

PROJECT FINANCE

NewsWire

December 2002

Enron Rulings May Affect Other Companies

by Lynn Hargis, in Washington

US securities regulators have started investigations, with fast-track hearings, into the validity of Enron's exemptions from rules governing public utility holding companies.

Meanwhile, US energy regulators are also looking into whether Enron took unjustified actions to avoid restrictions on utility ownership of so-called "QF" power plants. These are power plants from which utilities are required by law to buy electricity. A utility cannot own more than 50% of such a power plant. Enron is treated for purposes of this ownership restriction as a utility since it owns Portland General Electric, an electric utility in Oregon.

The results of these hearings could set bad precedent or even negatively affect the current holding company exemptions of other companies and the qualifying status of other QFs.

Investigations

The Securities and Exchange Commission and the Federal Energy Regulatory Commission have, respectively, instigated investigations into alleged Enron Corporation activities affecting Enron's exempt status under the Public Utility Holding Company Act, known as "PUHCA," Enron's consequent ability to own more than 50% of its QFs under the Public Utility Regulatory Policies Act, or "PURPA," / *continued page 2*

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A DEPRECIATION BONUS will be harder to claim on power plants if changes that key members of Congress proposed in November are enacted.

Congress enacted a 30% "depreciation bonus" last March as an incentive for US companies to make new investments during the period September 11 last year through 2004 or 2005, depending on the project. The hope was this would help jump start the economy. The bonus reduces the cost of a new gas- or coal-fired power plant by as much as 5.39%.

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Enron Rulings

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and whether FERC should revoke the qualification of certain QFs of which Enron is at least a part owner.

The SEC has set for hearing the question of whether — particularly in light of Enron’s bankruptcy proceeding and the cessation of its power trading activities — Enron is entitled to certain exemptions from the Holding Company Act. Such exemptions allowed Enron to avoid comprehensive regulation of its financial activities and restrictions on its business activities by the SEC under PUHCA. The SEC has

The SEC and FERC are investigating whether Enron was entitled to holding company exemptions and QF status for its power plants.

also set for hearing Enron’s section 3(a)(1) PUHCA exemption. This is the so-called “single state” exemption and is the one most frequently claimed by parent companies of US utilities. It requires a holding company to be incorporated and to operate primarily as a utility holding company in the same state in which its utility is incorporated and operates. (The purpose is to aid state utility commissions in regulating state utilities owned by holding companies. The thought was that a state commission ought to be able to regulate a holding company on its own where the company’s operations are limited to a single state, while multistate utilities require help from the federal government to regulate effectively.) Enron’s section 3(a)(1) exemption, which has traditionally simply been claimed under an SEC rule without getting a formal order, is being questioned because part of Enron’s utility business is conducted outside the state of Oregon, which is where Enron and its utility (Portland General Electric) are incorporated.

The SEC hearings will also address Enron’s pending applications for other exemptions under sections 3(a)(3) and 3(a)(5) of PUHCA, which were requested specifically to allow Enron to own 100% of QFs. Section 3(a)(3) applies to a company engaging in another business that is only

“incidentally” a utility holding company, and section 3(a)(5) — traditionally known as the “foreign holding company” exemption — applies to a holding company that derives no material part of its income from a public utility company in the United States. FERC rules provide that a holding company with either of these two PUHCA exemptions is not “primarily engaged” in the generation or sale of electricity and, therefore, it may own 100% of a QF.

The Federal Energy Regulatory Commission is investigating whether an alleged transfer of Enron’s interest in certain QFs to special-purpose subsidiaries controlled by individuals was a sham transaction designed to evade QF rules while

keeping the QFs under Enron’s control. FERC ordered an investigation into whether the QF certification had misrepresented the facts or otherwise failed to meet FERC rules and whether the QFs’ status as qualifying facilities should be revoked retroactively. The order setting the investigation

for hearing noted that FERC might take stronger remedial action than it has in the past in the face of intentional misbehavior. In the past, FERC has ordered retroactive refunds but allowed the QF to keep certain exemptions, such as its exemption from PUHCA and state utility laws.

Political Backdrop

The investigations at both commissions appear to have resulted directly from accusations that the two agencies were “asleep at the switch” in their statutory oversight of Enron as a holding company or as a QF owner. These accusations were made at hearings before the Senate Committee on Government Oversight. The committee has been looking into the Enron scandal generally, but also, in particular, into the admissions of former Enron employee Michael Kopper that he and Andrew Fastow, his former boss at Enron, used special-purpose subsidiaries intentionally to evade the FERC ownership rules for certain QFs and for other personal gains. (Enron’s position in the SEC proceeding is that this was a fraud on the company, not by the company.)

A report issued by the Senate committee in conjunction with the hearings discusses the PUHCA exemption questions and the Enron QF ownership issues at length, as

did committee members at the hearing. (Four FERC commissioners and their top staff were present at the hearing, which may raise questions about the fairness of the commission's ultimate decisions.)

The SEC investigation order, which was issued the same day as the Senate committee report criticizing the SEC's oversight of Enron, specified the unusual procedures of not only setting the matter for a fast-track hearing, but also providing that an SEC commissioner, rather than an administrative law judge, would preside at the hearing. Moreover, the presiding commissioner is a Democratic commissioner (Roel Campos) in a currently highly-politicized SEC.

Status of Proceedings

The SEC investigation is well underway, with the first hearings scheduled for December 5, 2002. So far, the sitting commissioner has refused to allow other parties to participate fully as intervenors, but only to participate on a limited basis.

The SEC hearing has two phases. The first phase will address whether Enron meets the requirements of any of the three PUHCA exemptions on their faces. Even if it does, the second phase will address whether the public interest dictates that the exemptions should nonetheless be denied. Many holding companies that currently have or plan to obtain section 3(a)(1) exemptions, as well as section 3(a)(3) or 3(a)(5) exemptions, may be affected if the outcome of the proceeding is a change in SEC precedent for the criteria necessary for these exemptions.

Southern California Edison has jumped into the proceedings at both agencies to attack its power contracts with QFs that are traceable to Enron. In addition to submitting filings in the SEC and FERC investigations, Edison has also asked FERC to start another proceeding to broaden its investigation into other Enron-owned QFs and to consolidate the "sham" sale question with the PUHCA exemption question. Edison has further asked FERC to determine for itself that Enron's PUHCA exemption filings at the SEC under sections 3(a)(3) and 3(a)(5) were not made in "good faith" and, therefore, that the QF certifications should be revoked retroactively. (Under PUHCA, a "good faith" application exempts the applicant until the SEC acts on the application.) A number of parties have filed for intervention to protect their rights as the holders of PUHCA exemptions or as the owners of QFs. */ continued page 4*

Frustratingly, Congress has still not settled on the rules for the bonus more than a year into the eligibility period.

A company cannot claim the bonus on a project to which it was "committed" before September 11 last year. The idea was to reward new investments after the terrorist attacks. An open issue is what it means to be "committed." Most power companies have assumed that as long as construction had not started at the site by September 11, a project should qualify. This is based on language in the Congressional committee reports when the depreciation bonus was enacted.

However, a "technical corrections" bill that the chairmen of the House and Senate tax-writing committees introduced in November would deny the bonus on any project for which a written binding contract was in effect before September 11 last year. The bill was put out for comment. Odds are that it will be enacted next year. A binding contract before September 11 last year would forever taint the project: no one could claim a bonus on it — even if a new investor is found during construction to complete a project that the original developer has abandoned. This rule would apply retroactively.

Two other issues remain in play. The Joint Tax Committee staff is working on a "blue book" that may address these other issues.

One is what to make of the fact that many power companies signed master contracts to buy multiple turbines well before September 11 last year and without knowing at which projects the turbines would be used. The issue is whether a bonus can be claimed on such turbines if they are used at a project that otherwise qualifies.

The other open issue is the Joint Tax Committee staff has held open the possibility that an institutional equity participant that invests in a project */ continued page 5*

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Industry Concerns

The haste with which both agencies are acting and the political backdrop to the proceedings, as well as the notoriety of Enron Corporation itself, may lead the agencies to a rush to judgment that could have unintended consequences for other companies with Holding Company Act exemptions or owning qualifying facilities. The SEC hearing probably constitutes the most investigative attention that the agency has paid to the Holding Company Act in two decades. At the

The decisions could affect the exemptions claimed by other power companies.

FERC, since QF ownership rules are affected by both PUHCA and PURPA, FERC may be tempted to determine the PUHCA “good faith” issue as Edison is urging it to do, despite FERC’s lack of familiarity with that statute or its far-reaching consequences. The old saying that “bad facts (or bad actors) make bad law” may be applicable here. ☺

Anticipating A Possible Bankruptcy

by Joseph H. Smolinsky, in New York

A Standard & Poor’s report in late November said that \$90 billion in short- and medium-term debt will come due from US merchant power companies in the next four years. Many merchant power companies are in workout or refinancing talks with their lenders. Some bankruptcies are expected. What can a lender do to protect its interests?

Starting even before a loan is made, there are several steps a lender can take to protect itself against the possibility of a borrower bankruptcy.

Contracts

Both during a workout preceding bankruptcy and in making a new loan, the lender should evaluate what might happen in bankruptcy to contracts that the borrower has with third parties.

Once a borrower has filed for bankruptcy, section 365 of the bankruptcy code permits the borrower to pick and choose among its unexpired leases and contracts. It can select which contracts to assume (adopt) and which to reject (disavow).

Generally a borrower may assume a contract if, at the time of assumption, the borrower cures past defaults under

the agreement and demonstrates its financial ability to perform its obligations under the agreement going forward. A borrower has the power to reject a contract if it is burdensome to the borrower’s business and, in the borrower’s business judgment, it is appropriate to

do so. If a contract is rejected, then it is deemed to be a court-authorized breach of the contract and remedies of the counterparty to the contract will be restricted to a pre-petition general unsecured claim for damages. In contrast, if a borrower assumes a contract and then subsequently breaches it, the counterparty will have a claim for damages that is not limited by the bankruptcy laws.

Another possibility is that a borrower can assign most of its leases and contracts, on a nonrecourse basis, to third parties. This is true even for contracts that include anti-assignment clauses. The effect of such an assignment is to release the borrower from all further liability and to transfer all past and future obligations to the new contract party. In fact, a number of reorganizations have been funded by the borrower’s ability to assign below-market leases and other types of agreements for fair market value.

A lender should consider the impact of the possible rejection of key contracts in making its credit evaluation of the borrower. It should consider not only the possibility of the borrower’s bankruptcy, but also that of the counterparty. Are there sweetheart agreements with affiliates or long-term, below-market contracts that could be rejected were the counterparty to file for bankruptcy? If so, a lender

should insist on seeing a revised business plan that takes into account the loss of these valuable contract rights.

Affiliates

A lending decision should take into consideration the borrower's affiliates. A bankruptcy court under certain circumstances has the power to pool and merge the assets and liabilities of all affiliates affected by a bankruptcy. Through this remedy, known as "substantive consolidation," all affiliates of the borrower in the substantively consolidated group are treated as if they were a single corporate and economic entity. The consolidated assets create a single fund from which all claims against the consolidated companies are to be satisfied. Consequently, a creditor of one of the substantively consolidated companies is treated as a creditor of the whole group of companies, and issues of individual corporate ownership of property and individual corporate liability on debts and other obligations are ignored.

A lender to one member of a group of companies should evaluate the risks of substantive consolidation if the borrower files for bankruptcy. In a worst-case scenario, a lender could lose its place in line for collateral to a prior lender to another affiliate that relied on the affiliate's ownership of the collateral in making the prior loan.

If the borrower is a newly-formed entity wholly owned by a controlling affiliate, then a lender making a new loan should ordinarily require the formation of the borrower as a bankruptcy-remote, special-purpose vehicle. The loan documents and corporate charter would ensure that the vote of an independent director is needed to commence a bankruptcy case for the borrower and would further ensure that commingling of assets and other factors favoring substantive consolidation are not present. For those borrowers that have been in existence long enough to have a history, the lender should survey transactions and business practices between the borrower and its affiliates to evaluate whether the relationships are kept at arms' length. The lender can request legal opinions or officers' certificates to support the borrower's representations with respect to such matters.

In evaluating a potential loan, a lender should also be aware that substantive consolidation will eliminate cross-corporate guarantees given by one member of the group for another member's obligations. It will also / *continued page 6*

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while it is still under construction might be able to claim a bonus on its spending — after it buys into the project — to complete construction, even though the project would not otherwise qualify for a bonus in the hands of the original developer. It could not claim a bonus on its purchase price to buy into the project.

The "blue book" is expected out around year end.

POWER PLANT REPAIRS will be the focus of a meeting at the Internal Revenue Service on December 3.

The IRS is working on a set of bright-line tests for deciding when spending on an existing power plant qualifies as a "repair" versus an "improvement." The cost of repairs can be deducted immediately. The cost of improvements must be recovered over time as the power plant depreciates. The quick deduction makes repairs less expensive after the tax effects are taken into account.

The line between them is often fuzzy. Power companies are challenged frequently by the IRS on audit. The hope is that clearer rules will let the IRS and taxpayers spend their time arguing about other things.

The IRS plans to brief representatives from the power industry at the December meeting about what it is considering proposing. An IRS official said the meeting is "not a negotiating session," but merely a chance to ask questions.

Judging from questions the agency has been asking the industry trade associations, IRS officials seem inclined to treat a power plant as many separate pieces of equipment — for example, turbine, precipitator, boiler, generator, pulverizer. This would make it harder to claim that work was a "repair" since the cost will seem more significant in relation to the article being repaired. For example, \$100,000 spent for work on a "power plant" seems less / *continued page 7*

Anticipating Bankruptcy

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eliminate duplicative claims that a lender has against more than one debtor in the group, as well as an inter-company claims between the members of the group.

Assets

Research how the borrower obtained its assets. A bankruptcy court can unwind a transaction made by the borrower up to a year prior to its bankruptcy filing (or longer under applicable state law) if the court finds it to be a “fraudulent conveyance.” A fraudulent conveyance is a transfer of property by a borrower for which the borrower received less than fair consideration at a time when the borrower was insolvent, was unable to pay its debts as they came due, or was left with unreasonably small capital to conduct its business.

There are nine steps that a lender ought to take to protect itself in anticipation of a possible borrower bankruptcy.

It is worthwhile for a lender to a newly-formed borrower to review the transactions under which the borrower received or will receive its assets to determine whether the transactions could be subject to avoidance as fraudulent conveyances. The lender should also review transactions with affiliates to ensure that large claims are not likely to be brought against the borrower if one or more affiliates were to file for bankruptcy.

Insiders

Plan ahead to avoid being cast as an “insider” of the borrower.

Although rarely successful, a borrower, its shareholders or other creditors may sue a lender on the theory that the lender was at least partly responsible for the debtor’s finan-

cial difficulties. Such “lender liability” actions may arise where a creditor exercises significant control over its borrower, either by actively managing the borrower’s day-to-day affairs or by holding a significant equity stake in the borrower. The theory behind such suits is that the creditor has become the principal and the borrower, over which the creditor has control, its agent.

Even where a lender is not exercising pervasive control over the borrower, lender liability has been alleged where funding is terminated based on a “material adverse change” provision or upon default under a nonmonetary covenant in a loan agreement. Thus, lenders should be careful to document material defaults and seek legal counsel prior to termination of funding – for any reason – to avoid liability.

Bankruptcy Petition

Review the borrower’s proposed bankruptcy petition and related papers before they are submitted to the court.

A voluntary chapter 11 bankruptcy case formally begins with the borrower filing a petition for reorganization and other documents required by the bankruptcy code and rules. The borrower will have to address significant issues before it submits a single piece of paper. For example, it will have to gather volumes of information,

decide which affiliates — foreign and domestic — will join in the filing, and choose the proper venue in which to file the case.

It is not uncommon for a borrower to begin working with its creditors on a post-petition financing facility while the borrower prepares to file. In such situations, it is reasonable and common practice for a lender to review all proposed filings prior to the commencement of the case.

Collateral Package

Gather evidence about the value of the borrower’s overall collateral package for its loan even before the debtor files for bankruptcy.

The bankruptcy code precludes a borrower from using “cash collateral” for any purpose without the express

consent of its secured creditor or an order of the bankruptcy court. “Cash collateral” refers to certain types of property pledged by the debtor as security for a debt. The types of property include cash, negotiable instruments, documents of title, securities, deposit accounts and proceeds of items such as accounts receivable.

A debtor cannot use any cash collateral until its lender consents or the court approves such use. A debtor may not have a source of liquid funds with which to run its business other than the cash collateral. Accordingly, a borrower may seek an emergency order from a bankruptcy court permitting the use of cash collateral over a secured creditor’s objection. A bankruptcy court will override a creditor’s objections and permit the borrower to use cash collateral when the borrower can show that its use of the funds will not jeopardize the secured creditor’s ability to recover on its debt.

Proceedings on this issue are often conducted on an expedited and emergency basis because the survival of the borrower may depend on its immediate ability to obtain use of the cash collateral. For this same reason, courts are often willing to give great deference to the borrower’s evidence that the secured creditor will not be harmed by the borrower’s use of the cash. Thus, even prior to filing, a lender should be ready to defeat the borrower’s request by arming itself with strong evidentiary support on valuation of all its collateral (including expert testimony).

Insurance

Don’t depend on insurance proceeds.

A borrower in bankruptcy must maintain adequate insurance at all times, including casualty insurance, worker’s compensation and unemployment insurance and general public and product liability insurance. Once a borrower has filed for chapter 11, the law precludes an insurer from refusing to renew a borrower’s insurance policy if premiums are current.

Despite the fact that a lender may have negotiated to the contrary in a loan agreement, insurance proceeds received post-petition from a casualty loss may not be required to be turned over to the lender for application to the loan balance. As with other cash collateral, the borrower may be allowed to use the funds if it can demonstrate that the lender is adequately protected. However, depending on the jurisdiction, there may be ways to limit the borrower’s access to the funds. */ continued page 8*

significant than the same money spent on just the boiler.

The IRS issued a similar set of bright-line tests for the airlines in early 2001. A revenue ruling directed at the power industry is expected early next year.

PAKISTAN is expected to offer tax incentives, including an exemption from income taxes, for new power projects that use indigenous fuels.

The country needs another 5,529 megawatts in additional generating capacity by 2010 to meet expected demand. Mirza Hamid Hasan, an official in the Water and Power Ministry, said October 24 that both the income tax exemption and a reduced 5% customs duty on imported machinery and equipment that is not produced locally, will be part of a package of incentives the government plans to offer to induce private developers to build new power plants.

MAURITIUS won a round in the Indian courts.

Most inbound investment into India is run through offshore holding companies in Mauritius or Holland. Foreign investors go through the two countries in order to take advantage of favorable tax treaties. The main treaty benefit is the potential to escape capital gains taxes in India when the investment is sold.

Any holding company set up in Mauritius to invest into India must be a “tax resident” of Mauritius in order to benefit from the tax treaty. The Central Board of Direct Taxes in India issued a circular in April 2000 indicating that it would accept a certificate of tax residence from Mauritius without asking further questions. A court in New Delhi quashed the circular in May this year as part of a long-running battle to deny “shell” holding companies in Mauritius any treaty benefits. The */ continued page 9*

Anticipating Bankruptcy

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Prior to the debtor's bankruptcy filing, a lender can take steps to put itself in a better position when the "automatic stay" kicks in.

As soon as a borrower files its chapter 11 petition, claims against the borrower are put on immediate hold. This "automatic stay" stops almost all litigation, collection efforts, lien enforcement efforts and foreclosure-related actions. The scope of the automatic stay is extremely broad — it applies to virtually every type of action, whether formal or informal, against a borrower or its property. It is designed to provide a borrower with a breathing spell from its creditors and give it some immediate relief from the financial pressures that necessitated the bankruptcy filing. It gives the borrower the opportunity to address business problems and formulate a plan of reorganization to satisfy its creditors' claims.

However, the automatic stay benefits creditors as well. It prevents the arbitrary disposition of the borrower's property to creditors utilizing "self-help" remedies or racing to the courthouse to enforce state law rights ("grab-law"). The stay promotes equality of distribution of a borrower's assets by assuring that the borrower's business and property and the payment of its creditors are administered in an orderly fashion.

A lender can take steps prior to the borrower's filing that will enhance its position with respect to the subsequent imposition of an automatic stay. For example, it can make sure that funds the borrower receives from selling any property used as collateral for the lender's loan are segregated in a blocked account to prevent use of the funds without satisfying the requirements for use of cash collateral. In addition, a lender can require the borrower to keep all funds in the lender's banks so that the lender can impose an administrative freeze on them, which may not be prevented by the automatic stay.

It is also useful for a lender to keep in mind that by entering into a financing agreement after the borrower's filing or consenting to the use of cash collateral, a lender can require an automatic lifting of the automatic stay in the event of future default by the borrower.

Asset Sales

Know your rights if a sale of the borrower's assets is contemplated as part of the bankruptcy.

In a chapter 11 bankruptcy case, the sale of the borrower's operating business may be accomplished either by selling substantially all of the borrower's assets under section 363 of the bankruptcy code, or by confirming a plan of reorganization that provides for such a sale. The sale of stock in a nonbankrupt subsidiary can also be accomplished in either manner. Typically a sale under section 363 is preferred by purchasers because it is faster and can be accomplished early in the bankruptcy case. In addition, the sale removes the proposed purchaser from the disputes that usually arise between a borrower and its various creditors.

A creditor will have significant input into the timing and manner in which the borrower conducts its sale. The language in the financing documents relating to the application of sale proceeds is very important as well, particularly when the borrower sells its assets in pieces. A lender should pay careful attention to such documents. Plus, a pre-petition lender will have rights to object to a sale of substantially all the borrower's assets if the sale proceeds are not sufficient to satisfy all obligations under the loans. ☉

Tax Issues and Incentives For Windpower Projects

by Keith Martin, in Washington

The US government offers two significant subsidies through the tax code for generating electricity from wind. They reduce the cost of a project by almost 65%. State incentives reduce the cost on average by another 10%.

The problem with tax subsidies is smaller developers who tend to develop wind projects often lack the tax base to use them. There are several ways for developers in this position to get value for them or — put differently — there are tax efficient ways for institutional equity participants who want to acquire windpower projects to bid on them.

The main subsidy is a tax credit of 1.8¢ a kilowatt hour for generating electricity from wind. This credit goes to the owner of the project. It can be claimed on the output for the first 10 years after the project is first put into service. It is worth about 33.5¢ for each dollar in capital cost. For example,

an 80 megawatt project that cost \$88 million to build might expect a subsidy on the order of \$29.46 million. This is the present value of the tax savings from 10 years of credits. (The calculation assumes the typical project costs about \$1.1 million per megawatt to build, and each megawatt of capacity leads to output of 3,329 megawatt hours a year. It uses a 10% discount rate to distill the tax savings to a single figure.)

The other subsidy is the ability to deduct the cost of the project over five years as tax depreciation. In addition, new projects that are completed during a “window period” running from September 11 last year through December 2004 qualify potentially for a 30% “depreciation bonus.” The depreciation without the bonus produces about 29.77¢ in tax savings for each dollar of capital cost. The depreciation bonus adds another 1.57¢.

Section 45 Credits

Wind projects have qualified for a tax credit on output since 1994. The credit was originally 1.5¢ a kilowatt hour, but has increased to 1.8¢ due to inflation adjustments. The figure 1.8¢ was the credit for electricity sold during calendar year 2001. The Internal Revenue Service will not announce the figure for 2002 sales until next spring.

Projects must go into service by December 2003 to qualify. Congress is expected to extend the deadline. Both houses of Congress voted to extend it to December 2006 as part of a national energy bill that President Bush made a priority to get through Congress this year. However, House and Senate negotiators have been unable to reach agreement on a final bill to send to the president. The deadline could still be extended this year if Congress returns after the elections for a brief “lame duck” session in late November and December. The odds of an extension next year are good if there is none this year.

New Projects

Only “new” projects qualify for tax credits. The credits run for 10 years after the project is originally placed in service.

It is possible by spending money to upgrade an existing facility to improve it so significantly that it is considered “new” with the result that another 10 years of tax credits can be claimed on output. The IRS said in a 1994 revenue ruling that it would look at each unit of a turbine, tower and pad as a separate facility, and it would treat each such unit as brand new — thus qualifying for 10 years of tax / *continued page 10*

Supreme Court suspended the lower court action on November 18. A hearing in the case is expected early next year.

TRANSMISSION CREDITS puzzle the IRS.

Owners of independent power plants in the US sign interconnection agreements with utilities allowing their plants to connect to the grid. However, 60% of such agreements are filed with the Federal Energy Regulatory Commission unsigned because the parties cannot agree on terms. The commission is tired of acting as an arbiter so, in late April, it published a proposed model interconnection agreement that all generators and utilities would be required to use in the future. FERC hopes to publish a final agreement by the end of the year.

Utilities make generators pay the cost to connect their power plants to the grid. There may be both “direct” costs of radial lines and circuit breakers to link into the grid and also “system upgrades,” or improvements to the grid itself to accommodate another power plant.

Under the proposed model agreement, utilities would be required to return any money that a generator advances to pay for system upgrades. FERC believes that utilities should charge the cost of such upgrades to all users of the grid through transmission tariffs rather than make the generator pay the cost. However, there is a timing problem. The utility must make the grid improvements before it can collect the cost through its tariffs. Therefore, some utilities ask the generator to advance the funds for the upgrades and then award the generator “transmission credits” for the amount that the generator can work off against future charges for wheeling electricity from the generator’s plant. In cases where the generator has no need for transmission credits, the utility returns the advance dollar for dollar as it collects from someone / *continued page 11*

Wind Tax Issues

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credits — if the cost of the upgrades accounted for more than 80% of the unit's value after the renovations.

Haircut

The credit is subject to a “haircut” to the extent the project benefited from tax-exempt financing, federal, state or local

Tax benefits pay as much as 65% of the capital cost of wind projects in the United States.

government grants, other tax credits, or “subsidized energy financing.” An example of subsidized energy financing is “governmental programs to compensate financial intermediaries for extending low-interest loans to taxpayers who purchase or construct qualifying facilities.” Only subsidies paid by a government in the United States are taken into account. Thus, for example, export credits from Denmark or Germany on equipment purchased in those countries would apparently not reduce the credit.

The haircut is calculated by putting in the numerator of a fraction the amount of the tax-exempt bonds, government grants or other benefits. The denominator is the total capital cost of the project.

Once tainted, a project remains tainted even in the hands of future owners. However, additional capital spending on improvements has the effect of reducing the haircut since this increases the denominator.

The wind industry has worked hard to persuade state legislatures to enact their own tax incentives, but perhaps without realizing — at least initially — that success at the state level could come at the expense of a smaller federal tax subsidy. Companies buying into existing wind projects should be sure to check during due diligence what sort of

state tax incentives are offered. At last count, 11 states — Arizona, California, Hawaii, Idaho, Montana, North Carolina, North Dakota, Oregon, Rhode Island and Utah — allow a tax credit that is a percentage of the cost of a wind project. Minnesota, New Mexico and Oklahoma have tax credits that are tied to output.

Tax subsidies that are tied to the cost of a project reduce the federal credit. Tax subsidies that are tied to the amount of output should not. The IRS ruled privately in 2001 that the

owner of a wind project did not have to reduce his federal tax credit on account of receiving “renewable energy credits” — or RECs — from the state where the project is located. The state requires local utilities to accumulate a certain number of RECs each year. Generators of electricity using renewable technologies are awarded credits by the state and then sell them to utilities.

The credits are based on output. In another private ruling in late 2001, the IRS said that there was no haircut in a case where a wind developer received a grant from a nonprofit entity set up and funded by an investor-owned utility. The utility formed the organization to encourage renewable energy projects. It was part of a deal with state regulators in exchange for permission to let the utility restructure. The IRS said the fact that the organization was created as part of a deal with state regulators did not transform the program into a government subsidy.

The credit begins automatically to phase out if the “reference price” for electricity ever tops 9.3¢ a kWh. It phases out as electricity prices move across the next three cents from 9.5¢ to 12.5¢ per kWh. Thus, if the reference price in 2003 is 10.5¢, then taxpayers will qualify for only two-thirds of the normal credit that year. (The 9.5¢ is adjusted for inflation. The 3¢ range is not.)

There seems little danger of a phaseout in the near term. The IRS said the reference price for wind electricity was 5.54¢ in 2001. The reference price is the average price at which such electricity was sold in the United States during the year. Only sales under post-1989 “contracts” are taken into account. Thus, spot sales through power pools are not counted.

Location

The project must be in the United States to qualify. “United States” is defined broadly to include US possessions, like Puerto Rico, the US Virgin Islands and Guam. There is no bar against selling the electricity across the border — for example — into Canada or Mexico. However, Canada recently complained to the World Trade Organization that the United States is using so-called section 29 tax credits to reward US producers of syncoal — some of which is sold in Canada at subsidized prices that make it hard for Canadian coal companies to compete.

Whose Credit?

The credit belongs to the company that is the “owner” of the power plant and the “producer” of the electricity. It must be both. Thus, for example, if Company A owns the power plant but leases it to Company B, neither will qualify for tax credits since one is the owner and the other is the producer.

A contract operator of a power plant is not the producer. The company hiring the operator is still considered the “producer” as long as the operator contract is not recharacterized by the IRS as some other relationship due to profit sharing or other unusual contract terms.

Electricity Sales

Tax credits are triggered by sale of the electricity to an “unrelated person.” In general, the electricity purchaser must be unrelated to the owner of the power plant. The IRS has ruled privately that there can be up to 50% overlapping ownership. Thus, for example, a utility can own up to 50% of a power plant in partnership with a developer — and claim half the tax credits — and also buy all the electricity.

Congress voted in 1999, after lobbying by the California utilities, to deny section 45 tax credits to any wind project that a taxpayer places in service after June 1999 to the extent the electricity is sold under a power sales agreement with a utility signed before 1987. The only exception is if the contract is amended to limit the electricity that can be sold under the contract at above-market prices to no more than the average annual quantity of electricity supplied under the contract in the five years 1994 through 1998 or to the estimate the contract gave for electricity output. “Above market” means for more than the avoided cost of the electricity to the utility — or the amount the utility would have had to spend itself to generate the electricity — at time of delivery. / *continued page 12*

else to move power across its grid from the generator’s power plant.

Various utilities have submitted ruling requests to the IRS asking for confirmation that such an arrangement should be viewed in substance as a loan or deposit by the generator to the utility. This would mean the utility would not have to report the system upgrade payment as income.

The IRS said in October that it was “tentatively adverse” to issuing such a ruling to the first utility in the queue. However, IRS officials appeared to be more comfortable with the proposed tax analysis after a meeting in November. The issue was still unresolved as the *NewsWire* went to press.

The proposed model agreement would require all utilities to repay system upgrade payments from generators over a period no longer than five years with interest, so long as the utility continues to receive revenue from someone for moving electricity that originated at the generator’s plant during that period.

The tax issue is important because, if a utility must report such payments from a generator as income, then it will require the generator to “gross up” the payments for the tax cost.

SOME SWAP TERMINATION PAYMENTS can be reported over time.

The IRS said in November that when one party makes a termination payment to get out of an interest rate swap, the other party can report its gain over the remaining period the swap would have run. This assumes that the underlying loan against which the swap served as a hedge remains outstanding. If the loan is also retired, then the remaining gain must be reported at that time.

The IRS analysis is in Revenue Ruling 2002-71. The swap in the ruling was used as a hedge. The rules for other types of swaps used as hedges — for / *continued page 13*

Wind Tax Issues

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This provision could come into play if an existing wind project is sold to a new owner.

Other Rules

Tax credits cannot be used by a company to reduce its corporate income taxes below a floor. The floor is 75% of the company's regular tax liability or the amount it would owe under the alternative minimum tax. Any credits that go

The most common approach for financing new wind projects is a "partnership flip" structure.

unused because of this limitation can be carried back one year and forward for 20 years.

Wind credits are almost impossible for individuals, S corporations and small, "closely-held" C corporations to use. (A "closely-held" C corporation is one in which five or fewer individuals own more than half the stock.) That's because the credits are subject to passive loss rules that limit these types of taxpayers to using them solely to offset income from other "passive" investments. To avoid this problem, the taxpayer must be involved personally in the day-to-day operation of the project in a material way. The passive loss rules do not apply to larger companies.

Structures

Project developers often have too little tax appetite to use the tax credits efficiently. There are ways to transfer tax credits to other companies that can use them.

The simplest approach is to sell the project. The developer can be hired back as the operator or in other capacities.

The IRS ruled privately in 1994 that a developer could sell interests in his project to limited partners and remain the general partner. The partnership planned to hire the developer as the operator for a fixed fee "plus a variable fee

dependent on the [project's] productivity." It also planned to pay the developer a percentage of gross receipts under a separate contract for handling administrative chores for the partnership.

Probably the most common approach recently for financing new projects is a "partnership flip" structure. The developer and an institutional equity form a partnership to own the project. Taxable income, loss and cash are split 99.9% to 0.1% in favor of the equity until the later of 10 years or when the equity reaches its target internal rate of return. After that, the percentages flip in two stages to something like

between 40% and 70% for the developer — and then again after 20 years to 80% or 90% for the developer — with the balance to the equity. There are many variations on this theme. The developer gets some return until the first flip in the form of fees for acting as the general partner and for operating the facility. The

partnership borrows the project cost from a bank. The partners agree to make capital contributions when construction is completed to pay down the construction debt to the level of the permanent debt, and then to make ongoing capital contributions to the partnership in the amount of the section 45 tax credits to cover debt service on the permanent debt. In effect, the partnership is borrowing against the future tax credits. The bank will not take tax risk that the credits are not there, but it will take operating risk.

Banks typically lend 75% of the cost during the construction; the gap is closed by getting the construction contractor and turbine vendor to agree to defer 25% of their fees. The permanent debt funds at the level of 50% to 55% of capital cost. Banks insist on a 1.4 coverage ratio. About half the coverage ratio is met through the capital contributions tied to tax credits.

The IRS has approved a "pay-as-you-go" structure for the sale of existing landfill gas and synfuel projects. Under a pay-as-you-go structure, the developer sells the project to an institutional equity participant for an amount in cash plus contingent payments over time that are a percentage of the tax credits. The IRS requires that the contingent payments be no more than 50% of the total purchase price in present-

value terms. The developer can be hired to operate. Institutional equity using such structures usually require the developer to get a private letter ruling on the structure from the IRS. The equity usually has an option to unwind the transaction if the developer cannot get a favorable ruling. If the project unexpectedly runs operating deficits, then tax credit payments are diverted to cover operating costs, although the equity may remain liable to the developer for the amount ultimately with interest.

A pay-as-you-go structure should also work in theory to transfer section 45 credits in wind deals. However, it has not been used to date in practice. Unlike synfuel deals, the tax subsidy for wind projects is not found money; this is not a case where \$50 million in tax credits a year might easily be generated on a facility that cost as little as \$3 million to build. The wind credits are needed to cover the capital cost of the project. Therefore, any sale of an existing project is more likely to be structured as a transaction in which the new equity assumes the obligations of the original equity to make ongoing capital contributions tied to tax credits.

There is growing interest in the institutional equity market in wind projects. Strategic investors who are already in the power business may be willing to take construction risk; more traditional institutional equity appear for now to want to wait to come into the deal until the project is placed in service. Current yields in wind deals are on the order of 9% unleveraged for institutional equity participants and 10.5% to 12% for strategic investors who are willing to take construction risk. Construction takes as little as six months. Leveraged equity returns are as high as 14 to 18% in the current market. Investors in synfuel projects speak in terms of the projects costing X¢ per dollar of tax credit for an investor to buy in. Investors in synfuel projects are having to pay currently as much as 90¢ to \$1.25 per dollar of tax credit. For various reasons, the wind market does not speak in similar terms.

One area of active evolution in structures in the sharing ratios among partners. Many people ask whether it is possible to share some benefits among partners in a project in a different ratio than is used for tax credits. IRS regulations require that section 45 credits must be shared among partners in the same ratio as they share in “receipts.” The regulations do not define “receipts.” The IRS ruled privately in 2001 that tax depreciation can be shared among partners in a different ratio than section 29 tax credits, which operate the same way as section / continued page 14

example, to hedge commodity risk — are more complicated.

ADVANCE PAYMENTS guidance is expected soon.

Merchant power companies sometimes try to structure payments from utilities for electricity as “advance payments” allowing the amounts to be reported as taxable income over time. An advance payment is a payment for “goods” to be delivered in the future. The payment can be reported for tax purposes over the same period the goods are delivered. This approach is sometimes used when a merchant power company receives a payment from a utility to “buy down” the price for electricity under a long-term contract. The buydown payment is structured so that it qualifies as an advance payment for electricity to be delivered over the remaining term of the contract in the hope that the buydown payment can be reported over the same period.

The IRS is working on guidance about advance payments. Sharon Kay, a US Treasury official, told an American Bar Association meeting in October that the guidance will address when payments are considered for “services” rather than “goods.” Only payments for goods can be deferred. The guidance is also expected to address renewable and multiyear contracts.

A LEVERAGED PARTNERSHIP transaction is under attack from the IRS.

With many power companies trying to sell assets to raise cash to make debt payments, there is a premium on finding a way to do so without triggering taxes on gains. Lower taxes mean more cash for the power company.

One approach some companies have considered using is to sell the assets through a leveraged partnership. The seller contributes the power / continued page 15

Wind Tax Issues

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45 credits. There is room for argument about what else can be shared differently.

Depreciation

Most windpower projects qualify for tax depreciation over five years using the 200% declining balance method.

The month when a project is placed in service can affect

An issue to watch on due diligence is some state tax incentives lead to a “haircut” in the federal wind credit.

the first-year depreciation allowance. *Pro formas* for projects sometimes overlook this. The US tax laws make an assumption that all assets put into service during a year go into service in the middle of the year (for example, on July 1 for companies paying taxes on a calendar-year basis). This means that the first-year depreciation allowance is one half what one would normally get. This “half-year convention” is built into the depreciation tables. However, if a company places more than 40% of its assets in service for a year during the last three months, then it must calculate depreciation that year using a “mid-quarter convention.” This means that assets put into service in the last three months of the year qualify for only 1/8th the normal depreciation allowance. Assets put into service during the first three months of the year qualify for 7/8ths of the normal allowance.

Many people also overlook the fact that a new partnership has a “short” tax year when it starts business. This will reduce the first-year depreciation allowance even further. This is a reason to own projects through existing entities. Where this cannot be avoided, an alternative is to have the partnership make an election under section 761 of the US tax code to treat the partners as if each owns an “undivided interest” in the wind project directly rather than through a

partnership. Such elections can only be made in cases where each partner takes his share of the electricity in kind.

A short year means that the first tax year of the partnership runs only from when its principal assets went into service to the end of the year. For example, if a new partnership is formed to own a wind project that is put into service on November 1, the partnership will have a tax year of only two months — and its gets only one month worth of depreciation — or 1/12th of the normal depreciation allowance — the first year (after taking into account not only the short tax year but also the half-year convention).

Depreciation Bonus

A special 30% “depreciation bonus” is available for new windpower projects placed in service during a window period that runs from September 11, 2001 through the end of 2004. The bonus

can also be claimed on improvements to existing projects during this period.

The 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. His depreciation allowance in the year the project is put into service is a) (30% of his “tax basis” in the project (basically the cost of the project) (plus b) depreciation for that year calculated in the regular manner on the remaining 70% of basis. For example, without the bonus, the first-year depreciation deduction on a wind project that cost \$100 million to build is \$20 million. With the bonus, it is \$44 million. Depreciation in later years is reduced commensurately, since only \$100 million in depreciation can be claimed in total.

A company will not be able to claim the bonus if it was committed to the investment before September 11 last year.

It is unclear how to apply this principle to many power projects. The IRS is expected to issue guidance by next June.

The House and Senate tax-writing committees weighed in during November with a draft technical corrections bill that the committees hope to put through Congress next year. Under this bill, a project would not qualify for the bonus if anyone had signed a binding construction contract before

September 11 last year to have the project built. The committee staffs are still debating whether equity investors who form a partnership during construction with the developer of a project that does not qualify for a bonus would still be able to claim a bonus on their spending after they become partners to complete such a project.

The depreciation bonus can only be claimed on assets in the United States. Assets used in US possessions, like Puerto Rico and the US Virgin Islands, also qualify. The bonus cannot be claimed on property that has been financed with tax-exempt bonds or that is “used” by a municipality.

Only the first company to put the asset in service qualifies for a bonus. The goal is to encourage US businesses to buy new equipment — not churn used assets.

Projects that are placed in service in 2004 after September 10 that year will only qualify for the depreciation bonus if a binding contract to acquire the project is signed or — in cases where the taxpayer is building the project himself — if construction begins no later than September 10.

There has been speculation in Washington that the deadline to place projects in service will be extended. Five Republican members of the House Ways and Means Committee are already on record as in favor of making the depreciation bonus permanent. ☉

Texas Wind Projects

by James Scarrow, in Washington

A program enacted just last year in Texas to encourage the generation of electricity from renewable energy has helped fuel a boom in the installation of wind projects in that state. Wind farm developers and policymakers in other parts of the country can learn valuable lessons from the Texas experience.

Proliferation of RPS Programs

In recent years, a growing number of states have adopted renewable portfolio standards — called “RPS” — requiring electricity retailers within the state to supply a minimum percentage of retail load with electricity generated from qualified renewable energy sources, such as wind, biomass and small-scale hydro. Eleven states, representing about one-third of total US electricity consump- / continued page 16

plant to a partnership. The buyer contributes assets that generate cash. The partnership then borrows against the cash-generating assets and distributes the borrowed funds to the seller to redeem most of its partnership interest.

Under the IRS regulations, such a transaction will ordinarily be recharacterized as a “disguised sale” of the power plant if the seller contributes assets and is distributed cash within two years by the partnership. However, IRS regulations make an exception where the cash is money the partnership has just borrowed within the last 90 days, and the debt at the partnership level is “allocable” to the partner to whom the cash is distributed. Sellers make sure the debt is allocable to them by guaranteeing repayment of the partnership debt. This gets the assets off the seller’s hands and cash to the seller without an immediate income tax.

However, an internal IRS memorandum made public in November takes issue with the transaction. The IRS national office argues in the memorandum that the transaction in fact is a disguised sale. It suggests a number of grounds for attacking the transaction. One is that the guarantee of the partnership-level debt by the seller is a “sham” since the seller is a special-purpose entity that is too undercapitalized to make good on the guarantee.

The agency also suggests arguing that the transaction is in substance a sale of assets, despite the form. The IRS suggests this argument can be used where the seller announced an intention to sell assets and negotiated for such a sale before trying to structure the transaction to save on taxes.

The IRS memorandum is ILM 200246014.

CALIFORNIA reduced the tax grossup rate that utilities are authorized to collect on “contributions in aid of construction.”

The reduction is / continued page 17

Texas

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tion, now have some form of RPS program. Other states are actively considering instituting such programs.

Each state RPS program is unique. However, each program addresses six large issues. They are 1) the types of resources that qualify as being “renewable” (for example – hydropower projects over a certain size are usually excluded), 2) the ultimate goal to be attained, often expressed as a percentage of the state’s total retail load, 3) a phase-in schedule, 4) the manner in which electricity retailers are allocated responsibility for achieving the goal, 5) whether renewable energy credits can be traded among retailers in order to achieve compliance, and 6) the penalties for noncompliance.

Texas RPS Program

The Texas RPS program was adopted in 2001 in conjunction with the opening of the state’s retail electricity market. The RPS calls for 2,000 megawatts of new renewables to be installed by 2009, with interim goals of 400 megawatts for years 2002 and 2003, 850 megawatts for 2004 and 2005, and 1,400 megawatts for years 2006 and 2007.

To achieve this goal, each electricity retailer in Texas is allocated a specific number of megawatt hours of renewable energy for which it is responsible, based on the retailer’s share of the statewide electricity retail market. The allocations are made assuming a capacity factor of 35%. (The capacity factor represents the actual output from a facility relative to its maximum potential output over the

same period of time. Because of the intermittent nature of wind, a capacity factor of 35% for a wind farm is typical.) As such, the state-wide RPS requirement of 400 megawatts of new renewables capacity for calendar year 2002 translates into 1,226,400 MWhs of load that must be supplied with qualified renewable energy for that year (400 mW x 8,760 hours/year x 35%). An electric retailer in Texas having a 5% share of the state’s retail electricity market would therefore be responsible for 61,320 MWhs.

The Electric Reliability Council of Texas, or “ERCOT,” administers the state’s renewable energy credit program, which is the mechanism through which retailers achieve compliance with RPS requirements. Under this program, ERCOT distributes renewable energy credits, or “RECs,” each quarter to certified generators of renewable energy. Each REC represents all of the renewable attributes associated with 1 MWh of renewable electricity production. The generators can sell the RECs to other retailers or to other third parties, who can then choose to use, sell or bank the RECs. In this way, the renewable “attributes” of the energy are unbundled from the commodity electricity. Accounts administered by ERCOT track the accumulation and transfer of RECs. RECs expire in three years if not otherwise retired before then.

No later than March 1 of each year, beginning in 2003, ERCOT will allocate among electricity retailers the statewide REC requirements for the previous calendar year. The retailers then have until March 31 to procure any additional RECs they may need to meet their obligations for that year. If the retailer fails to meet its requirement by retiring the necessary number of RECs, then it is subject to a fine of up to \$50 for each MWh by which it fell short.

Gusher of Wind Projects

The Texas RPS program, in combination with a federal tax credit of 1.8¢ a kWh for wind producers, resulted in a Texas-style gusher of wind projects. In 2001 — the first year of the Texas program — 915 megawatts of new wind power projects were installed in Texas, representing more new wind generation than had ever been installed in the entire country in any other year, according to Randall Swisher, executive director of the American Wind Energy Association. The rate of new wind farm installations slowed in late 2001 and early 2002 as a result of the expiration of the federal production tax credit in December 2001. However, with the extension of the tax credit in March 2002, installations

<i>State RPS Programs</i>	
<i>State</i>	<i>RPS Goal</i>
Arizona	1.1% by 2007
California	20% by 2017
Connecticut	6% by 2009
Maine	30% by 2000
Massachusetts	4% by 2009
Nevada	15% by 2003
New Jersey	4% by 2012
New Mexico	10% by 2007
Pennsylvania	varies by utility
Texas	2880 mW by 2009
Wisconsin	2.2% by 2011

Source: American Wind Energy Association

picked up again and the Texas Public Utilities Commission expects an additional 500 megawatts of new wind installations to come on line by the end of 2002.

REC Trading Activity

At the same time that wind farm construction in Texas was setting records, the secondary market for RECs was getting off to a slow start. Trading in RECs opened in July 2001, but very few transactions were entered and REC prices hovered at around \$4/mWh. Light trading and low prices continued through the remainder of 2001 and into the beginning of 2002. Then, as the RPS program's first settlement date of March 31, 2003 approached, both REC prices and the volume of REC transactions began to rise steadily.

From March through October 2002, the price of RECs rose more than 400%, from about \$4/mWh to \$17/mWh, according to Randy Lack, senior broker and principal of Emission Credit Brokers Inc. Lack said some experts believe that REC prices could be headed to \$40/mWh by March 2003, before prices are expected to drop back down as additional capacity is installed in coming months.

At today's price of \$17/mWh, the price of RECs — which, it should be remembered, does not include the price of the electricity but only its renewable attributes — is approaching 50% of the price of peak power on the Texas spot market. Put another way, the market value of RECs in Texas currently represents about one third of the overall commercial value of the renewable energy product. According to Lack, approximately 200,000 mWhs of RECs were traded in October 2002 and trading activity is expected to remain high through March 2003.

Notwithstanding expectations that REC prices will drop next year, it is difficult to predict future REC prices with any certainty. While the near-term supply of renewable energy sources in Texas is known to a fair degree of accuracy, as is the number of RECs required each year to meet RPS program goals, other variables affecting prices are less understood. First, there currently are four electricity retailers in Texas that give their customers the option of selecting a "green choice" plan through which the customer pays a premium rate in exchange for the retailer's commitment to purchase more renewable energy than otherwise required by the RPS program. As these four — and perhaps additional — retailers market green energy, there will be an increased demand for renewable energy, which will / continued page 18

IN OTHER NEWS

temporary. It will apply from July 1 this year and not back to September 11, 2001 as was requested.

California allows utilities that receive contributions in aid of construction from developers to charge the developers additional income taxes the utilities have to pay upon receiving such contributions. The amount of such charges varies between 34% and 37% of the contribution — the so-called "grossup rate" — depending on the electric utility receiving it.

In May this year, four California utilities lowered the grossup rate they have been using temporarily to 27%. The reduction was attributed to the lower tax burdens the utilities experienced as a result of the bonus depreciation the Bush administration has made available to them for certain investments made after September 11, 2001. The utilities have made this lower grossup rate effective as of July 1, 2002.

The Bay Area Rapid Transit District requested that the lower grossup rate apply retroactively to September 11, 2001 since investments made after that date qualify potentially for the depreciation bonus. The utilities have advanced various reasons, including administrative difficulty, for why the July 1, 2002 effective date should not be changed.

BART put its proposal on the agenda for a California Public Utilities Commission meeting in November. However, the commission failed to act on the proposal and, according to CPUC staff, it is expected to be withdrawn.

SALES TAX liability follows the assets in California unless the buyer receives a certificate from the State Board of Equalization that the seller has paid all sales or use taxes due, a state appeals court ruled recently.

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Texas

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Texas RECs per mWh			
Year	Bid	Offer	Last Trades
2002	\$15.50	\$18.00	\$17.25
2003	\$ 7.50	\$11.00	\$ 8.50
2004	\$ 7.00	\$10.00	—

Source: Emission Credit Brokers, Inc.

tend to drive REC prices higher. Nobody knows what the demand for green power will turn out to be, nor the precise way in which such demand would result in REC price increases. Second, just because additional wind farms are being built in Texas does not mean that all of the associated RECs will be available in the market. As with any other tradable commodity (particularly a relatively thinly-traded one), owners of large blocks of RECs could elect to keep them out of the market in order to support prices. Indeed, one broker suggested to the NewsWire that the presently

Prices for "renewable energy credits" in Texas may peak next year at as much as \$40 an mWh.

high price of \$17/mWh for RECs is due in part to such "market-maker" behavior.

REC "Offtake" Agreements

The ability of wind farms to sell RECs as a product separate from electricity means that wind farms might be financed based not only on revenue from power offtake agreements (and production tax credits), but also from the sale of RECs, either through long-term sales agreements or by selling RECs on a "merchant" basis.

Interviews conducted by the NewsWire indicate that in

each of the eight wind farm projects built in Texas during 2001, the power purchaser was also the purchaser of the RECs. Some of these offtakers retained all of the RECs, while others retained some of the RECs and sold the excess in the market or (in two cases) through multiyear REC supply agreements with third parties. It is unclear whether owners of future wind projects will sell RECs and electricity as an aggregated product. However, at least one project under development has entered into separate ten-year offtake agreements (with separate offtakers) for electricity and RECs respectively. Although the commercial terms of these agreements are not publicly available, the long-term firm price for the RECs is likely to be in the neighborhood of \$4/ to 5/mWh. While certainly not representing a large percentage of the cash flow to be generated by the project, this revenue stream is being used to support the overall financing structure.

Going Forward

It is too early to tell whether the other states will follow Texas' lead in establishing systems of tradable renewable energy credits. If a federal renewables mandate is enacted next year as part of a national energy plan, this may make states less likely to act on their own. Parties to long-term offtake agreements for all renewable energy projects — not just wind — would be well advised to allocate clearly REC ownership as between owner and offtaker, even if the project is in a state that does not currently have any form of RPS legislation. With the number of states with REC programs growing and the prospect for cross-state markets for RECs real, the project finance community should not ignore the potential value of RECs.

More broadly, developers and owners of wind projects should be on the look-out for innovative ways to monetize the environmental benefits and good will generated by these projects. For example, a developer of a wind farm in Texas has negotiated to sell naming rights for the wind farm to a third party that is hoping to benefit from its name being associated with an environmentally friendly project even though the party has no other connection to the project. ☺

UK Wind Projects

by Adrian Congdon, in London

Interest is increasing across the world in renewable sources of energy, especially wind. The commitment is perhaps greatest in Europe. Germany has half the installed windpower in Europe, and a third of that in the world. In the United Kingdom, the government has attracted attention by introducing a scheme under which suppliers of non-renewable energy pay financial penalties, the proceeds of which are distributed among those supporting renewable sources. At the same time, conscious of the limited space inland, the UK government is promoting the construction of wind farms off the coast: 18 agreements for such projects have been signed so far.

This article looks at the “renewables obligation” — as the law in the UK is called that promotes use of renewable energy — and at offshore wind farms in the UK.

Renewables Obligation

Since earlier this year, every *supplier* of electricity in the UK has been under a “renewables obligation,” meaning that it has to pay £30/mWh for electricity supplied from nonrenewable sources such as coal and gas. A supplier for these purposes is not a generator; it is someone who buys electricity from a generator and resells it to users. An example of a supplier is London Electricity plc.

Generators using renewable sources such as windpower are awarded renewables obligations certificates — called “ROCs” — which exempt the holders from having to pay this penalty.

The proceeds from the penalties do not go to the government: instead, they are distributed among renewable electricity generators and other holders of ROCs. This dynamic creates a market for ROCs. The generators can sell them for at least £30/mWh, effectively receiving something for nothing.

Suppliers have an interest in obtaining ROCs, not just because they will thus avoid having to pay the £30/mWh penalty, but also because of the right to a share of the penalty proceeds. The market has yet to settle down, but — in September 2002 — ROCs were at one point trading at £48/mWh.

Generators get value for their ROCs by / *continued page 20*

IN OTHER NEWS

The case is a warning to buyers to insist on a tax certificate at closing.

In the case, certain California taxpayers agreed to purchase business assets from a seller and placed a portion of the sales price in escrow, to be released when the SBOE issued a certificate that the seller owed no sales or use taxes. Before closing, the buyers’ escrow agent received multiple creditor claims against the seller for amounts exceeding the escrowed funds, including claims from the IRS. The escrow agent then filed an “interpleader” complaint in court naming as defendants both the SBOE and the IRS to let the two tax agencies fight it out between themselves over who was entitled to the money in escrow. However, the SBOE disclaimed any interest “it my have in the [escrowed] funds.”

Later, the SBOE held the buyers personally liable for failing to withhold the amounts the seller owed in unpaid sales and use taxes under a “successor liability statute.” The court found that the buyers failed to comply with the literal words of the successor liability statute because, so long as a claimant superior to the SBOE — the IRS — had rights to the money in the escrow account, the buyers did not “withhold” sales taxes at closing as required by the statute. The court also said the escrowed funds were released before the SBOE produced a certificate clearing the seller of any tax liability. It was irrelevant that the SBOE had a chance through the interpleader action to get the escrowed funds but left them for the IRS.

The case is Schnyder v. State Board of Equalization.

ALABAMA lost again in its effort to collect property taxes on merchant power plants at the higher rates for utility property.

Alabama divides property into four classes for property tax assessment. “Class 1” utility property is / *continued page 21*

United Kingdom

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selling them for cash. There is no inherent reason why a generator should not sell the ROC to someone other than the person to whom he sells the electricity, but this is not very common in practice. Usually, the "supplier" buys the ROCs along with the electricity.

Prices for ROCs might differ from one project to the next. The price is a function of such things as the flexibility of the generator, the length of the contract, the technology and size of the renewables project, and the general apportionment of risk sharing. For example, the greater the commitment the

"Renewable obligations certificates" in the United Kingdom were trading for £48 a mWh in September.

generator can give in respect of reliability and flexibility, the higher the price the supplier should be willing to pay for ROCs. Conversely, the longer the term of the offtake contract, the more willing the generator may be to lower the price. Despite the fact that there will be two separate price negotiations, one for electricity and the other for the ROC, the existence of the ROC will be key. A political act resulting in the abolition of ROCs is likely to lead to the termination of the offtake contract; and lenders' funding of a renewables project will be contingent on the continuing existence of the ROC mechanism.

In the renewables obligation, the British government has developed a market-based policy for reducing greenhouse gas emissions rather than one based on taxation. The European Commission is planning an EU-wide emissions trading scheme of which ROCs will form part. (They will be cancelled for domestic purposes to the extent that they are used in the wider scheme.) The government has given a commitment that ROCs will be around until at least 2027; and, while this does not eliminate political risk, it should be of comfort to sponsors and lenders wishing to take advantage of the scheme.

A final observation on the financial incentives created by ROCs is that they may end up as victims of their own success. The less renewable energy is generated, the more £30/mWh penalties will be paid and the greater the rewards for ROC holders. However, as more renewable sources come on line, there may be fewer people paying penalties and so less to be shared round the greater number of ROC holders.

Offshore Wind Farms

The British government is also providing capital grants towards offshore wind projects.

A preliminary sum of some £70 million has been

allocated for the development of offshore windpower over the next three years. It is unclear whether this will be targeted or thinly spread, although it appears likely it will be applied to up to 40% of a project's eligible costs (in order to comply with EU competition law). Some might argue that it would be preferable to subsidise the tariff

rather than construction since the subsidy would then apply only to the extent assets actually generate electricity and not to underperforming ones.

Wind farms have been constructed inland over the past dozen years or so, but with improvements in turbine technology, wind farms off the coast have increased in appeal. Space is constrained on a small island, and there is a limit to the number of places - almost inevitably places of natural beauty - in which wind farms can be located. Onshore wind farms have typically been around 10 to 20 megawatts in size. Offshore, 20 megawatts is seen as a minimum and projects of around 100 megawatts are contemplated. Indeed, the proportionate cost of an offshore wind project is, at an estimated £1,000 a kilowatt, some 30% more than that of an onshore wind farm. This means there is an added incentive to build larger projects. Economy of scale and bigger turbines may lead to higher yields.

The Crown Estate, which owns the seabed, has entered into 18 agreements for lease of sites for offshore wind farms. Property held by the Crown Estate is, as the name suggests, owned by the Crown itself, technically the owner of last

resort of all land in the UK. The revenue from these leases will however, like all Crown Estate revenue, be assigned to the Treasury and thus be under the control of the government. It is envisaged that a similar number of leases will be made available in mid-2003.

In order to pre-qualify for the right to a lease, an applicant must have at least £50 million in net assets, offshore development expertise and wind turbine experience. The financial standing requirements suggest that no such project can be nonrecourse. Exploration for, and extraction of, oil and gas from the North Sea over the past quarter century means there is plenty of offshore development expertise; but that is unlikely (at least at first) to be found in those with wind turbine experience. The result is that consortia will be formed.

The site for a project must be within 12 miles of the coast and not more than 10 kilometers from any other wind project. Each project must have a minimum generating capacity of 20 megawatts but no more than 30 turbines. In addition, no site can be more than 10 square kilometers. A successful applicant has a three-year grace period within which to decide whether to go ahead. On grant of the lease, the applicant has two years within which to commission the project. Each lease is for a term of 22 years, which includes one year at the end for decommissioning. The rent is broadly 2% of project revenues. Force majeure is at the tenant's risk, as is change in law (typical in UK government-promoted projects). The lease is granted subject to public rights of navigation and fishing.

Risks

While incentives have been put in place to make offshore wind farms attractive to investors — ROCs, capital grants and the generally favorable political environment being among them — there are a number of substantive risks that need managing.

Onshore wind turbines have typically been around 0.6 to 1.5 megawatts in size. The UK government expects that, owing to higher installation costs, turbines used offshore will exceed 2 megawatts. Taller turbines experience higher wind speed and thus should produce greater yields. Turbines are available currently with output of up to 4.3 megawatts, but bankability and syndication both demand a conservative approach that does not favor unproven technology. Lenders will look for an established name and the / continued page 22

assessed at 30% of market value. Single-family homes and farms are assessed at 10% of market value. Cars and trucks are assessed at 15%. All other property is assessed at 20%.

Alabama argued that a power plant that a Tenaska partnership owns and uses to supply electricity under a tolling agreement to William Energy should be assessed as class I utility property.

Two state courts have now said that the plant should be taxed at the lower rates for “other property.” In the latest decision, an appeals court said in October that the Tenaska project “bears none of the usual characteristics of a utility.” It has no obligation to serve the public, it has no power of eminent domain, and it is not subject to regulation by the Alabama Public Service Commission.

The case is State v. Tenaska Alabama Power Partners, L.P.

THE PARTNERSHIP ANTI-ABUSE RULES are getting broader use by the IRS.

IRS regulations warn that the IRS will deny tax benefits whenever a partnership is “formed or availed of in connection with a transaction the principal purpose of which is to reduce substantially the present value of the partners’ aggregate federal tax liability in a manner that is inconsistent with” partnership tax rules.

The authority the IRS has reserved for itself is so broad — and so vague — that many tax advisers assume the IRS will not invoke this rule unless a transaction falls into one of 14 fact patterns in its regulations.

However, Paul Kugler, the associate IRS chief counsel for partnerships, warned when he left the government last summer that the agency had rulings in the works that would invoke the rule in other settings.

The first such ruling may be a “field service advice” the agency released in late October. / continued page 23

United Kingdom

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history of operating hours for a particular turbine make, as well as for an independent engineer review. Warranties of at least five years duration are likely to be sought, and this means that the interests of the turbine supplier and the operator tend to conflate.

The turbine supplier is usually responsible for installing the turbine. It does not follow that lenders will be looking for

not just the construction phase, but also the first, say, five years of operation, subject to achievement of performance, warranty and availability obligations. This is the same approach taken to the construction and operation of gas storage facilities within salt caverns. However, the difference between such gas storage facilities and an offshore wind farm is that, after the first five years of operation, the geological risks inherent in a salt cavern should be in the past, while there will still be a need to carry out maintenance of a wind turbine in stormy seas.

Offshore wind projects present additional issues in risk allocation.

a single point of responsibility for all engineering, procurement and construction works. The turbine supply and installation works may be split from the balance of plant (for example, civil works onshore). Key risks to be allocated between the developer and the construction contractor include what happens if there is a shortage of cranes, the difficulty of raising turbines in a windy environment, and weather risk generally. How the weather risk is apportioned may well be contentious: the developer may take this risk in the construction phase, but the turbine supplier may be required to assume it during the warranty period.

Operation and maintenance services, and reliance on the turbine supplier's warranty, are matters of greater sensitivity in offshore projects than would be the case with an onshore wind farm. Unscheduled maintenance is likely to be required at times when accessibility is most difficult, during bad weather. Particular areas in which problems have arisen on existing offshore wind turbines have included gear boxes, cabling and blades coming off. The risks that the O&M contractor will be required to assume will be disproportionate to the financial rewards typically available to such a contractor in a power project. For this reason, there are merits in combining the construction and O&M functions and paying the construction fee on an amortized basis over

Finally, there is the offtake risk, or the question of who takes the risk of shortfall in dispatch of the generator. This is particularly sensitive in the UK following the introduction in 2001 of new electricity trading arrangements, or "NETA," under which a generator can face very high financial liabilities for dispatching,

in a half-hour period, a volume different than that which it notified centrally at least an hour before. Typically, offtakers are better suited than generators to manage this risk: for example, it can be hedged by way of derivatives in the electricity trading markets. The risk is most likely to materialize for reasons related to the weather. In addition, weather derivatives are available to protect against weather risk, and these should enhance both bankability and return on equity. The particular advantage they have over insurance policies is that no loss need be shown. In practice, the offtaker will tend to take the risk of non-delivery, but the one risk it will not take is the political risk of the loss of the renewables benefit.

Conclusion

The British government agreed at Kyoto in 1997 to reduce the country's greenhouse gas emissions by 12.5% by the period 2008 to 2012. It has an additional target of reducing carbon dioxide emissions by 20% by 2010 (against 1990 levels). To further this goal, it is aiming for 5% of UK electricity to be generated from renewable sources by 2003, rising to 10% by 2010. The "renewables obligation" fits well with these targets and its existence (together with the direction of EU policy) may give offshore wind projects the push they need. ☉

Wind Projects In Brazil

by *Martim Francisco M. Machado, with Machado Associados in São Paulo*

Precise measurements of wind speed carried out in Brazil in the early 1990's revealed the existence of a large potential for windpower generation, currently estimated at 143,000 megawatts. This potential has remained essentially unexploited. There are only eight small windpower plants in operation in Brazil today with a combined installed capacity of 21.4 megawatts.

This situation is likely to change — and rapidly. Developers have announced plans for 73 new windpower plants, mainly in the northeastern states of Brazil. These plants, which are expected to add approximately 5,532 megawatts to the system, will be fairly large, with an average installed capacity of approximately 76 megawatts. Eighteen of these plants will have an installed capacity of more than 100 megawatts, the largest one being the Redonda windpower plant, in the state of Ceará, with 167 wind turbines and an installed capacity of 300.6 megawatts. These new wind-power plants are supposed to enter into commercial operation over the next five years, but the projects face challenges getting constructed and financed. So far, developers — mainly international groups such as the Spanish Iberdrola and the French Electricité de France — have only obtained preliminary environmental licenses and other required authorizations.

Regulatory Framework

Windpower plants are subject to the same general rules that apply to hydroelectric and thermal plants. Wind projects are constructed and operated under 30-year authorizations issued by Agência Nacional de Energia Elétrica, or “ANEEL,” the Brazilian regulatory agency responsible for the power sector. These authorizations are issued on a first-come-first-served basis upon request of developers, without the need of complicated bidding processes or complex agreements between developers and Brazilian authorities. The authorizations are very simple documents that specify the basic terms and conditions for the project and its technical characteristics and location.

The Brazilian government adopted incentives for wind projects in December 2001. These incentives are available to all power producers using “alternative / continued page 24

IN OTHER NEWS

Two foreign banks held notes from insolvent borrowers. Since the foreign banks could not benefit in their own countries from bad debt deductions, they contributed the notes with built-in losses to a limited liability company treated as a partnership for US tax purposes, and later sold their membership interests in the LLC to an unrelated US taxpayer. The partnership did not have in place a “section 754 election,” and the notes in the partnership's hands retained the built-in loss. The unrelated partner tried to make use of its share of losses when the LLC later sold the notes at a loss.

The IRS invoked the anti-abuse rules to disallow the transaction. The transaction does not exactly fit in any of the examples. The one example to which the IRS pointed involved a case where losses were duplicated. In that example, the partner who contributed the loss property claimed a loss when his partnership interest was later redeemed, and the new unrelated partners again claimed the losses when the partnership sold the property at a loss.

In this case, there was no evidence that the losses were duplicated. The IRS itself pointed out this broader application: “We note that the anti-abuse arguments would be even stronger if additional evidence could be developed with respect to the benefit the [foreign banks] received as a result of the [transaction]. If the [foreign banks] received some tax benefit, either foreign or domestic, from the loss, the facts would more closely resemble the doubling of losses found in [the example cited] . . . and would strengthen the anti-abuse arguments.”

The IRS ruling discussing the transaction is FSA 200242004.

CERTAIN “ACQUISITIONS of control of a corporation” and any “substantial change in capital structure” will have to be reported to the IRS in the future. / continued page 25

Brazil

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sources of energy,” an expression that includes not only windpower plants, but also biomass thermal power plants and very small hydroelectric power plants. The incentives can be found in Law No. 10,438.

There are two different sets of incentives. The first one, referred to as the “Incentive Program for Alternative Sources of Electric Energy” (in its Portuguese acronym, “PROINFA”) is available to all producers using alternative sources of energy that qualify as “autonomous independent power producers,” or “AIPPs.” The second set of incentives, which is not designated by any specific name, is intended to benefit producers, whether or not qualified as AIPPs, using alternative sources of energy.

Developers have announced plans for 73 new windpower projects in Brazil.

Incentives: PROINFA

The first set of incentives is an assurance Eletrobrás will purchase all energy generated by the project under a 15-year power purchase agreement. Eletrobrás is a mixed-capital holding company controlled by the Brazilian federal government and is responsible, through its several subsidiaries, for almost 60% of all energy generated in the country.

Projects that qualify for such contracts are called AIPPs. To qualify, the owner must be an independent power producer that is unrelated to distribution, generation and transmission concessionaires in Brazil. In addition, an AIPP can only have the participation of a manufacturer of generating equipment if the local content of the generating equipment to be supplied to the AIPP is at least 50%.

There is one exception to the rule that only AIPPs qualify for 15-year contracts to sell their output to Eletrobrás. The federal government may authorize Eletrobrás to purchase

energy from producers not qualified as AIPPs, provided that the amount of energy purchased from such other producers does not exceed, during the first phase of PROINFA, 50% of all energy that Eletrobrás is required to purchase under that phase, and during the second phase of PROINFA, 25% of such energy. In addition, all energy offered by AIPPs must be covered by purchase agreements with Eletrobrás, so that no AIPP will be adversely affected by purchases from other producers.

PROINFA is divided into two phases with slightly different characteristics.

First Phase

During the first phase of PROINFA, AIPPs may offer to Eletrobrás all energy that they generate. However, this only applies to projects that are in operation by December 30, 2006. Eletrobrás is required to buy electricity from such AIPPs, but the total amount to be purchased during the first phase of PROINFA cannot exceed 1,100 megawatts. This limit represents a third of all energy expected to be purchased by Eletrobrás from AIPPs relying on alternative sources of energy under the PROINFA.

Since the amount of energy purchased by Eletrobrás during the first phase will probably be smaller than the total installed capacity of windpower plants in operation during this period, Eletrobrás will have to decide from which AIPPs to purchase electricity based on a “public invitation process.” Eletrobrás will initially invite all interested AIPPs to enter into power purchase agreements, but will contract first with those that, in addition to the ANEEL authorization, already hold “environmental licenses for installation” (“licença ambiental de instalação”), and then only with those that hold preliminary environmental licenses (“licença prévia ambiental”). All power purchase agreements must be signed by April 25, 2004.

During the first phase of PROINFA, Eletrobrás will pay more for electricity from AIPPs than it pays for electricity generated from traditional sources. Although the actual purchase price must still be determined, project owners are guaranteed by statute that the price will correspond to the

“economic value of the windpower,” and there will be a floor price equal to 80% of the national average tariff charged by distribution concessionaires to final consumers. As an illustration, from January through August 2002, the national average tariff charged to final consumers was, according to ANEEL, R\$140.06 per mWh. Therefore, the 80% floor would correspond to R\$112.05 per mWh. This amount is substantially higher than the so-called “normative value” — the limit for the electricity costs that can be passed through by distribution companies to their consumers and that has been recently established at R\$72.35 per mWh. (Due to its characteristics, the normative value functions as a “reference value” for the price of electricity sold by generators to distribution companies under long-term power purchase agreements.)

Obviously, the “economic value” of the windpower to be established by the federal government will be essential for the success of PROINFA. In light of the still high generating cost of windpower plants, these types of plants in Brazil will not be viable if the electricity price under the Eletrobrás contracts is set at a level close to the normative value.

Second Phase

The second phase of PROINFA will begin as soon as Eletrobrás has acquired a total of 3,300 megawatts from producers relying on alternative sources of energy under the first phase (which include the 1,100 megawatts allocated to windpower plants, and the 2,200 megawatts allocated to producers using other sources of energy). During the second phase, Eletrobrás will be required to purchase from wind, biomass and small hydroelectric projects an amount of electricity so that such projects account for 10% of all electricity consumed in Brazil.

Although 15-year power purchase agreements will still be available during this second phase, the electricity price in such contracts will be different from contracts signed during the first phase. In the case of windpower plants, the electricity price to be paid by Eletrobrás will be equivalent to the “economic value of the competitive energy” (instead of the “economic value of the windpower”), which is defined as the weighted average generating cost of new hydroelectric power plants with over 30 megawatts of installed capacity, and of new natural gas-fired thermal power plants. The “economic value of the competitive energy” will be calculated by the federal government.

However, windpower producers will / *continued page 26*

The IRS issued temporary regulations in mid-November requiring such reporting. The regulations are retroactive to transactions occurring after December 31, 2001. Reports are to be filed by attaching a Form 8806 to the income tax return that a corporation files for the year. Reports must be made by any domestic corporation participating in such a transaction.

Two types of transactions must be reported. One is an “acquisition of control of a corporation.” This occurs whenever stock representing control of a target company is distributed by its parent or such stock is acquired by another corporation for cash, stock or other property. “Control” means at least 50% by vote or value.

The other transaction that must be reported is any “substantial change in capital structure.” Examples of such transactions are a recapitalization, a merger, or a change in identity, form or place of organization.

Transactions do not have to be reported if they are within affiliated groups or the amount of cash and property provided to shareholders of the target corporation is less than \$100 million.

“DISQUALIFIED INTEREST” will not lose its taint, even if the borrower later removes the condition that led to its disqualification.

Section 163(j) of the US tax code prevents foreign parent companies from stripping earnings of their US subsidiaries by capitalizing the subsidiaries with debt and then trying to pull out the earnings as “interest” on the debt. Interest payments are deductible by the subsidiary, and they attract a 0% withholding tax at the US border under many tax treaties.

Section 163(j) denies an interest deduction for the US subsidiary in cases where the US subsidiary has a higher debt-equity ratio than 1.5 to 1 and its interest expense for the year exceeds 50% of its / *continued page 27*

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be entitled to receive a monthly subsidy called “additional credit” to compensate for the lower electricity price under their contracts with Eletrobrás. This subsidy will correspond to the difference between the “economic value of the windpower” (to be established by the federal government, but having a floor equal to 80% of the national average tariff

Brazil is moving toward a 10% renewables mandate.

charged to final consumers) and the actual energy price received under the power purchase agreement with Eletrobrás.

A central account — called the “CDE” — will be set up to pay the monthly subsidies. It will be funded with annual payments by concessionaires in the power sector under their concession agreements, fines imposed by ANEEL and, as of 2003, from annual quotas to be paid by all parties selling electricity directly to final consumers. The amounts on deposit in the central account will be managed by Eletrobrás.

Subsidies will be paid to wind projects only to the extent there is money in the account. Wind subsidies cannot exceed annually more than 30% of all amounts scheduled to be deposited into the central account during that year. Funds in the account are available for other uses. This could leave the account short of the amount required to fund the monthly wind subsidies fully.

More Incentives

A second set of incentives is available to all producers using alternative sources of energy, whether or not qualified as AIPPs, provided they sell their electricity directly to final consumers.

This set of incentives is very similar to the incentives during the second phase of PROINFA. Producers relying on

alternative sources of energy will be entitled to a subsidy corresponding to the difference between the “economic value of the windpower” and the “economic value of the competitive energy.” The basic difference is that producers will not have the right to sell their energy to Eletrobrás under 15-year power purchase agreements.

In order to be entitled to the benefit, producers must sell their electricity to “final consumers,” which excludes sales to generating companies, distribution companies and energy

traders, but includes sales to so-called “free consumers,” large industrial users who consume at least 3 megawatts and who are free to choose their electricity suppliers.

These subsidies are also to be funded out of the same CDE account that was discussed earlier.

Conclusion

Brazil is seeking to have 10% of its electricity supply come from renewable sources. The two new incentives adopted last December should help it meet that goal. The new Lula administration is committed to implementing them. They have already led developers to announce plans for 73 new windpower projects. ☺

Corporate Tax Shelter Disclosure

by Keith Martin, in Washington

The US government identified six broad categories of transactions in October that it wants corporations to report to the Internal Revenue Service as potential tax shelters.

Reporting is already required for corporate tax shelters, but the government recast the net more widely after deciding that too few transactions were being disclosed under the existing rules.

The IRS plans to study deals that are disclosed and rush out guidance in the future in cases where it believes tax results are unwarranted. However, the first reports using the

new broader definition of corporate tax shelter will not be received by the IRS until 2004. The new broader reporting requirements apply to transactions entered into on or after January 1, 2003. A company must report any tax shelter in which it participates by attaching a form to its tax return. Since most large corporations will not file their 2003 returns until September 2004, there will be a significant time lag before the new rules begin to have an effect (unless corporations are deterred in the meantime from entering into deals that will eventually have to be reported).

This is the third time that the IRS has tried to define what it considers a potential corporate tax shelter. Reporting of a narrower set of transactions has been required since March 2000.

Disclosure

Any corporation that participates “directly or indirectly” in a “reportable transaction” must attach a form with the details of the transaction to its tax return for each year the transaction affects its US tax position. A copy of the form must also be sent the first year to a special office the IRS has set up in Washington to monitor aggressive tax schemes.

A transaction is a “reportable transaction” under the latest IRS regulations released in October if it fits in any of the following six categories.

- It is on a list of transactions the government considers abusive — so-called “listed transactions” — or it is “substantially similar.” The IRS published an initial list of listed transactions in February 2000, but has updated it several times since then. The list now has on it 21 items. They include LLOs, or lease-leaseback transactions where a foreign entity or US municipality leases a power plant, gas pipeline, railcars or other equipment to a US institutional equity participant and subleases it back, certain tax plays involving foreign tax credits that are described in IRS Notice 98-5, “lease strips” and ACM Partnership-type transactions.
- The corporation participated in the transaction “under conditions of confidentiality.” A transaction fits in this category if the taxpayer’s “disclosure of the structure or tax aspects . . . is limited in any way by an express or implied understanding,” regardless of whether the understanding is legally binding. An example of an implied understanding is where the broker offering the deal describes it as “proprietary” or “exclusive.” The IRS suggested — perhaps facetiously — / continued page 28

income. Ordinarily, the focus is on interest paid to a foreign parent company. However, interest the subsidiary pays to a bank or other third party is also disallowed if the interest is paid on debt that a foreign affiliate has guaranteed (on the theory that this is no different than if the interest were paid to the foreign affiliate directly, which it then pays to the bank).

Disallowed interest is carried forward until the US subsidiary has the capacity to use it within the cap imposed by section 163(j).

A US company asked the IRS earlier this year for a private ruling that disqualified interest had lost its taint. The company had paid the interest to a bank. A foreign affiliate guaranteed the bank debt. However, by the time of the ruling, the debt had been refinanced without a guarantee. The interest in question was still being carried forward.

The IRS declined and ruled, instead, that the interest remained tainted. Its status as disqualified interest is determined in the year the interest is paid. That status is not changed by later events. The ruling is PLR 200243035.

MINOR MEMOS. A study in *Tax Notes Magazine* in November reported, “The effective rate of tax on profits generated by foreign affiliates of US corporations was more than halved between 1983, when it stood at 49.6%, and 1999, when it had declined to 22.2%.” This is not surprising when one considers that the 1990’s were a period when companies were adopting ever more elaborate ownership structures to reduce taxes on foreign projects. The study found that half the reduction in effective tax rates was due to shifting of earnings from project countries to tax havens. The other half was due to government decisions to cut taxes. In 1999, US multinational corporations reported that 45% of / continued page 29

Corporate Tax Shelters

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that it will accept that an offering is not confidential if “every person who makes or provides a statement, oral or

The US government ordered companies to report six types of transactions in the future as potential tax shelters.

written . . . as to the potential tax consequences” signs a written authorization permitting the company investing in the deal and all its employees, representatives and agents to disclose the deal structure and tax analyses to “any and all persons, without limitation of any kind.” The authorization must extend to disclosure of any “opinions or other tax analyses” the company was given.

- The corporation has contractual protection against the possibility that some of the tax benefits will be disallowed. Examples of contractual protection are an unwind clause, a right to partial refund of fees, fees that are contingent in the first instance on the tax benefits from the transaction, insurance against loss of tax benefits, or a tax indemnity. However, a tax indemnity from another participant in the transaction who had no role in promoting it — such as the tax indemnities that lessees typically give lessors in big-ticket lease transactions — is not a problem.
- The transaction is expected to allow the corporation to claim a tax loss of at least \$10 million in any single year or \$20 million in a combination of years either under section 165 of the US tax code or by virtue of a “sale or other disposition” of an asset, like a partnership interest. Operating losses and tax depreciation are not the types of losses the IRS has in mind. The thresholds to trigger reporting by partnerships and S corporations are half these figures.

- The expected tax treatment of the transaction for tax purposes is expected to differ from its book treatment by more than \$10 million in a single tax year. Reporting under this trigger only applies to public companies that are required to report financial information to the US Securities and Exchange Commission under the Exchange Act of 1934 and other companies with \$100 million or more in gross assets. The IRS has already made 13 exceptions where book-tax differences do not bother it, including disparities caused by differences in how assets are depreciated for book and tax purposes. Such disparities can be ignored. Jeffrey Paravano, a senior Treasury official, said in

November that the government is considering making as many as another 40 to 50 exceptions.

- The transaction is expected to generate tax credits of at least \$250,000 for holding assets generating the credits for fewer than 45 days. This trigger is aimed mainly at foreign tax credit plays.

Partnerships will be required to disclose transactions in which they participated, even though the partners must also report them.

The reporting will be on a new IRS Form 8886 that the agency is still in the process of developing.

Companies are barred from disposing of any documents “that are material to an understanding of the facts of the transactions, the expected tax treatment of the transaction, or the taxpayer’s decision to participate” in it. Such materials must be retained until the statute of limitations expires for the last tax year affected by the transaction. The new disclosure regulations are “temporary and proposed” and may undergo some further revision before they are reissued in final form. They are effective as written in the meantime.

Promoters

Existing IRS regulations require promoters of corporate tax shelters to register them with the Internal Revenue Service before the shelters are offered to corporations. These regulations have not changed. “Tax shelter” is defined more broadly

under them than under the new rules for taxpayer disclosure.

Promoters must register with the IRS in advance any deals about which the following three things are true.

First, the transaction must have “avoidance or evasion” of federal income taxes as a “significant purpose.” So-called listed transactions fall into this category automatically. Other transactions where federal income tax benefits are “an important part of the intended results” do also, but only where the promoter expects to offer the transaction to more than one potential participant. Thus, unless the transaction is a one-off deal that will never be repeated, it will trip this “avoidance or evasion” test.

Second, the transaction must be offered “under conditions of confidentiality.” This condition is not easy to avoid. There is implied confidentiality where the accountant, investment banker or other promoter pitching the idea leads the company to believe the idea is proprietary. The IRS has effectively issued a challenge to promoters: a transaction is not offered under conditions of confidentiality if the promoter signs a written agreement with everyone with whom he discusses possible participation “expressly authoriz[ing] such persons to disclose every aspect of the transaction with any and all persons, without limitation of any kind.”

Finally, the promoter must be expected to receive more than \$100,000 in total fees. Fees from all “substantially similar” deals the promoter does must be aggregated. Thus, if he expects to repeat the deal several times with other companies, the fees add up to a much larger number.

Advance registration applies to tax shelters offered after February 28, 2000. If a shelter was offered before, registration will be triggered the first time it is offered again after February 28. Registration must occur before interests in the transaction are “offered for sale.”

Deals are registered with the IRS by filing a Form 8264.

Tax maneuvers engaged in by some foreign companies also must be registered. These will be viewed as involving indirect participation by a US company — and, therefore, as potentially involving the “avoidance or evasion” of US taxes — if a US company owns at least 10% of the shares by vote or value of the foreign company that is the direct participant in the scheme. If the foreign company is a partnership for US tax purposes, ownership by the US company of at least a 10% capital or profits interest, or expected receipt of at least 10% of loss allocations, will be enough to require US registration.

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their foreign earnings were earned in 13 countries considered tax havens The IRS turned down a request by a utility in November for a “change in accounting method” that would allow it to depreciate certain tools and shop equipment — like lathes, band saws and hydraulic presses — over seven years rather than the 15 or 20 years it uses for its power plants. The IRS said the equipment belongs in the same depreciation class as the power plants. ☺

— *contributed by Keith Martin, Heléna Klumpp and Samuel R. Kwon in Washington.*

Corporate Tax Shelters

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Material Advisers

Existing IRS regulations require promoters also to keep a list for seven years of companies they persuade to invest in corporate tax shelters in case the IRS wants to see it.

However, the IRS broadened these rules in October. After this year, every “material adviser” will have to keep not only a list of participants, but also be available to supply information about the structure of the transaction and the tax

Promoters of the deals must register them in advance with the IRS before offering them to investors.

analysis to the IRS if so requested. The information must be retained for 10 years.

A “material adviser” is anyone who “makes or provides any statement, oral or written, to any person as to the potential tax consequences of the transaction.” However, he or she must receive a fee of at \$50,000. The figure increases to \$250,000 if all participants in the transaction were C corporations. Some communications between lawyers and their clients may be protected from disclosure to the IRS by the attorney-client privilege. ☉

Pakistan Update

by Muhammad Bashir Chaudhry, in Karachi

The World Bank is encouraging Pakistan to let the market set the price for electricity. The country faces difficult policy issues in moving to such a system.

James Wolfenson, president of The World Bank, said in response to a question during annual meetings of world finance ministers in Washington in October that Pakistan is suffering from imbalances in power prices as a result of

WAPDA’s “line losses” and implicit subsidies to richer people who should be able to afford electricity without government help. He said he hoped that the government would introduce a more market-based pricing system and get rid of the subsidies, but that The World Bank would not interfere in the timing and method of implementation. The person asking the question had observed that increases in electricity and gas prices might create problems for the manufacturing sector.

The government released a long report called “Power Policy 2002” on October 24. Deregulation of power supply remains high on the government agenda. The government said it is “committed to pursue a far-reaching reform program” that entails moving to a “decentralized system with separate generation, transmission and distribution entities, having substantial private ownership and management, reflecting and encouraging a commercial and competitive operating environment.”

Background

Total nominal generating capacity in Pakistan at present is 18,062 megawatts. Independent power companies control 5,914 megawatts in the private sector, while WAPDA owns and controls 9,930 megawatts, KESC has 1,756 megawatts, and PAEC has 462 megawatts in the public sector. Of the total nominal capacity, 5,009 megawatts (about 28%) is hydroelectric power while the remaining 13,053 megawatts is thermal capacity. WAPDA and KESC are engaged in transmission and distribution of electricity, within their respective license areas in the country. The WAPDA and KESC systems are interconnected through a 220 kv double-circuit transmission line. PAEC and the independent power companies sell power in bulk to WAPDA and KESC.

There are serious technical shortcomings in the WAPDA and KESC systems that extend to all areas of operations: generation, dispatch, transmission and distribution. Most of the equipment and lines are old, are overloaded but poorly maintained, and are in need of urgent replacement or major revamping. Due to this, there are frequent breakdowns and service interruptions. Transmission and distribution losses

are abnormally high, and the utility operations are in the red. Losses in the WAPDA system have been reduced to 24.3%. Despite efforts by the KESC management, losses at KESC are still abnormally high.

The government has recently extended significant financial support to WAPDA and KESC. There is a need to rationalize input costs including fuel costs, plant efficiencies, line losses, arrangements for bulk sale and purchases, and the net power tariff realized by the utilities.

Without removing the inefficiencies in the power system, any increase in electricity price would be seen by consumers as a means to prop up inefficient operations. Therefore, it would be better to attack the sources of inefficiency first.

With the rapid urbanization, extension of electricity grid supply and village electrification, the number of ratepayers has increased to 12.5 million. Composition of consumption of electricity by the economic groups at present is: domestic 46%, industry 28%, agriculture 12%, bulk supply 9%, commercial 5%, and railways 0.02%. With only about half of nearly 140.5 million people (2001 population estimate) having access to electricity, a huge population base provides an ideal opportunity for expansion of electricity generation.

Many industrial users have installed their own captive power plants to avoid having to pay the high electricity prices charged by WAPDA and KESC and spare themselves from the frequent interruptions to service. This loss of large customers has adversely affected the utilities. The Ministry of Water and Power gave notice recently of an average increase of Rs 0.065 per unit in the WAPDA tariff under the automatic fuel adjustment formula. There have been protests, particularly from small factory owners, against this increase.

Projected Shortfall

The combined generation capacity available in the public and private sector is sufficient to meet the future power demand up to the years 2004 to 2005. It will require augmentation in subsequent years.

In view of the long lead time required to bring new power plants on line, particularly those based on indigenous resources like water, coal and gas, work on new power projects must commence soon. The government plans to solicit bids shortly for hydroelectric and indigenous fuel-based projects, for which feasibility studies are already available, and to initiate feasibility study work on raw sites for exploiting indigenous and renewable resources.

WAPDA has prepared a "Hydropower Development Plan — Vision 2025." A consolidated list of potential projects to be implemented in the short, medium and long term has also been prepared. The choice of implementing projects by the public sector, private sector, or by public-private partnership will depend upon the urgency of meeting demand. A shortfall of 5,529 megawatts in electricity is foreseen by 2009 to 2010.

The Sindh government efforts are continuing for a 1,000-

Pakistan needs another 5,529 megawatts in additional generating capacity by 2010 to meet expected demand for electricity.

megawatt mine-mouth coal-fired power plant based on Thar coal with technical and financial assistance from China. Another 884 megawatts of other hydroelectric projects are also in the works in other provinces.

Originally about 70% of total electricity generated in the country was hydroelectric power. However, over time, more thermal generation was added, thereby reducing the share of electricity that comes from water, a cheaper source of power. Shortages of river water in the last few years have further aggravated this balance. More reliance on thermal power has increased the utilities' financial burdens, particularly in foreign exchange. As a consequence, the government is again interested in promoting more hydroelectric projects.

WAPDA Restructuring

After the upcoming privatization of

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Pakistan

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WAPDA-Gencos and KESC, the role of private sector in power generation will increase sharply.

The power wing of WAPDA is being restructured into independent companies: there are nine distribution companies called “Discos” and four power generating companies called “Gencos.” The National Transmission and Dispatch Company — called “NTDC” — has been formed to transmit power in bulk to the distribution companies for distribution. The Pakistan Electric Power Company, or “PEPCO,” may act as the new holding company for all these corpora-

Only about half of the nearly 140.5 million people have access currently to electricity.

tized entities. The capitalization of over a dozen new companies is understood to be in process. The challenge will be to structure each company so that it can sustain itself in future without being a drain on WAPDA, PEPCO or the government. The government might have to make cash contributions to bring the equity of each new company to a satisfactory level. Ultimately, the Discos and Gencos will be privatized. Initial steps have been taken for the privatization of Peshawar Electric Supply Company by inviting expressions of interest from reputable institutions to act as financial adviser.

After the restructuring, bulk power sale and purchase are expected to be along the following lines:

1. WAPDA will sell hydroelectric power to NTDC. The Gencos and independent power companies will sell thermal power to NTDC. NTDC might replace WAPDA under existing contracts with independent power companies and the PAEC.

2. NTDC will sell power in bulk to the Discos as well as to KESC. NTDC may expect some profit for its efforts in

addition to recovery of transmission charges and the adjustment for the transmission losses.

3. The Discos will distribute electricity to their consumers within their respective areas. They should recover the purchase price, distribution cost, adjustment for reasonable transmission and distribution losses, and some profit margin for growth.

KESC

The abnormally high transmission and distribution losses at KESC might be controlled quickly if the distribution function were privatized first. Based on the areas served by different grid stations, four to five private-sector KESC-Discos might

be created. KESC-Gencos could be incorporated later for subsequent privatization. Transmission and dispatch in the KESC service area might be merged with NTDC. Like WAPDA’s power wing, KESC could be restructured after an objective study.

According to press reports, WAPDA has agreed to supply power to KESC only for about nine months, but will not

assure supply during low water months. This might not be adequate to cover shortfalls fully in the KESC system.

Issues Requiring Attention

The existing policy on thermal and hydroelectric power are outdated and need to be revised.

The tariff for independent power projects does not reflect fiscal and other incentives allowed to the independent power companies, so the real tariff would be higher if the impact of these incentives were factored into the nominal tariff. Careful review of the risks the government should assume in future projects would be useful. It is also worth reviewing what lessons have been learned from the experience to date with private sector provision of services that used to be solely the domain of the public sector.

Pricing for electricity distribution must be settled. The government must choose between a uniform tariff to all Discos or a separate tariff for each Disco. This is linked with the tariff for sale of bulk power to the Discos.

NEPRA

NEPRA is an independent body that was set up under a 1997 law to regulate electric power services in the country. NEPRA has since issued generation and distribution licenses to a number distribution and generation companies, independent power producers and captive or small power plants. NEPRA has also approved a number of increases in electricity tariffs. NEPRA is committed to providing a fair return to the investor while ensuring safe and reliable service at competitive rates to consumers. WAPDA and KESC have not been happy with NEPRA in respect of tariff determinations. A special seven-member committee has been formed to look into the matter.

Overall, Pakistan's approach should be that the power system gets the cheapest electricity, from whatever sources, whether Gencos, WAPDA, PAEC or independent power producers. WAPDA has certain special tariffs with independent power producers. To the IPPs, WAPDA pays 100% of the capacity purchase price at a specified load factor, say 60%. If WAPDA asks the independent power producer to supply power below that load factor, then WAPDA will be paying a higher total average price per unit. However, if electricity is purchased at more than the specified load factor, then it will be cheaper for WAPDA per unit. WAPDA must be careful in comparing its own cost to generate with the cost of buying more electricity from independent power producers.

The tariff determination has not been worked out for each plant based on its capital structure, cost and the cost of generation. Rather, NEPRA is believed to have adopted the existing tariff as the base and allowed increases on the basis of increases in the costs of inputs, particularly the fuel oil. In the future, there would be different Gencos and Discos and so there are likely to be two or three different tariffs — one for bulk sales by Gencos to Discos or NTDC, another for sales by NTDC to Discos, and another for sales by Discos to

consumers. The sales of power are likely to be at different locations. Detailed bases and benchmarks need to be developed for deciding on each tariff for bulk or retail sales, at whatever location.

Tariffs include government taxes. The consumers pay higher amounts, but the utility is left with a smaller amount after passing the taxes on to the government. This is not all. Fuels used for power generation are also taxed. Taxes along each step of the process make for a higher cost of generating electricity. The final tariff the consumers pay, as well as the financial help extended to WAPDA and KESC, should be viewed in this perspective. There might be some justification to rationalize the taxes to maintain the power tariff at a reasonable level with a view to promoting industrial and economic development.

Conclusion

WAPDA, the independent power producers, KESC and every other entity in any way associated with power generation, transmission or distribution must be managed efficiently and assigned a tariff that is reasonable and commensurate

WAPDA has drawn up a list of potential projects, and decisions are being made about which to leave to the private sector.

with the quality and reliability of service. The government has its work cut out for it moving to a reasonable tariff. Adoption of an equitable approach in determining the fuel prices and applicable taxes at different stages of electricity might free the electric utilities to concentrate more on tackling the technical and managerial issues of power generation, transmission and distribution. ☉

Banker Confidentiality Obligations

by Neil Golden, in Washington

A developer asked recently whether materials submitted to a bank in connection with a proposed lending transaction would be subject to confidential treatment by the lender.

The materials to be submitted included financial projections and other sensitive materials about the company's prospects.

There is no implied duty under New York law for banks to keep information given to them by borrowers confidential.

The client wondered whether, in the absence of a specific agreement with the lender to treat these materials confidentially, the bank would be under a legal obligation to keep such information confidential. The bank is located in New York and the loan documents were to be governed by New York law.

Many loan documents do not explicitly require lenders to keep information obtained from a borrower confidential. This may be because many borrowers assume that lenders are bound by an obligation to keep such information confidential and do not ask for a confidentiality provision, perhaps thinking of jurisdictions like Switzerland and the Cayman Islands that have historically held strong bank secrecy policies, or perhaps assuming that there is some implied duty of confidentiality in the relationship between the borrower and the lender. However, there is no implied duty of confidentiality running from a lender in favor of a borrower under New York law. Borrowers should be aware that, absent highly unusual circumstances, they cannot rely on New York common law to protect financial or other sensitive business information provided to a lender unless the parties have

expressly agreed that the lender will keep such information confidential.

Depositors v. Borrowers

Courts in a number of states have held over the years that banks have a duty not to disclose confidential information received from borrowers and depositors. One early court decision to this effect was *Peterson v. Idaho First Nat'l Bank* in 1961 in which the Idaho supreme court held a bank liable for damages to a depositor where the depositor was fired from his job after the bank disclosed to his employer that he had written checks against insufficient funds. In *Milohnich v. First*

Nat'l Bank of Miami Springs, a court in Florida held a bank liable to a depositor for revealing information to a third party that led to the depositor being subjected to various lawsuits.

The New York courts have consistently taken a more conservative approach to this issue. New York courts have recognized that banks have a

fiduciary duty to depositors under which a bank may not disclose confidential information about the depositor's accounts, but the protection afforded a depositor by this duty is a weak one that can be overridden in circumstances where public policy considerations favor disclosure of the information. (For example, federal anti-money laundering statutes compel banks to disclose information about deposit accounts to regulatory authorities in specific circumstances. Disclosure by banks of depositors' confidential account information in such circumstances may well have been permitted even under New York common law given the public policy considerations that favor disclosure in connection with criminal matters.)

However, in the case of a borrower-lender relationship, New York law clearly comes down on the side of the lender in providing that the lender has no duty to maintain the confidentiality of information received from a borrower in the context of a loan transaction. One of the earliest New York court decisions to address the issue was *Graney Development Corp. v. Taksen* — a New York appeals court decision in 1978 — in which an officer of the bank disclosed to another bank and a person who intended to sell certain property to the

borrower that the borrower had defaulted on a loan to the bank. While noting in some general terms that borrowers may have expectations of confidentiality, the court said it found no reason to impose a duty of confidentiality on the bank in a borrower-lender relationship and held that relationship to be “solely that of creditor and debtor.” The court distinguished the bank-depositor relationship, in which the bank acts as agent for the depositor and the depositor has a reasonable expectation that confidentiality of account records will be maintained.

Confidentiality expectations in the borrower-lender relationship under New York law were also addressed in *Sharma v. Skaarup Ship Management Corporation*, a 1988 federal district court case. In *Sharma*, the borrower had a series of loan agreements with a large New York bank to finance tankers used in the shipping industry. Ultimately, the borrower defaulted on the loans, and the tankers were transferred by the bank to Skaarup Ship Management Corporation, which was also a customer of the bank. The borrower sued, alleging among other causes of action that the bank had disclosed the borrower’s confidential financial information to Skaarup in connection with the transfer in breach of the bank’s duty of confidentiality. A federal district court in New York dismissed the borrower’s claim for breach of duty of confidentiality based on the reasoning in the *Graney* decision, noting that a bank’s relationship with its borrowers differs from its relationship with depositors. The court cited *Graney* for the proposition that “one who defaults on his debts cannot expect that the default will be kept a secret.”

A subsequent case in which the confidentiality issue arose was *Boccardo v. Citibank, N.A.*, a 1991 case in the New York state courts that involved a bank representative falsely reporting to a third party that there were insufficient funds in the borrower’s line of credit account to cover a check that the borrower had written on the account. As a result, the third party refused to proceed with a transaction with the plaintiff. The plaintiff brought suit on a theory of tortious breach of confidentiality. Noting the prior decision in *Graney*,

the court in *Boccardo* said, “New York courts have not definitively recognized a cause of action based upon a breach of confidence theory in the context of bank/customer relationships” and it dismissed the borrower’s claim.

A somewhat more recent New York federal court case raised the possibility of a narrow exception in New York law relating to confidentiality in the borrower-lender relationship. In *Bartell v. OnBank & Trust Co.* in 1996, the court addressed a borrower’s claim that an employee of the bank had improperly distributed the borrower’s loan application materials, albeit in an altered form, to attendees at a mergers and acqui-

Borrowers providing particularly sensitive materials should attempt to negotiate a specific confidentiality undertaking on the part of the bank.

sitions seminar sponsored by the bank as an example of the bank’s services. The borrower claimed that it suffered damage to its reputation as a result. The court said New York law does not recognize a duty of confidentiality on the part of a lender in favor of a borrower unless the borrower can show malice or bad faith on the part of the bank. The court held that the borrower had made a sufficient showing of malice to survive the bank’s motion to dismiss the claim.

Conclusion

In sum, borrowers in loan transactions governed by New York law should not have an expectation that financial plans, projections and other sensitive business information are automatically subject to a duty of confidentiality on the part of the lender. New York is a major banking center, and its courts have been reluctant to impose non-disclosure duties on lenders that some other states have imposed by case law or statute. Borrowers providing particularly sensitive material to a bank in the course of a lending relationship should attempt to negotiate a specific confidentiality undertaking on the part of the bank. ☉

Environmental Update

The Republican victory in the mid-term elections in November should help the Bush administration advance two of its high-profile environmental initiatives — the “clear skies initiative” to reduce emissions of nitrogen oxides, or “NOx,” sulfur dioxide, or “SO₂,” and mercury for power plants, and a comprehensive energy bill.

Clear Skies

The Bush administration’s “clear skies initiative” was introduced as the “Clear Skies Act” at the end of July, but the measure did not advance due to opposition from Senator James Jeffords (I.-Vermont), then chairman of the Senate Environment Committee, as well as from most Democratic

The “clear skies initiative” will require reductions by 2018 of 70% in SO₂ emissions and 66% in NOx emissions.

members of the committee. With the Republicans assuming the committee chairmanships in the next Congress, the clear skies initiative should receive renewed consideration.

Senator James Inhofe (R-Oklahoma), the expected new chairman of the Senate Environment Committee, has indicated that he plans to make reauthorization of the Clean Air Act one of his top legislative priorities. Senator Inhofe has been a strong advocate of injecting “sound science” and employing a “cost-benefit analysis” in Clean Air Act rulemaking. Portions of the Bush administration’s clear skies initiative may also ultimately be incorporated into Congressional proposals to reauthorize the Clean Air Act.

The clear skies initiative calls for steep reductions in NOx, SO₂, and mercury emissions in a two-phase process with specific reduction targets for years 2010 and 2018. The president’s proposal does not address carbon dioxide, or

“CO₂,” emissions, a greenhouse gas. The initiative would create a mandatory “cap-and-trade” emission allocation program similar to the federal acid rain program. The legislative language provided by the administration calls for reductions by 2018 of approximately 70% in SO₂ emissions, about 66% in NOx emissions, and approximately 68% in mercury emissions from current levels. The Bush legislative proposal would also create a “backstop” ceiling price for emission allowances of \$4,000 for each ton of SO₂ or NOx and \$2,187.50 for each ounce of mercury. If the market price of allowances starts to rise above these backstop amounts, then plants could go directly to the US Environmental Protection Agency to purchase the allowances instead of buying them from another company on the open market.

The clear skies initiative would also exempt power plants from having to comply with other, similar programs such as the “new source review” permitting program and the “best available retrofit technology,” or “BART,” standards that apply to older sources of air pollution

located near national parks and wilderness areas, as well as from certain air toxics standards. Exemption from these programs would be a quid pro quo for having to meet new stringent emission reductions targets under the initiative. If a version of the Bush plan is ultimately enacted, many older power plants would have to be retrofitted with costly pollution control technology or spend significant funds to purchase a sufficient number of allowances to ensure compliance.

Not surprisingly, many environmental groups have claimed that Senator Inhofe and his counterpart in the House, Rep. W.J. “Billy” Tauzin (R.-Louisiana.), will engage in efforts to roll back over 30 years of progress made under the Clean Air Act. Senate Democrats have pledged to fight against reforms that weaken the Clean Air Act.

While sweeping reforms of the Clean Air Act may be

debated in the respective Congressional committees in the next Congress, it seems unlikely that wholesale changes will be made, with the possible exception of the implementation of a multi-pollutant emission reduction program for power plants that draws upon some of the concepts addressed in the administration's clear skies initiative. If agreement cannot be reached next year on reauthorizing the Clean Air Act and other limited reforms, then both sides will probably prefer to wait until after the 2004 elections before tackling the issues again.

Other Legislative Initiatives

In addition to reforming the Clean Air Act, the incoming Republican Congress hopes to work towards other environmental goals. One of the top priorities is passage of a comprehensive energy bill that adopts many of the proposals advanced by the Bush administration. The president's wish list for the bill includes programs to increase domestic oil and gas supplies (such as permitting limited exploration in the Arctic National Wildlife Refuge in Alaska and adding more financial incentives for oil and gas exploration in other areas), electricity reform to promote increased competition and encourage renewable energy, conservation, and alternative fuels, and increased funding for energy research and development.

Chemical security legislation is also likely to receive attention in the new Congress. There is a growing consensus in Washington that a measure requiring enhanced security at chemical plants and other facilities, including some power plants, is needed. Senator Jon Corzine (D.-New Jersey) introduced a bill in the Congress that just ended that would have required preparation of vulnerability assessments and response plans and required that they be submitted to the federal government for approval. The Corzine bill would have affected as many as 15,000 facilities. The regulated community

largely opposes the bill on grounds that it is overly prescriptive and would conflict with voluntary measures that many chemical companies are already committed to implement. An effort to add the Corzine bill to legislation creating the new federal Department of Homeland Security failed. The new Republican Congress is expected to pass a chemical security bill, but in a form that tracks what private industry is already doing.

Congress may also consider legislation to streamline asbestos litigation and impose consistent triggers for

Legislation expected next year will require enhanced security at chemical plants and other facilities.

when a claim for asbestos liability can be filed. There has been an explosion of asbestos cases in recent years involving plaintiffs who were allegedly exposed to asbestos, but do not exhibit any symptoms of asbestos-related illnesses. Thousands of asbestos cases have been filed against power companies and boiler manufacturers related to asbestos present in boilers, piping insulation, and other areas at power plants.

EPA Issues NSR Reforms

After years of waiting, the US Environmental Protection Agency released a final rule that rewrites several provisions of the "new source review," or "NSR," air permitting program. The EPA's announcement on November 22, 2002 immediately drew a firestorm of criticism from leading environmental groups and several Democratic members of Congress. Nine attorneys general from northeastern and mid-Atlantic states said they plan to challenge the NSR revisions in court.

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The final rule makes some important changes in the program, but the revisions are not as broad as many in the regulatory community had hoped.

The NSR permitting program imposes a fairly rigorous pre-construction review of new and modified major sources of pollution in so-called “nonattainment” areas (areas that do not meet federal ambient air quality standards) and for all major emitters in “attainment” (clean) areas. The NSR program has been criticized by the regulated community in the past as being overly time consuming and excessively burdensome and costly. Industry has asserted that the NSR program discourages the modernization of existing plants and hampers the siting of new, more efficient, and less-polluting plants. EPA’s final rule is intended to address some of these criticisms and provide added certainty to the NSR permitting process.

The final rule has five key components. Each of the

The Kyoto protocol is expected to come into force next year once Russia and one other country ratify it.

five is a reform that was originally proposed in 1996 by the Clinton administration. The first change affects “baseline actual emissions.” Sources of pollution other than power plants will calculate pre-change emissions based on a “baseline” period of any consecutive 24-month period in the past 10 years, instead of the current practice of generally using the most recent two-year period of emissions. The current policy for power plants — a baseline period of a consecutive 24-month period in the past five years — would become law. The baseline calculation is important because it is the starting point for measuring an emissions increase. The higher the baseline, the lower the projected emissions increase.

Under the second major component of the final rule, EPA’s rule for calculating emission increases for power plants that have begun normal operations (i.e., compar-

ing past actual emissions to projected future actual emissions) will also apply to other industrial facilities, including plants with industrial boilers.

Third, sources that keep their emissions below a plant-wide cap will be able to make operational changes and equipment modifications without undergoing a major source NSR permitting process. Such a plantwide applicability limit would generally be effective for 10 years.

Fourth, plants that have recently installed state-of-the-art pollution control technology on new or modified emission units as part of an NSR or similar state permitting process would have operational flexibility to make certain future changes without triggering additional NSR permitting for a 10-year period.

Finally, under the final rule, EPA will formally adopt its current policy of excluding pollution control and prevention projects from NSR permitting review where such

projects result in a net beneficial impact on the environment. The final rule contains a presumptive list of technologies that will automatically qualify for the exclusion.

In addition to the above reforms to the final rule, EPA proposed a separate rule that defines

what qualifies as exempted “routine maintenance, repair, and replacement.” The EPA proposal lists a range of options for two types of qualifying categories of “routine maintenance, repair, and replacement.” These categories are annual maintenance, repair and replacement allowances and an equipment replacement approach. With respect to the former, the proposed rule will establish an industry-specific cost allowance, and certain types of activities that fall under the allowance cap would qualify for the exemption. With respect to the second category, most projects replacing existing equipment with functionally-equivalent new equipment would generally qualify for the exemption so long as a cost threshold was not exceeded. For this category, the cost threshold would generally be pegged to a percentage of the replacement cost of the particular process unit. EPA

is seeking comments on whether one or the other category is more appropriate or whether both categories of “routine maintenance, repair, and replacement” should be adopted.

Because it is only a proposed rule, the “routine maintenance, repair, and replacement” proposal will be subject to public notice and comment. The proposed rule is controversial. The ongoing, high-profile EPA enforcement actions against older utility plants assume that the equipment modifications and upgrades over the years did not qualify as exempted “routine maintenance, repair, and replacement” activities. This makes the latest EPA proposal especially sensitive, and explains why the proposal has already elicited a strong negative reaction from environmental groups and certain elected officials.

Kyoto Protocol

The Canadian government said in November that it will attempt to implement the Kyoto protocol requirements through negotiated voluntary emission reduction agreements with the major Canadian industrial sectors. A back-up regulatory structure will be put in place to ensure that the industrial sectors follow through on their voluntary reduction commitments.

The Canadian government is under pressure from several key industrial sectors to reject the Kyoto protocol. The prime minister, Jean Chretien, hopes the House of Commons will approve the treaty by the end of 2002.

Canadian ratification is not essential to implementation of the treaty. International implementation of the Kyoto protocol hinges on ratification by Russia and at least one smaller country. Chances of the Kyoto protocol entering into force by the end of 2002 were recently dashed when Russia announced that its parliament will take three months to a year to decide whether to ratify the treaty. In the end, Russia is expected to ratify, largely because it will have a surplus of carbon credits to sell to

other “Annex I” (more industrialized) countries. At a meeting of the protocol parties last year, Russia succeeded in doubling its allocated amount of carbon sequestration credits from 17 megatons to 33 megatons on account of its carbon-absorbing forests. Even more surplus credits will be available because greenhouse gas emissions from Russian industry have declined since 1990 due to the breakup of the former Soviet Union. Russia is expected to use the surplus carbon credits to help modernize its energy sector.

The Kyoto protocol will enter into force after it is ratified by 55 or more countries (including both industrialized Annex I nations and Annex II developing countries) whose emissions represent at least 55% of the carbon dioxide emissions from Annex I countries in 1990. Once

EPA is assessing whether coal ash used as mine fill should be subject to special handling and management regulations.

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.

Brief Updates

EPA recently announced that it is preparing to test a web-based database that will provide public access to environmental compliance information on over 80,000 regulated facilities. The “enforcement and compliance history online,” or “ECHO,” database will reportedly include information on permitting status, inspection reports and compliance history for a broad range of facilities regulated under the Clean Air Act, Clean Water Act, Resource Conservation and Recovery / *continued page 40*

Environmental Update

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Act and other federal programs. A notice was published in the November 20, 2002 Federal Register seeking comments on the proposed database. Comments are due by January 21, 2003.

California unveiled a new voluntary greenhouse gas state registry — the California climate action registry — that is intended to track in-state emissions of greenhouse gases. The program has 23 charter members, including British Petroleum and Pacific Gas & Electric.

Senator John McCain (R.-Arizona), the incoming chairman of the Senate Commerce Committee, has said the committee will hold hearings on the potential effects of climate change on the US economy, the environment and public health, and may consider legislative proposals to address climate change in the next Congress.

EPA recently agreed as part of a settlement with nine environmental groups to issue final designations of new nonattainment areas by April 15, 2004. The agency is obligated to identify areas not meeting the 1997 air quality standard for ozone.

According to EPA, more than 290 US counties fail currently to meet the new ozone air quality standard. The designation of these counties as nonattainment areas will trigger actions by the states to develop plans to bring these areas into compliance with the ozone standards. States may be forced to implement new emission limitations on power plants and other industrial sources in order to meet federally-mandated reductions.

EPA is reportedly weighing whether to launch a new Clean Air Act investigation into excess air emissions generated during start up, shutdown, or malfunction periods at power plants and other pollution sources. If the agency's investigation concludes that significant pollution is being emitted during these periods, EPA could launch new enforcement actions against sources with high incidences of unexcused excess emissions during start up, shutdown and malfunction periods.

Finally, several environmental groups are accusing EPA of reneging on its word to develop new solid waste regulations to govern the disposal of coal combustion ash in mines. EPA is currently evaluating whether coal ash used as mine fill should be subject to special handling and management regulations. EPA was originally scheduled to propose new coal combustion ash regulations in 2004 with a final rule slated for 2005. ☉

— *contributed by Roy Belden in New York*

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