plus in Henry Hub.

MR. CHAUDHRY: How do renewables fit into a market with low gas prices? Is it possible to get a solar project done on a merchant basis?

MR. CARTER: You need to have a favorable offtake contract or a large tax credit. I hope we build all the solar and wind that we can. We think, because we use natural gas, that we are perfect dance partners for renewables. You have to have something there when the wind is not blowing or when the sun is not shining. It would be very difficult to do merchant renewables.

MR. PANTELOGIANIS: PPAs have been a big driver in the renewables market. If there is enough resource that you can make it work without a PPA, so be it, but it is tough to see merchant renewables.

MR. CARTER: You need an offtaker to make the economics work. You need predictable power prices as an offset to the intermittency of renewable resources. Solar residential is a merchant play of sorts. There are some sustainability goals that are served, but the business model is driven by grid parity. In markets where homeowners can lower their costs by installing solar, the business model flourishes. */ continued page 18*

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said the terms were otherwise virtually identical. No money changed hands in practice during the sublease term other than a payment by Hancock to the European counterparty as a fee to enter into the transaction. The upfront amount Hancock paid the counterparty was never really at risk during the sublease term since the counterparty's obligations to Hancock were fully defeased. Hancock argued that it had credit risk on the defeasance bank. The court called this risk *"de minimis."*

The court said Hancock had basically a predetermined fixed return. The European counterparties had options at the end of each sublease to buy the remaining leasehold interest Hancock held in the assets for a fixed price. The court assumed the purchase options would be exercised after concluding exercise is a "reasonable likelihood."

This view of purchase options is in line with a decision by the US appeals court for the federal circuit last January in a LILO case involving Consolidated Edison. The court in that case said it is a problem to give a lessee a fixed-price option to purchase equipment at the end of the lease term if exercise of the option is "reasonably expected." Many tax lawyers believe the Con Ed court used the wrong standard. Most courts to date have allowed fixed-price purchase options without disturbing true lease treatment as long as exercise is not a foregone conclusion.

The Tax Court defended the approach: "Neither the Tax Court nor the Court of Appeals for the First Circuit [where the Hancock decision may be appealed] has ever set an 'inevitable' or similar threshold for determining whether a lessee will exercise a purchase option, and we decline to adopt such a standard here." It insisted this is consistent not only with the approach taken in the federal circuit where the Con Ed case was heard, but also in the prestigious second circuit in New York.

Turning to the SILOs, the Tax Court said that in three of the four test SILOs, Hancock acquired only a future interest in */ continued page 19*

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MR. ROSENBAUM: Theoretically, there is room for merchant renewables, but think about combined-cycle gas turbines operating in a base load capacity. They give you a high degree of visibility toward the earnings potential. Compare that to renewables, which are generally interruptible and it is very hard to get a clear view of cash flows, which is what necessarily leads to a discussion about PPAs and other price supports.

The other factor with renewable energy projects is that the cost is known going into them. You have stakeholders that all need to get their pounds of flesh out of the project. Whether it is hedge counterparties that need to be paid an appropriate return for the risk they are taking, the lenders that need to be paid an appropriate return for risk or the equity. If those three parties can find a way to split the value and still leave something meaningful for the developer, then the opportunity to proceed on a merchant basis exists.

Right now, a combined-cycle gas turbine operating in a baseload fashion clearly has the opportunity to proceed on a merchant basis. At RBC, we did a merchant hydro deal with Brookfield. It was a secondary trade — it was not construction financing — and it was in a market where we had very clear price signals allowing us to size debt appropriately.

MR. CHAUDHRY: Are there any utility-scale wind or solar projects which have been done on a merchant or quasi-merchant basis or that are currently in the market?

MR. CARTER: Historically, there have been many quasi-merchant projects with financial hedges overlaid. A ton of activity occurred in ERCOT. A lot of the transmission issues in Texas are a function of the mass capacity additions that we saw in the mid-2000s associated with wind construction. Fundamentally, equity looks at achieving its returns during the period of the financial hedges. The hedges went out on the shortest side for only five to seven years, but it was more common to see 10-year hedges.

MR. CHAUDHRY: Andrew Rosenbaum, as a banker, what are the fundamentals you look for to make a merchant project or a quasi-merchant project attractive?

MR. ROSENBAUM: We focus on the risk that the project will be unable to pay debt service. Equity needs to be there in sufficient size. We look at how the project can de-lever when any hedge or cash flow support that was baked into the project expires. We look at the loan-to-value ratio. There are technology factors that will matter significantly. There are some things that we just cannot get our minds around and probably will not be able to lend through, but in terms of the base factors, that is probably it.

MR. SPITZLEY: Sponsorship is critical to us. We see the projects as being very complex. Not just anyone can build and operate a plant. If you look at who has been able to finance a merchant plant recently, two names, Panda and LS Power, keep coming up. There have been only two sponsors who have successfully financed large merchant projects to date.

After a good sponsor, we want cash flow stability during the tenor of our debt. Finally, we look strongly at what liquidity there has been around these types of assets in the M&A market.

Pricing and Leverage

MR. CHAUDHRY: At what rate is the debt for merchant projects being priced?

MR. CARTER: Ours was priced at about 950 basis points over LIBOR in July 2012 with fewer than 10 participants. We financed our second project 45 days later with 35 investment groups at 725 basis points over LIBOR in September 2012. We financed Temple II a few months ago at 600 basis points over LIBOR. We could talk about lots of other things. The original issue discount was much better. It was 98 the first time, then 98.5 and then 99.

MR. CHAUDHRY: There was such a dramatic decrease in the pricing between your first one to the third one in a matter of months. To what do you attribute this?

MR. CARTER: The first one is always hard. We were clearly the first project in ERCOT. There were a lot of people swirling around saying, "Man, I am trying to get a handle on this. There is no futures market. Okay, put a synthetic hedge in place." That was a big part of it.

The second part is that the potential pool of investors is larger. We went from a small investment to a larger one and then to an even larger one by the third project. People got comfortable with the structure because we did not change it much. People became better educated about ERCOT and the risks over time.

MR. CHAUDHRY: What kind of leverage did you get?

MR. CARTER: It was not great. Our first project was less than 50% debt, so we had to come up with a significant amount of equity. Then we got a little bit over 50% debt in the second project, which was 45 days later, and then closer to 55% debt by the end.

MR. CHAUDHRY: Scott Taylor, you are in the market currently and talking to banks. There have been press reports as to what pricing is being thrown around.

MR. TAYLOR: I cannot go into the details of what we are doing right now, but I will comment generally. We started looking at different financing structures from last year — with hedges, without hedges — but one of the key things that has not changed is the leverage and overall structure. Even last year when we were looking at higher pricing, the leverage levels that we were being told we could achieve were above 50% because of our gas benefit.

The reduced pricing is not a sign that there are more people willing to lend into weak deals, which goes back to my comment earlier. I do not think you are seeing lenders stretching to take on credit risk, but we are benefiting from lower pricing. We were looking at pricing last year of 625 to 725 basis points, but now the price is definitely below that. We are benefiting from the deals that went ahead of us and an improved market.

MR. CHAUDHRY: According to press reports, your deal is being priced in the 600s. What are the potential ranges for pricing and leverage for these types of projects?

MR. CARTER: I think you have seen the potential price range. The new construction projects have tended to be the highest priced because they are new entrants into the market. Naturally, there should be more speculation associated with those, and that translates into price.

As for leverage, on the first transaction, it was closer to $400 per kilowatt of capacity, but as we got to Temple II, it had moved toward $500 a kilowatt.

Then there are the existing, stand-alone, quasi-merchant assets that have proven track records. They have been pricing around 400 to 500 basis points above LIBOR, but may be able to get to 350 to 400. As investors and rating agencies get more confident about the operating assets, the price follows.

MR. CHAUDHRY: Andrew Rosenbaum, you mentioned to me that the market is pushing back on some of the pricing.

MR. ROSENBAUM: I would not say that the market is pushing back because that gives the impression that investors are saying things have gone too far and they do not like the terms any more. That is not what is happening.

Over the course of the last year, we have seen the institutional debt markets tighten. Some were on the verge of 150 basis points. We would not have done a small gen co financing with a high degree of confidence and / *continued page 20*

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the leased assets after the leases end. Hancock had little risk during the lease term because the lessees had defeased the rent even though this was not required by the documents, and Hancock was not directly a party to the defeasance arrangements. Although Hancock had no present interest in the assets, it acquired at least a future interest because the lessees seemed more likely to enter into service contracts to buy the output at the end of the lease terms rather than buy the assets.

Hancock said the Tax Court's approach threatens all leveraged lease transactions. The court disagreed. It said the lessor in a typical lease has credit risk that the lessee will default on rent during the lease term. Hancock had no such risk because of defeasance. There are two types of defeasance: "legal defeasance" where the bank into which the lessee deposits money to pay future rent assumes the legal obligation to pay rent and the lessee is released, and "in-substance defeasance" where the lessee remains legally obligated. The distinction made no difference in this case.

One of the SILOs did not involve any defeasance, but the court felt the purchase option in that transaction was reasonably likely to be exercised. The court said Hancock had basically made a loan to the lessee in that case. Assuming exercise of the purchase option, Hancock had a predetermined return without regard to the asset value and no upside potential or downside risk tied to ownership.

On the positive side, the court rejected an IRS claim that the transactions lacked economic substance. Courts deny tax benefits in transactions that are entered into solely for tax reasons without any real business purpose or expectation of a return beyond the tax benefits. Congress has since written this requirement into the US tax code. The Hancock transactions preceded codification.

Hancock said it expected a pre-tax return in the LILOs of 2.54% to 4.33% if the purchase options were not exercised, ***/ continued page 21***

Going Merchant

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call it below the BB- ratings range 18 months ago. There just was not a lot of precedent for that. The spread would have been something like LIBOR plus 425 to 450, with a 125-basis-point floor. Everybody that accessed that market has increased leverage and re-priced his deal; some were in the neighborhood of 100 to 150 basis points tighter. The incremental leverage has usually been taken out in the form of a dividend.

We have seen the market get more aggressive in pretty much every measure. In the last couple weeks, the credit markets at large have sold off. Whether it is the market at which Panda and Moxie Energy are looking or what some of the mid-market sponsor portfolios are tapping or the Treasury market, everything sold off over the last couple weeks. You saw the Calpine deal get pulled right after NRG priced its deal. I cannot tell you that there is a meaningful credit differential between those names that explains why one got done and one did not. They are both phenomenal companies with great stories, sort of the sweethearts of the independent power space. But the market sold off and one company got in before the window closed and one tried shortly thereafter. That just happens in credit markets.

Companies bidding to buy portfolios of operating projects are taking merchant risk after the existing PPAs expire.

1990s Redux?

MR. CHAUDHRY: Ray Spitzley, you have been doing this for a long time. Merchant, quasi-merchant — haven't we seen this before? In the 1990s, it all ended badly. Why do you think it will be different this time around?

MR. SPITZLEY: In the 1990s, a bunch of things were different, but fundamentally that was an equity market. There was a general view that deregulation convergence between gas and power and the new, efficient combined-cycle turbines were going instantly to displace the old coal-fired inefficient power plants. Companies could not start construction fast enough, and you had highly-leveraged companies looking to banks to take bank loans that had been 100% financed for construction projects into the public capital markets. For a while that worked. When Enron collapsed, the music stopped, and there was a re-evaluation.

The public equity capital markets are not looking for merchant growth. It is a much more disciplined equity environment. Their focus is cash flow, and they scrutinize new projects heavily. It is no accident that the people who are developing new projects are independent entrepreneurial private equity folks and then, once the projects get built, some will be acquired by the bigger publicly-traded players.

The merchant space is heading toward consolidation. Some of the big names that own generation portfolios will exit the business as we have seen with Dominion, PEPCO and Duke. Some of the private equity portfolios will become public and then, once they are public, will undoubtedly look to merge because the public markets will pay for operating and locational synergies of having a broader portfolio. That is what is really being rewarded in the market today. Private equity will continue to play a role in early development. Consolidation is where it will head.

MR. CARTER: When I look at my career and what we were doing during deregulation and how we were financing, I remember doing computer models and bond deal after bond deal around gen cos that were rated investment grade. Then all of a sudden, we found out that these were not investment grade. As we were learning about the merchant markets and the merchant game, the market pulled back.

We are in a far more mature period today on the trading side, the capital side and the development side. That allows for more prudent investing and for the right assets to be developed, and so I am not worried that we will get another head fake from the rating agencies that contributes to what happened the last time. ◎

Market Outlook

Will there be a rush in the United States to start construction of new wind, geothermal, biomass and other renewable energy projects by year end in order to qualify for expiring tax subsidies? Growth in demand for electricity has slowed to just 0.7% a year. Contracted electricity prices for wind projects have fallen in some states to less than $30 a megawatt hour, but are the low prices making utilities more interested in buying long term? Many developers were keen the last three years to get as much output as possible under contract, but are they now keener to retain the potential upside if prices increase? Do low returns and low load growth still justify investment in the US or are the best opportunities in places like Latin America where prices for contracted power can be $200 or more a megawatt hour?

A panel discussed these and other questions at the 24th annual Chadbourne global energy and finance conference in June. The panelists are Gabriel Alonso, CEO of EDP Renewables North America, Tristan Grimbert, CEO of EDF Renewable Energy, Carlos Domenech, president of SunEdison, Christopher Hunt, managing director of Riverstone Holdings, the parent company of Pattern Energy, and Kevin Smith, CEO of SolarReserve. The panel was moderated by Evelyn Lim with Chadbourne in Los Angeles and Keith Martin with Chadbourne in Washington.

MS. LIM: Gabriel Alonso, will there be a rush at the end of 2013 to start construction of new wind farms to qualify for tax credits?

MR. ALONSO: Yes. If we look at the history of the wind industry, there are clear boom-and-bust cycles. We have been here before, and we know how the industry behaves in these situations. We are hoping to cover our 2014 to 2015 business plan growth by starting construction of all 2014 and 2015 projects by the end of the year. I expect other wind companies will be trying to do the same thing.

MS. LIM: Tristan Grimbert, what else do you take into consideration, besides a desire to qualify for tax credits, when deciding whether to try to start construction this year?

MR. GRIMBERT: Ideally we would like an offtaker for the electricity. It may be possible to start construction with just a hedge that provides a floor under the electricity price. It takes longer to secure a power purchase agreement than to put in place a hedge.

MS. LIM: Chris Hunt, as a private equity investor, how

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and 2.83% to 3.43% if exercised. A government witness argued that Hancock has a pre-tax loss on the deals if the calculations are done correctly using present-value concepts. The court agreed the numbers should have been discounted, but was not persuaded by the government's calculations. It also said Hancock had a clear business purpose: the need to fulfill its insurance policy and annuity obligations contributed significantly to its investment decisions.

The court called the LILOs and one of the four SILOs mere "financial arrangements" and recast them basically as loans by Hancock to the counterparties. In so doing, it not only denied the tax benefits Hancock claimed, but also required it to report the difference in what it paid and what it was expecting back as original issue discount over the life of the "loans."

ANOTHER LEVERAGED PARTNERSHIP has come under attack.

Such transactions are sometimes used by sellers of assets to defer a tax on gain. Rather than make a direct sale, the seller and buyer both contribute assets to a partnership. The seller contributes the assets it intends to sell. In this particular case, the buyer contributed notes and cash for the purchase price. The partnership then borrowed the amount of the notes from a bank and distributed the amount to the seller.

The seller does not have to pay tax on the cash distribution as long as the distribution is not recast by the IRS as purchase price for a disguised sale of the assets to the partnership. It should not be as long as the seller is ultimately liable for the partnership-level debt.

Two special-purpose subsidiaries through which the buyer held its interest in the partnership guaranteed repayment of the loan. The seller agreed to indemnify the buyer's subsidiaries if they had to pay on the guarantee. However, there was no requirement in the indemnity for the seller to maintain any particular net worth.

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willing are you to start construction of projects to take advantage of tax subsidies if there are no offtake agreements?

MR. HUNT: We are always willing to invest money if we see a return. The big question is whether the return will be there. I do not see as big a rush as some of my colleagues do. The rush at year end will be muted for two reasons. First, a lot of the utilities that were prepared to enter into long-term power purchase agreements did so in 2011 and 2012, and there will not be as many new PPAs in 2013 as there have been in the past. Second, the bigger players are just not as active in new wind development as they have been in the past. The question is then whether that will create opportunities for guys like me. There is plenty of private equity money available for investment. I think there is a shortage of projects that fit the criteria by which we invest.

Finding PPAs

MR. MARTIN: Carlos Domenech, how easy or hard is it to get a power contract today in the US market?

MR. DOMENECH: It is not easy in the utility-scale market. The market is highly saturated. We do not develop greenfield projects at the utility scale because there are plenty of quality projects to buy. We are a very aggressive buyer of companies, projects and portfolios and there are many companies that are willing to sell themselves or their development pipelines. The challenge is visibility and predictability around interconnection on the utility side. You might have a power contract, but it is subject to a utility building the intertie needed to connect the project to the grid by a certain deadline, and we see slippage on the utility side. That casts a cloud over the PPA.

MR. MARTIN: Kevin Smith, what is your experience in the US market trying to secure long-term power contracts?

MR. SMITH: The big rush was last year. Contract prices have been driven down largely because of low natural gas prices. That is hurting both the wind and solar sectors. Some companies are willing to go into construction with short-term hedges and worry about power contracts later. We cannot do that. We will see a bit of a rush, but we will not see what we have seen in previous years when programs expired.

US Versus Foreign Markets

MR. MARTIN: Chris Hunt, a Spanish solar company that visited our office in Washington last fall said that the US market no longer produces high enough returns. The company is no longer interested in doing solar projects in the United States and is looking mainly at Africa and Latin America. You sit in London and see the whole globe. Is the US now a poor market for renewables?

MR. HUNT: Foreign companies are at a disadvantage when doing business in the United States. Repatriation and other tax issues make it more challenging for foreigners to compete here. The industry is tough regardless of where you are. I would not say that Europe or Latin America or Africa is risk free.

I think there are good projects in Europe. The European market bifurcates between northern and southern Europe, and northern is probably a safer, more stable place than southern to invest right now. That said, there are perfectly valid projects to pursue in southern Europe. We are actively building wind and solar in those markets.

We are building projects in Chile where it is possible to earn decent returns.

A lot of people have been turned off by Africa. We have not chosen to pursue projects there for a number of reasons. It is a market that if you got in early and made some of the early-stage rounds, you may have been able to earn decent returns and find some decent projects, but it took a fair amount of risk to get them.

MS. LIM: Are there areas

Developers are bidding for PPAs with California utilities at prices that will be lucky to earn them a 6% return.

outside the United States where the spot market prices for electricity are high enough that you do not need a long-term contract to build a project? Are you finding opportunities to supply power directly to industrials inside or outside the US?

MR. GRIMBERT: The safest investment anywhere remains a wind farm in the US with the 20-year power purchase agreement.

European governments have been looking at budget deficits and cutting subsidies for renewable energy. A project with a 20-year PPA is a safe investment. It does not have to be in the United States. You can enter into a 20-year PPA in Brazil, and South Africa is also a good investment. However, there is currency risk in cross-border projects. How can you rely on Brazilian reais or, if you are a European company, on the dollar-versus-euro exchange rate?

The beauty of a 20-year PPA, if you are a disciplined operator, is that even if you believe the contracted electricity price is low, the project will have a merchant tail when you can sell at full market prices.

MS. LIM: What do you do during a period like today when it is hard to get a 20-year PPA in the United States?

MR. ALONSO: It is hard, but not impossible, to find a PPA. Xcel is actively reacting to the extension of production tax credits, and there are other utilities that are also looking to enter into long-term PPAs. Now more than ever, utilities are looking for different structures. They are expecting developers to take the intermittency risk around wind. They are open to PPAs with developers whose projects are one or more states away.

There are opportunities in states like Kansas or Oklahoma where utilities are looking to enter into PPAs beyond what they are required to do under state renewable portfolio standards because electricity prices are low and the public utility commission is willing to allow prices under those long-term contracts to be passed through to ratepayers. We are seeing more industrials willing to sign long-term power purchase agreements. The industrials are not a big game changer at this point, but I hope it is the start of something that will really drive demand for our industry.

MR. DOMENECH: A lot of the recent growth in the US market has been in distributed solar. We also manufacture solar panels, and we announced a 40¢-per-watt panel with around 19% efficiency that is competitive even in Chinese terms. I would not expect a private equity fund to be able to compete in that market with tax equity as an alternative source of financing at 6 3/4% or 7%.

Frankly, we are really excited about the / continued page 24

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The IRS has challenged the transaction on audit. The IRS national office rejected the idea in an internal memo that the seller is ultimately on the hook for the partnership-level debt because no payments have to be made on the indemnity unless the buyer has had first to pay out on the guarantee. If the transaction runs into trouble, then the buyer would default on the guarantee, and the seller would not have to make a payment, the IRS said.

The IRS also does not believe that the seller should get a pass as a policy matter on re-characterization of the transaction as a disguised sale. Congress intended that these sorts of transactions would not be recast as disguised sales, the IRS said, only where a partner contributes to a partnership property that is already subject to debt and then receives a cash distribution or else the partnership borrows against the assets after the contribution to make the cash distribution. The IRS said the borrowing in this case is nothing more than an advance against the notes from the buyer.

The national office suggested that if its technical arguments fail, then the audit team should attack the transaction head on, either by recasting it as a borrowing by the buyer to buy the assets followed by formation of the partnership or by arguing that the transaction is in reality a sale.

The facts appear to match a transaction that the Tribune Co. did when it sold Newsday in 2008 in the hope of deferring tax on the gain for 10 years. It did a similar transaction in 2009 when it sold the Chicago Cubs. The IRS wants $190 million in back taxes on the Newsday sale plus a $38 million penalty and $17 million in interest through December 2012. The Tribune Co. said in a financial filing that it plans to take the case to IRS appeals. It is currently under audit in the Cubs transaction. The company warned that it could be liable for another $225 million in federal and state income taxes on the Cubs deal before penalties and interest. / continued page 25

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international market. Our goal is to have 50% US and 50% global projects. Global PPAs are a phenomenal market with great returns. In the US, non-utility-scale PPAs are really high growth for us and also have great returns.

MR. SMITH: There is a difference between your market sector, which is more residential and large commercial, versus the very large utility-scale projects. There was a big rush into large solar projects with the DOE loan guarantee program and section 1603 Treasury grants. I do not think we will see many big projects in the US solar market now that those programs are winding down.

We have a 150-megawatt power contract for our Rice project in California. We are trying to get it into construction early next year. We are in financing now. We moved overseas a few years ago. We are still active in the US market, and we just committed to a project in Arizona. Including PV and solar thermal, we have 250 megawatts under construction in South Africa. We use a developer's model, which is that we lead the development activities, take the development risk and bring in other, largely local equity players, although Google came into our most recent deal that we closed in late May in South Africa.

We see a lot of growth in the international markets such as Saudi Arabia and Chile. We are doing things in Australia. The fact that we combine storage with solar thermal is even allowing us to engage in China. We would love to do more in the US, but in an age of 8¢ power contracts, we do not think the returns work.

If you look at all the bids in the last 12 months in California, you are lucky to be able to supply electricity at a 6% return. Such low returns will not work for the equity investors that we can find in the market. It will be interesting to see how many developers holding power contracts in California will walk away from them without building the projects.

MR. GRIMBERT: Six percent is on the high side of where some of these power contracts are being bid. Some bids in recent rounds in California were 6¢ and below. Solar companies, desperate to secure power contracts in a hard market, are underbidding each other. It happened in the wind sector. I have been in the US market for 10 years, and you have this underbidding and consolidation cycle. We are in such a cycle for solar today.

Current PPA Prices

MR. MARTIN: If solar developers are being offered 6¢ to 8¢ a kilowatt hour and earning only 6% returns, what are the current prices in the wind market for electricity and what are the returns?

MR. GRIMBERT: Too low. We are below 3¢ in the central Plains, but production tax credits add another 2.3¢ after taxes. It is a head-to-head competition in California between wind and solar, and solar is winning most of the bids.

When I was talking about a rush at year end to start construction of additional wind farms, it will be a rush to find enough equipment for delivery by year end in a market where turbine manufacturing capacity has shrunk. The size of the market has contracted. There will be a rush within that smaller market.

The key question for US developers is what is the return and how does it compare to what could be earned by deploying the same capital outside the US. The returns in the US are pretty tight, but as Gabriel Alonso said, this is a secure market with lower risk. Success is building a project that adds value. There used to be 350 gigawatts of wind in the pipeline a year ago with a build out expected of five to 10 gigawatts a year. That was 50 years of inventory. Now we have 150 gigawatts in the wind pipeline. That is about 20 years of inventory.

We have to think differently, whether it is taking some transmission rights risk or putting in storage or even developing in a difficult area. There are still very interesting projects, but you have to find them. The good news is that the pool has shrunk and a lot of players have pulled out. Some have gone bankrupt. There is still a way for the strongest to survive.

MR. HUNT: I fully agree. The phrase commodity wind or commodity solar is a good one because if you just stick to a project that anybody could do or anybody could bid, you will have a terrible return. The way to make money is to look at a project that has some differentiation.

If I were to look at the range of power prices in our current stable of power purchase agreements, there is an eightfold differentiation between the lowest and highest price. Obviously, you want to focus on the higher priced contracts. The key is to stick to fundamentals: find the best located project, the best resource, the best PPA and, if nothing good presents itself, wait. Right now, we sit on a lot of projects, and we will wait until there is a better contracting environment. In the meantime, we will continue to look for other projects. If you get lured into a commodity wind or commodity solar project, then you will get lured into an unexciting return.

MR. MARTIN: Gabriel Alonso, like many other wind companies, you have been dabbling in solar. Is that a sign that wind is not the best place to be at the moment?

MR. ALONSO: For us, wind is a better place to be. We have been looking at solar, but it is a race to the bottom. The solar market is much stronger, but also much harder than what we are seeing in wind. We are late to solar, so I would not call solar an attractive space.

We did not see PV coming. We were more involved with CSP five years ago in the belief that it would be the winning technology. What we are seeing is that there are some utilities that are late to the space. They are very aggressively buying solar projects, more than wind, because they have the ability currently or expect to have the ability in the future to use the investment tax credits on such projects. We do not have that ability. They feel more comfortable with the operational risks of solar versus wind so that we cannot compete. Our true equity cost is similar to theirs, but when you take into account that they can get full value for the tax subsidies on solar projects while we lose part of the benefit by having to monetize the tax subsidies, we cannot compete with them.

Electricity Storage

MR. HUNT: We have a different technology. We have storage technology that can run 24 hours a day as a non-intermittent supply. The problem in the US is that while the utilities say they love storage, no one is willing to pay a premium for storage. We are seeing international markets demand storage that don't have quite the robust transmission system we have here in the United States. Differentiated projects in the US are really few and far between. We have a very differentiated product, but the US market is not assigning value to it right now.

MS. LIM: We understand that Puerto Rican utilities are asking for storage in connection with bids to sell electricity. How are you approaching storage and the demand by utilities to smooth out intermittency?

MR. DOMENECH: We were the first company to contract with the largest Chilean mining company, COCAM, for a 100-megawatt power contract. Chile has an issue because Argentina decided to stop sending gas to Chile; it is exporting all gas to Asia. The cost of gas is way above the cost of solar, so it creates an opportunity. We can deploy solar alongside gas and create a synthetic PPA that allows mines to lower their overall cost of energy.

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The internal IRS memo is Chief Counsel Advice 201304013. The IRS released a redacted version in June.

The US Tax Court treated a similar transaction as a sale in 2010 after Chesapeake Corporation — now called Canal Corporation — conveyed the assets of a subsidiary that made paper products to Georgia Pacific using a leveraged partnership. See earlier coverage about the structure in the September 2010 NewsWire starting on page 17 and a "Special Update: Tax Issues in Project Sales" in June 2004.

SOLAR ROOFTOP SYSTEMS owned by solar companies and leased to homeowners are not "immovable" property and, therefore, the homeowners leasing them must pay a 4% sales tax on the rents, Louisiana said in a ruling in late June. The ruling is Revenue Ruling No. 13-006.

Louisiana allows a 50% tax credit on residential solar systems, up to a maximum credit of $12,500. The credit drops to 38% of the system cost for systems installed after 2013, up to a maximum of $9,500. Homeowners sometimes assign the tax credit to the solar company leasing them the systems. The ruling said that in such cases, the assigned tax credit is considered additional rent to the solar company and is also subject to the sales taxes.

ARGENTINA is replacing a list of countries considered tax havens with a new list of "cooperative jurisdictions" that share tax information with the Argentine tax authorities. Any countries not on the new list will be considered tax havens.

Higher withholding taxes apply on payments to tax havens, and arrangements with tax haven companies are not considered at arm's length and are subject to greater scrutiny.

Many Latin American countries maintain such blacklists.

The current Argentine blacklist includes 88 jurisdictions, including Bermuda, the British Virgin Islands,

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Our core storage solution is molten salt storage. We are building our lead project in Nevada and have an extensive overseas portfolio. We are looking at both large-scale solar PV and solar thermal. Storage for PV is more difficult. There are some markets where there are clear requirements for storage. The mining sector is looking for electricity 24 hours a day and seven days a week. We are looking at combining solar thermal or PV and with backup diesel generators.

MR. HUNT: The storage market has been frustrating for me. I would love to do an electricity storage project. I have danced around and looked at projects over the last four or five years and have not found anything yet in which to invest. There are several reasons why.

First, the market in the US simply does not value constant power the way it should, and I cannot explain why. Solar electricity from a CPV project has a monumentally higher value than electricity from a PV project.

Second, in a period of low gas prices, it is easier for other types of generation to provide ancillary services cheaply.

Adding storage to wind farms is challenging because the market does not value constant power the way it should.

Third, just as solar panel prices have plummeted, the cost of batteries is also falling. This brings the day closer when batteries can be added economically to wind and solar projects.

Fourth, I see storage as not so much an issue for solar as for wind. When you are able to sell solar during a peak period, you get a good price. It is hard to justify diverting solar kilowatt hours to storage when you can get a good price by selling directly to the grid. If you can charge a battery in the middle of the night with wind when power is virtually free, it makes more sense.

MS. LIM: Tristan Grimbert and Gabriel Alonso, have you been considering storage for your wind projects?

MR. GRIMBERT: Yes. The key question is whether to add storage at the project or the utility level.

We have been focusing mostly on the project level, and there are some wind projects where it makes sense. With wind, you get more bang for your buck at the project level.

It is very difficult today to justify solar storage at the project level. With solar, we have to look at storage at the utility level. The utilities are best equipped to balance their needs.

MR. ALONSO: I have to be frank; we are not considering storage. We have looked at storage, but the wholesale markets in the US are not favoring storage. They are solely focused on electricity prices. There are utilities asking us to deliver a product that is not intermittent, but they are not willing to pay enough for it to justify storage.

MR. DOMENECH: There are a few exceptions to that in the US. The pricing structure in California is based on time of day, so the California peak market is paying two to three times what you will get off peak, and the peak period in California is 1 p.m. to 8 p.m., so utilities will pay 15¢ per kilowatt hour during summer on peak hours and 4¢ to 5¢ for off-peak energy. Time-of-day pricing has happened very slowly over time, and we expect to see more.

The utility in Nevada is pushing our project in that state into the evening hours because that is when it reaches peak load, but there is no payout for that.

Time-of-day pricing is showing up in some of the international markets such as South Africa in the third round. Their solar thermal bids have time-of-day pricing, which is an interesting development.

Wind Turbines

MR. MARTIN: What is the current wait time for wind turbines? Have turbine prices stabilized? Do you see yourself placing another large order this year?

MR. ALONSO: Turbine prices are going down. However, we do not see a consistent behavior. Some turbine suppliers do not expect a large rush at year end in the US, so they are rushing to be the first ones to book orders for what they expect will be a small number of new turbine orders. Some others believe there is a rush coming, so they are in no hurry to sell turbines quickly or cheaply.

The larger trend is for the marginal price of turbines to keep falling as the technology keeps improving, so the cost of wind energy is coming down. How much of that do I keep for myself? Zero, because it is a market in which wind companies are racing to the bottom to secure scarce power contracts. If I can do something more special on the structures to sell the electricity, maybe I can keep a good amount of that upside, but in a commodity wind scenario, it is not something that I can keep.

We will not be placing a large order without offtake contracts behind it.

MR. HUNT: You are seeing the wind market bifurcate a bit. It is fairly clear there are too many wind turbine manufacturers in the world. Some will survive and some will fail. You are going to see a lot more price cutting by those who are less likely to survive. The tough decision wind companies must make is whether go for the lowest price when there is greater risk that the vendor will not be around in 10 or 15 years.

MR. MARTIN: There was only one Chinese turbine vendor at the global windpower convention in Chicago in May. What do you make of that?

MR. GRIMBERT: I think they are busy at home, and they do not see the US market being as interesting as it used to be. This is because, while there may be a year-end rush, there is no growth. I am not sure I agree with Chris Hunt, but I agree with Gabriel Alonso that the price keeps trending down because there is competition with half a dozen first-tier vendors. The good news is that we see the turbine prices trending down even among the survivors. It is going in the right direction, and we already placed one order for North America since the beginning of the year, and we will place more before the end of the year.

MR. MARTIN: Is that ahead of having power contracts for projects?

MR. GRIMBERT: No.

MR. ALONSO: This is a technology market, unlike the solar space. Solar panels are a commodity. I am sure the panel manufacturers are trying to change that dynamic. The wind industry has always understood that the Chinese were coming, and there was a rush to develop new technologies that would keep the US and European turbines two / continued page 28

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Cayman Islands and Luxembourg. Bermuda and the Cayman Islands are no longer expected to be treated as tax havens after the new list is issued.

CURTAILMENTS may not prevent a power plant from being considered in service for tax purposes.

Solar, fuel cell and small cogeneration or CHP projects face deadlines to be put in service to qualify for investment tax credits.

The IRS said in private letter rulings that the agency made public in late June that two utility-scale solar photovoltaic projects will be in service notwithstanding that the local utility to whose grids the projects need to connect to get their electricity to market will not have completed part of the network upgrades required to accommodate the electricity on a segment of the grid due to litigation with local residents. The utility determined that the projects are able to deliver their full capacity despite not having made the upgrades to the segment. However, the projects may have to be curtailed while the segment is under construction.

The IRS said the projects will be considered in service even "if more frequent than anticipated curtailment . . . occurs due to the unanticipated delays" in completing the upgrades.

The rulings are Private Letter Rulings 201326008 and 201326009.

A PUERTO RICAN solar project will qualify for an investment tax credit and accelerated depreciation in the United States, the IRS said.

The IRS confirmed that a US limited liability company that is treated as a partnership for US tax purposes and that is developing a solar project in Puerto Rico will be able to claim the tax benefits when the project is completed. The partnership has two partners. Both are US corporations. Projects outside the United States do not normally qualify for these tax benefits. However, projects in Puerto Rico and other US possessions qualify if owned by US citizens or corporations. The ruling is Private Letter Ruling 201324006. It was released in June. / continued page 29

Market Outlook

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steps ahead of the Chinese, and that dynamic has been fundamental to get to the cheap PPA prices we have seen here. The other problem that the Chinese turbine suppliers have is that they thought they could run their businesses from China and do business in the US, and that is a big mistake.

The section 1603 program was an opportunity for Chinese vendors to deploy their own equipment in projects they were developing for their own accounts, and build a track record without the need for external financing. They did not take advantage of that window. The first question US wind companies ask is whether they can finance a particular turbine. If the turbine has no track record in the US, the answer is pretty much no. That makes the barriers to entry in the US market pretty daunting.

Solar Economics

MR. MARTIN: Kevin Smith, what does a PV project cost per installed megawatt? What does a CSP project cost? When do you see the gap closing between solar and wind and natural gas?

MR. SMITH: I will give you the answer on the PV side. We do not like to talk dollars per megawatt with CSP because such projects operate at a much higher capacity factor, meaning dollars per megawatt are not a good basis for comparison. A CSP facility will generate two times more output than a PV facility. Our 110-megawatt CSP facility in Nevada will make 500,000 megawatt hours a year. A PV facility of that size will make half that.

On the PV side, we are active in the US even though the PPA market is very difficult. Overseas, solar panels are being offered at prices as low as 40¢ a watt. In the US, panel prices dropped into the 50¢-per-watt range for a while, and now we are seeing them trend up into the low 60¢ range. The question is whether the trend will remain up. If there are some 40¢ panels entering the market, then that is good news. We are a price taker on the panel side.

We have heard all-in prices between $1.20 a watt and $1.70 a watt for utility-scale PV projects. That is pretty competitive, but it does not really support power contracts at 6¢ or less a kilowatt hour. It is a dynamic market. There will be a lot of panel manfacturers who will not survive.

MR. DOMENECH: I was just checking the math, and I do not agree with what has been said about PV being a commodity. We sold SunEdison to MEMC, which is a semiconductor company. The good thing about the semiconductor folks is that they have worked for five decades to perfect the art of making high-efficiency wafers. The reason that we can get to 40¢ a watt is because we have a production process for polysilicon that the Chinese cannot match. We are the only remaining company today that can produce silicon. We have a joint venture with Samsung to deploy even more capital in that effort. We are projecting a levelized cost of energy of 7¢. You do not have to think too far out to see where things are going in terms of solar and what it means for the industry. We are excited.

MR. HUNT: I think you'll see a two-stage adjustment in pricing on solar. People are selling at zero or negative margin, so that will correct when competition levels out. It is not hard to believe that through procurement, technology, efficiency and building cost, you can drive down the numbers. I expect that we will do better than 40¢ a watt.

MR. ALONSO: If the market is currently at 60¢ a watt and you expect it to go to 40¢ a watt, why would you buy any panels today?

MR. DOMENECH: I said that by 2016, we will be able to do 40¢ a watt. If a developer has a power contract for which it has to build today, it comes down to a question of profit margin. I cannot speak for people bidding to supply power at 6¢ a kilowatt hour. We have done a thousand projects, and we will do close to 500 megawatts this year and 750 megawatts next year. Our gross profit margins are in the 20% range. I know what works for us.

Today when we bid, it is really important to get into the details. It is true that there is a race to the bottom in the US when bidding into utility procurements. In almost half the situations that we see, the winning bidder bid too low a price to build the project. Someone else then came in and renegotiated the contract with the utility at a price that was economic. It happens all the time because the utilities have to satisfy state renewable portfolio standards that require they deliver a certain percentage of electricity from renewable sources.

We have not talked about it yet, but as we get into 2016 and the investment tax credit for solar drops at year end 2016 from 30% to 10% and some of the utilities are way behind where what they need to be to satisfy state RPS requirements, there will be a chaotic effort to secure additional capacity. Anyone who is long in capacity should be in a good position to arbitrage what he has and increase his profit margin.

MR. ALONSO: Then I should be bidding at 50¢ a watt and not 40¢ in 2016 since demand for solar equipment will increase, potentially driving up equipment prices.

MR. DOMENECH: I think you should sit on your current hand. You have to be patient. Why hasn't SunEdison built out its three gigawatts of solar pipeline? Why should it? We are arbitraging on the right time.

MR. ALONSO: I am concerned that it is a very crowded market in terms of numbers of solar developers, and this will continue to drive down PPA prices to levels that make the projects uneconomic.

MR. SMITH: That is one of the difficulties. The equipment side of wind is a lot more stable than on the PV side. We purchased 96 megawatts of solar panels from Yingli for our solar project in South Africa, and we had to insure the PV supply. You are going to see that a lot. There is clearly a top tier among PV suppliers, but even they are struggling, and you are going to see some of them fail.

MR. DOMENECH: We will sell you panels.

MR. SMITH: I am happy to buy them at 40¢ a watt all day long, but I don't want to wait until 2016.

MR. GRIMBERT: When I was talking about wind being a commodity business, I was talking about the manufacturing side.

As developers, we are in a cost-plus business. It is a race to the bottom in bidding into utility procurements. That's why there is not a lot of money in solar for developers. The big procurement season is over for solar in the US for a little while. The key to success has been to be either clever enough or dumb enough to forecast where the costs are headed. The fact that SunEdison is vertically integrated gives it an advantage. It is much more difficult for the rest of us to predict future costs. The differentiating factor for those who make money in this business has either been to be lucky or very clever. It is that rather than the ability to develop. ◎

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The IRS has issued other rulings recently about projects in Puerto Rico. For other coverage of this subject, see the June 2011 NewsWire starting on page 21 and the November 2011 NewsWire starting on page 13.

PURCHASE PRICE ALLOCATIONS usually cannot be changed later.

A US appeals court refused to let a poultry company that bought two poultry processing plants in Mississippi, and agreed with the sellers to schedules showing how the parties intended to allocate the purchase price, revise the allocations. It said section 1060(a) of the US tax code binds the parties to the original allocation unless the IRS agrees to a change. The buyer is depreciating one of the poultry processing plants over 39 years on a straight-line basis on the theory that the plant is a building. It is depreciating the other plant partly over seven years and partly over 15 years on the theory that the plant is equipment. It tried retroactively to treat the first plant also as equipment. The IRS objected. The appeals court said the US tax code provision binding the buyer and seller to the same purchase price allocations is important for preventing the government from being whipsawed by inconsistent treatment.

The case is *PECO Foods, Inc. v. Commissioner*. The appeals court released its decision in July.

TARGETED PARTNERSHIP ALLOCATIONS are starting to get attention.

Curt Wilson, the IRS associate chief counsel for partnerships, said, in response to questions at a tax conference in San Antonio in June, that the IRS will probably have to issue guidance at some point on such allocations. They are becoming more widespread in partnership agreements. Traditionally, partnership agreements have required that a "capital account" be maintained for each partner measuring what he put in and what he is allowed to take out of the partnership. When the partnership */ continued page 31*

Disruptive Business Models

Fuel cells, rooftop solar, small CHP projects, microgrids and other forms of distributed generation threaten to undermine the traditional US utility model. How do distributed generation and regulated utilities co-exist? Is it fair to have the full burden of cost recovery for utility assets fall on a shrinking pool of ratepayers who have not moved to generate their own electricity? Do utilities that have divested generating capacity and are merely wires companies care? Is the most sensible utility response to move into distributed generation themselves and, if so, how? Three utility executives talked about these issues at the 24th annual Chadbourne global energy and finance conference in June.

The panelists are Bert Valdman, senior vice president of strategic planning for Edison International, James Lambright, senior vice president of corporate development for Sempra Energy, and Rye Barcott, special advisor to the chairman and CEO of Duke Energy. The moderator is Todd Alexander with Chadbourne in New York.

MR. ALEXANDER: The Edison Electric Institute released a report that says regulated utilities are facing a serious long-term threat from distributed generation and other demand-side energy programs. The traditional utility model relied on central station power production. Customers are moving off the grid and are no longer sharing the fixed costs. That creates upward pressure on rates and may lead eventually to downgrades in utility credit ratings and a downward spiral. How much of this is hyperbole and how much is reality?

MR. LAMBRIGHT: This is a real topic of conversation inside the utilities. There are numerous new, potentially-disruptive technologies that are at different stages of commercialization and availability to customers. The biggest one that gets discussed is distributed generation.

California utilities get their returns on infrastructure, not the electricity. The electricity is largely purchased from independent generators and passed through at cost to ratepayers. California utilities have a tiered residential rate structure that allows customers who buy low quantities of electricity to pay roughly half of what higher-consumption customers pay. The cost of rooftop solar has been falling. Utility rates have been increasing. Over the last few years, we have seen rapid growth in rooftop solar installations. However, we have not seen many customers go completely off the grid.

One topic of debate is what those customers should pay since they are still connected to the grid and still rely on the utility for certain services, including standby power.

MR. ALEXANDER: Rye Barcott, rooftop solar has not taken hold in North Carolina in the same way it has in California. Does Duke view rooftop solar as a threat?

MR. BARCOTT: We believe that distributed generation is both a potential threat and an opportunity for Duke. We continue to debate what makes the most sense as an entry point. The options range from least aggressive, where we limit ourselves to advocating for rate changes, to most aggressive, where we enter directly into the business, perhaps through the unregulated affiliate.

MR. ALEXANDER: Bert Valdman, the EEI paper talks about whether the utility business is going the way of the telephone and airline businesses where there was heavy regulation, but the regulation did not keep up with the times. Is there a need for a major overhaul in how utility rates are set?

MR. VALDMAN: We are not the first industry to face the existential question of what the future looks like and how to serve customers better. If you look at other industries that have successfully navigated through uncertainty, you find common features.

They have strengthened the core business by providing excellent service while cutting costs and they have adapted to change, particularly as it relates to what customers want. Our core business is delivery of electricity, and our customers increasingly want a product that gives them

Distributed generation is threatening to undermine the traditional utility business model.

energy independence and advances sustainability. There is a clear priority to decarbonize. We need to take a thoughtful approach, adapt our business models, and invest in new businesses that achieve these outcomes. We can enable the business models that show promise and support management teams that have talent. We have to accept that these new activities might compete with our existing business and, while it might create some tension within our organizations, it is a healthy tension.

Rethinking Utility Rates

MR. ALEXANDER: Jim Lambright, will this lead inevitably to an overhaul of the ratemaking process?

MR. LAMBRIGHT: A bill is already working its way through the California legislature to return ratemaking authority to the California Public Utilities Commission as opposed to leaving it in the state legislature where it has been since the energy crisis more than a decade ago. An open and frank conversation about ratemaking is on the way and is long overdue.

If you look at the proliferation of new technologies, there is a strong case for revamping the rate structure. We need to send the right price signals to customers and ensure that customers pay for the services they receive from the utility.

One way to do that could be by unbundling the components in today's tariffs. You would have a rate structure that breaks down services and products into fixed costs and policy-driven subsidies that everyone connected to the grid should bear and energy charges for the variable amount of electricity consumed. There could be a time-of-use feature so that people driving electric vehicles would have incentives to recharge during off-peak hours. These issues are starting to work their way through the political process.

MR. VALDMAN: We should ask ourselves what a perfect rate structure should do. It would provide price signals to customers so they make informed decisions about how to make better use of energy. It would allocate costs equitably across different customer rate classes. It would balance the interests of utilities and emerging competitive businesses and support investment. The current rate structure does not serve any stakeholder well.

MR. ALEXANDER: If you start charging people for specific things, those with means will opt out. The bigger customers will drop off the grid and may be comfortable not paying a standby charge. That will leave those without means or other options having to pay more for electricity.

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liquidates, each partner is distributed the balance in his capital account out of the proceeds from liquidating the partnership's assets.

In a partnership with targeted allocations, the partners share in what is left when the partnership liquidates in whatever ratio their business deal is for sharing cash. Capital accounts are not used to divide up what remains.

IRS regulations require partners to use capital accounts for dividing up cash at liquidation unless sharing in some other ratio reflects the partners' underlying economic interests in the partnership. The IRS has not explained how to determine the underlying economic interests, but its regulations suggest that the ratios in which the partners contribute capital and share income and losses are relevant in addition to how they have agreed to share cash flow.

IRS guidance is not imminent. Wilson was skeptical whether any guidance the IRS issues would prove useful since anything the agency publishes is likely to be fairly rudimentary and uncontroversial. Conference attendees said even an IRS acknowledgment that such allocations are allowed would have value.

The agency will look into including the subject on its 2014 business plan. The business plan is a list of issues the IRS hopes to address in the coming year.

RESCISSIONS will not be addressed any time soon, the IRS said.

The agency had been considering whether to revise its existing policy on when two companies can unwind a transaction and be treated as if the transaction never occurred. It said Revenue Ruling 80-58 will remain the IRS's guidance on the issue for the foreseeable future. Bill Alexander, the IRS associate chief counsel for corporations, made the comment at a New York Bar Association tax section meeting in late June.

Revenue Ruling 80-58 said that a sale of real estate in 1978 could be rescinded in the same year, and the buyer given all his money back when he could not get / continued page 33

Disruptive Business Models

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MR. BARCOTT: Utilities may not be able to carry the day with arguments solely about fairness. I do not think it is enough just to adjust rates. A company like ours needs 4% to 6% earnings growth every year. One way to do that as the utility industry evolves is to own the distributed generating assets and be in the rooftop solar business. That is where the creative energy, teamed with rate adjustments, needs to occur.

Utilities have been slow to respond, but the tension is starting play out in states like Arizona where rooftop solar has made large inroads.

Regulated companies have a hard time adjusting to change. They have very different cultures than the distributed generators who are making inroads into our service territories. One of the things we have struggled with at Duke is the overall process of how disruptive investment proposals can find support as they move through the corporation. A risk review process for regulated investments and utility-scale projects does not work with disruptive ventures. Disruptive ventures are best evaluated separately with different metrics, time horizons and other strategic considerations.

MR. ALEXANDER: So the utilities are still building central power stations when the future may be distributed generation.

MR. BARCOTT: Room must be made within large utilities for a traditional business model focused on operational excellence and a disruptive business model to co-exist. There are precedents in other industries. Smart utilities will ask hard questions about how to own disruptive ventures and keep them independent long enough from the parent company so that they can seed, grow and compete.

Potential Disruptions

MR. ALEXANDER: Jim Lambright, the rating agencies do not seem worried about the potential for disruption. Is there is a risk that will change?

MR. LAMBRIGHT: The conversation has begun. The risk in not facing these issues head on now is that while these disruptive business models may command a very small market share today, markets can shift quickly. This is especially true of technologies whose cost and effectiveness keep changing every day. More and more customers may be attracted to new technologies. The earlier a business anticipates that and makes the right adjustments, the better. In a regulated business, that means you have to start the conversation with your regulators as early as possible, because it is not likely to be a quick conversation. It will take years, not months.

MR. VALDMAN: It is dangerous to think about utilities as if they are all the same. You have 50 states and the District of Columbia each with its own regulations. But there are common themes that bring the industry together, regardless of regulatory jurisdiction: safety, reliability and affordability.

Within the transmission and distribution business, there are many applications for new technologies to balance the system and make it more resilient and reliable. Instead of putting in a new substation, is there a storage technology that could achieve the same outcome? Part of the challenge is how to adapt the traditional way of thinking about system planning so that new technologies can be properly evaluated and deployed. A number of us are thinking about installing storage on our distribution systems. There is a lot of opportunity.

MR. ALEXANDER: What does potential disruption to the traditional utility model mean for the independent generators and bankers in the room? They do not view utilities as particularly nimble. Almost all of the utilities with which they deal are investment grade. If utilities have to adjust to change and only 80% of them are successful, that will have a profound effect on the broader market.

MR. VALDMAN: No one is suggesting that utilities will be sub-investment grade in the future. Utilities have a good infrastructure business when managed well. There is room under the same roof for a number of different business models with different risk profiles that can be capitalized differently. It then becomes a matter of effective portfolio management. Other industries have done this and can serve as models. It will be a dynamic process. The investor community will reward management teams who manage their portfolio and risk profiles well.

MR. BARCOTT: One question facing utilities is whether this is the right time to act. Take the rooftop solar business, for example. There is a natural bias in a regulated company against taking risk. Employees are often incentivized to defend the status quo, not attack it. In such a culture, it is no surprise that employees are more comfortable giving hard looks at deals and passing on them rather than placing calculated bets. In this day and age, utilities need both attackers and defenders.

Moreover, what's the point of being a large company if you cannot make some smart, small strategic bets, and realize that some of them will not pan out? If you really want to understand something, you have to be in it.

MR. VALDMAN: I agree. Moreover, for a lot of these emerging business models, there is a lot that utilities can do to help. That should be our role, whether it is providing capital, an opportunity to test these technologies on our system or an understanding of how the regulatory process works. These are all things that we as an industry can undertake to advance new technologies in areas where all interests are aligned. The worst outcome is to sit back and do nothing.

MR. BARCOTT: The market is changing. Distributed generation is gaining ground. My own view is utilities need to adapt by owning distributed generating assets themselves.

MR. VALDMAN: I entered the energy business more than 25 years ago in oil and gas. On my first day, someone told me something I never forgot: never bet against the engineers. Today, engineers are hard at work in labs creating and perfecting a whole range of new technologies that will transform our industry. We need to pay attention.

MR. LAMBRIGHT: We are in the middle of a shift from a one-way flow of electrons to a two-way flow. Not only do you have rooftop solar, you also have more data through smart meters and smart grids. Customers now have more tools to monitor usage. Given this, there are a lot of products and services that can be offered by utilities and third parties alike. The customer is in the driver's seat and will shape ultimately how the industry realigns itself. ◎

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the land rezoned as he wanted, and the parties would be treated for tax purposes as if the sale never occurred. However, if the buyer waited until 1979 to rescind, then there was a completed sale in 1978 and returning the property in 1979 was a sale back to the original seller. The sales contract gave the buyer a right to rescind if he was unable to get the property rezoned. A rescission should put the parties back in the same position economically as if the transaction never occurred.

The IRS will not issue any private letter rulings on rescissions.

There is a risk when a buyer has a right to unwind a transaction that the buyer may not be considered the owner until the unwind right lapses. This is a potential issue in deals where it is important for the buyer to be a partner or owner before assets are placed in service to claim tax credits.

TAX-EXEMPT BONDS lost their tax exemption.

The IRS said in a technical advice memorandum issued to a bond issuer in late May, but not formally released yet to the public, that community development districts formed in Florida to issue tax-exempt bonds to finance real estate projects are not subdivisions of the state and, therefore, the interest on bonds issued by such districts must be reported by the bondholders as taxable income.

A technical advice memorandum is a ruling by the IRS national office to settle a dispute between a taxpayer and an IRS agent in an audit.

The IRS looked at 12 special districts set up to finance projects by billionaire real estate developer H. Gary Morse. Morse, family members and employees control the districts.

The IRS memorandum focused on one of the 12 districts that issued $426.2 million in bonds over time to finance a retirement community called The Village in Lake County in central Florida. The bond proceeds were used to buy real estate and a right to collect amenities fees from existing residents for use of recreational facilities like the golf course. Morse */ continued page 35*

Portfolio Sales and Consolidation

Edison Mission Energy and BP Wind are just the latest companies to put portfolios of operating projects up for sale. More portfolios are expected to follow as some larger players pull back from new wind and solar development or find their European parents no longer willing to provide capital for new development. Various portfolios of gas-fired power plants are also for sale. There has been ongoing consolidation in the distributed solar market as a few national brands emerge. Is this a good time to buy? What does it take to win the bidding? A panel discussed the market for projects at the 24th annual Chadbourne global energy and finance conference in June.

The panelists are Ted Brandt, CEO of Marathon Capital, Jon Fouts, managing director of the global power and utilities group at Morgan Stanley, Andrew Murphy, senior managing director of Macquarie Infrastructure, and Declan Flanagan, CEO of Lincoln Renewable Energy. The moderator is Eli Katz with Chadbourne in New York.

MR. KATZ: What trends do you see in the US market? Who is buying and who is selling?

MR. BRANDT: Clearly NextEra has been a net buyer through thick and thin, but it is hard to judge the rest of the players in the top 15. Everybody knows that BP and Edison Mission Energy will soon be selling large portfolios of wind farms. *[Ed. BP later withdrew its portfolio after receiving bids.]* There will probably be other divestments, but it is not clear who will be the buyers other than NextEra. There are some private equity firms that would like to bulk up and get larger. There are a lot of people who are thinking about public exits as opposed to strategic exits.

Motivations to Sell

MR. KATZ: Where do you think the next wave of sellers will come from? Why would they be selling now?

MR. MURPHY: We would like to be a buyer in this market. As an infrastructure fund, we have some challenges that the other potential buyers do not have. We cannot use tax benefits that are a large driver of the economics. We are only interested in contracted portfolios with stable returns.

That being said, it really is a question of looking at who are the natural longer-term holders of the assets. An emerging trend is for companies to sell off assets into yield cos. NRG is putting some of its solar assets up for sale into a yield co. This highlights the fact that NRG is not necessarily a long-term holder; it needs to free up the capital that it has invested in that business. This is one of the drivers of portfolio sales. You see some of the other strategics exiting or partially exiting the space.

We could be a natural long-term holder of those assets if we can deal with the structuring issues. We can hold assets for 10 or more years. You are beginning to see that dynamic at work as some of these portfolios mature. There are more natural places to put them for the longer term so that developers can free up capital for reuse.

MR. KATZ: Some large investors put a lot of money into wind and solar and now infrastructure or private equity funds have taken them out. Do you see that trend continuing or can you even call it a trend?

MR. FOUTS: We see that trend continuing. The reason that a lot of the Europeans entered the renewable energy market in the mid-2000s is as much strategic as anything else. Now the assets are migrating to new owners who can hold them long term at a lower cost of capital. People are optimizing their portfolios. We are seeing a lot of Canadians buyers. They have long-term hold periods, they are sitting on other assets with yields in the single digits, and they have a lot of money to put to work.

MR. KATZ: There has probably been some maturation of wind and solar assets that make them more attractive to people who used to buy conventional assets. What are the differences for a buyer looking to buy a portfolio of conventional assets versus renewable assets, and what might motivate him to do one over the other?

MR. FLANIGAN: Ultimately, it comes down now to contracted cash flows. That is what people are buying. Whereas years ago, it was all about supporting renewable energy and helping with climate change, that is completely gone as a motivator. Now it is about contracted cash flow, and the technology elements that lie below that can be less important. That being said, in renewable assets, most of the major economic decisions are locked in up front and so there is less room for optimization than in a gas plant. The kind of play where people buy at the right point in the cycle on gas plants and multiply their capital by reselling in the right cycle is harder to do when you are buying a wind or solar project with a 25-year power purchase agreement.

MR. KATZ: Do you see a new type of buyer focused on renewable energy assets, and are there more complications with a renewable portfolio than a conventional portfolio?

MR. BRANDT: You have to look at wind and solar differently. Wind is clearly moving toward maturity. Solar is pretty fragmented, and it is not yet clear who will be the ultimate long-term owners, although MidAmerican is pretty strong right now. With wind, unless you have 1,000 megawatts, you cannot really be a scaled player in the wind business. There has been a huge effort to get to the point; there are now something like 10 players who are at about 1,000 megawatts. The guys who are at 1,000 megawatts are saying they would really like to get around 3,000 megawatts. There is a desire to consolidate in a difficult market with scarce PPAs.

On the other hand, there is probably more capital available for a developer than ever before, and there is passive capital for the first time. Just a few years ago, you only had the choice of active capital where you had to give up control in order to get access to capital. Now the pension funds are viewing contracted renewable projects as infrastructure quality, and we are seeing pension and infrastructure funds with wide open wallets. I would not call it an ATM card, but a contracted project will give a developer the ability to attract capital.

Purely Cost of Capital?

MR. KATZ: Does the bidding for projects come down simply to who has the lowest cost of capital? How does anyone differentiate himself? What are potential bidders doing that might give themselves an advantage?

MR. MURPHY: One of the challenges we face is how to differentiate ourselves. Our cost of capital is low, but not as low as some others. What we try to do is go farther up the risk spectrum by coming in during construction. We also look for opportunities to build strategic relationships because we want to write bigger checks. If we can talk about writing a big check in pieces over time and develop a relationship with a partner who can bring multiple projects over time, that is another way to try to avoid being just a cost of capital play, and it has value to the good developers.

MR. FOUTS: This is an important but subtle change that we have probably seen over the past 12 months. Twelve months ago, the focus was entirely yield and current cash flow. In the past 12 months, the pendulum has swung back and people are willing to take exposure to development and construction risk. They want that growth dynamic.

One way to distinguish yourself as a seller is to have a development team with a proven track record in developing assets and getting them through construction. Buyers today are

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retained the rights to amenities fees from future residents.

The bond proceeds substantially exceeded the cost of the real estate. The bonds were issued in multiple tranches over time.

They were trading at an average yield of around 5% earlier this summer, or 2.07% above an index of benchmark municipal bonds with similar maturity. Holders as of April 30 included Goldman Sachs Asset Management and Nuveen Asset Management.

The National Association of Bond Lawyers says the decision could affect bonds issued by hundreds of similar entities.

MINOR MEMOS: Lease accounting in the United States is still on track to change. The accounting standards boards in the United States and Europe — FASB in the US and the IASB in Europe — are moving forward with a plan to eliminate distinctions between operating and capital leases for book purposes. Lessees would be required to treat leased assets essentially as owned, and the obligation to rent as a liability, on their balance sheets in any cases where the lessee is expected to have more than an insignificant portion of the economic benefits embedded in a leased asset under proposed guidance issued in August 2010 and updated in May this year. Existing leases will not be grandfathered once the change takes place . . . . The IRS said in an internal legal memo that two companies that cooperated on development of a product and jointly marketed it under a trademark held jointly and with documents that showed both company logos created a partnership and should have filed a US partnership return. They said in a side agreement that they did not intend to create a partnership. However, they split the income from product sales by charging costs against the revenue and then dividing up the revenue in one ratio until $X in operating profits was reached, and then in a different ratio. The IRS said they could not elect out of partnership treatment by filing an election under section 761 of the US / continued page 37

Portfolio Sales

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putting more emphasis on that.

MR. FLANAGAN: Once the project is ready to start construction or beyond, it is exclusively a cost of capital play. Anyone who is looking to be a buyer is probably wasting time at the notice-to-proceed stage or beyond, unless he has a compelling cost-of-capital advantage.

MR. KATZ: What about post-PPA revenues? Can there be differences in what people expect the power prices will be after the power purchase agreement expires?

The winning bidders in portfolio sales are using 8.5% to 9.5% discount rates for wind and less than 7.5% for solar.

MR. FOUTS: It is the tail wagging the dog. The cost of capital is still key. A residual assumption discounted over 20 years is not going to swing the deal as much as a 100-basis-point advantage on cost of capital.

MR. KATZ: Who has the edge today between financial bidders and strategic bidders? Is there a different answer in renewables versus conventional?

MR. FOUTS: Clearly, what happens in the BP and Edison Mission Energy sales will be the story of 2013. A strategic player like MidAmerican that can use the tax credits and deferrals on a real-time basis has a fundamental advantage over everybody else.

Warren Buffett's money is pretty attractive. MidAmerican can write a big check, and it has been smart about not leaving much money on the table. Clearly it has more room to increase the price if it has to do so to win.

MR. MURPHY: Other than MidAmerican, there are not many players with tax appetite. That narrows the field pretty aggressively. After MidAmerican, it is back to some of the pension funds and infrastructure funds that are buying on a cost-of-capital basis.

MR. BRANDT: I agree. The tax capacity of the strategics is a huge differentiator. The strategics are more efficient buyers than anyone who has to go to Jon and his colleagues for tax equity structures.

On the conventional side, it is a different dynamic. It depends on where the asset is and its locational value. A conventional power plant can be a compelling play for a strategic if it fits into a portfolio and can bring synergies. Some strategics can be competitive on that, even if it is a fully contracted asset. It depends on the asset itself, because the ability to use tax benefits is not a differentiating factor.

MR. FLANAGAN: A few years ago, no doubt a strategic had the edge. The best long-term owner of these assets was clearly a strategic, but the advantage is now with the financial investors due to their lower cost of capital. The gap is narrow, but tax capacity cannot tilt it back the other way. It goes back to who wants to be the long-term owner. Strategics do not want to be long-term owners. Everyone is ultimately trying to get to that mythical 6% yield-seeking retail investor. That changes the dynamic completely from where it was four or five years ago.

Shift in Buyers

MR. KATZ: Jon Fouts, you had some interesting statistics about what happened in 2012.

MR. FOUTS: In 2010, most buyers of US renewable energy projects were Asians. It was strategic driven. The Chinese were interested in getting into the US and putting their equipment here. That has shifted so that the majority of buyers of renewable assets today are Canadian infrastructure funds. They account for two thirds of the market, and they have been very, very aggressive.

The story is different on the conventional side. In 2010, we saw Japanese, Korean and Chinese bidding aggressively for conventional contracted assets. Today the bidders are more likely to be private equity funds. They have a higher cost of capital, but many private equity guys are betting on gas prices. There is a growing view that gas prices are going to recover, replacement values are improving or reserve margins are getting better. We are seeing people take selective bets on conventional assets in very specific markets. It is counter-intuitive that private equity funds should be able to win given their costs of capital. They are winning in a different way on the conventional side.

MR. BRANDT: If you have a utility-scale solar project under 150 megawatts, tax equity is efficient and we see a lot of people who have been able to compete very nicely with the strategics. The larger deals have had very short bidder lists because they exceed the capacity of the tax equity guys to do them. They come down to a pure cost of capital bid among four to five utilities. As you move into distributed generation, it is a completely different world, and we have not seen the strategics take an interest.

MR. KATZ: Drew Murphy, before joining Macquarie, you were at NRG, which is probably focused on its stock price and earnings per share. Does that influence acquisition strategy?

MR. MURPHY: Any public company must look at an acquisition through a couple of different lenses. We always focused on showing our shareholders that the acquisition was a wise way to spend their money. We wanted to show a long-term return. The acquisition also had to be accretive to earnings. If you compare that to how a fund like ours looks at assets, the fund has different metrics. We look for yield and some growth. All of that said, often it just comes down to what your actual cost of capital is regardless of other metrics.

MR. KATZ: Private equity funds have put money into portfolio companies that develop wind, solar and even conventional power plants. At some point they want to exit or give the money back to their limited partners. There was a point in time when it looked like they might be able to go the IPO route, but that appears mostly blocked now. Maybe there are some yield co opportunities, but do these people now become sellers in the sense that they have to get money back to their investors? How does this figure into the M&A markets?

MR. MURPHY: You have just described several major players in the renewable energy business. All of the well-run companies are hiring banks and exploring options. They are looking at private and public yield cos. They are looking at realizing shareholder value while trying to balance that against overhead and maintaining organic growth.

MR. FOUTS: This is just the natural rotation of funds by private equity. Assets, whether renewable or conventional, are owned by private equity funds and, at some point, the assets will be put on the market to be monetized. That is how it works.

MR. FLANAGAN: The key point is that sellers are motivated by trends, and the current trend is to / *continued page 38*

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tax code because the arrangement was not a mere investment partnership with a passive role and they were not joint owners of a property in a position to calculate their incomes from use of the property separately. The memo is Chief Counsel Advice 201323015. The IRS made it public in June.

— contributed by Keith Martin in Washington

Portfolio Sales

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reach scale. Over the next five or 10 years, you should be looking to be a 10,000-megawatt operator. There are material benefits potentially on operations and maintenance as you reach such scale. There are a large number of sub-optimally small operators today. The rise of these yield co entities is a move toward groups of 1,000-megawatt portfolios. Eventually, they are going to have to move toward greater economies of scale.

We are only at the beginning of major consolidation. Owners of wind assets will be focused on what they own. The strategics who own wind assets have not been motivated particularly by earnings. That is about to change, and you will see people more dispassionately viewing issues of economy of scale and of spares and inventory management, and this will drive aggregation. I would put the new goal around 10,000 megawatts. I know for certain that 1,000 megawatts is still way too small.

MR. BRANDT: Owning one power plant and one wind project in a couple of places is not optimal because it represents too much concentration in single markets and single assets. Buyers will be most interested in trying to buy portfolios that have different yield profiles across the assets and different contract terms so that they can manage residual values and risk.

Discount Rates

MR. KATZ: Say you have a fully contracted asset, with a BB or stronger offtaker. At what discount rates do those assets trade in the current market?

MR. BRANDT: Is it a not-yet-constructed asset with a PPA? Is it an asset under construction or is it an asset that is actually operating? Is it a project that will qualify for an investment tax credit, a section 1603 grant or production tax credits over time? Not to dodge the question, but I think wind is still an 8 1/2% to 9 1/2% market using unleveraged, after-tax P50 numbers. Solar is well below 7 1/2% with a few deals below 7%.

Nobody really has a handle on where wind turbine prices are headed. The bigger guys think that there may be more flexibility than what some of the smaller guys are seeing. We are telling sellers not to rush to procure turbines. Let the buyer procure the turbines. That has been a phenomenon for a couple of years with solar projects, where buyers may have a more optimistic view than the seller about where solar panel prices are headed.

MR. KATZ: We have seen some bidders offer capital that is 100 basis points cheaper for a 49% interest in a project, but it may not be wise to take the money because a 49% owner can block the 51% owner from exiting the rest of the portfolio.

MR. FLANAGAN: I agree with Ted's numbers. The solar number is materially lower than wind, but unjustifiably so. It is not that I think solar should be more expensive, I just do not think there should be as big a risk premium attached to wind.

MR. KATZ: In the distributed market, the sense is that maybe five players have consolidated and are dominating. Are they just aggregating a portfolio and trying to sell it later? Where do you see distributed solar portfolios trading?

MR. BRANDT: The discount rate is clearly higher.

MR. FLANAGAN: I think distributed generation is a great space. It is a space in which we are not active. It is so vastly different than utility scale. It is nearly impossible to do utility scale and distributed generation in the same business. It is a very different type of business. That being said, I really struggle with how to value the equity in a distributed generation business. I am not sure how to factor in credit and counterparty risk. A lot of very interesting stuff is being done, but I have no idea of how to value the equity, and I do not think anyone else does either.

MR. BRANDT: You have to distinguish between the commercial and industrial side and the residential side. The residential side is clearly mature and has found scale. The commercial and industrial side has been struggling to find scale and make the business work. A number of private equity guys have broken their picks in the business. Some companies have done well on a regional basis, but there is not yet a dominant national player. ◎

California Dreaming

What will the California power markets look like in the next 10 years? Will there be incentives for new gas plants? What is the future for a separate capacity market? How much need will there be for additional power? Will the RPS targets increase again? How will California deal with imports of out-of-state power? What transmission challenges will the state face? What will it take to integrate the huge amount of renewables with the grid? How will CO_2 cap and trade affect pricing and capacity? What new environmental restrictions are likely to be imposed? A panel talked about the challenges and potential opportunities in the California market at the 24th annual Chadbourne global energy and finance conference in California in June.

The panelists are Dr. Robert Weisenmiller, chairman of the California Energy Commission, Jan Smutney-Jones, executive director of the Independent Energy Producers Association, Mitchell Ross, general counsel of NextEra Energy Resources, and Bill Monsen, a principal with MRW & Associates, a prominent California consultancy. The moderators are Bob Shapiro with Chadbourne in Washington and Paul Kaufman with Chadbourne in Los Angeles.

MR. SHAPIRO: Bob Weisenmiller, what is the difference between the California Energy Commission and the California Public Utilities Commission?

DR. WEISENMILLER: The California Energy Commission was started in the 1970s. It does power plant siting. Any thermal power plant over 50 megawatts must come to us for approval. We also do energy planning for the state, and we look at all the various options.

One of the things we look at is energy efficiency. We do building and appliance standards in California for new construction. We also do renewable energy development. We decide what qualifies as a renewable, and we are now starting to look at what the municipal utilities are doing in terms of their renewable portfolios. We also do contingency planning to make sure the state is prepared in case anything goes wrong.

The CPUC is more than 100 years old. It started as a railroad commission. It regulates the rates that utilities can charge for power, telephone, transportation and water.

MR. SHAPIRO: Jan Smutny-Jones, how are the California utilities doing on meeting their renewable portfolio targets, and are both investor-owned utilities and municipal utilities now required to meet state renewable energy targets?

MR. SMUTNEY-JONES: They are at about a 20% renewable energy mix. We will be at 25% by 2016. The utilities will tell you that they are well on their way to reach 33% by 2020. The municipal utilities have also become fairly active. The municipal utilities in northern California are ahead of their colleagues in the south. There is a significant amount of new activity in the renewables sector. The portfolio part of the renewable portfolio standard is gone. All the new development is largely solar PV right now, which is creating a new set of dynamics and issues.

PPA Failure Rates

MR. KAUFMAN: All of the procurement in California for renewables is done through requests for proposals and some bilateral contract negotiation. You hear about high failure rates as some developers were too aggressive in their bids. What do you think the failure rate is today?

DR. WEISENMILLER: The utilities will be on track to reach a 33% renewable portfolio by 2020 assuming a 40% failure rate. If we look at projects on the ground, the actual failure rate is not close to 40%. What happens is that someone turns in a bid, but cannot develop the project, and someone else steps in and gets the project done. I think there will be more development of renewables than we are projecting.

MR. MONSEN: I am a little more pessimistic about the failure rates, but between 30% and 40% is a fair estimate. The other thing that will happen over the next 10 years is that we will start to see some of the shorter-term renewable contracts end, a peak in the contracted levels in 2018 or 2019 and then a fall off. There may be room for new contracts after 2019.

MR. ROSS: There are quite a few wind projects that will start coming off contracts in the next several years, and those are excellent opportunities for renewables.

MR. SHAPIRO: Is it still the case that new renewable energy projects in California cannot be financed without long-term power contracts? Can a power hedge work?

MR. ROSS: We think a PPA is essential. We think that the state RPS targets are aggressive and that the municipal utilities are behind the investor-owned utilities in achieving their goals. These projects are perfectly suited, from an operational perspective, for PPAs.

Future Drivers

MR. SMUTNEY-JONES: I would be careful about getting fixated on the 33%. That number materialized out of the ether.

Climate change policy will be driving */ continued page 40*

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California energy policy over the next several decades. My sense is that we reach 33% and then people will go "Well, now what are we going to do?" Climate change is a fairly big and complicated issue that cuts across all technologies. The big issue today is how to have more renewables and also have the electricity during the time of day when you need it most.

MR. SHAPIRO: So even if the state reaches 33% renewable energy by 2020, the utilities will have to buy even more renewable energy to meet new CO_2 targets?

DR. WEISENMILLER: When I joined the governor on a trip to China recently, we visited with provincial officials at every stop, and climate change was very much on their minds. I am the scientist on the California Energy Commission. If there are any doubters, go down to the Scripps Oceanographic Institute where they have a pier where they have measured the temperature of the water since 1910. The water temperature has gone up two degrees in that period of time. We are seeing clear climate change during our lifetimes. We have very aggressive goals for 2020, but we are also now starting to look at 2050. We are being forced to think about decarbonizing our power system. We are starting to set very aggressive goals by 2050 and to think about where we need to be by 2035 to reach them.

MR. SHAPIRO: Has the CEC been looking at how electric cars in California will affect electricity demand as well as carbon reduction?

DR. WEISENMILLER: The governor set a target for 1.5 million electric vehicles on the highway by 2025. One reason is we still have major air pollution issues in Southern California. Eighteen percent of the economy along the south coast is goods movement. We have no choice but to electrify the transportation system. As we electrify the transportation system, it will affect the power system. As we shift more vehicles over to electricity, that will enhance the mandate for renewables since 33% of a growing number of megawatt hours is a larger number of renewables. The transportation system is such a huge lift for our economy and it affects all of us in such fundamental ways that electrification will require thousands and thousands of decisions to make it happen.

MR. SMUTNEY-JONES: Forty percent of the carbon footprint in California is transportation. Twenty percent is the electric sector, of which only half of that is electricity generated in California as opposed to neighboring states. We will not get to our climate change goals unless the transportation issue is addressed, and we view that as a potentially big market opportunity.

MR. SHAPIRO: It will drive up demand for electricity.

DR. WEISENMILLER: Right. We are very concerned that charging all those cars occurs off peak, although when we assess the impact of the explosive growth of solar PV on our systems, we could easily end up double peaking. We have wind at night and solar during the day and, as the wind drops off in the morning just as loads go up, solar will bear some of that load. At some point when the solar peaks, we could basically see the net load dropping and then, as the sun sets, have this incredible load spike followed by the sun setting and the wind coming up and loads dropping. That is basically a double peak, and it means that we may find ourselves at some point trying to encourage people to charge at what would have been our traditional peak times.

We have a couple things to think through trying to figure out the operational impacts of renewables plus transportation. Add on top of that the decision to close the San Onofre nuclear plant. It is a pretty challenging set of options to think through now.

MR. SHAPIRO: And you have growing distributed generation, which may end up reducing load.

DR. WEISENMILLER: In the last year, we have added about 1,000 megawatts of large-scale solar. I expect by the end of this year, another 1,000 megawatts will be added to our grid. We also have about 1,700 megawatts of behind-the-meter renewable distributed generation installed. We have 160,000 solar installations in California, and we are on target to get to one million. A lot of it is behind the meter and coastal. We have a lot of it along the coast in areas that have fog coming in and out. These are huge operational issues with which we are dealing.

Power Plant Retirements

MR. SHAPIRO: San Diego Gas & Electric and Southern California Edison have decided not to try to restart the San Onofre nuclear plant. That is 2,300 megawatts of generating capacity that will disappear.

MR. ROSS: I feel a lot of sympathy for Southern California Edison and San Diego Gas & Electric customers in Los Angeles and San Diego. It was not a technical issue that prevented the restart of the San Onofre units. It was an issue of how much time and money would have to be invested and just the difficulty nuclear faces in public perception. There are other examples of nuclear units across the country that were in perfectly good shape, but that for regulatory uncertainty or other economic reasons were shut down. It is usually not due to technical issues. Nuclear has a challenging reputation. When something goes wrong on a wind farm, you fix a turbine blade here and there. When something goes wrong in a nuclear plant, it is a very bad day.

MR. MONSEN: San Onofre was obviously a critical asset in the Southern California grid. It supplied local capacity to the load pocket in Southern California. It will be an enormous challenge to replace the generating capacity in an area in which it is very difficult to site new power plants given air and water regulation in California. It will mean a larger effort to implement demand-side measures that may or may not perform.

MR. SMUTNY-JONES: A question that will have to be addressed is how to reach carbon policy goals after shutting down 2,300 megawatts of carbon-free energy.

Renewable energy growth in California will be driven more by state policy on reducing carbon emissions than by RPS targets.

MR. KAUFMAN: Once-through cooling is another problem in California. The last time I checked, something like 17 or 19 power plants, many of them in southern California, had this type of cooling system.

DR. WEISENMILLER: We have about 6,000 megawatts of existing power plants along the coast with these types of systems. They will have to be either repowered or replaced. Federal law requires them to stop using ocean water for cooling. Most of those plants are old, post-Korean War vintage. They operate about 5% of the time. So they are not exactly barn burners in operational capacity, but they are very important to reliability.

Statewide, we have a lot of power. Reserve margins are well over 20% for a one-in-10 weather event, which is the conventional metric, so that is not the issue. The issue is that the transmission system is built around the assumption that San Onofre is operating so that we can power San Diego. We are struggling with the issue of what happens without San Onofre, what is the right mix of preferred resources and how many of those coastal thermal units should be retired or replaced.

MR. MONSEN: The CPUC in its decision on local capacity requirements authorized Southern California Edison to procure between 1,000 and 1,200 megawatts of new gas-fired generation over a certain number of years on the understanding that the cooling regulations would be met. The CPUC did not say those plants will not be repowered, but did say those plants as they exist today will not continue to operate.

MR. SMUTNEY-JONES: This is a very complicated problem because you need 8,000 to 10,000 megawatts of generation in in the area north of San Diego to keep the system going. You cannot just import all of that. There is a big issue of how to replace these units.

When Huntington Beach was built, there was nothing but farmland around it. There are now very expensive homes, and we have a very strong environmental community that is happy to see the rest of the country moving from coal to gas but wants California to move off gas. In some proceedings, we end up with people saying, "You don't need to do anything because we are going to meet it all with rooftop solar and demand response." This is "the unicorns are coming" theory of utility planning. This is going to be a huge issue. Those units were built in the Eisenhower era. The capacity factors of those units were around 60%. The 2010 number was something like 4% in terms of capacity.

Skewed Incentives

MR. SHAPIRO: It is one thing to say that you need capacity. It is another to have a mechanism to encourage people actually to build the new capacity. Is there going to be a capacity market? Why has the CPUC been reluctant to encourage a capacity market, and what is happening with flexible capacity?

DR. WEISENMILLER: We have very little demand response in California that can activate within a half-hour time frame. Most of it requires 24 hours. So if you are looking at renewable integration, demand response is not / *continued page 42*

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particularly useful. At the same time, we have existing thermal units that are operating less than 40% of the time.

All of us, the CPUC, the California Independent System Operator that runs the grid and the CEC, agree that we need some sort of forward market. Part of the issue is jurisdiction. Is it under federal or state jurisdiction? We had a pretty horrible experience around the year 2000 with FERC jurisdiction. There is a lot of reticence by the CPUC to cede any more jurisdiction to the Federal Energy Regulatory Commission. At the same time, there is certainly an understanding that we need some sort of multi-year procurement process.

The reality is that conversation is going to go on for a few years until we put in place a mechanism that provides the pricing signals we need, but that has the jurisdictional aspects that we can live with.

MR. MONSEN: The utilities have held all-source solicitations for new resources, and they have explicitly excluded existing resources from those solicitations. So we have this bifurcated capacity market in California. You can get up to a 10-year PPA for new gas-fired generation. However, existing generation is stuck in the one to three-year resource adequacy world, and it is very hard to make long-term capital decisions given a one- to three-year time frame.

MR. SMUTNEY-JONES: The problem really comes down to the jurisdictional issue as the chairman indicated. During the energy crisis in 2000 and 2001, a letter was sent by every member of our Congressional delegation, including Darrell Issa, telling FERC to leave its hands off the California ISO.

However, people forget that the CPUC failed to approve long-term contracts, which would have eliminated all the volatility we saw that summer. The only story anyone here remembers is that FERC did this to us and so the problem is that the California ISO is regulated by FERC.

We have added 16,000 megawatts of gas-fired generating capacity since 1999. At the end of a 10-year PPA, you are just out. You cannot bid into any new solicitations. We probably have 10,000 megawatts in contracts coming to their 11th year within the next four years. This is going to be a noisy, complicated mess, but we will sort it out within the next 18 months. It will not look like a capacity market.

MR. KAUFMAN: It has been said that when California, sneezes the rest of the country catches a cold. When you look at the entire country, where do you think the capacity issues have been handled correctly?

MR. ROSS: I am not sure that I can attest to a very good or even a preferred approach to handling capacity markets. We are struggling in a lot of places like the Northeast because they are going to turn that market upside down. We are happy to serve California. We are happy to provide services to our customers in California. We pretty much stay out of this discussion.

Out-of-State Generation

MR. SHAPIRO: To what extent can out-of-state generators help solve this problem? Are transmission constraints so severe that new transmission cannot really be part of the solution?

DR. WEISENMILLER: There is a role for out-of-state generation. We have a very good relationship with Nevada. It is only going to improve. The energy imbalance market is a way to help on a lot of the renewable integration issues around the West. Ultimately, we will have to deal with the fact that we have 38 balancing authorities in the West, but it is a good first step.

Many out-of-state generators come to my office saying, "We are able to provide 3,000 megawatts so you can get to 33%." The answer is that we are going to get to 33% even without out-of-state generation. Out-of-state generation can be a part of a future conversation. By law, we have a pretty strong preference for the first 33% to be California-centric.

The only real question is the timing of when we go above 33% in our planning. We are trying to deal with some of the consequences of success that I do not think anyone anticipated. Most of these people, when they built the gas-fired assets, thought they would be operating at about 80% and not 40%.

The next question is how to deal with the operational issues. The last time that we looked at capacity markets, we looked at what was occurring in the rest of the country. That was part of the reason to step back. We figured that we had been at the cutting edge enough, and we wanted other people to run that gauntlet for a while. Hopefully, we can move forward and build off of some of the experience elsewhere.

MR. MONSEN: In terms of out-of-state generation, California has a very clear mandate for in-state renewable generation. Out-of-state gas-fired generation is not going to play a large incremental role in the state primarily because the state is awash in capacity. The value of out-of-state capacity to the investor-owned utilities is low. Its capacity is much more valuable when it is targeted to local capacity areas.

Cogeneration

MR. KAUFMAN: That is a beautiful segué to my next question. What role will combined heat and power or CHP play in meeting capacity needs?

DR. WEISENMILLER: CHP is great as a local resource. The issue we are running into is a very complicated settlement among the CHP community and the utilities that is rolling through utility procurements to enter into PPAs.

The utilities see themselves as being baseload long. This means that existing geothermal is having a hard time getting any contract. CHP, if it is baseload, is going have a hard time getting a contract. I have had my folks go through the state facilities in Orange County and San Diego to see whether there are any CHP opportunities. Unfortunately, there is just not a lot of thermal load in Orange County.

MR. MONSEN: The Crockett cogeneration project is 240 megawatts. It is up in the San Francisco basin area and was essentially fully dispatchable earlier. It has since gone back to a more baseload type of agreement. It is not impossible for combined heat and power to do that.

MR. SMUTNEY-JONES: Our air board came up with around 7,000 megawatts of potential demand for new CHP facilities. Someone made that figure up, too. Back in the early days of the independent power industry, the reality was that we actually had industries in California that needed steam for industrial uses. We were making paper, glass and things like that. Well, we don't do that anymore. We do all kinds of other things. I think the thermal load from an industrial perspective is gone. I do not see demand for another 7,000 megawatts of power plants that generate both steam and electricity.

The kind of capacity that California really needs is locational and flexible. For example, at 12 p.m. today, there will be 1,900 megawatts of utility-scale solar and about 1,500 megawatts of solar behind the meter. That will run at maximum output until 2 p.m. and, by 5 p.m., it will drop to almost nothing. We peak at 4:30 p.m. in California. The ramp rate at the end of the day is going to be huge. You are going to need enough gas-fired generation to integrate the solar. Without this, you have a big problem. ◎

Renewable Energy Installations Accelerate In Hawaii

by Megan Strand and Jake Seligman, in Washington

Recent legislation, regulatory support and utility-backed initiatives are accelerating Hawaii's deployment of renewable energy. The state's lofty mandate is to achieve 70% renewable energy generation by 2030. The state has an innovative approach to reaching this target.

The state moved in late June to create an on-bill financing program under a new Hawaii statute called Act 211. The Act establishes an initial framework for the on-bill financing of renewables and energy efficiency improvements for utility customers.

The state will issue bonds to raise money to help utility customers cover the upfront costs of installing renewable energy systems and making efficiency improvements. Customers will pay back the costs through their utility bills.

Meanwhile, the state Public Utilities Commission has been under orders since April to implement new cost recovery mechanisms to encourage renewables by discouraging fossil fuel generation and decreasing energy costs. (Unlike on the mainland, renewable energy in the islands generally costs less than electricity from fossil fuels.)

The Hawaiian Electric Companies, including the Hawaiian Electric Company (serving Oahu) and its subsidiaries, the Maui Electric Company (serving Maui, Lanai and Molokai) and the Hawaii Electric Company (serving the island of Hawaii), have been working on complementary measures. One such measure is to implement interconnection procedures more favorable to distributed solar development by replacing system-wide de facto caps on solar installations at the circuit level with a forecast modeling approach.

In a related move, the Hawaiian Electric Company filed with the PUC in June 2013 for a waiver of the normal competitive bidding requirements. This would expedite five renewable energy projects on Oahu, representing 64 megawatts of renewable energy generating capacity, via direct negotiation with the respective developers.

Hawaii's renewable portfolio standard and the Hawaii Clean Energy Initiative set a goal of generating 70% of electricity from renewable sources by 2030: 40% from */ continued page 44*

Hawaii

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local generation and 30% from energy efficiency and conservation measures.

In 2012, the Hawaiian Electric Companies generated 13.9% of electricity from renewable energy. The next RPS milestone is 15% renewable energy by 2015. The integrated resource planning report and action plan, which the Hawaiian Electric Companies filed on June 28, projects 18% renewable energy by the end of 2013. The steps described below support such progress.

On-Bill Financing

The Hawaii PUC issued a decision and order in February 2013 concluding that an on-bill financing program for electric utility customers in the state is viable, subject to seeing how the state would implement it.

Act 211, which became law in late June, allocates an initial $100 million that the state will raise by issuing bonds to cover the deployment of green infrastructure equipment. "Green infrastructure equipment" includes rooftop solar, demand-response technology and energy-use-reduction and demand-side-management infrastructure.

The GEMS program, as it is called, will be administered by the Hawaii Green Infrastructure Authority, a new state agency created under the Department of Business, Economic Development & Tourism (DBEDT). ("GEMS" is short for Green Energy Market Securitization.) Loans to cover the upfront costs of such green infrastructure equipment may be made directly to electric utility customers by the Authority using funds drawn from the bond proceeds. Loans may also be made, at what are expected to be favorable interest rates compared to what is on offer from private lenders, to private entities, such as residential solar developers, who may then lease or provide green infrastructure equipment to customers.

The GEMs program is financed through a combination of up to $200 million in state-issued revenue bonds and on-bill repayment, supported by two separate funds operating in tandem.

One fund is a green infrastructure special fund into which net bond proceeds and on-bill repayments are deposited by the utilities. The utilities will serve as billing and collection agents for both the green infrastructure fee (assessed on all customers) and on-bill repayments. Amounts in this special fund will be used for customer loans and to pay principal and interest on the bonds.

With on-bill financing, participating customers recognize immediate utility bill savings by requiring less energy from the grid. In order to repay the upfront cost of the equipment, each participant pays a portion of its savings back to the utility, which deposits this amount into the special fund. The participant pays a lower bill than before the improvement, but does not realize full energy bill savings until the equipment is completely paid off.

The second of the two funds is a green bond infrastructure fund into which a green infrastructure fee assessed on each customer's utility bill, regardless of whether such customer is a participant in the program, will be paid. This fee is expected to replace a portion of the existing public benefits fee assessed on all utility customers.

The up to $200 million in bonds that the state will issue as part of the GEMS program will be repaid out of the green infrastructure fee and be secured by the green bond infrastructure fund that is the repository for those fees.

DBEDT and the utilities will work with the Hawaii PUC to issue the financing and program orders necessary to implement the GEMS program. The fully-designed GEMS program, including specific customer loan terms and details on bond financing, is expected to roll out in early 2014.

Hawaii has set a goal of 70% renewable electricity by 2030.

Increasing Renewables

The Hawaii PUC has been instructed to consider four incentives and mechanisms to promote renewable energy as it sets utility rates.

First, it is supposed to establish a shared cost savings mechanism that would induce utilities to reduce energy and operating costs. Under traditional rate regulation, utilities are paid based on their costs and asset base. Energy costs are passed through to customers directly. The Hawaii PUC could encourage utilities to reduce costs by allowing utilities to keep some of the savings from transitioning to cheaper energy sources. In Hawaii, this means shifting away from oil generation and toward renewables.

Second, the Hawaii PUC must consider establishing a mechanism to allow utilities to recover stranded costs from accelerated retirement of fossil fuel power plants. Hawaii is the most oil dependent state in the nation. Hawaii's reliance on oil electricity generation is the main reason its average electricity rates are the highest in the country, at over 36¢ per kWh.

Because utilities earn a return on their investments in assets, Hawaii's electric utilities are generally incentivized to keep running existing oil plants, and to keep making investments to prolong their useful lives. If a plant is prematurely retired, any unrecovered investment in it is lost, or stranded.

By establishing a stranded cost recovery mechanism, the PUC would allow a utility to recover its stranded investments in old oil power plants in rates. This would assist the ongoing transition toward renewables. The Hawaiian Electric Companies plan to decommission six oil-fired generating units on Oahu, Maui and the island of Hawaii in 2014.

Third, the Hawaii PUC will consider allowing utilities to earn a higher return on investments in modern transmission and distribution infrastructure than they do for investments in fossil fuel power plants. (Most of the investment in renewable generation comes from the private sector.) This requirement would allow utilities to benefit from investing in renewables indirectly, by earning more for building the infrastructure necessary for renewables, than for prolonging the life of fossil fuel generators.

The last measure that the Hawaii PUC must consider is a renewable energy curtailment mitigation incentive mechanism. Currently, renewable energy projects can be curtailed at times of low demand when curtailing baseload fossil fuel generators would be inefficient because of on-and-off cycling costs. The PUC is supposed to encourage utilities to avoid curtailing renewable energy when it is available and cheaper by sharing cost savings with the utility.

Proactive Interconnection

In addition to pursuing grid modernization and lowering energy costs, the Hawaiian Electric Companies are changing how they manage interconnection. Distributed renewables, namely solar, will benefit. The new approach to interconnection is one of the country's most progressive.

Under the existing interconnection process, the utilities essentially implemented de facto caps on renewable penetration. Out of grid balancing concerns, proxies or limits are set at 15% of peak load and 50% of minimum load (75% for certain smaller systems) on a given circuit. If a new project like a distributed solar system fails to pass these screening limits, then the utility has to perform an interconnection requirements study. These studies, which test the impact of a project on the grid, are costly and time consuming and serve as a barrier to solar development.

Under a revised "proactive approach" currently before the Hawaii PUC in docket no. 2011-0206, Hawaii's utilities will analyze solar growth potential and interconnection issues on an ongoing basis, rather than reacting to individual projects. The proactive approach should lead to more accurate and higher circuit penetration limits. Projects are also less likely to stall because of the time it takes to perform an interconnection study. This new approach should accelerate the already rapid growth of distributed solar in the islands, which saw 12,215 new systems added in 2012 on the islands of Oahu, Maui, Lanai, Molokai and Hawaii.

Direct Negotiation

The Hawaii Electric Company (HECO) filed an application for waiver of the existing competitive bidding rules with the Hawaii PUC in June. HECO is required currently to hold a competitive bidding process for power purchase agreements for projects that are larger than 5 megawatts.

The waiver application covers five utility scale projects on Oahu. Each project was recently selected by HECO through a competitive bidding process.

HECO issued a solicitation for low-cost projects in February 2013, requiring proposed projects to have a levelized energy price below 17¢ a kWh over a 20-year power purchase agreement term (before any Hawaii state tax incentives are taken into account) and an anticipated commercial operation date no later than the end of 2015. This aligns with the previously discussed RPS benchmark of 15% renewable energy by 2015.

Out of 25 submissions, HECO selected / continued page 46

Hawaii

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five projects with an aggregate nameplate capacity of 64 megawatts: four PV solar projects, ranging in size from 6 megawatts to 15 megawatts, and a 21-megawatt wind project. The average levelized energy price for the selected projects is 15.934¢ a kWh. This is roughly 29% lower than HECO's on-peak avoided cost of 22.491¢ a kWh in June 2013.

According to HECO, PUC approval of the waiver request will allow HECO to negotiate directly with the five developers for renewable energy at prices significantly lower than average costs, and put the projects on a fast track to commercial operation in order to take advantage of available tax credits. HECO is requiring the project developers to agree in the final power purchase agreements to allow 90% of any Hawaii state tax incentives or credits on the projects to be passed through to ratepayers. ◎

Federal Loan Guarantees for Projects in Rural Areas

by Kenneth W. Hansen and Charlotte Del Duca, in Washington

Some US renewable energy projects — including generation, transmission, distribution and energy efficiency projects — may have greater access soon to attractively-priced debt through a loan guarantee program run by the Rural Utilities Service.

Debt through the program can price as low as 12.5 basis points above Treasury yields.

The RUS

The Rural Utilities Service is part of the US Department of Agriculture. It is not an experienced project finance lender. Nor does it cater to investor-owned utilities or private sector project developers. Yet, it represents the largest federal direct investment in the electric sector, manages an active electric loan portfolio of more than $44.5 billion, and, in 2012, had $6.5 billion in loan guarantee authority for electric generation, distribution, transmission and efficiency projects, of which $4.3 billion was used to guarantee 120 loans.

As its name implies, the RUS is focused on rural America. It has been financing rural electrification and improvements in electric services to rural areas under the authority of the Rural Electrification Act since 1936. What started as a pure loan program has evolved to encompass three authorized financing options, each available in appropriate circumstances to both on-grid and off-grid renewable energy systems. The options are insured loans at the corresponding municipal bond rate, direct loans at the direct Treasury loan rate, plus 12.5 basis points and 100% loan guarantees, most often funded by the Federal Financing Bank with rates at 12.5 basis points above Treasury yields.

Guaranteed loans made through the Federal Financing Bank dominate RUS financing today. In fiscal year 2012, RUS approved more than $4.33 billion in loan guarantees in contrast to $4.24 million in insured loans. The direct Treasury lending program is dormant.

RUS has managed its portfolio prudently and managed to stay out of Washington's political crosshairs. The program boasts a default rate of less than 1% and requires little budget beyond staff salaries and expenses.

Given the size of its electric loan portfolio, and a mandate under the Farm Act of 2008 to fund renewable energy generating facilities serving mixtures of rural and non-rural customers, the RUS program would seem to have the potential to be a popular source of low-cost debt for renewable energy projects. However, RUS eligibility requirements and financing structures are major deterrents to many prospective project borrowers. Of the $4.33 billion in loan guarantees issued in FY 2012, only $278 million (less than 6.5%) went to four renewable energy projects (out of 120 overall projects).

The RUS is under the gun to attract more renewable energy projects into the program and intends to make some major changes in order to do so.

It has asked for comments by August 5, 2013 on proposed changes in how the RUS determines rural eligibility for its loans and loan guarantees and limits on the percentage of total project costs the RUS will finance when a project supplies electricity to an area that is only partially rural.

The proposed changes also include special provisions for for-profit renewable energy projects and designate renewable energy applications as a loan processing priority. The agency is also looking for comments on the design of a proposed RUS project financing program.

How Rural?

Under existing rules, RUS loan guarantees are available only to applicants that provide or improve electric facilities to persons, businesses or other entities in a rural area with a population less than 20,000 (unless the area is otherwise grandfathered — see below). There is an exception for entities and projects to serve non-rural customers in cases where such service is "necessary and incidental" to the primary purpose of meeting the rural customers' needs.

The RUS has proposed instead that a project would be eligible for financing if it serves, directly or indirectly, any person in a rural area. In most cases, the percentage of rural customers relative to the total population in the service area determines a "rural percentage," which, in turn, affects the percentage of project costs that RUS will finance.

Under the new rules, the prospective borrower would select one of four methods to calculate the rural percentage that RUS will assign to a "hybrid" project, meaning one that serves both rural and non-rural customers. Two methods — based on the ratio of either rural meters to total meters or rural sales to total energy sales — require existing geographic information software data on meter locations in the service area that is then compared with US Census Bureau maps. Absent geographic data, the borrower may use Census data alone to estimate the percentage of rural customers. A fourth method, where the data is lacking for one of the other three approaches, requires a load flow study in and around the proposed plant site to estimate the degree of rural utilization.

Loan guarantees for projects in rural areas can reduce the cost of debt to 12.5 basis points above Treasury yields.

Today, if a project with a hybrid service area is eligible under the "necessary and incidental" exception, the RUS may fund up to the percentage of eligible project costs that correspond to the portion of the service area considered rural. If the required equity is insufficient to cover the difference between permitted RUS debt and total project costs, then another lender must fill the gap. An exception occurs if the power purchaser is an existing RUS borrower operating within its 2008 "rural" footprint, in which case the rural eligibility requirement is considered met and RUS may fund up to 100% of project debt.

Under the new rules, RUS would finance up to 100% of debt for all qualifying projects in a hybrid service area until total RUS financing allocated to that service area reaches a newly-defined "rural cap" (or in some instances, a "financing cap" derived from the rural cap). Once the rural cap has been reached, the power company (borrower or offtaker) would be ineligible for additional RUS financing.

Methods for determining the rural cap differ, depending on whether the applicant is seeking to finance a generation, transmission, distribution or energy efficiency project. The service area's rural percentage is a key factor in setting the rural cap.

Other Changes

The RUS program lending authority, history and selection criteria are skewed today toward well-established utilities, mostly non-profit rural electric cooperatives that serve rural communities. The agency is required by law to give preferential treatment to public sector and non-profit borrowers. RUS lending to privately-owned, for-profit applicants, while occasionally feasible, is rare.

The agency is proposing to maintain a non-profit preference, but also to bring for-profit renewable energy developers (and their municipal, coop or investor-owned utility offtakers) into the RUS camp.

For power plants, for-profit borrowers would still be subject to a more restrictive version of the financing cap, couched in state renewable portfolio standard terms, than are their non-profit counterparts. A for-profit borrower's financing cap will be the lesser of the rural cap and the state's renewable portfolio standard (or 20% as a default cap for states that have not set an RPS), measured in terms of the offtaker / *continued page 48*

Rural Projects

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utility's peak demand or total energy sold.

The RUS could fully finance the project debt, with 20% to 25% of project costs being covered by equity.

For example, a rural cooperative with an 80% rural service area and a coincident peak demand recorded at 1,000 megawatts would have a rural cap, measured in megawatts, of 800 megawatts. Accordingly, RUS would be able to provide 100% of debt for a given project or fleet of projects owned by the coop until the cumulative nameplate capacity financed by RUS in the service area reached 800 megawatts (the rural percentage times 1,000 megawatts). In contrast, an investor-owned utility with the same 80% rural service area, same coincident peak demand, and in a state without an RPS would have a financing cap of 20% times 1,000 megawatts or 200 megawatts. RUS would be able to provide 100% of debt for qualifying projects until the cumulative nameplate capacity financed by RUS reaches 200 megawatts.

The Rural Utilities Service is proposing to change how it determines eligibility.

The same would hold true at the project level. For example, a 50-megawatt wind project applying for a loan guarantee secured in part by a long-term PPA with the coop described earlier would be subject to the coop's service area cap of 800 megawatts. As long as the cumulative nameplate capacity financed by RUS in the service area was less than or equal to 750 megawatts, the project could borrow up to 100% debt. However, if the offtaker were the investor-owned utility described earlier, then the project could borrow up to 100% debt only to the extent that the cumulative nameplate capacity financed by RUS in the IOU's service area was less than or equal to 150 megawatts.

In contrast to power plants, RUS proposes no differences in financing caps for nonprofit and for-profit developers of distribution, energy efficiency and transmission projects.

Renewable energy projects receive no special accommodations today in the applicant review process.

Under the proposal, the RUS may give top priority to processing loan applications for generating facilities that use renewable fuel and to transmission facilities that deliver electricity from a renewable energy supplier.

The agency has also proposed to revamp the basic program structure.

Loans under the RUS loan guarantee program are generally made today at the power company level and are secured on a "system" basis. That is, RUS requires a first lien with full recourse to the borrower's entire electrical system (not just the assets being financed) as well as its revenue streams and after-acquired property. For example, the RUS $14.6 million loan guarantee issued for the SMECO solar project was supported by a general repayment obligation of SMECO, the cooperative that owns the project. Similarly, RUS's FY 2012 $151 million loan guarantee for the Woodville biomass project was made to the East Texas Electric Cooperative, the project's owner and developer, which pledged all its assets to repayment of the RUS-guaranteed loan.

In the case of a non-utility borrower, current policy provides for a "constructive system" loan where the developer signs a power purchase agreement with a utility and the utility offtaker guarantees loan payments as a partner-in-risk with RUS.

Where a utility system is the borrower, construction financing is available from the RUS. For project-level commercial borrowers, the RUS generally disburses term financing only on commencement of commercial operation. Thus, the program is designed to refinance construction lenders following COD. However, because the Rural Electrification Act has been interpreted not to allow refinancing as a general matter, RUS can reimburse general funds or replace interim financing used for construction only if the project's RUS-approved construction work plan anticipated an RUS takeout. Both Eagle Valley Clean Energy, LLC (the recipient of an RUS FY 2012 $40 million loan guarantee for an 11.5-megawatt woody biomass facility in Colorado) and Green Energy Team, LLC (the recipient of an RUS FY 2012 $72.8 million loan guarantee for a 7.5-megawatt woody biomass facility in Hawaii) had to line up commercial lenders to provide interim financing for (and to assume the construction risk of) their respective projects.

In the future, the RUS is considering a move to a "focused project financing program" for investments in electric generation, transmission and distribution facilities, "including plants necessary for generating electricity from renewable energy resources." This means moving away from lending secured on a system-wide basis to lending secured by the assets of individual projects.

Based on the topics the notice identifies for public comment, the RUS is looking at debt issued at the project level and secured by the project assets, with FFB loans for up to 75% of eligible project costs and a required minimum of 25% equity investment. The agency still does not intend to take on construction risk under the proposed program.

Practical Considerations

The RUS program will by law continue to include a number of provisions not typically found in private sector financing, such as a review of each project pursuant to the National Environmental Policy Act.

Although these reviews can vary in complexity, all are time consuming and involve additional cost. At best, project activities "categorically excluded" by RUS can get by without a formal review or with completion of an "environmental review," the lowest level of RUS scrutiny. Projects not categorically excluded require a more detailed "environmental assessment" or a full-blown "environmental impact assessment." The federal environmental review must be completed before the project starts any meaningful construction and, importantly, before RUS will process the loan application.

Comments on the rural eligibility, financing cap and accommodations for project-level and for-profit borrowers were due August 5. The timing for issuing a final rule is unclear and depends on clearance from the Office of Management and Budget. Approval for the establishment of the project financing program, if it happens, will probably take considerably longer.

CFIUS and In-Bound US Investments

Many foreign investors making investments in US companies or projects are unaware that the federal government has sometimes set aside such investments on national security grounds, including a recent sale by a Greek developer of a wind project in Oregon to a US subsidiary of a Chinese company. Foreign investors can protect themselves by informing CFIUS, a federal interagency committee, in advance of the proposed investments. The following is a conversation that took place at the 24th annual Chadbourne global energy and finance conference in June between Amanda Forsythe, a Chadbourne lawyer in Washington who handles CFIUS filings, and Keith Martin, also in the Washington office.

MR. MARTIN: Amanda Forsythe, we are going to talk about something called CFIUS. What is it?

MS. FORSYTHE: CFIUS is the Committee on Foreign Investments in the United States. It is an interagency committee under the US Department of the Treasury that reviews transactions that could result in a foreign person controlling a US business. Over the course of the review, the committee focuses on whether these transactions present national security risks. The Treasury Department chairs the committee. There is a core staff within Treasury, but the committee itself is made up of the heads of various government departments, so everybody from the National Security Council to the Office of Management and Budget is involved in these decisions.

MR. MARTIN: Do acquisitions in the power sector have to be reported — for example, an acquisition of a small wind farm or an acquisition of a wind company? Are such acquisitions potentially of interest to CFIUS?

MS. FORSYTHE: Yes, they are potentially of interest. CFIUS filings are voluntary for the most part. The parties to the acquisition are not required to file a notice. However, in certain instances, CFIUS can initiate a review if it thinks there are potential national security concerns. One thing that the committee has specifically noted as being potentially a national security concern is the effect that the transaction will have on what CFIUS calls critical infrastructure. The regulations state specifically that major energy assets are part of our critical infrastructure.

MR. MARTIN: When is an energy asset a / continued page 50

CFIUS

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"major" asset?

MS. FORSYTHE: The word "major" is undefined.

MR. MARTIN: Does it matter if the foreign investor is buying only a minority interest?

MS. FORSYTHE: For the most part, if the foreign person buys a minority interest, then the transaction is probably in the clear. If the minority interest holder has special powers so that it is a dominant minority and it is the one who makes decisions about the US business, then the acquisition of a minority interest could cause the transaction to be subject to CFIUS.

MR. MARTIN: Does it matter if the foreign investor uses a US subsidiary or US company to make the acquisition. Is that considered a non-foreign acquisition?

MS. FORSYTHE: You have to look up the ownership chain. CFIUS looks at the ultimate owner. If there are power blocks in between the foreign company and the US subsidiary so that the US subsidiary is not controlled by the foreign company, then the transaction should not be subject to CFIUS review. If the foreign company is exerting control over the US subsidiary that is making the acquisition, then CFIUS would be interested in it.

MR. MARTIN: Who has to report — the seller or the buyer?

MS. FORSYTHE: For the most part, transactions are reported jointly by the parties simply as a logistics matter because there is a significant amount of information that is required from both sides in the filing.

MR. MARTIN: And what happens if someone does not report a foreign acquisition?

MS. FORSYTHE: If you do not report a transaction, then you run the risk of being forced later to unwind the transaction. If you file on your own and you get CFIUS clearance, then it is essentially a safe harbor that the government will not try to unwind the acquisition later.

MR. MARTIN: Does CFIUS really want to hear about deals where Canadian or British companies buy US wind or solar projects? Canada and Great Britain have been long-standing US allies. Does CFIUS want to be buried in paperwork about transactions involving investors from such countries?

MS. FORSYTHE: Yes. Actually, most reported transactions involve foreign persons from our allied countries. The most recent report that CFIUS gave to Congress covers 2009 to 2011, and about half of the transactions at which CFIUS looked during that period involved investors from France, Canada or the United Kingdom. Chinese in-bound transactions are also increasingly a subject of filings.

MR. MARTIN: How long does it take to get a response from CFIUS after one files?

MS. FORSYTHE: The CFIUS process involves four discrete periods. The first is the pre-filing period when the parties can submit a voluntary pre-filing notice that allows CFIUS to ask questions about the transaction and request certain information be included in the formal filing. This voluntary period is essentially mandatory at this point. There is not a defined time frame for the pre-filing period. In our experience, it runs a couple of weeks most of the time. The second stage is the actual CFIUS review, and that is a statutorily mandated 30-day review period. CFIUS then has the option to initiate an investigation if it thinks there are national security concerns. Investigations are 45 days. If there are still issues after the investigation, then, in practice, there is period for negotiation. If the deal terms are not changed enough to accommodate the US government's concerns, then CFIUS makes a recommendation to the President. That, for the most part, happens quickly. Overall, you are looking at anywhere from two months plus preparation time to six months if it drags on through an investigation and possibly a Presidential intervention.

Foreign companies acquiring US power projects should probably file with CFIUS.

MR. MARTIN: Is there a filing fee and, if so, how much?

MS. FORSYTHE: There is not a filing fee.

MR. MARTIN: How often does CFIUS turn down acquisitions in practice?

MS. FORSYTHE: Before 2006, at most one or two transactions a year were withdrawn. During the period 2006 through 2009, 64 transactions were withdrawn, or roughly 14% of the 469 transactions submitted to CFIUS for review during that period. From 2009 through 2011, 9% of transactions were withdrawn. Some of the transactions withdrawn are later resubmitted. For example, there were 111 CFIUS filings in 2011. Of that number, 40, or 36%, took another 45 days beyond the initial 30 for an investigation. In eight, or 20% of the cases that went to investigation, the parties agreed to mitigation measures to address government concerns.

MR. MARTIN: Are acquisitions by Chinese or Near Eastern companies more likely to be turned down?

MS. FORSYTHE: You are probably more likely to encounter problems if you are a Chinese company. There have been only two Presidentially-ordered divestments. Both involved Chinese companies. In the most recent case, involving a wind farm in Oregon, the Chinese company failed to file with CFIUS.

[Ed. For more information about this subject, see the February 2013 NewsWire starting on page 9.] ◎

How to Avoid Creating a Tax Presence in Other Countries

by Kelly Kogan, in Washington

When a company engages in cross-border business in another country, it should be careful, when possible, not to create a taxable presence in the other country.

An example is where a solar panel, wind turbine or fuel cell manufacturer puts some of its employees on the ground in another country to help with sales or overseeing the construction work on a project.

Recognizing the types of activities that will create a taxable presence is important to reducing tax costs.

Project developers tend to form a subsidiary in the other country to own the project in that country. The subsidiary will be taxed in the project country.

This article focuses on situations where a parent company also has employees on the ground.

The key is the level of business activity in the other country. Once a threshold level of business activity is exceeded, then the other country will assert its right to tax the parent and the employees both on the business income derived from sources within that country. It is one thing for a local project company to be subject fully to tax. What companies want to avoid is also having the parent company and its employees do too much directly in country so that they also become subject to local income tax.

The specific threshold is established by each country's own law, and local tax advisors should always be consulted. Also, there may be an income tax treaty that covers the situation and modifies the tax regime that would otherwise apply.

Putting tax treaties to the side, the US taxable presence rules are unusual. There are enough similarities in the taxable presence laws of many other countries to make a summary of the key features possible.

US Trade or Business

In the US, the threshold for recognizing a taxable presence is known as having a "US trade or business," and is quite low.

In the case of a foreign individual, any business activity by that individual while physically present in the US usually causes him or her to be taxed on the share of income he or she earns while physically present. Often this attribution is based on the proportion of time the individual spends working in the US relative to the time spent working outside the US.

For example, if a non-U.S. employee of a foreign turbine manufacturer travels to the US to solicit sales of turbines to US customers, stays for nine days, and on each of those nine days meets with numerous potential customers, then the US could assert the right to tax 9/365ths of the employee's salary for the year.

For manufacturing companies, the threshold for triggering a taxable presence in the US is less straightforward and requires consideration of both the qualitative and quantitative aspects of the company's activities in the US. Activities are qualitatively significant if they are material to the business as opposed to ministerial, clerical or incidental. Whether activities are quantitatively significant will often depend on the size of the business and the history of its activities in the US.

For example, suppose an employer is a large, well-established manufacturer that generates revenues / *continued page 52*

Avoiding PEs

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from numerous sales to customers in other parts of the world and is now looking to enter the US market. A single visit to the US by its employee for nine days to solicit sales is unlikely to create a US trade or business for the employer, even if the employee is successful in signing a contract with a US customer. On the other hand, if the employee makes numerous visits to the US during the year and signs several contracts with US customers during those visits, then his or her activities in the US on behalf of the employer are likely to be qualitatively and quantitatively significant enough to cause the employer to have a US trade or business.

In the case of a foreign services company, the results are the same. For example, a foreign consultancy that provides testing services to PV projects around the world would not be treated as having a US trade or business based on a single visit by one of its employees to the US to conduct tests on a US project.

On the other hand, if the consultancy sends numerous employees on frequent short trips to the US, or if one or two employees it sends in a single year stay for extended periods, the activities would run the risk of creating a US trade or business.

Manufacturers risk creating a tax presence in a country if their employees spend too long at a project site.

Outside the US

Outside the US, an individual's liability for local income tax turns on whether the individual has spent enough time in the country to be considered a tax resident and what income he or she is considered to have earned in the country.

Depending on local law, individuals who qualify as tax residents of a host country may be taxed on their worldwide income. In most cases, an individual does not become a tax resident unless he or she spends a minimum number of days in the country during a 12-month period. This number can range from 183 to 365 days. In some countries, it may be even longer if the individual has a specific type of visa.

If an individual is not a tax resident, then he or she will usually be taxed only on the portion of the income that is considered from sources within the country. In this area, many countries follow the same approach as the US in that they will treat the salary an employee receives from his or her employer while physically present and working in the country as earned in the country even if the individual is not a tax resident and the employer does not have a local tax presence.

Turning to companies and what subjects them to local income taxes, the trigger in many countries is the existence of a level of activities referred to sometimes as a "branch" and other times as a "permanent establishment" or "PE." (The term "permanent establishment" is also used in income tax treaties, and it may have a different definition for treaty purposes. Treaties may spare companies from local income taxes if their activities do not rise to the level of a PE as defined in the treaty. The treaty definition of a PE usually has a slightly higher threshold for creation of a taxable presence than under local law. That is why it is always important to check treaties.)

In general, most countries require more significant business activity inside the country than the US before those countries view a company as having a taxable presence.

Most countries have adopted one of several general definitions of PE with possible local variations. The most common is a fixed place of business in the country through which at least some of the business of the company is conducted. This "fixed place PE" must meet two key requirements. First, it must be a distinct office or other place with a certain degree of permanence in the country. Second, it must be used to carry on business activities.

For a foreign manufacturer, a fixed place PE in a country includes a local office or factory used by its employees to engage in manufacturing or sales activities. It does not matter whether the office or factory is owned or leased by the foreign manufacturer. It is not a defense that the space is "borrowed" from an affiliate in the country (meaning that the manufacturer does not compensate the affiliate for its use of the affiliate's space) if the manufacturer's use of the space is lengthy or frequent. A fixed place PE can even be a hotel where the non-resident company's employees stay repeatedly and conduct business activities.

On the other hand, a fixed place PE is not established if it is not "fixed" or if it is not used to conduct business. For example, even if employees of a foreign manufacturer visit a country frequently during a 12-month period to solicit sales, the manufacturer is unlikely to have a fixed place PE if the employees visit different cities or stay in different hotels. On the other hand, if those employees repeatedly visit the same location and during each visit conduct business using the same conference room in the office of a local affiliate, then it is likely that the conference room will be treated as a fixed place PE of the foreign manufacturer.

Some countries may have specific exceptions where a fixed place PE is not considered to have been created. An example is for activities that are preparatory or auxiliary in nature. They can include, for example, certain storage facilities used to store goods on a temporary basis or a location used solely for the purpose of purchasing goods or merchandise or for collecting information. Because the scope of these exceptions can be rather opaque, local counsel should usually be consulted.

Construction PE

For a service provider, such as an EPC contractor, the existence of a PE may depend on whether it is performing its services as part of the construction or installation of a project inside the project country. Many countries have a special definition of PE that treats a building site or construction or installation project as a PE, but only if it lasts for a specified period of days or months. (This period generally ranges from 90 days in a 12-month period up to a full 12 months.)

There are typically two things that have to happen before a contractor has created a construction PE.

The first relates to the substantive activities that are taking place. They must qualify in most countries as "construction, assembly, or installation projects." What rises to the level of construction may vary from one country to the next. For example, construction activities could include the construction or renovation of access roads, the installation of cables needed to connect a power plant to the utility grid, or excavation and dredging activities. Assembly and installation may not be limited to a fully-blown construction project — they could also cover assembly or installation of new equipment, such as a complex machine, in an existing building or project. Some countries even treat as construction supervising a local construction company at the project site.

The second thing that must happen to have a construction PE is the activities in the country must last long enough to rise to the level of a construction PE. The critical question is when the activities begin and end. In most cases, a construction PE is considered to exist from the date on which a contractor begins its work, including any preparatory work, and ends when that work is completed. In addition, temporary or seasonal cessations of work, including those outside of the contractor's control, are usually included in determining how long the work lasts.

For example, assume an EPC contractor installs a trailer to serve as an office on April 1 at the site of a power plant that it has contracted to build, begins constructing the plant on June 1, is forced to halt construction during November and December due to equipment shortages and bad weather, and finally completes the plant on May 1 of the following year. The EPC contractor's construction site will be considered to have lasted 13 months (April 1 to May 1 of the following year) and not 10 months (May 1 of the first year when construction began to May 1 of the following year when construction ended, less the two months when construction ceased due to factors outside of the EPC contractor's control). If the temporal component of the construction PE definition is 12 months, then the EPC contractor in this instance will have a construction PE.

If an EPC contractor, which has undertaken a general contractor role on a project, subcontracts parts of the project to one or more subcontractors, the time spent by each subcontractor working on the construction site will likely count for purposes of determining whether the general contractor has a construction PE. This is because the time spent by the subcontractor working on the project will probably be considered time spent by the EPC contractor working on the project under general agency principles. Alternatively, if the country includes supervision as a construction-related activity, any time the general contractor spends supervising the subcontractor's work will have to be taken into account for purposes of determining whether the general contractor has a / *continued page 54*

Avoiding PEs

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construction PE. The degree of supervision necessary to apply this rule will depend on local law.

As for a foreign subcontractor, it will have a construction PE only if its activities last longer than the period needed to trigger a construction PE.

To illustrate, assume an EPC contractor signs a contract to build a solar thermal facility that will be used to supply steam to a nearby power plant. The EPC contractor hires numerous subcontractors to perform various aspects of the EPC contract. The construction of the entire CSP facility takes more than 18 months to complete, while each subcontractor's activities take five months or less to complete. If the threshold for a construction PE is six months, only the EPC contractor will have a construction PE.

Agency PE

One other type of PE is an agency PE. This is a PE created by the activities of a dependent agent in a country who is acting on behalf of a foreign company.

Dependent agents may include employees and others under the control of the principal, regardless of whether they are residents of the country. They are on the ground. However, they do not include persons considered "independent" agents, such as local transportation companies and other established independent local service providers who have more say over how any work will be performed and no ability to bind the principal legally. A local subsidiary of the principal is not usually a dependent agent, unless the subsidiary is specifically acting in such a capacity. In some, but not all cases, a country's law may require that the dependent agent also have the authority to bind the principal legally to local contracts.

For example, assume that an employee of a foreign manufacturer visits a country once during the year, remains in the country for only a couple of days and, while there, finishes negotiating and signs a contract with the customer that is binding on the principal. Under these facts, it is unlikely that the employee's activities will have created a fixed place PE. However, if the country's laws also include a dependent agent PE, then the employee's activities run the risk of creating an agency PE.

Taxable presence rules are highly complex, fact dependent and sometimes counter-intuitive. They create both pitfalls for the unwary and opportunities to reduce overall tax exposure for those who plan ahead. Companies expanding outside their home bases should proceed with care. ◎

DOE Loan Guarantees for Advanced Fossil Fuels: They're Back!

by Kenneth W. Hansen and Charlotte Del Duca, in Washington

Four years after the Department of Energy issued its last solicitation for loan guarantee applications and approaching two years since its last financial closing, the DOE is back into the loan guarantee business with up to $8 billion in guarantee authority to be made available for innovative fossil fuel energy projects.

A draft solicitation for applications, issued July 2, sets a September 9 deadline for industry and public comment, making delivery of a final solicitation likely before the end of the year.

The first public comment meeting at DOE headquarters took place on July 31. Two other meetings are scheduled for August 14 and August 27.

This article explains what types of projects are eligible for loan guarantees and discusses some key provisions and the application process in the draft solicitation.

These loan guarantees will be issued under section 1703 of the Energy Policy Act of 2005, meaning that the "guarantees" are actually an opportunity to borrow directly from the Federal Financing Bank at interest rates that are currently 37.5 basis points above Treasury bond rates. DOE can guarantee loans covering up to 80% of total project costs for the lesser of 30 years or 90% of the projected useful life of the project's major physical assets.

The new loan guarantees will differ from loan guarantees for Recovery Act project financings that closed before September 30, 2011 in three major respects.

First, eligibility is limited to projects that "employ New or Significantly Improved Technology as compared to Commercial Technology in service in the United States at the time the Term Sheet is issued." (While the Recovery Act program ultimately supported many innovative projects, conventional technologies were also welcome.) Second, with limited exceptions, loan guarantee recipients cannot "double dip" (meaning they cannot benefit from most other kinds of federal support). Third, these project borrowers will have to pay their own credit subsidy costs at closing (a significant cost that has been avoided by all DOE loan guarantee recipients to date thanks to the now-expired Recovery Act funding). Credit subsidy charges are like the premium paid to buy insurance.

These requirements did not apply to any of the approximately $15 billion in loan guarantees issued by DOE through September 2011 under the section 1705 program. Absent further legislation, all future recipients of loan guarantees under DOE's remaining $34 billion in loan guarantee authority will be subject to these provisions, with one exception. In April 2011, Congress appropriated $170 million to pay subsidy costs for energy efficiency and renewable energy projects and later provided that DOE could mix appropriated and borrower funds to pay the credit subsidy costs for such projects. However, no help is available to avoid credit subsidy costs for fossil fuel projects pursuant to this solicitation.

The US Department of Energy will start accepting applications soon for up to $8 billion in loan guarantees for projects that use fossil fuels.

Eligibility

The new solicitation covers both "electrical and non-electrical" fossil energy uses. "Fossil fuels" includes coal, natural gas, oil shale gas, oil gas, coal-bed methane, methane hydrates and "others." Projects may involve any stage of the full life cycle of fossil fuel development (resource, process, products and downstream). Projects that employ innovative technologies to improve the efficiency of conventional production processes are within the scope.

DOE has cast a broad net in terms of qualifying technologies. To be eligible, a project must be innovative, (meaning employ a new or significantly-improved technology), be in the United States or a US territory and avoid, reduce or sequester air pollutants or greenhouse gas emissions.

Technologies must not have been deployed in more than three projects active in the United States for more than five years.

DOE is looking to back four types of projects. One is *advanced resource development* that reduces gas emissions related to the mining or recovery of traditional and non-traditional fossil fuels, such as novel oil and gas drilling technologies, use of associated gas production to reduce flaring, coal-bed methane recovery and underground coal gasification. Another is *carbon capture* projects that remove CO_2 emissions for permanent underground storage or through beneficial reuse, such as CO_2 capture from synthesis gases in fuel reforming or gasification processes, flue gases in traditional coal or natural gas electricity generation and effluent steams of industrial processing facilities.

Another project type is *low-carbon power systems* that integrate fossil fuel electricity generation with CO_2 storage for beneficial reuse, such as coal or natural gas oxy-combustion, chemical-looping processes, hydrogen turbines and synthesis gas-, natural gas- or hydrogen-based fuel cells.

Finally, projects to make *efficiency improvements* also qualify. These are projects that reduce emissions-per-product by improving feedstock utilization of fossil-based systems, such as combined-heat-and-power projects, waste heat recovery on industrial facilities and high-efficiency distributed fossil power systems.

Double Dipping

The FY 2009 Omnibus Appropriations Act that provided the $8 billion being allocated under the solicitation prohibits loan guarantees to any projects where funds, personnel, or property (tangible or intangible) of any Federal agency, instrumentality, personnel or affiliated entity are expected to be used (directly or indirectly) through acquisitions, contracts, demonstrations, exchanges, grants, incentives, leases, procurements, sales, or other transactions or other arrangements, to support the project or to obtain goods or services from / *continued page 56*

DOE Loan Guarantees

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the project.

The following federal benefits are carved out from this prohibition against double dipping: federal income tax benefits, leases of federal land complying with certain arms-length requirements and federal insurance programs (such as the Price-Anderson Act under which the federal government provides insurance for nuclear energy projects).

The bar against double dipping will rule out any loan guarantees for projects that have already received DOE grants. It remains to be seen how much deft structuring will be able to mitigate this impact (for example, by developing the project in a different company than the one that received the federal grant). Given that the innovative projects that are the focus of the section 1703 program are the ones most likely to have previously benefited from federal grants, the bar against double-dipping could undermine the effectiveness of the program.

Key Provisions

The draft solicitation includes other requirements that are familiar in the DOE loan guarantee program.

For example, the Davis-Bacon Act requires projects to pay all on-site (and certain off-site) construction laborers and mechanics the Department of Labor's prevailing wage for the job category and location. For projects that have DOE financing subsequent to having commenced construction, the Davis-Bacon Act will apply retroactively to the start of construction, but the government has discretion to waive retroactivity if the project starts construction before the decision is made to apply for federal financing.

Unless a project qualifies for a categorical exclusion under the National Environmental Policy Act, it must also complete either an environmental assessment or full-blown environmental impact statement before DOE can decide whether to issue a loan guarantee. An environmental assessment typically takes six to nine months, while an environmental impact statement takes 18 to 24 months.

In addition, any information collected by DOE is subject to disclosure under the Freedom of Information Act. Applicants would be wise not to divulge patentable ideas, trade secrets or proprietary and confidential information to DOE beyond what is needed to explain the project. Although an applicant may restrict DOE's use and disclosure of sensitive data if it specifically identifies and marks the data, DOE recently found itself responding not only to FOIA requests but also to Congressional oversight information requests, which are not afforded the same non-disclosure protections that exist under FOIA and the Trade Secrets Act. The risk of disclosure of information submitted to DOE exists for all applicants and not just successful ones.

Finally, DOE has agreed with the Department of Transportation to require, as a matter of policy, that all ocean transport of cargos destined for section 1703 loan guarantee recipients be carried on US-flag vessels. The US Maritime Administration can grant waivers on a case-by-case basis.

Application Process

Applications are to be submitted in two parts.

DOE will evaluate part I submissions competitively (to determine which projects are eligible and ready to proceed. Applicants that pass muster will be invited to file a part II submission.

The solicitation anticipates up to six rounds of part I submissions, each by a yet-to-be determined deadline, staggered with six due dates for part II submissions. A project invited to file a part II submission may do so prior to any of the then remaining part II due dates. At the close of each round of part II reviews, DOE will announce the projects selected (again in competition with other projects submitted by the same part II deadline) to proceed to due diligence and negotiation of a term sheet.

The round-specific competitive review of projects suggests a possible incentive to choose a deadline carefully, ideally targeting one seen to provide the least, or weakest, competition. However, it is easy to imagine that a broader competitive review will develop, with DOE reflecting the full actual and expected applicant pipeline. To the extent that proves true, strategically targeting a particularly lonesome part I or part II deadline will be less important.

The required elements of the part I submission include a top-level technical overview outlining the project's eligibility and potential to reduce greenhouse gas emissions, the status of permitting and evidence that the project could not be fully financed on a long-term basis absent the DOE loan guarantee.

Applicants must also disclose any past or ongoing lobbying activities "in connection with a commitment providing for the United States to insure or guarantee a loan."

There is no limit to the number of applications an applicant can file, but a single applicant may not submit applications for more than one project using the same innovative technology.

In part II submissions, DOE will look at, among other things, whether the project has a reasonable prospect of repaying the DOE guaranteed loan and whether the loan, when combined with funding from other sources, will cover project costs.

The relative weightings assigned to the assorted financial, technical and policy factors to be considered in competitively ranking applications are blank in the draft solicitation. DOE would welcome public input on appropriate weights.

Cost

Participation in this DOE program will not be cheap. The tally begins with a non-refundable $1 million filing fee, payable in two steps: $250,000 for part I and $750,000 for part II. Applicants selected for due diligence review then pay 25% of a non-refundable facility fee on or before signing the DOE-approved term sheet. The remaining 75% is due at financial close. The facility fee is expected to range from 0.5% to 1% of the principal amount of the loan to be guaranteed by DOE.

DOE's independent consultants and outside counsel fees, as well as any extraordinary expenses related to the project financing, can easily add millions more dollars to the applicant's transaction costs.

DOE also extracts a non-refundable maintenance fee over the life of the guaranteed loan, paid annually in advance. The solicitation anticipates a maintenance fee of $500,000 per calendar year. The first prorated installment is to be paid before the financial closing date.

A separate credit subsidy charge will also have to be paid. It is reasonable to expect that a more innovative project with a higher level of performance risk will have a higher credit subsidy cost than would a project without such risks. A firm, creditworthy offtaker helps in all cases. Many discussions heroically assume an average of 10%, but that is for lack of any real basis for a better estimate.

DOE will provide project sponsors a preliminary credit subsidy cost estimate at the same time as the draft term sheet (after the applicant has paid the $1 million in application fees but before the first 25% of the facility fee is due). The final credit subsidy cost is set immediately prior to financial closing, when it is due in full and payable from equity or non-federal debt. It cannot be paid with the proceeds of the DOE-guaranteed loan or from any other federal funding source.

The New Normal

The solicitation is on a fast track. DOE apparently intends to get the program rolling before year's end. The window for public and industry comment is set to close in early September, and the title page of the solicitation suggests that the solicitation will be issued, and the first round of part I and part II filings will be complete, in 2013.

DOE has not issued a loan guarantee or conditional commitment since September 2011. It has spent a lot of time since then answering to mainly Republican critics in the US House of Representatives.

Nonetheless, the DOE loan guarantee program still has $34 billion in unused section 1703 loan guarantee authority. In addition to the $8 billion earmarked for advance fossil fuel projects, $1.5 billion is allocated to energy efficiency and renewable energy projects, $18.5 billion for nuclear generation and $2 billion for other nuclear projects. Another $4 billion of "mixed" authority remains that canbe used in principle for any of the loan guarantee categories, although DOE notified Congress that it expects to use $2 billion of that authority for nuclear fuel projects so that it can accommodate a second nuclear fuel project.

Absent further Congressional action, all future solicitations will be issued under the section 1703 authority. All will be subject to the innovative technology, double-dipping prohibition and self-pay credit subsidy cost requirements as presented in the fossil fuel solicitation. The sole exception to self-pay of credit subsidy costs would be any lucky developers of renewable energy or energy efficiency projects that manage to tap the surviving $170 million appropriation for credit subsidy costs. ◎

Energy Storage Update

by Paul Kaufman and John Frenkil in Los Angeles, and Shellka Arora in New York

The nascent electricity storage industry is starting to make progress both in California and at the federal level.

The California Public Utilities Commission proposed in June that the state's three investor-owned utilities — Pacific Gas & Electric, Southern California Edison and San Diego Gas & Electric — be required to buy approximately 1,300 megawatts of energy storage by 2020. The Federal Energy Regulatory Commission issued an order in late July that expands opportunities for competitive suppliers of ancillary services, which can include energy storage providers.

California

The California Public Utilities Commission is proposing to set the electricity storage targets in the chart below. The figures are in megawatt amounts. Individual targets are set for each utility. Targets will have to be met starting in 2014. The targets will ramp up every two years.

There are separate targets for electricity storage tied to the type of benefit provided by the storage system. To qualify as transmission storage, the services provided should reduce the need for transmission upgrades, for example, by helping to shave the peak demand on the transmission system, improve grid operation and reliability or provide relief from congestion. To qualify as distribution storage, the services provided should include peak capacity support and voltage control. To qualify as customer storage, the storage should provide back-up power and improve quality for a customer.

The proposal, or a variation of it, will be approved or modified by the full commission and is expected to become final by October 1, 2013.

Utilities would be required to buy "commercially available, eligible storage technologies utilized in grid applications that may have been demonstrated but are not yet generally deployed on the grid in California." The targets subsume other storage directives already issued by the CPUC, including a storage directive in a recent CPUC procurement decision for Southern California Edison. In that decision, the CPUC ordered a 50-megawatt set aside for Southern California Edison to procure 1,400 megawatts of energy storage in the western Los Angeles basin in order to meet its 2021 local capacity requirements.

The CPUC is proposing that storage be procured through a mechanism modeled after the "renewables auction mechanism" currently used as the primary method for California utilities to take bids from renewable energy generators to supply electricity on a short-term basis. Renewable generators bid into four competitive auctions. The winners sign standard non-negotiable contracts. Generators bid their full costs and, if selected, are paid their costs as bid, less any portion of the cost that is publicly funded, over the life of the contract.

	2014	2016	2018	2020	Total
Southern California Edison					
Transmission	50	65	85	110	310
Distribution	30	40	50	65	185
Customer	10	15	25	35	85
Subtotal SCE	**90**	**120**	**160**	**210**	**580**
Pacific Gas and Electric					
Transmission	50	65	85	110	310
Distribution	30	40	50	65	185
Customer	10	15	25	35	85
Subtotal PG&E	**90**	**120**	**160**	**210**	**580**
San Diego Gas & Electric					
Transmission	10	15	22	33	80
Distribution	7	10	15	23	55
Customer	3	5	8	14	30
Subtotal SDG&E	**20**	**30**	**45**	**70**	**165**
Total - all 3 utilities	**200**	**270**	**365**	**490**	**1,325**

Government actions in California and at the federal level should create new opportunities for energy storage companies.

If adopted, the CPUC proposal would require that the first storage auction be held by June 30, 2014. Auctions would be held biannually thereafter, in 2016, 2018 and 2020. The auctions would use the CPUC's least-cost, best-fit analysis to evaluate bids, and each investor-owned utility would employ an independent evaluator to assess the competitiveness and integrity of its auction. Following the auction, each utility would submit an advice letter to the CPUC, providing details on the winning bids and requesting approval and rate recovery.

The CPUC is also proposing an evaluation, measurement and verification program to ensure the integrity of the energy storage procurement program. The CPUC plans to monitor the progress of the energy storage market in California as well as the operational data collected and the cost effectiveness of deploying energy storage technologies.

The auction process and proposed new storage targets are not the only programs for storage in California. The CPUC has a "self-generation incentive program" or "SGIP" that gives utilities an incentive to support existing, distributed energy resources, including advanced energy storage systems. While SGIP was originally introduced to reduce peak loads after the 2001 California energy crisis, SGIP has evolved into a comprehensive set of incentives on a per-watt basis for renewable and waste heat technologies ($1.19/watt), non-renewable conventional combined heat and power ($0.48/watt) and emerging technologies such as advanced energy storage ($1.80/watt) and fuel cells ($2.03/watt). The utilities pay these dollar amounts per watt of capacity to the retail utility customer on whose premises the storage device is located. The payments start when the storage device is put in service and continue until the customer has been paid the $5 million limit.

The CPUC also has a "permanent load shifting" program that is currently authorized for $32 million in funding and provides incentives for utilities to transfer load (or demand for electricity) from congested peak times to over-generating off-peak times. An energy storage device helping with load shifting would be located behind the meter — meaning on the customer side of the electric meter — but could be owned by the customer, utility or a third party. Payments are made by the utility to the owner of the storage device as an inducement to participate in such load shifting. The utility is repaid, in turn, out of the $32 million in funding for the program.

FERC Action to Promote Storage

The Federal Energy Regulatory Commission has been wrestling with whether to classify storage devices connected to the grid as transmission, generation or a hybrid. If the devices are transmission assets, then their cost can be recovered from all users of the grid through rates the grid operator charges for transmission.

In the meantime, the agency made it easier in late July for electricity storage companies to compete to provide ancillary services to the grid at market-based rates.

The agency has been evaluating how to classify storage projects to date on a case-by-case basis.

For example, in one decision, FERC evaluated a request by Western Grid Development LLC for various incentives, as well as a finding that the company's projects were eligible for incentive ratemaking treatment that is available to wholesale transmission facilities. FERC granted the request for incentives, but required Western Grid to operate as a "participating transmission operator" or "PTO" subject to the California Independent System Operator's tariffs and enter into a transmission control agreement. As a PTO, Western Grid will be responsible for energizing the project's batteries, as well as performing all the duties associated with the day-to-day operations and maintenance of the projects, but its operations will be subject to CAISO control.

FERC has also encouraged storage through other ratemaking orders and rulemakings. In June 2012, it issued a notice of proposed rulemaking to encourage the / *continued page 60*

Energy Storage

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development of competitive markets for the supply of ancillary services, such as those provided by energy storage projects.

The final rule on this subject came out in late July as Order No. 784. It permits third parties to supply various ancillary services at negotiated rates to transmission utilities, without the third party having to prove it lacks market power for such services, if the third party passes existing market power screens for sales of energy and capacity, the rates are established in a competitive solicitation or they do not exceed the published rates in the utility's "OATT" or open-access transmission tariff for the services. (Independent generators and other suppliers sometimes are not allowed to charge negotiated, "market-based" rates if they have too much market power, calling into question whether the negotiated rates are truly arm's length.) The expansion of the market for ancillary services should boost the fortunes of energy storage providers since they are well suited to provide various ancillary services.

Order No. 784 also requires each transmission utility to add to its OATT schedule 3 a statement that it will take into account the speed and accuracy of regulation resources in its determination of reserve requirements for regulation and frequency response service, including as it reviews whether a self-supplying customer has made "alternative comparable arrangements" as required by the schedule. The order also requires each public utility transmission provider to post on the open access same-time information system — called OASIS — historical one-minute and 10-minute area control error data for the most recent calendar year, and to update the information once a year. The reforms are supposed to enable transmission customers who want to self-supply regulation and frequency response service to demonstrate that the resources they use for such service are comparable to those of the transmission utility and address the potential for discrimination against transmission customers choosing to "self-supply" regulation and frequency response service.

The hope is that the reforms will ensure that an appropriate quantity of resources is used for self-supply, whether those resources are faster and more accurate or slower and less accurate than those used by the transmission utility and enhance the customer's ability to meet the self-supply requirements at the lowest possible cost. For example, a self-supplying customer could save money either by relying on a smaller amount of high quality regulation resources at a slightly higher per-unit price or by relying on a larger amount of lower quality regulation resources at a much lower per-unit price.

The order creates significant opportunities for fast responding sources such as batteries and flywheels that bid into frequency regulation service markets.

Real Impediment

Implementation of storage continues to be hampered by the need for a commercial model that values storage intrinsically, rather than on the basis of the energy or capacity that it provides to the market. Without that commercial model, it will be difficult to see investment made in storage other than by those responsible for maintaining grid stability. California's storage initiatives may force the creation of that model by promoting demand through the currently-proposed storage targets. ◎

Environmental Update

The confirmation of Gina McCarthy as head of the US Environmental Protection Agency in July is a sign the Obama administration will put greater emphasis on climate change issues. McCarthy was assistant administrator of the office of air and radiation, where she oversaw the efforts the administration has been making to reduce greenhouse gas emissions.

McCarthy is expected to be a detail-oriented administrator and a pragmatic regulator. Her past actions suggest she will consider the practical implications before she acts. She inherits a full inbox, including new rules on greenhouse gas power plant emissions, management of coal ash from power plants and guidance on hydraulic fracking fluids.

Climate Change

The administration released a multi-pronged climate action plan in July to reduce US greenhouse gas emissions, better prepare the US for the unavoidable effects of climate change and reengage in international efforts. The plan involves more than 30 new policy actions. It does not require action by Congress to implement. The goal is to reduce US greenhouse gas emissions by 17% below 2005 levels by 2020. The plan is already receiving significant Congressional criticism, particularly from members in coal-producing states.

The centerpiece of the plan is a Presidential memorandum directing EPA to issue greenhouse gas performance standards or other regulatory or market-based measures to reduce greenhouse gas emissions from both new and existing power plants.

The agency has been ordered to re-propose greenhouse gas performance standards for new power plants no later than September 20, 2013, with a final rule to be issued in a "timely fashion" following public comment. Since the announcement, EPA has already sent a revised proposal to limit emissions from new power plants to the White House for interagency review.

Since the plan was released, several sources have suggested that EPA will re-propose performance standards for new power plants that set different emissions limits based on fuel type, including for coal-, oil- and natural gas-fired plants. The coal industry had called for different standards for different fuels because a uniform standard would put coal units at a disadvantage. EPA is expected to back away from an April 2012 proposal to require new coal-fired units to install carbon capture and sequestration within a decade.

In a more controversial move among certain sectors of the power industry, the President instructed EPA to issue draft greenhouse gas performance standards for modified, reconstructed and existing power plants by June 1, 2014, and then to make them final a year later. The states will then have another year until June 30, 2016 to submit their own plans for controlling greenhouse gas emissions from existing power plants in accordance with the EPA guidelines.

This will be the first time the federal government has tried to limit greenhouse gas emissions from existing power plants.

EPA has flexibility under the plan to adopt a market-based approach and to require states to impose cuts in greenhouse gas emissions. This "flexibility" may mean that EPA will consider some form of federal cap-and-trade system for the power sector, possibly a federal program that accommodates existing state or regional market-based programs to reduce carbon pollution. EPA has been directed to engage with stakeholders on establishing the new standards.

The plan sets a goal of doubling renewable energy generation in the United States by 2020. Among a variety of planned means to that end, the federal government will work toward consuming 20% of its electricity from renewable sources, and the Department of the Interior has been instructed to allow 10,000 megawatts of renewable energy facilities to be built on federal lands by 2020.

The plan directs the US Department of Energy to open the window to applications for up to $8 billion in federal loan guarantees under the section 1703 loan guarantee program for advanced fossil energy and efficiency projects. The goal is to encourage use of "clean coal" and other innovative technologies.

Looking beyond the US, the US government will work to encourage greater free trade in clean energy technologies worldwide, including those used in solar and wind power facilities. The administration also intends to encourage other countries to switch from coal to cleaner forms of electricity production and to spur the advancement of carbon capture and storage. The plan calls for an end to US taxpayer financing of new coal plants in other */ continued page 62*

Environmental Update

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nations unless carbon capture and storage are used, at least in the absence of feasible alternatives.

The President said he will also push for a global climate treaty at the next United Nations Framework Convention on Climate Change in November.

China-US Pact

The United States and China agreed to five new initiatives to reduce greenhouse gas emissions and other types of air pollution on July 10. Specifically, by October 2013, the two nations will develop plans to reduce emissions from heavy-duty vehicles, promote carbon capture and increase energy efficiency in buildings, industry and transport. They also agreed to improve greenhouse gas emissions data collection and promote the use of smart grid technology. Together, the US and China account for more than 40% of global carbon dioxide emissions.

Bats, Birds and Wind

The US Fish and Wildlife Service announced a $950,000 grant in early July to help agencies in eight Midwestern states prepare habitat conservation plans that allow wind energy development to continue while limiting the effects on the Indiana bat and certain endangered bird and bat species.

A habitat conservation plan is an agreement between a landowner and the Fish and Wildlife Service that allows the landowner to undertake otherwise lawful activities on his or her property, such as wind and solar development, even at a cost of affecting specifically identified listed species. In exchange, the landowner agrees in advance to conservation measures designed to minimize and mitigate the potential impact. The agreements are called "HCPs." HCPs developed by counties or states can cover multiple landowners within a jurisdiction and address multiple species.

The grant is supposed to make it easier to draw up individual HCPs by funding baseline surveys and inventories, document preparation, outreach and similar planning activities by states and territories. Specifically, these funds will allow the natural resource agencies within the Great Lakes-Big Rivers Region (Illinois, Indiana, Iowa, Michigan, Missouri, Minnesota, Ohio and Wisconsin) to continue to develop a landscape-level, multi-species HCP throughout the eight states to provide conservation benefits to listed species while accommodating wind development.

This should provide a means for wind developers to avoid, minimize, mitigate and compensate for adverse effects to covered species, including the endangered Indiana bat, gray bat, interior least tern, Kirtland's warbler and piping plover, as well as several unlisted bat species. All eight states are expected to collaborate with the wind industry and The Conservation Fund to lead a strategic conservation planning process that focuses on integrating species' needs with potential habitat mitigation across the area.

The National Environmental Policy Act requires the Fish and Wildlife Service to do an analysis before it permits any incidental take of a protected species.

In what may be a first for the Fish and Wildlife Service, the agency also approved an extensive HCP designed specifically for the Indiana bat and issued an incidental take permit to the Buckeye wind project in Ohio on July 17. The permit allows for the incidental "take" of a small number of endangered Indiana bats at a wind farm in eastern Champaign County. The permit allows the take of 130 Indiana bats over the project's projected 30-year lifespan. If more than 5.2 Indiana bats are "taken" in any given year, Buckeye is required to take action.

The project must take measures to reduce the likelihood of taking Indiana bats by adjusting operating hours during spring and fall migrations, the summer maternity period and between sunset and sunrise. Some habitat protection and enhancement efforts, monitoring of any take through post-construction mortality studies and adaptive management are required, as well as research to understand Indiana bat and wind turbine interactions.

Indiana bats have been considered an endangered species since 1967. They are dwindling in numbers, in part due to the spread of white-nose syndrome. Indiana bats are found over most of the eastern half of the United States. Other HCPs and incidental take permits related to Indiana bats are now under consideration by the Fish and Wildlife Service at both the Fowler Ridge wind farm in Indiana and the Beech Ridge wind project in West Virginia.

In June, the Fish and Wildlife Service issued another "first" — a "biological opinion" that would allow the taking of one

California condor. The opinion dealt with the Alta East project on mainly public lands in Southern California. It includes an "incidental take statement" that allows one "lethal take" of a California condor over the project's 30-year lifespan. If the Bureau of Land Management approves and the project proceeds, the Fish and Wildlife Service would require another formal review of the potential effect of the project on condors in the event a single condor is killed. The project is expected to generate a maximum of 318 megawatts from 106 turbines, each with 190-foot-long blades. Fewer than 250 California condors are known to exist in the wild and nearly 65 of those live in the Tehachapi mountains near the project.

Coal Ash and Wastewater Effluent

A showdown is developing over a cost-benefit analysis that EPA did before issuing proposed wastewater effluent guidelines to regulate discharges from power plants. The proposed effluent guidelines were published in June as part of a court-approved settlement with environmental groups. The agreement requires EPA to finalize the effluent guidelines by May 22, 2014.

The proposed guidelines address discharges of mercury, selenium, zinc and phosphorus from 1,200 existing power plants nationwide, as well as from any new plants.

EPA proposed eight options, each covering various waste streams. Different size units have been selected for control with varying degrees of controls. The proposed requirements would apply to discharges of wastewater associated with flue gas desulfurization, fly ash, bottom ash, combustion residual leachate, flue gas mercury control, non-chemical metal cleaning wastes and gasification of fuels like coal and petroleum coke.

EPA acknowledges that many of the discharges result from the implementation of stricter air pollution controls that redirect pollutants from air emissions into other waste streams.

The agency extended the comment period to September 30, 2013.

Environmentalists want EPA to adopt a standard that requires dry handling of coal ash and moves away from use of settling ponds. The power industry argues that EPA has underestimated the cost of removing bottom ash from wastewater and significantly overestimated the bottom ash removal efficiencies of power plants in its cost-benefit analysis.

EPA is also asking for comment on whether to align the proposed effluent guidelines for power plants with a related rule for coal combustion residuals that the agency proposed in 2010. Coal ash is a byproduct of burning coal at power plants for electricity. In 2010, EPA issued standards for ash disposal under the Resource Conservation and Recovery Act that would have regulated coal ash as either a special waste or as non-waste material. The agency has still not issued a final coal ash rule, but has been collecting additional technical data. Its final decision could significantly affect coal ash recycling and reuse and potentially require more stringent storage requirements. Coal ash is used in a variety of products, including roof shingles and cement.

The US House of Representatives voted in late July to transfer control of coal ash regulation to the states. The bill is not expected to pass the Senate.

"Good Neighbor" Petitions

A US appeals court said in July that EPA can grant petitions by downwind states to impose emissions cuts in neighboring, upwind states. The unanimous ruling is expected to boost efforts by downwind states to force power plants and factories in upwind states to curb their emissions.

The court said that section 126(b) of the Clean Air Act "unambiguously" allows the federal government to order sulfur dioxide cuts at a 427-megawatt power plant in Portland, Pennsylvania in response to a good neighbor petition filed by New Jersey. New Jersey argues that the plant's emissions make it impossible the state to meet EPA's one-hour SO2 national ambient air quality standard. The case is called *GenOn REMA, LLC v. EPA*.

The decision opens the door to attempts to do piecemeal what EPA tried to do more broadly in a "cross-state interstate transport rule" that another appeals court struck down last year.

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Greenhouse Gas Challenge

A US appeals court dismissed a lawsuit in late July by Texas, Wyoming and the Utility Air Regulatory Group to block rules that EPA issued in December 2010 requiring states to enlarge their state implementation plans for reducing air pollutants to include greenhouse gases. Any large industrial source of air emissions that expands or modifies its facilities to increase emissions must get a prevention of significant deterioration permit from the state before doing so. The permit requires installation of updated pollution controls known as best available control technology. EPA required 13 states, including Texas and Wyoming, to revise their implementation plans to address greenhouse gases.

— *by Andrew Skroback in Washington*

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