CHADBOURNE
& PARKE LLP

PROJECT FINANCE
NewsWire

October 2003

Limits in Structured Finance Transactions

by Chris Groobey, in Washington

Many bankers and financial advisers may be wondering when they risk being charged with aiding in manipulating earnings in the wake of recent enforcement actions against three New York investment banks for acting as counterparties in transactions with Enron.

Each of the investment banks recently settled — without admitting guilt or liability — charges brought by federal and state regulatory authorities arising from transactions with Enron and, in one bank's case, with Dynegy. The three are Citigroup, JP Morgan and Merrill Lynch.

In September, the US Department of Justice also brought criminal charges against three former investment bankers at Merrill Lynch in connection with transactions arranged for Enron, and prosecutors have indicated that criminal investigations of similar transactions are continuing. Enron itself also sued its former banks and investment banks at the end of September, alleging fraud and unjust enrichment in connection with transactions they engaged in with Enron.

The charges define new liabilities for banks lending into structured finance transactions and for arrangers of such transactions. They also provide a roadmap that bankers and financial advisers should follow to ensure they do not expose their companies and themselves to criminal or civil liability. */ continued page 2*

IN OTHER NEWS

WIND DEVELOPERS got more helpful rulings from the Internal Revenue Service.

The IRS told one wind developer in a private ruling released in August that its wind farm would be considered "in service" for tax purposes, even though the wind farm was unable to move its full output on to the local utility grid until the utility made improvements to a substation.

The utility was expecting a delay in when it could make the substation improvements. In the meantime, the wind farm could send a percentage of its output to the grid through a temporary connection to an existing transformer at the substation. Once the new trans- */ continued page 3*

IN THIS ISSUE

Structured Finance

continued from page 1

What Did They Do?

The transactions that drew the regulators' attention took different forms. Some involved commodities, others involved financial instruments and still others involved hard assets. Each of them was a loan in substance.

In the commodities area, Enron entered into approximately $8.3 billion of prepaid forward commodities transactions with its investment banks that were criticized by the US Securities and Exchange Commission and the Manhattan district attorney as being fraudulent. "Prepaids" can be routine transactions that are a normal part of commodities trading. However, in the case of the Enron prepaids, regulators charged that the transactions were "trades" on paper only. For example, in one set of prepaids, the arranging investment bank paid a one-time amount to a special-purpose entity formed by the bank in return for the special-purpose entity's, or SPE's, promise to make future deliveries of a commodity. The SPE then entered into a matching agreement to buy the commodity from Enron for a payment substantially equal to the amount the SPE received from the bank. The net effect of these two agreements was that Enron agreed to make future deliveries of a commodity to the bank in return for an up-front payment from the bank. Enron and the bank then entered into a series of swaps and physical sales that caused Enron to reclaim possession of the commodity and repay the bank's investment in the transaction at a significant premium. The transaction gave the impression that three independent entities were engaged in legitimate, arm's-length commodities trading but, according to the government, the contracts eliminated all market-price risk to the bank and guaranteed an agreed-upon return for the bank. Based on these facts and those relating to similar transactions, the regulators determined that Enron's reporting of the proceeds of the prepaids as cash flow from operations rather than proceeds from loans was fraudulent. The regulators then sanctioned the investment banks for participating in the transactions on the basis that the banks knew or should have known that their purpose was to cause Enron's finances to appear more healthy than they really were.

Another transaction that the SEC criticized involved creation of an SPE to which a bank lent money. A few weeks before the end of Enron's fiscal year, the SPE used the borrowed money to purchase Treasury bonds and contributed the bonds to a partnership controlled by Enron. The partnership then sold the Treasury bonds. The proceeds from the sale were reported on Enron's financial statements as cash from operations. Three weeks into the new fiscal year, Enron arranged for the SPE's loan to be repaid in full with interest. The regulators determined that the net economic effect of this transaction was that the bank made a loan to Enron. They were also troubled by the short life of the transaction, especially when it originated shortly before the end of Enron's reporting period.

> One transaction was memorialized in a tombstone with the slogan "let the circle be unbroken."

The SEC also took issue with another transaction on grounds that it was an "asset-parking" arrangement. In this transaction, an investment bank purchased an asset from Enron on December 29, 1999, and Enron reported the proceeds as income from operations in its fiscal year ending December 31, 1999. However, Enron had given verbal assurances to the bank that it would arrange for repurchase of the asset from the bank within six months at an agreed price that included a specified rate of return. Just prior to the agreed repurchase deadline, an Enron affiliate purchased the assets on the agreed terms. The SEC argued that this transaction constituted more of a bridge loan than a true sale and sanctioned the bank for accommodating its client despite "express concerns that [the bank] could appear to be aiding and abetting Enron's earnings manipulation."

No matter whether they involved commodities, financial instruments or hard assets, the common thread to the transactions — the regulators charge — is that they originated from a client's desire to manipulate its financial results. Wall Street considers operating income more tangible than gains from mark-to-market activities and indicative of a strong and growing business. According to the regulators, when Enron and Dynegy believed they would not be able to post sufficient income from operations to satisfy Wall Street and fulfill their own projections, they turned to their bankers to devise transactions that would create operating income even though no true "operations" supported the impact on the balance sheet. Because the transactions arose from the clients' desires to manipulate financial results, it did not matter whether the effect of the transactions on earnings was "material" or whether they were legal on a stand-alone basis. From the regulators' point of view, it only mattered that the banks participated in the transactions whose purpose was to manage earnings in a manner that misled investors about the companies' true financial health.

What Law Was Broken?

Last March, the SEC filed civil charges against Merrill Lynch and four of its former employees for aiding and abetting Enron's securities fraud. Merrill settled on a lesser charge and paid a fine of $80 million, but the four individuals are contesting the allegations.

In July, JP Morgan paid $135 million to settle allegations that it assisted Enron in manipulating its financial statements, and Citigroup paid $120 million to settle similar allegations with respect to Enron and Dynegy. In September, Merrill Lynch faced criminal charges relating to its dealings with Enron but agreed to adopt companywide reforms and accept monitoring by the government in return for the Department of Justice foregoing prosecution. Three former Merrill Lynch investment bankers also face criminal charges of conspiracy to commit fraud, perjury and obstruction of justice arising from their professional dealings with Enron.

The government charged in each case that the banks and bankers violated SEC Rule 10b-5. That rule prohibits, among other things, "engaging in a course of business which operates or would operate as a fraud or deceit upon any person in connection with the purchase or sale of any security." Publishing materially misleading financial statements "in connection with" the purchase or sale of a publicly-traded security, as Enron and Dynegy are alleged to have done, constitutes a violation of Rule 10b-5. Banks and other financial intermediaries also face liability for their clients' violations of Rule 10b-5 when they "aid and abet" or are deemed to be the "cause" of the violation. / *continued page 4*

IN OTHER NEWS

former was built, the wind farm would have to reroute its lines to connect through it. The IRS said the wind farm was in the service in the meantime, even though it was restricted in the amount of electricity it could deliver to market and might be disconnected from the grid intermittently in the future to allow for construction of the substation improvements — although for periods of only up to 48 hours at a time.

The ruling is important because wind farms need to be in service by this December to qualify for federal tax credits of 1.8¢ a kilowatt hour on output. It is Private Letter Ruling 200334031. Congress is expected eventually to extend the deadline, possibly to December 2006.

In another private ruling released in September, the IRS said a wind project did not have to suffer a "haircut" in its federal tax credits on account of a state tax credit. By law, the federal tax credit is reduced for any other tax credits "allowable with respect to any property that is part of the project." The IRS has interpreted this phrase to require a haircut only for other tax credits whose amount is tied to the capital cost of the property. The tax credit in this case was tied to the amount of property taxes the project paid and the number of workers it employed. The ruling is Private Letter Ruling 200336023.

TURBINES that a power company ordered but no longer needs can sometimes be sold to a municipal utility without complications, the IRS said.

The key word is "sometimes."

Municipal utilities must be careful when buying equipment not to buy any that has already been "used (or held for use)" by a private company "in connection with" a power plant or other "output facility." The problem with buying such equipment is the municipal utility may have a hard time using funds borrowed in the tax-exempt bond market to make the purchase. Most / *continued page 5*

Structured Finance

continued from page 3

To charge a company with aiding and abetting, the government must prove improper manipulation of earnings, knowledge that this was occurring, and substantial participation by the company charged with aiding and abetting in the manipulation. A company cannot put its head in the sand. Actual knowledge is not required if there were red flags that should have caused the company to inquire further. Aiding and abetting is a more serious charge than that a company helped to "cause" the earnings fraud. There is a debate among securities lawyers about what exactly must be shown to establish "cause." Companies accused of aiding and abetting sometimes settle for the lesser charge of helping to "cause" the misleading financial reporting.

The government charged that all three investment banks were aware that the purpose of the transactions they engaged in with Enron and Dynegy was artificially to inflate earnings. No one has suggested it was illegal for the banks to make loans to the companies or to document the transactions in the form they did. Securities lawyers used to focus after such charges on whether the earnings misstatements were "material," or amounted to at least 5% of earnings. What is novel about the latest enforcement actions is they suggest the government's new approach is to make materiality irrelevant in cases where a bank or arranger was aware of an improper purpose by its counterparty in the transaction. Obviously, proving such knowledge is harder in cases where a bank merely lends into a transaction than where the bank pitched the idea for the transaction and helped to structure it. As the SEC put it bluntly in one of the cases, "if you know or have reason to know that you are helping a company mislead its investors, you are in violation of the federal securities laws."

Citigroup, JP Morgan and Merrill Lynch have all adopted new internal approval procedures for structured finance transactions and have submitted to increased oversight by regulators and independent auditors. These new review procedures, and the regulators' criticisms of the transactions arranged for Enron and Dynegy, are a guide about where to draw lines for other companies that participate in or arrange structured finance transactions.

Potential Red Flags

Banks lending into structured finance transactions and investment bankers and other arrangers helping to structure such transactions do not control their clients' financial reporting, but they can reduce their exposure to a client's fraudulent disclosure by examining the client's motivations for entering into a specific transaction and, if necessary, refusing to participate in a transaction that they suspect could be used to mislead the investing public. They should be alert to the following "red flags" and ask questions that they might not have thought to ask in the past.

1. How does the client intend to report the transaction on its financials? If the transaction is in substance a loan, will it be reflected as proceeds of financing activities? Or as cash flow from operating activities? Is the repayment obligation disclosed? Arrangers can protect themselves from liability by enforcing their clients' obligations to disclose the full impact of a transaction. For example, Citigroup now states that, with respect to all clients that have publicly-traded securities, it will execute a material financing that will not be accounted for as debt on the client's balance sheet only if the customer agrees to disclose the net effect of the transaction on its financial statements.

2. Does the transaction, or group of transactions, have a legitimate business purpose? The government alleged that certain Enron and Dynegy transactions had no business purpose other than to allay investor, analyst and rating agency concerns about cash flows from operations and outstanding debt. If the primary purpose of a transaction is to boost operating income, and it appears that there are no true operations to support the income, then the transaction warrants additional scrutiny. For example, Merrill Lynch has agreed with the Department of Justice that it will not engage in any transaction near the end of a client's fiscal year where Merrill knows or believes that the client's "primary motivation" for the transaction is to achieve accounting objectives, including off-balance-sheet treatment, without first subjecting the transaction to a rigorous internal review process.

3. When all is said and done, is the transaction nothing more than a loan? A loan consists of an advance of money, repayment of the money and payment of an agreed rate of return. The government treats discrete transactions that are interrelated steps in a larger deal as a single transaction for purposes of distilling the net effect. If a participant in a structured finance transaction is exposed to no more credit risk than a commercial lender and is entitled to an agreed return on its investment, then the transaction will be viewed as a

loan and any treatment of it as operating income on the client's financials may result in liability for the bank participating as a counterparty.

4. What is the purpose of any special-purpose entity involved in the transaction? If an SPE is formed largely to create distance from one of the other participants in the transaction, and in particular to enter into a discrete transaction that offsets another discrete transaction with an affiliate of the SPE, then the proposed transaction warrants closer scrutiny. In a July letter to US and New York bank regulators, the Manhattan district attorney said "the use of special purpose entities by banks calls for particular scrutiny," described SPEs as the "source of much mischief" and recommended that SPEs be used only when "there is a genuine need and only when their function is transparent to all concerned parties, including investors, creditors and regulators." The DA further recommended that banks and financial institutions be prohibited from utilizing SPEs that are chartered or domiciled in locations with unreasonably strict corporate and bank secrecy laws (including, in the DA's opinion, the Cayman Islands, the British Virgin Islands and the Bahamas), saying that "it is courting disaster for responsible authorities to continue to permit SPEs to be set up in offshore secrecy havens."

5. Is the transaction expected to close just prior to the end of a reporting period and are there continuing obligations after the end of the reporting period? Is there an "early" termination option? As described above, the Enron "asset-parking" transaction was created and closed shortly before the end of Enron's fiscal year (and allowed Enron to meet Wall Street's financial expectations) and then unwound shortly thereafter. Regulators have indicated that year-end transactions will be assumed to have been entered into for the purpose of meeting earnings expectations, which could give rise to liability for misleading investors. Merrill Lynch has promised the Department of Justice that all year-end transactions will pass a special internal review process before the company will participate in the transaction.

6. Does the transaction offset another substantially contemporaneous transaction executed with the same or affiliated parties? As part of the analysis of the net effect and business purposes of transactions, regulators will group together transactions that, when viewed as a whole, result in reductions in risk to counterparties, return of "sold" assets or repayment of "at risk" funds. One "prepaid" transaction */ continued page 6*

IN OTHER NEWS

municipal utility borrowing is in the tax-exempt bond market. It may be hard to segregate where a municipal utility's money has come from.

Many power companies ordered more gas turbines in 2000 and 2001 from turbine manufacturers than they now need given the collapse in the merchant power market. These turbines have been put up for sale.

A municipal utility bought two such turbines. The turbines had never been used by the power company, and the IRS described them as "mass produced, off-the-shelf products that were not customized" for use by the power company. The company had never designated them for use at a particular project. The IRS said it reads the law to say that equipment might still be considered to have been "used (or held for use)" by a private company — ***even though the company never actually used it*** — if the equipment was manufactured specially for that private company. In other words, custom-built articles are off limits.

In this case, the IRS told the municipal utility that it could buy the turbines because they were not custom-built. It helped that the municipal utility made the purchase before the turbine manufacturer had even started physical assembly of the units at its plant. The ruling is Private Letter Ruling 200336019.

FAVORABLE FINANCING TERMS are a separate asset, the US Tax Court said.

The Federal Home Loan Mortgage Corporation — known as Freddie Mac — was set up by the US government to create a secondary market in residential mortgages. It was originally exempted from US income taxes, but Congress made it subject to such taxes starting in 1985. Freddie Mac was the borrower of billions of dollars under notes, bonds, subordinated debt instruments, collateralized mortgage obligations and guaranteed mortgage certificates on January 1, 1985 when it became subject to taxes. */ continued page 7*

Structured Finance

continued from page 5

in which JP Morgan acted as a counterparty was memorialized by an Enron-designed tombstone with the slogan “let the circle be unbroken,” a fact that the Manhattan DA mentioned in his report to federal and state regulators as an indication of the absence of risk for the participants and the transaction’s true purpose of generating misleading financial results.

7. Is the client seeking to counteract a delay or failure of another transaction? Banks and investment bankers need to be wary when clients approach them looking for quick, balance-sheet solutions to shortfalls in operating income that result from a failure to close another, genuine transaction. For example, the Enron “asset-parking” transaction described earlier was instigated by Enron only after an expected sale of the asset failed to close.

8. Is the client seeking to replace debt with funds characterized as other than debt? For example, would the transaction result in debt being retired by funds that would be characterized as a minority interest in a subsidiary? Clients perceived by Wall Street as being overleveraged or hindered by excess debt may be seeking to reduce their reported debt without actually reducing their true repayment obligations. This is a red flag requiring caution — not an indication necessarily that the transaction is flawed.

9. Are verbal assurances or other side agreements (whether written or oral) an important part of the deal? If the entire deal cannot be reflected in the principal governing documents, the side agreements may raise questions in the minds of regulators. Enron’s “asset-parking” transaction would not have been consummated had not Enron given verbal assurances to the bank that its financial participation would not be at risk. If those verbal assurances had been reduced to writing, Enron’s desired accounting treatment would not have been possible as the putative “sale” would have been required to have been accounted for as a financing activity.

10. Even if the transaction complies with the rules, is it ethical? Does it give rise to “reputational risk” for the bank acting as a counterparty or the investment bank that structured it? Regulators have indicated that their ultimate goal is to shift the transaction review process from one that is based on a strict reading of the applicable rules to one that is more grounded in ethics. Citigroup now examines the “economic reality” of a transaction as well as its legal form, and Merrill Lynch’s new review committee is charged with reviewing the “reputational risk” of a transaction as well as its legality. For purposes of avoiding liability, subjective, qualitative factors deserve at least as much consideration as more concrete, quantitative matters. ◎

Depreciation Bonus Clarified

by Keith Martin, in Washington

The Internal Revenue Service answered many questions that US companies had about when a "depreciation bonus" can be claimed on new power plants, transmission lines, LNG terminals, toll roads and other new infrastructure projects in regulations the agency issued in September.

The depreciation bonus is a limited-time offer by the US government to reward companies that spend money on capital improvements during a "window period" that started September 11, 2001 and ends in December 2004 or 2005, depending on the project.

The bonus is the right to deduct 30% or 50% of the cost of new capital improvements immediately. The remaining cost is deducted over the normal depreciation schedule.

The tax savings from a 50% bonus are worth as much as 9% of the capital cost of a project.

Projects must be completed during the window period to qualify. Only spending on assets that will be used in the United States or in US possessions like Puerto Rico and the US Virgin Islands qualifies. The Bush administration hopes that an increase in such spending will help revive the US economy.

Only New Equipment

The bonus is a reward for spending on new equipment. For example, about 95% to 97% of spending at a typical power project is for equipment as opposed to a building. Only the spending on equipment would qualify.

There is no bonus for investing in an existing facility — "existing" means it was already in operation when the taxpayer made the investment — with three exceptions. First, new improvements to an existing plant qualify. Second, a project developer without the tax base to use the bonus can transfer it (along with the remaining depreciation) to another company by selling and leasing back a project within three months after the developer put the project into service. Third, a project developer can contribute the project to a partnership with a new investor at any time during the same tax year the project went into service. The investor will get a share of the bonus. The IRS will require that the bonus be allocated between the project developer and the partnership based on the number of months that each owned the project during the year.

Some companies had wondered whether it would be possible to create a bonus where the project developer could not have claimed one — for example, because the project developer got started on the project too early to qualify — by selling the project to someone else during the window period and leasing it back. The IRS appears to have intended to say no. It wrote an "anti-churning rule" into the new regulations. However, the anti-churning rule is not well drafted. It rules out sale-leaseback transactions to create bonuses in cases where the project developer (or a related party) signed a binding contract to "acquire" the project from someone else, but not where the project developer is considered to be "self constructing" the project. The vast majority of infrastructure projects are self constructed. The anti-churning rule applies retroactively to when the bonus was first enacted.

During the last few years, too many gas turbines were ordered from manufacturers than are needed today. Some merchant power companies have had to take delivery of the turbines, but then parked them in warehouses. If a developer were to buy one of these turbines today and use it, he could claim a bonus on the cost of it. That's because the turbine was never put into service by anyone. Property is not considered used equipment until it has been in service.

On the other hand, if a developer bought a used turbine from a utility to incorporate into a new power plant, a bonus could not be claimed on the cost of it. A bonus cannot be claimed on used equipment.

This raises the question whether companies need meticulously to catalog whether used parts are used in the construction of their facilities. The answer is no. A company should determine whether parts that are large enough to qualify as separate "components" of a project are used property. The IRS did not try to define "component" in the new regulations. Smaller parts are considered subsumed in a larger property, and unless more than 20% of its value is tied to the cost of used parts, the larger property is consid- */ continued page 8*

IN OTHER NEWS

It had to value all of its assets as of that date so that it would be able to calculate gains and losses from any future sales of the assets.

Interest rates had gone up since it borrowed a lot of its debts. Freddie Mac took the position that one of its "assets" was the fact that it had borrowed at what were then below-market rates. It calculated the future savings on interest payments on its debts at $465 million and began amortizing — or deducting — that amount over the remaining life of its outstanding debts. It claimed an amortization deduction in 1985 of $50.2 million.

The IRS objected. The IRS had previously taken the position that a debt cannot be an "asset." The US Tax Court held for Freddie Mac in late September. The court said, "It is beyond doubt that the right to use money represents a valuable property interest." The court said it could see no difference between a right to use money at below-market rates and the right to use property under a lease at below-market rents. In either case, any "basis" — or cost allocated to — the property right can be recovered through amortization.

The decision has implications for companies making acquisitions. The IRS is considering whether to appeal.

SYNFUEL PLANT owners are cautiously optimistic.

IRS agents in the field have been seemingly on the warpath this year about tax credits claimed by owners of coal agglomeration facilities, or plants that add chemical reagents to crushed coal in order to turn it into synfuel. An outside expert hired by the IRS advised the agency that the plants do not make synfuel. The US government offers a tax credit of $1.095 an mmBtu as an inducement to Americans to look in unusual places for fuel. The idea was that this would make the US less dependent on imported oil from the Middle East. The tax credit can be claimed by */ continued page 9*

Depreciation Bonus

continued from page 7

ered entirely new. Thus, for example, if a developer bought an older wind farm and rebuilt it using the latest generation of wind turbines, the entire project should qualify for a bonus — including the cost of acquiring the existing project — as long as the existing equipment does not account for more than 20% of the value of the wind farm after reconstruction.

Previously Committed?

The bonus is supposed to encourage new investment after the terrorist attacks on the Pentagon and the World Trade Center. Therefore, a taxpayer cannot claim a bonus on any investment to which he was "committed" before September 11, 2001.

The power industry spent more than a year talking to senior Treasury and IRS officials and staff on Capitol Hill about what it means to have been "committed." Most power plants and other infrastructure projects have such long gestation periods that any project that is completed during the "window period" for the bonus would necessarily have had to have been under development before the terrorist attacks.

The IRS regulations take a generous approach. Most projects should qualify for a bonus as long as work "of a significant nature" did not start at the site before September 11, 2001. Site clearing, test drilling and excavation to change the contour of the land is not considered the start of work at the site. Work "of a significant nature" is considered to commence at the site once work starts on the foundation. The IRS said that driving pilings into the ground counts as work on the foundation. However, it adopted a "safe harbor" under which work is not considered to have reached the threshold "of a significant nature" until the taxpayer has incurred more than 10% of the expected total cost of the project. Spending on "land and preliminary activities such as planning or designing, securing financing, exploring, or researching" design is ignored: it is not counted in either the numerator or the denominator. Thus, if a project is expected to cost $300 million after backing out soft costs that are not allocated to the hard assets and after backing out the cost of the land, design work and other preliminary activities, work is not considered to have reached the threshold "of a significant nature" until the taxpayer has incurred more than $30 million.

The starting point for analyzing whether a project qualifies for a bonus is to decide whether the taxpayer is "acquiring" the project or "self constructing" it.

"Acquired" property qualifies for a bonus only if the taxpayer did not sign a "binding" contract to acquire it before September 11, 2001.

"Self-constructed" property qualifies as long as the taxpayer had not started work "of a significant nature" at the site before September 11, 2001.

Most infrastructure projects are considered self constructed. Congress wrote an unusually broad definition of "self constructed" into the law, and the IRS accepted it in the regulations. Property is considered self constructed as long as the taxpayer signed a contract with the manufacturer to have the property built for him before physical assembly of the property started. Thus, for example, purchase of existing equipment out of inventory would not qualify. However, in the typical power project, the developer signs a construction contract with an outside contractor before work starts at the site. Turbines that a power company signed a contract with a manufacturer to have custom built are self constructed.

> The tax savings from the depreciation bonus are worth as much as 9% of the capital cost of a project.

The IRS takes the position that the contract signed with the manufacturer or construction contractor before work started had to be a "binding" contract. This means it had to be with a third party. The IRS has argued in the past that a contract signed with a related party is not "binding" since it is too easy for the parties to walk away. The regulations indicate that two companies are considered "related" if they have more than 50% common ownership. A contract is not "binding" if it limits the damages the owner must pay for canceling the contract to less than 5% of the total contract price. It is not a problem if the contract is silent about damages. There cannot be any conditions standing in the way of performance of the contract or the contract is not binding — unless the conditions are outside the control of the parties.

Anyone who is treating his project as "self constructed" had better be careful about amending the contract later. The IRS said "[a] contract will continue to be binding if the parties make insubstantial changes," thus implying that substantial changes after work "of a significant nature" has already started at the site could turn the project into "acquired" property. In most cases, the taxpayer should not be harmed by a later amendment. As long as the amendment is signed by the end of 2004, it should not be a problem. However, significant amendments should be avoided during 2005 because they might call into question whether the project that is ultimately placed in service in 2005 is the same project to which the taxpayer was committed earlier. To qualify for a bonus, the taxpayer must not have been committed to the investment before the terrorist attacks on September 11, but he must be committed to it no later than December 2004.

Some merchant power companies signed master turbine contracts with manufacturers before September 2001 to buy 10, 15, 20 or more turbines at a time. The IRS said the fact that a company committed to purchase a turbine before September 11 will not taint the rest of the project. Moreover, a bonus can be claimed on the turbine as long as the manufacturer had not started physical assembly before September 11. Components like turbines are treated as separate properties. The same 10% safe harbor on costs incurred before work "of a significant nature" is considered to have started should also apply to each component.

Project Sales

Many power projects have been put up for sale in the past year and a half since Enron went bankrupt. Some of the projects being sold are still under development or construction. The IRS said that anyone who buys a project before it is completed will qualify for a bonus, not only on the amount spent to complete the project but also on the amount paid to buy the work in progress. It does not matter that the original developer would not have qualified for a bonus had he kept the project.

The regulations give an example of a developer who had started construction of a power plant before September 11. He would not have qualified for a bonus. He sold the project while it was still under construction to someone else for $6 million on May 1, 2003. The new buyer spent another $1.2 million to complete the project during the period May 6 through June 30, 2003. The IRS said in the example that / continued page 10

IN OTHER NEWS

anyone producing "synthetic fuel" from coal. The issue with the coal agglomeration facilities — at last count there were approximately 53 of them — is whether they do enough to the coal for the output from the plants to qualify as synthetic fuel.

The IRS has issued more than 80 private rulings since 1995 to owners of the plants confirming that they qualify for credits. The IRS field agents who are auditing the tax returns filed by plant owners are considering asking the IRS national office to revoke some or all of the rulings. This is a necessary first step before disallowing the tax credits claimed by the plant owners. The IRS announced a "pause" in any further rulings at the end of April. Plant owners are outraged that the government might consider disallowing tax credits after they spent millions of dollars based on rulings that they qualify for the credits.

As the *NewsWire* went to press in late September, an announcement was expected from the IRS national office "soon." Senior government officials have signaled that the announcement will be positive for the industry.

NETWORK UPGRADES — or improvements to utility grids —remain under study at the IRS.

A general ruling on which all utilities can rely is expected in the spring. In the meantime, the IRS is collecting fact patterns that should be addressed in the general ruling.

The issue is whether utilities must pay income taxes on monies that an independent generator advances to cover the cost of improvements that must be made to the grid to accommodate the generator's power plant. A generator seeking to connect his plant must pay the cost of the radial line, protective devices and other equipment that are part of the "direct intertie." However, the Federal Energy Regulatory Commission has taken the position since late 2000 that the cost of improvements to the grid itself should be borne by all users of the / continued page 11

Depreciation Bonus

continued from page 9

not only could the buyer claim a bonus on the full $7.2 million, but he qualified for a 50% bonus on the $1.2 million to complete construction. (The bonus increased from 30% to 50% on May 6, 2003.) The buyer was limited to a 30% bonus on the $6 million he paid for the work in progress. That's because he "acquired" the work in progress before the bonus increased on May 6, 2003. The remaining work is considered self constructed and the buyer did not start work on it until the period during which the bonus had increased.

Another common situation in infrastructure projects is where someone buys into a project — for example, as a partner — during the construction period. The analysis of such situations is more complicated than where a project that is still under construction is purchased outright. Someone buying into an existing partnership can claim a share of the bonus to which the partnership is entitled. However, he ordinarily cannot claim a bonus on any premium to buy into the project. (In other words, a bonus ordinarily cannot be claimed on a "section 754 stepup.") The IRS did not address what happens if the project does not qualify for a bonus in the hands of the original developer. However, it should be possible to structure many buy ins in such situations so that the investor qualifies for a bonus on his share of the project.

A developer who places a new project in service and sells the entire project later the same year to someone else cannot claim any bonus. The bonus is lost. (An exception is where the project is sold in a sale-leaseback within three months after the project went into service.)

Some projects are owned by partnerships. A partnership "terminates" for tax purposes if at least a 50% interest in partnership capital and profits is sold. (The old partnership is considered to disappear and a new one to spring into being with the new partners.) If a project is put into service in a year and, later the same year, an interest in the partnership is sold causing the partnership to terminate, then the bonus is shared among the new partners — not the old ones.

Calculating the Bonus

The depreciation bonus is an acceleration of tax depreciation to which the owner of a project would have been entitled anyway.

The owner gets a much larger depreciation deduction the first year and smaller ones later. The depreciation allowance in the year the project is put into service — assuming a 30% bonus — is a) 30% of his "tax basis" in the project (basically the cost of the project) plus b) depreciation for the year calculated in the regular manner on the remaining 70% of basis. For example, without the bonus, the first-year depreciation deduction on a coal-fired power plant that cost $100 million to build is $3.75 million. With a 30% bonus, it is $32.625 million. Depreciation in later years is reduced commensurately, since only $100 million in depreciation can be claimed in total.

The bonus was increased to 50% in May this year. Congress did this in the hope of giving a stronger spark to the economy. The 50% bonus applies to investments to which a taxpayer committed after May 5, 2003.

The faster writeoff can be a significant benefit. The benefit is greater the longer the normal depreciation period for an asset. A 50% depreciation bonus reduces the cost of assets that are depreciated over 20 years — for example, transmission lines and coal- and combined-cycle gas-fired power plants — by 8.98%. It reduces the cost of gas pipelines and simple-cycle gas-fired power plants that are depreciated over 15 years by 7.54%. The cost of a power plant that burns waste is reduced by 3.61%. Wind farms and biomass projects cost 2.61% less. These calculations only take into account federal tax savings from the depreciation bonus — not also the state tax savings — and they use a 10% discount rate. (At last count, 25 states have "decoupled" from the depreciation bonus — they do not allow it to be claimed against state income taxes — and another six allow only a partial or delayed bonus.)

> A company cannot have "committed" to the project before September 11, 2001, and it must finish the project by 2004 or, in some cases, 2005.

Other Issues

Most renewable energy projects must be placed in service by December 2004 to qualify for a bonus. Most gas- and coal-fired power plants, gas pipelines and transmission lines have until December 2005.

The deadline for completing a project turns on its depreciable life for tax purposes. A project qualifies for the later deadline if its depreciable life is 10 years or longer and the project is expected to take more than a year to construct (assuming the project costs more than $1 million). The power industry asked the IRS whether developers of projects that qualify for more rapid depreciation — for example, wind farms or power plants that burn waste that can be depreciated over five or seven years — could buy more time by electing to depreciate them over 10 years. The IRS said no.

The bonus can only be claimed on spending through December 2004 regardless of when the project is placed in service.

A bonus cannot be claimed on property that is financed with tax-exempt bonds or that is "used" by a government or tax-exempt entity or that is used predominantly outside the United States or US possessions. ◎

Hidden Pension Liabilities in Deals

by Scott D. Segal, in New York

Concern about giant potential liabilities tied to under-funded pension plans at some of America's largest companies is spilling over into project sales in the power sector.

By the beginning of 2003, industrial giant General Motors' defined benefit plan was underfunded by more than 137% of the market capitalization for the entire company. In an attempt to make up this shortfall, GM issued more than $13 billion in debt to inject into the defined benefit plan. And GM is not alone in its underfunding problems. The list of companies with defined benefit plans that are underfunded by 50% or more of market capitalization as of the start of this year includes many of America's top companies such as Delta Airlines and Xerox Corp. — to name a few.

The sheer scale of this underfunding is causing buyers of power projects from distressed merchant / *continued page 12*

IN OTHER NEWS

grid. It recognizes that there is a timing problem: the utility must make the network upgrades before it can collect the cost through rates. Therefore, it lets utilities require generators to advance the funds. Under new rules for future interconnection agreements that FERC announced on July 23, the utility must repay the generator within five years with interest.

US tax rules are clear that a utility does not have to report income when it is reimbursed by a generator for the cost of the direct intertie — at least in cases where the generator is not a customer of the utility for anything, including transmission service. (For this reason, most generators are careful to make sure title to their electricity transfers to someone else before the electricity reaches the grid.)

However, the IRS is less sure about the tax treatment in cases where the utility has to repay the money. The IRS is leaning toward letting utilities report advances for network upgrades as loans. It issued one private letter ruling to that effect in February, but on unusual facts. In September, it announced that it will not issue any further private rulings while it sorts out its position. The 10 or 12 ruling requests that it had in the queue in September are being returned to the utilities that requested them.

Lon Smith, an IRS associate chief counsel, said it is a manpower issue. The agency does not have the people to wade through dozens of ruling requests. It expects that with formal adoption of the FERC pricing policy on July 23, all utilities in the country will eventually ask for rulings. The plan is to issue a general ruling on which all utilities can rely and to try in that ruling to address all the fact patterns of which the power industry is aware at this time. Smith said that anyone who still has questions after reading the general ruling can apply for a private ruling. However, he hopes that will not be necessary.

Meanwhile, a model interconnection agreement that FERC / *continued page 13*

Hidden Pension Liabilities

continued from page 11

power companies to ask whether they face any potential exposure to such liabilities. With liabilities in underfunded pension plans reaching into the billions of dollars, depending on the size of the company, the concern is understandable.

The liability is imposed under a 1974 law called the "Employee Retirement Income Security Act of 1974," or "ERISA." Although ERISA has been around for almost 30 years, most people are surprised to learn how far the long arm of ERISA reaches. In an era where over 50% of pension plans are underfunded by more than $300 billion, where many companies are in bankruptcy, and where the Pension Benefit Guaranty Corporation — the United States government agency that insures underfunded pension plans — had a deficit as of April of more than $5.4 billion, perhaps at no time has ERISA's long arm become more evident.

Two Types of Plans

There are two different types of pension plans that companies can offer their employees: "defined contribution plans" and "defined benefit plans." Underfunded pension liabilities are potentially a problem for anyone buying a project from a company with a defined benefit plan.

A defined contribution plan provides retirement income to its participants based on the actual value of the assets in the plan at the time of the participant's retirement. Defined contribution plans are funded by contributions made by the company and its employees. Defined contribution plans usually provide for individual participant accounts so that each participant will know exactly how much he or she has to draw on as retirement benefits at any given time. Typical forms of defined contribution plans are 401(k) plans and employee stock ownership plans.

A defined benefit plan provides retirement income to participants based on a specified formula in the plan. The formula is usually based on a participant's average compensation over a specified period of years, the participant's years of service with the company and the participant's age at retirement. Defined benefit plans do not normally provide for individual participant accounts. Instead, all assets of the plan are combined together. Defined benefit plans must be funded by the company. The amount of funding required for a particular year is determined actuarially under rules in the US tax code and ERISA aimed at ensuring that there will be enough money in the plan to meet the plan's benefit obligations as they come due. The actuarial assumptions used to determine the annual required funding are also governed by the tax code and ERISA and include assumptions about long-term interest rates, mortality rates, turnover and retirement age.

Many companies adopted defined benefit plans for their employees during the period 1900 through about 1985. During this period, defined benefit plans grew in number from 12 to approximately 112,000 plans. However, starting around 1985, defined contribution plans began to eclipse defined benefit plans in popularity and, in fact, the number of defined benefit plans contracted to a point where there are only about 32,000 such plans today (covering about 44 million workers and retirees). Most companies that still offer defined benefit plans are in the manufacturing and services industries. Also, companies with union workers are more likely to have defined benefit plans. In the United States, more than 80% of companies whose employees are covered by a union contract offer a defined benefit plan.

Controlled Group Liability

Power projects are usually owned by special-purpose companies. It does not matter that the special-purpose company has no defined benefit plan if affiliated companies in the same "controlled group" do.

A controlled group consists of two or more entities that are connected, either directly or indirectly, through ownership of at least an 80% interest. In the case of partnerships, such ownership is measured by at least 80% of the profits interest or capital interest of the partnership. However, the ownership test is not a bright-line test. The Pension Benefit Guaranty Corporation, or PBGC, will review the facts and circumstances to determine whether the 80% threshold has been met. The PBGC has a strong interest in trying to recharacterize debt or other interests as capital or profits interests in order to argue that the 80% threshold has been met.

Under ERISA, a project company is "jointly and severally" liable for any underfunding of defined benefit plans maintained by other members of its controlled group, even if the company's employees do not participate in the defined benefit plan and even if the company does not have any employees. "Joint and several" liability means that a project company can be held liable for the full underfunding in an affiliate's defined benefit plan.

Liability for underfunding is triggered when one of three events occurs: 1) when the underfunded defined benefit plan is terminated, 2) when the affiliate with the defined benefit plan fails to make a contribution when due, or 3) when the affiliate fails to pay insurance premiums when due to the PBGC to insure the defined benefit plan.

A company may remain jointly and severally liable for pension benefits even after it leaves a controlled group. Under section 4069 of ERISA, a company may be held jointly and severally liable for certain pension-related liabilities of its former controlled group members, if a defined benefit plan maintained by a former controlled group member is terminated (or contributions or premium payments are missed) within five years after the company leaves the controlled group and the PBGC establishes that a principal purpose of the sale resulting in the company leaving the controlled group is to evade liability under ERISA. Although section 4069 of ERISA — known as the "successor liability" or "sham transaction" provision of ERISA — has rarely been invoked, the PBGC has threatened companies with liability under this section.

How Much Exposure?

Typically, the latest actuarial valuation of the plan is the best source of data for measuring the amount that a defined benefit plan is underfunded. The actuarial valuation is usually part of the latest federal income tax return filed for the plan on Form 5500. Buyers of distressed energy projects should ask for a copy of this form as part of their due diligence. The actuarial valuation shows the assets and liabilities of the plan and its annual costs. It also shows the assumptions used to calculate these liabilities. Buyers should pay careful attention to the assumptions used by the plan, particularly the interest assumption. The interest assumption determines the rate at which plan assets will appreciate. The higher the assumed interest rate, the less likely the plan is to show potential liabilities.

The actuarial valuation also normally shows the accumulated benefit obligation (accrued benefits to date) and the projected benefit obligation (estimated accrued benefits for the plan as it continues). The valuation also shows whether assets would exceed liabilities if the plan were terminated immediately. However, it usually uses actuarial assumptions that suggest a smaller liability than may actually be imposed if PBGC actuarial assumptions were used. The PBGC retests the adequacy of the amounts in the plan after */ continued page 14*

IN OTHER NEWS

issued in late July for use by generators and utilities suggests a utility that takes the position it does not have income may require a tax indemnity from a generator in case the IRS assesses taxes. However, security cannot be required where the utility has a private letter ruling from the IRS confirming that the utility has no income. (FERC said the same thing in an order issued this summer in a dispute between AES and New England Power Company surrounding the Londonderry project.)

This new policy raises interesting questions in California where utilities routinely require that generators post security for 20% of the potential taxes in case something happens to the intertie in the future to trigger a tax.

The model agreement also suggests that the utility must give the generator security in cases where the utility makes the generator "gross up" its interconnection payments for taxes and the parties submit the issue whether a tax is owed to the IRS in a ruling request. The security ensures that the utility will return the tax grossup once the ruling is issued.

Congress may throw a monkey wrench into the process. The energy bill that Congress is expected to pass in late October will probably overrule FERC by requiring generators to pay the cost of grid improvements — with no refund. If that were to occur, then the tax issue with which the IRS is wrestling would disappear because the law is already clear that amounts the utility can keep do not have to be reported as income.

REPAIRS at power plants and other facilities are more likely to be deductible after a court decision in September.

The IRS has been struggling to draw a clear line for utilities, airlines and other industries about when spending on an existing plant can be deducted immediately as a "repair" and when it must be capitalized as a longer-term "improvement" and deducted over time as asset depreciation. The */ continued page 15*

Hidden Pension Liabilities

continued from page 13

involuntary termination of the plan by the PBGC or a voluntary termination by the plan sponsor. Therefore, buyers should ask that the calculations be redone using PBGC termination rates. However, this calculation is often not available and may not be easily obtained.

Buyers should also check for what purpose the liabilities have been calculated. There are three ways to calculate plan liabilities: 1) for funding purposes, 2) under financial accounting rules, and 3) on a termination basis. Liabilities measured for funding purposes use assumptions that reflect long-term projections and do not necessarily represent current conditions. Therefore, it is possible that a defined benefit plan uses an interest rate assumption that is higher than the current rate. Liabilities measured for financial accounting purposes are typically based on a portfolio of highly-rated corporate bonds. Due to fluctuations in corporate bond rates, there can be considerable volatility in this valuation from year to year. Liabilities measured on a termination basis are calculated by using assumptions set by the PBGC. This liability is based on benefits accrued to the date of a plan termination, without any liability for future salary increases. Additionally, PBGC interest rates are generally lower than those used under the financial accounting method and the funding method. A plan that appears to be fully funded on a funding and financial accounting basis could be substantially underfunded on a termination basis.

Concern about giant potential liabilities tied to underfunded pension plans is spilling over into project sales in the power sector.

The consequences of losing sight of which accounting method was used can be staggering. Consider two large American companies who were recently going through the bankruptcy process and attempted to terminate their defined benefit plans: Bethlehem Steel and US Airways. When Bethlehem Steel terminated its defined benefit plan, its last filing with the US Department of Labor said the pension plan was 84% funded on a current liability basis. However, the PBGC found that the pension plan was only 45% funded on a termination basis, with a total underfunding of $4.3 billion. US Airways had a similar experience. Its last filing with the US Department of Labor said its defined benefit plan was 94% funded on a current liability basis. However, the defined benefit plan was only funded 33% on a termination basis, with a total underfunding of $2.5 billion.

Any buyer who finds there is a defined benefit plan in any company that is a member of the same controlled group as the project company he is purchasing should have an actuary review the financial information reported to the IRS on Form 5500 to assess the risks involved.

Protection From Liabilities

The most important ways a buyer can protect himself from potential defined benefit plan liabilities are doing thorough due diligence and incorporating strong representations and warranties in the purchase agreement.

Due diligence is usually a simple process. Information on the employee benefits of the acquisition company such as current and prior years actuarial reports and Form 5500s should be made available to the purchasing company by the seller. In addition, employee benefit information can be found in the Form 10-K that the seller files with the US Securities and Exchange Commission. Also, older Form 5500s should be reviewed to reflect any changes made to the accounting assumptions.

Do not make the mistake many buyers do of assuming there is no issue because the project company being purchased has no employees and no pension plan. Ask questions about the employee benefits of the controlled group and the capital structure of both the target company being acquired and potentially affiliated companies. Assess whether the PBGC might be able to rechararactize debt instruments as equity in order to bring more companies into the controlled group. The information needed may be hard to obtain due to confidentiality provisions and the lack of access. Regardless of the difficulty involved, with potential liabilities running into the millions or billions of dollars, this step cannot be pushed to the side and should remain one of the top issues when discussing any transaction.

The employee benefits sections of the purchase agreement should contain strong representations, warranties and indemnity provisions. The seller should represent that no defined benefit plan in the controlled group has been terminated in other than a standard termination. He should also represent that all required funding contributions have been made to all pension plans in the controlled group. Other representations might state that the target company is not a member of any controlled group, that no employee of the target company has provided services — for example, under an employee leasing arrangement — to another company in the same controlled group whose employees participate in a defined benefit plan, that no ERISA event has occurred (an event that requires notice to the PBGC) and that could cause every member of the controlled group to be liable for defined benefit plan liabilities, and that no ERISA event is likely to occur. Finally, the buyer should receive the strongest indemnification possible for any breach of the representations.

Relief in Sight?

With the US stock market still struggling and interest rates still low, the total amount of underfunding in all defined benefit plans has hit amounts never seen before. Some estimates have the total defined benefit plan underfunding in the trillions of dollars. ERISA requires pension plans to project future earnings on pension plan assets using the average interest rate on 30-year Treasury bonds over the last four years. The US government has discontinued the 30-year bond. A dwindling number of such bonds is still outstanding. Interest rates on the bonds have fallen to levels below the rates on similarly-rated corporate bonds.

Two years ago, Congress responded to the problem by allowing companies to use 120% of the 30-year Treasury bond rate. However, this relief was temporary. Authorization to use 120% expires at the end of this year. Congress is debating what to do next. Among the options being considered are to use corporate bond rates or a "yield curve." The yield curve is the interest rate on a bond with a duration equal to the period from the calculation date through the date the average plan participant is expected to retire. This issue is high on the Congressional agenda, but it is possible that only a "stopgap" measure will be passed by the end of the year. And whatever Congress will not eliminate the problem — only change the formula for calculating the amount of underfunding. ◎

IN OTHER NEWS

more quickly the cost of work can be deducted, the less expensive it is after taxes are taken into account.

Federal Express argued that work it did on its aircraft engines qualified as "repairs" rather than "improvements." Some of the maintenance work was done in regular 2- to 3-year intervals. Other such work was done in 5-year intervals. The engines were disassembled and worn parts replaced. Most trips to the repair shop cost between $150,000 and $300,000, but in some cases, the cost reached as much as $900,000 or $1.1 million per engine.

A federal district court in Tennessee ruled in mid-September that the work qualified as repairs because the "unit of property" is not the engine standing alone but the entire aircraft. Obviously, $100,000 spent on an aircraft looks less significant than the same amount spent on just an engine. The case is *FedEx Corp. v. United States*.

The IRS is working on a revenue ruling that is expected to describe three fact patterns involving power plants and draw lines between repairs and improvements. However, the IRS task force that is working on the ruling cannot agree what is the "unit of property."

> *The task force feels certain that the entire power plant is not a single item of property. It believes each turbine — and perhaps even something larger — is a separate item of property. It does not know where to draw lines on boilers. The ruling will skirt this issue.*

HOLLAND will have to allow some Dutch companies additional tax deductions, the European Court of Justice said in September.

The case is important to Dutch companies with subsidiaries elsewhere in Europe. It applies potentially to all open tax years of Dutch companies. The Dutch government is moving to limit the damage.

Bosal Holding, N.V. is a Dutch manufacturer of car fuel exhaust / continued page 17

Found Money in Interconnection Agreements?

by Adam Wenner, in Washington

Generators and utilities are anxiously watching a complaint that Mirant filed with the Federal Energy Regulatory Commission asking the commission to revise a 2002 interconnection agreement with Nevada Power Company.

Mirant has asked FERC to revise the contract and reclassify facilities installed at the substation where the line from a power plant Mirant built in Nevada ties into the Nevada Power system as "network upgrades" instead of "interconnection facilities." If Mirant is successful, Nevada Power will have to refund the $3.4 million costs of these facilities, plus interest, to Mirant through credits against the transmission charges that a power marketing affiliate of Mirant pays Nevada Power.

In other similar cases, FERC has responded favorably to requests to revise interconnection agreements in this fashion.

Generators may be owed refunds under existing interconnection agreements for amounts they paid for improvements to the transmission grid.

The Mirant request is the first such complaint to be filed since FERC adopted lengthy and detailed rules governing generator and utility interconnections. The rules adopted the pricing policy reflected in earlier FERC orders going back to 2000, namely that the generator is only responsible for the cost of facilities, plus operating and maintenance costs, from his power plant to the point of interconnection with the grid, and that the utility must ultimately pay the cost of facilities and O&M on the grid side of the point of interconnection.

Background

Historically, independent generators seeking to connect their power plants with the grid have had almost no bargaining leverage with utilities. The local utility that owns the grid could adopt a "take-it-or-leave-it" posture. In most circumstances, no other transmission lines are located near enough to provide a viable alternative: as a result, absent regulatory interference, utilities have been able to maintain the upper hand in negotiating interconnection arrangements.

In July 2003, FERC adopted Order No. 2003, which requires utilities to adopt standard generator interconnection procedures and to file a standard interconnection agreement for use with generators whose projects have a capacity of more than 20 megawatts. The July 2003 order affirms and codifies recent FERC decisions specifying how the costs of interconnection are to be allocated between the utility and the independent generator. Under these decisions and Order No. 2003, the generator is responsible for all costs (including the capital cost of the facilities as well as the cost of operating and maintaining facilities) on the generator's side of the "point of interconnection," which FERC defines as the point where the facilities from the generator connect to the utility's transmission system. These facilities are called "interconnection facilities." The "transmission system" is defined as all of the facilities used to provide transmission service that is subject to FERC regulation.

Cost responsibility for all "additions, modifications, and upgrades" to the transmission system "at or beyond" the point of interconnection — called "network upgrades" — falls on the utility. Under this policy, there is no need to show who benefits from facilities required to effect the interconnection; instead, the "point of interconnection" is a "bright line" that FERC uses as the sole determinant of how interconnection costs will be allocated.

Recognizing that there can be regulatory delay in a utility's ability to recover the cost of network upgrades through its rates, FERC requires generators initially to advance the money required to build the network upgrades. The generator is repaid its advance with interest, through a "cash equivalent refund," which may be set up in form as a credit against amounts the utility charges for transmitting electricity from the generator's power plant. However the amounts are credited, the generator must be repaid in full within five years of the generator's commercial operation date. Credits must be usable against charges for any transmission services provided by the interconnected utility to the generator, even, for example, service provided to other plants owned by the generator.

In general, rules adopted by FERC are applied prospectively, and existing arrangements are not affected.

However, in this case, FERC has authority under section 206 of the Federal Power Act to review existing agreements and, if it determines that they are "unjust, unreasonable, unduly discriminatory or preferential," to revise their terms. Under section 206, unless a generator has contractually waived its right to file a complaint at FERC or otherwise to seek FERC review of its interconnection agreement, even if it has executed an interconnection agreement in which the generator is responsible for costs of network upgrades, the generator may seek FERC review and revision of its interconnection agreement to conform to FERC's current policies that are more favorable to generators.

Mirant Complaint

In a complaint recently filed by a generator owned by an affiliate of Mirant Corporation (Mirant Las Vegas, LLC), Mirant did just this — asked FERC to revise an interconnection agreement that Mirant entered into in August 2002 with Nevada Power Company, in which improvements to the Harry Allen 500 kV substation were classified as "interconnection facilities" the costs of which were allocated to Mirant.

Mirant said it acquiesced in the interconnection agreement because it had no other way to transmit its output to the market and the commission had not yet clearly established the test for distinguishing interconnection facilities from network upgrades. Mirant contends that under the test codified in Order No. 2003, the improvements to the Harry Allen substation are network upgrades and not interconnection facilities and the interconnection agreement should be revised accordingly.

The effect of such a change to the interconnection agreement would be to require Nevada Power to provide transmission credits to Mirant for the $3,415,739 cost of the substation improvements, plus interest, during the five-year refund period for repayment of generator-funded network upgrades.

Mirant's filing refers to a FERC decision involving an interconnection at the same Harry Allen substation by the Silverhawk power plant owned by Gen West. In that case, Nevada Power filed an unexecuted interconnection agreement that similarly characterized modifications / *continued page 18*

IN OTHER NEWS

systems. The company has subsidiaries with operations in other member countries in the European Union. It tried to deduct its costs of acquiring and financing these subsidiaries against its tax base in Holland. Holland has a "participation exemption" that exempts Dutch parent companies from having to pay tax in Holland on earnings distributed to them by subsidiaries in other countries. Certain requirements have to be met to qualify for this exemption. The exemption also applies to capital gains from the sale of shares in a qualifying subsidiary. Since the income from the subsidiary is not taxed in Holland, Holland does not allow the parent company's costs tied to the subsidiary to be deducted. However, Holland denies the parent company a deduction only for costs tied to subsidiaries with no operations in Holland. A parent can deduct costs tied to a subsidiary — foreign or domestic — with operations in Holland.

The European Court of Justice ruled in September that this feature of the Dutch tax system is discriminatory, because costs incurred by Dutch taxpayers in connection with subsidiaries with Dutch activities are deductible while costs incurred for subsidiaries with activities solely in other countries in the European Community are not. This makes the establishment of activities outside The Netherlands relatively unfavorable, which is an infringement of the freedom of establishment, one of the fundamental freedoms provided for in the EC treaty.

"The judgment of the Court of Justice means that costs incurred by Dutch taxpayers in connection with subsidiaries with activities in other EC member states are deductible for Dutch corporate income tax purposes," according to Waldo Kapoen, a tax partner with Loyens & Loeff in Amsterdam. The decision applies to deductions in all open tax years. The judgment is not clear about whether costs attributable to a subsidiary with activities in a country outside the EC should also be / *continued page 19*

Found Money?

continued from page 17

to the Harry Allen switchyard as part of the "interconnection facilities" to be paid for by the generator. FERC rejected this characterization, stating that "the switchyard is a network facility today . . . [and] the fact that it is being reconfigured or upgraded [to accommodate the generator] does not transform it into a non-network facility." FERC required Nevada Power to amend its interconnection agreement to provide transmission credits to Gen West, reflecting FERC's reclassification of the modifications to Nevada Power's substation as network upgrades. These costs amounted to $3.4 million.

Many of the prior FERC rulings do not mention a dollar figure for the amount of interconnection costs to be reclassified as network upgrade costs. However, in a decision involving Consumers Energy Company, the generator, Kinder Morgan, estimated that $10.2 million of the $13.2 million it was required to pay in interconnection fees should be reclassified as network upgrade costs. In another case involving American Electric Power, FERC determined that AEP should credit to a generator that was interconnecting with it $2.3 million for network upgrades.

A key issue in FERC's review of previously executed interconnection agreements is the standard of review that FERC will employ. Under the Federal Power Act, if a contract over which FERC has jurisdiction — here the interconnection agreement — preserves the right of one or both parties to submit unilateral applications to FERC for a change to the contract, or to file a complaint under section 206, then the FERC standard of review is the "just and reasonable" standard. Under this test, if the contract fails to conform to extant FERC policies, and no compelling countervailing circumstances are present, then FERC will normally revise the agreement upon the submittal of such a request. However, if the contract, either expressly or implicitly, waives the parties' rights unilaterally to seek FERC changes to the contract, then FERC may revise the contract only if failure to so would result in harm to the public interest.

So far, the FERC decisions to reclassify interconnection facilities as network upgrades have all involved either contracts that preserved the parties' ability to seek unilateral changes or unexecuted contracts. Mirant's complaint similarly asserts that its interconnection agreement with Nevada Power preserves its right unilaterally to request FERC to revise the agreement, and to do so under the "just and reasonable" standard. Also, the FERC decisions and Order No. 2003 do not address the case where the generator is not a customer of the utility for transmission service and in which there are no transmission charges against which to credit the costs of network upgrades initially funded by the generator. Nevertheless, the reasoning behind the FERC cost allocation policies applies equally to generators that sell their output to the interconnected utility or to third parties, and there is no apparent policy basis why such generators should not be entitled to cash payments for network upgrades for which they have paid, to be paid over the same five-year period that applies to transmission customers.

Generators are carefully watching this case, as it is the first post-Order No. 2003 case that FERC will decide and because the amount at stake is significant.

More Refunds?

Generators who believe they may be entitled to similar refunds and credits should answer the following questions:

- Does the interconnection agreement classify facilities on the utility's side of the point of interconnection as "interconnection facilities" to be paid for by the generator? Note that under the "bright-line" test, if facilities that benefit the entire transmission grid are located on the generator's side of the point of interconnection, they are nevertheless deemed to be interconnection facilities for which the generator must bear the costs.
- Is the project interconnected with a utility that is a member of an ISO (independent system operator) or RTO (regional transmission organization)? Order No. 2003 permits RTO's, subject to FERC approval, to adopt different policies for sharing the costs of network upgrades.
- Does the interconnection agreement permit unilateral filings seeking FERC revisions to the agreement? Most agreements contain such a provision; however, if the contract does not permit such filings, there is a greater likelihood that FERC will require the parties to live with the contract, notwithstanding FERC's policy positions on interconnection cost allocation.

If the answers to these questions are "yes," "no" (or "yes" but no differing policy has been sought or approved), and "yes," then the generator may be in a position to have FERC revise its interconnection agreement. FERC proceedings of this type generally take three to six months to resolve. They ordinarily involve the submittal of pleadings, called a "paper hearing," but do not involve a trial-type hearing before an administrative law judge. For generators, there may indeed be gold in those dusty interconnection agreements.

When Power Plant Repairs Go Too Far

by Roy Belden, in New York

The US Environmental Protection Agency issued new rules in late August that draw a "bright line" for when planned repairs to a power plant or other industrial facility require an air permit before they can be made.

Some utilities are facing stiff fines and costly pollution control equipment upgrades for having made too extensive repairs in the past without first getting an air permit. The new rules were issued under the "new source review," or "NSR," program.

The leading environmental groups and several members of Congress have already criticized the new rules as further evidence that the Bush administration is trying to "gut" the Clean Air Act. Several states — including California, Massachusetts and New York — immediately vowed to sue the federal government over its legal authority to issue the new rules. Legal challenges are expected to be filed immediately after the rules are published in the Federal Register. Senator James Jeffords (I.-Vermont) is threatening to try to block implementation of the rules in Congress.

Anyone doing "routine maintenance, repair, and replacement" of equipment at a power plant or other industrial facility does not have to get an air permit under current law. The problem is the phrase has never been clearly defined, with the result that the exemption has spawned several lawsuits and conflicting agency interpretations.

The new rules create a safe harbor for equipment replacement at a power plant or other industrial facility where three things are true. First, the owner must be replacing an existing component of a process unit with identical components or components that serve the same purpose. Second, the fixed capital cost of the replaced component and any other costs associated with the replacement activity — for example, labor and contract services — must not exceed 20% of the current replacement value of the unit. Finally, the replacement must not alter the basic design of the unit or / continued page 20

IN OTHER NEWS

allowed as a deduction. For subsidiaries in countries that form part of the European Economic Area (Lichtenstein, Norway and Iceland), the costs will probably be deductible, Kapoen said.

The Dutch government announced the day after the court ruling that it would propose legislation to deal with the consequences. The Ministry of Finance said in a press release that expenses tied to domestic and foreign participations will be deductible, but that two measures will be introduced to avoid erosion of the Dutch corporate tax base. One measure will limit excess intercompany loan financing by placing a limit on the debt-to-equity ratio that will be allowed. The other measure will limit the ability of Dutch holding companies to use losses in one year to shelter income from a different activity in another year. The new measures are expected to take effect on January 1, 2004.

DISCHARGED DEBT did not have to be reported as income.

Ordinarily when a company is released from a debt, it must report the amount discharged as taxable income. The IRS said in an interesting private ruling released in September that one company did not have to do so.

The company had both senior and subordinated debt. The company could not pay both debts currently. The holder of the subordinated debt agreed to release the company from having to repay it. The subordinated debt was purchase price that the company had promised to pay for some assets it purchased. Under a special rule in the US tax code, when a debt owed to the seller of property is reduced, the debtor can simply take the position that it paid less for the property than appeared earlier. This special rule is in section 108(b)(5). The debtor cannot be insolvent or in bankruptcy proceedings when it is released from the debt. The IRS discussed the case in / continued page 21

Plant Repairs

continued from page 19

cause the unit to exceed any emission limitations.

The new rules only address part of the "routine maintenance, repair, and replacement" exemption — how to define "replacement" — but they are a critical clarification of how the government intends to administer the exemption going forward. The new rules do not directly affect pending NSR enforcement actions against a number of utilities that replaced equipment at older coal-fired power plants, and they will not provide "amnesty" for questionable equipment modifications that occurred before the new rules take effect.

The rest of this article explains why the "routine maintenance, repair, and replacement" exemption is so important to the regulated community and discusses the types of replacement activities that should qualify in the future for the exemption.

Background

New and modified major sources of air pollution in both "nonattainment" areas (areas that do not meet federal ambient air quality standards) and in "attainment" areas (areas that currently meet federal ambient air quality standards) must undergo a rigorous pre-construction permitting review. "Prevention of significant deterioration," or "PSD," permits are issued for major sources in attainment areas, and nonattainment NSR permits are required for major emitters in nonattainment areas. Anyone needing a permit in an attainment or nonattainment area must usually agree to install state-of-the-art pollution control equipment and to comply with strict emission limits. Plants sited in nonattainment areas must also usually purchase "emission offsets."

Over the past 30 years, the NSR permitting program has been criticized by the regulated community as being overly costly, excessively burdensome and time consuming. It is not surprising that many companies do everything they can to avoid repairs or equipment modifications that are so extensive as to require an NSR permit. The issue is what upgrades and improvements can be made to keep existing plants running efficiently and at full or near full capacity without crossing the NSR tripwire, namely an activity that constitutes a "major modification." A major modification triggering NSR review at an existing plant occurs if there is a physical change or a change in the method of operation that would result in a "significant net emissions increase" in a pollutant regulated by the Clean Air Act.

Many power plants and other older industrial facilities never had to go through a pre-construction NSR review because they were in existence before the NSR program rules were adopted in the early 1970s.

Many of these "grandfathered" plants have made changes over the years to restore efficiency and replace worn out equipment, and most have opted not to go through an NSR permitting review but have relied instead on the "routine maintenance, repair, and replacement" exemption. "Routine maintenance, repair, and replacement" are not considered a "physical change or change in the method of operation." Therefore, they are not a "major modification."

Unfortunately, until now, the US Environmental Protection Agency never explained clearly what qualifies for the exemption. Many utility companies were caught off guard by the agency's high-profile enforcement actions filed in 1999 and 2000 alleging that several coal-fired power plants failed to undergo NSR permitting for major modifications.

The current NSR regulations — before the new revisions in late August — defined "routine maintenance, repair and replacement" narrowly and said the government would consider, on a case-by-case basis, the nature, extent, purpose, frequency and cost of the work to arrive at a "common-sense" finding. This case-by-case approach has left utilities uncertain whether their planned repairs qualify for the exemption. Few companies have requested NSR applicability determinations for fear that the agency's "we-know-it-when-we-see-it" approach would create bad precedents or ultimately delay or forestall planned plant equipment maintenance and repair work.

In the preamble to the final rules, the US Environmental Protection Agency acknowledged that the lack of certainty surrounding the "routine, maintenance, repair, and replacement" exemption has discouraged plant owners and operators from replacing equipment that might be needed to improve plant safety, reliability or efficiency. It said that in situations where plant equipment replacements presented a "close call" on whether an NSR modification was triggered, the options available to plant owners were relatively unattractive. The plant owner could apply for an NSR permit, seek an NSR applicability determination, forego replacement of the equipment, or proceed at his own risk to install the equipment.

Future Equipment Replacements

Under the new rules, equipment replacement will not require a permit where three criteria are met. First, the action must involve replacement of an existing component with an identical or functionally-equivalent component. Existing equipment can be replaced with equipment that is improved or different in some respects so long as it serves the same purpose. In the preamble to the new rules, there is an example of replacing a worn-out distillation column pump with a new and improved model. The limiting factor is that the new piece of equipment must not change the basic design parameters of the unit.

Second, the fixed capital and activity costs associated with the equipment replacement must not exceed 20% of the current replacement value of the unit. This cost threshold applies separately to each individual unit. There is some flexibility in calculating these costs. The preamble to the new rules said any one of four methods may be used to do the calculations. The four methods are: 1) replacement cost based on an estimate of the fixed capital cost of building a new process unit or the current appraised value of the unit, 2) invested cost (adjusted for inflation), 3) insurance value, where the insurance covers complete replacement, or 4) another accounting procedure based on generally accepted accounting principles. If a company chooses either of the last two methods for calculating the replacement value, a notice must be sent to the permitting agency reflecting this decision. In the absence of providing notice, a company must use either of the first two methods.

The Environmental Protection Agency had asked for comments earlier on an equipment replacement threshold of 50%. The final rules use a 20% threshold because this was more consistent with past case law and data the agency collected demonstrated that most typical replacement activities will fall within the 20% threshold. While some major replacement activities will cross the 20% trigger, the agency said that the case-by-case evaluation method for determining whether a replacement activity is exempted will still be available as an alternative mechanism.

Finally, the replacement equipment must not alter the basic design of the process unit or cause the unit to exceed an emissions limitation or an operational limitation. For electric utility steam generating units, the rule specifies maximum hourly heat input and the fuel consumption rate as basic design parameters. Owners and operators */ continued page 22*

IN OTHER NEWS

Private Letter Ruling 200336032.

PARTNERSHIPS that do business in the United States must withhold income taxes on US income that is allocated to any foreign partners.

The withholding is not on cash distributed to the foreign partners, but on the ***income*** allocated to them. For example, if a partnership earns $100 in a year and $25 of it is allocated to a foreign partner, then even if no cash is distributed that year to the partner, the partnership must withhold and pay over to the IRS tax at the highest US rate on the $25. The foreign partner receives a credit for the taxes paid on his behalf that he can claim against any US taxes he might otherwise owe — assuming he files a US tax return.

The IRS issued proposed regulations in September to implement these rules. The withholding is only on income that is considered "effectively connected" to a US trade or business of the partnership. Under the proposed regulations, a partnership must receive a Form W-8BEN, Form W-81MY or Form W-9 from each of its partners revealing its status. It must assume any partner from whom it does not receive such a form is a foreigner and withhold taxes, unless it has proof from other sources that the partner is US person.

The partnership will be held accountable if its "proof" proves incorrect.

CALIFORNIA is expected to require broader registration of corporate tax shelter transactions starting next January 1.

Until now, any company required to register a transaction as a corporate tax shelter with the IRS under the federal income tax laws had also to report it to the Franchise Tax Board in California, but only if the tax shelter was "organized in California." The California legislature voted in September to broaden the reporting by requiring any "tax shelter organizer" to report to the board those */ continued page 23*

Plant Repairs

continued from page 21

of power plants also have the option of using the maximum hourly electric output rate or maximum steam flow rate as alternatives to input-based parameters. Owners of other industrial facilities may also focus on similar input-based or output-based design parameters to determine compliance. Alternative design parameters not specified in the rule may be used with approval from the permitting authority.

Anyone buying an older power plant should make sure the owner did not make upgrades that requried an air permit. There could be fines.

In the preamble to the new rules, EPA said that an equipment replacement that improves a unit's efficiency and enables it to return to its design parameters can qualify for the exemption. For example, if boiler tubes are replaced on a boiler and the cost is below the 20% threshold and the unit's design parameters are not exceeded, then the replacement would qualify for the exemption even if efficiency was improved and actual emissions increased due to the fact that more fuel could now be burned. Conversely, a replacement and upgrade in the type of combustion turbine blades used would not qualify for the exemption if the unit's process design parameters were exceeded as a result.

No Retroactive Effect

The new rules will take effect 60 days after publication in the Federal Register. The new rules will not apply retroactively. The Environmental Protection Agency said that it believes its prior case-by-case interpretations of the scope of the "routine maintenance, repair, and replacement" exemption were based on permissible constructions of the Clean Air Act. Further, the agency said that it will continue to pursue pending enforcement actions against a number of utilities with coal-fired plants.

Of note, on August 7, 2003, a federal district court in Ohio ruled that the Ohio Edison Company violated NSR permitting requirements when it made major modifications to its W.H. Sammis station without first obtaining a PSD permit. The Ohio Edison case (*US v. Ohio Edison*, No. 2:99-CV-1181 (C.D. Ohio 2003) was a major victory for the US Environmental Protection Agency, and the case now enters the next phase to determine the remedies for each of the eleven NSR violations identified by the court. Ohio Edison could be facing substantial penalties of as much as $27,500 a day per violation as well as significant capital costs to install state-of-the-art pollution controls on some or all of its seven coal-fired units.

In an August 26, 2003 decision, a federal district court in North Carolina took a slightly different approach and agreed with industry on a key interpretation of the scope of the "routine maintenance, repair, and replacement exemption." The court held that the scope of the exemption should be analyzed based on what is commonly viewed as "routine" throughout the particular industry (instead of at a particular plant as found by the Ohio Edison court). The court handling the case (*US v. Duke Energy Corporation*, No. 1:00-CV-01262 (M.D.N.C. 2003))said the burden will be on EPA to prove that Duke Energy's projects do not fall within the exemption. It turned down a motion by Duke Energy to dismiss , and the matter will be scheduled for trial.

A decision in another high-profile utility enforcement case is expected later this year in *United States v. Illinois Power Co*. The Illinois Power case involves the status of a number of construction projects carried out between 1982 and 1994 at an Illinois Power plant located in Baldwin, Illinois. Several of the US Environmental Protection Agency's utility enforcement cases have settled for large sums. Earlier this year, the US government settled three major NSR enforcement actions against Dominion, Southern Indiana Gas and Electric Company and Wisconsin Electric Power Company.

In the Dominion settlement — the largest Clean Air Act enforcement settlement with a utility to date — the company agreed to spend as much as $1.2 billion by 2013 to install new pollution controls and upgrade existing pollution controls at eight coal-fired power plants. The company also agreed to pay a $5.3 million civil penalty and to spend at least $13.9 million on environmental mitigation projects. Southern Indiana Gas and Electric Company agreed to settle after a federal district court rejected a number of affirmative defenses raised by the company. The parties agreed that Southern Indiana Gas and Electric Company would spend about $30 million on new pollution control devices and other plant upgrades to reduce air emissions at its Culley station. SIGECO also agreed to upgrade its oldest unit by repowering it with natural gas. SIGECO will also pay a $600,000 penalty and spend approximately $2.5 million on an environmental mitigation project.

Wisconsin Electric Power Company agreed to spend approximately $600 million to reduce SO_2 and NOx emissions from five coal-fired plants, and it will install state-of-the-art pollution controls or shut down operations at 80% of its coal-fired power plants. All of the company's coal-fired units will be subject to a system-wide cap on SO_2 and NOx that will result in as much as a 70% reduction in emissions by 2013. The utility also agreed to pay a $3.2 million penalty and spend $20 million on environmental mitigation projects.

Challenge Expected

Attorneys general from several northeastern and mid-Atlantic states are expected to join several environmental groups in filing a lawsuit challenging the new NSR equipment replacement rule as soon as it is printed in the Federal Register. These same parties have already filed a suit challenging the earlier changes that the Bush administration made in the NSR program in December 2002 (*New York v. EPA* (DC Cir. No. 02-1387)). A decision by the DC circuit court is expected in the *New York v. EPA* case in 2004. Courts usually defer to an agency's rulemakings on complex issues within its areas of expertise. Therefore, the litigants are expected to have a hard time persuading the court to overturn the new rules.

More Exemptions Expected

The new NSR rules released in August are final rules. They follow on the heels of proposals that EPA made in the same area in December 2002. However, the August final rules do not address all of the subjects about which EPA made proposals last December. There are other aspects of the "routine maintenance, repair, and replacement" exemption that remain to be addressed.

For example, EPA proposed an annual maintenance, repair and replacement allowance option last December. Under this proposal, industry-specific cost allowances would be established, and certain types of activities that fall under the allowance cap would qualify for the / continued page 24

IN OTHER NEWS

tax shelters required to be registered with the IRS that are "organized," involve "doing business" or "derive[e] income from sources" in California. The organizer must also report any transactions considered tax shelters under federal law if one or more of the participants is a "California taxpayer."

Governor Gray Davis has until October 12 to veto the bill or it will go into effect automatically. A Franchise Tax Board official said he does not expect the governor to veto the bill. The bill passed both chambers on party-line votes, with Democrats voting for it. If Davis loses the recall election and is replaced by Arnold Schwarzenegger, Schwarzenegger might not take office until as late as the last week in November.

California defines tax shelter basically the same way as the US tax code. The definition under California law is "a partnership or other entity, any investment plan or arrangement, or any other plan or arrangement if a significant purpose of that partnership, entity, plan, or arrangement is the avoidance or evasion of federal income tax or [any California income or franchise taxes]."

The new law will also require any "organizer, seller, or material advisor" of a "potentially abusive tax shelter" to keep a list of investors in such transactions as is the case under federal law. It adopts the same definition of organizer, seller and material advisor as the IRS uses. A "potentially abusive tax shelter" refers both to any tax shelter that organizers are required to register with the IRS under the federal tax laws and any "entity, investment plan or arrangement, or other plan or arrangement which is of a type that the Secretary of the Treasury or the Franchise Tax Board determines by regulations as having a potential for tax avoidance or evasion." The requirement to maintain a list of investors applies only to those tax shelters that are organized, that involve doing business, or that derive income from sources in California, or tax shelters in which a / continued page 25

Plant Repairs

continued from page 23

exemption. The agency is reportedly preparing a draft rule that would modify the proposal to create an allowance for "maintenance and repair" activities, such as repairing equipment parts and instrumentation, upgrading software programs, and cleaning and maintaining process equipment.

The annual allowance may be applied on a calendar or fiscal year basis, and it is intended to cover relatively small dollar amounts compared with the replacement cost of the facility. Certain activities would be excluded from the annual allowance —for example, the construction of a new process unit, the replacement of an entire process unit, and any change that would result in an increase in a source's design parameters. EPA might still formally adopt a new annual allowance test as a method for qualifying for the "routine maintenance, repair, and replacement" exemption by the end of the year. ◎

Help for Projects in Developing Countries

by Kenneth W. Hansen, in Washington

The World Bank is moving to make more useful and accessible a "partial risk guarantee program" under which it stands behind foreign government undertakings to sponsors of private infrastructure projects. The program is an additional tool for financing projects in developing countries.

Background

A core question for project developers and lenders has been how to take government undertakings seriously when developing and financing infrastructure projects.

The project's economics may depend on the host government standing behind the terms of the concession, an offtake agreement, or an agreement to supply fuel or build related facilities. The host government may have agreed to guarantee performance or payment by offtakers or suppliers whose own credit ratings are too weak to support adequately the financing. The risk of nonperformance of government obligations has become an ever greater challenge with the increasing number of projects that have suffered government defaults.

Unfortunately, the prospective host government is likely to lack a track record of performing such obligations if only because infrastructure project structures are relatively novel. The governments themselves may be relatively young, particularly in the former Soviet Union. The term of the debt supporting many important emerging market projects very likely exceeds the prospective terms in office of the specific individuals who signed the various governmental undertakings upon which the project's economics are based. Thus arises the difficulty in taking host government promises seriously.

This is where the World Bank partial risk guarantee could come to the rescue. Under its charter, the World Bank can only lend to governments or under a sovereign guaranty. Thus, where governments are trying to keep the project financing off the public balance sheet, the utility of the bank's core sovereign lending program is limited.

The World Bank decided more than a decade ago that it could guarantee commercial loans to a private project against the specific risk that the host government might fail to perform its contractual undertakings in favor of the project.

The World Bank can make that guarantee — notwithstanding its charter — if the World Bank can get a backup agreement with the host country in which that government promises to reimburse the World Bank for any amount that the World Bank must pay out as a consequence of the government's breach of its promises to the project. This gives the World Bank the financial recourse to the host government required by the bank's charter.

While the conventional expropriation coverage that is typically available from political risk insurers envisions the insured project as being a business apart from the government, the partial risk guaranty was invented with public-private joint ventures in mind. As such, these guarantees –- which have now been offered by, besides the World Bank, also the Inter-American Development Bank, the European Bank for Reconstruction and Development and the Asian Development Bank –- fill a large hole in the fabric of effective project risk mitigation that was created by the past decade's proliferation of public-private partnerships.

Although partial risk guarantees have been an exciting development in theory, their actual track record has been limited. At the World Bank, this has been the case for two principal reasons. First, until recently they have only been offered as a source of project support "of last resort." The bank has encouraged potential applicants first to seek debt financing from the International Finance Corporation (better known by its acronym "IFC") and conventional political risk insurance from the World Bank Group's Multilateral Investment Guarantee Agency (called "MIGA"). Only if such support was determined to be unavailable, and only if the project complied with a number of World Bank policies, would an application for a partial risk guarantee have any prospect of receiving serious attention.

The very value in the partial risk guarantee lies in the fact that the World Bank Group's more conventional investment support programs through the IFC and MIGA typically fail to address the risk of sovereign breach of contract. MIGA's breach of contract coverage, patterned after similar coverage available through the Overseas Private Investment Corporation, is restricted to standing behind arbitral awards. If, for instance, a host government is not willing to submit to arbitration in a foreign tribunal (and some constitutions prohibit their doing so), then MIGA coverage is unlikely to be of much help.

Similarly, the IFC, as a project lender, is subject to, and possibly deterred by, the very risks of governmental breach that the partial risk guarantee program addresses. Consequently, these three branches of the World Bank Group offer private investment support that is mutually complementary. The World Bank's practice over the past decade of treating them as substitutes rather than complements has limited the impact of the partial risk guarantee program.

A second factor stunting demand for partial risk guarantees has been their accounting treatment within the World Bank. The full face amount of a partial risk guarantee has typically been counted against a country's borrowing limit. Thus, if a host government accepts a $100 million partial risk guarantee, it receives no cash, only enhanced credibility permitting the privately-sponsored project to go forward. The host government's ability to borrow from the World Bank for public sector purposes — for example, for schools and roads — is reduced by the full $100 million. Consequently, the partial risk guarantees have been favored in countries where World Bank borrowing has been beneath the ceiling. This has rendered the program substantially useless for the poorest countries that generally borrow to their limits and are often unwilling to assign, in effect, a portion of their credit limit to the private sector.

New Developments

In recent weeks, the World Bank has taken / continued page 26

IN OTHER NEWS

California taxpayer is an investor.

Failure to register a tax shelter will result in a $15,000 fine. Failure to provide the list of investors in a "listed transaction" will lead to a fine of $100,000 or 50% of the gross income that the organizer derived from the transaction, if greater. If the failure was due to "intentional disregard" of the law, then the penalty increases to 75% of the gross income. The Franchise Tax Board is required to publish the "listed transactions" through notices and on its website.

The bill provides an amnesty for companies that should already have registered transactions under existing law but failed to do so. Between January 1, 2004 and April 15, 2004, a taxpayer may file an amended return to report participation in a tax shelter. If the taxpayer at the same time agrees not to appeal the Franchise Tax Board's determination of tax liability, the board will waive all penalties related to underreporting due to participation in a tax shelter. The board will also waive its right to bring criminal action. If the taxpayer reserves its right to appeal, thus preserving the option to file a claim for refund, then the board will waive the penalties and its right to bring criminal action, but if the taxpayer does not win on appeal, it will be subject to accuracy related penalties based on the amount of the understatement.

STATES like Oregon are opening the door to corporate tax planning.

Each state taxes companies doing business in the state only on income from sources inside the state. Most states use a weighted three-factor formula to figure out how much income to allocate to the state. The three factors are the portion of a company's total sales, property and payroll that are in the state. If all states used the same approach, then most income earned by a corporation would end up parceled out among the states in which it does business, and it would be / continued page 27

Developing Countries

continued from page 25

steps to improve the partial risk guarantee program.

First, project sponsors (or lenders or host governments) can now approach the World Bank directly (without prior approaches to MIGA or IFC) for an initial expression of the bank's interest in supporting a project. The bank promises a response within 10 days.

Second, going forward, guarantees will be available to support equity as well as debt investors. This is a structural innovation rather than a formal change to the program. Equity will get the benefit of the partial risk guaranty through a letter of credit that will be posted to guarantee performance of the host government's obligations. If the government beaches its undertakings, the letter of credit is drawn and is reimbursed by the World Bank, which then has recourse against the government. The beneficiary of the letter of credit can be either a debt or equity investor. Whether the investor can have direct recourse to the World Bank in the event the letter of credit provider defaults is, apparently, still open to negotiation. No deals have been closed under this structure, but the first, being offered in support of a major West African project, is in the pipeline.

Third, the World Bank is trying to reduce the credit limit disincentives for host countries to use the partial risk product. For non-IDA countries — the less poor member countries of the World Bank — only 25% (versus the previous 100%) of the amount of a guarantee now counts against a country's credit limit at the World Bank. Although the impact of a guarantee in reducing borrowing capacity is even more important for the IDA countries — that is, the poorest members — no such change has been adopted yet for them. However, such a change (though perhaps with less than the 75% discount approved for richer countries) was proposed for approval at the bank's annual meeting in September in Dubai. ◎

Tax Consequences from Discharging Debt

by Richard M. Leder and David Danon, in New York

The Internal Revenue Service issued regulations in late August that clarify what happens when a corporation that is in bankruptcy is released from some of its debts.

The government was unhappy with a tax position that the giant long-distance telephone company Worldcom — now called MCI — claimed in a plan the company presented to a bankruptcy court. The regulations bar other companies from taking the same position. However, at the same time, they contain some welcome news for distressed power companies.

Ordinarily when a company is released from some or all of its debts, it must report the amount relieved as "cancellation of debt," or "COD," income. However, section 108 of the US tax code lets any company whose discharge occurs in a chapter 11 bankruptcy proceeding or otherwise when the company is insolvent avoid reporting the discharged amount as income. (In the case of a company that is merely insolvent, this rule applies only to the extent the company is insolvent.) Instead, the company must reduce certain tax attributes by the discharged amount. For example, if it was discharged from $100 million in debt and has $100 million in net operating loss carryforwards, the loss carryforwards would be eliminated as the tradeoff for not having to report any COD income.

Section 108 has a list of tax attributes that the discharged amount must be used to offset. Complications arise when the debtor corporation that was discharged joins with other companies in filing a consolidated — or group — income tax return.

The new IRS regulations in August clarify the manner in which the attributes of a consolidated group and its members must be reduced as a result of the realization of COD by a member of the group that is in bankruptcy.

Under the new regulations, consolidated groups with bankrupt members that have COD income in many cases will not be able to insulate tax attributes of other companies in the group from reduction.

Attribute Reduction

The principal attributes that are reduced are net operating losses, or "NOLs," tax credits, capital losses and asset bases —

largely in that order of priority.

Any reductions in asset basis (which occur at the beginning of the next tax year after the discharge) are subject to the limitation that the reduction cannot reduce the aggregate tax bases that the debtor corporation has in all of its assets below the level of the debtor's remaining indebtedness immediately following the discharge. Reductions in asset basis occur in the following order: 1) buildings and other real property used in a trade or business or held for investment, other than inventory property, that secured the debt giving rise to the COD income, 2) personal property used in a trade or business or held for investment, other than inventory property, that secured the debt giving rise to the COD income, 3) any remaining property used in a trade or business other than inventory, accounts receivable, notes receivable and real property that is inventory property, 4) inventory, accounts receivable, notes receivable and real property that is inventory property, and 5) property not used in a trade or business or held for investment.

Any COD that does not in fact lead to attribute reduction under these rules simply disappears.

Consolidated Groups

COD realized by a member of a consolidated group is determined on an entity-by-entity basis.

Before the new regulations, whether attribute reduction occurred on a separate entity or consolidated approach was unclear. The IRS had ruled that a group's entire consolidated net operating loss was reduced by a debtor member's COD, not just the portion of the consolidated NOL attributable to the debtor corporation that had the COD income. A US Supreme Court decision in a case involving United Dominion, although dealing with a different issue involving special carryback rules for product liability losses, was viewed as lending support to that position. The IRS had also issued rulings to the effect that only the debtor corporation's asset bases were subject to reduction, a view universally believed by tax lawyers to be correct (although the IRS expressly raised doubt as to correctness of this position in the ruling referred to earlier).

Worldcom

WorldCom and the members of its affiliated group file consolidated income tax returns. The company is currently in bankruptcy. The WorldCom group's COD income is reportedly in one or more holding companies while the / continued page 28

IN OTHER NEWS

taxed somewhere.

However, Oregon is moving to a single factor for allocating income — it will look just at the portion of a company's sales that occur in the state — in the hope of attracting companies that sell most of their products outside Oregon. A company that has lots of employees but few sales in Oregon would have little income to report there. However, because its property and payroll are largely in Oregon, it would also have less income to report in other states. Until May this year, Oregon double-weighted the sales factor. Since May, it has given 80% weight to sales and 10% weight to each of property and payroll.

The governor signed a bill in late August to move to 90% weighting for sales and 5% each for property and payroll as a transition to using sales as the sole factor. The change solely to sales will take effect in July 2006.

LANDFILLS that are listed as "Superfund" cleanup sites got bad news from a federal court in August.

Landfill owners are required by law to prevent gas and leachate from decomposing trash from leaking into the atmosphere or the surrounding soil. They set aside money in a reserve account while the landfill is still earning tipping fees from garbage collection to cover their ongoing obligations after the landfill has closed. Ordinarily, no tax deduction is allowed for merely setting money aside in a reserve account. The amounts cannot be deducted until they are actually spent on cleanup. However, section 468 of the US tax code makes an exception in this case.

A federal district court in Michigan in August denied tax deductions for contributions that were made to a reserve to cover future closing costs in years when the landfill was listed on the "national priorities list" of Superfund sites. The court said section 468 bars deductions for reserve contributions in

Debt Discharges

continued from page 27

group's NOLs are principally attributable to operating subsidiaries. Worldcom took the position in the plan it presented to the court for emerging from bankruptcy that only the portion of the consolidated NOL attributable to the holding companies and the bases of the holding companies' assets, which consisted primarily of the stock of their subsidiaries, had to be reduced. WorldCom did not plan to reduce the consolidated NOL to the extent attributable to group members other than the particular holding companies that had the COD income.

New IRS Position

The new IRS regulations adopt what might be called a "hybrid consolidated approach" to COD attribute reduction for a consolidated group.

Under the regulations, attribute reduction is first applied to the debtor corporation with the COD income; the attributes of that member are reduced under the ordering rules described earlier, and the attributes of other members are initially ignored.

If attribute reduction of the debtor corporation with the COD income results in a reduction in basis of subsidiary stock held by the debtor corporation, then the COD and required attribute reduction will tier down the ownership chain from the COD member. This tier down will occur layer-by-layer because if all or a portion of the COD member's attribute reduction is a reduction in the basis of the stock of a subsidiary, then the amount of the reduction in that subsidiary's stock will tier down to become deemed COD of that subsidiary. The attribute reduction rules will apply at the level of that subsidiary in the same way as with the COD member, starting with such subsidiary's share, if any, of consolidated NOLs. For each entity going down the chain, the attribute reduction follows the same separate entity approach.

Example 1: P owns 100% of the stock of Sub1. Sub1 owns 100% of the stock of Sub2 and Sub2 owns 100% of the stock of Sub3. P, Sub1, Sub2 and Sub3 file a consolidated federal income tax return. Sub1's basis in Sub2 equals $100, and Sub2's basis in Sub3 is $50. The P group has a $150 consolidated NOL, $50 of which is attributable to each of Sub1, Sub2 and Sub3. Sub1, Sub2, and Sub3 have no other tax attributes and no liabilities. Sub1 has $150 of COD.

As a result of Sub1's $150 of COD, first Sub1's $50 NOL will be eliminated, then its $100 basis in Sub2 will be reduced to $0. As a result of the $100 reduction in the basis of its stock Sub2 will be deemed to have $100 of COD income. This deemed COD income will eliminate Sub2's $50 NOL and will reduce Sub2's basis in its Sub3 stock from $50 to $0. As a result of the $50 reduction in the basis of its stock, Sub3's NOL will be eliminated.

If the COD member has sufficient attributes to reduce to offset the member's entire COD, then members outside the ownership chain below the COD member will have no attribute reduction. If the COD member does not have sufficient attributes to reduce, then the attributes of members outside the chain can have their attributes — other than asset basis — reduced.

When a company is relieved from its debts, some tax benefits that belong to affiliated companies of the debtor must be reduced.

Example 2: Same as Example 1, except 1) P also owns 100% of the stock of Sub4, 2) Sub4 owns 100% of the stock of Sub5, 3) the group consolidated NOL is $200 of which $50 is attributable to Sub5, and 4) Sub1 has $250 of COD.

As in Example 1, $150 of Sub1's COD reduces Sub1's NOL and tiers down to reduce Sub2 and Sub3 stock basis, and the $50 of the consolidated NOL attributable to each of these group members. Since Sub1's attributes have been fully reduced and $100 of COD remains, $50 of the remaining $100 of Sub1's COD that does not reduce its attributes reduces the $50 Sub5 NOL. The remaining $50 of COD does not reduce any other attributes of the group, such as P's basis in Sub1, or Sub4 or Sub4's basis in Sub5, and is eliminated.

The rule that asset reduction cannot reduce aggregate asset basis below the level of the particular corporation's debt level is applied separately at each level. Furthermore, while COD of a group member is generally available to reduce consolidated attributes of other members after tax attributes of the COD member have been exhausted, deemed COD of a member resulting from a reduction in the basis of its stock will not reduce the tax attributes of any other member of the group (except through tiering down of its deemed COD).

Example 3: Same as Example 2, except 1) Sub1 has liabilities of $20, 2) Sub2 has liabilities of $50, 3) the group consolidated NOL is $150 of which $50 is attributable to each of Sub1, Sub2 and Sub5, and 4) Sub1 has COD of $150.

As in Example 2, $50 of Sub1's $150 of COD eliminates Sub1's $50 NOL. However, because Sub1 has only $80 of asset basis in excess of liabilities, only $80 of Sub1's remaining $100 of COD reduces Sub1's basis in Sub2 stock. Sub1's remaining $20 of COD reduces Sub5's NOL by $20 to $30.

As in Example 2, Sub2's $50 NOL is eliminated as a result of the reduction in the basis of its stock. However, because Sub2 has no excess of asset basis over liabilities, no portion of the remaining $30 of deemed COD income reduces Sub2's basis in the stock of Sub3. Furthermore, since Sub2's COD is deemed COD resulting from a reduction in basis of its stock, its excess $30 of COD does not reduce Sub5's NOL.

Before the latest IRS regulations, a reduction in the basis of a subsidiary's stock did not require the reduction to tier down to the subsidiary's attributes.

Example 4: Same as Example 1, except 1) the consolidated NOL is $50, of which all $50 is attributable to Sub1, and 2) Sub3 has a basis in its operating assets of $50.

As in Example 1, $50 of Sub1's COD reduces Sub1's NOL and the remaining $100 of COD reduces Sub1's basis in Sub2. However, Sub2 does not have deemed COD as a result of the reduction in the basis of its stock and therefore Sub2 is not required to reduce its attributes as it is in Example 1. Therefore, Sub2's basis in Sub3 is not reduced and Sub3's basis in its operating assets is not reduced.

Effect on Worldcom Plan

Under the new regulations, each member of the WorldCom consolidated group that has COD income will have to reduce basis in the stock of its subsidiaries. The NOLs of these subsidiaries and the NOLs of any other subsidiaries further down this holding company's ownership chain will also be reduced to the extent of the COD.

If this tiering down of COD from a WorldCom holding company does not fully exhaust the WorldCom holding company's COD, then the excess COD will reduce consolidated NOLs attributable to other WorldCom */ continued page 30*

IN OTHER NEWS

such years, presumably on grounds that no tax "carrot" is needed at that point for a landfill owner to set aside money once cleanup has been ordered by the environmental authorities.

The court rejected an IRS claim that the landfill owner had to reverse all the deductions he had taken for reserve contributions in years before the landfill was listed by reporting the full amount in the reserve as income. The case is South Side Landfill v. United States.

FLORIDA stamp taxes had to be paid on a property transfer because of poor planning.

A limited partnership set up a limited liability company as a subsidiary and transferred land to it. The documents said that the property was being transferred to the LLC for $10 and other "good and valuable consideration." Florida collects a documentary stamp tax on transfers of real property to a "purchaser." The tax in this case was $1.2 million. The transfer should have been merely a capital contribution by a parent company to a new subsidiary.

However, a Florida appeals court said in September that the tax had to be paid because the statute defines a "purchaser" as anyone who "acquires property by paying an equivalent in money or other exchange in value," and there is a presumption where the documents suggest that nonmonetary consideration was given in exchange for property, the consideration was equivalent in value.

The case is a warning to be careful to describe transfers of property clearly as capital contributions when that is what they are in substance. It is Crescent Miami Center LLC v. Department of Revenue.

PHONE COMPANIES won a property tax case in Florida and lost another in Wyoming. The cases have implications for companies in other newly deregulated industries.

Florida limits counties from collecting

Debt Discharges

continued from page 29

operating companies whose holding companies do not have sufficient COD to eliminate the portion of the consolidated NOL attributable to those members beneath them in the WorldCom ownership chain. However, deemed COD of a WorldCom member that results from tiering down of COD from a WorldCom COD member will not reduce the portion of WorldCom consolidated NOLs that are attributable to other members (except through a tiering down of the member's deemed COD). This will result in a reduction of the WorldCom consolidated NOL (and perhaps the basis of WorldCom operating assets), rather than the hoped for reduction in stock basis of subsidiaries of COD members.

The change means there is probably less value in Worldcom than the company claimed in the plan the company presented to the bankruptcy court. ◎

Patents for Financing Structures

by Daniel Basov, in New York

Some companies in the project finance market claim to have unique enough financing structures that they are moving to patent them. Is this possible?

The answer used to be no, but a 1998 decision by a federal appeals court in the case *State Street Bank & Trust Co. v. Signature Financial Group, Inc.* and several subsequent court decisions have opened the door to patents for "methods of doing business." The result is the answer today to the question whether a financing structure can be patented is an anxiety-provoking "possibly."

Basic Principles

Anyone holding a patent has the right "to exclude others from making, copying, using, selling, or offering for sale" the systems or methods covered by the patent. The protection lasts for 20 years from the date of filing of the patent application.

This virtual monopoly conferred by the patent law involves a trade off. In exchange for the right to exclude others, the patentee must fully disclose to the public the specifics of his method or system. This public disclosure typically occurs through publication of the patent application by the US Patent Office, either 18 months after the patent application was filed or, in some cases, when the patent is issued.

Because the exclusive rights granted to a patent holder are a significant price for society to pay to encourage inventors to share their inventions and knowledge with the public, there are many strict requirements for patentability. First, the idea must meet a "threshold requirement" for patentability. Patents may be obtained for "any new and useful process, machine, manufacture, or composition of matter, or any new and useful improvement thereof." Second, the differences between the idea the applicant wants to patent and what is already known to others cannot be so insubstantial as to make the claimed invention obvious to a person skilled in the pertinent field. Third, an applicant is given at most one year to apply for a patent on a system or method that he or she has started to use publicly, sold or offered for sale to others. Any delay beyond that point creates an absolute bar to obtaining a patent for the invention.

Once an applicant files his application, the patent request moves into the "prosecution" stage. An examiner in the Patent Office reviews the application, searches for the relevant "prior art" in databases, industry publications, and in all references that are submitted by the applicant and determines whether the invention is novel and not obvious. Typically during this stage, the examiner and applicant exchange written responses. The examiner often rejects an application because of some prior art. The applicant then responds by distinguishing the claimed invention from the prior art cited by the examiner, rewriting or modifying his application so as not to overlap with the prior art, or trying to prove that his invention predated the prior art. If the applicant cannot convince the examiner within a set time period, then the application is considered abandoned. On the other hand, if the examiner can be convinced of the invention's novelty and uniqueness, then a patent is issued.

The process of obtaining a patent, particularly for a method of doing business, takes on the average about three years, from initial filing to issuance of a patent.

Business Methods

"Business method" inventions were historically treated by the courts and the Patent Office as unpatentable because they did not satisfy the threshold requirement for patentability.

The first case to consider the question was in 1902. A US appeals court invalidated a patent in *Hotel Security Checking Co. v. Lorraine Co.* for a new bookkeeping method for hotel staff. The hotel required each waiter to wear a badge with a designated number, to use this number on all order slips sent by that waiter to the kitchen and to tally totals against the main book at the end of the shift. Even though the patent itself was held to be invalid for lack of novelty, the court said that a generalized method of transacting business, particularly when disconnected from any concrete means for carrying out this method, is not patentable.

The "business method exception" doctrine was generally followed by the Patent Office and the courts until the highly controversial 1998 decision in *State Street*, which involved determination of the threshold patentability for a data processing system used in financial services networks. The patent described a way of organizing different mutual funds into a common investment portfolio, forming a "hub" on the network for each such portfolio, and placing each individual mutual fund at the end of a "spoke." This data processing system allowed each participant to determine the exact value of his shares at any given moment in time. The court hearing the case adopted a new test that permits any method or system to pass the threshold patentability requirement if it produces a useful, concrete and tangible result.

Following the *State Street* decision, this new test for the patentability of business methods was reaffirmed by the same US appeals court in another case, *AT&T Corp. v. Excel Communications*, Inc. In that case, the court said that while mathematical algorithms in the abstract cannot be patented because they do not meet the threshold requirement for patentability, a business method that uses a mathematical algorithm to produce a number with specific meaning and representing a "useful, concrete and tangible result," rather than a mere mathematical abstraction, can be patented.

Practical Experience

There are still very few issued patents that involve new financing methods and structures, but even a casual search of the Patent Office database reveals that this type of application might become the subject matter of an issued patent.

For example, US Patent No. 5,694,552, issued on Dec. 2, 1997, claims a new financing method for factoring trade acceptance drafts. US Patent No. 6,167,385, issued on Dec. 26, 2000, claims a novel method for financing a supply of */ continued page 32*

IN OTHER NEWS

property taxes on intangible property. Only the state can do so. Counties are limited to collecting such taxes on tangible assets.

Sarasota County used two methods to value GTE's property in the county and then averaged the two. One method was to use the depreciated cost of its tangible assets in the county. The other was to discount the income it earned. A Florida appeals court said in late August that while this approach might have worked before deregulation — since the income a phone company could charge was a function of its "rate base," or investment in tangible assets — after deregulation, the income reflected the value of all the assets of the phone company — both tangible and intangible. This was not allowed. The case is *GTE Florida v. Todora*.

In the other case, Wyoming assesses "telephone companies" at the state level using a "unitary method" under which the state assigns a value to the entire company as a going concern as opposed to trying to add up the value of each individual asset used by the company. This has the effect of roping in the value of intangible assets. Intangible assets are not supposed to be subject to property taxes.

Four cellular telephone companies protested that — as in Florida — the state's valuation method may work for the traditional telephone companies that charge regulated rates, but not for the unregulated companies. The state supreme court acknowledged the inequity, but challenged the state legislature to give the tax department clearer direction if it did not like what was happening.

In the meantime, the Wyoming court said the burden is on the cellular companies to prove how much "identifiable and separable" value their intangible assets have. It said that burden was not met in this case. The case is Airtouch et al. v. Department of Revenue. *The court released its decision in mid-September.*

Patents

continued from page 31

goods from the supplier to the buyer (where the buyer has a lower cost of funds than the supplier). There are currently many pending applications that cover the methods of allocation and analysis of risk — for example, for insurance purposes — and financing of ventures based on their determined risk allocation and analysis.

The elimination of the bar against business method patent claims, and the subsequent increase in the number of business method patent applications, may force more companies to try to patent their business methods as a defensive measure against possible infringement claims by others. Regardless of how one feels about the holding in *State Street* or about its impact on the affected industries, it appears that business method patents have become a permanent fixture on the landscape of US intellectual property protection. With this in mind, there are a few practical considerations that any company faced with the tough decision of seeking (or not seeking) patent protection should consider.

First, the patent monopoly conferred by US patent law provides a patent owner with a weapon against competitors who use the same business method. In addition to being entitled to collect damages stemming from infringement of the patent (calculated as either "lost profits" or "reasonable royalty" that a patent owner should have collected), a patent owner might also seek an injunction against infringement by others. If granted by the court, injunction could essentially shut down a competitor's business, particularly when the method or system involved in the patent dispute constitutes that company's "core business" and cannot be easily modified to place it beyond the scope of the patent claims. The burden is on an accused infringer to prove by clear and convincing evidence to the court and/or jury that the government made a mistake in issuing the patent. This is usually a difficult task because most judges and jurors do not have a technical or advanced business background.

Second, the primary expenditure associated with obtaining a patent on a method of doing business involves the cost of preparing the patent application. This cost typically ranges from $5,000 to $25,000 (depending on the length and complexity of the business method). The applicant must also devote time to collecting information about the services and methods used (or being developed) by competitors to the extent known and described in manuals, public announcements, marketing literature or on the internet to prove the business method is not public knowledge. This has the benefit of helping management decide whether the proposed patent application is "mission critical" for the enterprise or something that could easily be circumvented by an alternative method or simply become obsolete by the time a patent is granted. It also helps focus on what competitors are doing.

Third, it is important to note that filing a patent application and receiving a patent does not guarantee that the business method would not infringe someone else's patent. Some part of the business method may be covered by another patent. However, having a patent in hand may discourage infringement claims by others. A competitor with its own patent may not sue for fear of being counter-sued for infringement. It might be willing to enter into a cross-licensing arrangement instead of risking an expensive and prolonged court battle.

Many companies that choose not to acquire patents for themselves may elect other means of protection. For example, some monitor pending patent applications that are published by the US Patent Office — unless non-publication is expressly requested by the applicant, pending patent applications are published 18 months after submission. The Patent Office has also made it easier for third parties to submit "prior art" references known to them or the industry (but often unavailable to the Patent Office) to the patent examiner's attention for the purposes of considering the patentability of pending published patent applications. Thus, a material prior art reference that is timely submitted by a competitor might prevent issuance of a patent.

There is growing concern that the newly established protection for business methods might be misused by some companies to go after competitors. Partly with this in mind, Congress codified in the "American Inventor's Protection Act of 1999" a new defense to the claims of patent infringement. This defense is open only to a "good faith" user of a business method, who created and used commercially any system covered by a patent at least one year before the filing date of the asserted patent. This new defense against claims for infringement applies only when the patented invention is for a method of doing or conducting business. ◎

Network Upgrades Controversy

by Donna J. Bobbish, in Washington

A number of public utility companies and state public service commissions are pressing the Federal Energy Regulatory Commission to reconsider its policy of "socializing" the cost of grid improvements. Will the policy stand?

As the *NewsWire* went to press, Congress seemed poised as part of the energy bill to overturn the policy by requiring independent generators to pay the cost of such improvements.

Background

Owners of independent power plants must connect their plants to the nearest utility grid in order to move their electricity to market.

Interconnection requires construction of a radial line and may also involve construction of other equipment like a substation to step up the voltage, a ring bus or circuit breaker to prevent damage caused by power surges, and system or network upgrades — improvements to the grid itself — to accommodate another power plant. The utility usually constructs most of the intertie. The generator reimburses it for the cost.

FERC policy on who should pay the cost of grid improvements — as opposed to the direct intertie — has been evolving. Its policy since 2000 has been that it is inappropriate to make independent generators pay for "network upgrades" (defined as improvements to property on the utility side of the "interconnection point"). It believes the cost of grid improvements should be borne by all users of the grid through the general tariff that the utility charges transmission customers rather than charged solely to the generator. FERC recognizes that this puts the utility in a bind because the utility must make the grid improvements today to accommodate the generator's power plant, but it takes time to collect money through rates to cover the cost. Therefore, FERC allows the utility to collect the cost from the generator as an advance that must be repaid over time. This policy is reflected in a series of orders issued to settle individual disputes between generators and utilities.

In late July, FERC adopted a set of standard interconnection procedures and model interconnection agreement that generators and utilities will be expected to use in */ continued page 34*

IN OTHER NEWS

SWEDEN will require industry to pay in tax on electricity consumption the Swedish kroner equivalent of .065¢ a kilowatt hour starting in 2004. Industry had been exempted from the tax until now.

DIVIDENDS from foreign corporations qualify for a reduced US tax rate when received by individuals.

The US Treasury published a list in late September of countries whose corporations will be favored under the new reduced tax rates on dividends. The United States cut the tax rate that individuals holding shares in corporations have to pay on their dividends to 15% earlier this year. This applies to dividends received from US companies. It does not always apply to dividends received from foreign corporations.

One way dividends from foreign corporations qualify is if the foreign corporation has its tax residence in a country with a "comprehensive" tax treaty with the United States. The US Treasury published a list of such countries in late September. There are 52 countries on the list, including the United Kingdom, Holland, Luxembourg and many other countries in Europe and Asia but only one Latin American country (Venezuela). The Treasury singled out four countries that it said do not have suitable tax treaties. They are Bermuda, the Netherlands Antilles, Barbados and some former Soviet republics still covered by the US-USSR tax treaty. Russia, the Ukraine and Kazakhstan are included among the 52 "good" countries.

MINOR MEMO. A federal district court said that Black & Decker Corp. could not refuse an IRS demand for copies of tax planning communications from its accountants, Deloitte + Touche, on grounds that the communications are protected by the attorney-client privilege. The court suggested the only circumstance where communications

Network Upgrades

continued from page 33

the future. These require repayment of amounts advanced for network upgrades within five years with interest. The FERC announcement codifying this pricing policy is called Order No. 2003 (Standardization of Generator Interconnection Agreements and Procedures, Docket No. RM02-1-000).

As is typical, the order was greeted by a host of requests for rehearing. Critics charge the "socializing" the cost of grid improvements will lead to poor siting decisions, since generators will have no incentive to put their power plants in places where fewer upgrades will be required to the grid. Order No. 2003 requires utilities to repay generators any amounts advanced for network upgrades within five years with interest.

Complaints

FERC received a number of requests for a rehearing soon after the order was issued.The South Carolina Public Service Commission argued that permitting generators to be reimbursed for any of their network upgrade costs amounts to "cost socialization," violates cost-causation principles (which hold that properly designed rates should produce revenues from each class of customers that match, as closely as practicable, the costs to serve each class or individual customer), promotes economic inefficiency, and is inequitable to ultimate electric consumers. The South Carolina PSC recommended that the FERC "implement a pricing policy that encourages siting in a location that minimizes the need for network upgrades, and consider alternatives to cost socialization to provide generators with incentives for making economic efficient siting decisions."

The Alabama Public Service Commission told FERC that it is concerned making all grid users pay for upgrades "would unjustly and inappropriately impose the vast majority of the costs of generator interconnections on native load customers who are likely to receive little to no benefits from many of the new generator interconnections covered by the Rule." The Alabama PSC also charged that FERC is using its pricing policy as a stick (or a carrot, depending on one's point of view) to force utilities to cede operating control over their grids to regional transmission organizations, or RTOs. That's because FERC has given RTOs and ISOs more latitude to decide who should pay for network upgrades in their areas. Utilities that have not turned over operating control of their transmission facilities to RTOs have less room to maneuver. Utilities and state commissions in the south and west have been the fiercest opponents of the FERC RTO policy.

Southern Company Services, Inc. urged FERC to adopt an approach of deciding which upgrades benefit all grid users and having the utility bear these, but charging independent generators with the costs of other grid improvements.

The National Rural Electric Cooperative Association and the American Public Power Association challenge the factual predicate for FERC's pricing policy, arguing that "it is not clear that consumer subsidies are required to encourage the construction of competitive generation." According to the NRECA and the APPA, "the competitive generation market has been dramatically overbuilt in the past several years," and "it provides consumers little comfort if the Commission adopts a policy that encourages the construction of additional generation, but ensures that it is located inefficiently, in a manner that either require the construction of unnecessary transmission or causes unnecessary congestion."

What Did FERC Order?

Approximately 60% of interconnection agreements between independent generators and utilities are filed with FERC unexecuted because the parties cannot agree on terms. FERC is tired of acting as a mediator. It adopted standard procedures and a model agreement in late July in the hope that this would allow it to spend less time mediating disputes.

The new procedures and model agreement apply whenever an independent power plant that is more than 20 megawatts in size wants to connect to the grid. They require public utilities that offer transmission services to offer nondiscriminatory standardized interconnection service to such generators. FERC said that Order No. 2003 will "prevent undue discrimination, preserve reliability, increase energy supply, and lower wholesale prices for customers by increasing the number and variety of new generation that will compete in the wholesale electricity market." According to FERC, the delays caused because the parties cannot agree on terms for interconnection provide an unfair advantage to public utilities that own both transmission and generation facilities and, ultimately, undermine the ability of generators to compete.

The new standard procedures and model agreement only apply to new interconnection agreements, and with some exceptions described in an article by Adam Wenner elsewhere in this issue of the NewsWire, do not affect the terms or conditions of existing interconnection arrangements.

Network Upgrades

Under new standardized procedures, all facilities and equipment between the generator's power plant and the point of interconnection with the public utility's transmission system must be paid for entirely by the generator seeking interconnection with a public utility.

However, all "network upgrades" past the point of interconnection will be funded initially by the interconnecting generator, which would then be entitled to a cash-equivalent refund equal to the total amount paid for the network upgrades, including any tax gross-up or other tax-related payments. This refund would be paid to the interconnecting generator on a dollar-for-dollar basis, as the utility collects for wheeling electricity from the generator's plant across its grid. Under the final rule, the full amount must be refunded to the interconnecting generator, with interest, within five years of the date on which the generating facilities become commercially operational. Thus, under FERC's pricing policy, the cost of network upgrades would be borne by all of the transmission customers of the utility rather than by the generator.

The only condition to the generator getting his money back is his power plant must be put into commercial operation. Even if too little electricity is later carried from the power plant over the grid for the utility to recoup the cost of the upgrades through rates for carrying electricity from the generator's plant, the utility must refund the generator whatever he paid for network upgrades within five years with interest. The utility may decline to refund amounts that are designed to recover out-of-pocket costs, such as the cost of line losses, associated with the delivery of the output of the generating facility.

FERC gave transmission providing entities that are not affiliated with generators or power merchants, such as regional transmission organizations or independent system operators, "flexibility" as to interconnection pricing policy in their regions. This flexibility could, for example, permit utilities that are members of RTOs or ISOs to propose that interconnecting generators fund network upgrades that are not part of a regional plan.

Outlook

Order No. 2003 becomes effective on October 20, 2003. FERC has required all public utilities with open access transmission tariffs to amend their tariffs to comply with Order No. 2003 no later than that date. The fact that a */ continued page 36*

IN OTHER NEWS

from an accounting firm would be privileged is where the accounting firm is helping lawyers "translate" difficult materials so that the lawyers can provide legal advice. However, the court did find that the particular communications in this case were protected from disclosure to the IRS under a separate "work-product privilege" that protects materials prepared in anticipation of litigation. It also said that Black & Decker did not waive this privilege by selectively disclosing to the IRS a formal opinion that Deloitte gave it about the transaction. The case is *Black & Decker v. United States*. The court rendered its decision in mid-September.

— contributed by Keith Martin, Heléna Klumpp and Samuel R. Kwon in Washington, and Waldo Kapoen with Loyens & Loeff in Amsterdam.

Network Upgrades

continued from page 35

number of utilities and public service commissions have asked for a rehearing on the new standardized policies will not automatically delay the effective date. Thus, all public utilities must make filings with the FERC to amend their open access transmission tariffs to comply with the new rules no later than October 20, 2003.

Several parties have asked FERC to "stay" Order No. 2003 until both it and the courts have had a chance to reconsider the final rule. These requests for a stay will probably be denied. Other parties, such as the New England Power Pool Participants Committee and ISO-New England Inc. and the Midwest Independent Transmission System Operator, Inc., requested an extension of time to make their compliance filings. FERC gave RTOs and ISOs an extension until January 20, 2004 to making their filings. It had not ruled on similar requests from utilities as the NewsWire was going to press in late September.

Precisely when the FERC will address arguments raised on rehearing is unclear. On September 22, FERC issued a "tolling order" granting rehearing of Order No. 2003 but without setting a date for the rehearing. Once the FERC issues a "tolling order," there is no fixed time within which it must issue an order addressing the requests for rehearing of Order No. 2003.

FERC is unlikely in the end to alter its policy concerning the cost of network upgrades. This means the policy will end up being challenged in court. The challengers face an uphill battle. In the first place, the Federal Power Act permits only persons "aggrieved" by a FERC order to seek court review of that order. Court precedents hold that FERC policies may not be challenged on a theoretical basis. Therefore, parties wishing to challenge the pricing policy will have to demonstrate to a court that they have been harmed by the pricing policy.

This means that it is more likely that challenges to the policy will be raised in specific cases in which public utilities seek to recover from their transmission customers costs of network upgrades under the policy announced in Order No. 2003. For example, in a FERC proceeding involving Public Service Company of New Mexico's proposed interconnection agreement with an FPL Energy wind farm (Public Service Company of New Mexico, Docket No. ER03-914-000), the New Mexico attorney general expressed his concern that the FERC pricing policy will allow PNM "to recover the costs of interconnecting the wind project in transmission rates paid by all retail customers." The attorney general said he plans to "ask the New Mexico PRC to order that interconnection costs of the FPLE wind generation project be recovered from the cost causers. . . ." Any such actions by state authorities raise issues of federal preemption. In 1986, the US Supreme Court ruled that states may not prevent regulated utilities from passing through to retail customers FERC-mandated wholesale rates.

The courts probably will give considerable deference to the FERC pricing policy. Particularly in light of the August 2003 blackouts in the northeast and midwest, courts are unlikely to second guess FERC policies aimed at increasing electric system reliability and encouraging investment in generator and transmission infrastructure. Also, a US appeals court in Washington upheld a FERC order requiring all transmission customers of Entergy Service, Inc. to pay for certain specific network upgrades to Entergy's transmission system earlier this year. The court found that FERC had explained sufficiently its policy that short-circuit and stability-related upgrades that facilitate network expansion benefit all users, not just the newly-interconnecting generator, since the grid is continuously expanding and all users of the grid benefit from its continued reliability. The court also found that there was sufficient support in the record for the FERC's conclusion that its pricing policy provided a systemwide benefit for all users of the public utility company's grid. (Entergy Services, Inc v. FERC, 319 F.3d 536 (D.C. Cir. 2003)). FERC certainly will rely on this decision in any defense of the pricing policy established in Order No. 2003.

Nonetheless, the FERC's pricing policy may be vulnerable to a charge of undue discrimination as to the application of the policy. FERC gave pricing flexibility to RTOs and ISOs. Parties will argue that the FERC has not articulated a rational basis for distinguishing between RTOs and others. If a federal appeals court finds that FERC has not articulated an acceptable basis for distinguishing between transmission providers that are members of RTOs and ISOs and those that are not, the court could either reverse the rule or send the decision back to the FERC for further explanation.

Environmental Update

Combustion Turbines

The US Environmental Protection Agency issued a final rule in late August that sets maximum achievable control technology, or "MACT," standards for new and reconstructed stationary combustion turbines built after January 14, 2003.

Under the new rule, existing combustion turbines do not need to meet specific emission limitations. Because there were not enough existing combustion turbines to establish a "floor" level of control for the different subcategories of turbines, EPA concluded that no emission reductions are required from existing sources. EPA also determined that to go beyond the floor by requiring existing sources to install add-on pollution controls would be cost prohibitive.

The rule affects major sources of air pollutants. It requires them to reduce formaldehyde emissions to 91 parts per billion or less. Four categories of combustion turbines must meet this standard, including "lean premix" and "diffusion flame" combustion turbines that burn either natural gas or distillate oil. The rule focuses on reductions of acetaldehyde, benzene, formaldehyde, and toluene, and uses formaldehyde reductions as a surrogate for achieving similar reductions of the other air toxics.

Turbines covered by the rule must comply when they are brought on line and plants will have six months after startup to demonstrate compliance.

The final rule is based on the emission reductions achieved by installing a carbon monoxide catalytic oxidation system. Under the rule, affected sources may install either a carbon monoxide oxidation catalyst system or reduce formaldehyde emissions to 91 parts per billion to achieve compliance. If a source elects to comply without installing an oxidation catalyst, then the source must petition the EPA Administrator for approval of either plant-specific operating limitations or no operating limitations. Sources using an oxidation catalyst must also install a continuous parameter monitoring system.

Regional Haze

The Environmental Protection Agency and Environmental Defense, an environmental group, reached a proposed settlement in August on a new timetable for issuing revised rules that would require the installation of best available retrofit technology, or "BART," on certain plants and other industrial facilities that affect visibility in national parks and federal wilderness areas or so-called "class I" areas under the Clean Air Act.

EPA agreed as part of the proposed settlement to propose revised BART regulations by April 15, 2004 and to issue final regulations by April 15, 2005. The proposed settlement will be subject to a public comment period.

A federal appeals court set aside a key provision of the EPA "regional haze" rule last year that would have allowed states to impose pollution control requirements on a group of sources as a class instead of individual sources. The court concluded that the Clean Air Act requires a finding that a particular source contributes to visibility impairment at a class I area before BART controls can be imposed.

The regional haze rule, issued in July 1999, requires states to review all major air emission sources built between 1962 and 1977 that emit over 250 tons per year of any of five visibility-impairing pollutants and are located up-wind of class I areas. The five pollutants are nitrogen oxide, sulfur dioxide, particulate matter, volatile organic compounds and ammonia. The rule provides that sources that are reasonably anticipated to cause or contribute to class I visibility impairment must install BART controls.

In 2001, EPA proposed BART guidelines that recommend flue-gas desulfurization or scrubbers as the presumptive BART standard for utility boilers. Installing a scrubber on a large electric generating unit could result in costs ranging from $50 million to $100 million. As a result of the federal court decision, EPA will have to go back to the drawing board and repropose several key provisions of the BART regulations.

In practice, it may be difficult to demonstrate that an individual source affects visibility at a downwind class I area, except for situations involving very large air emission sources. EPA's proposed revisions to the regional haze rule are expected to identify a new mechanism for identifying BART-eligible sources in conformance with the court's decision.

New EPA Administrator

Senate Democrats are threatening to hold up confirmation of the man President Bush has appointed to the post of EPA administrator.

/ continued page 38

Environmental Update

continued from page 37

Bush named Utah governor Mike Leavitt to replace Christine Todd Whitman. The Senate Environment and Public Works Committee has held one hearing on the nomination and is expected to vote on it in early October. However, a number of Democratic senators have placed holds on the nomination, and presidential election politics are playing a role in the confirmation process.

At his September 23 confirmation hearing, Leavitt faced tough questioning from senators about the Bush administration environmental policies. Leavitt said he supports the administration's efforts to reform the new source review, or "NSR," air permitting program and would not consider freezing implementation of new NSR rules that were issued by EPA on August 27.

Several senators have placed "holds" on the nomination as a way to show displeasure about administration environmental policies. A hold prevents the nomination from reaching the full Senate for a vote. The Senate must confirm appointees to head government agencies. Two of the Senator who put holds on the nomination — Hillary Rodham Clinton (D-New York) and Joseph Lieberman (D-Connecticut) — want EPA to provide more information about the air quality in New York City after the September 11, 2001 terrorist attack on the World Trade Center. Senator John Edwards (D-North Carolina) has a hold linked to his calls for a new National Academy of Sciences study to review the projected impacts of the Bush administration's NSR reforms. Senator John Kerry (D-Massachusetts) put a hold on the nomination until EPA funds a Superfund site cleanup in Massachusetts, and Senator Harry Reid (D-Nevada) placed a hold as leverage to seek White House action on a pending appointment to the Nuclear Regulatory Commission.

None of the holds on the Leavitt nomination is expected ultimately to derail the nomination, but they could delay his confirmation.

Clear Skies

New air toxics limits on mercury emissions expected to be issued by EPA in December are taking on added importance, as the Bush administration appears to be getting nowhere with its plan to enact different limits as part of its "clear skies" initiative. Compliance costs with the new rules are expected to be high for certain coal-fired power plants.

President Bush went on the offensive in early September, making two separate addresses advocating passage of his initiative by the end of the year. The clear skies initiative would set limits on sulfur dioxide, nitrogen oxides and mercury emissions from power plants. His words fueled speculation that the administration will try to attach the clear skies initiative to the comprehensive energy bill that is currently being considered by a joint House-Senate conference committee. However, chances of this are slim.

The mercury provisions in the clear skies initiative would supplant the maximum achievable control technology, or "MACT," standards scheduled to be proposed by EPA for utility plant boilers in December. Thus, assuming the clear skies initiative is stuck in neutral for the remainder of the current Congress — which runs through the next year — the MACT standards take on added importance. These new federal MACT standards are scheduled to be finalized by December 15, 2004. The potential compliance costs for achieving the mandated mercury reductions in the utility MACT rule may be considerable for certain coal-fired plants.

The MACT rule for power plants will apply to major sources of air toxics – that is, plants that have a potential to emit 10 tons or more of any one hazardous air pollutant or 25 tons or more of any combination of such pollutants.

The rule, if finalized, is expected to require many coal-fired plants to install pollution control technologies to reduce mercury emissions starting in December 2007.

The new emission standards will probably be based on the particular type of coal being burned. This subcategorization based on the coal types is a critical issue for utilities. There are several different types of coal, including anthracite, bituminous, sub-bituminous, and lignite, and each type of coal has a different level of mercury content. There are also differences in the types of mercury within each type of coal. For example, divalent oxidized mercury is soluble in water and is more easily removed than elemental mercury, which is insoluble in water.

Energy Bill

A House-Senate conference committee was still working on the comprehensive energy bill as the NewsWire went to press.

The Senate version of the bill would establish a comprehensive greenhouse gas inventory reductions registry. Reporting emissions of greenhouse gases to the registry would be voluntary, but would become mandatory if reporting does not cover 60% of the total US greenhouse gas emissions within five years. If the program becomes mandatory, non-exempt companies failing to report could be subject to penalties of up to $25,000 per day.

The Senate bill would also establish a renewable portfolio standard, or "RPS," that would eventually require 10% of electricity generated in the US to come from renewable energy sources such as wind, solar, and landfill gas. The conferees decided not to put an RPS in the final bill. Fifty-three Senators wrote the conference committee as the NewsWire went to press urging them to reconsider.

Both the House and the Bush administration oppose both the Senate climate change language and a national RPS standard.

CO_2 Reductions

EPA denied a petition asking the agency to regulate motor vehicle emissions of carbon dioxide, or "CO_2," and other greenhouse gases in early September. The rejection of the petition was expected, and it will now set up a court battle on whether CO_2 and other greenhouse gases can be directly regulated under the Clean Air Act.

In October 1999, the International Center for Technology Assessment and eighteen other environmental and public interest groups filed a petition asserting that the Clean Air Act provided authority to regulate CO_2 and other greenhouse gases. In their petition, the interest groups argued that CO_2 and other greenhouse gases, including methane, nitrous oxide, and hydrofluorocarbons, emitted by motor vehicles fell within the scope of the definition of "air pollutant" under the act. The groups also asserted that prior agency statements acknowledged that these greenhouse gases may be reasonably anticipated to endanger public heath and welfare.

In its notice of denial, EPA concluded, based on its review of the statute and its legislative history, other Congressional action and Supreme Court precedent, that it lacks authority to address global climate change under the Clean Air Act. EPA also found that it lacks authority to develop motor vehicle fuel standards regarding fuel efficiency since this area is governed by a statute administered by the Department of Transportation.

The coalition of environmental and public interest groups is expected to file suit in federal court challenging the agency's decision. The attorneys general of Connecticut, Maine and Massachusetts also plan to file their own suit challenging the notice of denial. A decision by a federal court that reverses the EPA decision could have far-reaching implications; however, EPA will be starting with a distinct advantage — in general, courts are reluctant to overturn agency actions. A decision in the case is not expected until late 2004.

In related climate change news, three Western governors — Gray Davis (D-California), Ted Kulongoski (D-Oregon) and Gary Locke (D-Washington) —- announced a plan in late September to develop regional climate change policies, including the development of greenhouse gas registries and accounting procedures and purchasing fuel-efficient motor vehicles. The pact by the governors follows a similar announcement by a group of New England and mid-Atlantic governors to develop regional climate change policies. Their announcement signals a continuing trend by states to address climate change issues on a state and regional basis since the federal government has shown no interest in acting.

Kyoto Protocol

The Kyoto protocol remains on indefinite hold while Russia debates whether to ratify the treaty.

International implementation of the Kyoto protocol hinges on Russia's actions. The agreement's chances of entering into force by the end of 2003 were recently dashed when the Russian premier, Vladimir Putin, announced that the Russian government wants to continue to evaluate the implications of ratifying the treaty. The Kyoto protocol will enter into effect after it is ratified by 55 or more countries (including both industrialized "annex I" nations and developing "annex II" countries) whose emissions represent at least 55% of the carbon dioxide emissions from annex I countries in 1990. To date, 119 nations have ratified the Kyoto protocol accounting for 44.2% of the 1990 carbon dioxide emissions. Russia accounts for 17.4% of the emissions and, thus, its ratification would put the agreement over the 55% implementation threshhold.

Russia is reportedly considering the potential impact that entering the Kyoto protocol will have on oil and natural gas prices if there is a shift toward renewable fuel sources. Russia is also apparently interested in greater certainty that there will be a market for Russian greenhouse gas credits. The decline in Russian industry has resulted in large emission decreases since 1990, which should translate into a

Environmental Update

continued from page 39

significant surplus of carbon credits to sell to other industrialized countries that have ratified the Kyoto protocol.

Once in effect, the Kyoto protocol will require approximately a 5.2% reduction in greenhouse gas emissions during the first commitment period –- 2008 to 2012 –- compared to 1990 emission levels. The United States has rejected the Kyoto protocol.

Brief Updates

A US appeals court upheld a lower-court decision in Clean Air Markets Group v. Pataki finding that a New York law to impose financial sanctions on the sale of sulfur dioxide allowances by in-state utilities to certain upwind states is unconstitutional. The lower court had ruled that the federal Clean Air Act preempts the New York law and, accordingly, the state law violated the "supremacy clause" in the US constitution.

In August, the first renewable energy certificate — or REC — trade was announced in Connecticut. Under the trade, 10,000 vintage 2004 Connecticut "class I" New England Power Pool certificates were sold for $37.50 per certificate. A certificate represents the renewable attributes of one mWh of electricity. As of January 1, 2004, Connecticut utilities must hold RECs equivalent to 1% of their supply portfolios, and the percentage increases to 7% by 2010. Class I certificates in Connecticut may be generated by wind, landfill gas, fuel cells, solar photovataic, and some biomass generation sources.

Massachusetts has proposed mercury emission standards that will apply to the state's four coal-fired power plants starting in October 1, 2006. The Massachusetts rule will be issued under a law that was enacted in 2001 and that calls for substantial nitrogen oxide, sulfur dioxide, mercury, and CO2 emission reductions from the six oldest power plants in the state. Four of the state's plants are coal-fired, and the others are fired by natural gas and oil. Under the proposed rule, the four coal-fired plants will need to meet an 85% mercury reduction level by October 1, 2006. A second phase starting on October 1, 2012 requires further mercury reductions to a 95% level. The rules are expected to be finalized in 2004.

California governor Gray Davis signed into law a bill that sets minimum standards for implementing new source review, or "NSR," requirements in each of the state's 35 air districts. The law prohibits any of the state's air districts from implementing the EPA revisions to the federal NSR rules that were issued in December 2002, and it codifies into state law the pre-existing NSR program rules. The California air districts are also free to enact stricter local NSR programs.

At the end of August, the US Export-Import Bank board voted 2-1 to reject financing for the Camisea natural gas project in Peru. The Ex-Im Bank reportedly decided against making a loan of $213.6 million to the project because it did not fully meet the Ex-Im Bank's environmental guidelines. The Inter-American Development Bank approved a $135 million loan to the Camisea project in early September. The US member to the IADB's board of directors abstained from the vote due to concerns raised by the environmental impact review.

— contributed by Roy Belden in New York

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

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

350 South Grand Ave.
Suite 3300
Los Angeles, CA 90071
(213) 892-1000

1100 Louisiana, Suite 3500
Houston, TX 77002
(713) 571-5900

Riverside Towers
52/5 Kosmodamianskaya Nab.
Moscow, Russian Federation 115054
(7-095) 974-2424
Direct line from outside C.I.S.:
(212) 408-1190

Beijing Representative Office
Suite C3, Plaza Business Centre
3rd Floor, North Tower
Beijing Kerry Centre
1 Guang Hua Road
Chao Yang District
Beijing 100020, China
(86-10) 8529-8892

Chadbourne & Parke
a multinational partnership

Regis House
45 King William Street
London EC4R 9AN
(44-20) 7337-8000