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Financing Projects with Unproven Technologies

Many new projects are coming to the market for financing after a lull of several years. The next wave of new construction is not like the boom years of the 1980s and 1990s when most large transactions in the project finance market involved power plants that burned either natural gas or coal and used proven technologies. Many more technologies are competing for attention in the current market. Projects that involve new ways of making transportation fuels or generating electricity or that rely on equipment that does not have a long operating history can be severely challenging to finance.

Four veterans of the project finance market discussed the challenges facing such projects in October. The panelists are Herb Magid, managing partner of Energy Investors Funds, a group of six private equity funds that has been a source of capital for many smaller project developers, John McKenna, managing director of Hamilton Clark & Co., an investment bank that helps smaller companies raise capital and list on the AIM market in London, Jerome Peters, senior vice president and group head of project finance for TD Banknorth, N.A., a prominent lender in the renewable energy and biofuels markets, and Paul Ho, director of global energy at Credit Suisse, which has been acting as the financial adviser on many innovative financings. The moderator is Keith Martin with Chadbourne in Washington.

MR. MARTIN: We are talking about whether projects with new / continued page 2

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A NEW STRUCTURE for financing baseball stadiums should also work for road and other infrastructure projects.

The Internal Revenue Service released two private rulings in late October that describe how new ballparks for the New York Yankees and Mets are being financed.

New York City wanted to use as much tax-exempt financing as possible. It issued a combination of taxable and tax-exempt debt for the ballparks. The structure is expected to save the two baseball clubs more than a $100 million each.

Assets that will be put to more than 10% "private / continued page 3

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technologies can be financed and, if so, how. Herb Magid, what is “technology risk”?

MR. MAGID: Technology risk is present in the power sector in any project that incorporates an unproven system, whether it is a turbine, a new fuel handling system, or an uncommon type of fuel. For example, there is technology risk in a project that uses a new gas turbine. The turbine may be just one component of what is otherwise a traditional power plant, but the turbine is so important that the entire plant would have technology risk.

MR. MARTIN: So it is both whether the equipment works and whether it works with the particular fuel. Paul Ho, can technology risk be addressed by focusing on the risk only during a limited time period? For example, is it enough to persuade the construction contractor or equipment vendor to guarantee that the system will pass performance tests at the end of construction?

MR. HO: When people think of technology risk, they think of it primarily as risk during the construction and start-up period. To me, technology risk is first the issue of at what level of capacity is the project capable of working after construction. Once you get past construction and start up, there is also the issue of conversion or efficiency ratio.

Lenders may be able to assume part of the conversion risk if an experienced independent engineer can certify that the plant is able to operate at least at a level that will permit repayment of the debt plus some margin for error.

A lot of energy projects, especially in the alternative energy space, involve new technologies. The general belief is that once these kinds of new projects have run successfully for a couple of years, they should continue to function properly for a much longer period of time. As a result, people tend to focus more on technology risk during the construction and start-up periods than during the operating period.

MR. MARTIN: John McKenna, is there anything you would add to the definition of technology risk?

MR. McKENNA: Technology risk related to products, for example, might be the risk of whether the piston ring will work and whether the mechanical engineering is correct. It is very difficult to get an engineering or construction firm to provide a “wrap” guarantee of this process technology. Technology risk is a question of whether the developer can prove that this particular product will work over time.

MR. MARTIN: Jerry Peters, isn’t there a degree of technology risk in every project?

MR. PETERS: Yes, to one extent or another. Many technologies have been demonstrated over a long enough period of time to make lenders comfortable about the risk, but the reason lenders analyze the debt-service coverage ratios in projects is because there is an element of project risk that never disappears completely.

Banks will not take unquantifiable risks. Unless the technology has been used successfully in a number of projects, it presents such a risk.

Lender Risk Tolerance

MR. MARTIN: What degree of technology risk presents a challenge for raising financing? How do you know whether a particular project presents too much risk?

MR. PETERS: How many successful projects use the same technology? Unless a fair number of projects using the same technology have been in operation for a period of time, then you have an element of technology risk that you really cannot assess. It is when the technology risk is unquantifiable that I think you have reached a level of risk that a lender usually cannot absorb.

For example, in a conventional power plant that uses a combustion turbine that has many hundreds of thousands or millions of hours of operation, you pretty much know that it will operate within 95% to 100% of its projected output and efficiency simply because other, similar turbines have operated that way. If you are looking at a type of cellulosic ethanol plant that has never been built, you really don't know at what through-put efficiency level it will operate. At that point, you say the project has an undeterminable level of technology risk. Therefore, I cannot take the risk.

MR. MARTIN: What should someone who is bringing the first project of its kind to you bring with him to prove the technology risk is manageable, or is it just impossible?

MR. PETERS: We are dealing with that question with some of the biofuels technologies today. It comes down to whether you have already demonstrated that the technology works on a smaller scale. Is there a successful pilot plant? Can you then get a construction contractor to take the risk that a technology that works in a pilot plant will work when it is replicated on a commercial scale? The construction contract must have adequate through-put efficiency and time-delay liquidated damages to repay the debt if the project does not work as guaranteed under the construction contract.

MR. MARTIN: So the maxim in project finance that lenders won't accept technology risk is true?

MR. PETERS: Pretty much.

MR. MARTIN: Paul Ho, must the construction contractor take the risk?

MR. HO: The construction contractor or the equity provider should wrap the risk. If you have a technology that is being championed by someone with a substantial balance sheet, that champion should, in theory, be willing to stand behind the technology.

Equity View

MR. MARTIN: Herb Magid, if someone comes to you as a private equity fund with the first project of its kind, would you consider putting money into the project?

MR. MAGID: We have looked at a lot of first-of-its-kind projects. Those are the kinds of deals that usually have an individual developer who is knocking on all of the doors, and they are often the most interesting projects to think about. We have invested in the past in several early-stage development projects. One was a tire pyrolysis plant in London that made so much sense on a variety of levels, and the components of the system were all proven. The risk was in combining it all together. At the end of the day, as Jerry Peters said, the construction contractor was unwilling / continued page 4

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business use" are a challenge to finance in the tax-exempt bond market; the bonds will not be tax exempt if more than 10% of the payments used to repay the bonds or the security behind the bonds also comes from a private party. Both stadiums will have too much private business use; each is for a private baseball team. Bonds that flunk *both* the private business use test and the payment or security test are labeled "private activity bonds." In other words, they are viewed as a borrowing for a private project.

The tax-exempt bond market is supposed to be off limits to private borrowing. There are exceptions for 15 types of projects that Congress felt throw off public benefits. Sports stadiums are not on this list.

New York City owns the land where the ballparks are being built. It leased the land in each case to a local government agency called an industrial development authority, or IDA. The IDA subleased the land to the baseball team and issued a combination of tax-exempt and taxable debt to finance construction of the stadium. Each team is building its stadium as the "agent" for the IDA. The IDA will hold legal title to the stadium. The team will sign an agreement promising to operate and maintain it.

Each team will make four kinds of periodic payments to the IDA. It will pay rent for use of the ballpark, unspecified installment sale payments, a percentage of net revenue from stadium parking and PILOT payments that are specially-negotiated property taxes. (The term PILOT stands for payments in lieu of taxes.) The parties are being careful about which parts of the debt are secured by which payments. The PILOT payments are dedicated to the tax-exempt debt, and the rents and installment sale payments are each used to secure a different series of taxable debt.

The question with which the IRS wrestled in the rulings is whether the PILOT payments are a form of private payment. A city can use revenue from "generally applicable taxes" to secure a bond offering without / continued page 5

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to wrap the final performance, and the project was never able to get financed.

We continue to look at such projects, but a project has to be more along the line of one of the first 10 GE new turbines, with proper guarantees and reserves, as opposed to a brand new system. I view the brand new systems as more of a smaller-scale venture capital investment than a large project finance transaction where you are relying on 20 years of cash flow.

MR. MARTIN: I was wondering whether an equity investor looks at this differently than a lender. The answer is the equity investor wants to know the lender will be there eventually to finance construction.

MR. MAGID: That's right. Unless you are going to fund the project entirely with equity, you will need eventually to bring in lenders and have the proper wraps. If you don't think you can get there, then it will be hard to persuade a private equity fund to provide development capital.

Alternatives

MR. MARTIN: John McKenna, you have spent a great deal of time thinking about how smaller ventures get off the ground using new technologies. We have now heard from both the lender and the private equity investor that the lender will not take the risk on unproven technologies and the private equity investor won't provide funding unless he is confident a lender will eventually finance construction. What would you advise someone whose project uses a new technology? How should he start moving down the path toward financing?

MR. McKENNA: That is precisely the dilemma. If Jerry Peters can't afford to take the risk, then the project has a problem. All of us who have been in the lending business know that the profit margins for banks are much too small to accept that kind of risk.

The private equity venture capital world for energy technologies today is rather small. The average deal size is $5 million to $7 million, and that is nowhere close to the kind of equity capital that is required for many projects.

The construction contractor or vendor may be willing to guarantee the technology will work. Liquidated damages must cover the full construction cost through mechanical completion.

We advise clients to look at other alternatives. Try the larger private equity firms. I was in New York for the Private Equity Analysts conference a couple of weeks ago. That's the crowd: non-traditional energy tech venture capital firms. Also, the London Stock Exchange has been the major source of equity for some of these larger project-type companies.

MR. MARTIN: The London Stock Exchange meaning the AIM?

MR. McKENNA: The AIM portion of the London Stock Exchange. They have served as a source of pure project equity financing. Yes, the London AIM is another alternative.

MR. MARTIN: I heard from Herb Magid, who runs six private equity funds, that even for him it is tough if he can't foresee the lenders putting money up to construct.

MR. McKENNA: The developer must prove that he has all of the other components in place, like a proper wrap from a construction contractor or backstop from a sponsor with deep pockets. It is also a question of risk-reward ratio. What return is he offering the private equity shop in relation to the risk he is asking it to take?

MR. MARTIN: Paul Ho, I know you have spent time thinking about how to finance novel projects, ones that may not be the first of their kind in the world, but perhaps the first in the United States. What advice do you have for someone who is trying to build such a project?

MR. HO: I echo some of the other comments. I think the technology risk for an unproven technology that has not been proven on the pilot scale is too great for project financing. Such a project will have to be financed primarily with equity. Once such a project has run successfully for a few years, then maybe some of the equity can be replaced with project-level debt.

Another possibility is perhaps you can separate the part of the project that has the greatest technology risk from the rest of the project, and use traditional project financing for the part that does not have the heavy technology risk and all equity for the part that does. That is the strategy we are pursuing for Rentech, a US coal-to-liquids developer for its first commercial-scale project. Rentech purchased a fertilizer plant in Illinois that it intends to convert into a coal-to-liquids facility. The technology risk is for the Fischer-Tropsch portion of the project, or the part that takes gas made from a gasification train and converts it into a liquid fuel. What Rentech plans to do is to treat the FT portion of the project as a separate project and finance it with equity. The gasification train and fertilizer plant can be financed with traditional project financing. Overall, the project will end up with a blend of equity and traditional project financing.

MR. MARTIN: Herb Magid, I thought I heard you say — or maybe you merely implied — that you would not put in all equity for a completely new technology?

MR. MAGID: I suspect Paul is describing a case where the equity will get the benefit of two potential cash flow streams — one proven from fertilizer sales and the other more uncertain from the FT liquids sales, but like any equity, it will stand in line behind the debt.

We are looking at a lot of coal-to-liquids and IGCC plants, and it is really a challenge to figure out a way that you can make an equity return with reasonable risk given the huge scale of these projects. It is hard to see how such plants will get financed without someone like the federal government or a deep-pocket construction contractor stepping up and guaranteeing performance.

MR. MARTIN: So once again, the project is not going to be able to secure full funding from a private equity fund. You are still looking to have a lender alongside you?

MR. MAGID: You really have to, unless you go down the tax side where some new technologies can be financed with all tax equity, and then there is less of a concern whether the technology actually works because the tax benefits are a function of construction cost rather than output. */ continued page 6*

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endangering the tax exemption on the bonds. However, the payments in this case were specially negotiated. Are they still essentially property taxes? The IRS said yes based on a highly technical two-part test in the IRS regulations (and after concluding that the payments did not follow any set formula for negotiated PILOT agreements in New York). The rulings are PLRs 200641001 and 200641002.

The agency has since revised its regulations.

New regulations issued in late October leave the same two-part test for PILOT payments, but they explain in more detail how the IRS wants the test interpreted. The agency said it was concerned that the old rules could be interpreted in an "overly broad manner."

PILOT payments will be treated as a generally applicable tax as long two things are true. First, they must be "commensurate with and not greater than" the regular tax for which they are a substitute. Second, the payments must be "designated for a public purpose" and cannot be a "special charge."

The IRS said that, to be considered "commensurate," in the future the payments must either be a fixed percentage or fixed adjustment to the regular tax. A fixed adjustment means a fixed dollar discount off the regular tax or a fixed reduction based on the characteristics of the property, such as the size of the business or number of employees. There can be a one-time increase in rate at the end of construction. In the case of property taxes, the payment must be tied to current property values; the property must be reassessed for PILOT purposes with the same frequency that other property is reassessed. The IRS said the PILOT payments cannot be tied to the amount of debt service, and they cannot be fixed amounts that do not vary with the assessed value of the property.

The new rules will apply to bonds sold on or after February 19, 2007. The IRS is collecting comments in the meantime. Comments are due by January 16.

Tax increment bonds that */ continued page 7*

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Liquidated Damages

MR. MARTIN: Jerry Peters, you said that one way to get past technology risk is to get the construction contractor or the equipment vendor to agree to take it and pay suitable liquidated damages. How much in liquidated damages and over what time period of coverage would you require?

MR. PETERS: You have to break that down into several components. First, you can't limit the liquidated damages to anything less than the complete construction cost until you get to mechanical completion, because you have to make sure you have a plant that has been fully constructed. The plant has to be guaranteed to reach the stage where it is ready to start up. If the contractor guarantees you anything less than that, the risk exposure is too great.

Next, we have to move the plant from mechanical completion to substantial completion by demonstrating that the project can work. You must set a target for what the plant can do. For example, in a biofuels plant, the target is 50% of capacity. The usual limit in the industry for liquidated damages during that period is 10% to 20% of construction cost.

Next, you have final liquidated damages for the period when the plant is moving from substantial completion to final completion. During this period, the plant is tested fully to prove that it is capable of operating at the minimum capacity promised in the contract. The level of liquidated damages does not usually drop below 10% of construction cost during this stage.

If you can get those levels of damages, then we would generally be comfortable.

However, if you are talking about a project that is a scale up from a pilot plant, then we may need to maintain the guarantee at the mechanical completion levels through final completion because there are a lot of variables involved in start up that may not be able to be proven at the mechanical completion date.

MR. MARTIN: Most of what you said has to do with completion risk. Are you not as concerned about operating risk? Are you not as concerned about the risk of technological obsolescence during the 10 to 12 years that the debt will remain outstanding?

MR. PETERS: It depends on the technologies that you are employing. A lot of us found out when we were financing some of the newer models of combustion turbines that the improvements in efficiency that were claimed by the manufacturer did not pan out over time. If you are looking at a new technology where a 3% or 4% difference in efficiency could mean the difference between a project that provides adequate debt service than one that doesn't, additional performance guarantees may be required.

If a 3% or 4% swing in efficiency makes a difference in whether the project can repay debt, then additional performance guarantees may be required.

Focusing again on biofuels, once you prove a conversion ratio — once you prove energy consumption — there is not much about the process that will go wrong because it is a very simple process. It is a lot of tanks and pumps and gears and things that generally don't go bad.

Everything is technology specific. The length of guarantee required varies potentially with each technology. It is very, very difficult to get a construction contractor to provide more than a one-year performance guarantee on the process engineering. Obviously on the wind turbine side, we have several manufacturers will give guarantees lasting up to five years. The length varies with the technology involved.

MR. MARTIN: John McKenna, suppose a developer has a process for gasifying biomass or poultry litter, and he is planning to use a process that has not been used yet in the United States. The normal approach for this type of fuel is to burn it directly. This developer wants to gasify it first. What would you advise him to do before approaching Jerry Peters or Herb Magid?

MR. McKENNA: I don't know if you asked me that question because you know that I spent three years trying to develop a company that actually tried to use chicken litter in a Stirling-cycle engine. I spent three years of my life with that technology. The answer is that the technology really has to work, and it has to work for a long period of time. It has to have a warranty reserve, which is almost a working capital reserve for the company. It has to have worked at scale before Jerry is even going to agree to a meeting. He is going to ask me these kinds of questions over the phone before he will agree to meet. A company in this position has little choice but to try to raise equity capital, thoroughly test the product and then look for debt financing.

Venture Capital

MR. MARTIN: You said venture capitalists will put in money for early stage development. How large an investment will venture capitalists make typically? What is the maximum?

MR. McKENNA: The trends we are seeing now are in the $25 to $50 million range in terms of total amount, and that probably assumes four or five venture firms will invest alongside one another. New process technologies will probably need $50 million to get through the beta stage. It is during the beta stage that the testing regime occurs.

MR. MARTIN: "Beta stage" means what?

MR. McKENNA: The beta stage is where the equipment has worked for X years or X period of mean time between failure (MTBF). The original question was how technology that will end up going into a poultry-litter-to-electricity plant would make its way through the testing process so the plant can get financed. I believe that venture capital equity has to finance it during the equipment testing phase. It is only after the project has moved past the beta stage that Jerry will organize the meeting with the developer who is using this new technology.

MR. MARTIN: Why are the venture capitalists more willing to put in money than Herb is as a private equity fund? What sorts of questions would they want answered before they will invest?

MR. McKENNA: One question as technology moves into the beta stage is who financed it during */ continued page 8*

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are secured by tax payments from a particular project are already used in many states. New York law barred the state from using such bonds, so another structure had to be found. There is no reason states and cities cannot use the same PILOT structure to finance other new infrastructure projects. The structure should also work with other types of taxes besides property taxes.

CANADIAN INCOME TRUSTS lost value after the finance minister announced plans to subject their earnings to higher taxes. US private equity firms are now scouting for bargains among trust assets.

Finance Minister James Flaherty announced plans on October 31 to subject income trusts to taxes on distributed earnings and to tax investors as if they received corporate dividends. The new taxes will not take effect for existing trusts until 2011. They take effect in 2007 for new trusts organized after October 2006. The new taxes will apply to "specified investment flowthroughs." The category covers not only income trusts but also limited partnerships. The action is expected to increase taxes on US investors in such entities from roughly 15% to the 42% that applies to earnings received through corporate shareholdings.

The government acted in the face of plans by two large telecommunications companies — Bell Canada Enterprises and Telus Communications Corp. — to convert to trust form. The government estimates that it is currently losing C$500 million a year in revenue on account of the trusts. The loss would have increased by another C$300 million a year after conversion of the two telecom companies. The government feared the erosion of the corporate tax base would turn into a stampede.

Trust units in the aggregate had lost 12% in value by the first week in November. The latest action breaks a campaign promise made just last year by the conservative government not to change the tax treatment of income trusts. */ continued page 9*

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the alpha stage and what performance has been promised? What is the mean time between failure for that particular product? What is the overall return for this business? Where will this business end up going? How quickly can the venture capital investor see an exit or assure that the B and C rounds of financing get the technology to commercialization? I would say today that maybe a 25% to 35% internal rate of return will be required for this kind of equity. Herb, would you agree?

MR. MAGID: Yes, I would. I think the big difference is that the venture money is looking for a quicker and larger return, a way of taking this technology and building a company and getting value for selling more units, where the traditional private equity investor in a power or other infrastructure project is looking for a return over a very long period of time.

The technology risk continues. It is not just construction and start-up risk. It really is a long-term operating risk, and you do have to have the reserves and the comfort that the sponsor will have skin in the game — a back-end interest or a carried interest — that will make him keen to see that the financial projections are met. There is a big difference in what a venture capital investor and a more traditional private equity investor will require. This then affects the type of diligence that each will do before making an investment.

MR. MARTIN: Jerry Peters, if the developer who is planning to gasify chicken litter can show that there is one other plant that was built recently in Europe, and it is working properly, is that good enough to get over your hurdle on technology risk?

MR. PETERS: If the technology has not been demonstrated in any other place other than that one plant, I would probably find it difficult to finance the project. A lot of the problems specific to that technology have to do with corrosion, and that is a longer-term problem that you can probably address with performance guarantees from a construction contractor or equipment vendor.

With that particular technology, if there is only one plant in operation — whether it is a demonstration plant or even full-scale facility — I would have trouble making a loan if the plant has not been operating for at least the period of time for which the developer wants to borrow money.

The limit for venture capital is about $50 million. Such capital requires a 25% to 30% return.

MR. MARTIN: At what scale must a pilot plant have worked in relation to a commercial-scale plant before you will accept that the technology works?

MR. PETERS: The answer is technology specific. If it is a modular technology, as in gasification, you just add modular gasifiers; then the scaling up of the plant is easy. An example is where the pilot plant has one gasifier and the new plant will have 10 gasifiers. If it is another technology that is not modular and no one has built a certain component that is needed for the commercial-scale plant, that would present a level of technology risk that I would probably be unwilling to take.

MR. MARTIN: John McKenna, you mentioned there are just a handful of venture capitalists in clean tech. What is the best way to identify those people? How do you find them?

MR. McKENNA: There is a Cleantech Ventures organization of all venture capitalists that invest in this area. This includes energy tech plus other clean technologies. The National Renewable Energy Laboratory organizes a conference every year that is very well attended by all the major players in the industry. NREL has a website that includes a comprehensive list of investors.

Other Ways to Allocate Risk?

MR. MARTIN: Paul Ho, suppose we got past the venture capital round and managed to persuade Herb Magid to invest some equity and Jerry Peters is willing to consider lending, but he doesn't want any of the technology risk. You are a project finance expert, and project finance is an exercise in deconstructing and parceling out risk. There are a number of potential risk takers. Is insurance an option? What about making the offtakers, sponsors, construction contractor or technology licensor each take a share of the risk? Where would you try to put the risk? What has been your experience?

MR. HO: That's a good question. I agree with Jerry Peters. The number one guy to wrap this risk is usually the construction contractor. If he is not comfortable, we would look next to the equity provider. Sometimes in very rare circumstances you might have an offtaker who believes enough in the technology that he might be willing to enter into a tolling-type agreement and take the conversion risk, but usually subject to some minimum thresholds.

MR. MARTIN: Construction companies are feeling beleaguered. Everyone wants to place the risk on them. Are there construction companies that are willing to take this risk in practice?

MR. HO: You would think that construction companies are in a better position than almost anyone else in the deal to evaluate the risks, especially contractors who deal regularly with the big-name technology providers and who partner in large-scale projects all the time. For example, with coal gasification projects, we will look for someone like a Fluor or Bechtel to work with a General Electric or ConocoPhillips. The two parties together will provide a comprehensive wrap or have the contractor alone provide a wrap on the technology, and in turn work out a back-to-back guarantee with the technology provider or equipment vendor. From a lender's perspective, that is a much cleaner approach than having different people guarantee different parts of the construction.

MR. MARTIN: What about insurance — have you seen it used effectively?

MR. HO: I personally have not seen insurance used effectively in wrapping new technologies.

MR. MARTIN: Jerry Peters, have you seen insurance used?

MR. PETERS: I have seen it tried several times, but when you drill down into the insurance coverage itself, you find out there are a lot of gaps. There is a big difference between having a performance bond on a construction contract, which is pretty easily collectible, versus trying to get an insurance company to pay under an insurance / continued page 10

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A DOUBLE-DIP INTEREST structure works, the IRS confirmed in an internal memorandum.

The IRS national office analyzed a transaction among a US parent company and two offshore subsidiaries in a memorandum to the field. Both offshore subsidiaries are in the same country. The IRS made the memorandum public in late September.

The US parent company owns each subsidiary directly. One subsidiary — X — is "disregarded," meaning that it does not exist for US tax purposes. The other — Y — is a corporation for US tax purposes.

X borrowed from a bank and relent the proceeds to Y. The loan from X to Y requires Y to pay interest in the form of shares in Y and then to pay all the principal in cash at maturity. Simultaneously with the making of the loan, the US parent entered into a forward contract with Y to buy more shares in Y for a dollar amount that is exactly the principal amount of the loan that will have to be repaid at maturity. The forward contract requires the US parent company to buy the Y shares on the loan maturity date — in other words, provide Y with the money to repay the loan from X.

The IRS said there was essentially no transaction for US tax purposes. It combined the two instruments since they are so closely linked in amount and timing and, for US tax purposes, they are just a circling of cash between the US parent company and Y.

The loan from the bank was real and should produce an interest deduction for the US parent company ; the loan by the bank to X is a loan to the parent company for US tax purposes since X does not exist. However, for tax purposes in the foreign country where both X and Y were based, Y has the interest deductions. It is viewed as the ultimate borrower. The memorandum is AM 2006-001.

PARTNERSHIP FLIP structures are under study in Washington.

In a partnership flip, a / continued page 11

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contract. There are usually many more outs for the insurance company.

I have been in this business for 25 years, and I have never seen a federal loan guarantee get done either.

MR. MARTIN: I was going to move to that. Why have loan guarantees at the federal level failed?

MR. PETERS: I think the current two-billion-dollar-level guarantee program run by the US Department of Energy is a good example. It will fail because the guarantees have been structured to put the lender in the first-loss position. The government guarantees up to 80% of the debt amount which, in turn, cannot be more than 80% of the project cost. The US government takes a first lien on the project. The lender is left with a second lien with respect to the 20% of his loan that is not guaranteed. This leaves the lender in the first-loss position. We would not be comfortable taking technology risk in such a financing structure.

The new federal loan guarantees for energy projects were poorly conceived. They leave banks in the "first loss" position on technology risk.

In this sense, the program is a failure. It was supposed to encourage lenders to finance projects that use new technologies. As a lender absorbing the first loss, that is the very last thing we would want to do.

MR. MARTIN: Herb Magid, have you had experience with government guarantees?

MR. MAGID: The only one that worked for us was about 20 years ago, and it was on a geothermal project where we were already fairly comfortable with the technology risk so the guarantee merely served as additional comfort. I think Jerry is right. If there is a meaningful risk that guarantee will be needed, then you really have to look to the equity or reserves to take the first hit, but not the lenders.

MR. PETERS: Let me be clear. I have not said the guarantees are worthless. I just have not seen deals done with them. The guarantees could be worth something if you can find a way to structure around that 20%, that first loss on which you are sitting with only a second lien. If we can structure around that, I would be more than happy to have the federal government guarantee 80% of my loan.

MR. HO: Are you saying that you would be happy with a *pari passu* first lien on the 20% unguaranteed piece?

MR. PETERS: That would be one way. Another way — again, currently prohibited — would be to do strips. Paul, you might be more than happy to do that 20% strip and then get real low-rate lenders to do the government guaranteed strip. Will the government allow us to do strips? I don't see the harm to the government of allowing them.

MR. MARTIN: "Strips" meaning one lender will lend at a higher rate for the first-loss portion.

MR. PETERS: I am more than happy to sit with the government-guaranteed piece and get 80 basis points over.

MR. MARTIN: You narrow the technology risk, but somebody is still going to have to step up for it.

MR. PETERS: If you look at the weighted average cost of funds where you have one lender that is taking the second-lien piece and the 20% percent uncovered risk at perhaps 1,000 basis points over, and then you combine it with an 80% guaranteed strip that is done at less than 100 basis points over, you still have a very good capital structure for the leverage in the deal.

It is very difficult to get senior lenders that are accustomed to taking project risk to take that 20% first-loss position. There are lots of funds that have no problem with taking that position.

MR. MARTIN: John McKenna, have you seen other sources of funds, perhaps state clean tech funds that people might try to tap as well as venture capital?

MR. McKENNA: Well, I think that the big source of capital in many of these projects — and this is especially true of projects that produce liquid fuels — will be the oil companies. At least in the biofuels area, until there is a buy in by the large oil companies with the capital to invest in these kinds of projects, the market will never reach its full potential.

Is there grant money? Yes, there are some small grant programs, and there are an incubator programs organized by the US Department of Energy. Details can be found on the DOE website. These are relatively small sources of capital, but nowhere near the amount of capital required for the projects we are talking about.

The only other source that we have not discussed is strategic investor money, which is primarily from energy companies with a strategic interest in seeing the technology develop.

MR. MARTIN: To sum up, it seems like for projects that use a technology that has not been proven, and "proven" means used more than once successfully, you are basically talking venture capital. Once you get past that stage, you are still going to have to show someone like Herb Magid or Jerry Peters that the technology risk is covered by somebody else in the deal besides the lender, and that somebody else is probably the construction contractor or the equipment vendor. Although, in theory, it is possible for others to step forward, like the government or insurance companies, government guarantees and insurance have not yet evolved to a stage that adequately covers the risk.

MR. MAGID: Keith, one potential source of support that is probably worth mentioning is the various state agencies. For example, the Massachusetts Renewable Energy Trust has a pot of money that has grown each year through a surcharge on electric bills. It was $150 million the last time I looked, and the trust is trying to do creative things to support renewable technology and efficiency. This is not the same thing as covering technology risk, but it helps to have in place price supports to renewable energy credits. Again, this support on a smaller scale, but some states recognize that seed money and support are required if some of these new technologies are ever going to get off the ground.

MR. PETERS: I want to go back to the construction contract side of things because, Keith, you mentioned they may be feeling a little beleaguered. In certain technologies, there is a huge potential for growth — one of those being the cellulosic ethanol field — so that there are enormous gains to be had by any construction contractor who is a first mover. */ continued page 12*

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developer who cannot use tax benefits brings in a partner who can, and the two form a partnership to own a project. The structures are popular in wind farms and other types of renewable energy projects. The partnership allocates 90% to 100% of partnership items — with the possible exception of cash — to the investor until the tax benefits have run or, if later, the investor reaches a target return. At that point, the investor's interest in the partnership flips down to a small percentage usually in the range of 5% to 10%, and the developer has an option to buy out the investor for the fair market value of his interest determined at the time. There are many variations on this basic theme and many other details.

The IRS is not happy with 100% allocations to investors. It is working on a revenue procedure that will create a "safe harbor" for partnership flip deals. Deals that fit in the safe harbor will not be questioned. Others may have to be defended on audit.

IRS officials had hoped earlier to issue the guidance by year end, but they now say work on it has slowed.

THE DOE LOAN GUARANTEE application deadline has been pushed back to December 31.

The deadline to apply for loan guarantees for energy projects had been November 6. The new deadline is for "pre" applications. Anyone who has already filed his or hers will be able to revise it before the new deadline.

The loan guarantees in question were authorized by Congress in the Energy Policy Act in August 2005. The Department of Energy issued guidelines in August 2006 that apply to the first round of loan guarantees to be issued under the program. The guidelines require pre-applicants to submit a business and financial plan, a financial model and commitment letters from lenders and sponsors. The department has heard a lot of complaints about the volume of information required at the pre- */ continued page 13*

Unproven Technologies

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If you look at some of the early builders of ethanol plants, like Fagen Inc., the fact that they held licenses to a technology that was eventually proven gave them first-mover status. They could then deploy the technology by duplicating it in plant after plant. They have made an enormous amount of money. I suspect other construction contractors are looking at how they can get first-mover status in other areas. The point is contractors have an incentive to provide guarantees to insure that a market in which they will enjoy first-mover status can get off the ground. ◎

The guarantees might work with different "strips" of debt, but debt strips are not allowed currently under the program.

Secrets of the Biodiesel Market

by Todd Alexander, in New York, and Marissa Leigh Alcala, in Washington

The ethanol market showed signs of cooling this fall because of falling oil prices and fears about overcapacity, but interest in new biodiesel plants remains hot.

Larger and larger biodiesel plants are being brought to market for financing. The projects are both new builds and expansion of existing facilities. Potential demand for biodiesel is also growing.

The distillate fuels market in the United States is currently 62 billion gallons a year, with potential for various blends of biodiesel throughout that market. The National Biodiesel Board reports that the maximum annual production capacity for US biodiesel plants in operation was 37.5 million gallons per year as of early September 2006. Of 86 plants in operation, only 20 have capacities of 10 million gallons a year or more. Thirteen of these existing facilities are adding additional capacity; the additions are currently under construction. The board said 65 *new* biodiesel plants were under construction in early September. Three of the new plants will have capacities of 80 million gallons a year or more. The largest has a capacity of 100 million gallons. Thirty two of the plants under construction have capacities between 10 and 80 million gallons.

As the demand for biodiesel increases, developers are turning to bigger projects in an effort to benefit from economies of scale. Banks and private equity funds are helping the construction boom by providing funding for ever larger projects.

Any developer seeking financing should secure a strategically-located site and negotiate a solid technology and construction contract before approaching potential lenders and equity investors.

Site Logistics

Because the operating costs for biodiesel plants tend to be fairly comparable regardless of the technology employed, one way a developer can stand out from the pack is site logistics. The key to a strategic site is to find one that reduces costs and increases flexibility.

Site location can have a significant impact on costs. For example, putting a plant close to a reliable source of feedstock will decrease transportation costs on the supply side. Siting a plant close to a committed offtaker or sizable blending market will help reduce transportation costs for offtake and delivery. A site near an active port or other waterway will reduce overall transportation costs because of the comparatively low cost of barge and other water-based transport (particularly when compared to transport by rail or road). The greater the number of destinations that a plant can access easily, the greater the ability a developer will have to manage feedstock supply and offtake to maximize profit at any point in time. Direct access to water also means direct access to the export market, making a facility less reliant on industry growth within the United States.

Construction Contracts

Developers often enter into turnkey construction contracts with a fixed price, guaranteed construction schedule and guaranteed performance level upon completion in an effort to reduce construction risk. Lenders usually require such a turnkey contract as a condition to funding. A project will cost more to build under a turnkey contract; the contractor will charge more in exchange for taking on more risk. The contractor usually agrees to cover the developer's fixed costs if there is a delay in construction. It also agrees to compensate the developer for lost value if the completed plant does not meet guaranteed performance levels. In a project finance transaction, these guarantee payments will be used to pay interest during a construction delay or, in the event that performance guarantees are not met at completion, to buy down the debt.

The number of contractors who will sign turnkey contracts to build biodiesel plants in the United States is small. These contractors include Lurgi PSI, Fagen, REG and Safer Energy. Because most of these contractors also build ethanol plants, they should be familiar with the standard turnkey provisions that lenders require. However, given the small pool of potential contractors, delays are to be expected in getting on a contractor's master schedule, and the actual schedules, once a project is listed, are elongated. Contractors are also using the high demand for their services to charge premium fees.

A non-turnkey contract can be used if the equity investors are comfortable taking construction risk. The project would have to be financed either with all equity or with debt backed by significant sponsor-completion support. The developer could arrange for a single contractor to build the facility without any performance guarantees, or arrange for various components to be provided by multiple contractors. The latter approach, often referred to as an owner-construct process, places an additional burden on the developer of managing the construction timeline and supervising multiple contractors. In exchange for this additional responsibility, the developer may be able to build the plant at a lower cost.

Developers also need to obtain rights */ continued page 14*

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application stage. The extension in the deadline is partly a response to these complaints.

Ten categories of projects qualify potentially for guarantees in the first round: biomass, hydrogen, solar, wind and hydro, coal, carbon sequestration, efficient electricity transmission and delivery and energy reliability, alternative fuel vehicles, industrial energy efficiency projects and pollution control equipment.

All projects have to meet two basic requirements to qualify for the guarantees: they must avoid, reduce or sequester pollutants and gases, and they must use new or significantly-improved technologies when compared to technologies in general use in the market.

The department will issue guarantees of up to $2 billion in total in the first round. No fee must be paid with the pre-application. The department is expected to notify pre-applicants within 90 days about whether they made it into the full application phase of the process.

No actual guarantees will be issued until Congress appropriates money for the program.

PRODUCTION TAX CREDITS can only be claimed on the net amount of electricity supplied to the grid, the IRS said.

Production tax credits are tax credits of 1¢ or 1.9¢ a kilowatt hour for generating electricity from wind, biomass, geothermal steam and other renewables. Credits can only be claimed on electricity sold to third parties. Some projects sell all of their output and buy back whatever electricity they require for startup and other station use from the local utility. The IRS said in October in a notice about power plants that burn open-loop biomass as fuel that the credits can only be claimed on the net amount of electricity supplied to the grid. The same logic should apply to credits for wind farms and other renewables projects.

The notice is Notice 2006-88.

The IRS had been expected to issue it last spring to answer a series of questions about power plants that burn biomass.

Production tax credits */ continued page 15*

Biodiesel

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to the process technology that will be used in the plant. In a turnkey arrangement, a technology license is incorporated into the construction contract or provided in an accompanying license agreement. In an owner-construct structure, the developer must sign a license directly with a biodiesel process technology provider.

Banks lending to biodiesel projects usually require a 50-50 ratio of equity to debt.

Seeking Equity

Biodiesel developers usually use one of two approaches to raise equity. The first is to do a private placement of shares or other equity interests in the project company. The second is to solicit proposals from a limited number of private equity firms, and select an investor through a competitive bid process.

Factors to consider in a bid process include timing, what, if any, preferred return the private equity investor will require, the carried interest to the developer, the degree of control the equity investor will insist on over the project and advisory or ancillary services. In some cases, a private equity firm might offer to provide both equity and subordinated debt. Such subordinated debt is typically priced in the range of 12% to 18% and might also include warrants in favor of the subordinated lenders for conversion to equity.

All equity investors look for strong projects with projected rates of return around 25%. Solid supply and offtake contracts with competitive pricing and dependable, experienced counterparties will help make a project more attractive. Equity investors may also be interested in multi-plant opportunities with the same developer.

A private placement would be expected to attract a larger number of small investors, and would draw investment based on expected returns with the developer's management team running the project. The carried interest to the developer would be determined in advance by the developer and identified in the placement memorandum. A developer using this approach usually retains more control over the project, but ends up with a smaller carried interest than in a private equity scenario. A private placement typically takes more time to execute than an auction involving just a few private equity houses.

It is usually faster to raise money from just a few private equity funds. Private equity management teams often bring valuable expertise and contacts to the table that may be of particular benefit to developers with less business experience. This can lessen the day-to-day burdens on the developer team. A developer may need to engage a financial adviser to make introductions and facilitate the review of proposals. Such financial advisers typically charge a finder's fee of between 4% and 7% of the equity raised from their efforts.

Private equity investors tend to have a shorter investment horizon than investors who buy equity offered through a private placement. Private equity firms usually want to hold an investment only for a few years before exiting. A private equity investor might sell its interest in a biodiesel facility to another private equity fund, to an interested company or, less frequently, to the original developer or company management. Another exit strategy that can be attractive to both private equity and other investors is to take the biodiesel company public eventually through an initial public offering. Many private equity firms would be interested in "master limited partnership" structures where a biodiesel company has units that are traded on a stock exchange or over-the-counter market. This would provide liquidity and make for an easy exit. It would also bring down the cost of equity to developers. Such structures have been slow to develop.

Regardless of approach, equity can always be split into different classes with various rates or priorities of return, as well as varied levels of voting or management rights. The right structure for each project will depend in part on timing and on the preferences of the developer and initial project sponsors. Developers can generally expect to maintain a carried interest in the range of 15% to 20%, with higher numbers in some exceptional cases.

Raising Debt

To date, most financing for biodiesel plants has come from midwestern banks in Minnesota and Iowa. However, lenders with experience with ethanol are showing a growing interest in biodiesel projects. With the significant growth in biodiesel production anticipated in the next few years, money-center banks are also expected to enter the market.

Because the biodiesel lending market is still relatively immature, developers should expect biodiesel financing terms to be more conservative than current ethanol financing terms. In particular, developers should expect lower debt-to-equity ratios (*i.e.* more equity and less debt). Midwestern banks are usually lending to biodiesel projects at a 1:1 debt-to-equity ratio. As is the case with ethanol financings, developers should also expect significant cash sweeps that protect the lenders against downside risk. While a 7- to 10-year term for biodiesel financing is common, lenders typically size cash sweeps that, if realized, would reduce the total life of the debt by two years or more.

Lenders evaluating biodiesel projects obviously focus on the expected returns and health of the project while the loan will be outstanding, but they also want the project to look healthy for a few years after the loan is expected to be repaid to provide a cushion in the event of delays or other complications. Lenders focus in particular on the supply of feedstock. There is a limited number of crushing facilities in operation currently, and ownership of them is concentrated in the hands of only a few companies. Lenders will insist that a project have a significant amount of working capital. There are long lead times between payment for feedstock from a crushing facility or importer and when the feedstock is delivered. Working capital could be borrowed as part of the debt principal, addressed through longer or more flexible payment terms, or provided by a strategic partner or separate lender. Banks usually offer working capital equal to 50% to 80% of the accounts receivable and inventory of the project.

Lenders also expect developers to have a commodity hedging strategy to shield the project / continued page 16

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can be claimed for five years on biomass power plants that were in existence before August 8, 2005. New plants put into service after that date qualify for 10 years of tax credits. Some owners of biomass plants have explored whether they can turn them into new plants by investing in upgrades. In order for this to work, the amount spent on upgrades would have to reach 80% of the sum of the upgrade costs plus the value of the used equipment retained from the old plant. This test is applied to looking only at amounts spent on or retained from the biomass "facility." The IRS explained in the new notice what counts as the "facility" for this purpose. The "facility" is all the equipment that is "necessary to the production of electricity." It does not include equipment for collecting, processing and storing the biomass before it is used as fuel, the inter-tie-related equipment to move the electricity to the grid, and site improvements like roads and fences.

Another open issue had been how much other fuel can be mixed with biomass and still have the plant qualify for production tax credits. The IRS said that as long as the other fuels are not fossil fuels, any mixture is fine. However, production tax credits can only be claimed on a portion of the output based on the Btu content of the biomass compared to the other fuels. Use of fossil fuels for more than startup and flame stabilization will taint the entire plant.

The IRS said it will not rule on issues about biomass plants. The branch chief who administers the production tax credit statute said it is a resource issue: she does not have enough staff to handle all the ruling requests. The agency is also not ruling on issues in transactions that use partnership flip structures.

ETHANOL BLENDERS can organize themselves as master limited partnerships, the IRS confirmed in September.

However, the real breakthrough would be if master limited partnerships can be used to "roll up" plants that produce / continued page 17

Biodiesel

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from volatility in biodiesel and feedstock prices. In addition to traditional hedging arrangements, developers can also control prices by entering into long-term fixed price contracts or by entering into tolling agreements where the biodiesel producer is paid a flat fee for turning feedstock into biodiesel. Some producers have also been able to secure offtake contracts with prices indexed to heating oil or ultra-low-sulfur diesel.

Most biodiesel loans have a 7- to 10-year term, but require cash sweeps that, if realized, would reduce the total life of the debt by at least two years.

Other mitigants that help attract lenders to the biodiesel industry include the use of equipment in biodiesel plants that lets the producer switch among various feedstocks depending on which is the most economic at any given time. This flexibility puts biodiesel in a unique position to weather fluctuations in feedstock pricing and availability (particularly compared to ethanol plants that usually require major plant or process modifications in order to switch feedstocks). As an export market develops for US biodiesel, this will also help make lenders more comfortable because of the flexibility it affords for dealing with changes in the US market. Use of biodiesel as a replacement for fuel oil in power plants would open a new segment in the offtake market; plans are underway to test the viability of biodiesel in power plants in the northeastern United States.

Risks

Just like in any project, there are risks that must be managed and monitored.

The US government offers a tax credit to blenders as an incentive for using biodiesel. Blenders can get a credit of $1 per gallon for blending agri-biodiesel (diesel fuel made from virgin oils derived from farm commodities and animal fats) or 50¢ per gallon for other biodiesel made directly from agricultural products and animal fats (sometimes called brown and yellow grease). Some market observers believe biodiesel consumption in the US depends on this blender's credit, at least outside states where biodiesel blending is required by law. The credit expires at the end of 2008. While there is risk that the blender credit will not be extended by Congress, most in the biodiesel industry are confident that it will be continued beyond 2008 in some form. Selling into a healthy export market may help to mitigate part of this risk.

Biodiesel prices fluctuate. Most biodiesel facilities are uneconomic to operate if wholesale prices for petro-diesel drop below $1.20 per gallon. The price for petro-diesel is a factor in what can be charged for biodiesel. However, there is no correlation between petro-diesel prices and prices for feedstock used to make biodiesel. This leaves plants exposed to being whipsawed if biodiesel prices drop at the same time that feedstock prices remain high. Use of one or more of the hedging strategies discussed earlier, together with the opportunity to switch feedstocks to get the best market price, is the best way to mitigate this risk.

Another risk is the potential harm caused by poor quality biodiesel making it to market. When the 2% biodiesel blending requirement first went into effect in Minnesota, unanticipated quality problems slowed acceptance of biodiesel and required that temporary waivers of the blending requirement be granted. The industry must ensure that biodiesel meets required production and performance standards, including cold flow properties, to succeed. To help address quality concerns, the National Biodiesel Board started a BQ-9000 accreditation program for producers and marketers of biodiesel. This is similar to the steps that wineries have taken with *appellation contrôlée* laws to guarantee quality. Many expect biodiesel eventually to become unmarketable without BQ-9000 accreditation.

The biodiesel market is still evolving, with rapid growth now being led by many of the large ethanol producers such as ADM and Cargill. Individual projects are getting larger. More banks are crowding into the market as potential lenders. This helps borrowers, but at the same time, the trend is also toward increasing complexity in loan arrangements. ◎

Gone with the Wind, or Whose Line Is It Anyway?

by Robert F. Shapiro, in Washington

What if you built a transmission line in order to get the electricity from your wind farm to market and you expected to be able to use the extra space on the line for your next project? Does that extra space belong to you?

This is the central issue in a Federal Energy Regulatory Commission proceeding that pits the need to encourage transmission investment against the requirements of open access to the grid under federal law.

In an application filed at FERC by wind developer Aero Energy LLC, the developer asked FERC to order another wind developer, called Sagebrush, to allow it to move its electricity to the grid over an existing transmission line belonging to Sagebrush. The line was currently used by Sagebrush and a few other wind project owners to transmit electricity from their existing wind farms.

FERC initially ordered Sagebrush to let Aero Energy connect its project to the line, but it required Sagebrush only to provide *non-firm* transmission service over the line on the strength of Sagebrush's claim that it had only 3 megawatts of excess capacity. However, after performing a system impact study, it became clear that Sagebrush had up to 120 megawatts of firm capacity available. So Aero asked FERC to revisit its finding and direct Sagebrush to provide *firm* transmission capacity over the line. Sagebrush responded by claiming that it was entitled to the excess capacity and for FERC to allow others to use it would create a disincentive for private entities to develop, finance and construct new transmission lines at a time when new transmission was desperately needed. */ continued page 18*

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ethanol, not just refineries that blend it with gasoline. The ruling suggests that it may be possible to have such a roll up by combining refineries that blend ethanol in the same partnership with one or more plants to produce ethanol.

Master limited partnerships are large partnerships with units that are publicly traded on a stock exchange or over-the-counter market. They have been used by energy companies to acquire gas pipelines, propane distributors, coal reserves and other properties. They can raise equity more cheaply than other businesses can. Since they operate as partnerships, their earnings are taxed only once (unlike corporate earnings that end up being taxed both to the corporation and again to investors when the earnings are distributed as dividends). Investors are also willing to pay more for interests for which there is a liquid market.

MLPs are suitable for projects that earn at least 90% of their income from the "exploration, development, mining or production, processing, refining, transportation . . . or the marketing of any mineral or natural resource." Crops are not considered natural resources for this purpose.

The IRS confirmed in a private letter ruling made public in September that fees that a partnership earns for injecting additives or blending ethanol with fuel are qualifying income for an MLP. This raises the question whether the partnership would qualify as an MLP if its revenue is entirely from sales of ethanol blends and the partnership makes its own ethanol. The ruling is PLR 200638018.

TAX SHELTER REPORTING rules are changing — again.

The IRS requires that any deal possessing at least one of six features must be reported to the agency as a potential corporate tax shelter. Corporations participating in such transactions must report them to a special office at the IRS at the same time they file a return for the year the transaction occurred, and a form must be attached to each return on */ continued page 19*

Wind

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No Hoarding

In an order on rehearing, FERC appeared to side with Aero Energy, but with a catch. The commission found that a transmission owner does not have the right to hoard transmission capacity until it needs it. To do so would overrule FERC's authority to direct a transmission provider to provide transmission service under sections 211 and 212 of the Federal Power Act. Moreover, the commission reasoned that since the project with the transmission line was already built and financed, there is no reason to believe that ordering transmission access for the excess capacity at compensatory rates will discourage financing for future projects.

The commission directed Sagebrush to provide *firm* service to Aero Energy up to 120 megawatts, or more if additional studies showed that more was available.

The commission distinguished this case from its holding in an earlier case involving Cross Sound Cable. In the Cross Sound Cable decision, FERC allowed the owners of a merchant transmission line to reassign transmission capacity in one of three ways: through direct reassignment, by posting on the company's open-access same-time information system, called "OASIS," or through a default release procedure. The commission approved this approach over the objection of ISO-New England, which claimed that the default procedure would give Cross Sound Cable the opportunity to game the system by withholding capacity. The commission noted that all of Cross Sound Cable's transmission capacity was purchased by the Long Island Power Authority and that it would be in LIPA's interest to sell off unneeded capacity in order to reduce its costs. In addition, the Cross Sound Cable line would be under the control of ISO-New England and would therefore benefit from the ISO-New England market mitigation rules. Thus, unlike the Aero Energy case, there was no withholding of available transmission capacity from the market, and there were safeguards to prevent future withholding.

FERC told a company that owns a wind farm that it cannot hoard unused capacity on the transmission line for the project.

The Catch

Now here comes the catch. FERC added in its order on rehearing that it was possible that Sagebrush already had specific expansion plans that would require the use of the excess transmission capacity. The commission gave Sagebrush the opportunity to make a filing at FERC to demonstrate that it had pre-existing contractual obligations or other specific plans that would require the use of the available firm transmission rights on the Sagebrush line.

Since the date of that order, Sagebrush submitted to the commission information on a confidential basis and Aero filed a response, and the parties have continued their jawboning with responses to each other's responses. The commission has not yet spoken. About the only thing that is clear at this point is that Aero Energy will be entitled to firm transmission service at least until the date that Sagebrush completes an expansion of its wind facilities, provided it demonstrates that it had a prior commitment to do so. Whether Aero Energy will get the available capacity it needs to support a long-term power sale will likely depend upon the strength of Sagebrush's submission of evidence of pre-existing commitments for wind development.

Another related and intriguing question, not yet raised specifically by this case, is whether Sagebrush would have to accommodate Aero Energy or another wind developer in any new transmission capacity that Sagebrush might build if Sagebrush's expansion plans require an amount of transmission capacity that exceeds the available capacity on the existing transmission line. FERC's position on sections 211 and 212 of the Federal Power Act would suggest that the answer is yes.

* * *

Radar

As part of the National Defense Authorization Act, the Secretary of Defense was required to provide an assessment of the effects of wind turbine blades on military radar installations. A few months ago the Secretary issued his report, and the wind community is waiting to see what the reaction is from Congress. The report has the potential to affect wind farms currently under development and limit future development of otherwise robust wind farm sites.

The issue is whether modern wind turbines can have a significant impact on the operational capabilities of military air defense radar systems. The preliminary answer from the Department of Defense is yes. A review of studies, both in the US and in Europe, revealed that the large size of the new turbines combined with the frequencies produced by the rotating blades can cause radar difficulties in distinguishing the wind turbine from an airplane. The review also indicated that wind farms could degrade certain tracking capabilities because they appear as "clutter" on radar screens.

According to the report, the only proven way to avoid radar issues is to place wind turbines outside of the radar line of sight of fixed-site air defense radars. The report explains that line of sight is dependent upon "the radar unit, the height of the wind turbine and the separation distance between them." The problem can be mitigated if there are elevated land barriers between the radar and the turbine or if the elevation of the radar is significantly higher than the location of the turbines. Beyond these conditions, there may be other site-specific solutions to the problem.

The report notes that it may be possible to develop radar suppression technologies that would require a modification to the shape of, and materials used in, the turbine construction. But the report goes on to state that, even if the technologies can be developed, those changes could result in greater costs of construction and operating costs over the turbine's useful life.

At the end of the day, the solution to the problem appears to be political, not technological. If the United States government is committed to a renewable energy future, it will spend the funds necessary to assure that the maximum amount of effective wind turbines will be developed and constructed in a manner that will allow military radar systems to function effectively. At the moment, however, there is no policy. ◎

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which benefits from the transaction are claimed. Lawyers, brokers and other "material advisers" must also report the deal to the IRS. Advisers are required to report within one month after the calendar quarter in which the deal closed.

The IRS keeps changing its view of what makes a deal a potential corporate tax shelter. The rules on what types of deals must be reported have undergone almost continuous revision since they were first issued in 2000.

The IRS proposed more changes in early November.

As expected, significant differences in how a transaction is reported for book and tax purposes will no longer be a factor in whether it must be reported.

However, the agency added a new placeholder to the list. The agency said it will issue periodic announcements as it spots "transactions of interest" that will have to be reported. It has not yet announced any. Retroactive reporting may be required for transactions closed after November 1 this year that are labeled "transactions of interest" in the future.

After the latest revisions, there are six features that will require a deal be reported. They are if the deal is a "listed transaction," meaning that it appears on a list of transactions that the IRS has announced it does not believe work, the broker or adviser offering the deal insists that the structure must be kept confidential, the fees the taxpayer pays to anyone who makes an oral or written statement about the potential tax consequences from investing in the transaction are contingent on the tax benefits or subject to a full or partial refund if any of the benefits is denied, the deal is expected to throw off at least $10 million in losses that are not compensated by insurance in one year or at least $20 million in such losses in the aggregate, the deal has been identified by the IRS as a "transaction of interest," or it is expected to generate tax credits of more than $250,000 for holding an asset for 45 days or less.

For a short time, the IRS / continued page 21

Using Derivatives to Finance New Power Plants

by Benjamin Mojuyé and Merrill Kramer, in Washington

Roughly 41,000 megawatts of generating capacity are expected to be retired in the United States from Maryland up the eastern seaboard to Maine in the next 10 years. This capacity will have to be replaced. Utilities are not signing long-term contracts to buy electricity from independent generators, and the banks that finance new power plant construction are not ready to take pure merchant risk. This makes it challenging for independent generators to finance new projects. It appears that derivatives are increasingly providing at least one solution.

This article calls attention to the special issues that energy companies should consider when entering into a derivatives transaction. Derivatives are used to manage risk. Yet, anyone entering into a derivatives transaction is also taking risk. The article explains the risks and how they are addressed in the standard documents used in derivatives deals. It also explores some serious legal issues arising out of derivatives contracts.

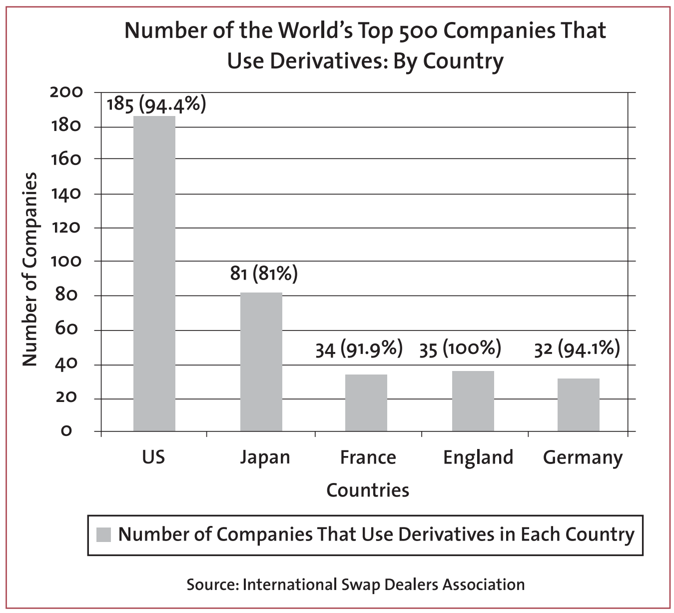
Background

Derivatives are risk-shifting products whose value is based on an underlying asset or instrument, called an "underlying." Underlyings generally include commodities (such as oil, natural gas or electricity), financial instruments (such as stocks, bonds, indices and interest rates), and virtually anything that has an economic value that can be tracked.

A derivatives contract consists of bilateral promises. One party undertakes to sell and the other to buy an underlying asset at a preset date in the future and at a specific price. The instruments usually involve a financial settlement where the party that lost the bet about how much the underlying asset would be worth at the maturity date set in the contract pays the other the difference between the actual value and the present price in the contract.

In the 1970s and 1980s, while much went wrong on Wall Street, derivatives began to change business and financial dealings as pervasively as the Internet has revolutionized communication. Derivatives have become a vital planning and financing tool.

Recent International Swaps and Derivatives Association, or ISDA, surveys are illuminating. Globally, in June 2003, derivatives markets amounted to a staggering $785 trillion in outstanding contracts, more than 10 times the gross national product of the United States. In 1991, that amount stood at $10 trillion and in 1995, at $56 trillion! More than one-third of derivatives activities occurred in off-exchange or over-the-counter markets where the notional amount of OTC derivatives contracts in 2003 was more than $170 trillion. In addition, a recent ISDA report revealed that 92% of the 500 largest companies in the world — located in 26 countries and representing a broad variety of industries from aerospace, energy to wholesalers of office and electronic equipment — use derivatives instruments to manage and hedge their risks more effectively.



The issue today for most CFOs and CEOs is not whether to use derivatives but how to do so.

Strategies

Anyone buying a derivative is usually interested in hedging an economic risk. In unstable markets, he may want to lock in a price, an interest rate or a currency exchange rate. In markets involving commodities, like electricity, for which demand is relatively inelastic, small changes in supply can lead to wide swings in prices. Independent generators like Mirant, Reliant or AES, for whom fuel costs make up 85% to 90% of the total costs of running their power plants, are very much affected by spot energy prices: high natural gas or coal prices may quickly eat up their margins. Such companies usually try to hedge against fuel prices by entering into long-term fuel contracts or by shifting the fuel price risk to the fuel supplier through tolling agreements. These are a form of hedge, as are going into the commodities markets to buy futures contracts that lock in prices but involve financial settlements rather than physical deliveries of the fuel. Federal banks are limited in their ability to enter into tolling arrangements. "Regulation Y" prohibits such banks from taking or making delivery of non-financial commodities such as natural gas and electricity.

The most popular derivatives instruments are options, swaps, futures and forwards. Which one a company should use depends on its tolerance for the risk of change in prices of the underlying asset or a default by the counterparty.

Options carry the least risk, at least from a buyer's perspective. The buyer of an option has the right, but not the obligation, to buy or sell an underlying asset or commodity at a specified "strike price" during a certain period. All the holder of the option stands to lose if the option is never exercised is the small amount he paid for the option. However, the seller is in a more risky posture. It must execute the promise it made if the holder exercises. The holder's exposure to counterparty risk that the seller will not perform may be considerable.

A *forward* is a contract where one party promises to sell and another promises to buy, at a future date, a commodity at a predetermined price. For example, on December 1, 2006, X, as seller, and Y, as buyer, sign a natural gas forward contract. Under the terms of the contract, the seller promises to deliver 100 million cubic feet, or mcf, of natural gas at $5 an mcf on February 28, 2007 to the buyer. Each party to the contract hopes its predictions about future market movements will prevail. The seller anticipates that an mcf of gas will be selling by late February at less than $5, and the buyer is worried that gas prices will increase. At maturity, if the transaction is cash settled, one party must pay the other the difference between the actual price of gas and $5 an mcf. If gas prices have fallen, the buyer pays the difference to the seller. If the transaction is physically settled, then the buyer will take actual delivery of the gas, but the economic result will be the same. Instead of buying gas in the spot market at the lower / continued page 22

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required that all deal papers contain an explicit statement that both the structure and tax treatment of the deal are not confidential. However, such statements are no longer required in the deal documents themselves. They are only needed in engagement letters with certain advisers.

The IRS is collecting comments on the new rules. Comments are due by January 31.

Treasury official Michael Desmond suggested at an American Bar Association luncheon in late October that the government may treat transactions that use a patented tax technique as "transactions of interest." The IRS is concerned about an upsurge in applications to the US Patent Office to patent tax strategies, and it wants to learn more about what types of strategies taxpayers are asking to have patented and how such strategies are employed.

PRE-TAX RETURNS are an area of controversy.

The United States offers generous tax credits to encourage private investment in renewable energy, coal gasification, biofuels, pollution control equipment, low-income housing and other endeavors. Many developers who undertake such projects have too little tax base to use the tax subsidies. They bring in partners who can use them. The large pool of potential investors, compared to the relatively small number of deals, has driven down returns to a point where most, if not all, of the return earned by the investor comes from tax benefits.

Many tax counsel insist that investors in energy deals must show they expect at least a 2% or 3% pre-tax return — meaning return before the tax benefits are taken into account — in order to prove they are in the deal for more than just tax benefits. The US does not allow pure sales of tax benefits. There is debate about whether such a return is required in the case of tax subsidies that are supposed to induce companies to undertake projects that would otherwise be uneconomic. It makes no sense to require someone in such a position / continued page 23

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spot price and paying the difference up to $5 to the seller of the forward contract, it pays the full $5 to the seller and takes the gas. The point is that, unlike with an option, both parties to a forward contract must perform.

Futures are similar to forwards except that, unlike forwards, they are traded on a regulated commodities exchange like the Chicago Board of Trade or New York Mercantile Exchange. Futures contracts are bought and sold in a standard form, while forwards are customized to suit the parties' needs. Generally, the terms of futures contracts are predetermined by the exchanges in which they are traded and may not be modified by the parties.

Project developers entering into hedges shed price risk but take on other risks tied to the derivatives transaction itself.

A *swap* is an agreement between two parties to exchange streams of cash flows or payment streams over a period of time based on changes in value of an underlying notional amount of something. The easiest example is an interest rate swap. One party might pay interest at a fixed rate on a notional loan. The other pays interest back at a floating rate. The swap market developed in response to the high variability of international interest rates and major currency exchange rates of the 1970s and 1980s. Today, swaps are used to manage more than just interest and currency risk.

Most currency swaps involve an exchange of an agreed amount of US dollars for euros, yen for euros, or yen for US dollars over an agreed time period regardless of changes in exchange rates.

Most interest rate swaps involve an exchange of fixed for floating interest on a notional loan. However, there exists another type of interest rate swap called "zero coupon," where one of the parties agrees to pay a fixed or floating rate, while the other pays nothing until the maturity date of the contract.

The most popular types of interest rate swaps in the early days of the market were *step-up* or *accreting swaps*, where the notional amount increases during the period of the swap (for loans in the form of a line of credit), *amortizing interest rate swaps,* which are opposite to *step-up swaps* in that the notional amount decreases over time (for loans to be repaid in installments), *forward swaps* that start at a specific date in the future (for a debt set to start in X months' time), *arrear swaps*, where at least one payment stream is based on a floating interest rate to be determined (LIBOR + 1/8%) in the future, generally at the end of the swap period, and reflects the average variation of such rate during such period (for example, the average variation of LIBOR over a two -year period of a swap, determined at the end of the two-year period).

In recent years, swap contracting has expanded into new markets. Today, almost any commodity or financial asset can be swapped. Equity swaps (exchange of returns or payoffs of a particular equity), and commodity swaps, including in power projects where there might be an exchange of commodity price payments, are common.

Documentation

The lawyer's role in derivatives traded on commodity exchanges is minimal. Such derivatives are standardized as to their maturity, quantity and delivery dates. Standardization produces four consequences. First, it limits the number of underlyings for exchange-traded derivatives. Second, the prospective purchaser or seller must place an order with a registered broker-dealer on a securities exchange, or with a futures commission merchant, who then will execute it on the market. Third, transactions are executed or settled through the interposition of a clearing organization, which reduces counterparty risk. Finally, immediately after execution of an order, the intermediary must send to his customer a "confirmation order."

In contrast, in over-the-counter transactions, the parties usually exchange oral promises by email or telephone. These are followed by written confirmations to each other that recite essential terms of the transactions. These confirmations become part of the "master agreement" that is then executed, along with other documents, by both parties.

Most OTC derivatives transactions, including ones based on energy and electricity products, are currently documented using ISDA forms. Although ISDA documentation is somewhat long and complex, it can fairly be described as being composed of six documents: the master agreement, a schedule, the confirmations, an annex with ISDA definitions, the protocols and a credit support annex.

The *master agreement* was first published in 1987, modified in 1992 and again in 2002. It is used to document all types of transactions (such as swaps, options, and forwards) and is supplemented by various addenda to accommodate the growing complexity and diversity of OTC transactions. The master agreement has 14 sections relating to agreements and undertakings, representations, events of default and termination, netting, transfers and the contractual currency.

Once signed, the master agreement and all of its attachments, including the schedule, the confirmations, addenda such as the caps, collars and floors, constitute a single agreement. Using the same basic agreement to document many transactions reduces transaction costs.

The use of a single master agreement for multiple transactions significantly reduces the risk of "*cherry-picking*" in the context of bankruptcy — that is, the risk that a bankruptcy trustee or liquidator would "cherry-pick" profitable transactions between two parties while disclaiming unprofitable ones. It also enables the parties to simplify the settlement of their contractual obligations by making a single payment netting all transactions.

The *schedule* is a document that is incorporated by reference in the master agreement and is usually the most contentious part of the ISDA documentation. While the master agreement contains provisions that the parties may agree broadly to apply to their transactions, the schedule allows them to fine tune, amend or reject some of these provisions. In contrast to preparing the master agreement, which involves merely filling in the blanks, negotiating the schedule is a demanding process that */ continued page 24*

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to show he does not need the tax subsidy in order to claim it.

A bank that invests in community development entities — called CDEs — that make loans to businesses in low-income areas has asked the US Treasury to confirm that its return on such investments can come solely from tax benefits. Investors in CDEs earn "new markets tax credits" of 39% of the amount of equity invested. The credits are claimed over seven years. The bank met with senior Treasury officials in early October and described how new markets tax credit deals work.

IRS officials concede privately that it makes no sense to require a pre-tax return in production tax credit and similar deals that would be uneconomic absent the tax subsidy. They are reluctant to say so publicly, even though numerous private letter rulings have acknowledged in the statement of facts that a taxpayer did not expect a pre-tax profit. The same logic might not apply to lending transactions backed by new markets tax credits since the a lender usually earns at least some return. In wind deals, tax counsel still apply a minimum profit test, but treat the production tax credits as equivalent to cash for this purpose. The tax credits are a supplement for electricity revenues.

The bank is unlikely to get the public statement it wants from the Treasury. It asked as a fallback for the same relief that investors in low-income housing projects enjoy from challenge under section 183 of the US tax code. That section bars individuals and S corporations from deducting "hobby losses." Investors in low-income housing projects take comfort from a statement in the IRS regulations that section 183 will not be used to deny tax credits for investing in such projects.

TOLLING AGREEMENTS cannot be used to change how a power plant is depreciated, the IRS said.

A company that owned a combined-cycle gas-fired power plant tried to */ continued page 25*

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requires careful negotiation, sound understanding of derivatives trading and careful drafting.

The critical issues raised during negotiations usually center around the following questions. What events should qualify as "events of default"? What events should qualify as "early termination events"? Should creditworthy affiliates be included in the definition of "party," and should the default of non-party affiliates under unrelated agreements with one of the parties trigger a cross-default under the schedule? What type of collateral and credit support should accompany each party's relative position? When hedging in the context of an asset or acquisition financing where collateral is shared with the lender, what are the relative rights of the lender, other hedge providers, and the counterparties in and to the collateral? Should a precipitous drop in market prices due to unforeseen events such as a terror attack constitute *force majeure* leading to the termination of the agreement or at least suspension of obligations? What is the method of calculation of close-out amounts?

The *confirmation* is a document where the parties record the financial and economic terms of specific transactions. Typically, transactions are initiated over the telephone. The parties reach an oral agreement that is documented in the confirmation. The principal terms of the confirmation include price, quantity, duration and tenor. The document is forwarded by one of the parties, generally the initiating party, to the other for its acceptance. The time frame of acceptance varies from two days to many months.

The confirmation is usually short — two to three pages — although the complexity of some transactions may lead the parties to draft a much longer form. ISDA published standardized confirmation forms recently.

One of the most useful achievements of ISDA is to provide derivatives dealers with a set of defined technical terms, thereby reducing the risk of misunderstanding between the parties. The standard definitions are used across many types of deals. The parties may still choose to either modify or disregard standard definitions.

ISDA also issues "user's guides" and "commentaries" in an effort to reduce the room for misunderstandings. For example, there is a commentary accompanying the three recently-published supplements to the 1999 credit derivatives definitions.

One risk is potential recharacterization of the transaction as a security or insurance, either of which would trigger a separate set of regulations.

The *protocols* govern future modifications by the parties of their agreements. For example, the parties would agree that on the occurrence of certain events, the contract would be amended at the option of one or both of them, or simply to adopt preagreed economic terms like whatever is prevailing in the market at the time. For example, the 1996 EMU protocol dealt with the consequences of the adoption of the euro.

The *credit support annex* is key to allocating and countering counterparty risk. Usually, each party to a derivatives transaction must post collateral in excess of an agreed amount to cover the risk that it will fail to perform under the contract. The collateral posted by each party must usually be assessed on a daily basis by marking it to market. Thus, if a party's exposure relative to the collateral it tendered has increased, it would be required to provide additional collateral or otherwise it would be in default under the contract.

Like the master agreement, the credit support annex contains standard terms and a schedule. It is the key document for providing security and managing credit and performance risk. However, the parties remain free to amend or disregard the standard provisions. They might also decide not to use it to document their transaction.

Legal Issues

Legal issues exist mainly in OTC derivatives transactions where many innovative and specifically-tailored contractual arrangements may be unenforceable.

The enforceability of a derivatives contract usually turns on risks that the contract might be recharacterized, insufficiently documented, entered into by an incapable or unauthorized party or unenforceable as the result of the application of bankruptcy provisions. In addition, one derivatives party may be held liable to the counterparty for failing to disclose the economic risks of the transaction.

Recharacterization is almost always a risk. A transaction may be recharacterized under securities and commodity laws, anti-gaming and anti-bucket shop laws and insurance laws. The Commodity Futures Modernization Act that was recently enacted reduced the risk of recharacterization under state anti-gaming and anti-bucket shop statutes. Any attempt to construe derivatives instruments as insurance will usually not succeed. The derivatives markets are supervised by both the US Securities and Exchange Commission and the Commodity Futures Trading Commission. The Federal Energy Regulatory Commission also oversees the physical trading of electricity and related contracts.

Instruments that are "securities" may not be traded unless they are registered with the SEC. Commodity-based derivatives that fall under the ambit of the CFTC may not be traded off-exchange, except for certain types of commercial options. Whether a particular instrument is a "security" or a "commodity" may not always be clear. The legal uncertainty can be costly. In case a derivatives product is reclassified as a security, severe consequences will attach against the parties: criminal and administrative sanctions for violation of securities acts and possible civil lawsuits by counterparties and by affected third parties for fraud and misrepresentation.

Likewise, recharacterization of an OTC derivatives contract as a "commodity" suggests that the parties have traded the instrument in violation of a broad prohibition against off-exchange trading. Until 2005, failure to comply with this off-exchange trading prohibition generally meant the OTC derivatives contract at issue could be held illegal and unenforceable, putting the parties at risk of heavy criminal and administrative sanctions and, possibly, high-stakes liability lawsuits from injured third parties. Exemptions granted by the Commodity Futures Trading Commission under the Futures Trading Practices Act proved */ continued page 26*

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depreciate it over seven years using the 200% declining-balance method. Power plants that generate electricity *primarily for sale* using coal or gas in a combined-cycle process must be depreciated over 20 years using 150% declining-balance depreciation. The taxpayer argued on audit that the plant was not producing electricity primarily for sale; rather it earned fees under a tolling agreement with a gas company for converting gas into electricity. The IRS national office rejected the argument. It said the fact that ownership of the plant and the electricity are split into two different entities is irrelevant. The proper depreciation turns on the functional use of the plant. Its use is to generate electricity for sale, even if the taxpayer who owns the plant is not the one selling the electricity.

The IRS position is in a "technical advice memorandum," or ruling by the national office to settle a dispute between a taxpayer and an IRS field agent. The number is TAM 200638024. The IRS made it public in September.

INDIAN TRIBES that would like to issue tax-exempt bonds to finance projects on reservations got help from a government report in September.

Tribes can issue tax-exempt debt, but only for projects that perform an "essential governmental function." The IRS proposed a narrow definition of what qualifies in August. It would limit eligibility to the kinds of projects that "numerous" state and local governments with general taxing powers have been using tax-exempt bonds to finance. The IRS also said it would not allows tribes to use tax-exempt debt to finance commercial or industrial activities.

The Government Accountability Office said in a report to Senator Max Baucus (D.-Montana) that state and local governments have used tax-exempt bonds historically for a wide range of projects. For example, such bonds have been used in 29 states to finance golf courses.

Baucus is pushing legislation in Congress that would make it easier for */ continued page 27*

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unclear and inconsistent. In reaction, Congress adopted a new statute in December 2000 that provides more legal certainty to OTC market participants in two respects.

First, Congress established separate treatments for derivatives transactions in three classes of commodities: "excluded commodities," "agricultural commodities" and "exempt commodities."

Another risk is the uncertain status of some transactions under the bankruptcy laws.

OTC derivatives transactions based on excluded commodities — essentially, financial variables (interest rates, currency rates) and off-exchange contracts based on exempt commodities — are not subject to CFTC oversight, provided that they are entered into solely between eligible contract participants and not on a "trading facility" like an exchange, or they are entered into between eligible commercial entities on a trading facility. Derivatives contracts based on agricultural commodities may only be traded on futures exchanges and are regulated by the CFTC.

Second, Congress directed that no OTC derivatives contract may be rescinded for the sole reason that it failed to comply with the statutory exclusions or government regulations. This no-rescission clause significantly increases the security of OTC transactions since a party can no longer escape its contractual obligations on the claim that the OTC contract at issue is illegal. Instead, Congress allowed the parties to cure the legal deficiency that the contract contains without permanently compromising its enforceability.

The legal security is not absolute. Most notably, it does not insulate the contracting parties from heavy administrative and criminal sanctions under US commodity and securities laws. Nor does it shield the parties from expensive lawsuits from affected third parties. Finally, in all circumstances, the parties remain accountable under the anti-fraud and anti-manipulation provisions of the commodity act and the securities acts.

The bottom line is that parties to an OTC derivatives transaction still face considerable, though abated, recharacterization risks.

Another potential legal issue is lack of documentation. Parties initiate contacts and agree upon the most essential terms of the deal by telephone, and exchange confirmations that they execute later. Until recently, such delays in documenting the transaction — usually referred to as "backlog" — were at odds with statutes of frauds that require enforceable contracts to be in writing. Fortunately, a 1994 amendment has practically eliminated the problem in New York, where most OTC derivatives transactions take place. Under the amended law, which applies to qualified financial contracts entered into as of September 20, 1994, oral agreements are enforceable provided that there is sufficient evidence to indicate that an agreement was made; such evidence may also be implied from prior dealings between the parties. In any event, a written confirmation must be received by the counterparty within five business days, who may object within three business days after receipt of such written confirmation. Such deadlines may be amended by the parties.

Another common legal problem is lack of capacity. Capacity refers to a party's legal authority to enter into a derivatives transaction. A party's lack of capacity is likely to foil the proper enforcement of a derivatives contract and, as a result, may cause substantial losses to any of the parties whose positions were in the money.

Capacity concerns regarding derivatives are not particularly relevant for major corporations. Generally, corporate charters are written in broad terms and grant expansive powers to the board to conduct business operations. Even where the articles of incorporation appear restrictive on their face, courts are likely to rely on the theory of apparent authority to quash any lack-of-authority claim.

However, the issue does arise with respect to derivatives agreements entered into with state and local governments and highly-regulated financial institutions such as insurance companies and banks. In such cases, questions may surface as to whether these entities, or the persons representing them, have the capacity to enter the transactions.

While a strict application of state law might result in invalidation of derivatives contracts entered into by most state and local authorities, states generally permit licensed insurers to engage in derivatives activities. The New York insurance law provides an informative illustration. In 1999, the New York state legislature added a new section to article 14 of the insurance law that governs the use of derivatives by insurance entities. The new law removed major restrictions to derivatives activities of domestic and foreign insurers and reinsurers licensed to operate in the state.

With respect to banks, although they do not have explicit authority to engage in derivatives transactions, federal and state regulatory agencies have proven accommodating. They generally make an expansive reading of bank regulatory powers.

Another potential legal issue is change in law, like the introduction of the euro. Generally, a change in law can cause executory contracts to be terminated if it causes a material alteration of the respective obligations of the parties. The introduction of the euro as the new currency in 12 countries in Europe in January 2002 was not a problem. The adopting legislation specifically directed that all executory contracts would remain legal, valid and enforceable. Major US states like New York, Illinois and California enacted similar statutes.

Another legal issue in derivatives transactions is the uncertain scope of bankruptcy provisions. The Bankruptcy Abuse Prevention and Consumer Protection Act of 2005 clarified the treatment of derivatives contracts when a market participant defaults. Similar concerns prompted New York to amend its banking laws to clarify the role of the New York banking superintendent as a receiver or liquidator in the context of bankruptcy of an uninsured state-chartered bank

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tribes to use such bonds. He will become chairman of the Senate tax-writing committee in January.

MINOR MEMOS. The IRS is taking a harder line on whether utilities can avoid paying taxes on amounts they receive from developers to move gas mains and power lines out of the way of new construction and from municipalities to bury power lines, according to a letter the Edison Electric Institute sent the Treasury in September. The letter also complains that utilities are having to report contributions from neighboring utilities to help pay for upgrades to their grids. For example, utility X might find it in its interest to help utility Y add to Y's grid so that more electricity can be transmitted by both utilities. The Treasury is considering whether it should get involved. The EEI letter focuses on one possible legal basis the utilities have for not reporting the amounts as income. The IRS does not believe it applies. However, the EEI letter overlooks two other legal bases with which the IRS has no problem. The other legal bases apply in some, but not all, of the cases . . . . The IRS added Barbados to a list of countries from which dividends qualify for a 15% tax rate. The United States taxes individuals on their dividend income at a 15% rate. The rate only applies to dividends received from domestic corporations and from foreign corporations in countries that the IRS has announced have acceptable tax treaties with the United States. Barbados has a tax treaty, but failed in the past to make the list. The IRS added it on October 30.

— contributed by Keith Martin, Laura Hegedus and Luis Torres, in Washington.

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or state-licensed agency of a foreign bank. Those provisions explicitly allow the set off of claims arising out of derivatives contracts when the bank becomes insolvent.

As background, under the 1898 bankruptcy code, upon filing of a bankruptcy petition, all lawsuits and collection activities against the debtor are automatically suspended. Until 1978, a debtor's derivatives obligations were treated in the same manner as other debtor payment obligations. A non-debtor derivatives counterparty could not collect against a debtor in bankruptcy, a situation that did little to foster development of derivatives markets. Fortunately, the bankruptcy code was amended in 1978, 1990 and 1994 to exempt qualifying financial derivatives contracts from the "automatic stay" provisions and enable eligible non-debtor entities to terminate those derivatives agreements with their debtor counterparties in bankruptcy, liquidate or set off their mutual claims and seize the underlying collateral.

The new federal bankruptcy amendments in 2005 expanded both the scope of financial contracts and the categories of market makers covered by the safe harbor by which derivatives and financial contracts are not subject to automatic stays. They expressly permit derivatives counterparties automatically to net payment amounts among different types of products without stay or avoidance "*or any other court interference*."

The 2005 amendments extended the right to set off to any "financial participant," meaning any large entity that is a party to one or more derivatives contracts or transactions with outstanding notional amounts of at least $1 billion in a 15-month period or that has gross mark-to-market positions of at least $100 million in one or more such derivatives contracts or transactions in a 15-month period. The catch-all phrases "*or any other similar agreement*" and "*any agreement or transaction that is similar to any other agreement or transaction referred to in this paragraph*" have considerably expanded the scope of the right to set off, thereby allowing for the continued and rapid development of new derivatives instruments.

On the other hand, the 2005 amendments restricted the ability of trustees to avoid pre-petition payments and other transfers made to eligible derivatives non-debtor counterparties, under qualifying derivatives contracts, such as "securities contracts," "commodity contracts," "forward contracts," "repurchase agreements" and "swap agreements." The bankruptcy code grants trustees broad powers to avoid or unwind certain pre-petition transfers made by a debtor in bankruptcy to its creditors to ensure the equitable distribution of the bankruptcy estate's assets to similarly-situated creditors. While prior amendments to the bankruptcy code have insulated transfers made under qualifying financial contracts from trustee avoidance powers, the 2005 amendments expanded the meaning of such contracts, thereby extending the safe harbor to a wider group of derivatives instruments. However, transfers and payments made by the debtor in bankruptcy "with actual intent to hinder, delay, or defraud" creditors will remain subject to possible avoidance.

Finally, failure to disclose the risks of the transaction is also a potential legal issue. Recently, some discontented derivatives users tried to get out of bad deals by claiming that their counterparties failed to disclose the risks. While most civil actions brought have been settled, one Ohio court held in a case between Proctor & Gamble and Bankers Trust Company in 1996 that no fiduciary relationship can exist where the two parties were acting and contracting at arm's length. The case involved a transaction that was governed by New York law. However, the court recognized an implied contractual duty to disclose in business negotiations when three conditions are met. There is a duty to disclose if one party has superior knowledge of certain information, that information is not readily available to the other party and the first party knows that the second party is acting on the basis of mistaken knowledge. That being said, it should be noted that the decision is limited to the specific transactions at hand and is not binding on other courts. As a result, in a derivatives transaction, the extent to which one party relies on another to disclose information must be carefully negotiated. Typically, in the schedule, each party will state that it does not rely on any communication (written or oral) of the other as investment advice or as a recommendation to enter into the transaction.

Derivatives are designed to subdivide and reallocate risks to those most willing to bear them. However, they do not eliminate risk. Derivatives themselves have built-in risks including collateral encumbrances that can cause substantial losses to market participants. Such risks can be mitigated through careful understanding of the market and deal documents.

New Rules Would Require Independent Generators to Help Maintain Grid Reliability

by Adam Wenner, in Washington

The Federal Energy Regulatory Commission proposed in late October to approve 83 "reliability standards" proposed by the North American Electric Reliability Corporation — called NERC — for maintaining reliability of the US electricity grid.

The new reliability standards will go into effect in June 2007. FERC and regional reliability councils are urging that users of the bulk power system commence compliance immediately on a voluntary basis.

The new standards apply not only to regulated utilities, but also to independent generators.

Any comments about the new standard are due at FERC by early February.

Background

Congress directed in the Energy Policy Act in August 2005 that more attention be paid to reliability of the grid. It did so in response to the cascading blackout that affected large portions of the central and eastern United States and Canada two years earlier and threw more than 50 million customers representing 61,800 megawatts of electric load into darkness. Review of the incident indicated that violation of NERC's then-voluntary standards was one of the primary causes of the blackout. The Energy Policy Act added a new section 215 to the Federal Power Act to establish mandatory and enforceable reliability standards. On February 3, 2006, the Federal Energy Regulatory Commission certified NERC as the electric reliability organization responsible for developing and enforcing mandatory reliability standards, subject to FERC review and approval.

NERC is, in turn, authorized to delegate authority to regional entities for the purpose of proposing reliability standards to NERC and enforcing approved reliability standards. The regional entities are the existing regional reliability councils —- namely the Electric Reliability Council of Texas, Inc. (ERCOT), the Florida Reliability Coordinating Council (FRCC), the Midwest Reliability Organization (MRO), the Northeast Power Coordinating Council (NPCC), the Reliability First Corporation (RFC), the SERC Reliability Corporation (SERC), the Southwest Power Pool, Inc. (SPP) and the Western Electricity Coordinating Council (WECC).

Many of these standards impose obligations on operators of generating plants, as well as on transmission system operators, balancing authorities and regional planning agencies.

This article focuses on how the proposed rule will affect independent generators in the continental US (including ERCOT), which is the area covered by the proposed rules.

New Standards

The new legislation and the FERC rules obligate all users, owners and operators of the bulk power system in the continental United States to comply with the FERC-approved reliability standards, and they subject such users to severe penalties for non-compliance. FERC analogized its proposals to requirements that commercial airliners be maintained pursuant to established standards. Rather than establishing an "outcome-based" standard that would punish airlines for plane crashes after the fact, there are specific standards for maintenance procedures, frequency of testing and qualification of personnel conducting the maintenance. FERC said it expects NERC to include proactive requirements in its proposed reliability standards.

The following are highlights of the proposed rules that apply to power plants.

NERC proposed limiting applicability of the reliability standards to plants whose capacity reaches specified power thresholds: for example, generators with a capacity of 20 megawatts or greater, or transmission facilities energized at 200 kV or greater. FERC questioned this blanket rule, on the ground that there may be instances where a smaller entity's compliance is critical to maintaining reliability, and it invited further comments on this topic.

Similarly, FERC rejected a NERC proposal to limit the definition of the bulk power system governed by the reliability standards to exclude radial transmission facilities serving load with one transmission source, citing concerns that, for example, the 239 cables connecting Mirant's Potomac river plant to Washington, DC would not be / continued page 30

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included; similarly, the NERC proposal to establish a 200 kV threshold would exclude the New York City 138 kV system.

FERC rejected the NERC proposal to require all generators to provide automatic generation control capabilities, noting that not all generation resources can be operated with such controls, and in other instances the controls are not economically feasible.

New reliability standards for the US power grid will affect independent generators.

The NERC proposal includes a group of reliability standards, the critical infrastructure protection group, which is aimed at reporting occurrences of sabotage to the proper authorities and establishing security for critical cyber assets. Regarding sabotage, NERC proposed that every generator operator, as well as each reliability coordinator, balancing authority and load-serving entity must have procedures for making its operating personnel aware of sabotage events and procedures for communicating information about sabotage events to the appropriate parties in the interconnection. In addition, generators must provide operating personnel with guidelines for reporting disturbances arising from sabotage events, and must establish communications contacts with applicable government officials. FERC directed NERC to modify its standards to identify agencies such as the Federal Bureau of Investigation or the Department of Homeland Security on a protocol for reporting sabotage.

Regarding telecommunications requirements, NERC proposed to establish such requirements for specific operating entities, to establish English as the common language to be used by operating personnel and to set policy for using the NERCNET telecommunications system. FERC noted that the NERC proposal would not apply to generators, which could create problems, for example, during a black start when normal communications are disrupted. In such circumstances, it would be crucial that generator operators have effective communications with transmission operators, balancing authorities and reliability coordinators.

During capacity or energy emergencies, balancing authorities must have the authority to bring all necessary generation on line, communicate the energy or capacity shortage to the reliability coordinators and coordinate with other balancing authorities. FERC proposed to adopt the NERC rule that would impose these requirements, but also to extend it to cover transmission emergencies. FERC agreed with concerns expressed that the transmission loading relief method is inappropriate for addressing transmission emergencies, as it is not fast or predictable enough to use in situations in which an operating security limit is close to or actually being violated.

When the electric grid has suffered an outage, there must be a plan for system restoration. The NERC proposed standard requires that transmission operators verify that black start units can perform as required and that simulation or testing be performed at least once every five years. FERC adopted this proposal in its proposed rules.

The next NERC proposal relevant to generators requires of generation facility owners, as well as transmission facility owners, distribution providers, load-serving entities, transmission planners and planning authorities that each assess the impact of integrating generation, transmission and end-user facilities into the interconnected transmission system. FERC adopted this requirement, as amended by a FERC staff proposal to require that evaluations of system performance be conducted under both normal and contingency conditions.

NERC proposed a facility ratings methodology standard, that would require each transmission and generation facility owner to develop a facility rating methodology based on manufacturing data, design criteria, ambient conditions, operating limitations and other such assumptions. The methodology would be made available to reliability coordinators and other responsible parties in the areas where the facility is located. FERC adopted the proposal, rejecting its staff criticism that the standard did not impose uniform standards, on the ground that it is appropriate to use input variables, such as ambient temperatures in Texas as compared to Maine.

A key aspect of the FERC proposed rules deals with training requirements for operating personnel. NERC proposed to require each transmission operator and balancing authority to provide training to all operating personnel who occupy positions of primary responsibility for real-time operation of the bulk power system or who are directly responsible for complying with the NERC reliability standards. Noting that deficient training contributed to the August 2003 blackout, FERC proposes to expand the training requirements to include generator operators. It also proposes to require NERC to develop a new training reliability standard for all personnel who may directly affect the reliable operation of the bulk power system and for those who have responsibility for compliance with the reliability standards.

Similarly, FERC augmented the NERC proposed requirement for system operators, and others with primary responsibility for real-time operations to use NERC-certified staff in these positions, by imposing the same requirement on generator operators.

Protection and control systems are designed to detect and isolate a faulty element from the system, so as to limit the spread of system disturbances and prevent damage to protected elements. The NERC reliability standards on this subject apply to generator owners and operators, as well as transmission operators and regional reliability organizations. These standards are intended to ensure coordination of protection and control systems among operating entities by requiring transmission and generator operators to notify appropriate entities of relay or equipment failures that could affect system reliability. FERC approved this standard as mandatory and enforceable.

NERC proposes to require generators of greater than 50 megawatts and transmission providers with systems greater than 100 kV to provide outage information so as to permit coordination of planned outages. FERC modified the thresholds to include any facility below the proposed thresholds that, in the opinion of the transmission operator, balancing authority or reliability coordinator, would have a direct impact on the operation of the bulk power system. Also, FERC proposes to require that notice of scheduled outages be given well in advance, to ensure reliability and accuracy of calculations.

The reliability standards include a requirement that transmission operators monitor and control voltage levels, reactive flows and reactive resources. They also require a generator operator to provide operating data to its transmission operator and to maintain generator field excitation at proper levels.

Finally, NERC and the regional entities are obligated to monitor compliance with the reliability standards and are empowered to direct violators to comply with the standards and impose penalties for violations, subject to review by the FERC. Although not discussed in the FERC proposed rulemaking proceeding, the Energy Policy Act requires any person who violates part II of the Federal Power Act (which includes the new reliability standards provision) to be subject to a civil penalty of up to $1 million for each day that the violation continues. This is certainly a strong incentive for users of the bulk power system to comply with the new rules. ◎

When Subsidies Reduce Tax Credits in Renewable Energy Projects

by Laura Hegedus, in Washington

Congratulations.

You have learned that your energy project will benefit from state or local financial incentives. Now you need to know whether these state or local grants, rebates or other subsidies will reduce the amount of federal tax credits that may be claimed on the project.

The answer depends on the characteristics of the state or local program. This article describes the existing guidance on the subject.

PTCs and ITCs

Federal production tax credits are available to taxpayers owning (and in the case of some biomass projects, leasing) power plants that generate electricity */ continued page 32*

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from certain renewable sources: wind, biomass, geothermal steam or fluid, landfill gas, garbage or water. This year PTCs are either 1¢ or 1.9¢ per kilowatt hour of electricity generated, depending on the type of renewable source.

The statute granting PTCs provides that available federal credits will be reduced, by as much as 50%, to the extent that the project benefits from federal, state or local grants, tax-exempt financing, subsidized energy financing or "other credits." The IRS said in February that the term "other credits" in the PTC statute means only federal credits, not state or local tax credits. However, we still need to analyze whether state and local tax credits are "grants" that reduce PTCs.

Federal investment tax credits are available for solar energy projects (and geothermal projects on which the owner chooses to forego production tax credits) . ITCs for solar projects are 30% (10% after 2007). They are that percentage of the cost of new equipment that uses solar energy to generate electricity, heat or cool or provide hot water for use in a structure, or provide solar process heat. There are also ITCs of 20% of the cost of certain new equipment to gasify biomass, although these credits are subject to a nationwide cap and must be allocated to the taxpayer by the IRS. The statute granting ITCs reduces the federal credits by the full amount of tax-exempt financing and subsidized energy financing that helped to pay for the assets. Grants are potentially subsidized energy financing for this purpose unless the recipient reports the grant as taxable income.

Tax credits for renewable energy projects may suffer a "haircut" when a project is also being helped in other ways by the government.

Grants

The PTC statute requires tax credits to be reduced by the amount of grants benefiting the project.

State or local grants and rebates do not reduce the basis of energy property on which the ITCs are calculated, as long as the grant or rebate is included in the federal gross income of the recipient.

Most state and local grants and rebates should be included in gross income for federal purposes, so they should not ordinarily reduce ITC basis. The IRS said in a 1979 revenue ruling that a state grant to fund the cost of a solar hot water heater was included in federal gross income and did not reduce the taxpayer's basis in the property for purposes of claiming the federal tax credit. A 1980 private letter ruling holds that Wisconsin refundable income tax credits for installing alternative energy systems that the IRS said were equivalent to grants did not reduce the basis of property for federal tax credit purposes on the same grounds that the value had to be reported as income.

However, rebates from a utility to a customer to help pay for energy conservation measures in a dwelling unit do not have to be reported as income under a special section of the US tax code. These "energy efficiency" rebates, because they are tax exempt, do reduce ITC basis in a solar project.

It is fairly clear that state and local grants and rebates (other than energy-efficiency rebates) benefiting an individual taxpayer who is not receiving the amount in connection with his business are included in federal gross income. It is not as clear that grants and rebates benefiting a business must always be included in federal gross income. However, businesses will derive a greater tax benefit if they include the grants in gross income and preserve the basis of property on which the ITC can be claimed.

Are all cash payments "grants"? No. The IRS said in a 2003 private letter ruling issued to a wind farm claiming PTCs that an operating subsidy paid by the state was not a "grant" because the wind farm would have to repay the money if it did not spend it on operating costs within a certain period of time. The IRS suggested that funds are a "grant" only if there are no circumstances in which they will have to be repaid. The IRS has also confirmed, in a 2002 private letter ruling about a wind project, that privately-funded grants do not reduce PTCs.

Renewable energy credits or other environmental attributes created and granted under law are not "grants." The IRS issued a private letter ruling in 2001 stating that PTCs accruing to a wind farm were not reduced due to receipt of state RECs.

Even if it is clear that a state or local benefit is not a "grant" that reduces federal tax credits, that benefit should also be analyzed to determine if it is "subsidized energy financing."

Tax-Exempt Financing

Otherwise available PTCs are reduced, by as much as 50%, to the extent that the project benefits from tax-exempt financing. The basis of property eligible for ITCs is reduced by the full amount of tax-exempt financing that is lent to the project.

State and local governments can issue tax-exempt bonds for public facilities and for certain private projects, listed in the tax code, that are considered to have public benefits. In tax-exempt financing for private projects, the state or local government issues the bonds and relends the proceeds to the project.

The entire amount of the financing is counted in figuring the reduction in PTCs or ITCs, not merely the value to the taxpayer of the reduced interest rate. In the case of ITCs, for example, if the project cost is $100 million and $60 million in bond proceeds are lent to the project, only $40 million in creditable basis remains. In the case of PTCs, if a tax credit of 1¢ per kWh would otherwise be available on a project that cost $100 million, and there is tax-exempt financing of $60 million, the PTCs are reduced by the full 50% permitted in the PTC statute (to 0.5¢ per KWh).

Subsidized Energy Financing

Even if you are certain that your state or local financial benefit is not a grant or the proceeds of tax-exempt bonds, you need to consider whether the benefit is "subsidized energy financing" that also reduces PTCs and ITCs.

Subsidized energy financing is defined as financing under a federal, state or local program with a principal purpose of providing subsidized financing for projects designed to conserve or produce energy. The following discussion assumes that the government program has such a focus.

It is subsidized energy financing if a government agency makes a direct loan to an energy project at a below-market rate. Proposed energy credit regulations state that funds are sourced to a government if the funds are provided directly or indirectly by a government agency, including through an intermediary that is a bank or other lender.

It is also subsidized energy financing if a government pays a bank that is lending to a project in order to compensate the bank for providing a lower interest rate on the loan than the bank would ordinary use. In this case, the entire amount of the financing to the project will reduce tax credit basis -— not just the amount paid by the government to the bank. In regulations issued under a now-repealed tax code section that also used the term "subsidized energy financing," the IRS provided an example of a bank lending $3,000 to a homeowner to install a solar water heater where the bank reduced the principal amount to $2,500 upon receipt of $500 from a federal conservation program. The amount of subsidized energy financing that reduced the homeowner's tax credit basis is $3,000, not just the $500. Another example in these regulations shows that "subsidized energy financing" includes low-interest financing from a bank under a state program that compensates the bank with state tax credits for making low-interest financing available to energy projects. Again, the entire amount of the financing reduces the taxpayer's ITC basis in property, not just the value of the state tax credits claimed by the bank.

A loan guarantee from a federal or state agency or utility is not subsidized energy financing. Thus, if a project benefits from a loan guarantee, the amount guaranteed should not ordinarily reduce PTCs or ITCs even though the interest rate on the loan is lower than it would have been without the guarantee.

Privately funded payments should not be considered subsidized energy financing. In a 2002 private letter ruling, the IRS held that wind incentive payments that were both funded and administered by private parties (a private utility and a charity, respectively) were not subsidized energy financing. In that ruling, the incentive payments were based on the kilowatt hours of energy generated and did not pay down capital costs of the project.

If a public utility is required to provide */ continued page 34*

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low-interest loans to businesses for the purchase of energy property and the public utility funds this financing by imposing a surcharge on its customers for utility service, the financing is not treated as subsidized energy financing. It does not matter that the utility is required by state law to offer the loans. They are privately funded. However, if the public utility funds its financing program with money received from a state or local government, the financing is subsidized energy financing. The IRS ruled privately in 2004 that an advance payment received by a wind project from a tax-exempt trust was not subsidized energy financing where the trust was prepaying for the environmental attributes of the energy; the trust was funded by a charge imposed on public utility customers under a state program to promote renewable energy.

The IRS has ruled that it is not subsidized energy financing when an investor-owned utility provides rebates on electricity bills to homeowners who install solar hot water heaters. This is because the money used to fund the program comes from the private sources. Neither is it subsidized energy financing when a federal utility makes loans at below-market interest rates to customers of local utilities to which the federal utility provides power. Since by law federal utilities must cover all costs from their own revenues, the cost of the below-market loan program does not fall on the federal government.

The IRS has ruled several times that direct operating subsidies paid by state or local governments to solar producers are not subsidized energy financing. Operating subsidies do not reduce PTCs; only help with the capital costs of a project is potentially a problem. ◎

More Tolls on Interstate Highways?

by Jacob S. Falk, in Washington, and Edwin Huang, in New York

Various states are moving to collect tolls on Interstate 95, the main north-south highway along the eastern seaboard in the United States. Private road developers are hoping the money collected from such tolls will be used to fund public-private partnerships to improve bridges and tunnels and add new lanes along US interstates.

South Carolina applied earlier this year to the Federal Highway Administration to collect tolls on I-95 in South Carolina. North Carolina may also be considering tolls on the part of the road that runs through it. On October 24, Virginia entered into an interim agreement with Fluor and Transurban to add high-occupancy toll lanes on I-95 immediately south of Washington, DC; the state may also be considering collecting tolls on existing portions of I-95 near the border with North Carolina.

US interstate highways are owned by states, but interstate projects are subject to federal review and approval and tolls are generally not permitted on interstates. However, Congress allowed states to apply to collect tolls on I-95 (and other interstates) in a 2005 law called the Safe, Accountable, Flexible, Efficient Transportation Equity Act: A Legacy for Users, or SAFETEA-LU.

Tolls and Interstates

The general ban on tolls is found in title 23 of the United States Code, section 301. Nevertheless, some interstate highways are tolled, including I-95. There are currently tolls on sections of I-95, including the Maine Turnpike, the New Hampshire Turnpike, the New England Thruway (in New York), the George Washington Bridge (linking New York and New Jersey), the New Jersey Turnpike, the Delaware Turnpike, the John F. Kennedy Memorial Highway (in Maryland) and the Fort McHenry Tunnel (in Baltimore, Maryland). There are currently no tolls south of Maryland on I-95 in Virginia, North Carolina, South Carolina, Georgia and Florida.

The tolled portions of I-95 and other interstates are permitted, for the most part, because tolls were being collected before creation of the interstate highway system in 1956. Congress at that time established gas taxes, rather than tolls, as the preferred method for funding the interstate system, but recognized that it would be unfair to the holders of existing toll road debt to eliminate tolls on the toll roads that were going to be incorporated into the interstate system or to build competing roads that would divert traffic from those toll roads. Congress also did not want to use money set aside for road development to buy out the existing bondholders.

SAFETEA-LU created three exceptions to the general rule that tolls are barred on federal roads and it reauthorized a fourth exception.

First, an "interstate system reconstruction and rehabilitation pilot program" permits tolls on three existing interstate facilities — highways, bridges or tunnels — to raise funds for reconstruction or rehabilitation of interstate highway corridors. The three projects must be in separate states. Tolls are allowed only if the interstate highway corridor could not otherwise be adequately maintained or improved. This program is a reauthorization of a program initially adopted in 1998.

Second, a separate "interstate system construction toll pilot program" authorizes tolls on up to three interstate facilities to finance construction of new interstate highways. Each applicant state must demonstrate that tolls are the most efficient and economical way to advance the project and the state is prohibited from entering into non-compete agreements with private entities that would restrict its ability to improve or expand competing capacity. Automatic toll collection is required for these projects, and tolls may only be used for debt service, reasonable returns on private financing and operations and maintenance costs.

More US states may start collecting tolls on the interstate highways to raise money for road projects.

Third, an "express lanes demonstration program" allows tolls on existing or new interstate express lanes that help manage congestion, reduce air emissions or finance added interstate lanes to reduce congestion. Variable pricing is required if the existing express lanes are HOV lanes (high-occupancy vehicle lanes); otherwise variable pricing is optional. Up to 15 express lane demonstration projects may be carried out through 2009. Automatic toll collection is required for these projects, and tolls may only be used for debt service, reasonable returns on private financing, operations and maintenance costs or any federally funded facility. SAFETEA-LU also amended the existing federal HOV lanes program by authorizing states to convert HOV lanes into HOT lanes (high-occupancy toll lanes) if the state creates a program to address the selection of certified vehicles and procedures for enforcing restrictions.

Finally, a "value pricing program" that was originally authorized in 1991 as the "congestion pricing program" provides grants for pre-implementation, design, development and start-up costs associated with qualifying value pricing pilot projects developed by states to ease congestion. The 15 authorized pilot projects have already been selected and may include area-wide pricing, tolls or other innovative market-based strategies.

The application process for federal authority to collect tolls on an interstate facility is initiated by submitting an "expression of interest" to the tolling and pricing team at the Federal Highway Administration. The Federal Highway Administration will send back comments on the expression of interest. After responding to the comments, the applicant must formally apply to the program office that offers the best fit tolling or pricing authority.

Future Tolls on I-95

The South Carolina expression of interest to collect tolls on I-95 said that, without innovative financing, the "much needed reconstruction and rehabilitation" of the state's portion of I-95 is beyond the financial capability of the South Carolina Department of Transportation. If tolls are authorized, SCDOT said it may decide to finance, construct and operate the project as a public-private partnership, or PPP. The project would involve reconstructing, rehabilitating and collecting tolls on 201 miles of I-95, which runs north-south through South Carolina.

South Carolina wants to put the project on a fast track and be collecting tolls within 24 to 36 months. Reducing congestion and increasing safety are primary concerns for the I-95 corridor. I-95 leads all South Carolina interstates in fatalities over the last five years with 128, and */ continued page 36*

Toll Roads

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crash rates on I-95 are the highest among South Carolina interstates. The state wants to widen the highway to six lanes for its full length (10 miles of I-95 in South Carolina have already been expanded to six lanes, but the corridor has only four lanes for 95% of its length), create electronic toll plazas and improve bridges throughout the corridor — 17 of 162 bridges on I-95 in South Carolina are substandard and would be widened or replaced as part of the project. Given the extent of the work needed, South Carolina concluded that "the I-95 facility cannot be adequately maintained or improved without an alternative revenue source, like the collection of tolls."

States are attracted to collecting tolls on I-95, in part, because it shifts some of the costs of highway maintenance to road users from other states. I-95 is a 1,927-mile interstate running the length of the east coast, from Miami, Florida in the south to the US-Canadian border in northern Maine. I-95 is one of the most well-known and well-traveled interstates in the country, passing through or around New York City, Washington, DC, Boston, Miami, Philadelphia, Baltimore, Richmond and other major cities. Because of its proximity to so many major cities along the east coast, I-95 is heavily used by trucks, buses and other out-of-state traffic that often rolls through South Carolina without stopping.

In its application, South Carolina said it would be willing to join neighboring states if they express similar interest in collecting tolls. In fact, North Carolina and Virginia have expressed such interest.

North Carolina and Virginia have a tentative compact to share the toll revenue the two states collect.

In 2005, the North Carolina legislature authorized tolls on interstates, subject to any required federal authorization. The legislature directed the North Carolina Department of Transportation to apply for federal authorization to collect tolls on interstate highways and set I-95 as the priority project. The 182-mile stretch of I-95 in North Carolina requires an estimated $4 billion in capital improvements, including overhauls of bridges and construction of additional lanes.

North Carolina is considering an interstate tolling compact with Virginia pursuant to which the two states would agree, upon adoption of the compact, to charge tolls for use of I-95 within their respective boundaries. Revenue from the tolls, which would be capped at $5.00 per car, would be split evenly between the neighboring states. The two states would also coordinate efforts "to establish welcome centers, rest areas, and facilities where travelers may obtain food, fuel, souvenirs, and vehicle repairs and service." The compact has already been adopted by the Virginia legislature. The North Carolina legislature failed this year to act on the compact.

Virginia is also applying for federal authorization to collect tolls on I-81.

Rep. Jon Porter (R.-Nevada) is proposing privately-built toll lanes for I-15, which connects Las Vegas, Nevada with California. Jeff Fontaine, the head of the Nevada Department of Transportation, plans to work with California for I-15 toll lanes and may submit an expression of interest to the Federal Highway Administration to collect tolls. According to Porter, voluntary tolls along I-15 would be attractive to motorists, especially truckers. "There are seven-, eight-, nine-hour delays at times for Californians, and one out third of the vehicles on the road are trucks . . . . We want to make sure that main artery to the Vegas community is a fast and enjoyable trip for our customers and for our residents." Eighty percent of trucks on I-15 are either from out of state or on their way out.

The I-95, I-81 and I-15 projects would be significant, but are a drop in the bucket. Only 2,900 miles of the 46,730-mile interstate system are subject to tolls today. ◎

Environmental Update

California Greenhouse Gas Measures

California became the first US state to impose statewide caps on greenhouse gas emissions in late September. The state also moved in October to allow trading of carbon credits created under state law between California and a group of New England states and to impose new requirements on power contracts that California utilities sign to buy electricity from independent generators.

The Global Warming Solutions Act, signed by California Governor Arnold Schwarzenegger on September 26, will regulate all but *de minimis* stationary sources of greenhouse gas emissions, but will not reach mobile source emissions.

It requires the California Air Resources Board — called "CARB" — to write regulations that would reduce carbon emissions to 1990 levels by the year 2020. This would amount to a 25% reduction in greenhouse gas emissions. By contrast, the Kyoto protocol that the Bush administration said would impose too great an economic cost on the United States would have committed the US to a 7% reduction in greenhouse gas emissions from 1990 levels by the year 2012.

The new law provides a framework for emissions reductions through a combination of measures: installing maximum technologically-feasible pollution control equipment, greenhouse gas emission caps and possible trading of credits or allowances. Any trading program has been left to CARB to develop and would presumably involve trading along the lines of that currently employed by the European Union. Credits or allowances authorizing the holder to emit a certain quantity of CO_2 or its equivalent would be available for purchase in the market. The idea is to allow companies the option of continuing to emit CO_2, but to cover the emissions by purchasing credits from other companies that have freed up credits for sale by reducing their emissions.

Opponents of the California legislation argue that the new law will impose a severe cost on the state's economy with limited environmental benefit in the absence of a broader national strategy. Although California is a large state, it may not have a large enough economic base upon which an efficient trading program could be developed. Even the European Union trading scheme has encountered significant difficulties in properly allocating emissions credits, despite its large scale, and there have been large swings in credit prices.

The outline of the California program should take shape fairly soon. There is a mind-numbing series of deadlines. CARB has until June 30, 2007 to publish a list of early action greenhouse gas emission reduction measures that can be implemented prior to January 1, 2012. The agency then has until January 1, 2010 to adopt regulations implementing this list of early action greenhouse gas emission reduction measures. Regulations for greenhouse gas reduction methods must also be enforceable by January 1, 2010.

CARB is supposed to announce by January 1, 2008 what the statewide greenhouse gas emissions level was in 1990 and to set a statewide cap on greenhouse gas emissions beginning in 2012 for significant sources that will have to start ratcheting down their emissions to meet the 2020 goal. By January 1, 2009, CARB must approve a scoping plan that achieves the maximum technologically-feasible and cost-effective reductions in greenhouse gas emissions from sources or categories of sources by 2020.

By January 1, 2011, CARB must adopt greenhouse gas emission limits and emission reduction measures to achieve the maximum technologically-feasible and cost-effective reductions in statewide greenhouse gas emissions to become operative January 1, 2012. California's governor retains the power to adjust deadlines under certain circumstances, including the threat of significant economic harm.

Governor Schwarzenegger is looking for ways to address concerns about California's capacity to establish an efficient greenhouse gas trading system by connecting the new state program with other large existing programs, including trading programs in the northeastern US and the European Union. On October 17, he signed an executive order directing CARB to explore ways for California to join both a "regional greenhouse gas initiative" — called RGGI — in New England and the EU trading scheme.

RGGI is a regional initiative to reduce greenhouse gas emissions. It was initially among seven states, but has now expanded to eight. The original seven were Connecticut, Delaware, Maine, New Hampshire, New Jersey, New York and Vermont. Maryland will join by June 2007. Under RGGI, states will use a regional cap-and-trade system to limit CO_2 emissions. Each ton of CO_2 emissions will be worth one tradable allowance. Unlike the new / continued page 38

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law in California, which regulates greenhouse gases from a wide variety of stationary sources, RGGI is limited to emissions from power plants.

Coordinating the two programs will be challenging, although there should be time to work out the details. The deadline for states to implement RGGI is 2009 while California has set a deadline for itself of 2011.

One nagging problem facing RGGI remains "leakage." Leakage occurs if emissions increase in neighboring states as reductions in RGGI states push the power industry to generate electricity elsewhere for export into the RGGI region.

California addressed the issue in its new legislation. The state is imposing new standards on contracts that California utilities sign to buy electricity from independent generators or to invest in power projects. The utilities will not be able to enter into any new long-term financial commitments unless any baseload generator complies with a greenhouse gas emission performance standard. A "long-term financial commitment" is "either a new ownership investment in baseload generation or a new or renewed contract with a term of five or more years, which includes procurement of baseload generation." In turn, "baseload generation" means "electricity generation from a power plant that is designed and intended to provide electricity at an annualized capacity factor of at least 60 percent."

California utilities must ensure that baseload generators contracting to sell them electricity in the future comply with tough new emissions standards.

It remains to be seen whether anyone will try to challenge the new California actions on grounds that they violate the US constitution. The commerce and supremacy clauses limit the ability of states to take actions that impede interstate commerce. In the past, courts have restricted state and local environmental programs that attempted to protect out-of-state sources from exploiting the economic disadvantages caused by heightened environmental requirements. Examples of state programs that were found to impede interstate commerce include efforts to require businesses to use local landfills rather than ship waste out of state.

Renewable Fuel Standards

The US Environmental Protection Agency proposed rules in late September for implementing a new federal renewable fuels program. The rules set standards for the average percentage of renewable fuel content in new motor vehicle fuels to be produced during 2007. When final, the rules would replace an interim program that was established by the Energy Policy Act of 2005.

The draft rules only apply to the 48 contiguous US states, although Hawaii and Alaska may opt into the program. EPA is required by law to increase the overall volume of renewable fuels produced each year from four billion gallons in 2006 to 7.5 billion gallons in 2012. To reach these goals, a standard will be published each November 30 for the following year showing the amount of renewable fuel that each obligated party must use as a percentage of gasoline sold. Because full rulemaking could not be completed for 2006, a default standard of 2.78% applies in 2006. This default standard will be treated as a collective obligation that applies to the pool of all gasoline sold to consumers. There are no provisions for credit generation or trading for the 2006 year. Also, because EPA will not be able to finalize the new rules by November 30 this year, it has chosen a fairly unaggressive standard of 3.71% for calendar year 2007.

Parties potentially subject to the new standard — called "obligated parties" — include refiners, importers and blenders (other than oxygenate blenders), but exclude small refineries and small refiners. To determine his or her individual obligation, an obligated party multiplies the percentage standard for the year by his or her annual gasoline production volume. This result is the volume of renewable fuel that must be blended into gasoline sold for use in the United States, with credit for certain renewable fuels that are not blended into gasoline. Renewable fuels include cellulosic ethanol and waste-derived ethanol. Renewable fuels also include biodiesel and motor vehicle fuels that are produced from biomass. Motor vehicle fuels using a feedstock of natural gas are included if the natural gas came from a biogas source such as a landfill, sewage waste treatment plant, feedlot, or source of decaying organic matter.

It does not matter whether the renewable fuel is blended with gasoline or used neat as ethanol, methanol and natural gas. However, fuels must be designated for use in a motor vehicle, including off-road vehicles, to count against the new standard. Fuels that are designated for any other use, such as fuel oil for boilers and heaters, will not qualify.

Compliance will be tracked with renewable identification numbers called "RINs." EPA is proposing to assign every gallon of renewable fuel produced or imported into the United States a RIN, or a block of RINs in the case of a batch of fuel. As renewable fuel travels though a distribution system, the RIN rides along on product transfer documents. The RIN can be separated from the renewable fuel when an obligated party purchases the renewable fuel or the fuel is blended into a vehicle fuel. At this point, the RIN could be used for compliance, banked or traded. Different fuels would have different values based upon their equivalence values. Equivalence values are based on the energy content of the fuel compared to ethanol. For example, corn-based ethanol would have an equivalence value 1.0, while cellulosic ethanol would have a value of 2.5.

Because EPA recognizes that biofuel production can contribute to pollution if appropriate practices are not followed, EPA is also considering voluntary labeling in an effort to minimize the potential environmental effects of relying more on renewable fuels. One suggested option is to attach a designation to the RIN. For example, fuel producers using best practices would have the option of adding a "G" (for green) to the RIN indicating that the fuel is environmentally friendly.

Under the proposed rules, RINs would be valid up to 12 months after they are generated. If a fuel producer has collected fewer RINs in a year than he needs to comply, then the deficit could be made up the next year. However a cap is proposed so that no more than 20% of the current year obligation may be satisfied using RINs from the previous year. Deficit carryovers would not be allowed two years in succession. Under the proposed rule, at most, deficits could occur every other year.

Comments on the proposed rules must be received by November 12.

Other Developments

Environmental groups have had mixed results in their efforts to use Clean Air Act permit requirements to force power companies to use integrated-gasification combined-cycle technology for new coal-fired power plants. IGCC is a process where coal is turned into gas before the gas is combusted to produce electricity.

Led by the Sierra Club, the groups have been trying to force states and the Environmental Protection Agency to require developers of coal-fired power plants applying for air permits to show they considered the use of IGCC as an alternative to traditional emissions control systems. The Clean Air Act requires that major new sources of air pollution employ the best available control technology — called "BACT" — for controlling emissions. Last year, EPA said in a letter that developers of new coal-fired power plants do not have to consider IGCC as a form of BACT. Environmental groups sued EPA in federal court, arguing that this was essentially a new regulation illegally promulgated in the form of a letter.

On October 12, the parties filed a preliminary settlement with the US appeals court in the District of Columbia. Under the settlement terms, which will be held open for public comment, the agency letter is not considered a "final agency action" and "creates no rights, duties, obligations, nor any other legally binding effects on EPA, the states, tribes, any other regulated entity or any person." While this settlement, if approved, disposes of the current litigation, US states now can no longer rely on the letter to dispose of IGCC issues. States must now decide whether to encourage the use of IGCC in their permitting processes.

Environmental groups have had less success in their efforts to challenge individual air permits for not applying IGCC. In August, the EPA environmental appeals board ruled in favor of a permit approving a new 1,500-mw coal-fired power plant in Illinois and a similar ruling was rendered earlier this year in a state administrative appeal of a Kentucky air permit. Although coal */ continued page 40*

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gasification was mentioned in another state-level decision in August ruling against a Texas air permit, the Texas administrative law judge appeared primarily concerned with the ability of the 1,500-mw coal plant to comply with the limits specified in its application.

In its ruling regarding the Illinois plant, the appeals board concluded that emissions of NO_X and SO_2 from IGCC are equivalent to emissions in other modern coal-burning plants, but IGCC is much more costly. The Clean Air Act requires that cost be considered as a factor in BACT determinations.

Separately, an important technical change took effect to the Superfund liability defense for "innocent purchasers" of what turn out to be contaminated properties. Superfund exempts bona fide purchasers from liability for cleaning up a site that was already polluted when it was purchased. To establish the requisite level of "innocence" for such a defense, a person must perform an investigation that qualifies as an appropriate inquiry under EPA regulations. That means researching the past and current uses of the property. Until November 1, the EPA had relied upon a six-year old standard developed by the independent standards organization called ASTM. An appropriate inquiry meant doing what is required by ASTM standard E 1527-00. Now EPA has adopted the newer ASTM standard E 1527-05 in place of its older version.

ASTM E 1527-05 is a more demanding standard. Purchasers will have to gather more information in the future. For example, interviews with neighboring or nearby property owners of abandoned properties are now mandatory parts of the phase I site assessment process.

The new standards will also have an immediate effect on private sector transactions. ASTM 1527-05 is now being adopted for phase I site assessments that are a staple of financing and M&A transactions. For pending transactions, older site assessments complying with the former standard may have to be re-performed or expanded to include the newly-required information.

Finally, the International Finance Corporation issued seven new environmental, health and safety guidelines for public comment in early November. These guidelines are important not only because the IFC uses them in its lending decisions, but also because they are widely employed by other lenders and investors across the globe. The new guidelines address environmental design and performance standards for seven industry sectors, including airports, gas distribution systems, railways, ports, harbors and terminals. The new guidelines were posted by the IFC on November 6 and will be available for comment until January 15, 2007. They are the third installment of 62 new IFC environmental guidelines. Twenty five have already been published. Prior guidelines included rules for wind energy and geothermal power projects. The widely-used thermal power guidelines have not yet been published formally. In addition to the industry sector guidelines, the IFC has also published a general environmental, health and safety guideline that remains open for public comment until December 15. ◎

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