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Storm Clouds In The Middle East

by Richard Keenan, in Dubai

Political unrest has turned what looked like a promising year for project finance in the Middle East into another year of uncertainty, at least in the short term.

Some government tenders for projects may be delayed. However, other projects are moving forward with financing. The ultimate test in the next few months may be the financing for the Muharraq wastewater treatment plant in Bahrain.

The projects sector in the Middle East had looked certain to be on the rebound this year. Escalating oil prices have helped the region recover from the credit crisis of 2008. A handful of projects were successfully financed in 2009 and gradually the market began to pick up in 2010.

Late last year, two new independent power projects came to the market, and the release of more projects was expected in the first quarter of this year. Egypt, in particular, was leading the way in terms of diversity of projects in the public-private partnership sector with new tenders for road, hospital, wastewater and power projects expected this year.

Then came the wave of political unrest and upheaval in North Africa that soon spread in more limited form to Yemen, Bahrain, Oman and Iraq.

Panelists at the MEED annual project finance conference in Dubai the first week in March were keen to emphasize the resilient nature of the economies of not just the emirates along the Persian Gulf but also many of the other countries that make up the wider Middle East and North Africa region. The conference is normally */ continued page 2*

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DEVELOPER FEES are becoming more common in renewable energy projects.

Developers are using them to increase the tax basis on which Treasury cash grants are paid under section 1603 of the American Recovery and Reinvestment Tax Act.

In the typical arrangement, the project company that owns the project pays the company that did the actual development work a fee at the end of construction. Fees of 8% to 15% on top of project cost are not unusual. Ellen Neubauer, the cash grant program manager at Treasury, said that the agency focuses more on whether the final basis */ continued page 3*

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held in Bahrain, but had to be moved due to a fear that the unrest in that country might disrupt the conference.

The most immediate economic effect of the recent events has been a significant rise in the price of oil. The price increases follow the same pattern as after other regional conflicts. The price of oil more than doubled immediately after Iraq invaded Kuwait in 1990. The US-led war in Iraq led to another price spike in 2003. Higher oil prices mean more revenue for the oil-producing countries, but create other issues.

Egypt

Egypt has put an impressive pipeline of public-private partnership projects out for tender. The projects at various stages in the tender process include two wastewater treatment plants, the Abu Rawash project and the 6 October plant. It also has tenders outstanding for the Rod El Farag Axis road project, two new university hospitals and the Dairut international power project.

One of the speakers at the MEED conference, Rania Zayed, head of the Public Private Partnership Central Unit in Cairo, said the new interim government is fully behind the continued procurement of these projects, but offered that the timing of bid submissions may be pushed back until after the general elections that are expected in Egypt in September. Ms. Zayed also emphasized that a new public-private partnership law that is key to these projects remains in force.

On the assumption that there is a relatively smooth transition from the current interim government to a stable longer-term government after the elections, what is the prognosis for Egypt's project finance market?

It is impossible to predict. Before the political crisis, there was a significant pool of local bank liquidity, and it was anticipated that many of the smaller-scale PPPs in Egypt would be wholly financed by Egyptian banks. The US$110 million debt facility for the New Cairo wastewater project, which is the PPP Central Unit's pilot project, was provided by a consortium of local banks.

The new projects being tendered are on a much larger scale and will require participation by the international lending community to be financed. For example, the Dairut independent power project is 1,500 megawatts. The release of the Dairut IPP tender was keenly anticipated by international developers and lenders before the government collapsed. Ten individual companies or consortia qualified to bid. Each of the bidders was expected to be supported by a consortium of international commercial banks and export credit agencies. The role of export credit agencies and multilateral lending agencies like the International Finance Corporation will now be more important than ever to bridge any gap if the potentially more skittish private sector lenders wait to take the measure of the new government that emerges after the elections.

Another challenge that Egypt will face with development of large infrastructure projects will be from projects elsewhere in the region competing for funding that may be somewhat scarcer in the short term until the political situation settles.

Egypt's credit ratings have been downgraded by each of the international credit rating agencies in the wake of the recent events. Standard & Poor's cut the long-term foreign currency debt rating on Egypt to BB, two levels below investment grade.

The country has had a somewhat mixed track record when it comes to implementation of projects through public-private partnerships. Three independent power projects were successfully financed in Egypt in the last decade: Sidi Krir, Port Said and Suez. The electricity tariffs for each of the projects were US dollar denominated. The Egyptian government floated the Egyptian pound in January 2003, sending shock waves through the entire Egyptian economy. The Egyptian pound underwent a major

Some government tenders for infrastructure projects in the Middle East have had to be delayed, but other financings are moving forward.

devaluation, and the Egyptian Electricity Authority's tariff payments (in terms of the Egyptian pound equivalent) doubled in two years. The experience contributed to some skepticism within the Egyptian government as to the merits of private sector involvement in infrastructure projects.

However, the implementation of a new PPP law and framework over the last few years promised a new era in private participation in Egyptian infrastructure projects.

Other Countries

The country in the Persian Gulf most affected by the wave of unrest is Bahrain. Standard & Poor's lowered Bahrain's long- and short-term sovereign rating from A- to A-2. Moody's downgraded the sovereign rating from A2 to A3. The Formula One World Championship that was scheduled to commence in Bahrain on March 13 has been cancelled. The country's tourism and hospitality sectors are reported to be significantly affected by a dramatic reduction in the number of foreign visitors the country would typically receive at this time of year.

There has been much speculation during the last few weeks that the contagion of the political unrest in North Africa would also spread to Jordan. So far, apart from some relatively minor and peaceful protests in Amman, this has not happened. On February 5, a gas pipeline that delivers natural gas to Jordan was seriously damaged by an explosion in the Egyptian Sinai town of Al Arish. It has been widely reported that Egyptian officials believe the explosion was caused by an act of sabotage. Jordan relies heavily on Egypt for the natural gas to fire its gas-fired power plants.

Two independent power projects have either been developed or are under development in Jordan. The Amman East project, developed by a consortium of AES and Mitsui, has been operating since July 2008. The Al Qatrana project is currently under construction by a consortium of the Korea Electric Power Company in partnership with the Saudi power company Xenel. The Amman East project operates on gas supplied via the Jordanian gas transmission pipeline that connects with the Egyptian pipeline damaged in the February 5 explosion. The Al Qatrana project will as well once it starts operating.

Repair of the damaged gas pipeline is reportedly going well, and gas supply from Egypt could resume soon, according to local press reports.

However, the longer-term impact of this disruption in gas supply on the Jordanian IPP market remains to be seen.

The Jordanian government has released / continued page 4

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claimed is reasonable than on the amount of any developer fee.

Tax counsel are using the following rules of thumb for when to allow a developer fee in basis.

The amount must be reasonable.

The sum of the developer fee and the project cost should not exceed the fair market value of the project.

The fee should not be paid out of circled cash. An example of circled cash is where the developer injects cash into the project company that is then paid back to the developer as a fee. Developer fees are common in many real estate projects, and they were common during the 1980's and 1990's in the independent power industry where a project company would pay the developer a fee that was often leftover construction loan proceeds or additional borrowing from a term lender as a reward for bringing the project across the finish line.

A development services agreement should be put in place as early as possible in the development process between the project company that will own the project and the development company describing the development work to be done in exchange for the fee, the fee amount and how and when it will be paid. If the development process is already far along before such an agreement is drafted, then the agreement should memorialize the understanding that the parties have had all along about a fee.

The fee should be paid to a real development company with the employees who did the work. It is best if the development company is not also a partner in any partnership that owns the project. The fee should not be paid to all the owners of the project in the same ratio as their ownership percentages or it may be viewed simply as a cash distribution that does not add to basis in the project.

Some developers have proposed having project companies pay a developer fee over time to the extent there is operating cash flow to cover it. Deferred fees with payments delayed up to 15 years are being proposed in / continued page 5

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tenders for two new independent power projects, known as IPP 3 and IPP 4. The Jordanian tendering authority, NEPCO, asked in a request for proposals in February for "base" bids for a 300 megawatt power plant to run on diesel fuel—this is IPP 3—together with an option for a 200 to 250 megawatt peaker plant using either diesel engine technology or combustion turbines operating in simple cycle, as IPP 4. Bids for both projects are due on March 24.

The level of interest shown by the shortlisted bidders in these projects will be a barometer of the current health of the project finance market in Jordan.

Bellwether Financings and Bids

Bankers speaking on panels at the MEED conference in Dubai all said that the successful financing of some of the projects scheduled to reach financial close in the next several months will be crucial in helping to restore confidence in the project finance sector in the region. These projects include the 1,600 megawatt Shuweihat 3 independent power project and the Shams 1 solar power project in Abu Dhabi and the Muharraq wastewater project in Bahrain.

Financing of the Shuweihat 3 project should not, despite recent events, pose too much of a challenge. The Abu Dhabi IPP model is probably the most bankable in the Middle East. A consortium of Sumitomo and the Korea Electric Power Company was appointed as preferred bidder for the project last year. Shuweihat 3 is the Abu Dhabi Water and Electricity Authority's first power-only independent power project. All other power projects procured under the Abu Dhabi project finance program have been combined with water desalination plants. The Abu Dhabi Water and Electric Authority has committed under the power contract for the project to purchase all of the output for 25 years. Of the total US$1.5 billion project cost, US$1.2 billion is to be financed by commercial banks and export credit agencies.

The United Arab Emirates have not experienced any demonstrations over the last few weeks and are unlikely to do so. The rulers of the Emirates enjoy high level of support among the local Emirati populations. Per capita incomes are high, even by the standards in Middle Eastern oil countries. Dubai has transformed itself into a hub for international air travel and has become an important international financial center. The public services and infrastructure in the Emirates, particularly in Dubai and Abu Dhabi, are the envy of the Middle East.

The financing of the Shams 1 project may present more of a challenge, but not due to the recent political instability as much as that it will be the first large-scale solar project to be financed on a project finance basis in the region. Shams 1 is a 100 megawatt concentrated solar project using parabolic trough technology spread over a site area of 2.5 square kilometers. The Abu Dhabi Water and Electricity Company will purchase output under a power purchase agreement with a term of 25 years. The debt facility is expected to be around US$600 million to be provided by a consortium of commercial banks. The preferred bidder is a joint venture of Abengoa Solar and Total.

The ultimate test of the market in the next few months may be the financing for the Muharraq wastewater treatment plant in Bahrain.

Perhaps the real test of the confidence of the international banking sector in the region will be the financing of the Muharraq wastewater treatment plant project in Bahrain. This project will be the first wastewater treatment plant done through a public-private partnership . Bahrain asked for proposals in June 2009. A consortium of Samsung, United Utilities and Invest AD was chosen as preferred bidder in July 2010. The 27-year concession agreement involves the construction of a 100,000 cubic metre per day wastewater treatment plant on a build, own and operate basis together with a deep gravity sewer network on a build, own, operate and transfer basis. The project debt is expected to fund at around US$300 million and to be provided by three commercial banks—Credit

Agricole, Sumitomo and Natixis—together with the Export-Import Bank of Korea.

Given the recent events in Bahrain, if the sponsors are able successfully to finance the Muharraq project in the next few months, the financing may prove to be the real litmus test for the project finance market not just in Bahrain, but also for the entire region. A number of other power projects in the region are currently in the bidding stage. Bidders have lined up for the Sur IPP project in Oman and the Quarayyah IPP project in Saudi Arabia. The Qurayyah project is expected to be 1,800 to 2,100 megawatts and has attracted significant interest among local, regional and international power developers. Bids for the Quarayyah project are due by March 19. Bids were due for the Sur project in Oman on March 7.

Liquidity

The extent to which the recent events in the Middle East have affected bank margins, the tenor of loans and other financing terms for these bids remains to be seen. The support of export credit agencies is likely to be more important than ever in the wake of Middle East tensions. The project finance market in the Middle East has been in recovery mode since the credit crisis of 2008. Liquidity for projects has been affected by the contagion of the European sovereign debt problems and the forthcoming implementation of Basel III by international banks. The fundamental drivers of growth in the region have not changed. Population growth in many of the Middle East and North African or "MENA" countries remains high, and some countries in the region still lack basic infrastructure. The political unrest has not altered demand. The current political climate may be symptomatic of a dramatic shift in the expectations of much of the population of the Middle East. The demonstrations that toppled governments in countries like Egypt and Tunisia are a cry for better economic services and faster economic growth. Unemployment among young college graduates is at levels that would not be tolerated in the West. A direct consequence of the recent political unrest for foreign sponsors of projects could be a hardening of local employment requirements in project documentation.

Project finance in the Middle East can be split into two groups in terms of countries: the oil- and gas-rich countries and Emirates such as Abu Dhabi, Qatar and the Saudi Arabia and other countries that have successfully implemented project finance initiatives but do not share the same depth of resources as their oil- and gas-rich neighbours. / continued page 6

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some deals. A deferred fee does not go into basis for the Treasury cash grant unless it is a real debt of the project company that is fixed in amount . It should not be subordinated to cash distributions to tax equity investors. It should be paid with interest. The deferral period should not be longer than a few years. It should be clear from the base case model for the project that the project will have the cash to pay the fee on schedule.

Fees paid between companies that join in filing a consolidated federal income tax return or to related parties in foreign countries raise special issues.

The developer must report the fee as ordinary income. Any fee that the parties intend to put into basis in the project should accrue in full at the end of construction. Payment should not be contingent on additional work or other events after construction.

What the parties in a transaction are calling a developer fee may not be one in fact. The term is used loosely in the market to refer to one of three things. One is a true developer fee. Another is a preferred cash distribution by a partnership to a partner that does not ordinarily have to be reported as income by the partner and does not get put into the basis the project company has in the project. Many developers also talk about receiving a developer fee when what they are really receiving is gain on the sale of part of the project to an investor.

The project company must allocate any fee it adds to basis among the various services the development company performed. Thus, for example, if part of the developer fee was for helping to arrange a tax equity transaction or permanent debt, then that part would not go into basis for the Treasury cash grant. Cash grants are paid only on basis in equipment—not in contracts, long-term loans or other intangible assets. However, a fee paid for arranging construction debt goes into basis in the equipment, since it is a cost of construction.

A fee may do nothing at the end of the day to increase the basis in a / continued page 7

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Countries that fall into this latter category are Bahrain, Jordan and Oman, although Oman as a significant exporter of oil sits somewhere in the middle of these two groups.

Countries in the second group in particular rely heavily on a reputation for stability to attract foreign capital. The ruling families and the governments of Bahrain, Oman and Jordan have enjoyed 20 to 30 years of relative peace and prosperity. The governments of these countries have implemented some very impressive public-private partnership programs, launched by the successful project financing of the first IPP in the Persian Gulf in the mid 1990s, the Al Manah IPP project in Oman and then followed by a series of other water and power projects. Even though their governments are not facing serious unrest at home, the broader regional instability has the potential to affect the economic prospects of these countries more than their oil-rich neighbors.

The oil-rich countries of the Gulf have the means of developing infrastructure with or without private investment. Their preference is clearly to involve the private sector to free up cash for other uses, but they can pay for it themselves if necessary.

Another factor in the project finance equation is the limits on the amount of exposure international banks and export credit agencies are prepared to take at any given time in the Middle East. These sources of funds are now in demand more than ever. The oil-rich countries have sometimes proven better at competing for scarce capacity. Mega projects in the oil and gas, petrochemical and refining sectors, like the Emirates aluminium smelter project and the US$14 billion Jubail refinery project in Saudi Arabia that closed on its financing late last year, have been able to attract very large commitments from the international banks and export credit agencies. Saudi Aramco is expected to launch the US$10 billion Yanbu refinery project within the next 18 months on the back of the successful financing of the Jubail refinery project. Plans are also underway for the expansion of the Emirates aluminium smelter project, which is expected to feature a large component of export credit agency funding.

Another possible source of competition for scarce funds is the nuclear energy program in the United Arab Emirates, which is now well advanced. A Korean consortium led by KEPCO was awarded a US$20 billion contract to design, build and operate four 1,400 megawatt nuclear power plants in Abu Dhabi in December 2009. The government-run Emirates Nuclear Energy Corporation is expected to establish a joint venture company with the KEPCO consortium using a structure similar to that used by Abu Dhabi Electricity and Water Authority for the Shuweihat 3 project. The Export-Import Bank of Korea is expected to lend around US$10 billion to the KEPCO consortium for development of this project.

Saudi Arabia has also recently announced ambitious nuclear energy plans and, last month, Saudi Arabia and France signed a bilateral cooperation agreement on developing nuclear energy for peaceful purposes.

Project Sales: Market Update

The following is an edited transcript from a roundtable discussion in late January at the Infocast Projects & Money conference in New Orleans about what to expect in 2011 in M&A transactions in the US power sector, particularly renewable energy. The panelists are Ted Brandt, CEO of Marathon Capital in Chicago, Charles Costenbader, an associate director with Macquarie Energy in Houston, and Daniel East, a vice president of The Carylyle Group in New York. The moderator is Keith Martin with Chadbourne in Washington.

MR. MARTIN: Ted Brandt, many people are expecting 2011 to be a big year for M&A transactions. Will it be and, if so, why?

MR. BRANDT: I think it will be a good year. The main drivers in both wind and solar really revolve around capital costs. While it is difficult for renewable energy developers to persuade utilities to enter into new long-term power purchase agreements, there are a number of PPAs that were priced in late 2009 and early 2010. Capital costs have dropped dramatically since then. For example, in wind, a lot of projects were priced at $2.2 or $2.3 million an installed megawatt and they are being built at $1.8 million and $1.9 million. That obviously translates into lots of net present value. We are seeing developers of very late-stage contracted solar and wind projects who can make $400,000 a megawatt by selling, and they would just rather have the cash and then build more.

MR. MARTIN: Any other views on whether 2011 will be a good year for sales of projects or companies?

MR. EAST: In 2008 and 2009, M&A felt like an academic exercise. You had had a dramatic drop in demand for power, and the capital markets were essentially in distress if not closed. The market recovered in 2010 in terms of volume of transactions, and the trend has continued into early 2011.

MR. COSTENBADER: A lot of capital has been on the sidelines for the last year or two, and fund managers will either have to put it to work in 2011 or give it back to their investors.

MR. MARTIN: The big news in the last week was the proposed merger between Duke and Progress Energy. Many people thought the 2005 energy bill would trigger a wave of utility consolidation. Does anyone on the panel think that the Duke-Progress merger is the start, and we will now see more rapid consolidation of utilities?

MR. BRANDT: Marathon is more focused on the independent power market, but our friends who focus on regulated utilities suggest waiting to see how the regulators react to the proposed merger before labeling it the start of a major trend.

MR. MARTIN: Ted Brandt, you think 2011 will be a good year for the M&A market in terms of transaction volume. You and I had the same discussion around this time in 2009. That year proved not so good because bid-ask spreads remained wide. What makes you think that sellers will be more realistic about what their projects are worth this year than they were in 2009?

MR. BRANDT: In 2006 and 2007, my phone would ring and it was "Ted, how do I get into the wind business?" In 2008, it was "Ted, how the heck do I get out?" [Laughter]

MR. MARTIN: What are they asking you in 2011?

MR. BRANDT: A lot has changed. The terms on offer in the debt market have probably never been better. You also have this drop in capital costs that can't be underestimated because it really fattens up the value that is embedded in contracted solar and wind projects, even for projects that have not been built yet. There is a lot of embedded value. Sellers are trying to figure out how to realize it. I expect a number of sales of holding companies that own multiple projects as well as sales of individual projects. I also agree with Charlie Costenbader. Put together the fact that there is an awful lot of money trying to find a home, the low cost of money in the debt market and this embedded value, and I think you have a perfect storm.

MR. MARTIN: Charlie Costenbader, you are a buyer. Are you finding more opportunities to close deals this year?

MR. COSTENBADER: Yes. I expect the deal velocity to pick up. I think what held it down for the last two years was low natural gas prices. They do not help renewable energy or the spark spreads on merchant plants. There was also / continued page 8

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project, depending on how the project is financed. It is irrelevant to the basis calculation in projects that are financed through sale-leasebacks or inverted leases.

Few developers can use the tax depreciation on their projects. The depreciation can be worth as much as 26¢ to 31¢ per dollar of capital cost in terms of tax savings. Many enter into tax equity transactions in which they effectively barter the depreciation for capital to cover part of the project cost.

In a sale-leaseback transaction, the developer sells the project within three months after completion to a bank leasing company or other tax equity investor and leases it back. The depreciation and Treasury cash grant are claimed by the lessor on the fair market value purchase price the lessor pays for the project. The fact that the lessee paid a developer fee to a development company is irrelevant.

Cash grants are also calculated on the fair market value of the project—rather than its cost—in inverted lease transactions. Such leases are common in the solar market.

The basis for calculating the grant in partnership flip transactions depends on how the transaction is implemented. There are two different forms of flip transactions—a "purchase model" where the tax equity investor pays the developer for an interest in the project and a "contribution model," where the tax equity investor makes a capital contribution to the project company or partnership for an interest in the project, and the capital contribution is usually used to repay construction debt.

Cash grants are calculated on the project cost in partnership flip transactions that use the contribution model. They are calculated partly on the fair market value and partly on cost in flip transactions that use the purchase model. The partnership takes a fair market value basis in the share of the project sold to the tax equity investor and a cost basis in the share retained by the developer. Thus, only a fraction of the developer fee adds to basis / continued page 9

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the general recession. I see both things improving.

One of the dynamics I have noticed is that people are starting to believe assets have value beyond a simple discounting of projected cash flows. They are assigning value to the location. There may be value to having existing infrastructure. They are expecting the economy to recover. More buyers are willing to stretch on valuation. They are looking at embedded options in the plants such as the potential to expand or to repower an asset into a lower heat rate.

MR. EAST: Other things that are contributing to a more buoyant outlook among buyers is an expectation that both the economy and electricity demand are on the upswing and, among some buyers, a belief, or perhaps a bet, that natural gas prices will increase.

MR. MARTIN: Do you see more demand for particular types of projects—wind versus solar versus geothermal versus gas-fired power plants? Projects already in operation versus those that are merely still under development? Where do you think most of the action will be?

MR. BRANDT: I think solar, particularly ground mounted PV solar, will continue to be busy.

There are a lot of solar PPAs. We have been involved in Ontario where there are supposed to be a thousand megawatts of contracts on ground-mounted projects, which will lead to a lot of action. The bigger and better wind companies are still getting PPAs. Wind will remain the largest dollar segment.

MR. EAST: In terms of sheer volume, contracted solar and wind projects will carry the day. However, there are a number of buyers who are gearing up to look at assets that are a little bit higher on the risk spectrum like merchant power plants.

MR. COSTENBADER: Many solar firms will start to pick up speed, and some of them will make it and some of them might not, but we see solar as definitely a big area. We are also keen to do biomass projects, but unpredictability of the fuel supply remains an issue.

MR. MARTIN: Let me play devil's advocate for a moment on solar. I moderated a panel discussion at the Solar Power International convention three months ago in San Diego. One of the panelists, a leading tax equity investor, said that financiers cannot figure out how anyone is making money on solar. The numbers don't add up. Reaction?

MR. COSTENBADER: I think solar compares favorably with biomass projects. It is hard to build a new biomass project costing $4,000 an installed kilowatt with a PPA for 10¢ a kilowatt hour, but solar can work at that price as long as you keep the costs to less than $4,500 a kilowatt with the section 1603 cash grant and SREC-type incentives.

> The falling cost of capital compared to what developers assumed when signing power contracts will spur some project sales as developers try to cash in on value to fund other projects.

MR. BRANDT: We are seeing construction costs come in on solar below $4 an installed megawatt all-in and fully loaded. What that effectively does in Ontario, for example, where they have a feed-in tariff of $440 a megawatt hour is that even if you can generate electricity only about 1,100 hours a year up in sunny Canada, there is something like $5 million of net present value for every 10 megawatts of capacity.

Lessons from 2010

MR. MARTIN: So a lot of action in solar. How would you characterize the M&A market last year? What lessons did you learn from watching the market last year?

MR. EAST: A number of large strategic investors were buyers last year and picked up projects opportunistically. There were few large auctions. Most deals were negotiated privately. It will be interesting to see whether we move back to auctions in 2011. That is generally what happens in a market when the number of potential buyers increases.

MR. MARTIN: Were there any other lessons from 2010?

MR. COSTENBADER: A lot of what happened in 2010 can be traced to $4 gas. Low natural gas prices changed the dynamics of the market. It hurt renewables and peaking plants.

Another dynamic in 2010 was the way Congress waited until the last two weeks of the year to announce that renewable energy developers would have more time to start construction of new projects to qualify for Treasury cash grants. That created uncertainty and led to a rush to start construction. A lot of developers were probably pretty concerned around December 12 about whether the deadline would be extended.

MR. BRANDT: We were involved with several auctions that ultimately resulted in final bids that were disappointing to sellers and the deals were cancelled. One lesson from 2010 is always put in some kind of an arrangement so that the bankers don't work completely for free.

MR. MARTIN: An important personal lesson.

Current Buyers

MR. MARTIN: Who are the current buyers? Chinese? Spanish? German? US private equity funds?

MR. BRANDT: We divide up the world between strategics, who tend to be either utilities or large independent power companies, and segment specialists—a company might only be interested in solar, only in wind—on the one side and then we also market to virtually all the financial players.

The big development in terms of new entrants is pension fund money. The pension funds have set up direct investment arms that now view contracted power projects as an acceptable form of long-term infrastructure investment, and we are seeing lots of that money coming in directly.

MR. MARTIN: Can pension funds really play in a renewable energy market that is so heavily tax driven? They have no tax base against which to use the large government incentives for these projects.

MR. BRANDT: We are working on a structure with a major utility that will provide tax equity alongside the pension funds, and we think the answer is yes, but it is not an easy thing unless you bring your own tax equity.

MR. MARTIN: Let's drill down further into particular market segments. Who are the major potential buyers or equity investors in the wind sector?

MR. BRANDT: I don't know is who is really psyched about holdco equity in wind these days. There are some people, who happen to be based in Juno Beach, who would love to consolidate the business if they can buy everything / continued page 10

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in transactions using the purchase model. The fraction is the share of the project sold to the tax equity investor.

THE 100% DEPRECIATION BONUS may prove illusory for many renewable energy projects.

The Internal Revenue Service is working on guidance that it hopes to issue in March.

A number of issues are in play that, depending on how they are decided, could make it hard for renewable energy developers to get much value from the bonus or even to claim it at all.

Congress voted as part of a bill extending Bush-era tax cuts in December to allow companies to deduct the full tax basis of new equipment placed in service after September 8, 2010 through 2011 or 2012, depending on the equipment.

Equipment that would be depreciated otherwise over five or seven years must be in service by December 2011 to qualify for a 100% bonus. It qualifies for a 50% bonus if placed in service in 2012. Examples are wind turbines and solar modules. A 50% bonus means that half the tax basis can deducted immediately and the other half is depreciated normally.

Equipment that would be depreciated over 15 to 20 years qualifies for a 100% bonus if completed by December 2012 and a 50% bonus if completed by December 2013. Examples are gas- or coal-fired power plants and some interties at wind and solar facilities.

A 100% bonus is worth 4.45¢ per dollar of capital cost at a wind farm or solar project. It is worth as much as 18¢ per dollar of capital cost at a combined-cycle gas or coal-fired power plant.

Four key issues are in play.

One is whether a project qualifies for the 100% bonus if a binding contract was signed with a turbine or module manufacturer or balance-of-plant construction contractor on or before September 8, 2010.

The depreciation bonus has been in the US tax code off and on since shortly after September 11, 2001. It was originally 30% and then was increased to 50% before the / continued page 11

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at a discount, but the Europeans with satchels of money who were coming over in 2006 and 2007 have not been as interested more recently in buying portfolios of undeveloped projects.

MR. MARTIN: It seems like the Spanish, Portuguese and Italians are having to conserve cash.

MR. BRANDT: We see the same thing. When we see some of the banks from those countries fund deals out of their South American branches, it is a sure sign that the environment has changed. You mentioned the Chinese. We continue to see the Chinese as players, although they have not closed much and our experience has been that they are still more in a looking mode. The single biggest buyers currently continue to be the private equity funds.

MR. MARTIN: Two of you said you expect the solar market to be hot. Who will be the buyers in that market?

MR. BRANDT: Some manufacturers are buying unbuilt solar projects as a strategy of vertical integration and as a way of deploying product. Otherwise, you have a rational market that is trying to buy to a return and trying to build scale into these businesses. You have some people, like AES Solar and some very well-capitalized companies, that have done it over in Europe and are now trying very hard to diversify in the United States.

MR. MARTIN: Dan East, you are with a private equity fund, and Charlie Costenbader, you are backed by private equity money in a sense. How do private equity funds play in a sector when the yields for developers seem to be in the high single digits?

MR. EAST: We are focused on putting our capital to work in the development stage where there is a higher return commensurate with the higher risk, but then using our experience and skills to manage the risk.

MR. COSTENBADER: We are also focused on projects that have a little bit more risk or merchant exposure, but then we work on the funding and hedging options to limit the amount of equity that is needed.

MR. MARTIN: Dan East, is the Carlyle Group putting equity or mezzanine debt into the projects you described?

MR. EAST: Our group is a mezzanine opportunities fund. We have a pretty wide mandate focused primarily on the US and Canada, but within that geographic footprint, we can do anything from upstream oil and gas down through power and renewables. There are no carve outs. There are some areas in which we will be more active than others.

MR. MARTIN: Ted Brandt, you mentioned the Chinese as potential buyers. There have been rumors in the market that the Chinese bring exceptionally favorable financing with them. Have you seen any evidence of such financing?

MR. BRANDT: I have seen no evidence. I have heard the same rumors now for about three years, and we keep hearing that such financing is on offer but have not yet seen it.

MR. MARTIN: Has anyone seen any such financing?

MR. COSTENBADER: I agree with Ted on the micro level. However at the macro level, if one believes the media reports, it appears the Chinese keep their currency exchange rate at a lower level than market, which makes their exports cheaper and ultimately gives their equipment manufacturers a pricing edge, at least with the equipment and solar panels that they are exporting to the United States.

Valuing Projects

MR. MARTIN: I used to keep on my computer screen a curve that showed how value builds in an average wind farm. A project is worth $X a megawatt when a PPA is signed. It is worth $Y a megawatt when all the permits have been obtained and the project is ready to start construction. Ted Brandt, any sense where average project values are? You have been running auctions.

MR. BRANDT: The auctions have usually been of operating projects, so let me start with them. The first thing you have to do is figure out how old the project is. In 2000, Garrad Hassan changed its methodology for measuring wind. A P50 forecast that was done before 2007 is almost certainly wrong. There was a systematic bias that was something like 10% too optimistic. To get to a value, you also have to look at whether the project is benefiting from investment credits, Treasury cash grants or production tax credits. If it is production tax credits, how much of the subsidy is left? Have the remaining tax benefits already been transferred to a tax equity investor?

Turning to a new project, what we are seeing is that at the time of full permitting, transmission connection and a PPA, the typical such project sold at auction is getting around $100,000 a megawatt. That is before anything is constructed and when all the construction and equipment costs remain to be paid. Projects with power contracts that were signed in late 2009 or have seen the projected capital cost drop compared to what was assumed in the power contract might have a net present value approaching $300,000 or higher per megawatt.

MR. MARTIN: Turning to utility-scale solar, what are such projects worth today? How much do you have to pay to purchase a contracted project that is still under development?

MR. BRANDT: A US project would sell to about an 8% yield in today's market. In Canada, what they typically do is ignore depreciation and carry it forward, and unless you've figured it out, Keith, there is no tax equity market up there. The discount rate for the calculation tends to be the same as in the US. That is an unleveraged after-tax yield.

MR. MARTIN: That is for solar utility-scale PV. Would a buyer in the current market use the same rate for wind?

MR. BRANDT: Wind is a bit higher.

MR. MARTIN: Why?

MR. BRANDT: The cash flow is more variable. The debt tends to carry a little higher premium in wind than in solar. A buyer would price to an 8.5% or 9% yield.

MR. MARTIN: Where were those rates last year?

MR. BRANDT: I can tell you from running a bunch of auctions that the differences between buyers and sellers almost always come down to different views of the wind forecasts or operating costs. The seller insists that the project will operate at a 35% capacity factor while the buyer is only willing to assume 31%. Rates of return have been pretty constant since the 2008 meltdown, although they have edged up somewhat during the liquidity crunch in early 2009.

MR. MARTIN: Charlie Costenbader, you have spent a lot of time looking at biomass projects. What do you think a developer can get for selling a biomass project that is still in the development stage?

MR. COSTENBADER: It depends on a number of things. The fuel story is always key. There are few tipping fees or tolling agreements in this market. The return requirements are higher than 8% because of the fuel risk. The return a buyer will want also depends on the technology. Circulating fluidized bed is usually preferred. The next three items on the diligence checklist are the projected operating costs, the risks of an outage, and the management team.

MR. BRANDT: For an existing biomass facility, it is fuel first and operational track record probably second.

MR. MARTIN: What discount rate would the typical buyer use to value a biomass project?

MR. COSTENBADER: It depends on where you are in the asset life cycle: development versus construction versus operations. Development is generally north of 25% as an overall return for a developer, possibly even higher. / continued page 12

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latest round when it went up to 100% as an additional economic stimulus measure urged on Congress by the Obama administration. The IRS has always divided projects into two categories: those that are "self constructed" and those that are "acquired." Almost all power projects are considered self constructed. The bonus is supposed to be a carrot to induce companies to make new investments. There is no need to give the carrot to a project to which the developer was already committed before the bonus was available. For a self-constructed project, the IRS has always been considered the project too far along if the developer "incurred" more than 10% of the total project cost before the date the carrot became available.

The second issue is the key date to use for the 100% bonus. The IRS is unsure whether it is September 8, 2010, when President Obama first proposed the 100% bonus in a campaign speech, or January 1, 2008, when the 50% bonus was restored to the US tax code to stimulate the faltering economy as it was headed into the most recent recession. What Congress did in December was to increase the size of a carrot that was already on offer as of January 1, 2008.

The third issue is, assuming a project qualifies for a bonus, should it only get the 100% bonus on costs "incurred" after September 8, 2010 and a 50% bonus on costs incurred between January 1, 2008 and September 8, 2010?

The last issue is whether companies that qualify for a 100% bonus should be given the option to take a 50% bonus instead.

The analysis for the 50% bonus is different than for the 100% bonus, so a project that the IRS decides does not qualify for a 100% bonus because the developer was committed too early to the project may still qualify for a 50% bonus.

A SOLAR DEVELOPER won an initial round in court against the US Treasury in January, but it has farther to go. / continued page 13

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Construction is between 15% and 25%, depending on whether you have an EPC wrap and good permit plan.

MR. BRANDT: Those are leveraged returns?

MR. COSTENBADER: Unleveraged.

MR. COSTENBADER: Once the plant is operating and has a PPA, the rate is down around 7% to maybe 12%.

Development Pipelines

MR. MARTIN: In the past, panelists on this type of panel have said that the market doesn't really assign any value to large pipelines of projects that are under development, but that are not expected to be completed in the next year or two.

MR. BRANDT: Unfortunately, I think that is still true. The tangible assets, which would include signed PPAs, tend to be valued. Buyers typically reimburse the developer for hard expenses and then it is an earnout above that. That is pretty much the formula for how development pipelines tend to sell. That being said, there are still a few exceptions—for example, if you have a fully permitted project in New York, a good area of Pennsylvania, New England or California, even without a PPA but with a position in the transmission queue—the project would sell for more than just reimbursement of costs.

MR. MARTIN: So in states where it is hard to connect to the grid or to get permits to build, passing those milestones builds value, even if the project is not ready to start construction.

MR. BRANDT: That's right. I don't know that it is tied to time as you are suggesting in your question. As the developer checks various boxes—site lease, permits, PPA, queue position, network upgrade studies—value builds.

MR. EAST: Deal pipelines are nice, but they can also be a distraction. We want the developer to get the project that is farthest along or in the best position to execute across the finish line. His ability to do that may be diminished if he is chasing all these other projects at the same time.

MR. MARTIN: It is not a selling point for a developer to say the company has 40 projects in the works, especially if the company has only a handful of employees. You want the company to have a laser-like focus to get the first project done.

Ted Brandt, you mentioned the typical structure is some money down to reimburse costs and then nothing else is paid until the project is completed. The balance is in the form of an earnout. Nothing further is paid until completion?

MR. BRANDT: Not everything is done that way. Some additional money might be paid when a PPA and interconnection agreement are signed. There might be other milestones. The payments might serve as incentives to keep the developer focused. If the buyer plans to keep the management team in place as well as acquire a development portfolio, then the deal is more likely to be structured with a series of incentive payments. There are other deals where a big company basically says, "Look, you're nice guys but thanks for getting the PPA signed. We'll take it from here."

Wind projects that are ready to start construction sell for $100,000 to $300,000 a megawatt.

MR. EAST: Even in the former case, the development fee premium usually isn't paid until after the facility is up and operating.

MR. MARTIN: Is it possible to give a rule of thumb about how large that premium is or does it depend on the particular transaction?

MR. BRANDT: It depends. If the project is finished and ready for prime time, it will be worth more. On the other hand, it may be like the guy that says he caught a bear as he is running through the camp with a bear chasing him. "I've got a PPA, but I need $20 million." That's a different valuation discussion. [Laughter]

MR. MARTIN: Is it typical for a developer to keep a carried interest and, if so, how much?

MR. COSTENBADER: We have a project now that we are trying to sell. We have an interested buyer, and we have decided that we would like to have a carried interest in the project. There is a bit of a valuation gap, so a carried interest is one way to bridge it. Sometimes the carried interest works. It requires a lot of brain damage keeping track of it going forward. Sometimes people like to cash out and be done with it. I haven't seen any particular pattern.

MR. EAST: It is a tool in the toolbox to bridge valuation differences.

MR. MARTIN: Does the carried interest start at X% at completion and then ramp up as progressively higher returns are reached by the buyer?

MR. EAST: It could take a number of forms. There is no one approach to such interests in the market.

MR. COSTENBADER: If you're negotiating 1%, it is not worth the legal costs. Five or 10% would be more typical.

MR. BRANDT: It really depends on the circumstances. Most big companies hate the notion of having partners, and so the big buyers will typically resist carried interests. They want to pay the money, get on to the next thing and run the project as part of their fleet. A carried interest is more common in deals where the buyer is a private equity fund. Even in those deals, we often hear from a developer, "If I'm getting $11 million from this deal, I'd like to put $2 million back in and be a partner," but almost always when we check again at the end of the process, the developer says, "Nah, I'd rather have the cash."

Where to Probe

MR. MARTIN: I'm down to my last question. If you are a buyer, where are you most likely to find a problem with a project that says you are wasting your time? What one thing is it best to probe first?

MR. EAST: We tend to drill down initially on the technical aspects and, by that I mean, whether the developer has a good permit plan and a good engineering plan. If the developer has not engaged a third party permitting consultant and has not engaged a Black & Veatch or similar company to do an engineering review, then that is a double red flag for us. It says the company has not spent the earnest money required to prove the project. The developer hasn't done his basic homework.

MR. COSTENBADER: On biomass, it is fuels first and operational track record to the extent that the facility is up and operational. On wind, it is studying the wind data and any complexities in the PPA.

MR. BRANDT: When we screen projects, / continued page 14

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The developer, Pure Power Development, sued the Treasury in the US Court of Federal Claims charging that it was refused Treasury cash grants on 25 mobile off-grid solar photovoltaic systems mounted on flat-bed trucks. Neither the complaint filed by the company nor the reply brief filed by government explains why the company was refused.

The government moved to dismiss the case on grounds that the Court of Federal Claims lacks jurisdiction over the case. Among other things, the government argued that section 1603 of the American Recovery and Reinvestment Tax Act, which requires the Treasury to pay owners of new renewable energy projects placed in service during the period 2009 through 2011 30% of the project cost in cash in lieu of tax credits that the owners might otherwise have claimed on the projects, is not a "money-mandating statute." The court disagreed; it said the Treasury is required to pay a grant to anyone who satisfies the eligibility requirements in the statute.

The court ordered the parties to explore a settlement and to report back. Otherwise, the case will be heard on the merits.

The company is seeking a total of $2.33 million in grants on the 25 systems.

Meanwhile, the Solar Energy Industries Association sent the US Treasury secretary a letter in early February complaining that the Treasury is paying many owners of solar equipment smaller grants than they applied for based on average prices for solar equipment rather than the "tax basis" that a company might use were it to claim an investment tax credit. The letter says the practice is "creating significant uncertainty" that is complicating financings for solar projects.

The Treasury is working on a response that is expected in March.

Many developers are using financing structures that allow them to claim grants on the fair market value of their projects rather than the construction cost. The Treasury is taking the position that prices established in such financing transactions / continued page 15

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we look for a lot of things, but the problems are most likely to turn up with permitting and transmission. Lots of potentially great projects, particularly in the upper Midwest, are having trouble with transmission. If the project is in a place like California or in some parts of the northeast, you have a combination of NIMBY and environmental issues, and the difficulty getting the project permitted cannot be underestimated.

MR. EAST: Part of the transmission issue is where the offtaker is taking delivery of the electricity and whether there is congestion in that location that might lead to congestion charges that the project will have to bear or whether the project risks being curtailed because of inadequate capacity on the transmission lines to take the electricity to the grid.

MR. MARTIN: Ted Brandt, coming back to you on transmission, is the problem in the Midwest inability to connect to the grid within a reasonable time? Congestion charges? Curtailment? Which?

MR. BRANDT: It is situation specific and ISO specific. I don't really have one way to talk about it other than to say we look for the developer to take us through the transmission story, and we feel at this point that we have had enough experience to judge whether it is cogent. ◎

USDA Loan Guarantees: A Viable Alternative for Renewable Energy Projects?

by Kenneth Hansen and Charlotte Del Duca, in Washington

As the Department of Energy section 1705 loan guarantee program for renewable energy projects using commercially-proven technologies approaches its legislative sunset on September 30, 2011, developers are looking for alternative means to tap attractive, low-cost debt.

Possible alternatives include the section 1703 loan guarantee program for innovative energy projects run by the Department of Energy and a separate loan guarantee program run by the Rural Utilities Service in the Department of Agriculture.

Neither is a direct substitute for the section 1705 program; however, for the right project, either offers access to attractive borrowing rates through the Federal Financing Bank.

The "DOE Loan Guarantee Update" in the January 2011 *NewsWire* compared the advantages and disadvantages of the section 1703 program in relation to the section 1705 program. This note provides an overview of the legislative authority, program requirements and implementing regulations of the less-familiar RUS program available through the Department of Agriculture.

RUS in the News

The RUS program recently made the renewable energy industry news with the February 9 announcement by the Secretary of Agriculture of a $204 million loan guarantee for the PrairieWinds wind farm, a 151.5 megawatt, $340 million project in central South Dakota. The project, heralded in the February announcement as a "model of public and private investment partnership," is being developed by PrairieWinds SD1, a for-profit subsidiary of Basin Electric Power Cooperative, a consumer-owned, regional cooperative. PrairieWinds has also been tapped to construct, operate and purchase (on behalf of the cooperative) the 10.5 megawatt output of seven additional, adjacent turbines financed through private investments by South Dakota residents.

This was not the cooperative's first successful bid for a loan guarantee. In late 2010, it received two RUS program loan guarantees totaling $153 million for wind projects in North Dakota. Around the same time, the Central Virginia Electric Cooperative was awarded an $84 million loan guarantee to finance its partial ownership of two hydroelectric projects in Kentucky.

RUS Loan Guarantees

The RUS enabling legislation has been around for a while. Title I of the Rural Electrification Act, first enacted in 1936, authorizes the Agriculture Department to make loans for rural electrification and for the purpose of furnishing and improving electric service to persons in rural areas.

In 1973, the statute was amended to reestablish a revolving fund for insured and guaranteed loans; Title XIII of the Federal Credit Reform Act of 1990 superseded the revolving loan fund legislative provision and first established loan guarantee authority. Most recently, Subtitle B of the Food, Conservation, and Energy Act of 2008, (known as the "farm act"), further amended the statute by extending the Agriculture Department's authority to make loans through RUS for electric generation from renewable energy resources, defining "renewable energy source" as "an energy conversion system fueled from a solar, wind, hydropower, biomass, or geothermal source of energy."

In its current form, the Rural Electrification Act authorizes direct lending as well as a loan guarantee program, with the availability of either option subject to appropriations. The guarantee program provides 100% guarantees of loans made by the Federal Financing Bank, an arm of the US Treasury. Since 1990, most RUS appropriations have been directed to the guarantee program.

RUS guaranteed and insured loan programs, including those for renewable energy, were funded at $6.6 billion for fiscal year 2009 and at $7.1 billion for fiscal year 2010. The Obama administration requested $4.1 billion for the current fiscal year 2011 that ends on September 30 and $6.1 billion for 2012. Farm-related programs remain more popular at the moment in Congress than renewable energy. In fiscal year 2010, $313 million was awarded in loans and loan guarantees to renewable energy applicants.

A Program for the Times

The Rural Electrification Act's preference for energy distributors and not-for-profits has, historically, shaped borrowers' perceptions of the RUS program as geared solely to utilities and non-for-profit applicants. This perception is not entirely accurate today.

In 2009, RUS signaled its willingness to consider loans to entities other than utility systems and to include private developer limited liability companies, provided that there is adequate credit assurance such that the associated credit risk is a "constructive system loan" (meaning that the developer has signed a power supply agreement and the offtaker has agreed to provide RUS revenue assurances). Under these conditions, the risk of these LLC transactions is commensurate with the risk level traditionally associated with the RUS guarantee program and related subsidy (risk of loss) rate assigned by the Office of Management and Budget. Of note, the OMB subsidy rate for the RUS program applies to the full loan program level rather than to individual projects, as is the case with the DOE loan guarantee programs. The higher the subsidy rate, */ continued page 16*

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are not arm's length and that it is free to substitute its judgment about the appropriate value based on the large number of solar applications it has received to date.

IRS REGULATIONS will be harder to challenge after a US Supreme Court decision in January.

The Mayo Clinic did not pay Social Security taxes on "stipends" paid to young doctors who work three to five years as residents after graduating from medical school as further training in specialty areas of medical practice. The residents are paid $41,000 to $56,000 a year. They work as much as 80 hours a week, but are also expected to do assigned reading, attend weekly lectures and take written exams.

Social Security taxes do not have to be paid on wages that a school, college or university pays students who work for the school while regularly attending classes. The IRS said in regulations issued in 1951 that the exemption applies only where the student works "as an incident" to attending classes. In 2004, it amended the regulations to clarify that it does not consider the work a student does as merely "incident" to attending classes if the work is the "predominant . . . aspect of the relationship" the student has with the school.

The change had the effect of requiring taxes be paid on the residents' stipends.

The Mayo Clinic and the IRS ended up in court. The clinic argued that the IRS regulations were invalid.

The Supreme Court sided with the IRS. It said Congress did not address the issue unambiguously in the tax code. Congress gave the IRS broad discretion in section 7805 of the US tax code to "prescribe all needful rules and regulations for the enforcement" of the tax laws. The IRS gave notice to the public of its position and allowed a period for comment. The position is not unreasonable.

In the past, courts have distinguished between "legislative" regulations that the IRS issues under a section of the tax */ continued page 17*

USDA Loan Guarantees

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the less the program loan level authorization is for a given dollar of appropriated budget authority.

In addition, the RUS program does not construe the Rural Electrification Act's not-for-profit preference as a prohibition against lending to for-profit entities. If the annual program level is undersubscribed, then the preference is not a problem in any event for for-profit LLC borrowers and, where a for-profit LLC is selling to a not-for-profit utility, the not-for-profit preference has been considered met as a policy matter.

However, time has yet to erode the primary purpose of the RUS program—the provision and improvement of electric service to persons in rural areas—or change its policy against non-recourse financing. While the farm act added a new section 317 to the Rural Electrification Act that authorized loans for the resale of renewable electricity to urban as well as rural residents, that section has not yet received any appropriations. However, for renewable projects that serve rural load, the absence of such appropriations is not an impediment to obtaining RUS financing. As a matter of policy, RUS does not make or guarantee non-recourse loans.

Federal loan guarantees may be available through the US Department of Agriculture for renewable energy projects that serve rural areas.

RUS Program Overview

The general contours and terms of RUS loan guarantees are found in section 306 and surrounding sections of the Rural Electrification Act. *NewsWire* readers familiar with the section 1703 and section 1705 programs will see numerous parallels between the DOE and RUS loan guarantee provisions.

The Rural Electrification Act provides that guarantees may be issued for the full amount (100%) of the loan and that, at the request of the borrower with such a guarantee, FFB shall make the loan at an interest rate not more than that applicable to other similar loans. The borrower has the option to repay the FFB loan at any time, in whole or in part. Make-whole premiums as required by the FFB will be assessed if the loan is repaid earlier than expected.

As the administrator of the loan guarantees, guided by private lender practices, is charged with relieving borrowers whose net worth exceeds 100% of the outstanding principal balance of the guaranteed loan of unnecessary and burdensome requirements. In addition, the RUS may give highest funding priority to designated projects in substantially underserved trust areas (for example, land held in trust by the United States for Native Americans) provided they are financially feasible. Such loans or loan guarantees may bear interest rates as low as 2%.

Program Implementation

Unlike the DOE section 1703 and section 1705 programs, which prompted issuance of a federal regulation tailored, initially, to innovative energy investments, the RUS program continues to operate under its existing regulations found in 7 CFR Part 1710 and 1714. There is an informal guide, available to prospective LLC applicants, that adapts these regulations to LLC developers who meet the constructive loan system requirement described earlier.

Terms of guarantee:

RUS will provide 100% loan guarantees. The guarantees are not to exceed the useful life of the facilities being financed, with a maximum term of 35 years. For generation and transmission power supply borrowers, the loan term is limited by the term of their wholesale power contracts. The interest rate is as agreed to by the borrower and lender, with RUS concurrence. The guarantee applies to the repayment of both principal and interest.

Purpose of financing:

Loans guaranteed by the RUS may be used to finance a range of projects, including energy conservation and efficiency programs and on-grid and off-grid renewable energy systems. Where a utility system is the borrower, construction financing is available from the RUS. For LLC borrowers, RUS provides only term financing upon commencement of commercial operation, and only where the interim construction financing contemplated an RUS takeout. (The Rural Electrification Act has been interpreted not to allow refinancing as a general matter.) Eligible costs include direct costs of procurement and construction and related costs of engineering, architectural, environmental and other studies and of plans needed to support the project, provided the costs are capitalized as part of the cost of the facilities and were included in a RUS-approved plan.

Eligibility requirements:

Both distribution and power supply borrowers are eligible for a section 306 loan guarantee. While preference is given to states, territories, municipalities and cooperative, nonprofit, limited-dividend or mutual associations that provide retail electric service in rural areas or the power supply needs of distribution borrowers, a private developer can qualify for a guarantee if it signs a power supply agreement satisfactory to RUS.

To the greatest extent practical, loan guarantees are limited to projects that provide and improve electric facilities to consumers who are Rural Electrification Act beneficiaries—that is, persons, businesses or other entities located in a rural area with a population of less than 20,000. The guaranteed loan may be used for facilities to serve non-Rural Electrification Act beneficiaries only if that service is necessary and incidental to the primary purpose of meeting rural area needs.

If a project LLC sells to a power purchaser that is an existing RUS borrower, the rural eligibility requirement is considered to be met, even if a portion of the service territory is no longer rural. If the power purchaser is not an RUS borrower, the percentage of the project that can be financed using RUS guaranteed financing may not exceed the proportion of the service territory that is considered rural.

Application:

In contrast to the DOE programs where applications are invited through formal solicitations, the RUS application process is consultative with the program office actively involved in assisting the prospective borrower in preparing the application. Once complete, applications are assigned an "application received date" and considered in order of the assigned date. If there are insufficient program resources to meet demand, the application rolls over to the following fiscal year.

Approval:

Applications for non-utility system borrowers are screened on a preliminary basis at the national level to determine whether the rural eligibility requirement is satisfied, the purchasing utility has provided adequate / *continued page 18*

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code in which Congress specifically asked the agency to fill in details and other regulations. Legislative regulations have been afforded more deference.

The Supreme Court declined to distinguish between the two.

The case is *Mayo Foundation for Medical Education and Research v. United States*. The Supreme Court released its decision on January 11.

The bottom line is that taxpayers will have a hard time challenging IRS positions taken in final regulations in the future. They would do better to argue that Congress was clear about what it intended. Once a court decides that there is room for interpretation, if there are several possible approaches any one of which is reasonable, the IRS gets to choose. It is not clear to what extent the decision applies to other forms of IRS guidance, most of which are issued without first proposing an approach and then letting the public comment.

COMMUNITY WIND PROJECTS have been using interesting financing structures, according to a report in January by the National Renewable Energy Laboratory.

The Fox Islands project, a 4.5-megawatt wind farm on Vinalhaven Island 12 miles off the coast of Maine, was developed by an electric cooperative, but the cooperative put the project in a subsidiary partnership in which it retains a 1% interest. The other 99% is owned by a local tax equity investor—an S corporation—that invested 34% of the project cost in exchange for a 99% interest.

The coop raised the other 66% of the project cost by borrowing from the Federal Financing Bank, an arm of the US Treasury, at 12.5 basis points above yields on comparable Treasury bonds and by passing the loan proceeds to the partnership. Such loans are available to wind farms that serve rural areas under a program run by the Rural Utilities Services in the US Department of Agriculture. (See related story in this issue.) / *continued page 19*

USDA Loan Guarantees

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sponsorship and credit assurance, and the timing allows for completion of the environmental review required pursuant to the RUS environmental regulations found at 7 CFR 1794. Approval authority for renewable energy loan guarantees is reserved solely to the RUS. Members of Congress are notified directly, and the public is notified through normal media communications. Loan guarantees are approved or rejected generally within an average of three to nine months following the assignment of an application received date.

Equity contribution:

The regulations do not set borrower contribution rates for non-municipality borrowers. The Rural Electrification Act affirmatively requires the RUS to make a finding of security and feasibility for each loan that is made. According to the informal guide available to prospective LLC applicants, LLC borrowers are expected to maintain a minimum equity requirement of 25%.

FFB loans:

Virtually all of the loans guaranteed by RUS are made by the FFB, although, historically, borrowers have obtained the RUS guarantee for loans from other sources. FFB determines the interest rate at the time of each advance, based on rates established daily by the US Treasury plus 12.5 basis points versus the DOE loan guarantee programs' norm of a spread of 37.5 basis points. FFB can set a different interest rate and has done so at the request of a borrower who was seeking an IRS private letter ruling that RUS guaranteed financing is not considered subsidized energy financing for purposes of production tax credits.

In most cases (Indian tribes, public utility districts and municipalities being the exceptions), all current and future assets of the borrowing entity are pledged as security for the loan.

Subsidy costs:

As previously noted, the OMB subsidy rate for the RUS program applies to the full loan program level rather than to individual projects, as is the case with the DOE loan guarantee programs. The higher the subsidy rate, the less the program's loan authorization is for a given dollar of appropriated budget authority. While borrowers as a group may feel the effect of a lower cap on the amount of loans RUS can guarantee, the individual borrower is not affected in terms of direct cost.

Looking Forward

While the PrairieWind wind farm loan guarantee showcased the RUS program as an alternative source of financing for renewable energy projects, it is not a straight shot for a loan guarantee in general or FFB financing in particular.

Just as the section 1703 program excludes candidates that cannot meet its "innovative technology" criteria, the RUS program excludes several renewable energy activities that conceivably would meet the broader section 1705 program requirements. For example, the "Rural Electrification Act-beneficiary" (rural) requirement weighs against, or would significantly reduce the amount of the loan guarantee available to, projects that benefit more populated regions. As a practical matter, the service territory needs to be at least 75% rural, or RUS cannot fund the entirety of the debt needed in excess of the equity requirement.

In addition, the RUS program could consider a project focused on installing and servicing renewable energy systems on consumers' premises (such as the distributed generation projects seeking DOE support) where the LLC is implementing the program on behalf of a utility within its rural service territory and the utility provides credit support for the RUS loan to the LLC. However, a project for manufacturing renewable energy system components (such as Abound Solar Manufacturing, which received a $400 million DOE loan guarantee) would not qualify under the Rural Electrification Act because it is not sufficiently directly related to the "purpose of furnishing and improving electric . . . service in rural areas."

Nuclear power is an eligible purpose under the Rural Electrification Act and, historically, the Rural Electrification Administration financed fractional ownership shares in nuclear plants owned by rural electric cooperatives. It is expected, as a practical matter, that DOE will provide financing for the nuclear plants now under consideration.

RUS support to privately-owned, for-profit applicants, while feasible under the Rural Electrification Act and the relevant regulations as a constructive system loan, is of untested and unproven potential. Despite the claim in the USDA February 9, 2011 news release that the PrairieWind project is a "model of public and private investment partnership," the recipient of the loan guarantee in fact is the consumer-owned cooperative, not its for-profit subsidiary charged with developing and operating the project, and private investor participation is limited to the seven turbines adjacent to the project, the financing of which falls outside of the RUS loan guarantee. Opportunities remain, however, for the private developer in a mutually-beneficial partnership with a utility offtaker to take advantage of the RUS program offerings.

Finally, the stability of funding for the RUS program is vulnerable to both the short-term effects of the ongoing fiscal year 2011 budget debate in Congress as well as the longer-term fiscal pressures and funding constraints on government spending in fiscal year 2012 and beyond. The extremely low, and at times, negative subsidy rate that the RUS program enjoys should, however, mitigate this vulnerability; nothing much is achieved toward the targeted budget cuts by cutting the RUS program because so little budget authority is needed to fund it in the first place.

Despite its limits and uncertainty, the RUS program may offer an attractive funding option for renewable energy projects, particularly where the developer has partnered with a utility with a rural service territory *and* the utility is willing to step up to the RUS revenue assurance requirement in order to realize lower costs. If it fits, it could work well—for both the renewable energy developer and the rural population the RUS is designed to serve. ◎

FERC Gen-Tie Policy Poses Risks to Renewable Project Developers

by Adam Wenner and Amanda Riggs Conner, in Washington

A recent Federal Energy Regulatory Commission decision increases the risk that competing third-party projects will be granted priority to use excess capacity on transmission lines that developers have built to connect their own wind, solar or geothermal projects to the grid.

Not surprisingly, most population centers are not located in areas with constant high winds, thousands of acres of empty land or steaming geothermal wells. As a result, to serve load, renewable energy developers frequently must build their own transmission lines to reach the grid so that utilities can deliver the power to customers. Since transmission lines can extend for tens or even hundreds of miles, rather than being located at a single site, developers can face the same, or */ continued page 20*

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The partnership sells the electricity from the project at cost to the cooperative. The tax equity investor claimed an investment tax credit as well as depreciation. According to NREL, the cooperative has an option to buy out the tax equity investor after the five-year recapture period has run on the investment credit for fair market value, which NREL speculated should be a low price because the project is not generating any net cash flow for the partnership.

Another small project in Washington state managed to combine new markets tax credits with an inverted lease. The project is a 6-megawatt wind farm in Grayland, Washington that is owned by a community service provider called the Coastal Community Action Program, or CCAP, that helps low-income, disabled and elderly residents. CCAP is hoping to use the income generated by the project to help fund its social programs. A local public utility district is buying the electricity from the project under a long-term contract.

The project company that CCAP established to own the project borrowed the project cost from a "community development enterprise" or "CDE"—an entity that lends or makes equity investments in businesses in low-income communities and that has been awarded new markets tax credits by the US Treasury to use as carrots to raise capital from investors that it can then lend or invest as equity. An investor in the CDE gets a tax credit for 39% of his investment in the CDE. The tax credit is spread over seven years.

Wells Fargo put money into the CDE specifically to fund the loans. It contributed an amount as equity to the CDE and borrowed the remaining 61% of its capital contribution from CCAP, the project sponsor, which lent Wells Fargo grant money that CCAP had received for the project from Washington state. The IRS has ruled in the past that the 39% tax credit can be taken on the full capital contribution, even though a large share of it is borrowed money.

CDEs are able to lend at low interest rates because the new markets tax credits give them a cheaper cost of capital than */ continued page 21*

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sometimes greater, development risks with the intertie as those associated with the development of power projects.

Under its open access transmission policy, FERC imposes the same obligations on independent power developers to make unused transmission capacity available to third parties as it does on traditional utilities. Although FERC requires these third party customers to pay to use this transmission capacity, it limits payments for transmission service to the developer's "cost-of-service." "Cost-of service" ratemaking compensates the developer for the construction and operating costs of the gen-tie lines, but includes only a regulated utility rate of return and, therefore, is not likely to compensate the developer for the non-utility type development risks it undertook.

This approach provides an incentive for a developer to bide its time while another developer attempts to permit, procure rights-of-way, finance and construct a transmission line, and offer to purchase transmission service only if the other developer succeeds.

Developers who build interties to connect their projects to the grid are at risk of having neighboring projects take over any spare transmission capacity.

Pending Proceeding

FERC is currently addressing the intertie open access issue in a proceeding involving a 212-mile line constructed in connection with a geothermal plant located in Nevada. The original owner of the project built the line to deliver the power from the plant to the Southern California Edison Company transmission system.

In December 2009, the current project owner sought a FERC ruling that would exempt it from the requirements to file an open access transmission tariff and to offer unused transmission capacity on its line to third parties. The project owner also sought FERC confirmation that it has "priority rights" to the capacity used for its geothermal project as well as priority rights on its planned expansion of capacity of the line. Another geothermal project developer intervened in the FERC proceeding and took the position that granting these requests would violate FERC's prohibition on "banking" unused transmission capacity, making the capacity unavailable to other potential users.

The project owner's filings cited FERC's ruling in a similar case that involved a dispute over access to the Sagebrush transmission line, a 46-mile transmission line extending from the Tehachapi region of California to the SCE system. The Sagebrush line is owned by Sagebrush Partnership, whose partners are the owners of the wind projects that use the line. A third party, non-owner, Aero Energy, requested FERC to rule that it could use available capacity on the line for its wind project. The Sagebrush partners argued that, as owners of the line, they should be entitled to reserve available capacity for their own future projects.

FERC rejected the Sagebrush partners' argument, noting that "[h]aving built the Sagebrush Line, Sagebrush now wants to bank unused transmission capacity until it, and no one else, wants to use it." FERC instead ruled that the Sagebrush partners may not reserve all of the Sagebrush line's transmission capacity to themselves since that would violate FERC's authority to require a transmission owner to provide open access transmission, so long as providing transmission to third parties does not adversely affect the reliability of the lines. However, FERC said that if a line owner could demonstrate that it had "specific, pre-existing generation expansion plans" that would require it to use additional transmission capacity on the Sagebrush line, those plans will take precedence over a third party's requested use of the line.

Following review of the Sagebrush partners' expansion plans, FERC concluded that only one of the partners satisfied the standard, finding that it had "specific expansion plans with definite dates and milestones for construction of wind generation" that will use additional firm transmission capacity on the line and that the owner had expended "considerable effort" to achieve these milestones. FERC granted priority rights to the owner for the additional capacity, thereby allowing it to bank this capacity for future use.

In the proceeding involving the 212-mile line, which is now before FERC, the owner of the line says that it satisfies the Sagebrush test because it has specific development plans for developing additional geothermal projects, that it has diligently pursued these plans and, as a result, it is entitled to priority rights for all of the planned capacity on the line. It pointed out that developing geothermal projects can take more than 10 years and that it has undertaken a number of activities demonstrating its commitment to future projects, including engaging in the exploration and geothermal development necessary to support them. The owner said it acquired pre-existing priority rights in the gen-tie line, paid a premium for geothermal development rights because of the line, and spent more than $25 million in developing additional projects. In addition, it entered into leases with the US Bureau of Land Management and submitted interconnection requests to the California ISO to interconnect the planned new generation, which conducted feasibility studies regarding the interconnection of new generation to the gen-tie line. Finally, the owner said it is in the process of negotiating purchase power agreements for the output of its planned geothermal projects and obtaining federal, state and local permits to develop these projects.

The intervenor in the FERC case challenged the claims that the gen-tie owner satisfied the Sagebrush test, contending that its plans are not sufficiently concrete. In a ruling issued in September 2010, FERC held that the gen-tie owner had not presented sufficient evidence of specific pre-existing plans to establish priority for its future projects. In order to develop a more detailed factual record on which to base its final decision, FERC permitted the line owner to submit further evidence of pre-existing development plans. In response, the owner submitted more than 1,500 pages of documents in support of its position. The case is now awaiting a decision by FERC, and FERC's decision will establish an important marker of which gen-tie developers must be keenly aware.

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other lenders.

US Bank injected money separately into another CDE that made an equity investment in the project company in exchange for an interest in the project. The project company then leased the entire project to US Bank under an "inverted" lease and assigned the power contract to US Bank as lessee. When the lease ends, the project company will get the project and power contract back. In the meantime, it elected to let US Bank claim a 30% Treasury cash grant on the project as lessee. The depreciation remains with the project company, but may be shared by the CDE as a part owner of the project company.

At the end of the day, the bank made a $6.86 million investment on which it can claim 39% in new markets tax credits and a 30% Treasury cash grant on the fair market value of the entire project.

CORPORATE TAX REFORM is on the agendas of both political parties in Congress.

The Senate tax-writing committee has started holding weekly hearings on tax reform, but it is hard to see a bill being enacted before the next elections in November 2012.

Business groups have been pressing for a lower tax rate. The US statutory tax rate of 35% is reportedly the highest among the 34 OECD countries, assuming Japan implements a planned rate reduction. According to PricewaterhouseCoopers, adding state and local taxes brought the US corporate income tax rate to 39.2% in 2010, 14 percentage points higher than the average rate of 25.1% within the OECD.

Comparisons of effective rates—or the rates at which companies actually pay taxes—are harder to find.

Any major tax reform probably needs to be revenue neutral because of the huge federal budget deficit. The Bush Treasury Department showed in a report in December 2007 why this will be a challenge. The Treasury estimated that eliminating all business tax incentives other than accelerated deprecia- */ continued page 23*

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Open Access Tariff

FERC also ruled that the gen-tie owner must file an open access transmission tariff or "OATT" that establishes the terms and conditions under which it will provide transmission service to third parties on the line. Any OATT must generally conform to FERC's *pro forma* tariff, but FERC said it would consider waiving or modifying certain OATT requirements to reflect the fact that the line is not an integrated transmission system, but rather is a radial line used only to transmit power from a power plant to the SCE system.

In November 2010, the gen-tie owner filed its OATT for transmission service on the gen-tie line. In the filing, it requested waivers of or proposed modifications to many provisions of the *pro forma* OATT, since the OATT was designed for use by large utilities and accordingly needed to be modified to reflect the services that could be provided by the owner of a gen-tie line.

FERC rejected many of the gen-tie owner's requests for waivers or modifications. In particular, it required the gen-tie owner to include *pro forma* OATT provisions that allow transmission customers to delay commencement of their transmission service by paying a fee, establish detailed procedures for scheduling transmission service, require the transmission provider to offer scheduling, system control and load dispatch, and reactive supply and voltage control ancillary services or explain to customers how the services may be obtained, and impose deadlines on a transmission provider for completing studies of the impact of a transmission service request on the transmission line and any required upgrades.

FERC also required the gen-tie owner to revise its descriptions of the methodology it uses to calculate available transfer capability. It also required the gen-tie owner to justify its proposed customer creditworthiness standards, which deviate from FERC's standard conditions to account for the fact that the gen-tie owner cannot assume significant credit risk. According to FERC, the gen-tie owner had not shown that its proposed variations were "consistent with or superior to" the FERC *pro forma* OATT, which is the standard FERC applies when a traditional utility or independent transmission company seeks to customize an OATT.

The gen-tie owner further requested FERC to rule that the *pro forma* OATT terms not apply to the transmission capacity needed for the gen-tie owner's existing geothermal plant or for its projects under development. FERC rejected this proposal, finding that the gen-tie owner had not justified this proposed exemption, in that it did not explain how it would implement transmission service for the existing capacity or for the future expansion capacity over the line and, in particular, it did not explain how the transmission service will be included in available transfer capability calculations. FERC directed the gen-tie owner to submit a revised OATT that reflected FERC's conclusions.

Self-Help Steps for Developers

Developers who are following the ongoing FERC proceeding are taking extra precautions and incurring additional expenses to ensure that they retain the rights to excess capacity on their own gen-tie lines.

For example, several affiliated companies are currently developing wind projects in California as phases of a large wind project, which are in various stages of development. The projects include gen-ties lines interconnecting with the California grid. None of the gen-tie lines is longer than six miles, and one is less than two miles.

The project developers recently filed a petition for a FERC declaratory order confirming that they are entitled to the transmission capacity on the gen-tie lines to deliver the output of their projects to the grid. This was not a simple or inexpensive exercise since a petition for a FERC declaratory order carries a filing fee of more than $23,000 and involves numerous filings, especially if the claim is challenged. Two of the projects commenced operation before FERC finally ruled on the petition.

FERC confirmed in a February 2011 order that the project companies have priority rights to the full capacity over the gen-tie lines. FERC found that the companies have specific, pre-existing plans with definite dates and milestones for the development of generation that would use the full capacity. It explained that for most of the projects, the companies had already entered into interconnection agreements with the California ISO and power purchase agreements for the output of their projects. FERC also found that the companies had presented evidence that they intend to construct additional projects that will use the remaining capacity on the lines, including specific milestones for construction, as well as a demonstration of progress in completing these milestones. Consistent with FERC's long-standing open access transmission policy, the companies must offer transmission service over the gen-tie lines on any unused capacity under an OATT if they receive a request from a third party.

Problems With FERC's Policy

In addition to forcing developers to waste resources seeking FERC confirmation that they will retain priority rights on their gen-tie lines, the FERC policy encourages sub-optimal decision making by developers.

A developer that would otherwise proceed with a development plan for multi-phased projects that allows adequate time to complete each milestone, but would risk forfeiting excess gen-tie capacity by proceeding under that timeline, would be incentivized to avoid this risk by artificially expediting its development plan. Expedition would include preparing detailed plans for project development earlier than otherwise called for—which can mean that performance data from the operation of earlier phases will not be available to "fine tune" later phases—applying for permits earlier than would otherwise be the case—and since many permits include milestones, artificially expediting studies and development schedules—ordering equipment solely to demonstrate that commitments have been made, entering interconnection queues and reserving (and paying for) transmission earlier than would have been the case, and otherwise undertaking activities for the sole purpose of developing a record that will pass FERC's standard and enable the developer to retain priority rights on its excess gen-tie capacity.

The authors believe that there are approaches that can mitigate the artificial incentives and associated sub-optimal behavior.

First, the exponential scale economies associated with using higher voltage transmission lines must be recognized in the discussion, since these scale economies mean that the per unit costs for all developers will be lower if larger (for example, 500 kV rather than 230 kV) gen-tie lines are constructed.

Second, the environmental degradation caused by one higher capacity line is considerably less than that caused by the construction of several lower capacity gen-tie lines and the associated transmission corridor. (For an informative discussion of scale economies in transmission, see "Interstate Project: 765 kV or 345 kV Transmission," available on American Electric Power's website, http://www.aep.com/about/i765project/technicalpapers.aspx.)

A Better Way

Not surprisingly, this is not the first time that FERC has encountered this type of issue. Beginning in gas pipeline certificate cases and continuing in

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tion would allow the corporate income tax rate to drop 4 percentage points to 31%. Eliminating accelerated depreciation would take it down to 28%.

Capital-intensive industries, like manufacturers, power companies, airlines, railroads and truckers, would be worse off from such an exchange. Retailers and financial firms would benefit the most. This will make it hard for major trade associations, like the US Chamber of Commerce, that cut across industries to support reforms.

In addition to rate reduction, US multinational corporations would like the US to move to a "territorial" system where they are taxed only on income earned in the United States. The current system of taxing US companies on worldwide income discourages them from repatriating earnings from subsidiaries in other countries that remain parked outside the US tax net in offshore holding companies. Any move to a territorial system would make US multinational corporations more competitive in foreign markets, but it could be perceived as making it easier to redeploy capital and move jobs abroad.

Meanwhile, the US tax laws have become less anchored. More and more tax provisions that reduce tax collections have sunset clauses. The first time the Joint Committee on Taxation published a list in 1998 of provisions that were scheduled to expire in the next three years, the list had 19 items. In 2010, there were 181.

EARN OUTS are common when companies with a number of wind, solar or other projects under development are sold.

An earn out is a right to an additional payment or share of project earnings in the future once certain milestones are reached.

A developer may not be able to agree with a potential buyer on how much the development pipeline is worth. An earn out is a way to bridge the gap. It may also be a way to keep key personnel at the company and focused on pushing projects across the finish line.

There is a risk that the

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its "merchant transmission" decisions, FERC has incentivized and, in some instances, required developers to offer to expand the capacity of their projects to accommodate all users that are willing to make the requisite financial commitment. In gas pipeline cases, FERC has the direct authority, through the Natural Gas Act certificate process, to require developers to build pipelines with sufficient capacity to serve all users and has stated that it can require capacity expansion as a condition of granting a certificate of public convenience and necessity.

Under the Federal Power Act, which governs electric transmission in the continental US except for the ERCOT region of Texas, FERC lacks certification authority. However, it clearly has the authority to impose a similar requirement to "expand the gen-tie capacity to serve all users" by conditioning its granting of market-based rate authority on gen-tie developers agreeing to expand the capacity of their lines to serve all users that agree to make the requisite financial commitment.

Similarly, in decisions involving merchant transmission, FERC requires the transmission project developer to conduct an "open season" auction for capacity rights. This requires the developer to provide adequate public notice of the upcoming auction and to use transparent bidding procedures with evaluations by a disinterested decision maker—usually an economic consulting firm. Recent FERC decisions have approved the "anchor tenant" approach, in which, in order to demonstrate to potential bidders that the line is viable and therefore participating in the auction is not a futile exercise, the project developer negotiates with a large customer ahead of the bid process for a percentage (for example, 50%) of the project's capacity. Bidders in the open season compete for the remaining capacity, with assurances that they will not pay more than the anchor tenant. Although FERC has not yet addressed a case where an affiliate of the transmission project developer is an anchor tenant, its decisions indicate that it would not prohibit such an arrangement, provided that third parties are able to obtain non-discriminatory pricing and terms of service.

The "gen-tie auction" approach that the authors propose would incorporate the open season process into the gen-tie development process. In seeking FERC approval for market-based rates for the generation project, the developer of a generating project that includes a gen-tie line would have the option of conducting an open season process pursuant to the standards that have been applied in merchant transmission cases. This would specifically include the generator or an affiliate as an anchor tenant that has agreed to sign up for transmission capacity on the new line. The generator could sign up for a percentage of the capacity of a specified line—for example, X% of a 230 kV line—or just for a stated amount of capacity—for example, 250 MW—with the line to be sized to accommodate all users. The generator would proceed with the open season process, would determine the appropriate configuration to accommodate all interested customers, and would enter into precedent agreements with customers that would impose secured obligations to fund their portions of the line.

In exchange for having opened up its transmission planning and development to all interested parties, the gen-tie project sponsor would be exempted from the FERC "use it or lose it" rule for a specified period, roughly corresponding to the planning and development cycle of its renewable resource project. The underlying principle is a "speak now or forfeit your open access rights," at least for projects for which a third party reasonably could have been expected to make financial commitments during the stated period—for example, three years. Under the gen-tie auction policy, only parties that put development funds at risk would be entitled to priority transmission rights during the development cycle.

All parties, including consumers of the power being produced, would benefit from the economies of scale that would result. This approach would eliminate the false incentive for developers to make concrete plans to develop subsequent phases of their projects because the developer would be exempted from the requirement to offer to enter into long-term commitments for unused capacity on their shares of the transmission line. Third parties who would otherwise raise complaints will instead be required to "speak now, or hold your peace until the next development cycle."

FERC has scheduled a technical conference to consider issues relating to ownership of and priority accss rights to new transmission projects, including the appropriate balance between FERC's policies on open access and the needs of gen-tie project developers. The conference will be held on March 15, 2011 from 9:30 a.m. to 4:00 p.m. in FERC's offices in Washington, D.C. A free webcast of the technical conference will be available and can be viewed by locating this event in FERC's calendar of events on its website, www.ferc.gov. ◎

Using Tradable Renewable Energy Credits in California

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

A decision by the California Public Utilities Commission in January lets California utilities satisfy part of their 20%-by-2010 renewable procurement requirements by buying "unbundled" credits from renewable generators in other states.

Credits are "unbundled" if they are purchased separately without also buying electricity.

Before this decision, a utility could not use unbundled credits—called tradable renewable energy credits or TRECs—to fulfill renewable procurement requirements. A controversial March 2010 decision and a subsequent stay on the decision had left the ability to rely on renewable energy credits purchased out of state in doubt. Even with the January decision, the issue remains highly contentious and may not have been settled.

After nine years, the extent to which TRECs can be used in California and even what qualifies as a TREC remain under debate. The ultimate answers may differ for the 20%-by-2010 renewable portfolio standard or "RPS" and the 33%-by-2020 renewable electricity standard or "RES."

Background

Investor-owned utilities and retail energy service providers in California are required to provide 20% of their electricity from renewable energy sources beginning in 2010, although flexible compliance rules in the RPS program effectively extend the compliance deadline to 2013. (A retail service provider is an entity that competes with investor-owned utilities to sell electricity to retail customers directly.)

The California Public Utilities Commission administers this 20%-by-2010 RPS program. The program has been underway since 2002 and is mostly well defined. The ability of utilities to use TRECs to meet their compliance obligations is among the few remaining aspects of the program that have not yet been finalized.

All California utilities, including retail service providers and public and municipal utilities not under CPUC jurisdiction, will be required to procure 33% of their electricity from renewable energy sources beginning in 2020. This / continued page 26

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payments may be treated as compensation to the seller rather than additional purchase price if the remaining payments are tied to additional work that must be done. This can affect the tax treatment to both the buyer and seller. Compensation must be reported as ordinary income rather than capital gain. The buyer can deduct compensation while a payment of purchase price would go into basis and be used to calculate Treasury cash grants, investment credits and depreciation on the projects.

One way to avoid confusion is to make sure employees are paid separately at market rates for ongoing services or offered retention bonuses. True earn out payments should be paid in proportion to the ownership interest of each seller, whether or not he performs additional services. The amount should be fixed at sale. It can be subject to future events, like project completion, but not whether the seller remains with the company.

IRAN SANCTIONS will get more attention in Congress.

The House Foreign Affairs Committee is working on a bill to tighten US sanctions further in the wake of charges by critics that a 2010 law imposing additional sanctions still has too many loopholes that allow companies to continue doing business with Iran. The 2010 law was a compromise between sanctions hawks in Congress and the Obama administration, which wanted flexibility to impose sanctions in individual cases, particularly against businesses in allied countries.

The administration has used the 2010 law to sanction just one company—Naftiran, a Swiss-based subsidiary of the Iranian national oil company that has entered into joint ventures with a number of European oil companies to import oil into Iran. The company had $21.9 billion in revenues in 2008.

The House may replace the word "should" take certain actions with "shall immediately" do so. / continued page 27

TRECs

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33%-by-2020 RES was approved by the California Air Resources Board in September 2010 and in many respects remains a work in progress. Notably, the authority for this program currently stems from an executive order issued by then-Governor Schwarzenegger; however, legislative efforts to enact a bill establishing a 33%-by-2020 renewable energy obligation continue. If a bill is passed, then the bill and its legislative requirements will supersede the executive order and the CARB regulatory framework.

A Tortured History

Parties have been asking the CPUC to authorize the use of TRECs for RPS compliance from the very earliest days of the RPS program, but the path toward establishing rules regarding use of TRECs has been tortured.

The CPUC initially considered the use of TRECs for RPS compliance as the parties were seeking, but fearing the issue would delay implementation of the RPS program, the CPUC decided to table the matter.

The CPUC subsequently revisited the issue in several proceedings and began focusing seriously on the TREC issue in 2006, when legislative activity on the matter also heated up. But once again the CPUC put off a decision to authorize the use of TRECs for RPS compliance, committing only to revisit the matter at a later date. Since that time, parties have held numerous workshops, filed briefs, and waited for the CPUC to act.

Finally, in March 2010, the CPUC issued a decision authorizing the use of TRECs for RPS compliance. However, rather than closing the issue, the March 2010 decision simply ignited more controversy.

A California Public Utilities Commission decision lets utilities purchase renewable energy credits from generators in other states to satisfy California renewable energy targets, but it may not be the last word.

TRECs Under the RPS

Before the March 2010 decision authorizing the use of TRECs, utilities and retail service providers could comply with their RPS requirements only through "bundled" contracts, in which physical energy and renewable energy credits were purchased in the same transaction.

The March 2010 decision expanded compliance options by allowing the use of unbundled TRECs for RPS compliance. It also allowed TRECs to be banked and used for RPS compliance for up to three years following the physical delivery of renewable energy to the grid. However, for the state's three large IOUs for the years 2010 and 2011, the decision limited the use of TRECs to 25% of the utility's annual RPS obligation. The CPUC also capped the price during these years at $50 per megawatt-hour for TRECs used for RPS compliance. (A subsequent decision extended these limitations to retail service providers.)

The March 2010 decision sparked controversy among both utilities and renewable energy project developers primarily on account of the 25% TRECs limit combined with the expansive definition of a TREC transaction, which redefined some already approved bundled contracts as TREC contracts.

Under the decision, all transactions are defined as TREC transactions unless they include either (1) physical energy deliveries from a generator that has its first point of interconnection with a California balancing authority such as the California Independent System Operator or (2) energy deliveries that are dynamically transferred to a California balancing authority area.

Under this sweeping definition, contracts with out-of-state generators are nearly always considered TREC contracts, even if they include physical energy deliveries.

However, the CPUC left open the possibility that out-of-state transactions that include firm transmission arrangements, but not dynamic transfers to a California balancing authority, could be reclassified as bundled contracts since, prior to the March 2010 decision, such transactions had been considered bundled transactions.

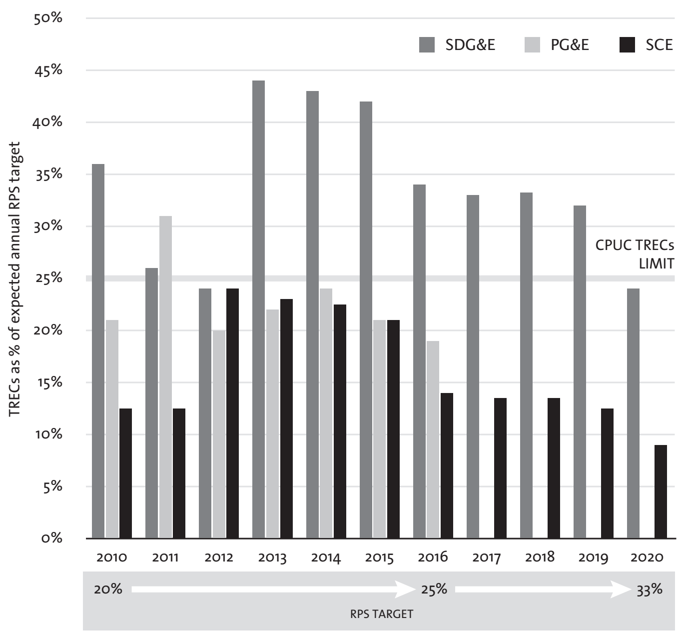
The narrow definition of bundled contracts imposed by the March 2010 decision and the application of the definition to already-approved contracts limit additional out-of-state procurement.

The chart below, which was created by The Utility Reform Network, a consumer advocacy group, shows the utilities' annual TREC procurement under the CPUC's adopted definition. As shown, San Diego Gas & Electric has already exceeded the 25% TREC usage limit in nearly each year through 2020 under this definition. This means that SDG&E would be able to enter into new RPS contracts with out-of-state generators only under very narrow circumstances. (SDG&E would be allowed to use deliveries from contracts exceeding the TREC usage cap for RPS compliance as long as the contracts were approved before March 11, 2010.)

The other two utilities approach the 25% limit for much of the first half of the decade and would have the opportunity for significant new out-of-state procurement beginning only around 2016. The utilities objected to being hamstrung by these limitations since they restricted procurement options, and developers of out-of-state renewable projects objected to being pushed out of the California market.

IOU Renewable Procurement

Approved/Submitted TREC contracts as a fraction of expected RPS procurement targets



Prepared by Matt Freedman (TURN) using public data provided by the IOUs

As a result of this controversy, the CPUC stayed the March 2010 decision in May 2010 and placed a moratorium on approving contracts that would be classified / *continued page 28*

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It could also require public companies to report any potentially sanctionable investments in Iran in quarterly and annual reports to the US Securities and Exchange Commission.

Any bill would also have to pass the Senate, which has been less critical of the administration's efforts.

NEW JERSEY confirmed that Treasury cash grants paid on renewable energy projects in the state are not subject to state corporate income taxes. The announcement is in a "technical advisory memorandum" issued on February 11 by the New Jersey Division of Taxation.

GRANTS that low-income housing developers received from state housing agencies out of federal stimulus dollars under a so-called TCAP program—tax credit assistance program—had to be reported as income.

Congress gave the Department of Housing and Urban Development $2.25 billion in the economic stimulus bill in February 2009 to allocate among state housing agencies. The states then made awards to certain privately-owned low-income housing projects that still needed money to finish construction.

The IRS national office told its agents in the field in an internal legal memorandum made public in February that the grants must be reported as income. The memorandum is ILM 201106008.

The memo also addresses the timing of the income.

Grants received by developers who determine their incomes on a cash basis must report income once they have access to the funds in a state account from which to pay project costs. Larger developers that use accrual accounting must report income upon signing an agreement with the state housing agency fixing the amount of the grant the developer will receive.

These positions have no effect on Treasury cash grants paid on renewable energy projects under section 1603 of / *continued page 29*

TRECs

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according to that decision as TREC contracts. The CPUC and interested parties then spent an additional eight months debating the issue, resulting in no less than six revisions to the administrative law judge's initial proposed decision as well as a competing proposed decision from a commissioner (which was also revised). Finally, the commission adopted a "final" decision in January 2011, reinstating the March 2010 decision in nearly all respects, except for extending the TREC usage and cost limitations until 2013. This decision also lifted the moratorium on approving TREC contracts.

Given the similarity between this decision and the highly unpopular March 2010 decision, it is not surprising that the controversy continues. In February, several parties submitted applications to rehear the January decision. Once again, their arguments primarily revolve around the very restrictive definition of bundled transactions.

Further revisions to the January 2011 decision are still possible. Only three sitting commissioners approved the January decision. (Two commissioner seats were vacant at that time.) The term of one of the three commissioners has since expired. Incoming Governor Jerry Brown appointed new commissioners to two of the three vacant seats. Thus, any future decisions on the TREC issue will be taken up by a commission that currently has four members, two of whom did not vote on the January decision. (A fifth appointment is still pending.)

TRECs Under the RES

The controversy at the CPUC over TRECs relates specifically to the 20%-by-2010 RPS, but the controversy could easily spill over to the 33%-by-2020 RES. This is because CARB has decided to defer to the CPUC on the TRECs matter. The CARB resolution approving the 33%-by-2020 RES requires CARB to initiate a rulemaking within 30 days of adoption of the CPUC decision "to ensure continued harmonization of the two programs, specifically incorporating provisions related to Tradable Renewable Energy Credits for all regulated parties under the RES regulation." This 30-day period ended on February 13, 2011, but CARB has not yet initiated the required rulemaking.

On the other hand, the discussion at the CPUC could also be substantially moot if the legislature passes 33%-by-2020 RPS legislation. A new 33% RPS bill currently moving through the California legislature identifies three categories of renewable energy resources rather than trying to define what is or is not a bundled transaction. One category is resources with a first point of interconnection with a California balancing authority or that would be dynamically transferred to a California balancing authority (*i.e.,* the CPUC's restrictive definition of bundled resources). Another category is firmed and shaped resources that are scheduled into a California balancing authority (*i.e.,* transactions that were redefined in the CPUC decision from bundled to TREC-only). The third category is all other resources (TREC transactions under all definitions).

The legislation sets separate procurement requirements or limits for each of these categories in three different time periods. For example, beginning in 2017, at least 75% of renewable resources must come from the first category, which is the equivalent of the CPUC requirement that no more than 25% come from TREC-only transactions. However, the legislation further specifies that of the remaining transactions, only 10% can come from the third category. These restrictions are outlined in Table 1 below.

Table 1: Comparison of TREC Usage Limits in California Programs

	First-point of interconnection with or dynamically transferred into California balancing authority	Firmed and shaped and scheduled into California balancing authority	All other out-of-state, REC only contracts
20%-by-2010 (CPUC January 2011 decision)			
2010-2013	At least 75%	No more than 25%	No more than 25%
2014+	No limit	No cap	No cap
33%-by-2020 (CARB, September 2010 decision)			
To be "harmonized" with CPUC rules			
33%-by-2020 (SBX1 2, active bill in legislature)			
Prior to 2013	At least 50%	No more than 50%	No more than 25%
2014-2016	At least 65%	No more than 35%	No more than 15%
2017+	At least 75%	No more than 25%	No more than 10%

The bottom line is that the recent decision by the CPUC to allow RPS-obligated entities to use TRECs to meet part of their RPS compliance obligations is an important first step to finally realizing a tradable REC market in California. But the CPUC framework applies only to the 20%-by-2010 RPS, creating uncertainty as to what the TREC rules might be under a 33%-by-2020 RES. The framework may also not be final, as it remains highly controversial.

This uncertainty will linger while the CPUC continues to grapple with TRECs rules for the 20% RPS and the legislature continues to debate 33% RPS legislation.

Even once these debates are completed, the two RPS (or RES) programs will need to be harmonized, which could provide another opportunity for modifications to the TRECs program and more uncertainty for out-of-state developers interested in selling renewable power into California. ◎

China Wind Power Update

by Christopher Flood, in Beijing

Despite a recent tide of positive news generated by the Chinese wind power industry, a deeper look reveals a large number of challenges facing both equipment manufacturers and project developers as the domestic industry continues to mature.

Days after the January announcement that China had surpassed the United States in 2010 as the world leader in installed wind power capacity, Sinovel, its largest wind turbine manufacturer, raised US$1.4 billion in an initial public offering on the Shanghai Stock Exchange, pricing the offering at the top of the range. Just weeks earlier, Datang Renewable Power, China's second largest wind power generator by capacity, raised US$643 million in its own Hong Kong IPO. The second half of 2010 also saw public offerings in Hong Kong by Shenzhen-listed wind turbine manufacturer Xingjiang Goldwind Science & Technology and on the New York Stock Exchange by China Ming Yang Wind Power Group, the country's largest non-state-owned turbine firm.

Away from the public markets, the news from the China Renewable Energy Industries Association that China had installed 16,800 megawatts of new wind generating capacity in 2010, for a total of 41,800 megawatts, was met with a mixture of surprise and resignation from those outside of the Chinese industry, as many observers predict China will dominate the world market for many years to come.

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the stimulus. Congress made clear when it authorized the renewable energy grants that they do not have to be reported as income.

Many renewable energy projects are owned by limited liability companies treated as partnerships. Even though section 1603 payments are exempted from taxes, their receipt still has an effect on partner capital accounts that determine, among other things, how much depreciation a partner can absorb from a project. A partnership receiving a grant treats it as tax-exempt income. Tax-exempt income increases the partner capital accounts. This gives partners more capacity to absorb depreciation from a project.

The timing of when this income bumps up capital accounts is unclear. Because of the uncertainty, tax equity investors would be wise still to invest in partnerships that own projects on which section 1603 payments will be made before the projects are placed in service to ensure they are partners before the bump up in capital accounts occurs.

CALIFORNIA said out-of-state corporations must file franchise tax returns if they own "disregarded" subsidiaries that do business in the state. It does not matter if the corporation has no other ties to the state.

The Franchise Tax Board took the position in Legal Ruling 2011-01 in mid-January.

THE DISTRICT OF COLUMBIA reneged on a promise to reimburse 51 residents who installed solar panels for roughly a third of the cost.

The city said it will try to find money in next year's budget.

The city set up an incentive program in 2009 that is funded by a dedicated tax on electricity and gas bills. The tax was supposed to raise $2 million a year through 2012. However, $700,000 from the fund that was supposed to be used to make incentive payments to the 51 residents who had been approved for the payments before they installed panels has been diverted to help close a citywide budget gap.

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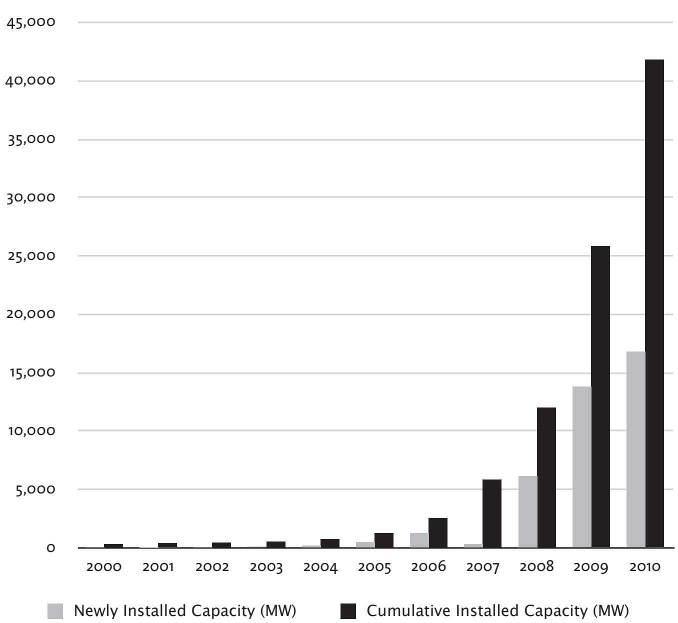
Continuing the trend, China's National Energy Administration has recently forecast that there will be 55,000 megawatts of total installed capacity in China by the end of 2011.

However, growth rates—while remaining far higher than any other major market—have slowed from the unsustainable doubling of the market for each of the five years from 2004 to 2009, to 61% last year and a projected 60% in 2011.

Table 1



Source: 2010 China Wind Power Outlook; the author

In addition, the People's Bank of China's recent monetary tightening, which began last fall, has increased pressure on highly leveraged developers who are now facing rising interest rates. Safety concerns are also being raised in the domestic market as a number of deaths and other accidents have recently been reported involving wind turbine technicians.

China is also facing challenges to its domestic innovation policies benefiting the wind sector. As reported in the January 2011 *NewsWire*, the United States has initiated dispute resolution proceedings at the World Trade Organization to challenge the legality of one of its wind turbine manufacturing subsidies, which is described in more detail below.

Other observers point to lingering concerns over grid connectivity for Chinese wind projects. In late February, the State Electricity Regulatory Commission, or the SERC, issued a report indicating that unused wind-generated electricity for the first six months of last year amounted to 2.8 billion kilowatt hours as a result of poor grid connections and transmission issues. Although the grid connection problem is not new to the Chinese wind sector, the news shows that the measures recently enacted to deal with the issue have been ineffective in the short run.

The difficulties facing Chinese equipment manufacturers are reflected in Sinovel's stock price, which is down more than 20% since its IPO on concerns over increased competition, declining turbine prices and slimmer margins in the domestic wind turbine sector. Although the market may to some extent simply be reacting to an overvalued offer price, it is telling that Goldwind is also down about 25% after its postponed offer raised only about half of the initial target.

Despite these and other issues facing the Chinese wind market, industry observers remain upbeat on the Chinese sector and see China as the key driver of global growth in the industry for the foreseeable future. Therefore, it is becoming increasingly important for wind industry participants from around the world to have an understanding of the factors driving the development of the Chinese market, its legal and policy framework and the dynamics of the market's major project developers and equipment manufacturers.

Policy Support

The foundation for the development of policy support to China's wind sector is the Renewable Energy Law, which was enacted in 2006 and amended in 2009. Consistent with lawmaking in most areas in China, the Renewable Energy Law serves as a framework allowing a number of government agencies to fill in the detail. It is supported by a large number of national, provincial and local policies, implementing regulations and technical standards.

As discussed in detail in the September 2010 issue of the *NewsWire*, the Renewable Energy Law covers four principal areas. First, it calls on the energy authority of the State Council (China's cabinet) to set renewable energy generation targets. Since the enactment of the Renewable Energy Law, the National Reform and Development Commission, or the NDRC, the government's principal economic planning agency, has set economy-wide targets for the reduction of energy and carbon intensity per unit of GDP and specific targets based on renewable energy technology.

However, the development of targets has not kept pace with the development of the market. To use only the most recent example, the target currently in place for wind generating capacity by 2020 (30,000 megawatts) was set only in 2008, but was surpassed in 2010 by a wide margin. The NDRC is reportedly now considering changes to the 2020 targets set out in Table 2, with some observers calling for a target of 230,000 megawatts or perhaps more by 2020.

Table 2

	2006 Actual	2009 Actual	2020 Current Target	2020 Proposed Target
Hydro power	130 GW	197 GW	300 GW	300 GW
Wind power	2.6 GW	25.8 GW	30 GW	150 GW
Biomass power	2 GW	3.2 GW	30 GW	30 GW
Solar PV	0.08 GW	0.4 GW	1.8 GW	20 GW

Source: Eric Martinot, 2010

The second key feature of the Renewable Energy Law is the mandatory market share provisions—known in some jurisdictions as a renewable portfolio standard—that require power companies to meet specified targets for producing power from renewable sources. The *Medium and Long-Term Plan for Renewable Energy Development* published by the NDRC in 2007 provides for an industry-wide requirement of 1% of total power generating capacity from non-hydro renewable energy by 2010, rising to 3% by 2020. On a generator-specific basis, every power company with a capacity of more than 5,000 megawatts must increase its share of installed non-hydro renewable energy capacity to 3% by 2010 and 8% by 2020.

A significant problem with basing the standard on installed capacity and not power generated is that the measures create distorted incentives. The actual performance of projects is not relevant to considering whether the targets have been met, which critics complain has led to inefficient investments. However, the binding effect of the targets has nonetheless created a powerful incentive for the big power generating firms to invest heavily in the development of the wind sector. This is a key reason for its enormous expansion in recent years.

Third, the Renewable Energy Law */ continued page 32*

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MINOR MEMOS. The chairman of the House tax-writing committee said in a speech at a meeting of the Federation of American Hospitals in early March that he will try to repeal a 3% withholding tax that must be collected by vendors on payments they receive from municipalities for goods or services starting in 2012. The tax applies to some power companies selling electricity to municipal utilities . . . . The IRS is re-evaluating when it will allow transactions to be rescinded, Bill Alexander, an IRS associate chief counsel, said at a tax conference in New York in late January. Current IRS policy is to allow rescissions as long as they occur in the same tax year as the original transaction and restore the parties to the same positions as if the transaction had never occurred. This policy is in Revenue Ruling 80-58. Alexander said the agency would continue to honor it until any new guidance is issued . . . . A tax consultancy that claimed to have copyrighted four sets of materials describing ideas that it sells clients for reducing taxes sued two former employees for breach of copyright after they used the same ideas with their own clients. Anyone can copyright written materials by sending two copies and a fee to the Library of Congress. A federal district court in Illinois assigned the case to a magistrate, who was not impressed, and decided the case for the defendants. The case is *International Tax Advisors Inc. v. Tax Law Associates LLC*. The magistrate released her decision in mid-February.

— *contributed by Keith Martin in Washington.*

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requires that grid companies provide grid connections to renewable energy projects within the geographic scope of their grid systems and that they purchase all of the power generated by these projects. However, the reluctance of grid companies to comply with this provision has left, according to various estimates, between 20% and 30% of China's wind projects without a grid connection. This reluctance arose principally because of the cost of providing connections to projects located in remote regions. A large proportion of China's wind energy resources are concentrated in a narrow band of about 200 kilometers along its northern border, far away from its major population and industrial centers. As a result, the cost of extending grid connections is high, as is the risk to grid stability posed by the addition of new and potentially unstable capacity.

The 2009 amendments to the Renewable Energy Law attempted to address this issue through a number of measures discussed in the September 2010 *NewsWire*. However, these amendments are clearly either insufficient or need more time to take effect. As noted earlier, the February SERC report estimates that grid connection problems led to 2.8 billion kilowatt hours of lost electricity in the first six months of 2010 alone.

Finally, the Renewable Energy Law lays the foundation for the enactment of a series of financial incentives, cost sharing measures and pricing arrangements intended to support the economic viability of renewable energy projects and government support of technological development and grid expansion costs. On cost sharing, the main principle reflected in the law is that the incremental cost of renewable power is to be paid by the end user through an electricity surcharge.

Prior to August 2009, pricing for wind power projects was determined primarily on the basis of bid prices submitted in connection with the NDRC's national concession tender process. However, the national concession system was dominated by large state-owned firms that were driven by the mandatory market share requirements to acquire wind generating assets and large enough to be able to subsidize money-losing wind projects with revenue from conventional generating assets. The result was very low tariffs for wind projects, corner cutting by some concession winners under pressure to reduce costs and a low level of private (*i.e.,* non-state-owned) investment in the sector.

In August 2009, the government took a major step toward dealing with these pricing issues by introducing a national feed-in tariff for onshore wind projects. The FIT divides China into four regions based upon the quality of their respective wind resources. The tariffs per kilowatt hour are RMB 0.51 (US$0.077), RMB 0.54, RMB 0.58 and RMB 0.61 (US$0.93) and represent a premium to the national average of RMB 0.34 per kilowatt hour paid to coal-fired electricity generators. The introduction of the FIT brought an end to pricing determined on the basis of the tender process and more certainty in investment decision-making. However, it remains to be seen whether it will lead to increased profitability of wind power projects in the long run.

Other Policy Initiatives

In addition to the Renewable Energy Law and related regulation and policies, the wind sector in China is supported by a number of other policies and initiatives.

Manufacturing Subsidy. The Ministry of Finance created a special fund in 2008 that provides grants to producers of wind turbines in China of RMB 600 (US$91) per kilowatt for the first 50 turbines produced, provided they have a capacity of at least 1.5 megawatts. To qualify for the grant, certain components of the turbines must be produced in China. The intention behind the subsidy was to encourage indigenous innovation in the wind sector. However, it is now the subject of the ongoing WTO consultations between the United States and China concerning its legality under the trade body's rules.

Local and Provincial-Level Incentives. A vast array of pricing and tax support, "soft" incentives and other policies have been adopted at the local and provincial level to attract wind energy equipment manufacturing and project development. Provinces and localities have competed in offering incentives in order to attract high-profile project and manufacturing developments.

Tax Incentives. A favorable income tax rate is available to renewable energy equipment manufacturers, which is among a group of eight "encouraged" high technology industries to benefit from the preferential rates. Under the policy, the preferential rate is 15% for renewable energy equipment manufacturers, as opposed to 25% for businesses in other industries. Project developers can also benefit from the favorable rates. Other tax incentives include a VAT and import tariff rebate available since 2008 on the import of certain wind turbine components. The rebate is available to manufacturers with sales of more than 50 units per year and a capacity of at least 1.2 megawatts, offering a substantial benefit to Chinese manufacturers, the majority of which remain heavily reliant on imports of certain key components.

Wind "Mega Bases." To accelerate growth of an industry with an abundance of existing momentum, the Chinese government in 2009 announced the planned development of seven wind "mega bases" located in the northern provinces of Hebei, Gansu, Xinjiang, Inner Mongolia (2) and Jilin and the eastern province of Jiangsu. Each is expected to have generating capacity of at least 10,000 megawatts, and according to the government's plan, they will collectively contain 138,000 megawatts of installed capacity by 2020, assuming adequate grid connections can be constructed. Development of the mega bases is to take place in phases and construction has begun on each of the seven projects, with some installed capacity already completed.

Offshore Wind Power. One of the areas being watched most closely by industry participants is the recent decision to move ahead with developing China's vast offshore wind resources. The government has been accelerating plans for offshore wind development and expects capacity to reach as much as 5,000 megawatts by 2015 and 30,000 megawatts by 2020. It was only in 2010 that China completed construction of its first offshore wind pilot project.

The *Interim Measures for the Administration of Offshore Wind Power Development* were introduced in 2010 and provide the regulatory basis for the development of the sector. Bidding on the first four concessions located off Jiangsu province concluded in October. The projects were awarded to three of the "big 5" state-owned power generating firms—China Longyuan (a listed subsidiary of China Guodian), Datang and China Power Investment Corporation—and to Shandong Luneng, another state-owned developer. Foreign developers are confined by the measures to holding a minority position in any offshore project.

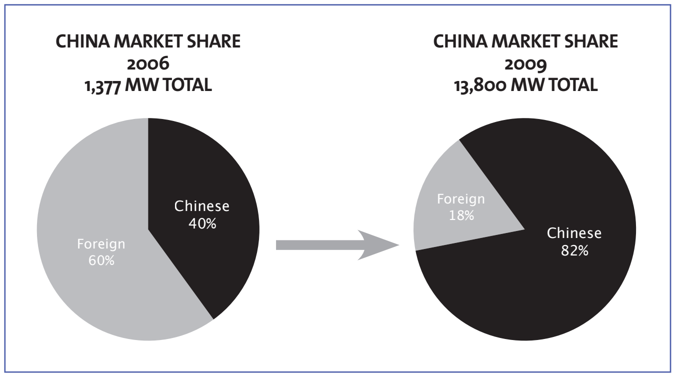
State of the Industry–Equipment Manufacturers

In addition to the overall development of the wind power industry initiated by the policy measures discussed earlier, specific measures aimed at boosting the capacity of the domestic manufacturing industry have contributed to its spectacular growth.

One such measure was the requirement—scrapped in 2009—that 70% of parts and components used in projects developed under China's national concession program be manufactured domestically, though not necessarily by Chinese manufacturers. In addition to incubating the domestic industry, the measure also brought a significant amount of foreign technology and know-how to China. In order to get a piece of the growing market, many foreign manufacturers set up manufacturing bases through joint ventures or wholly-owned Chinese subsidiaries. In addition to this, foreign market participants point to an informal preference for domestic manufacturers among project developers as another key factor boosting their development.

The principal consequence of these factors has been the remarkable growth of manufacturing capacity among domestic firms, both in absolute terms and also as a percentage of total capacity. In 2000, domestic manufacturers' share of the Chinese market was less than 10%. By 2009, this had grown to about 74% for both new and cumulative installed capacity.

Figure 1



Source: Joanne Lewis, 2010

In 2004, there were fewer than five domestic manufacturers of wind turbines. Now there are about 70 at various stages of development from large-scale mass producers to aspiring market entrants, which combined to make China the largest manufacturer of turbines in the world starting in 2009. Conversely, of the approximately 25 foreign manufacturers that have entered the China market at some stage, fewer than 10 remain today. However, those that do remain generally appear to be very committed to the market. Vestas, for example, has constructed the world's largest turbine manufacturing facility in northwest China.

Another consequence of domestic industry support has been the creation of "national champion" manufacturers, which are beginning to expand globally. Three Chinese turbine manufacturers—Sinovel, Goldwind and Dongfang Electric—rank among the world's top 10 manufacturers of turbines in terms of newly-installed capacity. They have done so by dominating the domestic market with 25%, 19% and 15% market share of newly-installed capacity, respectively.

Going forward, market watchers expect / *continued page 34*

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domestic manufacturers to achieve major advances in technological sophistication. All domestic manufacturers—including each of the three "national champions"—rely to some degree on foreign technology licenses. In fact, each of the top five domestic manufacturers license German technology. However, there is a movement towards more homegrown technological innovation, supported by various policy initiatives. There is now a group of 10 to 15 up-and-coming manufacturers capable of mass producing megawatt-scale wind turbines and about 10 more capable of producing megawatt-scale turbines in smaller numbers. Of the up-and-coming domestic manufacturers, about half rely on homegrown technology.

There are now 70 wind turbine manufacturers in China ranging from large-scale mass producers to aspiring market entrants.

Chinese manufacturers have also made large strides in the development of turbine capacity. Sinovel, which just last fall completed its first five-megawatt turbine, announced in February that its six megawatt model would be in production by June 2011 and that a 10-megawatt turbine is under development.

Another focus for the future is expected to be the export market. Pushed by declining growth rates domestically, equipment makers are expected to increase their efforts in this previously neglected market. The anecdotal evidence shows that Chinese manufacturers are already changing focus.

From the perspective of the foreign manufacturers in the domestic market, preliminary steps have been taken to address concerns over discriminatory treatment in favor of domestic manufacturers—for example, the elimination of the 70% local content rule. However, foreign manufacturers will continue to call for more transparency and openness in the concession tender process and for the elimination of preferential incentives directed at building the domestic industry.

State of the Industry–Developers

As with conventional power generation, state-owned firms dominate power generation in the wind sector. All of China's major project developers are state-owned enterprises. China's four developers with more than 1,000 megawatts of installed capacity are all among the "big 5" state-owned power generating firms—China Longyuan (a listed subsidiary of China Guodian), Datang, Huaneng and Huadian. All of the top 15 developers—representing about 80% of capacity—are state-owned or controlled. The dominance of the state-owned sector is the result of a combination of several factors, including mandatory market share provisions and other non-economic influences on investment decisions, easier access to financing from state-owned banks, greater familiarity with the tender and approval process for projects and greater ability to obtain grid connections from state-owned grid companies. Foreign and private investment potential has been left largely untapped, which has meant that a competitive market for wind project development has failed to develop.

A number of factors have led to foreign developers playing a limited role in Chinese wind power projects. The relative dominance of the state-owned sector is discussed above. Another critical barrier has been the inability of foreign-controlled projects to receive approval under China's clean development mechanism rules. Because of historically low pricing levels, many wind projects in China rely on additional revenue generated through the clean development mechanism, or CDM, under the Kyoto Protocol to ensure profitability. About half of China's wind projects are registered under the CDM, which in turn amount to about 40% of those registered worldwide. However, in order to qualify under the CDM, the project developer must be at least 51% Chinese-owned.

Other barriers commonly referred to by foreign market players arise out of the regulatory treatment of foreign investment in China regardless of the industry. The issues include the fact that, despite China's massive foreign exchange reserves, the ability to repatriate funds from China is subject to regulatory approval from the State Administration of Foreign Exchange. In addition, Chinese law requires project developers to structure their investments through a domestic Chinese investment vehicle, which must be capitalized onshore. Limits on the debt-to-equity ratio of a foreign invested entity means that a foreign-owned project company can only borrow approximately 66% of total project costs. In addition to the limitations on leverage, there is limited flexibility in structuring equity investments through Chinese investment vehicles. For example, preferred stock does not exist under Chinese corporate law, which limits the ability to structure a preferred return.

Economic and Environmental Pressures

So what is driving all of this activity in the wind sector? The short answer is that it is being driven by the same factors driving development of wind power capacity around the world. However, the scale and complexity of the Chinese situation requires a separate look.

Most observers are familiar with the rapid pace of China's economic growth since the beginning of the reform era in the late 1970s, with annual growth rates hovering at or around the 10% mark. Maintaining this pace of expansion has required a significant amount of energy, in part because of the structure of China's economy, which has historically relied to a large extent on energy-intensive manufacturing and heavy industry to drive growth. According to the International Energy Agency, China became the world's largest consumer of energy in 2010 (a conclusion China itself disputes), and its energy demand is expected to double during the period from 2005 and 2030.

The rapid increase in China's energy consumption and the energy intensity of its economy have raised two issues that have led policymakers to explore alternative sources of energy. First, China's limited domestic supply of natural resources has led to concerns over energy security. China became a net coal importer in 2007, despite abundant domestic supply, and has been a net importer of oil since 1993. In an effort to address these concerns, China's energy policymakers have pursued the twin goals of expanding access to alternative sources of supply, for example by acquiring overseas resources, and diversifying the energy supply mix, with a principal focus on renewable energy. Despite these efforts, however, China's oil imports have doubled since 2005.

The second consequence of China's rapid increase in energy consumption will be equally familiar to observers. A tremendous strain has been placed on China's environment, the most visible consequence of which is the high levels of air pollution affecting China's cities and industrialized areas. Though it is important to note that per capita carbon dioxide emissions amount to only 33% of the OECD average, China has become the world's single largest emitter of carbon dioxide. The large majority of new power generating capacity is being satisfied through the construction of coal-fired plants and coal-fired generating capacity still accounts for approximately 77% of total.

In response to these and other economic pressures, Chinese policymakers have been focusing on a number of measures aimed a shifting its economy's focus away from manufacturing and heavy industry toward higher value-added manufacturing and services. Policies aimed at stimulating this gradual shift in focus comprise the foundation of what is described by the Chinese government as "scientific development," which has become one of the catchphrases most closely tied to the current President Hu Jintao era.

The renewable energy industry has been a major beneficiary of this policy shift. Investments in the sector have allowed policymakers to encourage the development of clean energy sources while simultaneously promoting its value-added manufacturing sector. The wind sector has naturally benefitted the most. China's long coastline and large land mass contribute to it having abundant wind energy resources.

Although observers have questioned the reliability of the statistics, China appears to have in the range of 1,500,000 and 2,000,000 megawatts of wind energy resources based on the results of a series of government and independent studies. By way of comparison, China's total electric power capacity was 620,000 megawatts in 2006 and 860,000 megawatts in 2009, and according to at least one estimate, capacity is expected to reach 1,600,000 megawatts by 2020. Although wind energy currently accounts for less than 1% of that total, government and industry watchers see it accounting for a larger piece of China's future energy puzzle. ◎

Funding UK Subsidiaries: Debt or Equity?

by Paul White, in London

Foreign companies setting up subsidiaries or intermediate holding companies in the United Kingdom would do better to capitalize them with debt rather than all equity.

There is no simple rule of thumb—for example, three parts debt to two parts equity—in terms of how much debt will be respected by the UK tax authorities. The rules are more complicated.

Recent *NewsWire* articles have explained how the UK tax system has adapted to encourage inward investment. This article considers the form investment may take and, in particular, the differences between long-term debt and equity finance under UK rules.

Tax Rates

The taxation of an equity investment in ordinary UK shares is relatively straightforward. No capital duty is payable on the issue of new shares, stamp duty is chargeable on the acquisition of existing shares at 0.5% of the purchase price, and profits may be distributed without the imposition of withholding tax on share dividends.

On an eventual sale of the shares, a foreign investor would not be liable for UK tax on any capital gain unless, unusually, the shares had been held in a UK branch.

The treatment of the UK company that pays the dividends is also straightforward, although unattractive, in that dividends are not deductible in calculating the taxable profits of the distributing company.

By contrast, the taxation of long-term debt may prove more problematic in part because the ease with which what is actually an equity investment may be dressed-up as an interest-bearing loan.

As with shares, no capital duty is payable on the issue of debt and nor is stamp duty payable on subsequent transfers unless the debt is effectively disguised equity: for example, if the amount of interest payable is determined by reference to the issuer's earnings. Nor would a foreign investor usually be taxed on the eventual disposal, which again is similar to an equity disposal.

The major difference from the investor's perspective is that withholding tax of 20% may potentially apply on interest payable to a non-UK lender. However, there are structuring methods by which the withholding may legitimately be avoided or reduced, and then debt will often be preferable to equity because interest is potentially deductible for tax purposes.

The key is to focus on the avoidance of UK withholding tax and the availability of tax relief for interest expenditure.

Avoiding UK Withholding Tax

A UK company that is neither a bank nor other financial institution is required to withhold income tax equal to 20% of each interest payment made to a non-UK lender unless either the recipient qualifies for relief under a double tax treaty or the European Union legislation, the debt is in the form of a "quoted Eurobond" or the principal is required to be repaid within a year.

The UK is party to more than 100 double tax treaties the majority of which can reduce the required rate of withholding tax, often to 0%. The basic requirements for treaty relief are that the recipient of interest should be resident in the treaty partner state and not a mere branch lender, does not book the advance in a UK "permanent establishment," and is the beneficial owner of the interest. It is this last requirement that has caused some difficulty in recent years.

Since the 2006 *IndoFood* case, HM Revenue & Customs or "HMRC" has actively applied an "international fiscal meaning" to the "beneficial ownership" requirement. This may be a particular concern where the treaty recipient is an intermediate lender. Where a lender is contractually obliged to pass interest on to another party—for example, its parent or a joint-venturer—HMRC may question whether the immediate lender is the beneficial owner of the interest that it receives. HMRC may be expected to look particularly closely at any claim for relief where the recipient is effectively a conduit for a party that would not itself have been entitled to receive gross payment from a UK borrower. An example is where the ultimate lender is based in a tax haven. Until HMRC is satisfied that the treaty requirements are met and issues a gross payment direction, all interest payments should be paid subject to deduction of tax.

Where the immediate lender is not resident in a treaty state or there is doubt about its "beneficial ownership," then consideration may be given to issuing the debt as "quoted Eurobonds," which will require the bonds to be listed on a recognized stock exchange. A significant benefit of the Eurobond exemption is that interest can be paid gross simply by virtue of the nature of the debt obligations so there is no requirement to apply for relief from HMRC. The Eurobond exemption is particularly useful where the debt is likely to be sold on a secondary market or in a securitization structure.

Protecting the Deduction

Since the introduction of the corporate loan relationship regime in 1996, the basic entitlement of a UK corporate borrower to treat interest as a tax deductible expense has been linked to the correct accountancy treatment of the expense and, hence, has been fairly straightforward.

However, the potential to reduce taxable profits by paying interest has inevitably attracted the attention of tax planners and the UK legislation has developed a complicated web of anti-avoidance provisions to deny relief where the investment is disguised equity or where the debt has been structured artificially to reduce the borrower's profits.

The following is an overview of the main provisions that need to be considered when a UK company is debt funded by a parent or other interested party from outside the UK.

Generally, the borrower's entitlement to tax relief for interest should mirror the treatment in its properly prepared accounts as to both timing and quantum. If the UK borrower is connected with the lender, it will be required to use an amortized costs basis of accounting for the purposes of calculating relief. Usually this will mean that the time at which interest is actually paid has no bearing on the period in which it is accrued for tax purposes. However, if the connected lender is resident in a jurisdiction that has not entered in to a double tax treaty with the UK that includes a non-discrimination article, or if the lender is managed from a jurisdiction where it is not subject to tax by reason of residence, domicile or place of management, then tax relief may be delayed until the interest is actually paid. For example, if a Cayman Island parent provides a loan to its UK subsidiary that then fails to pay interest within the 12-month period following the accounting period in which it is accrued in the borrower's accounts, then the tax deduction is deferred until the period in which payment is eventually made.

Quasi Equity

Tax relief for interest may be also be denied or restricted where, in broad terms, the interest has certain characteristics of a return on equity and, in such cases, all or a part of the interest may be deemed to be a distribution of profits.

If the interest represents more than a commercial return for the use of the principal because, for example, the amount due exceeds what would be payable on market terms, then the excess is treated as a non-deductible dividend. (In such circumstances, it would be cold comfort that at least no withholding tax would apply!)Or, if the interest or other consideration given for the loan depends, to any extent, on the whole or any part of the borrower's business, the tax deduction is denied.

Profit Stripping

Although the UK now boasts a competitive corporate tax rate of 28% (which will reduce to 24% over the next four years), when rates were higher it was not uncommon for international groups to seek to reduce their UK taxable profits by, for example, paying artificially high rates of interest to an offshore lender subject to a lower tax rate in its jurisdiction. Historically, UK governments have tended to respond to avoidance schemes on a piecemeal basis, so there are now a number of overlapping provisions all aimed at preventing the artificial manipulation of debt liabilities designed to reduce taxable profits.

The loan relationship regime contains a number of targeted anti-avoidance rules.

For example, interest is only deductible to the extent it is "arm's length," which the legislation achieves by applying an "independent terms assumption." In effect, the quantum of interest is deemed to be what it would have been if the lender and borrower had been "knowledgeable and willing parties dealing at arm's length." Because of the potential for this provision to overlap the general transfer pricing rules, it is effectively disapplied where that is the case.

Also, the corporate debt regime includes a "targeted anti-avoidance rule." In a case where a loan has an "unallowable purpose," the borrower will be denied a tax deduction to the extent that interest is "on a just and reasonable apportionment" attributable to the unallowable purpose.

In addition to targeted loan relationship rules, the UK also has a general statutory transfer pricing regime that includes thin capitalization restrictions. The combined effect of these potentially overlapping provisions is that the UK corporate borrower may only recognize for tax purposes the funding costs it would have incurred had it borrowed on market terms from an unconnected lender.

The broad objective of the statutes is to prevent the UK company from obtaining tax relief for interest that exceeds what would have been due on an arms-length basis. Accordingly, the rules may bite even where */ continued page 38*

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the debt carries only a market rate of interest if, for example, the principal by reference to which the interest is charged exceeds what an independent lender would have been prepared to advance. For these purposes, the borrower's market standing and credit worthiness are to be ascertained without reference to its position in any group of which it may be a member.

Debt Cap

Perhaps the most significant recent legislative change that increased the attractiveness of the UK as a location for intermediate holding companies was the introduction of a "participation exemption." In most cases, foreign dividends received by UK companies will no longer be taxed in the UK.

However, to limit the opportunities for the exemption to be used for tax avoidance, the UK has also introduced a worldwide "debt cap." In broad terms, the entitlement of a UK group member to treat interest as deductible is limited by reference to the external debt obligations of the whole group.

The bottom line is that the ease with which withholding tax can be avoided and the potential for interest to be tax deductible means that, solely from a UK tax perspective, debt funding of UK companies is generally preferable to equity investment. But the UK has a mature anti-avoidance environment, which is continuing to evolve, with a "general anti-avoidance rule" currently under consideration. So the scope for structuring interest obligations so as artificially to avoid tax or to replicate a quasi-equity return is extremely limited, and any such structuring should only be undertaken with appropriate professional guidance. ◎

Environmental Update

Wind developers in the United States are concerned that two sets of guidelines that the US Fish and Wildlife Service issued in draft form in February could stall or significantly curtail further wind development on land.

Land Guidelines

One of the new proposed guidelines suggests what developers can do voluntarily to minimize the effects of new wind farms on fish and wildlife. The draft land guidelines, as they have come to be known, supersede interim voluntary guidelines under which the wind industry has been operating since July 2003.

The land guidelines suggest what developers should do to comply with three federal environmental statutes—the Endangered Species Act, the Migratory Bird Treaty Act and the Bald and Golden Eagle Protection Act.

The Endangered Species Act makes it unlawful to "take" any endangered or threatened species. "Take" is defined in the statute as "harass, harm, pursue, hunt, shoot, wound, kill, trap, capture or collect, or attempt to engage in any such conduct." Violations can lead to civil fines or, in extreme cases, imprisonment. In limited circumstances, the Fish and Wildlife Service may authorize the "taking" of protected species by issuing an incidental take permit.

Another statute is the Migratory Bird Treaty Act. It applies to more than 1,000 species of birds (including bald and golden eagles) and makes it illegal, among other things, to take, capture, kill or possess those species, unless specifically authorized by the Fish and Wildlife Service. There is currently no means to obtain a permit to take these species pursuant to an otherwise lawful activity. Violators risk fines and jail time of up to six months. In 2009, PacificCorp, a large utility, pled guilty to violations from electrocutions of migratory birds (including 232 golden eagles over roughly two years) on its power lines and agreed to pay more than $1.4 million in fines and restitution and spend an additional $9.1 million to repair or replace equipment.

In the past, many wind developers determined the design, scope and duration of avian and other wildlife assessments with the assistance of a wildlife consultant, but without consulting the Fish and Wildlife Service, except when such consultation was legally required.

The new land guidelines suggest that wind developers consult with the Fish and Wildlife Service "prior to any financial obligation or finalization of lease agreements to allow for the greatest range of development and mitigation options." In general, developers are encouraged to conduct multi-season, multi-year studies using a step-by-step process to assess potential risks to wildlife and determine how best to address them. The land guidelines suggest "three years of pre-construction studies may be appropriate in many circumstances." The government also expects at least two years of post-construction monitoring to help evaluate the effects on wildlife. These recommendations were largely unexpected by the industry.

The wind industry had asked for a phase-in period to give developers in the middle of planning or constructing projects time to adjust. The Fish and Wildlife Service did not adopt this recommendation and instead made the guidance effective on February 18, 2011, even though public comments are being accepted until May 19, 2011.

Eagle Guidelines

A second set of draft guidelines that also has the wind industry worried relates to eagles. These guidelines are supposed to help wind energy project developers and operators prepare eagle conservation plans as part of the process to obtain permits under the Bald and Golden Eagle Protection Act.

That statute prohibits the taking of bald and golden eagles unless otherwise authorized. Violators risk civil penalties and jail time of up to one year for the first conviction. Felony convictions could result in significantly higher fines and up to two years of jail time.

The Bald and Golden Eagle Protection Act is broader than the Migratory Bird Treaty Act because it also prohibits certain indirect effects on eagles. The word "take" is defined more broadly to include acts that merely "disturb" such birds, defined in turn under Fish and Wildlife Service regulations as any action "to agitate or bother a bald or golden eagle to a degree that causes, or is likely to cause, based on the best scientific information available, (1) injury to an eagle, (2) a decrease in its productivity, by substantially interfering with normal breeding, feeding, or sheltering behavior, or (3) nest abandonment, by substantially interfering with normal breeding, feeding, or sheltering behavior."

The Fish and Wildlife Service was authorized to issue permits to take bald eagles before November 2009 in connection with a very limited number of activities. In November 2009, agency started allowing "programmatic" or blanket take permits to take bald and golden eagles where the take is associated with, but not the purpose of, an activity. These permits are effective for up to five years at a time. Obtaining this type of permit triggers the National Environmental Policy Act, which requires a review of the environmental effects of a particular project. This means that many projects that normally would not trigger National Environmental Policy Act in the past—for example, because they are on private land with no federal nexus—need to go through the NEPA environmental review process.

The draft eagle guidelines provide step-by-step procedures to characterize and then mitigate the risk a wind farm poses to eagles. If a potential project site is not excluded during initial screening efforts, then the Fish and Wildlife Service recommends that the developer do eagle point counts twice a month during each season for at least two years and preferably for three years, identify nesting populations within 10 miles of the perimeters of the proposed project site, and determine whether any seasonal concentrations of eagles may be present in the area. Assuming that a site is suitable for development, the next step is to develop "advanced conservation practices" to minimize the effect on eagles. Examples of such practices during construction include minimizing the footprint of construction and stopping work if nearby nesting eagles show signs of distress. Examples of recommended practices during operation include controlling rodents, rabbits and other potential eagle prey on site and installing bird deterrent systems.

The government wants post-construction monitoring of eagle fatalities for a least three years and ideally for five years (longer if take permits are renewed), and monitoring of eagle nesting and roosting sites may also be required for at least three years. Post-construction monitoring may lead to additional mitigation measures like seasonal or daily turbine shut downs.

Although the draft eagle guidelines are really targeted at the earliest stages of project development, they say developers "with operating or soon-to-be operating facilities at the time the draft guidance was first released" should coordinate with the Fish and Wildlife Service if they are interested in obtaining a programmatic eagle take permit. The first set of guidelines—the draft land guidance—also recommends that existing projects and projects already far down the development path implement those portions of the draft land guidance that apply to the remaining phases of those projects. The Fish and Wildlife Service said it will view compliance with the new guidelines as evidence of good faith when deciding whether to impose fines or other penalties for violations of the environmental statutes the new guidelines address.

Some lenders can be expected to make compliance not only a diligence item but also a condition to continued draws on construction debt. They may also require consultation with the Fish and Wildlife Service, particularly where projects may pose a higher-than-average risk to wildlife as well as where projects have limited pre-construction wildlife assessments.

Boilers

The Environmental Protection Agency released final rules to regulate emissions of hazardous air pollutants from boilers and process heaters at at large power */ continued page 40*

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plants and factories—so-called major sources of hazardous pollutants—in February as well as a separate set of rules regulating such emissions from boilers and process heaters at smaller sources, sewage sludge incinerators and commercial and industrial solid waste incinerators. It then announced that it would begin a process to reconsider certain provisions of these rules.

It also proposed a new definition for the term "solid waste."

The new definition of "solid waste" is important because any incinerator burning "solid waste" is subject to more stringent air emissions requirements. Under the new definition, materials that are considered discarded would continue to be considered solid waste unless reprocessed in a manner that turns the material into a legitimate fuel. Traditional fuels like coal, oil and natural gas are not considered solid waste under the proposed definition.

"Major sources" of hazardous air pollutants are those that emit or have the potential to emit 10 or more tons per year of a single hazardous air pollutant or 25 or more tons per year of any combination of hazardous air pollutants. Boilers at such facilities considered major sources burn fuels like coal, natural gas and biomass to produce steam or heat. Process heaters are used to heat certain materials as part of an industrial process.

New and existing sources with heat capacities of less than 10 million British thermal units per hour (MMBtu/hr) or that are fueled by natural, refinery or equivalent gas are not subject to numeric emissions standards. Instead, such sources must comply with certain work practice standards, like periodic scheduled tune-ups of units.

The new rules also impose work practice standards for new and existing boilers that are operated less than 10% of the year as emergency or back-up boilers. The new boiler rules provide numeric emissions standards for all other existing and new boilers that are located at major sources of hazardous air pollutants. Compliance with these standards will require the use of the "maximum achievable control technology" or "MACT" to control emissions of mercury, dioxin/furan, particulate matter (used as a surrogate for certain metals), hydrogen chloride and carbon monoxide.

The boiler rules are not expected to take effect for existing units covered by the numeric emissions standards until 2014, unless implementation is delayed. They are attracting a lot of criticism from industry and Congress.

— contributed by Sue Cowell in Washington.

Chadbourne & Parke LLP
30 Rockefeller Plaza
New York, NY 10112
+1 (212) 408-5100

1200 New Hampshire Ave., NW
Washington, DC 20036
+1 (202) 974-5600

350 South Grand Ave.
32nd Floor
Los Angeles, CA 90071
+1 (213) 892-1000

Chadbourne & Parke SC
Paseo de Tamarindos, No. 400-B Piso 22
Col. Bosques de las Lomas
05120 México, D.F., México
+ 52 (55) 3000-0600

Av. Pres. Juscelino Kubitschek, 1726,
16th floor
São Paulo, SP 04543-000, Brazil
+55 (11) 3372 0000

Beijing Representative Office
Room 902, Tower A, Beijing Fortune Centre
7 Dongsanhuan Zhonglu, Chaoyang
District
Beijing 100020, China
+86 (10) 6530-8846

Dostyk Business Center
43 Dostyk Avenue, 4th floor
Almaty 050010, Republic of Kazakhstan
+7 (327) 258-5088

Riverside Towers
52/5 Kosmodamianskaya Nab.
Moscow 115054 Russian Federation
+7 (495) 974-2424
Direct line from outside C.I.S.:
+1 (212) 408-1190

25B Sahaydachnoho Street
Kyiv 04070, Ukraine
+380 (44) 461-75-75

Chadbourne & Parke
Radzikowski, Szubielska and Partners LLP
ul. Emilii Plater 53
00-113 Warsaw, Poland
+48 (22) 520-5000

Chadbourne & Parke LLC
City Tower I, Sheikh Zayed Road
P.O. Box 23927, Dubai, United Arab Emirates
+971 (4) 331-6123

Chadbourne & Parke (London) LLP
Regis House
45 King William Street
London EC4R 9AN, UK
+44 (0)20 7337-8000