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The Year Ahead: What to Expect from Washington

The Obama administration got off to a rousing start in 2009 with visible momentum for its programs. Many private equity fund investors came through Washington early in the year in an effort to keep an ear to the ground, since policy changes make winners and losers among investors. The financial capital seemed to shift to Washington. As the year ended, the gears of government seemed full of sand. Congress was gridlocked over health reform. The financial markets were making a gradual recovery. Republicans picked up a key Senate seat in Massachusetts that sent shock waves across the Capitol.

Nevertheless, many key issues that have the potential to make or break energy investments remain in play in Washington. Five veteran Washington lobbyists talked in mid-January about what to expect in 2010 as part of a webinar organized by Infocast. They are Joe Mikrut, a partner with Capitol Tax Partners, a premier lobbying shop for tax issues, Aaron Severn, director of federal legislative affairs for the American Wind Energy Association, John Shelk, president and CEO of the Electric Power Supply Association, the trade group for the US independent power industry, Jaime Steve, Washington office head for Pattern Energy, a US wind developer that spun off in 2009 from Babcock & Brown, and Jonathan Weisgall, vice president for legislative affairs for MidAmerican Energy Holdings Company, a large holding company with utilities in eight US states and the United Kingdom. The moderator is Keith Martin with Chadbourne in Washington.

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PRESIDENT OBAMA asked Congress, in the budget he submitted on February 1, to extend a 50% "depreciation bonus" for another year through December 2010.

This improves the odds that the benefit will be extended, perhaps as part of a "jobs" bill sometime between February and May. Any extension would be retroactive to January 1.

The President's budget is not automatically adopted in the United States, even when his own party controls Congress, unlike in countries with parliamentary systems.

The depreciation bonus would reward companies */ continued page 3*

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MR. MARTIN: Jon Weisgall, there has been talk that the Democrats, who control Congress, will draw up a "jobs II" bill early this year to deal with high unemployment. Will there be a "jobs II" bill?

MR. WEISGALL: Absolutely, yes. It may end up a massive bill with a lot folded into it.

MR. MARTIN: Jamie Steve, was there a "jobs I" bill and, if so, what was it?

MR. STEVE: There was, but it was essentially just an exercise in more proposed stimulus spending by the House. The Senate isn't expected to take it up given the growing concern about the federal budget deficit. There is pressure for another jobs bill, but it is not a foregone conclusion that there will be one. Parts of jobs I may be folded into any jobs II bill.

MR. MARTIN: Aaron Severn, was there anything in jobs I of interest to the wind industry?

MR. SEVERN: There were a number of items of interest, but the most important was probably restoration of $2 billion that was taken out of the Department of Energy loan guarantee program for renewable energy projects to fund the cash-for-clunkers program last August.

MR. MARTIN: Jon, what items of interest are in play for possible inclusion in the jobs II bill?

MR. WEISGALL: If we get an energy bill this year, it may end up as an add on to the jobs bill. The real question is whether we will get both an energy bill and a climate change bill this year and, if the answer is just an energy bill, then that is where I think you will see it, combined with jobs.

MR. MARTIN: Joe Mikrut, I am starting to get the feeling that jobs II will end up as the legislative vehicle for most of what remains of the domestic agenda this year.

MR. MIKRUT: I think that's right, and I think it will include some tax provisions, like an extension of depreciation bonus, that help stimulate investment and put people back to work. It may also include more money for the section 48C investment tax credit — a 30% tax credit for building new factories that make products for the green economy — and perhaps some modifications to the 30% Treasury cash grant program for renewable energy projects.

A carbon bill is well short of the 60 votes needed to pass the Senate, and may even be short of 50.

MR. MARTIN: What's the timing for jobs II?

MR. MIKRUT: Health care will be the main focus until it either gets enacted or jettisoned. Then there is the temporary spending authority for a large number of federal programs that expires on February 28 and must be addressed. After that, I think we are into March before we start to see consideration of a jobs II bill.

MR. MARTIN: Does everyone agree about the timing?

MR. WEISGALL: I think that's optimistic. The other big item that will take up time is financial sector regulatory reform, and that's not expected to emerge from committee in the Senate before late February and will probably not get to the Senate floor until early April. But, look, we are all reading the same tea leaves — certainly sometime in the spring for the jobs bill.

MR. STEVE: I agree with that. I think Joe was offering the most optimistic scenario. As Ronald Reagan once said years ago, anybody whose ever had his kitchen redone knows it takes longer to get things done than originally planned.

MR. WEISGALL: All of this has to be seen through the lens of growing dissatisfaction by the public with what it perceives as major government activism and big government solutions — whether it is the bank bailouts, auto bailout or health care, anger with the stimulus bill and anger with the soaring deficit. Congress has limited room to act. Whatever it does will have to be sold as a jobs measure.

MR. SHELK: I want to underscore what Jon just said because it is spot on. We are all focused on our individual wish lists of items we want to get into any jobs bill, but those of us on the two coasts underestimate the degree of public anger. Anything that looks like a subsidy for business, including some of the things we have just been talking about, will have a tough time getting through Congress, even if presented with a jobs spin.

Treasury Cash Grants

MR. MARTIN: Aaron Severn, one program of great interest to renewable energy developers is the 30% Treasury cash grants for new renewable energy projects that get under construction by the end of this year. What is your trade association telling its members about whether the deadline to start construction will be extended and, if so, when?

MR. SEVERN: Obviously, that is a huge priority for us. We think it is possible it will be extended as part of a jobs bill, but the problem is it is still not clear whether the tax committee staffs in Congress see the need to extend it before it is closer to expiring at year end. They like the stimulative effect of a short deadline.

MR. MARTIN: Jamie, is it clear that the deadline will be extended and it is just a matter of when?

MR. STEVE: I think so. The big question is not only when, but also for how long. What we have heard from the committee staff is they are comfortable with the program; they like it for a number of reasons, including that it costs the government less than production tax credits cost. If I had to put money on when it will be extended, I would bet not until late in the year.

MR. MARTIN: Joe Mikrut, if the cash grant program is extended, will it just be the deadline to start construction or will Congress also extend the deadlines to complete projects — currently 2012 for wind farms, 2016 for solar and fuel cell projects, and 2013 for other renewables? Also, how long of an extension do you expect for the construction start date?

MR. MIKRUT: I think only the construction start date will be extended. Congress usually extends expiring programs only for a year at a time. An extension or elimination of the construction date through 2012 is possible because that would match up with when production tax credits — for which the cash grants are a substitute — start to expire. An extension through 2012 should not have much revenue effect. A longer extension of the credit itself would add significantly to the budget deficit.

MR. MARTIN: Timing?

MR. MIKRUT: Late in the year. Congress generally acts when Congress needs to act — if not later.

MR. MARTIN: You said that you think the 50% depreciation bonus is likely to be extended as part of any jobs II bill. True?

MR. MIKRUT: Yes. It has only a modest / continued page 4

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investing in new equipment in 2010 by letting them deduct 50% of the cost immediately for tax purposes. The other 50% is depreciated normally.

The benefit is worth between 2.61¢ and 8.98¢ per dollar of capital cost in tax savings, with the higher savings on transmission lines, conventional power plants and other assets that would otherwise be depreciated over long periods. Such long-lived assets could be completed as late as 2011 under the Obama proposal and still qualify for a bonus, but the bonus would only be calculated on spending through December 2010.

Other energy facilities — like wind farms, solar and geothermal projects that are normally written off over five years — would have to be completed by December 2010 to qualify. The bonus on such projects would be only 42.5% in practice — not 50% — because only 85% of the cost of such projects can be depreciated if the owner also will receive a Treasury cash grant for 30% of the project cost. Most owners of such projects built in 2010 are expected to receive such grants.

Obama also asked Congress to allow another $5 billion in tax credits to be claimed by companies that build new factories to make wind turbines, solar panels and other products for the green economy. The tax credits are 30% of the factory cost. Anyone wanting to claim such credits must apply to the Internal Revenue Service for an allocation. The economic stimulus bill in February 2009 authorized $2.3 billion in such tax credits. Applications to the IRS for the credits were more than three times this amount. The IRS would allocate the new credits over the next two years.

This proposal has considerable support in Congress, although solar manufacturers have been urging Congress to move the credit to a different section of the US tax code that would let them claim it without having to apply for an allocation and without any cap.

The President proposed again that Congress tax hedge fund and private equity fund managers on the value of carried interests they receive in exchange for their services at ordinary income rates. The interests are inter- / continued page 5

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revenue effect and the Obama administration is now calling on Congress to extend it.

MR. MARTIN: You also said that you think the jobs bill will provide more money for a 30% tax credit for building new factories that make wind turbine blades, solar panels and the like. Congress provided $2.3 billion in such credits as part of the stimulus last year. The IRS allocated all the credits in early January. How much more money do you think Congress will provide for it?

MR. MIKRUT: I think it will provide close to what the vice president requested, which is another $5 billion for the program. The $5 billion is roughly the dollar value of the qualified applications that the IRS received, but could not fund.

MR. MARTIN: The House voted in December to extend a large number of expiring tax benefits for one year, including tax credits for biodiesel and renewable diesel, but not ethanol. What will happen to the ethanol credits, and what will happen to the extenders bill as a whole?

MR. MIKRUT: The House bill addresses provisions that expired on December 31, 2009; ethanol expires after 2010. In addition, ethanol has always been much more popular in the Senate than in the House. The House knows that, so it is easy to omit it and then negotiate with the Senate. I expect to see an ethanol extension in a final bill, perhaps later in the year. With respect to extenders in general, a lot of the tax benefits expired at year end, like the R&D tax credit, other fuels credits and some important international tax provisions. Congress has let these provisions expire in the past and has then extended them retroactively. My bet is the 2009 extenders will be folded in with the spending authority that Congress has to address by February 28. The 2010 extenders likely will be addressed later.

DOE Loan Guarantees

MR. MARTIN: Next topic — DOE loan guarantees. Aaron Severn mentioned earlier that $2 billion of the $6 billion loss reserve that Congress set aside last year in the stimulus to fund federal loan guarantees for renewable energy projects that use commercially-proven technologies and large transmission projects was taken away to spend on the cash-for-clunkers program. The money would be restored as part of the jobs I bill, but the consensus was jobs I isn't going anywhere. How and when does this money get restored?

MR. SEVERN: No one knows yet. All we know is that there have been public commitments by Obama, Pelosi and others to restore the funding.

Mr. MARTIN: John Shelk, the Department of Energy is taking a lot longer than Congress hoped to write any loan guarantees, and many developers have given up on the program. Is the situation attracting much attention on Capitol Hill?

MR. SHELK: The short answer is that Congress should be concerned. The department has had authority to write loan guarantees for projects using innovative technologies since August 2005. Years have passed and, if I am not mistaken, only one guarantee has been issued. The frustration in Congress with this chronic lack of action by the department can be seen in proposals to create a clean energy bank modeled on the US Export-Import Bank or Overseas Private Investment Corporation and moved outside the DOE bureaucracy. A lot of hardworking people at DOE have labored through two administrations to stand up the program, but there is just something wrong. There is frustration in Congress, as there should be.

MR. WEISGALL: The trade off is how long does it take to set up an entirely new agency versus give a kick in the pants to DOE. We have a Secretary of Energy who is painfully aware of the history here and who really does want to get the program moving. I think most lobbyists are concluding reluctantly that it is better to try to make the existing program work within DOE than to start over with an entirely new agency.

Climate Change

MR. MARTIN: The Copenhagen conference was a disappointment to many. Will the Senate vote on carbon controls this year? The House already passed a cap-and-trade regime in late June last year. If the Senate doesn't act on it this year, when do you see Congress enacting a carbon bill?

MR. SEVERN: I don't see the Senate tackling carbon this year unless Senate leaders feel they can get 60 votes, and they don't have them today.

MR. MARTIN: Jaime Steve, in what year do you think Congress will deal with carbon?

MR. STEVE: This is a huge priority for the Obama administration. I think they will try like hell to get it done this year while they are still at a high water mark in terms of the number of Democratic votes in the House and Senate.

MR. SHELK: As a trade association, we would like to see Congress tackle carbon sooner rather than later. We can deal with a clear set of rules; it is uncertainty that is a problem.

Being realistic, I think the other comments are right on the mark. If the vote were today or any time soon, the carbon bill is well short of the 60 votes it needs to pass the Senate. I have even heard speculation it may be well short of 50.

Your question assumes that if it doesn't happen in 2010, then it will happen in 2011 or 2012. I don't think that is a fair assumption for two reasons. First, we don't know how the elections will turn out and, if there is a substantial shift in Congressional seats to the Republicans, then all bets are off and we move perhaps to a whole new way of approaching the topic. Second, as you said, Copenhagen was a disappointment and what happens this year in the international arena will affect how much appetite there is in Congress to tackle the issue. If the international aspect doesn't come together better than it has thus far, a cap-and-trade bill will be very tough for Democrats in marginal seats to swallow.

MR. MARTIN: Jon Weisgall, has there been a shift in the politics of global warming? Is the pressure to act increasing or decreasing?

MR. WEISGALL: Let's start with Copenhagen — vague emission commitments, no timetable, no specific cuts, China played hardball, and no agreement on independent international verification of emissions reductions, which is a huge issue for the Senate.

The most you can say about Copenhagen is that, while it was not a complete disaster, it certainly left the US Senate without any increased sense of urgency to act.

So that's your starting point.

I was with the Senate majority leader, Harry Reid, in New York this week. He gave a speech to a group of geothermal developers. He seemed resigned to giving up on climate control this year. He didn't say it outright, but he talked about trying to muster 60 votes and he praised Senator Kerry for trying to broker a deal with Republicans, but he doesn't see those votes. I don't see the votes.

I think you really have to rethink the whole thing right now. One option is a cap-and-trade bill like the Waxman-Markey bill that passed the House last June. A second approach is an energy-only bill that uses other tools, like continuing to encourage the shift to more renewable sources of energy as way of reducing greenhouse gas emissions without a cap-and-trade program. A third option that is definitely going to happen is the Environmental Protection Agency has started using its existing regulatory authority to limit greenhouse gas emissions. A fourth option is to look for a set of

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ests in future profits. The managers are able to pay taxes on what is essentially compensation at reduced tax rates for long-term capital gain by selling the interests after holding them for at least a year. The proposal is not likely to pass Congress.

Obama also took aim at tax deferral by US multinational corporations on their earnings from offshore subsidiaries, but backed down from tougher proposals — that were not enacted — in the budget last year.

Under US tax rules, all borrowed money is considered fungible. If a US parent company borrows in the United States, a portion of the interest is considered a cost of its foreign operations in the same ratio that its assets are deployed in the US and abroad. This has the effect of making it harder for the US company to credit taxes it pays to other countries against its US income taxes. It can only claim credit for such taxes to the extent of the taxes the US would have collected on the company's foreign earnings. To the extent that its domestic borrowing in the United States is considered a cost partly of its business operations in India, for example, that means the company is considered to have earned less in India and this reduces its ability to credit taxes paid in India against its taxes in the United States.

Nevertheless, the full interest paid by the US parent is *deductible* when computing its US income taxes.

Obama asked Congress to allow any interest treated as a cost of foreign operations to be deducted only when the foreign earnings are repatriated and taxed in the United States. This would not prevent US companies from deferring US taxes on foreign earnings by keeping the earnings offshore, but it would reduce the benefit from deferral and complicate tax calculations.

The budget also attacks a growing trend by US companies to move intellectual property into offshore holding companies in places like Ireland and Luxembourg as a way of keeping a share of earnings outside the US tax net. It would treat the "excessive" after-tax returns earned by such holding companies as "subpart F income," meaning that the United States would look

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completely new approaches. I think the politics are moving away from a Waxman-Markey, 1,400-page, Rube Goldberg, cap-and-trade system.

MR. MARTIN: Joe Mikrut, there has been more talk in the last few months about a carbon tax as a more direct way to limit carbon emissions. Do you see it gaining momentum?

MR. MIKRUT: Almost everyone agrees that a carbon tax would be more efficient and easier to administer, but I don't see it having any renewed momentum. There are too many people still here who remember the House Democrats who lost their seats after voting for the Btu tax proposed by the Clinton administration.

MR. MARTIN: Jon Weigall, you suggested one approach is to let the negotiations among Senators John Kerry, Joe Lieberman and Lindsay Graham play out. Where are they headed? Are they headed toward a big, 1,400-page cap-and-trade system?

MR. WEISGALL: Good question. They started with a very dramatic op-ed piece in *The New York Times* in mid-October and we haven't really seen anything since then. There seem to be three key elements to whatever they are trying to do, all under the umbrella of energy independence. They are offshore drilling, a stronger nuclear industry and then something called climate change. The problem is Lindsay Graham's idea of a workable climate change plan is nothing like John Kerry's idea of a workable plan, and only God knows where Joe Lieberman is. It is now coming up on three months after the op-ed piece and we haven't seen a white paper. I don't give it a great chance of success.

This year is do or die for a national renewable energy standard.

MR. MARTIN: Aaron Severn, the House passed a cap-and-trade bill in June that would require a ratcheting down of US carbon emissions compared to 2005 levels. Do you recall the targets?

MR. SEVERN: Carbon emissions would have to be 3% below 2005 levels by 2012 and fall to 83% below 2005 levels by 2050.

MR. MARTIN: There are two levers the government has in a cap-and-trade system to affect emissions. One is the limit it sets on total emissions and the other is a requirement for anyone emitting carbon to have allowances to cover his emissions. The House set a cap, but then gave away most of the allowances for free, at least through the middle of the next decade, as a transition measure.

MR. STEVE: That is just a fact of life. It is how these bills move through Congress. The emissions cap still has meaning in the meantime.

MR. MARTIN: Senator Maria Cantwell was working on a different approach to cap-and-trade. I believe she proposes to have the government sell all the allowances but then turn 75% of the money back to US consumers. The other 25% would be used to fund research or projects that use new technologies. Is that her approach and does her bill have any legs?

MR. SHELK: She and Senator Susan Collins have introduced a bill that would regulate carbon upstream, not downstream like in the cap-and-trade bill that passed the House, so producers of coal and other types of fossil energy would buy allowances rather than require power plants that use the coal or other fossil energy to do so. They want all the allowances auctioned by the government. One thing you can say about a 100% auction is that you don't get into the food fight we saw over the allocation of allowances in the House. Trading in allowances would be restricted to regulated entities, so Wall Street would be largely frozen out. There would be a cost collar, both a floor and a ceiling on how much the price for allowances could vary. The approach is as close to a carbon tax and you can get without calling it a tax.

Does the approach have legs? Senator Lisa Murkowski, the senior Republican on the Senate energy committee, had nice things to say about it. It is a fascinating new approach. It runs only 39 pages.

MR. MARTIN: Perhaps summing up, it sounds like there won't be a combined carbon and energy bill, but just an energy bill and no carbon bill.

National RES

MR. WEISGALL: That's how I read it. Senator Reid will have to decide, but he faces a carbon bill on the one hand that is clearly short on votes, and an energy bill, on the other, on which the Senate energy committee worked for more than 12 weeks, before reporting it to the full Senate. It cleared the committee in June last year with five Republican votes.

It would require utilities to supply 15% of their electricity from renewable energy, although a quarter of the goal can be met by taking efficiency measures to reduce electricity demand. That's huge for the renewable energy industry. A federal RPS would do more for the industry than a cap-and-trade bill in terms of increasing demand for electricity from wind farms, solar panels and other renewable energy facilities.

If the Senate can get transmission planning and cost allocations straightened out, some liability protection for carbon capture and sequestration and even some provisions to encourage offshore oil and gas leasing, then you have yourself the makings of a pretty comprehensive energy bill that, even though it lacks cap-and-trade provisions, certainly offers tools to reduce greenhouse gas emissions. If Reid decides to let go of climate change, the odds of getting an energy bill through the Senate are pretty good this year.

MR. MARTIN: Aaron, the energy bill the House passed last June also had a federal renewable energy standard. Do you recall the percentages and when the program would go into effect? This is a requirement that utilities supply a certain percentage of electricity from renewable sources.

MR. SEVERN: The House bill requires that 6% of US electricity come from renewable energy by 2012, increasing to 20% in 2020. But there is lots of fine print. For one thing, it only applies to utilities that generate four million megawatt hours of electricity a year. Part of the standard can be met through efficiency measures. There is also the problem that some types of electricity generation, like from nuclear power plants, are taken out of the denominator in the fraction, which reduces the megawatt hours of renewable electricity required in the numerator. However, the House bill is stronger than what came out of the Senate energy committee. The Senate bill sets a standard of 3% in 2011 and increases to 15% in 2021.

On the House side, up to a quarter can */ continued page 8*

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through such holding companies and tax the US shareholders on the excess returns directly.

Congress is not expected to tackle foreign tax reform this year, although with US budget deficits now running to 11% of US gross domestic product, some form of tax increases are considered inevitable in the long run.

Obama would reinstate a top US tax rate of 39.6% on ordinary income and 20% on capital gains for higher-income individuals by letting Bush-era tax cuts that reduced the top individual rate to 35% and the capital gains rate to 15% expire at the end of this year.

The budget would also scale back a series of tax benefits for production of oil, gas and coal, following through on a promise the President made at the G-20 summit last year in Pittsburgh. However, such proposals lack broad support in Congress.

UNCERTAIN TAX POSITIONS would have to be identified on a schedule filed with corporate tax returns in the future under a new Internal Revenue Service proposal.

The IRS commissioner, Douglas Shulman, made the proposal at a meeting of the New York State Bar Association tax section in late January. Lee Sheppard wrote in *Tax Notes* magazine: "The silence in the room was palpable. The commissioner left without taking questions."

The IRS wants corporations with assets of more than $10 million that are already required by FIN 48 or other accounting rules to disclose uncertain tax positions in their financial statements to attach a schedule to their annual tax returns with a concise statement of each uncertain position, the reason for the uncertainty, and the amount of additional taxes the company would have to pay if the position were disallowed in whole.

The IRS wants comments by March 29. The proposal is in Announcement 2010-9.

Shulman argued that this will help IRS agents zero in more quickly in audits on where they should spend their time. Some speculate agents will be able to save even more time by simply disallowing all the positions the company identified.

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be met through energy efficiency. However, the House would also allow the governor of each state to petition to allow up to 40% efficiency measures. On the Senate side, efficiency measures can be used to meet up to 26% of the target.

MR. MARTIN: Jaime Steve, what are you telling your CEO at Pattern Energy about whether Congress will enact a national renewable energy standard this year?

MR. STEVE: If it doesn't happen this year, it will not happen. The House is at 20%. The Senate is at 15%. Maybe they will come out somewhere in between.

MR. SHELK: I agree that it will either happen this year or not at all, but I think it will be difficult to get through the Senate. You have a very well-financed natural gas coalition that will find it hard to swallow the notion that the federal government should carve out a portion of the electricity market for any one fuel. I don't think the nuclear folks will be happy, either. The coal folks will not be happy. The odds are against anything happening this year.

MR. WEISGALL: John Shelk is absolutely correct. A large part of the south will fight a federal RPS and will view it as a wealth transfer from the south to places like California that already have lots of renewable energy.

MR. STEVE: Everything you said is accurate and nothing is easy around here, but let's not lose sight that the President is for it, the speaker of the House is strongly for it, and the Senate majority leader is strongly for it. These people have a lot of power, and this is not one of those issues where the votes are divided along partisan lines. Lisa Murkowski, the ranking Republican on the Senate energy committee, voted for it.

MR. MARTIN: If a national RPS does move through the Senate, how likely are we to see the term "renewables" stretched beyond recognition to cover a lot of things that people might not normally think of as renewables?

MR. SHELK: Everything is renewable. It's just a question of your perspective on timing. [Laughter.]

MR. WEISGALL: Coal is vintage biomass. [More laughter.]

MR. SHELK: We are all fossil fuels in the making. [More laughter.] Keith, your comment is right on target. Lisa Murkowski voted for the package, but it is perfectly legitimate for her to try to promote certain types of fuels. If the goal is really carbon reduction and a green economy and jobs, then lots of other fuels meet that broader objective than simply the ones that we traditionally think of as renewables.

MR. WEISGALL: A production tax credit or renewable portfolio standard is nothing more than putting the thumb on the scale to favor a particular set of technologies. If we do end up with carbon controls or a national RPS, will the tax committees in Congress continue keeping the thumb on the scale for renewables through tax subsidies?

MR. MIKRUT: The tax committee staffs are aware of this issue. I should observe that ethanol has a fuels mandate, a tax incentive and a tariff, which for us lobbyists is the triple crown. A national renewable energy standard would phase in over time. I think it is clear that the tax committee staffs would consider coordinating how the RES gets phased in with how the tax incentives are phased out.

Transmission

MR. MARTIN: Let's move to transmission. Many people would like to see the federal government have the power of eminent domain to push through electric transmission lines like it has for gas pipelines. However, the politics in the Senate won't allow for that. Where did the House energy bill passed last June end up on federal authority and where do you see the Senate going on this issue?

MR. WEISGALL: The House bill, for all of its 1,428 pages, had remarkably little on transmission. The transmission debate distills to three big issues: permitting, siting and cost allocation. There is no consensus about how to proceed on any of them.

One of the two main sponsors of the House energy bill — Congressman Ed Markey from Massachusetts — was most bothered by cost allocation. His view was, "If we are going to do renewables, we will do them offshore in New England. That's where I want the jobs. I don't necessarily want to support a transmission super highway that will help move electricity generated at wind farms in the midwest to the east coast."

That's one view, but there are lots of other views. Wind farms tend to be distant from population centers. You need additional transmission capacity to move the electricity. As I have said before, you can't love renewables and hate transmission. The issue is who pays the cost.

Congress is not making particularly good progress on transmission. The Senate energy committee tried to address cost allocation in its version of the bill, but then Senator Corker added an amendment at the last moment that undid a lot of the progress by requiring proof of actual benefit to ratepayers before a transmission expansion is built. The full Senate may end up tinkering with the language.

Let's not forget we also have a federal agency called the Federal Energy Regulatory Commission that is tasked with figuring these things out. Another way Congress could go is to say to FERC, "We want to encourage renewables. You figure out the transmission side of the equation." Right now it's a bit of a mess.

MR. MARTIN: So Congress is really not giving much clear direction. John Shelk, there are three parties who may be asked to bear the cost of new transmission lines: the generators whose projects necessitate adding new lines, the shareholders or the utilities that own them, and the ratepayers. Is your trade association in the middle of that debate and, if so, how do you see it coming out?

MR. SHELK: Middle of the debate internally, and I can tell you this is one that, like a lot of issues, where you stand is where you sit. It has been difficult for our trade association to reach a unified view. Congress is having no easier time reaching consensus than we are.

Swaps and Hedges

MR. MARTIN: Changing subjects, the House has been wrestling with financial sector regulatory reform. I know that energy companies have been concerned about whether they would have to run swaps and hedges through exchanges and central clearing houses. Why is it such a big issue and where does it seem headed?

MR. SHELK: I'm glad you brought it up because this is one issue on which the power industry is united. The financial services bill presents problems in a number of areas, but this is the most likely one to be fixed. The House proposed requiring anyone entering even into bilateral swaps or hedges — for example, of gas or electricity — to run the transactions through central exchanges or clearing houses. Participants in such transactions would have to meet margin requirements and post billions of dollars in collateral that we do not think are necessary or appropriate. If the government wants transparency, there are other ways to do it, through contract repositories and databases. I think we got where we needed when the financial sector reform bill was taken up on the House floor, but we will need to educate people all over again in the Senate.

MR. WEISGALL: The problem has been that one person's exemption is another person's loophole. No one wants to penalize airlines hedging on jet fuel or a utility that hedges by buying natural gas strips. What the House did was provide an exemption for participants in commodity hedges and swaps who are end users of the commodities. / continued page 10

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THE 80-20 TEST may be being used incorrectly, an IRS official said.

Charles Ramsey, chief of the IRS branch that handles energy tax credits, said at a conference in Washington in November that the IRS is concerned that people who convert coal- and gas-fired power plants to run on biomass may be applying the 80-20 test incorrectly by taking the position that they built new power plants by merely bolting on expensive conversion equipment while leaving the rest of the power plant unchanged.

The 80-20 test is used in the United States to determine when renovations to an existing power plant or other facility are so extensive that they are essentially construction of a new facility. The test is important because anyone building a new plant may qualify for new tax subsidies.

Under the test, the plant will be considered new if the amount spent on upgrades is more than four times what the plant was worth. Application of the test can leave room for argument; for example, the calculations are supposed to focus only on the equipment considered the core "facility."

A company can also lose tax subsidies if extensive upgrades are made after a deadline has passed to qualify for tax subsidies. For example, a wind turbine that is extensively rebuilt after 2012 — the deadline to qualify for 10 years of production tax credits on the electricity output — might lose any further tax credits if it is extensively rebuilt in 2013.

STATE TAX CREDIT deals were helped by a US Tax Court decision in December.

The court said investors in a partnership who wanted state tax credits and made capital contributions to the partnership of 74¢ for each dollar of tax credit they were allocated were real partners, even though they expected nothing more out of the partnership than the tax credits.

The IRS argued that the partnership made a bare sale of the tax credits to the investors and the other partners should have reported the "capital contributions" from the partners as income.

The court said no. / continued page 11

Year Ahead

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The retirement announcement by the Senate banking committee chairman, Chris Dodd, greatly increases the odds that we will get a financial regulatory reform bill this year. Dodd will no longer feel beholden to the left wing and feel the need to thump his chest and go after Wall Street. The retirement also helps because the senior Republican on the committee can now relax; he will not be handing a victory to an incumbent Democrat if he lets the bill out of committee. The bill will not cost a lot of money. Finally, Wall Street bankers are not very popular at the moment with all the news stories about huge bonuses to executives at institutions that were taking government bailout money barely a year ago, so this will be an easy vote.

MR. MARTIN: Is it clear that anyone entering into an electricity price swap or hedge today would be exempted from this bill for no other reason than the swap was executed before the bill was enacted?

MR. WEISGALL: The retroactivity issue is a huge one. The House bill is silent on the question of retroactivity. We have been working hard to secure a grandfather provision. Congress may want to pick a retroactivity cut-off date — something like June 1, 2009 — to avoid shenanigans, but it needs something. Unless this is cleared up, the silence may lead to litigation. Every one of these contracts has a winning party and a losing party. A bill that is silent about retroactivity may allow the losing party to claim a regulatory out.

Congress is debating whether hedges and swaps should be run through central exchanges or clearing houses.

New Taxes?

MR. MARTIN: Switching topics again, Joe Mikrut, will Congress be forced by expensive health reform, the huge amount of stimulus spending and the wars in Iraq and Afghanistan to adopt a national value-added tax?

MR. MIKRUT: We will see how the Obama budget, due out in a month, attempts to address the projected budget deficits. One factor is that the Bush tax cuts that were enacted in 2001 and 2003 expire at the end of this year. Not extending them fully would bring in more money for the government. I don't sense much interest in a value-added tax as long as there are other ways to address deficits.

MR. MARTIN: What are the odds of a value-added tax at this point — 20%? Less? More?

MR. MIKRUT: Over the next 10 years, 20% is not a bad guess. In the short term, the odds are much less.

MR. MARTIN: What are the odds of a corporate tax rate increase?

MR. MIKRUT: A corporate tax rate increase is unlikely. There is growing concern among policy makers that the corporate tax rate is higher in the United States than in other countries with whom we compete. Charlie Rangel, the chairman of the House Ways and Means committee introduced a bill he calls the "mother of all tax reform" that would reduce the corporate rate from 35% to 30%, and he suggested he might even be willing to go lower to 28%. So I don't expect an increase in rate is on the table given these sentiments and concerns over the economy.

MR. MARTIN: There was talk last year by the Obama administration about making it harder for US multinational corporations to defer US taxes on their earnings from offshore investments. That affects US power companies with projects in other countries. Do you think Congress will act on that issue?

JOE MIKRUT: Yes, at some point, but more likely after 2010. ◎

DOE Moves on Loan Guarantees

by Kenneth Hansen, in Washington

Although progress has at times seemed painfully slow, the US Department of Energy is making progress toward issuing federal loan guarantees for renewable energy, transmission and other projects.

The department has had authority since August 2005 to guarantee loans to projects that use innovative technologies. A technology is considered innovative if it is has not seen at least three commercial applications in the United States lasting at least five years.

Congress gave the department additional authority in the economic stimulus bill last year to guarantee loans to finance new electric transmission lines and grid upgrades and renewable energy projects that use commercially-proven technologies.

Active Solicitations

There are currently two active solicitations under which developers can apply for guarantees for projects.

The first is a July 29, 2009 solicitation for assorted projects that involve innovative technologies (generation, manufacturing, energy efficiency, transmission and alternative fuel vehicle projects) under both section 1703 of the Energy Policy Act of 2005 and section 1705 (also under the Energy Policy Act but created by the economic stimulus bill last February). Absent early termination of the application period, part I applications can be filed through August 24, with part II submissions due by December 31, 2010.

The second is the October 7, 2009 solicitation establishing a "financial institutions partnership program," known as "FIPP," for energy projects that use commercially-proven technologies also under section 1705. Both part I and part II applications are expected to remain welcome through January 6, 2011.

A third solicitation, also issued July 29, recently closed and is a solicitation for major transmission projects under section 1705 only (thus requiring no innovation). The deadline for part II submissions was January 25, 2010.

More tracks, under further solicitations, are planned, but these three are where all the action is for the moment, at least pending Congressional restoration of $2 billion in cash that

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The case is important because it makes it easier for developers pursuing projects in states that offer state tax credits to keep more of the cash they raise by bartering the tax credits for cash.

The United States encourages renewables projects by offering large subsidies. Few developers can use them. Most end up bartering the tax subsidies in the "tax equity" market in exchange for capital to build their projects. However, national tax equity investors are usually unwilling to pay anything for state tax subsidies. In some states, the state subsidies can be transferred separately to a local tax equity investor.

What the Tax Court decision makes clear is that how the state allows its credits to be transferred is key. The case involved tax credits in Virginia that the state let partnerships specially allocate to local investors in a different ratio than partnership income and loss are allocated and cash is distributed. The case sheds no light on the tax treatment in states that allow overt sales of state tax credits.

Three individuals set up a large partnership to renovate historic buildings in Virginia. The federal government offers a tax credit for 20% of the amount spent on renovating certified historic structures. The federal tax credits were shared by partners in the partnership in the same ratio they shared in other partnership items. Virginia also offers a tax credit for up to 25% of eligible spending. However, it lets the partnership allocate the state credits however the "partners mutually agree."

The partnership allocated all the state credits to local investors who made capital contributions at inception in exchange for the future credits. The partners expected little else from the partnership, and would have received part of their capital back, as well as other compensation, if the tax credits were worth less than expected. The local investors had a 1% interest in partnership income and losses.

The IRS argued the local investors were not real partners. The Tax Court disagreed. It said they had an intention to join with the other partners in pooling capital for a business purpose of rehabilitating historic buildings. / continued page 13

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Congress moved from the section 1705 loan guarantee program last year to fund the cash payments by auto dealers for "clunkers." Congressional staff predict that restoration will happen in February.

Successful Closings

So far, the projects approaching financial closure are all under the section 1703 program for innovative technologies, though most also qualify under section 1705. The advantage of qualifying under both is that the project can be financed by borrowing at a low interest rate directly from a window at the US Treasury called the Federal Financing Bank. This type of borrowing is available only for innovative technology projects, whether receiving loan guarantees under section 1703 or section 1705. However, the projects that qualify under section 1705 do not have to pay "credit subsidy" charges for the guarantees.

The first, and so far only, loan guarantee to reach financial closure is that of Solyndra, Inc., a manufacturer of cylindrical solar photovoltaic panels. (Solyndra applied under a December 31, 2006 solicitation, announced it had signed a term sheet on March 20, 2009, and reached financial closure on September 4.)

Three other term sheets have been concluded, one with Nordic Windpower, USA, a maker of two-blade, one-megawatt wind turbines, one with Beacon Power, an energy storage company (both announced July 2), and one with Red River, an activated carbon manufacturing plant, announced in December. Each of these three subsequent projects had applied pursuant to the section 1703 solicitation that closed February 26, 2009.

A key question is whether the timing required for processing applications and closing loans can be expected to accelerate.

The Department of Energy has been criticized for the slowness with which opportunities to apply have been doled out and with which applications, once submitted, have been processed. More than two years elapsed following Solyndra's application before a term sheet was issued. In contrast, two of the more recent applicants in the February 26 round completed term sheets less than six moths later, though the third's term sheet took 10 months, and several other projects from the February 2009 round have term sheets at various stages of negotiation.

Nonetheless, the loan guarantee staff have indicated their expectation that, as the program gains experience, the pace of processing applications, finalizing term sheets and closing financings should accelerate. Given that projects to date have been delayed, at least in part by DOE sorting out resolutions to various threshold issues, later projects will benefit from those precedents and should indeed be able to move more quickly through the underwriting, negotiating and documentation processes.

Status of the FIPP

The FIPP continues as a repository of more potential than achievement.

Several part I applications have been received that are expected to yield part II applications and a good likelihood of closed financings. But experience to date is far from the flood of commercial technology projects under the stimulus that was expected.

One can speculate whether the early post-stimulus projections over-estimated prospective demand. Has resolution of the financial crisis sufficiently restored alternative financing sources? Did the specific hurdles in the solicitation (for example, simple financing structures and a BB credit rating) drastically limit the applicant pool? Did structural requirements imposed by the solicitation that were not required under the relevant statutes or the final program guidelines (for example, a prohibition against stripping the guaranteed and unguaranteed portions of the DOE-supported loans and precluding access to the Federal Financing Bank) impair the value of seeking the federal guarantee? Might the unexpectedly limited volume of financing made available under the solicitation have discouraged commercial lenders from investing time and effort in making the program work?

Whatever the reason, and no doubt the dismal pace of applications reflects a combination of these factors, the FIPP, for which there were great hopes for over-subscription (which would have bolstered the argument to restore the cash-for-clunkers money), may not need the relatively paltry $750 million in credit subsidy appropriation that was allocated to it.

For a number of the projects that have applied to date, the sponsors, rather than the banks, have led the way. These developers each have large projects costing more than $1 billion that caught the attention of banks anxious to win mandates to lead those financings. A condition of the mandate was to include a proposal to tap the DOE program. These mega-projects, which can accommodate the transaction costs necessitated by the terms of the solicitation if the capital markets are to be tapped, will likely break the ice for the FIPP.

One question is whether, with those precedents established, funding arrangements will be designed that can accommodate projects in the mere $50 to $500 million range that were the original target of the FIPP. A couple applications in that range have been filed, but without aspirations of capital market funding. Notwithstanding the handful of applications filed, it appears that the expected flood of such applications has been more discouraged than motivated by the terms of the FIPP.

Revised Final Rule

Other news is better. Proposed helpful changes to guidelines for the loan guarantee program as a whole — that were in the works, in one guise or another, for nearly a year — became effective on December 7. Each change addresses an important impediment to DOE co-financing with other lenders.

DOE is now prepared to share collateral with co-lenders.

Previously, DOE would only share collateral in one narrow context. If it were to provide a partially-guaranteed obligation, meaning if it were to guarantee payment of some cents on each dollar of financing, then it was prepared to share collateral with a guaranteed lender in proportion to the non-guaranteed portion of the loan. However, if DOE were to fully guarantee a loan, as applicants overwhelmingly preferred, but the project were to require complementary co-financing from another lender, then the co-lender would have to be unsecured because DOE insisted on a lien on all project assets and it was not permitted to share that lien. Co-financing required from export credit agencies to support nuclear power projects was the case most used to demonstrate the problem.

With the latest rule change, DOE is now free to share collateral with co-lenders on whatever terms are deemed appropriate from an underwriting perspective to assure compliance with the continuing statutory obligation to achieve "a reasonable prospect of repayment."

In another change, DOE relaxed the requirement that it must have a lien on all project assets.

This change permits the scope of the collateral package to be driven by underwriting considerations rather than rigid legal requirements. Although that facilitates co-financing, since co-lenders will be driven by similar underwriting concerns, the motivation for this was primarily to accommodate financing of contractual joint ventures where the collateral might consist of an assignment of contractual rights rather */ continued page 14*

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The IRS argued the investors had to expect a profit apart from tax benefits; the government routinely sets aside transactions that lack a business purpose other than to reduce taxes. The court disagreed; it said the IRS overlooked a "critical distinction," which was the cases the IRS had in mind involved *federal* taxes and this was a case of investors trying to reduce *state* taxes, which it said is a valid business purpose "as long as the reduction of non-Federal taxes is greater than the reduction of Federal taxes." It also suggested it does not make sense to require investors engaged in an activity that the government is trying to promote through tax incentives to show the incentives were not what motivated them.

The decision may not be the last word. The case is Virginia Historic Tax Credit Fund 2001 LP v. Commissioner. *The Tax Court released its opinion on December 21. The IRS has until late February to appeal.*

PURCHASERS OF STATE TAX CREDITS can deduct the state taxes they pay with the credits on their federal tax returns.

However, they can only deduct what they paid for the credits — not the full taxes paid with them.

The IRS made this comment in a private ruling it released in late December. The ruling is Private Letter Ruling 200951024.

The ruling involved an investor in a venture capital fund. The state guaranteed the investor it would earn at least a minimum return. If its return fell short, the investor was given transferable tax credits to make up the difference. A regulated utility in the state signed a forward purchase agreement to buy up to a certain amount of tax credits from the investor.

The IRS said the investor had to report the sales proceeds as gain on the sale.

The utility bought an asset. It had a basis in the asset equal to what it paid for it. When it turned over the asset to the state to satisfy state tax liabilities, it could deduct the taxes it paid in this fashion; state income taxes */ continued page 15*

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than a lien on the physical assets of a project in which multiple owners (including owners not benefiting from DOE financing) hold undivided interests.

A third key rule change is that DOE is now prepared to share decision-making after a borrower default.

The loan guarantee program rules originally provided that DOE could decide, in its sole discretion, how to respond to defaults. Whether construction should be completed or abandoned, whether security interests in collateral should be enforced, and whether a project should be liquidated or continue to operate were all to be solely DOE's call, regardless of the role, or the magnitude of the roles, played by co-lenders. Prospective lenders were concerned that DOE might be — indeed was bound to be — motivated by non-commercial considerations in exercising that discretion.

Not surprisingly, the DOE loan guarantee program, at least until roll-out of the FIPP, was bereft of co-financing. With these changes, not only has financing for the nuclear projects become more likely to succeed, but also any project interested in coupling DOE support with other financing — such as a tranche of tax-exempt bond debt — just became feasible with these changes. For the FIPP, which requires co-financing, the prospects of conventional inter-creditor terms prevailing have improved immensely.

Davis Bacon and New Director

The stimulus required Davis Bacon-compliant "prevailing wages" to be paid to all on-site construction workers and mechanics for projects supported by loan guarantees issued under section 1705. Section 310 of the Energy and Water Development and Related Agencies Appropriations Act, enacted at the end of 2009, expanded the scope of the Davis Bacon compliance requirement to include all DOE loan guarantees, including those issued under section 1703.

The DOE loan guarantee program had been housed, since its inception, in the office of the department's chief financial officer. In a demonstration of the importance that the Obama administration, through the Secretary of Energy, places on the program, it has been put under the control of a new recruit, Jonathan Silver, titled executive director, who reports directly to the Secretary of Energy. In a series of meetings with program applicants, prospective applicants and trade associations, Mr. Silver has indicated his commitment to accelerate loan processing and closing and his sympathy with the sorts of concerns listed later this article on the to-be-done list.

DOE has written only one loan guarantee to date and concluded term sheet negotiations on three others.

Open Issues

Among the continuing challenges Mr. Silver faces, as do program applicants, are the following.

Don't Ask, Don't Tell: Communicating with the loan guarantee program office can be challenging. DOE takes a quasi-government procurement approach to processing applications, such that each applicant under a solicitation for a loan guarantee is deemed to be in direct competition with each other applicant. The concern is that any question raised by an applicant could, if answered by DOE, give that applicant an unfair advantage in that competition.

A number of ways out of the dilemma seem evident. One would be to conclude that an applicant may achieve some advantage by asking a good question, but that there is nothing unfair about that advantage so long as other applicants can also ask their questions (which is the approach taken by the US Treasury with the cash grant program for renewable energy projects that was also part of the stimulus). Another would be to make the questions asked and the answers given publicly available. An applicant would have to decide, given raising a question, whether the answer is worth knowing if competitors will also get the benefit of it. DOE has taken steps in the latter direction by posting answers to "frequently asked questions" on the loan guarantee office webpage.

Unfortunately, DOE imposes a "quiet period" for applicants between the part I and part II submissions. Given the relative simplicity of the part I submission and the relative depth and complexity of the part II submission, important questions necessarily arise when preparing that second round submission. DOE's position to date is that it cannot, at that stage, provide any guidance.

For a still new financing program, with minimal track record and with its programs and policies still evolving, the inability to respond to questions is a problem. The good news is that program staff understand the problem and are working on a solution.

Refinancing Construction Debt: It has been clear from day one that DOE-guaranteed debt would not be available to refinance loans in place for a finished project. It has also become clear that a project under construction with a term debt commitment in place would not qualify for DOE support for lack of "additionality," meaning the project is going to happen anyway, with or without DOE support.

However, DOE staff have provided mixed signals — with different officials taking different public positions — with respect to whether DOE will be prepared to guarantee term loans that will refinance construction debt, if the availability of that term debt depends upon the availability of the DOE guarantee.

Some prospective projects that are excellent candidates for DOE support and that fit the popular image of "shovel-ready" can arrange construction financing (perhaps with an equity back-stop), but are concerned that DOE will take a view that "once financed, always financed" and that the availability of such construction financing itself will block access to a federal loan guarantee.

The consequence is that such projects are delaying construction while awaiting DOE processing of their applications. This effect is ironically anti-stimulative and unnecessary. DOE needs to resolve the doubt publicly — preferably by confirming that forward progress into construction will not, absent a term loan commitment being in place, disqualify a project for a loan guarantee.

Commencing Construction Ahead of NEPA Clearance: Many DOE loan guarantee applicants (though not / continued page 16

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are deductible at the federal level. However, to the extent the state gives it credit for more than it paid for the asset, then it has a gain equal to the difference. The net effect is the utility will end up with tax deductions equal to what it paid for the tax credits it uses.

WASTE may be about to get a new definition for US tax purposes.

The word is important because US power plants that burn waste can be financed in the tax-exempt bond market, even though they are privately owned.

In addition, power plants that burn waste and facilities that convert it into solid, liquid or gaseous fuels can be depreciated for tax purposes on an accelerated basis over seven years.

The word may also be important to whether power plants that burn biomass can receive cash grants from the US Treasury for 30% of the project cost.

"Waste" is defined currently for tax purposes as material that has no value in the place where it is located. Therefore, power companies that want to claim they use waste are careful not to pay anything for the fuel. They may pay to collect, sort and transport the material, but not for the underlying material itself.

Recyclers have never been happy with this definition. Their interest in recycling material creates a market for it.

The IRS has been trying to come up with a new definition since 2002, but with limited success. It proposed a brand new approach in October. Only one witness testified at a hearing on the new definition in January, suggesting most of the market can live with what the agency proposed.

Under the new definition, whether someone pays for the material does not matter.

However, it must be either "used" or "residual" material and be expected to be used "within a reasonable time after purchase or acquisition in a qualified solid waste disposal process," such as being burned in a power plant to make steam.

"Used" means it was used once by someone else. / continued page 17

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all) have been advised that a project cannot commence construction in advance of DOE's completion of its environmental review under the National Environmental Policy Act.

Even if a project proceeds along a path ultimately determined to be environmentally acceptable, or even environmentally optimal, the fact that some alternatives, albeit environmentally inferior, will have been foregone violates the DOE's NEPA process and may disqualify a project from a loan guarantee.

DOE has not received the flood of applications it expected for guarantees on projects using commercially-proven technologies.

This is another anti-stimulative element of the program. Obviously a developer that proceeds in advance of receiving NEPA clearance would be doing so at its own risk and running the risk that the project ultimately will not be deemed NEPA compliant. Many developers who are confident that they are on the right track environmentally would accept this risk in order to move forward with the project.

Whether this can be addressed administratively or requires legislative action is a point of some contention. We understand DOE is exploring a way forward.

Other Things That Haven't Happened

The $6 billion loss reserve that Congress provided originally in the stimulus to support loan guarantees under the section 1705 program was reduced to $4 billion; $2 billion was taken away to fund the cash-for-clunkers program.

The money is expected by some close watchers of energy matters on Capitol Hill to be restored in February. If it is, the loan guarantee program will have the resources to roll out financing opportunities that avoid or otherwise address some of the issues that have, at least to date, limited demand for the FIPP program. Other variations on the loan guarantee program, such as an indirect investment program in which DOE supports investment funds that, in turn, invest in downstream projects, could then also be expected.

When the cash-for-clunkers transfer occurred, there was speculation within DOE as well in the market that the inadvertent exclusion of renewable energy projects that use commercially-proven technologies from 81% of the loan guarantee program's resources under the stimulus would have to be addressed. (DOE has put most of the remaining loss reserve off limits to mainstream renewable energy projects by setting aside the reserve largely to support guarantees to projects that use innovative technologies and transmission projects.) The only clear solution, absent restoration of the transferred funds, appeared to be to reallocate some of the funds allocated under the July 29 solicitation for innovative projects (and perhaps also under the simultaneous solicitation for large transmission projects) over to the FIPP. The unpopularity of the FIPP may ironically have resolved this issue.

DOE has indicated that other federal agencies that have already reviewed a project for compliance with the National Environmental Policy Act need not repeat the process for DOE. Similar deference is not accorded to state environmental clearances since, after all, they are not pursuant to NEPA. Still, some states, in particular California, have environmental requirements no less stringent than NEPA. Applicants have argued that they should be given credit by DOE for activities undertaken for purposes of state compliance and that, for those states with environmental clearance requirements substantially as stringent as NEPA, state compliance should be sufficient for purposes of NEPA.

DOE reports extensive and continuing discussions with the Council on Environmental Quality at the White House in search of a way forward that gives projects appropriate credit for state-level compliance activity. This is another work in progress. ◎

Treasury Cash Grant Update

by Keith Martin, in Washington

The US Treasury Department is still wrestling with what it means to start construction of a new wind farm, solar project or other renewable energy facility. The answer is now not expected until March.

The issue is important because projects must be under construction by the end of 2010 to qualify for cash grants from the US Treasury for 30% of the project cost.

The Treasury is expected to say either that a company must have made nonrefundable payments of more than 5% of the eventual project cost or that it must have accrued such spending. Spending "accrues" when the company is on the hook legally to pay the amount even if the amount has not been paid yet.

Meanwhile, the House tax-writing committee is moving to extend the cash grant program.

The economic stimulus bill last year directed the US Treasury to pay owners of new wind, solar, geothermal, biomass, waste-to-energy, landfill gas, fuel cell and ocean energy projects 30% of the project cost — or, in some cases, 30% of the market value — in cash. Small cogeneration units of up to 50 megawatts in size also qualify for payments, but at a 10% level.

The payments are made within 60 days after a project is placed in service or, if later, after a complete application is submitted.

To qualify for a cash grant under the existing program, a project must either start construction or be completed in 2009 or 2010.

The program was intended as a temporary stimulus to keep projects on track in 2009 and 2010 when the economy was expected to remain weak. Projects that merely start construction in 2009 or 2010 must be completed by a deadline. The deadline is 2012 for wind farms, 2016 for solar, fuel cell and small cogeneration facilities and 2013 for other projects.

A bill expected to be introduced shortly in the House would create a new program that would replace the existing cash grant program when it expires. Under the new program, the government would treat the owner of a new project as if it overpaid income taxes for the year the / continued page 18

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"Residual" is what is left over after converting raw material into an agricultural, commercial, consumer or industrial product, but the leftovers cannot represent more than 5% of the original raw materials and they must be worth less than the product.

This residual test is hard to apply. The January witness, testifying for the National Association of Bond Lawyers, urged the IRS to drop the 5% limit.

In a helpful step, the IRS included as part of its new definition that anyone converting waste into energy would be able to introduce up to 35% non-waste to "accommodate ... processes that require" use of other inputs besides waste and still be considered to be using all waste.

A US UTILITY that had a 10-year tale of woe in what looks like China was told its losses were long-term capital losses — not ordinary losses.

Capital losses are much harder to deduct.

The IRS national office advised its agents in the field who denied deductions the utility claimed that the agents were right to deny them. The case looks headed to court.

The utility invested in a joint venture that was building a power plant to supply electricity to an industrial company. The joint venture received approvals for the project from both the provincial and national governments. The project had to be connected to the regional grid. The industrial company was responsible for handling that effort.

Three years into the project, the rules changed and control over the grid was vested in a new state entity that had commercial responsibility for the grid, but not regulatory authority. When planning for the project started, the region was short on electricity. By year three, the region had too much electricity, and the new grid company had little interest in seeing the project built because it wanted to sell its own excess electricity to the industrial company. For the next three years, the parties argued back and forth. The grid company said that the project could only sell to the grid and then only in limited quantities and at wholesale rates.

Six years into the project, / continued page 19

Treasury Cash Grants

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project is completed. The owner would be entitled to a refund of the money. The new program would apply to projects that start construction in 2011 or 2012. The deadlines to complete the projects would remain the same as under the existing program.

The House Ways and Means Committee staff began telling lobbyists last fall that it favors extending the cash grants because they are a more efficient way to direct money to renewable energy; more of the dollars end up being spent on projects than with tax credits that developers must barter in the tax equity market to convert into current cash.

The outlook for an extension in the Senate is unclear.

President Obama did not ask Congress to extend the cash grant program in the fiscal 2011 budget he presented to Congress on February 1. He did ask it to extend a similar cash grant program under which the Treasury pays the cash value of tax credits for low-income housing projects. The authority for the low-income housing program expired at the end of 2009, while the renewable energy program has another year to run.

Many lobbyists believe any extension of the cash grants for renewable energy will not occur before late in the year at the earliest. Nonetheless, they are eyeing a "jobs" bill that is expected to take shape in Congress as early as February as a possible vehicle for an extension.

Cash grants are being paid by the US Treasury in as little as two to three weeks after complete applications are received. This article describes a number of other developments.

Start of Construction

Projects must be under construction by December 2010 to qualify for grants under the existing program.

There are two ways for a developer to show that a project is under construction.

One is to show that "physical work of a significant nature" started.

The Treasury gave two examples in guidance last July 9. A project is considered under construction when "work begins on the excavation for the foundation, the setting of anchor bolts into the ground, or the pouring of the concrete pads of the foundation." It is also under construction "if a facility such as a wind turbine and tower unit is assembled on-site from modular units manufactured off-site" and assembly "of a significant nature" has started at the factory.

However, few wind and solar developers plan to rely on the physical work test; it is considered too vague. For example, the Treasury considers each turbine, pad and tower at a wind farm as a separate property. The developer can elect to treat all turbines on a single site as one project. Is it enough for a wind developer to have poured concrete for three of 67 turbine pads by December 2010? What percentage of the foundations for a multi-turbine project like a wind farm must have been excavated or laid? If the company wants to rely on physical assembly of turbines having started at the factory, how many must have been assembled?

Therefore, most attention has focused on the second test. Construction starts when the developer has "incurred" more than 5% of the total cost of the project.

Spending for "preliminary activities," such as engineering and design work, securing power contracts and permits and negotiating financing, does not count.

The Treasury said on July 9 that it is not enough merely to have spent the money on turbines and similar equipment that will be incorporated into the project; there must also be "economic performance," meaning that the developer must actually have taken delivery of (or legal title must have passed to) equipment that represents more than 5% of the total project cost.

Treasury officials have been saying privately since the fall that the economic performance requirement goes farther than Treasury intended.

The agency is considering treating companies as having started construction under the 5% test if they have merely "accrued" more than 5% of the project cost. An amount accrues when a company is legally obligated to pay it.

However, Treasury officials worry about trafficking after 2010 in grandfathered contracts. The fear is that a small industry will grow up in 2010 of brokers who use shell companies to sign equipment contracts that require payments of X% and then sell the contracts after 2010 to developers whose projects were not far enough along in 2010 to commit to their own contracts. One way to deal with this problem is to require developers actually to have paid the amounts they want to count toward the 5% test.

Projects often come in over budget. The Treasury is not keen to let developers apply the test based on expected costs in 2010. It advises paying well above 5% to leave a margin for error in case the final cost is higher than expected.

Larger wind and solar developers sometimes enter into frame or master agreements where they place a large turbine or module order and decide later where to use the equipment. It is not clear whether equipment ordered under a frame agreement can count toward the 5% test until it has been designated for use in a particular project. There was discussion at a Treasury meeting in October about letting such costs count as long as the turbines are designated for use in a particular project on a cash grant application filed with the Treasury by September 2011 — the deadline for all remaining grant applications to be submitted under the existing program.

These issues are expected to be addressed in a long list of questions and answers on which the Internal Revenue Service has been working since the fall. The current release date is sometime in March.

Extension?

Congressman Earl Blumenauer (D.-Oregon) is expected to introduce a bill in February that would extend the deadline to start construction of new projects to qualify for cash grants by another two years through 2012. It would also convert the program into a tax refund program rather than a cash grant program.

The difference is important.

Under the bill, the government would pretend that the owner of a project overpaid his taxes and could apply for a refund. Cash grants under the current program are paid within 60 days after a project is completed or, if later, a complete application is submitted. The tax refunds under the new program would be paid a lot later — after the annual tax return is filed for the year in which the project is completed.

The current cash grants are certain; the Treasury has no discretion. The refunds would be subject to offset if the taxpayer owes other taxes or has debts to other federal agencies and, in some cases, also owes unpaid state taxes.

Projects that are owned by partnerships do not qualify for any cash grant under current law if a government or tax-exempt entity owns an interest, no matter how small or indirect. Thus, projects owned by private equity funds have a hard time qualifying for grants. They can qualify if the private equity fund invests through a blocker corporation. The bill would get rid of this "cliff" and substitute a "proportionate disallowance" rule instead. For example, if state pension funds own 12% of a project, then any refund would be reduced by 12%.

The bill would help geothermal and other developers whose projects do not qualify for grants currently / continued page 20

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the US utility decided to refocus solely on the US and take a loss on its foreign operations. It filed a claim against its political risk insurance policy for the loss on the project. The insurer rejected the claim because it said there was no government expropriation of the project. After four more years, the utility lost in arbitration. Meanwhile, it sold what remaining interest it had in the project to a foreign investor for what it could get for the project rights.

The utility was clearly entitled to a loss on its taxes, since the loss was not covered by insurance.

The loss is ordinary under section 1231 of the US tax code if it results from an "involuntary conversion." In a somewhat narrow reading of the law, the IRS said there was no government seizure of the project; the grid company had killed it for its own commercial reasons rather than because it wanted to take the project for public use.

The case is discussed in an internal legal memorandum that the IRS national office made public in mid-January. The memo is CCA 201002035.

DISGUISED SALES are a risk, especially if the parties are trying to come close economically to a sale without triggering taxes.

GAF negotiated for the sale of assets from its surfactants chemical business to Rhone-Poulenc, but ended up structuring the transaction so that it looked like GAF contributed the assets to a joint venture with Rhone-Poulenc and then borrowed against its expected future cash distributions from the joint venture. The idea was to have immediate use of the cash value of the assets, but to defer any tax on gain.

The parties originally negotiated a sales price of $480 million.

However, GAF ultimately made a capital contribution of the assets to a joint venture with Rhone-Poulenc in exchange for a 49% limited partner interest. It then put the joint venture interest in a trust with Citibank. The trust borrowed $460 million from Credit Suisse on a nonrecourse basis against the expected future / continued page 21

Treasury Cash Grants

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because construction may have started before 2009. When construction started would no longer matter as long as it starts by 2012 and is completed by a deadline.

The deadlines would remain the same as under the existing program, except that geothermal projects would be given until 2016 — instead of 2013 — to be completed.

Developers would have the option to move to the new program immediately after it is enacted rather than have to wait until after the current cash grant program expires.

The Treasury is expected to explain shortly what renewable energy developers must do by December to qualify for 30% cash grants on remaining projects.

The bill would make it easier for regulated utilities to own renewables projects in states that have renewable portfolio standards requiring utilities to supply a certain percentage of electricity from renewable energy. Utilities in such states could qualify for refunds on projects they own without having to show that they use a "normalization" method of accounting. If the federal government were to adopt a national renewable energy standard, utilities in all states would have an easier time.

The reason the House wants to move to a refund program in place of cash grants has to do with committee jurisdiction in the House. The tax-writing committee shares jurisdiction over the cash grant program with two other "spending" committees. The tax-writing committee wants to extend the program of cash payments in as close a form as possible to the existing program. It is trying to find a way to do so without having to enter into a potentially tangled process with the spending committees.

Senate tax staff said last fall it was premature to talk about an extension before any results were in.

Any extension will have to be attached to another, larger measure; it will not pass alone.

California

Lobbyists for independent power companies are cautiously optimistic that the California legislature will vote by March to waive state taxes on the Treasury cash grants.

Leaders in both the state senate and state assembly appear to be on board. The move also has the support of the governor. The state estimates that waiving taxes will cost the state $70 million in revenue that it would otherwise have collected. If legislative leaders can find the money elsewhere, then the need for a two-thirds vote can be avoided. The state is facing a $20 billion hole in its budget this year.

The grants are not taxed at the federal level. However, grants paid on California projects are subject to tax in California, according to the Franchise Tax Board. The state franchise tax is 8.84%. Any state franchise taxes paid are deductible at the federal level.

The problem is California uses federal tax law as a starting point for calculating state taxable income, but it only "conforms" to the federal tax code as it existed on January 1, 2005. The cash grant program and the directive in the federal tax code that the grants not be taxed were enacted in February 2009.

The state legislature voted last summer to move the conformity date forward to January 1, 2009. Governor Schwarzenegger vetoed the bill on October 11. The veto message complained about an extraneous provision that was inserted in the bill at the last moment.

The state tax committee chairmen have said they have no appetite for trying to pass another general conformity bill this year. The lobbying efforts are focused instead on a narrow bill that deals just with the Treasury cash grants.

Companies who have not already been paid grants on California projects would be wise to wait to apply until after the legislature has acted in case any bill passed is only prospective in effect. Recent bill drafts have the measure taking effect retroactively, but there is no guarantee that is the form in which the bill will pass.

Geothermal

The Treasury has decided to make it easier for geothermal companies to qualify for cash grants on power projects on which drilling started before 2009.

Geothermal companies have a harder time qualifying for grants than many other developers because drilling at the field to prove the resource is sufficient to support the proposed power plant may have started in 2007 or 2008 for a power plant that will not be completed until 2011 or 2012. A developer qualifies for a grant only if his project is completed in 2009 or 2010 or starts construction in 2009 or 2010.

Exploratory drilling does not count as the start of construction. However, the line between an exploratory well and a production well is not always clear.

The Treasury has decided that it will count as an exploratory well drilling to prove the resource is adequate to support the power plant the developer wants to build, even when one or two wells are drilled to production depth and diameter and are converted later into production wells.

The Treasury is expected to post a question and answer to that effect on its website.

Tax-Exempt Entities

A project that is owned by a partnership for tax purposes does not qualify for a cash grant if a government or tax-exempt entity, electric cooperative or Indian tribe has an interest in the project, no matter how small or how remote. Most private equity funds have at least some such entities as investors. Therefore, projects or developers owned partly by private equity funds have trouble claiming cash grants.

The Treasury pointed to a way around the ban in January. It said in a question and answer posted on its website that a developer who does not qualify for a cash grant can still benefit indirectly by selling his project to a tax equity investor who can use the grant and leasing it back. The tax equity investor will qualify for the full grant.

The Treasury had been saying this since September. This was the first time it put its position in writing.

There would still be a partial loss of depreciation. The portion of the project that is considered owned by government and tax-exempt entities will be labeled "tax-exempt use property" and must be depreciated more slowly. / continued page 22

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cash distributions from the joint venture. The trust distributed $450 million to GAF and put the other $10 million in a reserve account to backstop payment of debt service on the loan from Credit Suisse.

The transaction gave GAF immediate use of the cash value of the assets, but the company argued the transaction did not trigger any taxes. Contributing assets to a joint venture does not trigger tax. Neither does borrowing money.

A federal district court in New Jersey disagreed. The IRS argued that the entire business was sold for $450 million in cash plus a partnership interest that unencumbered was worth $30 million. Cutting through everything, the court also saw a sale, but only of $450 million in value, with $30 million remaining invested in a joint venture with Rhone-Poulenc.

The court said the most telling facts were the history of the negotiations and the fact that GAF spent $11.8 million on legal fees implementing the transaction for what both its expert and the government's expert agreed was potential to earn about $8 million in true income and left it with exposure to a maximum of $26.3 million in loss under the particular terms of the joint venture. The joint venture made priority distributions to the GAF-Citibank trust to cover the interest on the loan from Credit Suisse. GAF was guaranteed that its capital account — or claim on the joint venture assets — would never fall below the remaining principal amount of the Credit Suisse loan. It also had a "put" to force Rhone-Poulenc to buy it out, after a loan default, for the amount of its capital account.

The transaction was supposed to save GAF $70 million in taxes.

The IRS has authority under the US tax code to recast transactions where partner A contributes property to a partnership and partner B contributes cash that is then distributed by the partnership to partner A within two years as, in substance, a sale of the property by partner A to the partnership. Congress said in a committee report, when it adopted the disguised sale provision, that the provision will also come into / continued page 23

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Projects must be sold and leased back within three months after they are first placed in service.

The ability to avoid the cash grant ban by selling and leasing back a project has several consequences.

Rooftop solar companies will be able to lease rooftop systems to public schools, universities, government agencies and other tax-exempt entities without losing the cash grant. However, it is still better to enter into power contracts to supply electricity to such entities — rather than lease them the equipment — to avoid a loss in time value of depreciation. A solar system leased to a government or tax-exempt entity is depreciated over 12 years on a straight-line basis rather than five years using the 200% declining-balance method.

Developers planning joint ventures with Indian tribes, municipal utilities or electric cooperatives to own projects would be able to benefit indirectly from a full cash grant on the project by having the joint venture sell and lease back the project.

A municipal utility or cooperative could develop and project and do the same.

Some developers have been pressing Congress to amend the stimulus bill to relax the cash grant ban. The House Ways and Means Committee staff offered in late December to rewrite the current ban so that partial ownership by government or tax-exempt entities would not lead to total loss of the cash grant, but rather to loss of the same fraction of the grant as the government or tax-exempt ownership. This fix is expected to be folded into any bill in the House to extend the cash grant program.

Leasing is most attractive to tax equity investors if they can use leveraged lease accounting. This sometimes requires leaving the cash grant with the developer, as lessee, so that the debt at the lessor level is at least 50% of the price the lessor paid for the project. The Treasury action does not help in these situations, since the developer would not be able to claim a cash grant directly.

There are questions about how deep a lease market there is for wind farms because of the potential variability of revenues to pay rents. At least two wind developers have had projects in the market trying to raise lease equity. One had reportedly been withdrawn by the time the *NewsWire* went to print. ◎

Update: M&A Market

The past year was a difficult one for project developers looking to raise capital by selling projects or whole companies, but 2010 looks more promising. The following is an edited transcript from a discussion at an Infocast conference on "Projects and Money" in New Orleans in January about the state of the market. The panelists are Jon Fouts, a managing director in the power and utility group at Morgan Stanley, Ted Brandt, CEO of Marathon Capital, which has auctioned off several prominent wind companies in the last few years, and Alex Darden, director of EQT Partners, Inc., the US arm of a northern European-based private equity fund with 12 offices in 10 countries and approximately €13 billion raised through five investment strategies, including €1.2 billion in a new infrastructure fund that closed in late 2008. The moderator is Keith Martin with Chadbourne in Washington.

MR. MARTIN: Jon Fouts, was there much M&A activity in 2009, and did it vary by sector?

MR. FOUTS: Obviously 2009 was a tough year. We saw overall M&A volumes drop by about 60%. Volumes in the power and utility sector were probably down even more than that. M&A has usually accounted for between 15% and 20% of overall deal volume in that sector. Deals last year were primarily distress sales; the sellers needed cash.

MR. MARTIN: Ted Brandt, there was a wide bid-ask spread last year. Sellers thought their assets were worth more than buyers were prepared to pay. This was a barrier to sales, except in cases where sellers had no choice. Are the bid-ask spreads narrowing as we head into 2010?

MR. BRANDT: I remember sitting on this panel this time last year. We were just launching the sale of the Babcock & Brown wind assets and my position at the time was that cash flow would still sell. It was an interesting year. Congress was just about to enact a program of 30% cash grants for new renewable energy projects. The next six months after that were a period of great uncertainty about how the new program would work, and whatever life there was in the market ground to a halt until people began to feel more comfortable they understood how the rules work. As we head into 2010, I think we are at a point of departure. The distress is done. We are seeing a lot of money returning to the market. I think the cost of capital will come down. We are running an auction now for the Infigen wind portfolio. I am optimistic about M&A deal volume.

MR. MARTIN: Jon Fouts, are you also optimistic about deal volume, and what will be the main drivers behind M&A deals in 2010?

MR. FOUTS: I am. We saw deal volume pick up considerably in the last quarter of 2009. I see five main drivers behind sales in 2010. One is portfolio rationalization: if a business is not strategic, move on and get out of it. We will see fewer distress sales and more sales by companies rethinking where it makes sense to deploy their resources. Another big driver will be the continued interest in clean tech, with even the big utilities seeking outside capital to develop their clean tech portfolios. We are seeing growing interest in the transmission side of the business; there are more people looking for partners to undertake transmission projects. We are seeing some interest in going-private transactions. And, finally, there will be some smaller companies put up for sale after their owners do a sober analysis and conclude, from the market cap perspective, "We are just not big enough to make it." All of that said, deals will be smaller, and they will be conservatively financed.

MR. MARTIN: Ted Brandt, to what extent will deadlines in the 2009 stimulus bill drive M&A in 2010?

MR. BRANDT: They could be a significant driver. We focus on wind and solar. Both types of projects must be under construction by the end of this year to qualify for 30% cash grants from the US Treasury. Everyone is operating like that is a real deadline, even though everyone remains hopeful that Congress will extend it. There will be companies who will be looking for partners or buyers for projects this year that they have concluded they lack the wherewithal to get underway in time.

If you have a late-stage contracted project, this is a wonderful time to sell. We have a couple large portfolios of projects in the market for sale, and we are seeing lots of interest and heavy bidding.

If you have a development project that will not be ripe to start construction until past 2011, we think that market is still pretty lackadaisical, but I tell potential buyers it is where the bargains are. We are seeing some high valuations for solar PV companies, but potential bidders in wind companies appear to assign almost no value to pipeline projects after 2011 because developers claim impressive numbers of projects under development but few such projects are actually built. We are not seeing anywhere near the valuations for project pipelines that we saw even a couple years ago.

We have a couple clients who are actively working on roll ups of pipeline projects that are still under development. They buy a small portfolio here, a medium-sized portfolio there, and none them is having to put out a lot of cash because the transactions are done typically with heavily contingent earnout structures.

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play where partner A "receives the proceeds of a loan related to the property to the extent responsibility for the repayment of the loan rests, directly or indirectly, with the partnership (or its assets) or the other partners."

The case is *In re: G-I Holdings, Inc. et al*. The decision was rendered on December 14.

The IRS won on the substance, but ultimately lost the war. The transaction occurred in 1990. The case had been in and out of the US Tax Court and a federal appeals court. GAF declared bankruptcy in the meantime. The court said the IRS was barred by the statute of limitations from collecting any tax.

GRANTS that a state entity paid to people whose homes were destroyed by a natural disaster to help them buy new homes had to be reported as income, the IRS said in a private ruling.

The state argued that its citizens receiving grants should not have to report them either because the grants are effectively a reduction in the purchase price of the new home or else a "general welfare" exception applies. The IRS said they are not a reduction in the cost of the home because each buyer, in fact, pays the full purchase price and they do not qualify for the "general welfare" exception because the grants are not limited to low-income buyers. The state also had to report the payments to the IRS on information returns at year end, the IRS said.

The ruling is 201004005. The agency made it public on February 1.

REFLECTIVE ROOF SURFACES that are installed alongside photovoltaic cells are considered part of the solar equipment rather than the roof, the IRS said in a private ruling.

Businesses installing such equipment can claim a Treasury cash grant or investment tax credit on the cost.

A knitting company asked the question. It planned to install solar cells to generate electricity on its roof, but the cells were in a cylindrical shape, with half the cells on */ continued page 25*

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Opportunities and Buyers

MR. MARTIN: Alex Darden, what are the areas of greatest interest for a private equity firm like yours?

MR. DARDEN: Picking up on what Jon and Ted said, the main driver for the private equity firms is finding places where they can deploy capital that offer an appropriate return in relation to risk. We see plenty of such opportunities, not just in renewables, but also transmission lines, midstream oil and gas and utility projects generally.

MR. MARTIN: Jon Fouts, a strategic player or private equity fund asks you for the two best places to deploy capital in 2010. What are they?

MR. FOUTS: That's a tough question because the answer turns on the strategic objectives of the person asking the question.

M&A deal volume was down 60% in 2009. It is expected to be more brisk in 2010, driven partly by deadlines in the stimulus bill.

From a value perspective, we still see a lot of opportunity in the development side of the business for investors who are willing to take development risk. A contracted, well-structured project with a good management team can generate returns in the high teens to low 20% range. We see a lot of interest in that. There is $500 billion in capital sitting on the sidelines, and that doesn't include the dedicated infrastructure funds. If you leverage that, you get to some pretty big numbers very quickly.

MR. MARTIN: Ted Brandt, you have been running auctions of large portfolios of wind projects, including the Infigen portfolio of 18 wind farms that is out in the market currently. Have you seen any change in the last year or two in the mix of companies bidding to acquire US renewable energy developers and project portfolios?

MR. BRANDT: Yes. Before the crash, there was a clear advantage to incumbent utilities. FPL is probably the best example. It had a competitive advantage in wind and solar because it did not need to engage in complicated tax equity transactions to take advantage of the large tax subsidies the US government throws at renewable energy projects. We have now moved into a cash grant world after the stimulus. Certainly for wind farms with capacity factors below 37%, which are something like two thirds of the market, there is a much more level playing field. The private equity-backed firms and the infrastructure funds are much more competitive, and we see that across both wind and solar.

The other thing worth noting is there is a new class of investors — infrastructure funds of which Alex's company is an example — that are looking for long-term cash flow. They appear willing to live with very low double-digit returns and, as a consequence, they have been putting in very competitive bids in auctions lately. They are also willing to live with minority positions in companies; they don't insist on control.

MR. DARDEN: There are some funds that are willing to invest during the development phase, but there are also plenty of funds who are returning to the basic private equity model of buying operating projects or companies with such projects and then trying to create value. They look for ways to improve the operating performance.

MR. MARTIN: I know your fund bought Midland Cogeneration Venture, a huge gas-fired power plant in Michigan, recently. That project has been around for a while. How you do you add value in a case like it?

MR. DARDEN: The plant is 20 years old, and you may think there are not many operating efficiencies that haven't already been found, but the truth is there can be tremendous unrealized value in an older plant. With our industrial heritage, we focus on using former industry executives who have specific industry expertise, including in the case of Midland, former ABB executives who built the facility and knew the plant and technology intimately. The plant is built on a former nuclear site. Its interconnection to the grid can support a lot more capacity. It has extra land where we might be able to build a renewable energy facility. There are some technical packages that can be added to the plant. And further operational enhancements can be achieved through simple changes in processes and procedures. An older power plant may actually confer a fair number of advantages not found in a newer plant.

MR. MARTIN: How visible have the Chinese become in the US market?

MR. BRANDT: They are visible and they will become even more so. CIC made a large investment in AES. Chinese money went into Cielo in Texas. It is clear from the dialogue we have been having not only with CIC, but also with other state-owned enterprises in China, that they are making a big push into the US because they like the regulatory climate.

MR. MARTIN: Are European buyers showing more or less interest in the US market?

MR. FOUTS: Our people have had lots of conversations in the last two to three years with companies that have successfully developed renewable energy businesses in Europe — for example, in Spain and Germany — and want to apply that expertise in the United States. I think there is still a growing interest in the US market in Europe. It goes back to the rationalization point. They are picking spots that make strategic sense.

MR. BRANDT: I agree. You have a lot of conversations. Some of the companies are slow to make a move.

How to Win Bids

MR. MARTIN: Ted Brandt, what is the key to winning a bid? Say you are advising a buyer who is trying to stand out in this market.

AUDIENCE MEMBER: Pay a high price. [Laughter]

AUDIENCE MEMBER: Pay all cash. [More laughter]

MR. BRANDT: Those are certainly keys, but we have had two examples in the last year of strategic buyers — Keith, you can appreciate this, and I can say that you were not representing either of these — strategic buyers that absolutely screwed up in the red zone on the document issues. At the same time, we have watched private equity-backed companies very dexterously manage the legal issues and get to the finish line. Obviously paying more is the easy answer, but I think there is an under-appreciated amount of execution ability that we have seen. I will say out loud and in public that one of the greatest displays of this was a couple of years ago when we sold development assets that are now the CHiPs wind project in California to Terra-Gen and ArcLight, and those guys were magnificent in the red zone and they won / continued page 26

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the underside of the cylinder facing away from the sun. Spaces between cells let sunlight pass through. The company planned to put a reflective surface on the roof to reflect the sunlight back up to the cells on the underside of the cylinder.

The IRS made the ruling public in late November. It is Private Letter Ruling 200947027.

MINOR MEMOS. The Wyoming governor asked the state legislature on February 1 to impose a 0.3¢ tax per kilowatt hour of electricity generated from wind farms in the state . . . . Danish holding companies are being used to launder and hide money from tax authorities in Russia and Ukraine, according to Danish tax officials. The Danish tax agency, SKAT, is investigating as many as 500 to 1,000 such companies. Misleading accounting statements and false invoices may have been used to hide income. The money may be difficult to trace as it can move through three and four tiers of companies, and the ultimate owners of the entities are disguised . . . . Congress authorized up to $2.4 billion in new "clean renewable energy bonds" in 2008 and 2009 — bonds that municipal utilities, electric cooperatives and Indian tribes can issue to finance wind, solar, geothermal and other renewable energy projects. The bonds require payment of only a little interest; lenders who buy the bonds get tax credits from the federal government instead. Senator Charles Grassley (R.-Iowa) is trying to prevent "credit stripping," or separately selling the tax credits. The tax code specifically allows such credit stripping, but under regulations the IRS is supposed to issue. Grassley is unhappy about the practice and has introduced a bill to stop it. The bill is S. 2826.

— contributed by Keith Martin and Jenny Kim in Washington.

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the deal over a consortium that offered a higher price and manages more money. They won the deal [with Chadbourne as counsel] because they executed better.

MR. MARTIN: So good counsel is third after pay a high price and pay cash. Jon Fouts, are asset values going up or down?

MR. FOUTS: I think they are going up, but valuations have been driven for the past six months by liquidity rather than fundamentals. Liquidity is getting better, so valuations are going up. The next phase will be when people resume focusing on fundamentals, but for now, they are going up because the financial markets are improving.

MR. MARTIN: Alex Darden, do you agree?

MR. DARDEN: Absolutely. There were plenty of potential sellers who sat on the sidelines last year because they thought asset values would recover, and they will feel vindicated to some extent. I don't know whether values will return all the way to where they were a few years ago.

MR. MARTIN: Ted Brandt, you said during our prep call that "financing is one of the main drivers for whether bidders win deals." What is an example of financing that helps win a bid?

MR. BRANDT: The best way to answer that question is this. Two or three years ago when the Europeans were coming here with bags of Euros and trying to acquire development companies, they all pretty quickly coalesced around a view that the weighted average cost of capital to finance a fully-built contracted project was 8%. Since the meltdown in late 2008, people are less sure of what capital costs. It depends on who you are and where you sit, whether you choose a 30% Treasury cash grant on a project instead of tax credits, and a host of other variables. It is pretty clear after the stimulus bill last February and the passage of time that the cost of funds is again in single digits, unleveraged, after taxes. The cost is still a little above what it was before, but it is approaching where it was before.

Now, relate that to an M&A deal. If Alex Darden and his fund decide to buy a project, Alex will have to take the proposition to his credit committee, and he will have to make an assumption about how much it will cost to finance the acquisition.

A couple years ago, there was a general view about how different types of projects are best financed. There is less certainty today. M&A is driven by certainty. If there is a gap between what you can develop a project for — say around 10 1/2 or 11% — and what capital costs, which is still somewhat of a question mark, projects don't tend to sell. They sell when people feel they have nailed down the capital cost, and the lower the cost of capital to a buyer, the more value he is likely to see in a project.

Little value is being assigned to "pipeline" projects after 2011.

Raising Capital

MR. MARTIN: Jon Fouts, you said during our prep call that a Chinese wind company had sold recently for 13 times EBITDA. What are the current multiples in the US market?

MR. FOUTS: It was a public market deal. It can be difficult to compare multiples in an initial public offering to multiples when selling assets to a private equity fund or strategic buyer. Prices in the US renewables sector are still very much driven by discounted cash flow analyses. That said, I think we will see a number of clean tech and renewables companies come to market here in the next 12 to 18 months, and we could see numbers in the double-digit EBITDA range.

MR. MARTIN: Ted Brandt, how far along does a project have to be before it is ripe for sale?

MR. BRANDT: I can tell you at our shop, we like to know that the developer has a site in a good location and he has either signed a financeable power purchase agreement or at least has a draft power contract with a utility and is fairly far along in the negotiations. There is not much appetite among strategic or financial buyers to get behind a project that is likely to sit on the shelf for a couple of years and that will just be a drain in the meantime on capital.

MR. MARTIN: Alex Darden, are you looking only at operating projects or will you come in at the developer stage?

MR. DARDEN: We are not a greenfield developer. I don't rule out taking development or construction risk, but, at the end of the day, we are looking where we can add value, whether it is through operational enhancements or additional capital investments.

MR. MARTIN: Jon Fouts, how much of a company should a developer trying to raise equity at the corporate level figure he will to have to give up in ownership? Is there a formula?

MR. FOUTS: No, there is no formula. It comes down to perception of value and many of the variables we have been talking about in terms of location of the asset, the quality of the management team and the returns on assets. It is really tough to generalize.

MR. MARTIN: Investment bankers were telling people at conferences like this one three or four years ago, particularly in the wind sector, that developers should move to initial public offerings as a way to raise capital rather than continuing to do one-off tax equity deals around projects. Do you think the wind sector is finally ripe for IPOs; hindsight suggests it may not have been when the investment bankers first started suggesting wind companies move in that direction.

MR. FOUTS: Look, I would make two observations. One is that there are very few opportunities for public investors to invest in renewables companies in the US market. Whether it is wind, solar or geothermal, there are just not that many opportunities. One thing that we learned when taking a lithium battery company public a couple months ago was that public investors are basically saying, "Bring me your deals because we have a renewables mandate, and there is nothing to invest in." We need a US-domiciled renewables business to invest in.

Second point: 2009 was a beta trade market in terms of, if you put money into the market, it didn't matter what sector or what stock you bought, you basically made money. I think 2010 will be more of an alpha market, which means you have to pick the right place to put money. Even within the renewables space or the power and utility space, the name matters.

To answer your question directly, I think we will see some wind companies go public in the next 12 to 18 months.

MR. MARTIN: A senior executive at a California utility told me that his company has doubts about whether renewables are an appropriate investment for public companies because they tend to produce a big earnings bounce right off the bat in the form of government subsidies, but the long-term cash flow after that is weak. Do you agree?

MR. BRANDT: The conclusion doesn't sound right to me. The FPL Group gets roughly half of its earnings from renewables. The analysis is certainly not right if you are talking about a regulated utility owning renewables because utilities earn a fixed return off a variable rate base. Anything that adds to rate base gives the utility more earnings.

MR. MARTIN: Do you see any trends in how buyers are paying the purchase price for companies or assets?

MR. BRANDT: We used earnouts as a tool in 2009 to bridge the gap between what sellers thought their assets were worth and what buyers were prepared for pay for them. Convertible instruments were another tool that were used to keep the seller involved rather than just disappear after the sale.

MR. MARTIN: What is "market" in terms of how long seller representations survive?

MR. BRANDT: That depends on which law firms are representing the seller and buyer. It also depends on who the seller is. Obviously a deep-pocketed seller who can put some heft behind the reps and warranties may have one view and a distressed seller who is selling at a very low price will have another. We have been involved with distressed sellers for the last year, and reps in distressed deals have been virtually as-is-where-is, do your own due diligence, and this is reflected in the price. In the more distant past, where people were paying sizable premiums for development companies, some percentage of the purchase price — say 10 or 15% — would be paid into a cash escrow against possible future claims and then released a year to 18 months later.

MR. MARTIN: Ted, you said during our prep call that "the ultimate question is the cost of capital" and you touched on this a little earlier. What should the cost of capital be to own a contracted wind farm or solar, geothermal or biomass project? Is there a large disparity between where the cost of capital is today and what these projects need to be economic?

MR. BRANDT: I will put a stake in the ground and say we are big believers that leveraged leasing will make a comeback and become a bigger part of the financing mix. We think the weighted average cost of capital in a leveraged lease are well below 8%, probably even below 7%, when you look at the blended cost of the debt and equity. A lease generally provides 100% financing. The sponsor may have to leave some cash in a reserve to ensure payment of rent, depend- / continued page 28

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ing on the profitability of the power purchase agreement. It is not hard to see the opportunity for lease structures because, if you ask tax equity investors currently in the market about the cost of tax equity in partnership flip deals, it is closer to 10% for a wind project, maybe 9 1/2% on an unleveraged after-tax basis. So there is a huge amount of inefficiency in the market. I think the cost of capital today is 9 1/2% with pressure to move lower. We will see where it goes.

MR. MARTIN: When you say the cost of capital with a lease structure could be as low as 7%, is that true of all asset classes or is that the figure for wind farms, and the cost of capital is higher for other types of projects?

MR. BRANDT: Leases certainly work for solar projects and some of the better biomass projects where there is a pass through of the fuel risk. There have been leveraged leases of hydroelectric projects for years. The production tax credits are probably too valuable in geothermal projects, and anyone claiming production tax credits must stick to a partnership flip. ◎

Update: Tax Equity and Debt Markets

More than 400 people listened to a panel discussion called "Show Us the Money: Insights from Active Tax Equity Investors and Lenders" at the fall finance conference of the American Wind Energy Association in New York in mid-October. The following is an edited transcript. The panelists are John Anderson, head of the power and infrastructure group at John Hancock Financial Services, Yale Henderson, a managing director of JPMorgan Capital Corporation, Gisela Kroess, a director of project finance for UniCredit Bank in New York, Timothy Howell, head of the origination team at GE Energy Financial Services, Christopher Stolarski, a senior vice president at Mizuho Corporate Bank, and Lance Markowitz, senior vice president and head of the leasing group at Union Bank of California. The moderator is Keith Martin with Chadbourne in Washington.

MR. MARTIN: Gisela Kroess, can one borrow today from a bank to make installment payments on turbines?

MS. KROESS: Not in the classic sense. I think most lenders stopped making turbine loans about 15 to 18 months ago. The classic turbine loan was structured as a revolver. The bank had a security interest in the turbines it was financing, but did not always have a broader interest in the underlying projects. Banks are shying away from such loans in the current market because they worry turbine prices will continue to fall. We might be prepared to provide a bridge loan secured by all the project assets, but development work on the project would have to be far enough along to have minimal development risk.

MR. STOLARSKI: You can call it a pre-construction loan. Construction should be ready to go but for administrative approvals and things like that.

MR. MARTIN: Not much help for a developer who must put out a lot of capital well before he is ready to start construction. Someone told me before this panel that turbine vendors — and perhaps export credit agencies in countries where the turbines will be manufactured — are the only real remaining source of turbine financing.

MS. KROESS: You also have developers trying to raise equity to cover those expenses.

Construction Debt

MR. MARTIN: Shifting gears, what share of the project cost can one expect to cover with construction debt?

MS. KROESS: If you include an equity bridge loan for the Treasury cash grant for which the project expects to qualify at the end of construction, a developer can borrow up to 80% of the project cost during construction. The math goes basically as follows: because of conservative debt sizing in the market, the project must have 1.0 times debt coverage using the one-year P99 output number. That translates to a maximum of 50% leverage. The equity bridge loan or the Treasury cash grant gives you an additional 30%.

MR. MARTIN: Chris Stolarski, do you agree?

MR. STOLARSKI: Yes. There may be a few cases where we are prepared to go above 80% for a well-known sponsor with a track record of building successful projects.

MR. MARTIN: Let's stick with Gisela's math and assume there are two tranches of debt. There is an equity bridge loan for 30% of the project cost that is repaid with the Treasury cash grant at the end of construction. There is a separate tranche for 50% of the project cost that rolls into term debt. Is there a lower interest on the equity bridge loan? Isn't it a loan against a federal government credit?

MS. KROESS: You can make an argument for a lower interest rate or upfront fee. You might get a discount on the interest rate or upfront fee of up to 50%.

MR. MARKOWITZ: I would charge the same interest rate on both tranches. They are both construction loans. If the project does not get built, neither tranche is repaid. The lender is taking the same risk on both.

MS. KROESS: It depends on how comfortable you are with the construction risk and the likelihood that the project will be built. The construction risk on a typical wind farm is pretty manageable. It is usually a short construction period. If you have a sponsor with a proven track record of finishing projects on which he starts construction, then a case can be made for lower pricing on the equity bridge tranche because it is basically a loan against a federal government credit.

MR. MARTIN: What does a discount of up to 50% mean? If the interest rate on the tranche that converts into term debt is 7%, what is the rate on the equity bridge tranche?

MS. KROESS: If you have a 3% margin and upfront fee on the term loan tranche, meaning you are charging 3% more than your cost of money, the rate and upfront fee on the equity bridge tranche might be set as low as 2%.

MR. STOLARSKI: I agree with Lance Markowitz. We are inclined not to discount the equity bridge tranche because the risk is the same on both tranches. If the project is not completed, then neither tranche will be repaid.

MS. KROESS: You no longer have traditional construction loans in this market. In many wind projects, the construction debt used to be taken out with tax equity at completion. Nowadays, embedded in the construction loan is a commitment to convert to term debt if the tax equity fails to fund. That's why a higher interest rate and upfront fee are justified on the portion of the construction debt that exceeds the amount of the future Treasury cash grant.

MR. MARKOWITZ: I still disagree. If the construction loan will convert at the end of construction into term debt, the project reaches completion and the lender converts the loan using its own money. The risk of that not happening is lower than being paid the amount of cash grant for which you calculated at the start of construction the project will qualify. I am not saying there is a high risk of the Treasury failing to pay the grant, but there is more risk than the loan will convert to term when the time comes.

MS. KROESS: I think if you are really comfortable with the guidance the Treasury issued about how the cash grant program works, and we are, and you see how quickly cash grants are being paid in fact, you can get very comfortable with that risk. The commitment to convert to term debt, especially if it involves a change in banks, is a higher risk.

Debt Rates

MR. MARTIN: Many lenders speaking on panels at conferences this year have said that bank debt is pricing at 350 basis points above LIBOR and requires a 300-basis-point fee be paid up front. Term debt runs seven to 10 years. Loans are being made in a mini-perm structure. Do you think that is where the market is today? This is bank debt, not insurance company debt. I will come back to the insurance companies.

MR. STOLARSKI: I think that is out of date. There is more liquidity coming back into the market. We are seeing some downward pressure on rates. The tenors are pushing more toward 10 years than seven years. There has not been a big change; I don't think you are going to see that as much as a gradual return of liquidity into the debt market. There are still a number of lenders who are sidelined or operating at limited capacity for the foreseeable future.

MR. MARTIN: Gisela Kroess, you said before the panel today that tenors are moving from seven to 10 years to eight to 12 years, but the rates have not changed.

MS. KROESS: Yes. We have seen the range of mini-perm tenors moving in the last couple of months to as long as 12 years, and just recently I heard about some banks being prepared to go back to fully amortizing term debt over as long as 15 years, but that will be the exception. There is clearly a momentum toward longer terms, although there will not be a return to the terms we saw in the past because banks, especially European banks, are now subject to Basel II, and they have either to reduce their risk assets or raise capital, and raising capital is pretty expensive. I do see gradually increasing liquidity in the bank market as a whole.

MR. MARTIN: How many banks are active in the wind market?

MS. KROESS: Sixteen to 20.

MR. MARTIN: The alternative to bank debt is insurance company debt and that tends to be much longer term. John Anderson, there are four or five insurance companies supplying debt, correct?

MR. ANDERSON: That's probably right. The market is a bit untested. The private placement market was not competitive on price with the banks. There has not been much deal flow over the last year and a half. However, our private placement activity, which is more corporate-level debt */ continued page 30*

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than project debt, is now priced competitively again after the rally in the institutional bond market. I have talked to some colleagues in investment banks looking into private placements and I think they can get to $500 million in terms of dollars raised per project.

MR. MARTIN: You are offering 20-year, fixed-rate debt?

MR. ANDERSON: Yes.

MR. MARTIN: Bank loans are floating rate?

MR. STOLARSKI: I think we could swap to protect our ourselves against changes in rates.

MS. KROESS: There used to be some deals where the sponsor gets the best of both worlds by arranging a shorter-term bank tranche within a longer-term institutional tranche.

MR. MARTIN: Coming back to John Anderson, you offer 20-year debt. The banks are offering seven- or eight- to 10- or 12-year debt in mini-perm structures. Bank debt is pricing at something like 350 basis points above LIBOR with an upfront charge of 300 basis points, plus a swap charge. Where are you in terms of cost of money?

MR. ANDERSON: It is tricky to say where the institutional market is, because the prices change every week, but it is something like Treasuries plus 350 and 1% up front.

MR. MARTIN: Most banks are insisting that the entire syndicate be put together before any of them will fund, and no one bank is taking more than about a $50 million ticket. Is that still correct? Gisela Kroess, you are shaking your head.

MS. KROESS: I don't think that remains correct. The market is not back to 100% funding by one institution, but we are seeing banks return to underwriting. We closed a deal a couple of months ago with another financial institution with both of us undertaking a 50% underwriting; two more banks came in later. We are now looking at a deal where we might be prepared to underwrite as much as 60% or 70% of the loan with another bank coming in for 30 to 40%. Hence, there is some form of underwriting in terms of 50 to 70% underwriting one commits at closing with another bank taking 30 to 50%. Following initial closing, you approach two to five other relationship banks later to round out the syndicate. It is easier to get to closing with just two banks than to have to negotiate with an entire syndicate.

The tax equity and debt markets are improving. Liquidity should return to 70% to 75% of the level before the crash.

Tax Equity

MR. MARTIN: Let's move to tax equity. Yale Henderson, do you get the sense that there is as much interest among developers in raising tax equity this year as in the past, given that the Treasury Department is offering to pay developers a large share of the tax subsidies in cash?

MR. HENDERSON: Developers are curious about what we are willing to do. I think what happened in the early part of the year with the grant option is developers focused on getting their construction financing in place with a term loan takeout so they knew that they had a fallback position where they could just stick with permanent debt. Now they are exploring tax equity alternatives that may make the deal more economic and avoid the need to use the term debt.

What we are seeing as the year draws to a close is a little bit of analysis paralysis. Everyone got comfortable in 2007 and 2008 with the tried and true partnership flip structure and production tax credits. Production tax credits made the decision how to finance easy, since the statute allowed only one financing structure. Now you have developers talking about sale-leasebacks, inverted leases and other structures. People are trying to figure out how real these other options are versus a partnership flip. They don't want to make the wrong call early on.

MR. MARTIN: So developers are evaluating other structures. Tim Howell?

MR. HOWELL: The biggest challenge in the market this year has been the inability to finance projects without power purchase agreements. It is hard for developers to persuade utilities to sign power contracts on economic terms with gas prices falling. That said, we still see lots of developers who want to convert tax benefits on their projects into current cash. There is heavy demand for tax equity. We think there will be a lot of deals next year.

MR. MARTIN: Lance Markowitz, one US developer is in the market currently trying to raise tax equity for a wind farm using a sale-leaseback. Does a lease work for a wind farm?

MR. MARKOWITZ: The cash flow is much more unpredictable because wind is less predictable. Lessors like fixed rent payments; it is not clear that wind farms are suitable for leasing. There is more use of lease structures in the solar market.

MS. KROESS: The other issue with leasing is debt tenor. Leveraged leasing offers better accounting treatment. However, it is hard to do a lease without long-term debt that comes closer to matching the lease term than the mini-perm debt currently on offer in the market.

MR. HOWELL: You have so much more flexibility to deal with variable revenues in a partnership flip structure, and developers prefer the partnership flip because it lets them keep more of the residual value.

MR. MARTIN: So it costs more for the developer to get the asset back at the end of the lease term and, Gisela Kroess, your point is mini-perm debt at the lessor level creates complications if it requires a balloon payment before the tax equity investor reaches its target yield. There is big refinancing risk.

Yale Henderson, to come back to you, how many active tax equity investors are there currently in the market?

MR. HENDERSON: It varies day to day, but I would say three.

MR. MARTIN: Three? There are more than three of you on this panel. [Laughter]

MR. MARTIN: Tim Howell, any sense of how many tax equity investors are active?

MR. HOWELL: I would say five or fewer.

MR. MARTIN: Current tax equity yields in the wind market seem to be between 8% and 9%, perhaps at the lower end of that spectrum. Do you have a sense which direction yields are headed?

MR. HOWELL: It is a hard question to answer. There are deals in the market today that certainly fall in that range. There are others that are outside it.

MR. MARTIN: My count is that there have been five partnership flip deals done in the wind sector involving Treasury cash grants since July 9 when the Treasury explained how the cash grant program works. Does anyone have a different count? How many more transactions are expected to close this year?

MR. HENDERSON: Our radar shows three other active transactions that have a good shot at closing this year.

MR. MARTIN: So that would be eight in total for the year?

MR. HOWELL: We expect to close at least a couple more traditional tax equity transactions by year end.

MR. MARTIN: Those are wind?

MR. HOWELL: All wind. I count 10 possible deals this year.

MR. MARTIN: Compared to 2007 when there were something like 18. I haven't seen a count for 2008.

MR. HENDERSON: We are talking about new commitments in 2009 on current deals. There were several legacy 2008 commitments that also closed in 2009.

MR. MARKOWITZ: We've closed five deals this year.

MR. MARTIN: Those were all wind?

MR. MARKOWITZ: Yes, but not cash grant deals.

MR. MARTIN: Were they legacy deals to which you committed before the market collapsed?

MR. MARKOWITZ: Four were legacy deals.

MR. MARTIN: So you have one new deal done since July 9?

MR. MARKOWITZ: No, I thought you said since January.

MR. MARTIN: I am not sure where that leaves us. It sounds like there were a number deals done early in the year, but most were legacy deals and none involved cash grants. Since July 9, there have been five cash grant deals with another five teed up possibly to close by year end. How long a commitment will a tax equity investor give at the start of construction to fund tax equity?

MR. HENDERSON: Historically, within a year. We are very comfortable currently with commitments to fund within six months. When we start going beyond that, the parameters around the commitment may not change.

MR. MARTIN: For example, the yield goes up the longer the commitment?

MR. HENDERSON: Yes. I think many developers would trade a lower yield subject to adjustment for a higher fixed yield committed for a longer period. They would rather not have the uncertainty.

MR. MARTIN: The Internal Revenue Service said last month that developers can have an option to buy the residual interest of the tax equity investor after the flip for a fixed price that is set at the start of the transaction. Do tax equity investors ask for a higher yield in exchange for giving / continued page 32

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the developer a fixed-price purchase option?

MR. HENDERSON: No. The existence of such an option will not affect the flip yield. I don't see the IRS announcement having a big effect on what the market has been doing, particularly when you consider most deals being done in the market today have 20-year power purchase agreements. The investor's residual value is fairly predictable.

MR. MARTIN: Tim Howell, is there an extra charge for giving a developer a fixed-price purchase option?

MR. HOWELL: I agree with Yale.

MR. MARTIN: So every developer should ask for such an option. There is no cost to the developer.

MR. HOWELL: You can, frankly, but the option price will have to based around a P50 case, so that the fixed price might end up higher than fair market value when you actually get to the flip.

MR. HENDERSON: The big value is in deals where the power purchase agreement is shorter than 20 years. If the PPA is only five or 10 years and the project is exposed to upward power prices and potential carbon and REC prices, that is where the discussion will get very interesting. The interesting question will be at what level to set the fixed price.

MR. HOWELL: I agree. The option appeals to developers who think there is a massive upside in these projects.

MR. MARTIN: There used to be a rule of thumb that tax equity raised through a partnership flip would cover 65% of the capital cost of a typical wind farm. That hasn't been true for at least a year. The figure was more like 50% before the Treasury moved to cash grants. What percentage of the capital cost can be raised in a cash grant partnership flip today?

MR. HENDERSON: On an unlevered deal, it would come out somewhere between 55% and 70% of upfront costs. I am counting the grant as part of that funding, so we are getting 30% of the project cost back 60 days after we fund.

MR. MARTIN: So 25% to 40% tax equity on top of the cash grant?

MR. HENDERSON: Yes.

MR. MARTIN: Tim Howell, do those numbers sound correct?

MR. HOWELL: We offer a broader range of products, so we will fund anywhere from 50% to 90% of the project cost whether it is with or without project-level debt.

MR. MARKOWITZ: A lot does depends on the structure. The cash grant is 30% of the project cost. We generally see the tax equity funding an additional 20% to 25% of the project cost in unlevered deals. The amount of cash that the project is expected to throw off is the key variable.

MR. MARTIN: If there is project-level debt, what would the capital structure look like?

MR. MARKOWITZ: The tax equity provides another 15% or 20% of capital on top of the cash grant.

Combining Debt and Tax Equity

MR. MARTIN: Gisela Kroess, I think you said the typical wind farm will support term debt in the amount of roughly 50% of the project cost.

MS. KROESS: Yes, based on a one-year P99 projection and average capacity factor.

MR. MARTIN: What's the required coverage ratio using P50 numbers?

MS. KROESS: The P50 coverage must be 1.4 to 1.45.

MR. MARTIN: Chris Stolarski, are you in the same place?

MR. STOLARSKI: Yes.

MR. MARTIN: So if you have 50% debt, what is the rest of the capital structure?

MR. HOWELL: My answer is the same with or without debt.

MR. HENDERSON: We're not that active in looking at leveraged deals, but it is a very interesting structure from the investor standpoint, particularly this year when there is still a 50% depreciation bonus on projects. The investor probably will get close to all his money back in the first 60 days with the Treasury cash grant and the depreciation bonus.

MR. MARTIN: Does it make you nervous as a tax equity investor to get all of your money back so quickly?

MR. HENDERSON: I think we can get comfortable that we are the owner if we have an ongoing interest in the asset and the transaction has been structured to remain within the IRS guidelines for partnership flip transactions. The concern is a practical one. You have put a lot of work into a deal and have made only a short-term investment.

MR. MARTIN: You want your money to remain invested and earning a return for a long period of time. Lance Markowitz, Union Bank has been offering developers to put both tax equity and term debt at the same time into a project. What is the attraction to developers?

MR. MARKOWITZ: We sell the term loan to another lender. It is a way of underwriting the debt. Having only Union Bank at the table makes it easier to close the transaction.

MR. MARTIN: Have you had many takers for the product?

MR. MARKOWITZ: We did a couple deals, but we are not doing them today because the underwriting market is largely nonexistent.

MR. MARTIN: So it is hard to resell the debt paper. Yale Henderson, how much of a premium does the tax equity investor charge in the current market if there is debt at the project level?

MR. HENDERSON: A significant one. Grant deals with debt at the project level are pricing in the low- to mid-teens on tax equity yields. However, the internal rates of return quoted are misleading because the tax equity gets back a large share of its investment in the first 60 to 180 days.

MR. MARTIN: So the internal rate of return overstates the real burden to the developer?

MR. HENDERSON: Most of the yield is paid quickly through the Treasury cash grant and depreciation. If you focus solely on the ongoing cash flows, the tax equity is probably only getting a 2% or 3% return on a pre-tax cash basis, if not lower.

What's Different?

MR. MARTIN: What if someone has been out of the market this year? He was familiar with how partnership flips were done the last couple years. What, if anything, has changed about how partnership flip deals are done in a cash grant world?

MR. HENDERSON: I think the biggest change is you can do shorter tax equity deals. Partnership flip deals were structured before the cash grant so that the flip was projected to occur in year 10 under a P50 case. You wanted to wait to flip until all the production tax credits had run. They run for 10 years. Today, there is no such constraint. Deals may price to flip in year six or eight. It depends on how much of the future cash flow you want to sell to the tax equity investor. The biggest constraint is investors run out of capital account before they can absorb the full depreciation on the project.

MR. MARTIN: Tim Howell, one of the ways people have gotten around the problem that the investor has too little capital account to absorb the tax benefits is to have the investor agree to step up to a deficit restoration obligation, meaning the tax equity investor promises to put money back into the partnership if he has a deficit in his capital account when the partnership liquidates. Are tax equity investors still agreeing to deficit restoration obligations? There used to be a rule of thumb that an investor would agree to put back up to 20% to 22% percent of his investment. Is there a similar rule of thumb today?

MR. HOWELL: Yes, but it is hard to state a rule of thumb. Investors are more likely today when agreeing to a deficit makeup obligation to insist on protections, like special allocations of income to eliminate the deficit after the flip occurs with additional cash allocated to the investor to make him whole.

MR. MARTIN: Lance Markowitz, will you agree to a deficit makeup obligation?

MR. MARKOWITZ: Yes.

MR. MARTIN: Is there a limit on how high it can go or is it open ended?

MR. MARKOWITZ: There is a limit; we analyze what we are comfortable with based upon various scenarios. It usually ends up in the 20% range.

MR. HENDERSON: Capital account deficits are more tolerable in cash grant deals. In transactions with production tax credits, there is a risk not only that the investor will be unable to absorb all the depreciation, but also that production tax credits will shift to the developer, who cannot use them. There is no risk of the cash grant shifting to the developer after the investor runs out of capital account.

MR. MARTIN: There are a number of tax equity investors who invest and then want to sell down the paper they are holding. Some have to — Lehman is an example. These pieces of paper are like bonds. As yields go up from where they were when the tax equity deal closed, the value of the paper goes down. Is there much of a secondary market? How do sellers of tax equity paper purchased at low yields avoid taking a loss when they resell the paper in today's market?

MR. MARKOWITZ: Who said they are avoiding losses?

MR. HENDERSON: Exactly. The only sellers in the current market are companies that are bankrupt and don't have a choice. The way they see it, they can either take a loss now or take the same loss over time. They sell in order to raise cash to pay off creditors.

MR. MARTIN: Let's talk briefly about prepaid service contracts. Three wind farms have now been financed with such contracts. The project sells its output under a long-term power contract to a utility. The utility prepays for a large share of the electricity to be delivered over time. Are you comfortable providing tax equity to such a project?

MR. HENDERSON: We are comfortable with the structure. The prepayment is economically equivalent to project-level debt.

MR. MARKOWITZ: There is nothing wrong with the structure, but there are more deals in the / continued page 34

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market than there is time to do all of them, so we are spending our time on other structures that work better for us.

Outlook for 2010

MR. MARTIN: Chris Stolarski, what do you expect from the debt market for the remainder of this year? What do you expect next year?

MR. STOLARSKI: We see continued improvement through the end of this year as far as liquidity is concerned, and further improvement next year. Do we return in 2010 to the same level of liquidity that there was 18 months or 24 months ago? I don't think so, but the market could get to 70% to 75% of where it was.

MR. MARTIN: Increasing liquidity brings lower interest rates?

MR. STOLARSKI: Not significantly lower in the next year or so.

Debt tenors are moving back to 12 to 15 years with 16 to 20 active banks.

MR. MARTIN: So more people can borrow but they still pay the same rates?

MR. STOLARSKI: There is still a backlog of deals and lenders are picking and choosing among potential transactions. You might start to see some easing in borrowing costs once supply and demand come back into balance.

MS. KROESS: It is important to keep in mind that we are in a record low interest environment. The argument can be made that even though margins are high, real interest rates are lower than they were two years ago. There is pressure on upfront fees and margins; for the right sponsor, they may fall below 300 basis points. However, I don't expect them to return to the 1% level any time soon.

MR. MARTIN: The 1% you are referring to is the upfront fee?

MS. KROESS: Yes, and the margin. There was construction debt on offer two or three years ago for margins as low as one and a quarter. I expect volume to be up substantially next year. We did a count of debt deals in the wind market in the last year and came up with 18 deals closed with about $3 billion in volume. This doesn't take into account the institutional debt market. Institutional debt added at least another $1 billion.

MR. MARTIN: John Anderson, what do you see for the debt markets for the remainder of 2009 and in 2010?

MR. ANDERSON: We closed on a project financing this year, but hadn't done one for 12 months before that. It is nice to see the institutional debt markets come back to life with competitive pricing. I see the market picking up momentum as we move into 2010.

MR. MARTIN: What is a good year for your shop? How many deals do you look to do in a typical year?

MR. ANDERSON: We invested $3 billion in 2008. It was a combination of corporate bonds, project finance and private equity. We have done $2 billion so far in 2009. If there is a lot of project financing, that's great, but if not, we will invest the money in corporate bonds or private equity funds.

MR. MARTIN: Lance Markowitz, what do you see for the remainder of this year and in 2010 for the tax equity market?

MR. MARKOWITZ: This was a transition year. I think we will see more investors coming back into the market in 2010, and there will be a lot more deal flow. We will also see more varied transactions; not everything will be a partnership flip deal.

MR. MARTIN: Tim Howell?

MR. HOWELL: The bottleneck in 2009 was lack of debt and tax equity. It will shift in 2010 to more market-driven constraints like difficulty getting power purchase agreements. There is no strong need for additional generating capacity anywhere in the country, so what will drive growth? It will have to come from something like a national renewable energy standard. I agree with Lance Markowitz: the worst is over in terms of tax equity and debt liquidity. The market will not come roaring back, but it will make a gradual recovery.

MR. MARTIN: Yale Henderson, what do you see for the tax equity market for the rest of 2009 and then 2010?

MR. HENDERSON: We are closing deals and getting money out the door this year. I see some of the old players who were out of the market returning in 2010. We spent a lot of time in 2009 trying to find other investors to come into deals with us because we have a limit on exposure to a single project. We feel we are making progress with three to five potential investors and hope to see some of them get across the finish line with us by early in 2010. ◎

Islamic Project Finance: Structures and Challenges

by Richard Keenan, in Dubai

Islamic finance is expected to make up 30% of the total project finance market in the Gulf Co-operation Council, or GCC, countries by 2012, compared to just over 12.5% in 2006, according to the latest estimates.

However, growth in Islamic finance as a percentage of the total market continues to be constrained by certain obstacles. A significant proportion of Islamic finance that has been provided in connection with project financings in the GCC countries has been supplied through the "Islamic windows" of conventional banks rather than by Islamic finance institutions.

This article summarizes some of the Islamic finance structures typically implemented in project financings and looks at some of the challenges that have faced and still face the continued growth of Islamic finance in the project finance sector and how some of these challenges may be overcome.

The relationship between Islamic finance institutions and their customers is not the same as the conventional creditor and debtor relationship, but rather one involving the sharing in financial risks and rewards. Islamic finance is also principally asset-based and, in line with *Shari'a* principles of risk sharing, Islamic lenders bear some of the risks associated with ownership of the relevant assets. Applying these principles to project finance is difficult.

It is worthwhile describing briefly how an Islamic finance tranche is typically structured in a project finance transaction.

The most frequently used structures in the project finance sector in the Middle East are the *Istisna'a-Ijara* structure, which is sometimes generally referred to as a "procurement" structure, and the *Wakala-Ijara* structure.

Istisna'a-Ijara

An *Istisna'a-Ijara* structure incorporates an *Istisna'a* contract that applies to the construction phase of a project, and an *Ijara* contract is put in place for the operations phase.

An *Istisna'a* is a contract for sale whereby one party undertakes to manufacture a specific asset according to agreed specifications and deliver the asset by an agreed time for an agreed price.

If a traditional *Istisna'a* contractual arrangement was applied to a project financing, the financiers would enter into a contract directly with the contractors engaged to construct the project's assets. To avoid the Islamic lenders being exposed to significant construction risk and the credit and performance risk of contractors, most project financings use a parallel structure where the borrower undertakes under an *Istisna'a* contract to procure the manufacture, delivery and construction of the relevant plant and equipment from the manufacturer. In parallel with the *Istisna'a* contract, the borrower enters into a construction contract with the construction contractor incorporating a pass through of the terms and conditions of the *Istisna'a* contract.The Islamic financiers make phased payments to the borrower, akin to draws under any conventional finance facility during the construction phase of a project. Some scholars have permitted the use of a forward lease arrangement, known as an *Ijara Mawsufah Fi Al Thimma*, whereby advance rental payments are paid by the borrower during the term of the *Istisna'a*. These advance rental payments are typically sized to cover the Islamic financier's funding costs, together with a profit margin, and are often effected by a deeming provision whereby certain phase payments equal to advance rental payments are deemed to have been paid by the Islamic financiers to the borrower.

The use of forward lease arrangements is often permitted by scholars only on the proviso that if the borrower never has the benefit of a lease of the assets under the *Ijara* (for example, due to a failure to deliver the assets), any such advance rental payments must be reimbursed to the borrower. To avoid such an unacceptable outcome from the point of view of the Islamic financiers, if the *Istisna'a* is terminated prior to project completion, the borrower is obliged to pay liquidated damages for failing to deliver the assets equal to the */ continued page 36*

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aggregate advance rental payments paid by the borrower.

Title to the relevant assets typically passes to the Islamic financiers automatically upon transfer of title under the EPC or construction contract.

If the borrower fails to deliver the assets, the remedies available to the Islamic financiers are more or less the same as the remedies conventional banks rely on in the same scenario. The Islamic financiers are entitled to accelerate the repayment obligations of the borrower and to terminate the *Istisna'a*. The borrower is typically obliged to reimburse to the Islamic financiers the aggregate of phase payments it has received prior to enforcement and is often also obliged to pay liquidated damages as described above.

The *Ijara* contract typically comes into effect upon project completion. An *Ijara*, in simple terms, is a lease contract where a lessor purchases an asset and rents it to the lessee for a specific period of time at an agreed rental.

The leased asset must have a usufruct, or a legal right to use and derive profit or benefit from the asset. In order to be *Shari'a* compliant, an *Ijara* must be transparent, detailed and the terms agreed prior to execution. The lessor under an *Ijara* must maintain legal and beneficial ownership of the asset and bear responsibility for risks associated with ownership of the asset, meaning there must be a link between an Islamic lender's ability to earn profits and the assumption of risk.

In the context of Islamic finance, the form of *Ijara* typically used is known as an *Ijara-wa-iqtina'a*; it includes a promise by the Islamic lenders as lessor to transfer the ownership of the leased asset to the borrower, as lessee, either at the end of the lease period or in stages during the term of the *Ijara*.

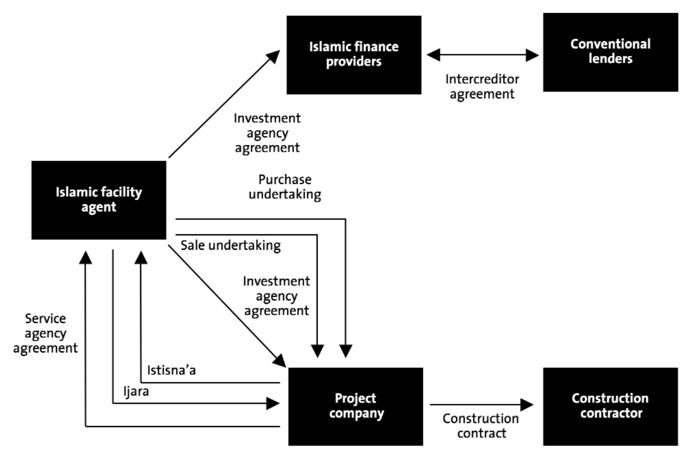
This form of *Ijara* is essentially the Islamic equivalent of a conventional equipment lease contract. Ownership of the assets is delivered to the Islamic financiers upon project completion pursuant to the *Istisna'a* contract and thereafter the Islamic lenders lease the assets to the borrower in consideration for rental payments that are sized to cover the capital cost of the equipment plus a profit margin.

The *Istisna'a-Ijara* documentation typically incorporates purchase and sale undertaking arrangements following termination or expiry of the lease. The Islamic lenders usually undertake to sell all or part of the assets to the borrower in the event of a partial or full cancellation or prepayment of the Islamic facility and following the discharge by the borrower of all outstanding payments owed to the Islamic financiers. After an event of a default by the borrower, the Islamic financiers normally have the benefit of a purchase undertaking from the borrower. This is a form of acceleration of the Islamic facility — the borrower in these circumstances is obliged to purchase the leased assets for a purchase price equal to the aggregate of amounts outstanding under the Islamic tranche. The documentation normally stipulates that title to the assets does not pass to the borrower until the amounts owed to the Islamic financiers have been discharged in full.

Obligations that would ordinarily fall to the Islamic lenders as owner and lessor of the assets, such as care and maintenance of the assets and responsibility for procurement of insurance, are normally performed by the borrower on behalf of the Islamic lenders pursuant to the terms of a service agency agreement. The amounts payable to the borrower in consideration for the performance of these obligations are normally recouped by the Islamic financiers as part of the rental payments payable by the borrower after delivery of the asset.

The Islamic financiers' rights to take any enforcement action in relation to the assets is governed by the terms of an intercreditor agreement between the Islamic lenders and the conventional financiers.

A typical *Istisna'a-Ijara* structure is illustrated in the following diagram:



1 Construction phase (*Istisna'a*) — the borrower procures construction of project assets and then transfers title to assets to Islamic financiers. As consideration, Islamic financiers makes phased payments to the borrower (equivalent to loan advances).

2 Operations phase (*Ijara*) — Islamic financiers lease project assets to the borrower. Borrower makes lease payments (equivalent to debt service).

Wakala-Ijara

An alternative but similar structure often implemented in project financings involving an Islamic tranche is what is known as the *Wakala-Ijara Mawsufah Fi Al Dhimmah* structure or "*Wakala-Ijara* structure."

This structure was used in connection with the Marafiq and Shuaibah IWPPs in Saudi Arabia.

Under this structure, the borrower is employed as the Islamic lenders' agent or "Wakil" in accordance with the terms of an agency agreement known as a *Wakala* agreement. The *Wakala* agreement more or less fulfills the same function as an *Istisna'a* agreement in the other structure, although being an agency agreement, the contractual relationship between the Islamic finance institutions and the borrower is different. The borrower procures the design, engineering, construction, testing, commissioning and delivery of the assets identified in the *Wakala* agreement as the agent for the Islamic lenders.

The *Istisna'a-Ijara* and *Wakala-Ijara* structures are otherwise similar. They both incorporate an *Ijara* agreement for the operations phase and a service agency agreement pursuant to which the borrower performs certain obligations with respect to maintenance of the assets and procurement of insurance. The documentation involved in a *Wakala-Ijara* structure does not include separate purchase and sale agreements; however, the same rights and obligations of the parties with respect to transfer of assets at the end of the term or in the event of early termination are embodied in the documents.

Challenges

What, then, have been some of the challenges affecting the integration of Islamic finance in the project finance sector?

A significant problem has been the difficulty that many Islamic financiers have had until recently competing with conventional lenders in terms of price and tenor.

Before the onset of the financial crisis in 2008, the pricing of project financings hit all-time lows and at these levels, project finance was not a particularly attractive proposition for many Islamic financial institutions. Pricing coupled with the length of tenors conventional lenders were able to commit to (up to 15 years in the oil and gas sector and over 20 years in connection with power and water transactions) made it very difficult for Islamic financiers to compete. Islamic financial institutions tend to focus more on retail banking and rely more on deposits as a source of liquidity rather than the longer-term bond market tapped by conventional banks.

A second obstacle for some Islamic financiers has been the risks associated with project finance.

A lot of time and effort have gone into the development of Islamic finance structures such as the *Istisna'a-Ijara* model in order to try to mitigate or eliminate risks to Islamic lenders. However, the remaining risks still make participation in these transactions prohibitive for many Islamic financiers.

As the legal owner of the project assets, Islamic financiers have exposure to third-party liabilities including environmental risk. Other obligations imposed on the Islamic lenders as owners of project assets include responsibilities relating to insurance and operation and maintenance of the assets. Under a typical *Istisna'a-Ijara* structure, these obligations are normally performed by the borrower on behalf of the Islamic lenders under a service agency agreement, and the borrower in its capacity as the service agent is liable for any loss or damage suffered by the Islamic financiers as a result of any failure to perform these obligations. However, notwithstanding the considerable effort that has gone into developing structures that transfer these risks to the borrower, the Islamic financiers still bear significant responsibility and risk as owners of the assets. The lenders often remain responsible for any capital improvements that are required and, although procurement of insurance is normally delegated to the borrower, the bottom line is that the Islamic financiers, as owners of the assets, bear the risk of availability of insurance and any vitiation by the borrower of its obligations with respect to the project insurance policies. Borrower indemnities to cover insurance shortfalls are of little value if the plant sustains serious damage or incurs significant third-party liability.

Add to these risks the standard risks that are always the concern of any project lender such as counterparty, technology and market risk and you end up with a risk profile that is too onerous for many Islamic financiers to take or results in the pricing of Islamic finance at levels that make it uncompetitive with conventional bank pricing.

A third impediment is, in the eyes of some Islamic finance experts and scholars, an incompatibility of some of the structures that have been developed with the principles of *Shari'a*.

Financial advisors, lawyers, Islamic financial institutions and their *Sharia'a* committees have spent a lot */ continued page 38*

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of time grappling with how to structure Islamic project finance in order to integrate Islamic finance with conventional finance. The end result of this has been the development of a somewhat cumbersome and document-heavy structure that in many respects mimics conventional financing (at least in terms of risk allocation).

Islamic finance is expected to make up 30% of the project finance market in the Arab Gulf states by 2012.

Outlook

What does the future hold for Islamic finance in the project finance sector, and how might some of the challenges faced by the sector be overcome?

In terms of pricing, the gap in margins between conventional and Islamic finance has more or less closed for the time being in the aftermath of the 2008 crisis in the international credit markets. However, the cost of borrowing from conventional banks is unlikely to remain as high as current levels in the medium to long term, and a pricing gap between conventional and Islamic finance will inevitably emerge again.

Looking ahead, there probably needs to be a greater recognition that Islamic finance and conventional finance are two different disciplines and that there will be price disparities between the two types of financing.

The disparity between pricing of conventional and Islamic finance is one of the drivers that has led to development of structures designed to put Islamic banks in more or less the same position as conventional lenders in terms of risk allocation. However, rather than implementing these structures or trying to "squeeze a square peg into a round hole," as some commentators have put it, perhaps the way forward is to embrace more fully the principles of *Shari'a* underpinning Islamic finance. This could lead to the development of Islamic finance structures where the Islamic financial institutions play a more active role in discharging their responsibilities as owner of project assets rather than passing these onto to the borrower or third parties. In turn, this could lead to a greater willingness in the market to accept that the risk profile of Islamic finance justifies higher compensation.

There is an ongoing debate among experts and commentators as to whether the fundamentals of Islamic project finance need to be re-examined and new structures put in place.

It is no secret that the Islamic project finance market has been dominated by the "Islamic windows" of conventional banks. In fact the proportion of funding by purely Islamic finance institutions in the project sector is comparatively small. The one exception to this is Saudi Arabia where the *Shari'a* compliant finance institutions, meaning those Saudi financial institutions that do not offer conventional forms of finance — such as Alinma, Islamic Development Bank, Al Rajhi and National Commercial Bank — have made and continue to make a very significant contribution to the funding of project-financed transactions in the Kingdom. For example, of the US$1.5 billion loaned by Saudi banks in connection with the Rabigh IPP that achieved financial close in June 2009, 65% was contributed by Alinma, Al Rajhi and National Commercial Bank. The fact that Islamic finance structures such as the *Wakala-Ijara* structure have been accepted by Islamic financial institutions such as Alinma, Al Rajhi and National Commercial Bank and have withstood the rigorous scrutiny of their *Shari'a* committees has to be seen as a strong endorsement of these structures in terms of compliance with *Shari'a* principles. The outlook for Islamic project finance in Saudi Arabia is strong.

There undoubtedly needs to be a greater degree of consistency among the *Shari'a* committees of Islamic finance institutions regarding *Shari'a* compliance. The fact that you can have one particular Islamic finance structure or specific aspect of a structure approved by the *Shari'a* committee of one particular

Islamic finance institution but not another is not helping the growth of this industry. A more standardized approach must be adopted not only to overcome a prevailing perception that the viability of Islamic finance continues to be hampered by uncertainty in terms of *Shari'a* compliance, but also in order to reduce the time and cost involved in executing Islamic project finance transactions.

The myriad legal documentation required to structure an Islamic finance tranche makes these transactions more expensive and more time consuming to execute compared to a conventional financing. Some recent initiatives have helped with market standardization. They include the growing list of industry standards published by the Accounting and Auditing Organization for Islamic Finance Institutions and Bahrain's International Islamic Finance Market. However, more work and collaboration between Islamic finance institutions and their respective *Shari'a* committees is required.

There may also be a greater role to play for those governments of the GCC keen to foster Islamic finance within their countries. Some of the risks assumed by Islamic finance institutions could be mitigated by different forms of government protection. One example is a backstop against insurance risk. If, as owners of project assets, Islamic financiers are obliged to insure the assets, governments might offer backstop insurance protection to mitigate the risk of insurance not being available. This type of protection has already been provided by governments in favor of sponsors in relation to project financings in certain jurisdictions in the GCC, including Saudi Arabia and Abu Dhabi.

The enforceability of insurance provisions has been questioned by some *Shari'a* scholars on the basis that a contract of insurance has been associated with gambling, an activity proscribed by the *Shari'a*. Making the government the insurer of last resort could spur development of *takaful* (Islamic insurance) industries within GCC countries.

Government sponsors could also provide some degree of protection, third party or environmental risk through an indemnity or statutory relief.

There are also often tax implications for Islamic financiers with which governments of the relevant countries could assist. The ownership of project assets by the Islamic finance institutions and the contractual arrangements that they are party to often raise tax concerns for both sponsors and lenders. From the Islamic financiers' point of view, taxes may be imposed in connection with the physical location of the asset or nature of the contractual arrangements — lease payments for example in some jurisdictions may be subject to withholding tax. From the borrower's point of view, these structures can also be disadvantageous. Interest payments under conventional loans can be claimed as a tax deduction in many jurisdictions, whereas lease payments may not attract the same tax relief and, if withholding tax is levied on such payments, this liability is most likely to be passed onto the borrower through tax gross-up provisions. Governments in many of the GCC jurisdictions could do more to ensure that Islamic financiers and sponsors of projects that involve Islamic tranches are not any worse off from a taxation point of view than they would be if they were participating in a conventional financing.

Islamic finance is undoubtedly more suited to certain type of projects than others. Islamic finance lends itself more to projects that incorporate a discrete set of assets that can be owned by the Islamic financiers without too much potential intrusion on the enjoyment of such rights by conventional banks under intercreditor arrangements. Furthermore, to qualify for an *Ijara* contract, the assets owned by the Islamic financiers must be separable and have an economic value as stand-alone assets.

However, this can be a difficult proposition for plants that are made up of integrated equipment. While certain assets forming part of a plant may be capable of being "ring fenced" from the rest of the plant, such assets, if valued as individual items of equipment, may not reflect their true value in terms of their importance to the overall operation of the plant.

Finally, there is the issue of tenor. As with pricing, the competitive advantage in favor of conventional banks in terms of tenor they can offer has been to some extent eroded in the aftermath of the credit crisis, but it is difficult to gauge any advantage in the current market. Over the last 12 months, conventional banks have struggled to commit to tenors of more than eight to 10 years. This has resulted in the emergence of the "mini-perm" structure that was adopted, for example, in connection with the Al Dur IWPP in Bahrain. However, there are examples of project financings that have closed in the last 12 months where tenors of 20 years or more have been achieved. The Rabigh IPP in Saudi Arabia and Shuweihat 2 in Abu Dhabi are two examples.

It is difficult for many Islamic financial institutions to commit to tenors beyond seven to eight years. Some bankers have for this reason considered Islamic finance better suited for bridge financing. The market for equity bridge finance in the Middle East has contracted significantly */ continued page 40*

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over the last 18 months. Prior to the credit crisis in 2008, it had become more or less standard market practice for sponsors of project financings in the power and water sector in the Middle East to fund their equity contributions initially through an equity bridge loan. At the height of the market in 2006 and 2007, EBL tenors were as long seven years often not expiring until three or four years into the operation phase of a project. Depending on pricing, Islamic finance would in many in ways be ideally suited to equity bridge financing and if the market for this form of finance recovers, it may be worthwhile for sponsors, lenders and their advisors to try to attract Islamic finance institutions into this market. ◎

Cross-Border Renewables — Baja to California

by David Markey, in Los Angeles

The high demand in California for electricity from renewable energy is creating opportunities for developers to build projects along the Baja peninsula in Mexico and then export the electricity across the border into California.

However, such projects face a series of practical and economic challenges.

Among these challenges are the uncertainties involved in negotiating financeable land rights in the Baja California region of Mexico, limited transmission capacity to carry power across the border and the fact that Baja projects will have to compete with domestic US projects in bidding to supply electricity to California utilities without the benefit of tax credits, cash grants and other incentives for projects on the US side of the border.

On the plus side of the ledger are sites south of the border may be easier to come by and the wind resource in northern Baja appears to be excellent. A number of projects are already under development with several developers having begun to secure land rights in the La Rumorosa region and acquire the requisite permits to generate and export power.

Supply and Demand

California has one of the most ambitious renewable portfolio standards, or RPS program, in the nation. Twenty-nine states and the District of Columbia have laws requiring electric utilities to supply a certain percentage of their electricity from renewable energy. The federal government may adopt a national RPS in 2010.

Electric utilities in California are required to increase procurement from eligible renewable energy resources by at least 1% of their retail sales annually, until they reach 20% by 2010 and 33% by 2020. Although there are numerous projects being developed in state, these targets will still be difficult to meet and, consequently, there are opportunities for out-of-state resources to assist California in reaching these targets.

By a fortunate coincidence, Baja California, as the Mexican side of the Baja peninsula is called, has excellent potential for wind, solar and geothermal projects. In the near term, the geothermal assets at Cierro Prieto will be used to satisfy demand in the Baja region itself, and solar energy seems prohibitively expensive to export due to the high cost to generate solar electricity compared to other types of power and the inability of solar projects on the Mexican side of the border to benefit from the 30% investment tax credit or cash grant that can be claimed on solar projects in the United States. Therefore, most of the attention in Baja is focused on wind. The La Rumorosa region in particular shows strong wind potential.

The "renewable energy transmission initiative" noted in its January 2009 report that wind resources in Mexico look particularly promising. The report suggests a potential for 5,000 megawatts of border region wind projects. (The initiative is a collaborative stakeholder planning process initiated as a joint effort among the California Public Utilities Commission, the California Energy Commission and the California Independent System Operator.) Its subsequent December 2009 report contains further analysis of the energy potential in Baja, comments favorably on the potential to use that potential to meet part of the demand in California for renewable energy and suggests that additional work will be done by the state to evaluate delivery of energy from Baja to Los Angeles.

The Challenge of Transmission

The lack of transmission is a major challenge facing developers, and it presents itself in two forms. First, there is the challenge of finding enough transmission on the Mexican side of the border to move the power north into California to an interconnection point for the California grid. Second, once the power crosses the border, the grid itself has problems with congestion.

It is not easy to move electricity within California to highly-populated urban areas.

Existing cross-border transmission is limited. There currently exists only 800 megawatts of transmission capacity between Baja California and California. This occurs through two 230-kV lines jointly referred to as Western Electricity Coordinating Council Path 45. On the Mexican side, the lines are owned by the *Commission Federal de Electricidad,* or CFE, and on the California side, they are owned by San Diego Gas & Electric. On the California side of the border, Path 45 interconnects with the Southwest Powerlink in the Imperial Valley. Much of this 800 megawatts is apparently unused and could be used to transport renewable energy from Baja to California.

This leaves a developer with two options. First, it can connect to Path 45, which is operated on the Mexican side of the border by the CFE, and contract with the CFE to carry the power to an interconnection point with the California grid. This is permitted in Mexico once a project has been issued with an export permit (the process for which is described below). Wheeling charges would add to the cost of the exported energy. The second option is to finance and construct its own transmission to an interconnection point within California grid territory. Although no renewable energy projects connect directly into California currently, two merchant-owned gas-fired plants in Mexico connect directly to the California grid at Imperial Valley. In a similar way, renewable energy projects could construct their own transmission trunk line from Baja to a substation in California such as the Imperial Valley substation. These trunk lines could also be used by future projects in the same area.

Developers attempting to pursue this second option are unlikely to receive assistance from the Mexican government. Since all public transmission is owned and operated by the CFE, there are no government incentives for private expansion of the transmission grid. Further, the CFE itself is likely to be constrained in constructing transmission lines to export electricity because its primary function and responsibility are the transmission and distribution for public service within Mexico.

There are positive signs that additional cross-border transmission capability will be added over the coming years. Sempra has applied to the US Department of Energy for a federal permit to allow it to build a cross-border transmission line connecting wind projects at La Rumorosa to the Southwest Powerlink in southern Imperial County and potentially carrying 1250 megawatts. A further possibility would be a cross-border tie-in to the Imperial Irrigation District. Power could then be wheeled to Southern California Edison or Los Angeles Department of Water and Power territory (although transmission to the later would be dependent on completion of proposed transmission upgrades). If additional transmission capacity is built by pioneering developers, this could be made available to future wind projects and make connecting to the California grid easier and less costly, further incentivizing development.

The second challenge for developers is how to transport the electricity to energy hungry urban areas once it has arrived in California. Existing cross-border transmission lines connect to the California grid in the Imperial Valley. Cross-border links from the La Rumorosa area could also tie into the California grid near this point. If this is the case, then the question of how this energy will make it to urban areas needs to be addressed. Upgrades to the California transmission system are currently under review, and a "regional energy transmission initiative" is underway in California to identify major upgrades that are needed to the California grid to allow the state to meet its renewable portfolio targets. If Baja is identified as an important competitive renewable energy zone, this could lead to significant transmission upgrades ensuring Mexico renewable energy reaches the utilities that need the electricity in California.

There are already signs that California transmission will improve in ways that will benefit projects located in Baja. The Sunrise Powerlink project was approved by the California Public Utilities Commission in December 2008. This project involves construction of a new 500-kv line from the Imperial Valley to SDG&E service territory. This has been seen as a significant boost for those wishing to export energy from Baja to California.

California RPS Process

Although the main driver behind development of Mexican wind projects for the purposes of export to California is the ambitious California RPS targets, the RPS process itself may present additional challenges to Mexican-based projects.

The California utilities must purchase renewable energy in competitive solicitations. Mexican projects are at a disadvantage in such bidding.

They do not qualify for the same tax credits or cash grants as US projects, and there is no tax credit incentive scheme currently in force in Mexico. Although the recently introduced Mexican law regarding renewable energy projects permits incentives for renewable energy projects, no concrete / *continued page 42*

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details have been provided yet and it is unlikely that tax incentives would be given to projects producing power for use outside Mexico.

Under the California RPS program, a Mexican project would have to be certified under out-of-state and out-of-country requirements. As part of the out-of-state requirements, projects located outside California must demonstrate that they have adequate transmission capability. Given the lack of existing transmission currently available, once transmission costs are factored into models for Mexican projects, it may be difficult for them to provide the most cost-effective option for California utilities.

A partial flip side to these economic disadvantages is that Mexican projects will likely benefit from lower construction and operation costs.

There may also be practical issues that arise from the RPS process. A non-US facility must demonstrate that it does not violate any California environmental quality standard or requirement. It must also show that it will protect the environment to the same extent as would be required under all laws, regulations and requirements for a similar facility located in California. This may be difficult to do in practice because it puts the burden on the developer while US projects will probably be assumed to be in compliance.

Securing land rights in Baja is a further challenge for developers. Unclear land records, ownership of land by cooperatives and lack of familiarity by landowners of what it takes to have a financeable wind lease may make swift and efficient negotiation of financeable wind leases difficult for developers.

Legal Requirements

The Mexican Public Electricity Service Act was modified in 1992 to allow private parties to generate power for a variety of purposes, including export.

A developer wishing to construct a private power plant to export electricity must obtain an export permit from the *Commission Reguladora de Energia,* or CRE, the independent regulatory agency with jurisdiction over the electric and gas industries.

Practically, the permitting process in Mexico can be arduous with a substantial amount of additional requests for information being made by the CRE. Three requirements to get a permit are worth noting. First, the power producer must be a Mexican corporation and be domiciled in Mexico. Second, the applicant must submit a document showing a commitment or letter of intent to acquire the electricity from persons in another country. Third, the developer will need confirmation from the CFE that it has the capacity to wheel the electricity.

If a developer plans to construct its own cross-border transmission line, then it must submit an environmental impact assessment and a risk analysis of the project to the *Secretaria del Medio Ambiente y Recursos Naturales* (SEMARNAT). The developer will need an environmental impact license and a risk license from SEMARNAT. Separate land use and construction licenses will also have to be obtained from the municipal authorities through whose territories the line passes. There are also a number of other regulatory bodies that sit underneath SEMARNAT and that are responsible for assessments of parts of the SEMARNAT permitting process, such as water and hazardous waste and emissions. Private transmission lines must also comply with official Mexican standards.

In the United States, the construction and operation of an international transmission line across the US border requires a permit from the US Department of Energy. Applications are filed with the office of electricity delivery and energy reliability. The Department of Energy will then make a determination as to whether an environmental impact study will be required in connection with the application. If such a study is required, the process for obtaining this permit may take between 18 and 24 months. If not, a six-month time frame should be sufficient.

The sale of the imported electricity in the United States is treated in the same way as domestic electricity. Federal regulation is limited to "sales for resale" in "interstate commerce" by a public utility. Since interstate commerce involves only situations where electric energy is transmitted from a US state and consumed at any point outside that state, if power from Baja California projects is purchased directly by a California utility, the transaction would not be considered interstate commerce and would not be the subject of federal regulation. ◎

Finding Development Capital

It has never been easy for smaller developers to raise the large sums of capital needed to develop a project. For many, the game is to push the project as close to construction as possible before selling. Projects build value as they pass certain milestones along the development path. The slope of the value curve steepens, indicating that value is building more quickly the closer the project gets to the start of construction.

The following is an edited transcript of a discussion among three investors who are potential sources of development capital. The conversation took place by phone as part of an Infocast webinar in the fall. The panelists are Scott Gardner, managing director with US Renewables Group, a private equity firm that manages funds focused on renewable energy, biofuels and other types of clean energy infrastructure, Patrick Eilers, managing director of Madison Dearborn, a fund manager that manages numerous funds, including one that has invested about $2 billion to date in the energy sector, and Ricardo Diaz, executive director with Grupo Santander, the investment banking arm of Banco Santander in Madrid, which has made a decision recently to start investing development capital in projects in the United States. The moderator is Keith Martin with Chadbourne in Washington.

MR. MARTIN: Scott Gardner, does US Renewables Group provide capital to developers and, if so, do you do it on a project basis or are you only interested in acquiring interests in companies with portfolios of projects?

MR. GARDNER: We do both. There have been instances where we will invest in a one-off project or in platform companies that focus in a particular sector, such as solar thermal or geothermal.

MR. MARTIN: Pat Eilers, does Madison Dearborn do both?

MR. EILERS: Yes, although our strong preference is to invest at the holding company or corporate level and then try to build out projects and, as the projects are built out, finance them at the project level, typically investing the appropriate amount of equity in the project itself.

MR. MARTIN: Ricardo Diaz, I believe Grupo Santander is more focused on projects, or is it like Madison Dearborn, you want a company?

MR. DIAZ: We are interested mainly in solar and wind and we invest on a project-by-project basis. We do not usually invest in companies. What we do is to create portfolios out of individual projects.

Preferred Structures

MR. MARTIN: Scott Gardner, how do you structure your participation if you are investing in a single project? Is it a loan, is it equity, is it warrants plus a loan? How does it work?

MR. GARDNER: There is more than one answer to that. While we don't often do one-off projects, we will do them if they have sufficient scale or there is a sufficient risk-reward profile. If we get involved in the development stage, we usually make a loan that is convertible, at closing of the construction financing, into equity in the project company that is developing the project. The idea is that if the project has issues or misses milestones, there would be triggers in the loan that would allow us to take control or, if the project has failed, to cause the company to liquidate and get what it can for the development assets.

MR. MARTIN: Conversion occurs when you start construction. How large an equity interest do you take at that point? How do you calculate your ownership interest?

MR. GARDNER: On a one-off project, we usually seek a controlling investment. We agree to provide 100% of the equity the project company requires, comprised of our development capital plus new capital. However, there is usually some uncertainty about how the negotiation will play out with lenders, so we make a commitment for a not-to-exceed number based on what should be a reasonable amount of debt on the project. For example, if the project costs $100 million and we think, with conservative coverage ratios, the project can achieve 70% leverage, then we would make an equity commitment not to exceed $30 million. The reality is that our actual equity investment is a negotiation with the banks and also depends on how firm a price is being quoted by the construction contractor.

MR. MARTIN: So you will supply all of the equity up to a cap. What is the developer left with? Does it have a carried interest? What percentage of the project does it retain?

MR. GARDNER: The developer's compensation has three components. These are reimbursement of development expenditures, a development fee at construction closing and a carried interest. The first two amounts are built into the capital budget. The proposed development fee may end up being further negotiated with the lenders. The carried interest is a right to a portion of equity distributions, back-ended after the equity investor earns back its capital, plus a preferred return.

MR. MARTIN: So the back-ended carried interest would be what percentage? What is typical: 20%, 30%, 5%?

MR. GARDNER: In a typical project, 100% */ continued page 44*

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of distributable cash flow would go to the equity investors until they have been returned all of their capital plus a pre-tax 12% to 15% return, at which point the distributions shift to something like 90% to the equity investors and 10% to the developer. After another return threshold is reached, say 25%, then anywhere from 20% to 50% of the cash flow might go to the developer, depending on the value of the project. The initial return threshold is usually projected to be reached in something like seven years after the project is completed, but it varies.

MR. MARTIN: Last question — and let me bring Ricardo Diaz into this — what is a typical developer fee as a percentage of total project cost?

MR. DIAZ: It depends on the technology. However, typical numbers we have seen in the market are between 10% and 15%.

MR. MARTIN: Scott Gardner, let me get your answer as well.

MR. GARDNER: It is a really hard question to answer. I agree that it depends on the sector. We have seen formulaic approaches that are more like two times or three times the invested development capital. For example, if the developer put $2 million during the development stage into the project, then his fee might be $4 to $6 million, in addition to the reimbursement of the $2 million at closing. Also, sometimes a portion of the development fee is made contingent on reaching further milestones — for example, commercial operation of the project.

MR. MARTIN: Ricardo Diaz, Banco Santander prefers to invest in individual projects. Is that investment a loan, an equity investment or some combination?

MR. DIAZ: We are flexible. We can buy 100% of the development rights. If the developer is only interested in selling the project when it is ready to start construction, we can provide capital with an option to buy then. If the investor wants to keep the project, we can invest between 50% and 100% of the equity.

MR. MARTIN: So you are willing to leave the developer in and just take a percentage interest?

MR. DIAZ: If the developer has the financial strength to invest equity, we do not need to be the only investor in the project. We can share that, as long as we have the control over the investment. So we can invest anywhere between 50% and 100% of the equity, but we need a controlling interest.

How Early Stage?

MR. MARTIN: Scott Gardner, going back to you, how far along must the project be in the development cycle before you have an interest in it?

MR. GARDNER: It depends. When we invest in portfolio companies, they usually have a series of projects, some fairly early stage, so we have to have patience as to when we might have the opportunity to invest project equity. In one-off projects, we like to wait until most of the off-take and resource arrangements have been worked out. We are looking to invest equity at the start of construction, but there have been cases when we invest earlier because there is competition for a good project, or a particularly attractive risk-reward profile.

MR. MARTIN: Is it fair to say that you will not usually invest in a power project until the developer has signed a power contract?

MR. GARDNER: I actually think it's a little different in today's market. It used to be that signing a power contract was the Holy Grail of having achieved a meaningful milestone, but today I think it is all about the resource in the renewable sector. It is about getting the wind site or the scarce turbine slots or, in geothermal, it is about having proven the resource through drilling or, in waste to energy, it is about locking in a supply of waste fuel. The feedstock or resource is the key asset. We tend to believe that once that piece is in place, there is so much demand for renewable power expressed through renewable portfolio standards, that a well-structured project with the right resource can be expected to get an offtake agreement.

MR. MARTIN: How large a project must it be in terms of capital cost to be of interest?

MR. GARDNER: It will change as our fund raises more money, but at the moment, we would look at a project that requires as little as $10 million in equity. That might mean a project as small as $30 million in total capital cost, on the assumption that two-thirds of the project cost will be financed by borrowing. As we grow the firm, our minimum deal size will increase, probably more in the $25 to $50 million range for the equity component.

MR. MARTIN: Ricardo Diaz, if you invest in a single project, how far along must it be in the development process? Must it have a power contract, for example?

MR. DIAZ: We look for a project in an advanced stage of development, meaning the project must have secured land, have a power purchase agreement with a creditworthy offtaker and have secured acceptable interconnection arrangements so that the project can move its electricity to the grid. Those are the main three things we look at. Other stuff like environmental licenses or construction permits do not need to be in place for us to start investing.

MR. MARTIN: That's very interesting. You are focused on the offtake arrangements and the ability to get the product to market, while Scott Gardner is focused on whether there is a strong enough resource. Ricardo Diaz, how large must the project be before you will look at it?

MR. DIAZ: The minimum equity required must be between $5 and $10 million, which translates into a total project cost of $20 to $50 million.

MR. MARTIN: So you are assuming greater leverage of four to five times equity.

MR. DIAZ: We are used to leverage of 80% or 85% in European wind projects. Solar power is a little less than that, perhaps 75%. In the US, there is a form of intermediate capital called tax equity that one might also treat as leverage.

MR. MARTIN: Scott Gardner, will you do a one-off project with a developer who has only one project, or must you see a pipeline of other deals?

MR. GARDNER: That's an important question. We usually focus on developers who have an anchor project, and that becomes our initial focus, but who also have a pipeline in the works. That's important because one of the top things that we have to evaluate when we make an investment is the management team, and often what we see is too top-heavy a company structure with too few resources devoted toward development. Good management teams are few and far between. Once you find one, particularly one with the skill set in a particular renewable sector, you don't want to do just one project. You want to keep the relationship going with that team and do multiple projects. Our goal is usually to build that team into more of a development company and work on a series of projects.

First Impressions

MR. MARTIN: Scott, you and I have both been in this business a long time. I am guessing the one thing that scares you away — correct me if I'm wrong — is a team that has ambitious plans, can reel off a long list of projects that it is developing, but lacks the focus to get the first deal across the finish line. Is that the number one thing that makes you run the other way or is there something else?

MR. GARDNER: I would rather see a couple of good lead projects with work completed, rather than 10 or 15 projects that we basically would discount and not view as real. Having evaluated a lot of projects and teams, you can judge quickly whether a team has looked in the mirror and assessed its capabilities. The company may have a strong and charismatic leader, but the leader has not surrounded himself or herself with people who have been through a project financing and someone else who has good construction management skills. You need a comprehensive and well-rounded team. That is the most important thing we look for. If a team lacks the skills to take a project all the way not only to financing but also through to COD, then that is a fatal flaw for us, unless we can bring someone in to enhance the team.

MR. MARTIN: Ricardo Diaz, where are equity yields for the two different technologies in which you are investing — wind and solar PV?

MR. DIAZ: We look for a long-term IRR for an investor over the life of the deal in the mid-teens for wind and in the low teens for solar PV. However, our strategy is to plan on an exit within a year after the project is completed. The yields I mentioned are what we think a long-term investor will want. Since we are coming in at a far riskier stage during development, we would be looking for a higher return on our capital. These are pre-tax numbers.

MR. MARTIN: Let me switch gears and pull Pat Eilers into this discussion. Madison Dearborn is interested mainly in buying whole companies rather than one-off projects. Are you interested in buying less than the entire company, and if so, do you insist on a controlling interest?

MR. EILERS: We are open to both. We do the full companies as well as minority investments. In the minority investments, though, we would look for certain negative control provisions that would give us seats on the board or at least a requirement for our consent for major corporate actions.

The only thing I would connect the dots to the prior conversation is that we have a wind development company, we are looking at solar development companies and we are doing transmission, but the premise is that the company has a pipeline of good projects that will be able to attract capital, some in construction, perhaps even some already built. When we look at a corporate investment opportunity, we go down to the project level and start with the question whether the company can attract the project-level debt required to make the model work. So even though we don't do one-off projects, we analyze individual projects to decide whether we want to invest at the corporate level.

MR. MARTIN: Your wind company, First Wind, is what I would call mid-tier. I am guessing that if / continued page 46

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that is the model, then you are not keen on true start-up companies, ones that may have just emerged from venture capital. Is that fair?

MR. EILERS: It depends on whether we can get comfortable. We look at companies that have no operating assets, but if the anchor project has the right components in place, such as a power purchase agreement, perhaps a commitment from the US Department of Energy for a federal loan guarantee, an EPC contract with a respectable contracting firm, and the company just needs the equity, and we are convinced that the company can build on time and on budget and get the performance it expects out of the asset, then we consider those types of opportunities as well.

MR. MARTIN: If you buy the company, how is the ongoing development pipeline funded? Do you fund it through capital contributions or is the company in the same boat as before, having to seek other capital?

MR. EILERS: No, we fund through capital contributions at the corporate level. If you think about how development work is done, it requires 100% equity during development. As you get to construction, you pull in the construction loan, and sometimes we are able to recycle some of the equity and, ultimately, when you get to permanent financing of the project, there will be a permanent share of equity that will remain invested at the project level. The equity that is freed up will go back into the corporation and be used to develop other projects.

Selling Part of the Company

MR. MARTIN: How do you determine the price you are prepared to pay for a company? Do you typically pay the developer something to buy an interest or do you just undertake to contribute capital to fund ongoing activities?

MR. EILERS: We will commit capital to fund a business plan, and there is always a management carry or percentage ownership that the developer retains in the company. Sometimes the developer takes out cash, but we prefer not to do that. We don't think it aligns interests well. We prefer to see the management team have skin in the game alongside us. Sometimes we will put our capital in at the project level, as we did with the Kaheawa project that First Wind developed in Hawaii, where we invested alongside a local developer who started the project and retained an interest. We will do individual project financings, and do equity participations with local partners, just as you were discussing earlier. Madison Dearborn does it as part of what is otherwise a corporate investment opportunity.

Investors want an experienced management team with realistic expectations and a laser-like focus on getting one or two projects done.

MR. MARTIN: You addressed part of this already, but what makes a company attractive, especially a start-up that comes to you seeking financial backing?

MR. EILERS: I think a couple of things that Scott Gardner touched on as well. First, the management team is very important. Is the management team credible? Has it done this before? Is it trying to do too much, as in where the company has four different types of renewable opportunities it is pursuing. That doesn't interest us. We are interested in a management team with realistic expectations, and then we take a close look at the project to assess the likelihood the project will be built.

MR. GARDNER: It is important to distinguish between multi-technology companies, like an independent power company that owns different projects with different technologies, and the kinds of developers and smaller companies who come to us seeking development capital. For smaller companies, a targeted focus is essential. We had somebody approach us recently about a project that was going to produce ethanol, electricity and one other product. Maybe they were also going to have wind turbines on site. That was all within one project. They felt the dispersed focus was helpful because it represents diversification.

Our response was just the opposite. What it represents is multiple offtake risks. If the project relies on all of the offtake being there and all of the resource being there for the various components, if you lose one of them, then you have lost the basis for a viable project. We think in terms of the downside and what happens when things go wrong. Having more bells and whistles and more integration is a negative rather than a positive.

MR. MARTIN: Pat Eilers, most private equity funds plan to hold and then shed assets. I don't know what your time horizon is, but many are five to seven years. What is your time horizon, and isn't this fairly disruptive to a developer to contemplate that he will have new owners within a short time period?

MR. EILERS: We have 10-year funds with an additional three years at our own discretion to extend each fund. We have been in a five- to 10-year hold on average. We fund a company's business plan over about a five-year period and then look ultimately to take the company public or sell down our position through secondary offerings, bringing in additional and hopefully lower-cost equity. There are times when a larger, strategic player acquires a company. That case probably goes to your point of being more disruptive from a management standpoint, but if we have done our job right, we have given the management team enough equity participation that any sense of disruption is offset by the investment returned.

MR. MARTIN: So you view yourself as providing a long landing strip like an airport for people to launch these businesses. Ten years is a long time.

MR. EILERS: That's one way to put it.

MR. MARTIN: Scott Gardner, any other thoughts on potential disruption? What is your typical hold period?

MR. GARDNER: We look at holding for three to seven years.

We usually look to get through construction, which may be two years, and then have one to three years to stabilize the operating business, and then it's time for us to exit and let the company replace us with cheaper capital during the lower-risk operating period.

Technologies of Interest

MR. MARTIN: Ricardo Diaz, you said Grupo Santander is interested in investing in two types of projects — wind and solar PV. Are you also interested in solar thermal?

MR. DIAZ: Yes. We have a strong pipeline of projects right now in southern Europe. We think the main market for concentrating solar power in 2010 will be Spain. We are very interested in exporting our expertise with both European industrial players and project financiers to the CSP market in the United States. The standard size for CSP could be around 50 megawatts, compared to 20 megawatts for PV. There are potential economies of scale not only in equipment cost, but also in financing.

MR. MARTIN: What about distributed solar companies, the ones that put solar panels on rooftops?

MR. DIAZ: Yes, we are interested in investing in such companies as well, as long as the size is attractive enough. Our equity investment must be a minimum of $5 to $10 million. So as long as these distributed generators set up a portfolio of different opportunities with an equity investment at least that size, we are interested. My only caveat is that we have some experience here in Europe with rooftops, and it is more difficult in such transactions to put term debt in place. If we are able to make it bankable, we are interested.

MR. MARTIN: Pat Eilers, are there other technologies besides wind, solar, geothermal and biomass that that you are watching — for example, wave, other forms of ocean energy or offshore wind? Are these technologies mature to enough to attract your attention?

MR. EILERS: Tidal energy is still too early stage for us. We are spending a lot of time on offshore wind. We have a minority interest through First Wind in a company called Deepwater, which has projects under development off Rhode Island and New York.

MR. MARTIN: Scott Gardner, are there other technologies besides the big four renewables that you think are ripe for investment?

MR. GARDNER: Yes. We have done very little in wind and solar because the project equity returns are not high enough for a private equity fund. A lot of the risks have been stamped out of those sectors. That's a good thing for developers, because it means less risk and access to cheaper sources of capital like bank debt. That doesn't mean that private equity funds have no role in the sector; there are still opportunities to build new companies. We have several platform companies focused on different sectors, even if for some of them, the underlying projects may not ultimately be things we invest in. They are what we call growth equity opportunities. They include a start-up geothermal developer, a waste-to-energy developer and a fairly significant investment in a biofuels company we helped found called Fulcrum BioEnergy. Fulcrum converts municipal solid waste into liquid fuels through plasma gasification and Fischer-Tropsch conversion. */ continued page 48*

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MR. MARTIN: So you are willing to take risks.

MR. GARDNER: Yes, but we are past the R&D phase. In the case of something like Fulcrum, I would describe it as technology integration or scale-up risk because each of those technologies has been separately proven. Plasma gasification is used regularly to create gas in things like medical wastes. Fischer-Tropsch has been used for decades in South Africa to convert coal to liquid fuel.

MR. MARTIN: Scott Gardner, what is the best way for a developer to get in the door to make his or her case to you?

MR. GARDNER: We have a portal on our web site for people with business plans. We probably would prefer people just to contact us directly and send introductory information without a lot of volume, so we can make a judgment about whether it's a fit. Let me give an example. I am looking at the area of waste heat recovery and industrial efficiency. It is an area that fits our mandate because it is carbon neutral. What we do in a sector like that is form a thesis around what we think is the right technology or the right approach to the business, and then we look for companies that are active in the sector. We often approach them. We are less likely to be turned on by a company who approaches us for money in a sector in which we have not already formed a thesis.

MR. MARTIN: Pat Eilers, what is the best way to get your attention at Madison Dearborn?

MR. EILERS: Go to our website and then just call us.

MR. MARTIN: Ricardo Diaz, same thing at Santander?

MR. DIAZ: We like preliminary information by e-mail, and we follow up by the phone after that. ◎

A New Transmission Superhighway Takes Shape in the West

by David Howarth and Dr. Robert Weisenmiller, with MRW & Associates, LLC in Oakland, California (Ed.: just before publication, Dr. Weisenmiller was appointed to the California Energy Commission and is no longer with MRW.)

A new transmission superhighway is starting to take shape in the west. Generators whose projects are located near the areas served by it will end up winners. More distant projects will be losers, in the same way that businesses along new interstate highways or subway lines prospered.

Pressing Need

New transmission lines will have to be built from the areas where renewable resources are abundant, which are often remote, to the load centers where electricity is consumed for the United States to have any hope of meeting ambitious renewable energy targets.

President Obama called for doubling renewable energy by 2012, a goal that is supported with considerable financial incentives contained in the American Recovery and Reinvestment Act of 2009. Congress has also taken up the issue with legislation that would establish a national renewable energy portfolio standard, or RPS, of 6% by 2012 and 20% by 2020. These targets were included in an energy bill that passed the House last June; the bill is expected to be taken up by the Senate this year.

In some cases, renewable energy projects are so remote that the cost of interconnecting to the transmission system may be prohibitive. As a result, generators may be unwilling to commit to the interconnection process until a transmission line is added and the incremental cost is reduced, while transmission owners may be unwilling or unable to build a line without commitments from generators in the location to be served by the line. This leads to a classic chicken-and-egg dilemma that prevents construction of new transmission lines. Even when a transmission project is economically justified, the planning and siting process can be extremely difficult given the effects on the environment and communities located along the transmission route.

The western states have been pursuing policy initiatives to address these problems.

The California experience, in particular, may hold lessons for people in other parts of the country.

The initiatives include ways of addressing cost-recovery as well as broad multi-stakeholder planning processes for new transmission lines.

California Experience to Date

California originally required investor-owned utilities to meet an RPS target of 20% by 2017. In 2006, it pushed the 20% target to 2010. In November 2008, Governor Schwarzenegger issued an executive order that increased the target to 33% by 2020 for all load-serving entities, including municipal utilities.

The executive order established a renewable energy action team and called for a streamlining of the renewable energy project siting process. It also directed state agencies to take the RPS into account in all regulatory proceedings, including transmission line permitting.

In 2009, the California legislature codified the 33% RPS target. However, the legislation limited reliance on out-of-state renewable sources, which led to a veto by Governor Schwarzenegger.

Instead the Governor issued another executive order directing the California Air Resources Board — called CARB — to adopt greenhouse gas regulations by July 31, 2010 that are consistent with the 33% renewable target. CARB has broad authority by statute to establish greenhouse gas standards. (See "California Plans a Carbon Diet" in the January 2009 Project Finance Newswire). It is under this authority that the 33% RPS will be implemented in California.

When the California RPS was first established, the state also took steps to support transmission projects necessary to reach the RPS goals.

Any projects deemed necessary by the California Public Utility Commission, or CPUC, to meet the RPS goals automatically meet the need test for the purpose of transmission siting. The CPUC also has authority to permit utilities to recover through retail electricity rates any costs for renewable energy transmission projects approved by the CPUC that the Federal Energy Regulatory Commission does not allow in transmission rates. Procedures for implementing this "backstop" renewable transmission cost recovery policy were formally adopted by the CPUC in June 2006.

California has had some recent success in planning and siting new large-scale transmission projects to serve renewable resource areas, including the Sunrise Powerlink to connect the Imperial Valley to San Diego and the Tehachapi transmission project north of Los Angeles. Although the planning and siting of these projects has not been easy, the experience with them led to policy and procedural changes that have improved the transmission siting process in California.

At least six other renewable energy transmission projects are currently being pursued in California: the California portion of Devers–Palo Verde 2 (Southern California Edison), the central California clean energy transmission project (Pacific Gas & Electric), the Green Path transmission projects (Los Angeles Department of Water and Power and Imperial Irrigation District),the Lake Elsinore advanced pumped storage and transmission project (Nevada Hydro) and the Canada-Pacific Northwest-Northern California transmission project (Pacific Gas & Electric).

The Sunrise project was initially proposed as a 150-mile 230/500 kv transmission line from the Imperial Valley to San Diego. The project included construction of a new substation and modification of several existing substations. Significantly, the proposed project traversed 25 miles of the Anza-Borrego State Park, including some wilderness areas. After completing a more than 11,000-page environmental impact report to comply with California and federal environmental regulations, and a three-year siting proceeding at the CPUC, the original proposal was denied and an "environmentally-superior southern route" was approved. The approved 123-mile southern route twists around the park and nearby Indian reservations, but still traverses part of the Cleveland National Forest. Some environmental groups, including the Sierra Club and the Center for Biological Diversity, continue to oppose the project and have appealed to the courts to overturn the approval.

The Tehachapi transmission project was innovative in that it was developed as a multi-user trunk line specifically to support remote renewable energy development. However, it, too, had a difficult siting process and the cost increased significantly as portions of the line went from 230 kv to 500 kv to support the addition of renewable energy projects not contemplated in the original transmission design. The initial three segments were approved in 2007 and are currently under construction. In December 2009, the CPUC issued a permit for Southern California Edison to complete the remaining phases of the project. There are still objections to at least one segment that is also likely to be challenged in state court.

The Tehachapi transmission project is being developed using an innovative regulatory scheme. The California Independent System Operator — called CAISO — is authorized by FERC to establish defined energy resource areas / continued page 50

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that would benefit from the establishment of multi-user resource trunk lines. These trunk lines would be eligible for favorable rate treatment, allowing transmission owners to include the costs that are not recovered from generators in their FERC-authorized transmission rates. The CPUC backstop cost recovery is still in place, but given federal approval of tariff-based rate recovery for renewable transmission lines, use of this backstop should not be necessary for Tehachapi.

Allocation of transmission costs to individual projects remains an issue and has been a subject of great controversy in the interconnection process.

Generator interconnection requests have historically been reviewed on a first-come, first-served basis. This approach resulted in cost discrepancies depending on the relative queue position of projects as well as a time-consuming iterative study process that would often need to be repeated when speculative projects dropped out of the queue or when project configurations were altered.

The CAISO recently overhauled its interconnection queue process, significantly increasing interconnection application fees and implementing a cluster approach to interconnection studies. About half of the projects in the queue dropped out when the higher fees were imposed. Under the new cluster approach, transmission system upgrades will be identified for groups of projects located in the same area and estimated costs will be allocated to each project on a *pro rata* basis based on project capacity. The cost estimates provided after the CAISO phase I interconnection study become a cost cap for a project, with any additional costs collected by the transmission owners through rates charged to their transmission customers.

Even with improvements in the process for interconnecting renewable energy projects to the existing transmission system, there are concerns that the current process will become a bottleneck.

What is needed is a transmission superhighway to connect high resource areas to high load areas.

Planning the Transmission Superhighway

The federal Energy Policy Act of 2005 addressed the transmission siting issue by requiring the US Department of Energy to study electric transmission congestion and, if needed, designate "national interest electric transmission corridors." In October 2007, DOE designated two such corridors, one in the mid-Atlantic and the other in the southwest. Applicants for transmission projects within the designated corridors who don't receive approval from state regulators within a year can seek permits from the FERC.

The 2005 law also requires federal agencies to designate energy transport corridors for pipelines, electric transmission and other energy facilities. A "programmatic" federal environmental impact statement for the entire western energy corridor program was completed in November 2007 and, in January 2008, more than 6,000 miles of energy corridors in 11 western states were designated by the US Bureau of Land Management and other federal agencies. Portions of the Sunrise Powerlink southern route are located within one of the designated western energy corridors.

California established a similar corridor designation process in 2006. The authority resides in the California Energy Commission, or CEC. Local agencies are required to take into account any corridor designations when authorizing land use changes to ensure that the designated corridors remain viable. These state corridors will be identified in future "strategic transmission investment plans" developed by the CEC. The 2009 plan adopted in December reviewed the status of transmission corridor planning, including utility indications of potential corridor needs, but did not identify any new corridors for designation. The CEC is working closely with federal agencies to coordinate designation of transmission corridors on federal lands in California.

At the state level, there are multiple entities involved in planning and siting high-voltage transmission lines with somewhat overlapping responsibilities. The CAISO and other transmission operators are responsible for conducting an open and transparent transmission planning process and ensuring non-discriminatory access to the transmission system. The "California transmission planning group" was formed in the past year to coordinate long-term planning among transmission operators. The group brings together not only the CAISO and its participating transmission owners, but also California municipal utilities into a statewide transmission planning effort. The CPUC is responsible for siting investor-owned utility transmission projects in California and is the lead agency for compliance with the state Environmental Quality Act. The CEC is responsible for energy planning and analysis and for designating transmission corridors. There has been discussion of possibly consolidating some of these responsibilities under a single regulatory entity, but there has been little movement.

RETI

To facilitate meeting Gov. Schwarzenegger's aggressive RPS goals and to build on the experience with the Sunrise and Tehachapi transmission projects, the California regulatory agencies, developers, utilities and other stakeholders formed a "renewable energy transmission initiative," or RETI, in 2007. The purpose is to identify renewable energy resource areas that can be developed in the most cost-effective and environmentally benign manner and to scope out the transmission projects needed to develop these renewable resource areas.

RETI is organized and driven by committees.

The coordinating committee includes the CPUC, CEC, CAISO, Southern California Public Power Authority, Northern California Power Agency and the Sacramento Municipal Utility District.

The primary working group is a 29-member stakeholder steering committee, consisting of all of the transmission owners, the CPUC, CEC, CAISO, Bureau of Land Management and US Forest Service, as well as one representative from each of the remaining classes of stakeholders.

A "plenary stakeholder group" represents the interests of all interested parties and reviews the work of the stakeholder steering committee. The plenary stakeholder group meets regularly.

The RETI work plan is organized into three phases. Phase 1, which was completed in January 2009, identified competitive renewable energy zones — called CREZs — that can be developed in the most cost-effective and environmentally benign manner. Phase 2A was completed in September 2009 and refined the analysis of resource potential, costs and environmental constraints for the CREZs identified in phase 1 and developed a conceptual transmission plan to serve the selected CREZs. Phase 2B may further refine the conceptual transmission plan, re-evaluate the contribution of out-of-state resources, and identify short-term measures that would speed interconnection of some projects before new transmission lines can be built. Phase 3 would turn the conceptual plan into specific proposals for transmission projects that can be pursued for development and siting approval.

Black & Veatch did the phase 1 study. The study focused on California, but also included Oregon, Nevada, Arizona, Washington, British Columbia and Baja Mexico.

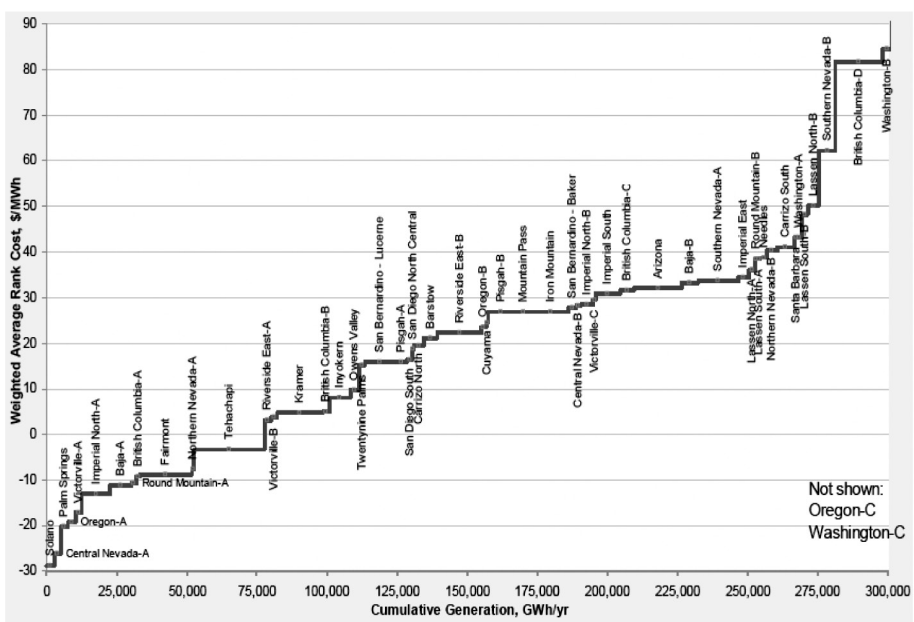
RETI Findings

The study identified 29 potential CREZs in California, with a total resource potential of over 200,000 gigawatt-hours per year (gWh/yr). It also identified 70,000 gWh/yr of smaller non-CREZ projects that do not require large-scale transmission. The remainder of the study area outside of California can provide another 110,000 gWh/yr of renewable resources.

To put these numbers in perspective, the amount of additional renewable generation needed to meet the 33% target in California by 2020 is roughly 69,000 gWh/yr. To account for the fact that not all of the identified resources will be developed, RETI initially set a target of identifying CREZs capable of supplying up to 100,000 gWh/yr.

The CREZs have been ranked in order of economic merit. Each has been assigned a "rank cost" on a \$/mWh basis. The rank cost for each CREZ is based on a generation-weighted average of the resources located within the CREZ. In some cases, CREZs are subdivided for the purpose of ranking to account for areas with both high-cost and low-cost generating projects. As shown in Figure 1, the rank costs and associated generation amounts create a renewable energy supply curve.

Figure 1. CREZ Economic Supply Curve



Source: RETI Phase 2A Final Report, September 2009.

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For any analysis of this type, there is a great deal of uncertainty in input assumptions, especially with respect to future costs and performance. Uncertainty in some assumptions, such as wind turbine costs, will affect all projects and is not likely to affect relative rankings. Other assumptions, such as location or project-specific costs and performance may affect relative rankings and are addressed in the study through the use of uncertainty ranges for capital cost, capacity factor and biomass fuel cost assumptions. These ranges are depicted in Figure 1 as an uncertainty band around the economic scores.

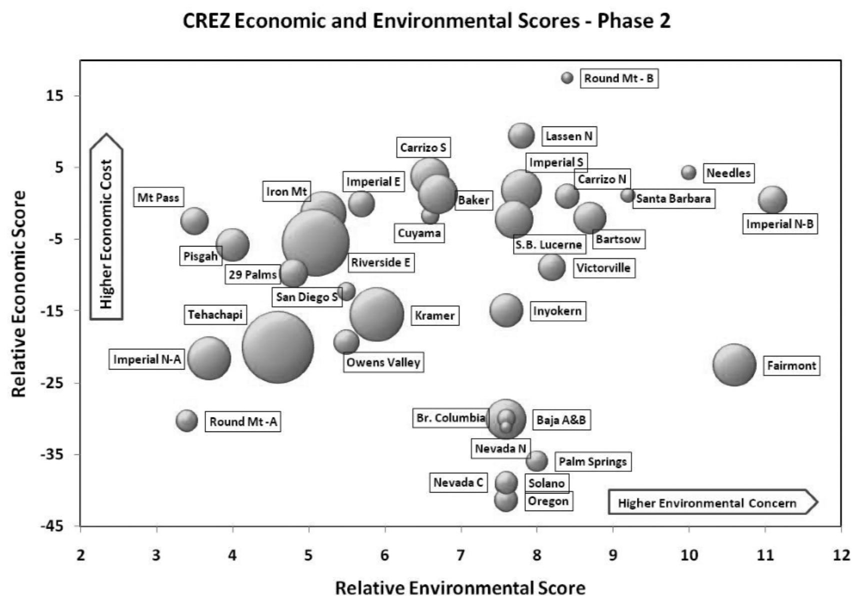
The results using these uncertainty ranges show there is a great deal of overlap among the rankings. In addition to the uncertainty analysis, the RETI study also considered a number of sensitivity scenarios concerning the value of tax credits, energy prices, capacity value, solar PV costs, geothermal potential and the allocation of transmission costs. On the basis of these sensitivity cases, the study identified a list of additional CREZs that could potentially be cost competitive.

An "environmental working group," chaired by representatives of the Natural Resources Defense Council and the Sierra Club, developed a method for rating the California CREZs on the basis of environmental concerns. The criteria were developed by consensus. For example, during the course of the analysis, the definition of the development footprint for wind areas was modified to include just 3.5% of the total area to reflect the land area actually occupied and disturbed by turbines and roads. This change was made after a great deal of discussion and based on input provided from wind developers.

In each case, a quantitative environmental indicator was selected (for example, acres of land for the energy development footprint), and the value for the CREZ was divided by the total annual energy output for the CREZ. The results were then normalized to a scale from zero to five to develop a ranking score for each criterion and then summed across all criteria to calculate a total ranking score for each CREZ. The resulting environmental supply curve provides a counterweight to the economic supply curve described above. The economic and environmental supply curves are combined in Figure 2 to show the relative economic cost and relative environmental concern in an array.

CREZs located in the lower left quadrant have relatively lower economic and environmental costs, while those in the upper right are at the high end of ranking for these factors. Most of the CREZs with the lowest costs and environmental impacts are in southern California.

Figure 2. Economic and Environmental Assessment of California CREZs



Source: RETI Phase 2A Final Report, September 2009.

Based on the results of this CREZ ranking process, which was updated in phase 2A, RETI stakeholders developed a statewide transmission expansion plan showing proposed access to the highest ranked CREZs. The plan is designed to allow enough incremental renewable energy to meet 160% of the estimated statewide renewable net short position in 2020. The plan put a premium on avoiding the need for new rights of way.

The plan devised by the RETI stakeholders consists of three main groups of transmission segments. "Renewable foundation lines" increase the capacity of the California transmission network between Palm Springs and Sacramento. This is the transmission superhighway that allows power to flow north or south as needed.

"Renewable delivery lines" move energy from the renewable foundation lines to major load centers. These are the off-ramps that ensure deliverability of supply. The on-ramps to the renewable transmission superhighway are "renewable collector lines," which are grouped geographically to allow access to multiple adjacent CREZs and deliver power from the resource areas to the renewable foundation lines.

The plan identifies segments that are likely to be needed under a range of future scenarios, regardless of whether they are ultimately needed for renewable energy. These are identified as "least-regrets" upgrades and are given the highest priority for further study and development.

With the completion of the phase 2 plan, RETI is at a crossroads.

The next step requires a handoff to the organizations responsible for planning and operating the transmission system. The handoff is expected to the "California transmission planning group" made up of the CAISO and its participating transmission owners as well as municipal utilities. For its part, the CAISO recently issued a draft renewable energy transmission planning process outlining the steps it will take to address renewable energy transmission planning and associated tariff changes. Specifically, the CAISO proposes establishing access to renewable resources as a formal criterion for assessing the need for transmission additions, alongside the existing economic and reliability criteria. One of the challenges facing transmission planners is reconciling the conceptual plans with the existing queue of interconnection requests and contracted resources.

In the meantime, various public agencies can use the RETI conceptual plan to focus environmental studies on the identified areas, address land ownership issues in identified corridors, identify potential routes and alternatives and possibly identify certain line segments for corridor designation.

The California transmission planning group has indicated that it will use the RETI plan as a starting point in its analysis. The group is being encouraged by state regulators to further embrace the transparent, collaborative process developed by RETI. Similarly, the RETI group has been encouraged by Commissioners Jeffrey Byron and Michael Peevey to continue its work and to provide stakeholder input into the detailed planning processes.

Broader Western Effort

While the RETI process is focused on California, a similar effort has been initiated by the Western Governors' Association to look at potential renewable resource areas and associated transmission corridors in 11 states and parts of Canada and Mexico. Steering committee members include the participating governors or ministers and their delegates, as well as representatives of state regulatory agencies. The technical committee includes representatives from a broad range of stakeholder interests similar to the RETI groups.

The "western renewable energy zone" or WREZ initiative was launched in May 2008 and has the goal of supporting the development of 30,000 megawatts of new clean energy across the west by 2015.

Depending on the capacity factor of the developed resources, meeting this goal could add roughly 50,000 gWhs to 100,000 gWhs of new generation.

The WREZ group issued a phase 1 report in June 2009 that identified resource hubs throughout the west and provided estimates of renewable resource potential and associated supply curves. As with the RETI process, the WREZ initiative will apply environmental screening criteria when designating renewable energy zones as it completes phase 1. The WREZ initiative is also developing a modeling tool for estimating the economic cost of delivering energy from WREZs to specific load centers. This tool and the environmental screening of identified WREZs will provide the basis for developing a conceptual transmission plan in phase 2. Detailed transmission studies would then be performed by the Western Electric Coordinating Council as part of its transmission planning process. Phase 3 of the WREZ initiative will involve working with state commissions, utilities and generators to coordinate the timing and scope of procurement processes to aggregate renewable energy supply needs and support large-scale development. Finally, phase 4 will involve interstate coordination of transmission siting and permitting and addressing cost allocation issues.

The US Department of Energy awarded $60 million in December to support these transmission planning efforts. The Western Governors Association received $12 million. The Western Electric Coordinating Council received $14.5 million. Similar funding was provided to transmission planning and government agencies in the eastern interconnect and in Texas.

It is clear that these initiatives represent not simply yet another set of studies to sit on the shelf, but will provide the foundation for actual transmission proposals and associated regulatory review. There will be winners and losers in the planning and siting of the transmission superhighway. Projects located near the on-ramps will benefit from the economies of scale and shared costs that these large transmission projects will provide, while projects that are bypassed or located in areas not served by the superhighway will be at a competitive disadvantage. ◎

Environmental Update

Many wind developers are asking whether they need "incidental take" permits after a decision in December by a federal district court in Maryland in case called *Animal Welfare Institute v. Beech Ridge Energy LLC*.

The permits are issued by the US Fish and Wildlife Service under the Endangered Species Act. They allow certain projects to "take" a specified number of endangered or threatened species, but only in limited circumstances. Section 9 of the Endangered Species Act makes it unlawful to "take" any endangered or threatened species. "Take" is defined as "harass, harm, pursue, hunt, shoot, wound, kill, trap, capture or collect, or attempt to engage in such conduct." Violation may lead to fines or even imprisonment.

The decision in the case is a reminder to investigate whether endangered or threatened species are present and to coordinate with the US Fish and Wildlife Service.

Wind farm developers routinely assess the potential effects of their projects on federal or state endangered and threatened species as well as on bats and migratory birds. Many developers comply with voluntary guidance issued by the Fish and Wildlife Service on May 13, 2003, entitled "Avoiding and Minimizing Wildlife Impacts from Wind Turbines," that provides suggestions as to the proper tower siting and monitoring to minimize wildlife impacts.

The federal district court in Maryland held on December 8, 2009 that Beech Ridge Energy LLC could not operate its existing wind turbines in West Virginia during certain times of the year without obtaining an incidental take permit because there is an endangered species of bat, called the Indiana bat, nearby. The court also ruled that Beech Ridge could not finish building out the wind farm without such a permit.

Although no take had occurred, the court said that in such a case, the animal rights group that sued to stop the project had shown by a preponderance of the evidence that the complained-of activity is "reasonably certain to imminently harm, kill, or wound the listed species." After reviewing the facts, the court said there was a "virtual certainty" that the project would take endangered bats.

The judge was critical of the project developer's experts and expressed concern that the developer's consultant ignored letters from the Fish and Wildlife Service recommending additional bat surveys. The court ended up barring operation of any turbines, except during winter when the Indiana bat hibernates, and issued an injunction prohibiting construction of the remaining turbines until an incidental take permit is issued.

8-Hour Ozone Standard

The US Environmental Protection Agency proposed lowering the 8-hour ozone standard in early January from 0.075 parts per million (ppm) to between 0.060 ppm and 0.070 ppm and also set a "secondary" standard to protect the environment. Although the practical effects on existing and new major sources of air emissions are unclear, EPA estimates that costs to comply could be as much as $90 billion a year by 2020.

Ground-level ozone is formed when nitrogen oxides and volatile organic compounds react in the presence of sunlight.

Under the Clean Air Act, EPA must set "national ambient air quality standards" for six air pollutants — ozone, particulate matter, nitrogen oxides, carbon monoxide, sulfur dioxide and lead — that are considered harmful to human health and the environment. Each state must designate areas in non-attainment with these standards — meaning the air is dirtier than the law allows — and adopt a state implementation plan describing how the state plans to bring the air back in compliance.

It is unclear how states will reduce NO_X and VOC emissions. Several options are available to the states, including regulating pollution from motor vehicles, requiring existing major stationary sources to use "reasonably available control technology," reducing the thresholds that require a "new source review" under the Clean Air Act before companies can start construction of new sources or make major modifications to existing sources of air emissions and requiring offsets for new or modified major sources.

EPA wants states to provide it with a list of non-attainment areas by January 2011 and submit a state implementation plan by December 2013. *The New York Times* quoted an Edison Electric Institute source on January 8, about the potential effect on utilities, who said,

> [w]e probably won't know for a couple of years just what utilities and other emissions sources will be required to

> do in response to a tighter ozone standard. States will have to cast a very wide net when targeting sources for emissions cuts, in part because utilities already have made substantial reductions in ozone-related emissions.

It is possible that more stringent ozone standards could require existing power plants to cut back hours of operation. If that were to happen, it could have ramifications under power purchase agreements.

Mercury Emissions from Coal

Coal-fired power plants are likely to become subject to more stringent mercury air emissions regulations.

Some speculate that more stringent regulations could have a huge financial effect on the coal-fired power industry; however, these concerns may be premature with respect to some facilities.

EPA abandoned an effort to develop a "maximum achievable compliance technology" or "MACT" for mercury in 2005 and came out instead with a "clean air act mercury rule" called "CAMR" to reduce the amount of mercury emissions from new and existing coal-fired power plants using a cap-and-trade approach.

Coal-fired power plants are expected to face stricter limits on mercury air emissions.

A federal appeals court struck down the EPA proposal in February 2008.

Without CAMR, EPA must require owners of coal-fired power plants to install whatever it decides is the maximum achievable technology. For new sources, MACT represents the "emissions control that is achieved in practice by the best controlled similar source, as determined by the Administrator." MACT for existing sources is determined using a potentially less stringent benchmark, specifically

> the average emission limitation achieved by the best performing 12 percent of existing sources (for which the Administrator has emissions information) . . . in the category or subcategory for categories and subcategories with 30 or more sources" or "the average emissions limitation achieved by the best performing five sources (for which the Administrator has or could be reasonably obtain emissions information) in the categories or subcategories with fewer than 30 sources.

In 2004, EPA proposed MACT for mercury emissions from existing coal-fired power plants at a level of 2 lb/TBtu (bituminous coal-fired) and 5.8 lb/TBtu (subbituminous coal-fired). For comparison, in June 2008, Virginia issued a permit allowing construction of a coal-fired power plant that included a mercury limit of 0.09 lb/TBtu.

Existing air emissions controls already used at many facilities to reduce emissions of particulate matter, sulfur dioxide and nitrogen oxides also help reduce the amount of mercury emitted .

The Government Accountability Office, an arm of Congress, reported in October 2009 that approximately 25% of coal-fired power plants and boilers achieve a 90% or more reduction of mercury using existing air emissions controls.

The efficiency of existing controls in controlling mercury depends on a number of variables, including plant configuration and type or rank of coal burned. Of course, depending on how stringent EPA sets the MACT for mercury, additional controls, such as sorbent injection systems, or changes in coal source may be needed.

Developers and lenders will need to assess the efficacy of current air emissions controls, as well as the costs of additional mercury reduction strategies, if needed, in connection with new and existing coal-fired power plants.

Coal Ash

EPA is considering revising its regulations for coal ash waste. The changes could make the cost of ash */ continued page 56*

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disposal prohibitively expensive for owners of some coal-fired power plants and could dramatically affect the market for reuse of coal ash.

Any changes would be in response to a December 2008 spill of approximately 5.4 million cubic yards of wet coal ash from a Tennessee Valley Authority coal impoundment in Tennessee.

EPA currently regulates coal ash as a solid, non-hazardous waste under the Resource Conservation and Recovery Act. It has several options as it considers what to do. It could retain the current regulations. It could regulate coal ash as a hazardous waste. It could regulate only some coal ash as hazardous. It could adopt some sort of hybrid approach.

Some commentators speculate that a hybrid approach might be used to define coal ash as hazardous when discarded, but as non-hazardous waste if recycled for a beneficial use.

If coal ash were defined as hazardous waste, then costs of ash disposal could increase dramatically. According to the Electric Power Research Institute, between 190 and 411 coal-fired units could shut down if ash is regulated as hazardous.

EPA postponed the anticipated release date of proposed coal ash regulations in December, citing the inherent complexity of the analysis.

One concern is that new regulations may dramatically affect the market for using coal ash for beneficial uses. In late December, the American Society for Testing and Materials, an international organization that publishes industry-recognized voluntary standards as guidelines (including specifications for fly ash for use in concrete), sent a letter to EPA encouraging it not to classify dry ash as hazardous. The group said:

> [a] "hazardous waste" designation, even with an exclusion for beneficial use, would cause the ASTM standard for fly ash to be removed from project specifications due to concerns over legal exposure, product liability, and public perception. This will likely result in little to no fly ash being used beneficially in concrete or other applications that support sustainability objectives.

Another consideration that EPA must also take into account is the fact that mercury air emissions limits are becoming increasingly more stringent. As a result, mercury that is not emitted into the atmosphere or discharged in wastewater may be deposited in ash. As the content of mercury in ash increases, the ash may become less suitable for reuse, making it more expensive to dispose of and possibly even voiding existing ash disposal agreements that were premised on the ash being non-hazardous.

— contributed by Andrew Giaccia and Sue Cowell in Washington

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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

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

Stroganovskiy Business Centre
19A Nevskiy Prospect
St. Petersburg 191186 Russian Federation
+7 (812) 332-9300

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
an affiliated partnership
Regis House
45 King William Street
London EC4R 9AN, UK
+44 (0)20 7337-8000