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US Tax Laws Change — Again

by Keith Martin, in Washington

A massive, 650-page corporate tax bill that the US Congress passed in mid-October before leaving Washington to campaign for reelection has many provisions that will affect the project finance community.

The bill will let US companies with earnings parked in offshore holding companies repatriate the earnings to the US and pay only a 5.25% income tax. The earnings must be brought back in cash and reinvested in the United States. Companies have through the end of the next tax year to take advantage of the provision.

Companies that own existing power plants that burn "biomass" to generate electricity have been given a windfall under the bill. They will be able to claim tax credits of 0.9¢ a kilowatt hour on the electricity they sell during the next five years starting next January 1. The electricity must be sold to a third party. It does not matter how old the power plant is. However, an energy tax credit cannot have already been claimed on the plant, and if any tax-exempt financing was used to pay the capital cost of the plant, there would be a reduction in the amount of the new tax credits. "Biomass" is material that was once living, like wood.

The bill may breathe new life into the domestic synfuel industry. Roughly 53 "coal agglomeration facilities" were built in the mid- to late 1990's that apply chemicals to raw coal to make a synthetic fuel. Any such facili- */ continued page 2*

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STATE TAX INCENTIVES are at risk after a decision by a US appeals court in September.

The court said an investment tax credit that Ohio offers businesses for investing in new manufacturing machinery and equipment in the state is unconstitutional. The decision calls into question tax credits and similar benefits at the state level for wind farms, clean coal technology plants, and other power projects. Ohio has asked the court for a rehearing, and a number of other states are expected to file briefs supporting Ohio's position.

The court said that incentives aimed at getting */ continued page 3*

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ties that were put into service by June 1998 qualify potentially for tax credits through 2007 of $1.1036 an mmBtu on the synfuel they produce. The bill would allow tax credits of $4.375 a ton to be claimed on output from new synfuel plants put into service between sometime later this month or November when President Bush signs the bill and the end of December 2008. The credits can be claimed for 10 years after the new plant goes into service. Existing coal agglomeration facilities can be rebuilt to qualify for the additional credits. Output from the new plants will have to satisfy a tougher definition of what qualifies as synfuel.

The bill will provide a boost to some power companies that use renewable fuels. Owners of wind farms receive a tax credit currently of 1.8¢ a kilowatt hour on the electricity they produce. The tax savings from this tax credit are equivalent to roughly a third of the capital cost of a typical wind project in present-value terms. Congress added biomass, geothermal energy, sunlight, water in irrigation ditches, landfill gas and municipal solid waste to the list of eligible fuels, but only gave power plant developers intending to use such fuels until the end of next year to get their projects in service. It remains to be seen how many new projects can be built in that time. For example, larger projects that use biomass usually take more than a year to construct. On the other hand, generators that produce electricity from landfill gas can be put into service more quickly.

Utilities have been given a window to shed transmission lines and spread the tax hit — if they dispose of the lines at a gain — over eight years. Any utility that wants to take advantage of this provision must act by the end of 2006.

Congress reduced the US tax rate on domestic "manufacturing" income by 3.15%, but the rate reduction will not be fully phased in until 2010. Congress requires itself to include a "tax complexity analysis" at the back of major tax bills. The analysis included with this measure commented dryly that the rules implementing the lower tax rate for manufacturing income will be "difficult" to draft and will burden "most small businesses" with the need to make complicated calculations. The analysis also noted that Canada had to repeal a similar law after it "led to numerous disputes and litigation between affected taxpayers and the Canadian tax authorities."

A massive tax bill that Congress passed in early October has many provisions that will affect the project finance community.

Electricity generation and gas production are defined as "manufacturing," but transmission and distribution of electricity and gas are not. US companies will have an incentive to treat income as from manufacturing but expenses as tied to other activities in order to use the expenses to offset a higher tax rate.

The bill goes a long way toward fixing a foreign tax credit problem for US multinationals. The United States taxes US companies on worldwide income. It gives them credit, in theory, for any taxes that were paid to other countries on their overseas earnings, but the foreign tax credit rules are so full of fine print that most US utilities and other capital-intensive companies are unable to use foreign tax credits in practice. The fix would not take effect until 2009.

There are other provisions to encourage more use of ethanol and biodiesel as vehicle fuel.

It is not clear, given the growing fiscal problems of the US government, whether some of the provisions that are not scheduled to take effect for several years will be fully implemented. This makes it difficult for companies to plan. The current Congress has not been satisfied with merely cutting taxes beyond what the federal government can currently afford, but it has moved with this bill to put in position further tax cuts five or seven years from now in an effort to bind the hands of future Congresses.

Repatriation

Most US power companies with projects in other countries own them through offshore holding companies in Holland, the Cayman Islands or similar jurisdictions. Income from the projects accumulates in the holding company and is reinvested offshore. This lets the US power company defer US taxes on the offshore earnings until they are brought back to the United States.

The bill lets US companies that repatriate earnings pay tax on them at only a 5.25% rate (or at a 3% rate for companies on the alternative minimum tax). This compares to a normal corporate tax rate of 35%. It is a limited-time offer.

The lower tax rate will only apply to earnings that are repatriated during a one-year period. The company must choose either its tax year that straddles the date President Bush signs the bill (expected to be in late October or early November) or its next tax year (for example, 2005).

A company must bring back more earnings than it did on average each year during a "base period" to benefit from the lower rate. The lower rate would only apply to the "excess" repatriation above what the company bought back on average each year during the base period. The base period is the five tax years ending on or before June 30, 2003, but two years are dropped from the calculation: the years in which it repatriated the highest and the lowest amounts. Thus, for example, a company that pays taxes on a calendar-year basis would look at the period 1998 through 2002. It must count as earnings repatriated during the base period not only the cash dividends it received from offshore, but also certain other amounts like distributions of property in kind, distributions of cash that did not have to be reported as dividends because the earnings were taxed in an earlier year, and any "section 956 inclusions." An example of a "section 956 inclusion" is where a US parent borrowed against cash that was parked in an offshore holding company with the result that it had effective use of the offshore earnings in the US. Such borrowing would have triggered a US tax on the offshore earnings that served as collateral for the loan to the US parent.

Earnings must be brought back in cash to benefit from the lower rate. The low rate would not apply to other types of offshore earnings on which the company might be taxed during the year. An example is passive income — like dividends or interest — earned by its offshore subsidiaries. This passive income is taxed immediately to the US parent under "subpart F" of the US tax code without waiting for the money to be repatriated to the United States.

A company cannot lend its offshore subsidiary money to pay the cash dividends. However, it can borrow from a bank. Any increases in shareholder or other / *continued page 4*

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businesses to relocate violate the commerce clause of the US constitution, which bars states from interfering with interstate commerce.

Daimler-Chrysler built a new automobile factory near its existing plant in Toledo, Ohio in 1998 at a cost of $1.2 billion. It claimed a 13.5% investment tax credit against its state franchise taxes. It also received a property tax exemption for 10 years from the two local school districts. The tax benefits were worth $280 million.

A group of Toledo homeowners and small business people challenged the tax benefits at the urging of Ralph Nader. The court suggested that direct subsidies like government grants are permitted under the US constitution, but tax credits are not because they involve a state's use of its taxing power to redirect interstate commerce. The court said the property tax exemption is not a problem. The case is *Cuno v. Daimler-Chrysler, Inc*. The court rendered its decision on September 2.

The Ohio attorney general asked the court on September 16 to reconsider its decision. At least 12 other parties have filed briefs seeking to become parties in the case.

SALE OF A SUBSIDIARY produced "nonbusiness" income. It is harder for states to tax such income.

An insurance company sold a subsidiary that was doing business in Illinois in 1997 and reported a $1.27 billion gain from the sale for federal income taxes, but it took the position that none of the gain was Illinois source income and, therefore, tax did not have to be paid on it in Illinois.

Illinois, like many states, distinguishes between "business" and "nonbusiness" income. A corporation must allocate a portion of its business income to Illinois based on the percentage of its total sales, property and payroll that are in Illinois. However, *non*business income is assigned / *continued page 5*

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related-party debt of offshore subsidiaries between October 3, 2004 and the end of the tax year in which the lower rate is being claimed are potentially a problem.

The company must reinvest the earnings in the United States "pursuant to" a reinvestment plan. The reinvestment plan must be approved by the company president, CEO or someone comparable before the repatriation occurs and the plan must also eventually be approved by the board or a similar body. The plan must provide for reinvestment of the earnings in the US "including as a source for the funding of worker hiring and training, infrastructure, research and development, capital investments, or the financial stabilization of the corporation for the purpose of job retention or creation." Congress did not set a time limit on the reinvestment.

Companies can repatriate earnings parked in offshore holding companies by the end of 2005 and pay US taxes only at a 5.25% rate.

A company would not be able to use net operating losses or most tax credits to shelter the earnings from the 5.25% tax.

There is a dollar limit of $500 million on the amount of earnings on which the company can pay tax at the special low rate. However, if the company can produce financial statements proving that it has more than $500 million in offshore earnings "permanently reinvested" outside the United States, then its cap is the higher figure.

Renewables

Power plants that use three types of renewables — wind, "closed-loop" biomass, and poultry waste — qualify currently for section 45 tax credits of 1.8¢ a kilowatt hour for the electricity they produce. The credits run for 10 years from when a plant is originally placed in service. A plant must be put in service by the end of next year to qualify. "Closed-loop" biomass is the term for plants that are grown exclusively to be used as fuel in a power facility. Congress envisioned so-called electricity farms when it first enacted the tax incentive in 1992. No power plants that use "closed-loop" biomass have been built (at least none with long-term contracts to sell the electricity), according to the Internal Revenue Service.

The bill adds to the list of eligible fuels, and it drops poultry waste as a separate fuel that qualifies in its own right. If power plants using poultry waste are to qualify in the future, it must be as a subcategory of one of the other fuels.

The eligible fuels list now consists of the following: wind, closed-loop biomass, open-loop biomass, geothermal energy, solar energy, water in irrigation ditches and canals, landfill gas and municipal solid waste.

Wind and closed-loop biomass projects will continue to qualify for 10 years of tax credits at 1.8¢ a kilowatt hour. This is the tax credit for electricity produced during 2004. The credit is adjusted each year for inflation. Such projects still face a deadline of the end of next year to be put in service.

The definition of what qualifies as a closed-loop biomass plant has been broadened. Existing coal-fired plants that are modified to co-fire with closed-loop biomass will qualify in the future. However, the modification plan must be accepted under the "biomass power rural development programs" or under a pilot program of the US Commodity Credit Corporation to qualify. The 1.8¢ credit would be calculated only on the fraction of the electricity output that is attributable to the biomass. This is done by setting up a ratio of the Btu content of the various fuels that are used to run the plant.

Geothermal and solar projects will qualify for credits of 1.8¢ a kWh, but only for five years.

Projects that use the other fuels — open-loop biomass, irrigation water, landfill gas and municipal solid waste — will qualify for credits of only 0.9¢ a kWh for five years. All credit amounts are adjusted for inflation.

Projects that use the newly-eligible fuels must be put in service after President Bush signs the bill (expected in late October or early November) and no later than the end of 2005, with one exception. This does not allow much time.

There is the possibility that Congress will extend the deadline again next year. The exception is that *existing* biomass plants — other than ones that use livestock or poultry manure — will be allowed to claim credits on their electricity sales for five years starting next year.

Credits tied to the newly-eligible fuels can only be claimed on electricity produced after 2004.

Companies on the alternative minimum tax have not been able to use section 45 credits in the past. The bill will let credits on new plants put into service after President Bush signs the bill be used against minimum taxes, but only for the first four years after the power plant is put into service.

Individuals, S corporations and closely-held C corporations also have a hard time using section 45 tax credits because of passive loss rules. This has not changed.

Plant owners who cannot use the tax credits have not been able to transfer them to other companies by using lease financing in the past. That's because the law has required until now that the person claiming the tax credits must be both the "owner" of the power plant and the "producer" of the electricity. In a lease, the lessor is the owner and the lessee is the producer. However, in the future, lease financing can be used to transfer credits on plants that use open-loop biomass and on coal-fired power plants that co-fire with closed-loop biomass.

Three types of matter are included under the heading "open-loop biomass." One is livestock and poultry manure, and wood chips or other bedding for the disposition of manure. Another is "solid waste material, including waste pallets, crates, dunnage, manufacturing and construction wood wastes (other than pressure-treated, chemically-treated, or painted wood wastes) and landscape or right-of-way tree trimmings." The last type of fuel is "agricultural sources, including orchard tree crops, vineyard, grain, legumes, sugar, and other crop by-products or residues." Municipal solid waste, landfill gas and paper that is commonly recycled are specifically excluded.

"Municipal solid waste," which also qualifies for credits, includes not only garbage, but also "sludge from a waste treatment plant, water supply treatment plant, or air pollution control" device.

Synfuel

The bill could breathe new life into the domestic synfuel industry. / continued page 6

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entirely to one state. It is assigned to the state where the corporation receiving the income is domiciled — the parent company that sold the shares was not domiciled in Illinois — or where the income-producing property is located.

Illinois argued the gain in this case was business income. Gain is ordinarily business income if it is from a type of transaction in which the taxpayer regularly engages or it is from sale of an asset that was an integral part of the taxpayer's regular business operations. The Illinois Supreme Court forced Texaco to treat gain from the sale of 90% of its gas pipelines as business income in 1994 on grounds that the pipelines were income-producing assets regularly used in its business. Texaco sold all of its pipelines in Illinois.

However, there is a growing consensus among states with similar tax laws to Illinois that gain from complete liquidation of a business is *non*business income. Such states include Pennsylvania, Ohio, Alabama, Tennessee, Kansas, New Mexico and Indiana. (California does not make such an exception.) Many states also treat gain from "partial liquidations" involving sale of only a line of business or geographic segments of a larger business as nonbusiness income. For example, Pennsylvania treated gain from the sale of two oil pipelines in the state as nonbusiness income, even though the seller retained pipelines in other states.

The Illinois Supreme Court said the gain from sale of the insurance subsidiary was nonbusiness income since, by selling its subsidiary, the insurance company was withdrawing from a separate and distinct portion of its business. It helped that the parties made a section 338(h)(10) election for federal income tax purposes to treat the sale of the subsidiary as a sale by the subsidiary of all of its assets. It was easier to see in such a case that the subsidiary was liquidating all of its assets.

The case is American / continued page 7

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Producers of "refined coal" will qualify for tax credits of $4.375 a ton in future on output from new plants put into service starting when President Bush signs the bill through December 2008. This is about a fifth of the section 29 tax credit for which such plants used to qualify. The credits will run for 10 years after a plant is put into service.

"Refined coal" is defined as a "liquid, gaseous, or solid synthetic fuel produced from coal (including lignite) or high carbon fly ash." The output must differ significantly in chemical composition from the raw coal or fly ash used to produce it in order to qualify as "synthetic fuel." The bill says in one place that the fuel can be used as a "feedstock," but suggests elsewhere that credits can only be claimed on fuel sold to someone who is expected to use it to make steam.

The output must have a market value at least 50% higher than the raw coal or fly ash used to produce it. This may be hard to do for a product that is supposed to compete with coal unless plant owners start with feedstocks with low value like fly ash or waste coal in culm or gob piles.

In addition, the output must reduce nitrogen oxide emissions and either sulfur dioxide or mercury emissions by at least 20% compared to the raw coal used to produce it or compared to "comparable coal predominantly available in the marketplace as of January 1, 2003." Congress did not explain what emissions comparison is to be done when making synfuel from fly ash.

The tax credits can be used by companies that are on the alternative minimum tax — unlike past synfuel credits — but only for the first four years after a plant is put into service. Individuals, S corporations and closely-held C corporations will have a hard time using synfuel credits because of passive loss rules.

Transmission Lines

The bill will make it easier for electric utilities to shed all or part of their transmission grids. One obstacle to doing this to date has been that the utilities face potentially large tax bills if they have little unrecovered "tax basis" in the grids. In such situations, virtually everything they receive is taxable.

They must act by December 2006.

Owners of existing power plants that burn biomass have been handed a huge windfall by Congress.

A utility that sells transmission lines or related equipment by then will have four years to reinvest the sales proceeds in other electric or gas utility property or another power or gas company. For example, the money can be put into power plants, gas wells, gas pipelines, electric transmission or distribution lines, an independent generator, or another utility. It could not be used to pay dividends or buy back stock from shareholders. Money spent on other utility property during the four years by an affiliate of the utility also counts as reinvestment. The utilities appear to have asked Congress to require them to reinvest to stave off directives from public utility commissions to return the money to ratepayers.

If the utility reinvests the full amount within four years, then its gain from the sale of its transmission equipment will be taxed ratably over eight years measured from the date of the original sale. If the utility fails to reinvest the full sales proceeds within that time, then it will be taxed on gain in the year of sale up to the amount it failed to reinvest. For example, if a utility sells a grid for $1,000X in which it has a "tax basis" of $100X, then it has a gain of $900X. If it reinvests all but $100X of the $1,000X in sales proceeds within four years, then it will be taxed in year one on $100X of gain plus a 1/8th share of the remaining $800X in gain. The rest of the gain will be spread over the balance of the next seven years.

The Joint Tax Committee estimated that the provision will be worth $3.9 billion in tax savings to utilities.

The grid must be sold to an "independent transmission company" to qualify for the eight-year spread. Only sales after President Bush signs the bill qualify. An independent transmission company can be an ISO (independent system operator), RTO (regional transmission organization) or other independent transmission provider approved by the Federal Energy Regulatory Commission, or any company that is not a "market participant" as FERC defines it and whose own transmission facilities are placed under operational control of an ISO or RTO before 2007.

Manufacturing Income

Congress reduced the tax rate on domestic manufacturing income by 3.15%, but the reduction will be phased in over time. Congress did not actually change the tax rate, but rather let companies deduct — or avoid paying tax on — as much as 9% of their domestic manufacturing income. With the corporate tax rate at 35%, this equates to a 3.15% reduction in tax rate.

The deduction is phased in. Only 3% of domestic manufacturing income may be deducted in tax years beginning in 2005 and 2006. The figure is 6% in 2007, 2008 and 2009. The full 9% deduction takes effect in 2010. Thus, any company with a November 30 tax year would not get any benefit from the deduction until its tax year that starts December 1, 2005.

The amount of deduction a company is allowed each year is capped. The limit is 50% of the wages reported on Form W-2 for the year for its employees.

Domestic manufacturing income is broadly defined. The Senate floor manager of the bill, Senator Charles Grassley (R.-Iowa), grumbled at one point that every industry with a Republican lobbyist managed to have its activities defined as "manufacturing." Qualifying income includes gross receipts from the "lease, rental, license, sale, exchange, or other disposition" of "tangible personal property," computer software, sound recordings and films (but not those with explicit sex scenes) "manufactured, produced, grown, or extracted *by the taxpayer* in whole or in significant part within the United States."

Electricity, natural gas, or potable water "produced by the taxpayer" in the United States qualify. So do "construction performed in the United States" and "engineering or architectural services performed in the United States for construction projects in the United States."

Receipts from the transmission or distribution of electricity, gas or water do not qualify. Electricity */ continued page 8*

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States Insurance Co. v. Hamer. *The court released its decision in late August.*

CALIFORNIA Governor Arnold Schwarzenegger vetoed a bill in late September that would have made it illegal for taxpayers to buy insurance against loss of tax benefits.

Schwarzenegger said the bill was at best premature because the legislature has not given other recent legislation time to curtail tax avoidance transactions and "at worst, [it] takes away an important type of indemnity insurance that allows legitimate business ventures to go forward." The measure would have taxed away as a penalty 75% of any proceeds received by California taxpayers "from insurance, guarantees, stop loss agreements or other similar arrangements" that ensure tax benefits in tax-motivated transactions.

AUSTRALIA cracked down further on the use of perpetual instruments that are stapled to shares.

US companies have used such instruments to reduce the tax burden on their projects in Australia. Australia took steps in 2001 to ban them. An Australian court decided in September that the instruments did not work even before 2001.

One of the tools that multinational corporations use in an effort to reduce income taxes in countries where they do business is to capitalize their subsidiaries in such countries with as much debt as the local tax authorities will allow. Earnings paid out as interest on such debt are deductible, thereby reducing the amount of income on which taxes have to be paid.

US multinationals must thread a needle. Many want not only to reduce taxes in foreign countries, but also to defer taxes in the United States. This requires keeping the earnings offshore. It also only means being careful not to capitalize their offshore subsidiaries with debt — at least not with */ continued page 9*

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traders do not have manufacturing income.

The Internal Revenue Service has been left to sort out the details, including how to allocate expenses among the various types of income and how to determine whether products that are assembled in the US out of parts made abroad or vice versa are US made. It is expected to have a difficult time.

The bill may breathe new life into the domestic synfuel industry.

Foreign Tax Credits

Most US utilities and other companies in heavy industries have a hard time using foreign tax credits. They are supposed to receive credit for taxes already paid abroad when calculating US taxes on their foreign earnings, but the fine print in the foreign tax credit rules is a problem.

The main impediment is interest allocation. A company may think it earned \$100X from its operations in Brazil. However, IRS regulations require the company to treat part of the interest it pays on its US borrowings as a cost of its foreign operations on the theory that money is fungible. Part of its domestic interest expense must be allocated to foreign operations in the same ratio as its assets are deployed in the US and abroad. By the time this occurs, the \$100X from Brazil may be only \$1X. Foreign tax credits can only be claimed in the United States in an amount equal to the US tax rate times the foreign source earnings — in this case, 35% times \$1X, or 35¢, even though the company paid taxes in Brazil — and will be taxed in the United States — on \$100X in earnings.

Another impediment is foreign earnings are put in 13 different "baskets." Credits from one basket cannot be used to offset US taxes on income in another basket.

The bill reduces the number of foreign tax credit baskets to two — passive income and other, or "general limitation," income — but not until tax years beginning after 2006.

It addresses the interest allocation problem by letting companies opt for a different formula for calculating the amount of domestic interest expense that is allocated to foreign operations.

The new formula should reduce the amount of interest allocated abroad in most cases. However, it is not as favorable a formula to the independent power industry as one that Congress passed in an earlier tax bill that President Clinton vetoed in 1999.

The new formula can be used in tax years beginning after 2008. Companies have that year to decide whether to switch to the new formula. Whatever they decide binds them for future years.

Congress called the new formula "worldwide fungibility," but this is misleading. The formula merely reduces the amount of domestic interest expense that will be allocated abroad. In some cases, it reduces it to zero.

Under the new formula, a company starts with the interest expense of its "worldwide affiliated group," defined as the interest expense for the year for itself and all its subsidiaries — both in the US and abroad — that are at least 80% owned by vote and value. It then multiplies this figure by the percentage of that group's total assets that are outside the US. It then subtracts the portion of the interest expense of the offshore members of the group that would be allocated to foreign operations if those foreign members were a standalone operation.

Thus, for example, suppose a US power company and its US subsidiaries have domestic interest expense of \$100X. Foreign interest expense of 80%-owned subsidiaries is \$25X. Six percent of total assets are outside the US. The amount of domestic interest expense that would be allocated abroad under current law is \$100X x 6% = \$6X. However, under the new formula, it would be (\$125X x 6%) - \$25X = \$0. (In fact, this equals -\$17.5X, but the result cannot be less than zero.) The reduction part of the equation acts as a cap on the amount of domestic interest expense that will be allocated abroad.

Mathematically, as long as foreign operations bear at least as heavy interest payment obligations (to unrelated lenders) on a proportionate basis as domestic operations, then there should be no allocation of domestic interest expense. It is only when foreign operations are less heavily debt financed that one gets an allocation of domestic interest expense.

The new provision is not as favorable to the independent power industry as one passed in 1999. The earlier provision would have let US companies take some US debt out of the calculation altogether. A company could have elected to treat any domestic subsidiary in the US whose debts are not "guaranteed (or otherwise supported)" by a related company as essentially a standalone enterprise. This could have helped independent power companies because they might have been able to ignore borrowing by special-purpose subsidiaries that use nonrecourse project financing to finance standalone projects.

Ethanol

The US government uses the tax laws currently in two ways to create a market for ethanol, a form of alcohol made from corn or other grains.

The first way is through a series of income tax credits. Companies that blend ethanol with gasoline are given a tax credit of 52¢ a gallon for the ethanol they use in such blending, provided the ethanol is at least 190 proof. (A smaller tax credit is allowed for ethanol of between 150 and 190 proof. There is no credit for using weaker alcohol.) A tax credit in the same amount can also be claimed by anyone who does not blend the ethanol with gasoline, but rather sells the ethanol directly at retail to consumers who will use it as fuel. Finally, small ethanol producers are allowed a tax credit of 10¢ a gallon for the ethanol they produce. This credit can only be claimed on 15 million of gallons of ethanol a year. A "small" producer is a company with a production capacity of no more than 30 million gallons a year.

The 52¢-figure for the credit is scheduled to drop to 51¢ in 2005.

These tax credits are not as valuable as they appear at first glance. Companies must add the dollar amount of the credits they claim to their taxable incomes.

The other way the US government encourages use of ethanol is by charging a lower excise tax on gasoline that is blended with ethanol. The federal */ continued page 10*

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instruments that the US views as debt. US taxes cannot be deferred on passive income like interest. Therefore, the key is to find instruments that are treated as debt for tax purposes in a country where the US multinational is doing business, but are not debt for US tax purposes.

In Australia, the debt took the form of perpetual instruments — debt instruments that had no deadline for repayment and that had other equity features. They were also "stapled" to shares, meaning they could not be sold without also selling the shares.

Income tax reforms adopted in mid-2001 in Australia make clear that debt instruments that cannot be sold or redeemed separately from shares will be treated as equity for tax purposes in Australia.

A federal judge ruled in September that such instruments were equity even before the 2001 tax reforms as to do otherwise would be to "take a blinkered approach." He also said the instruments ran afoul of a general anti-avoidance regime that allowed the tax collector to negate any transaction undertaken for the primary purpose of reducing taxes. The case is *Macquarie Finance Limited v. Commissioner of Taxation*.

LIMITED LIABILITY COMPANIES are being held accountable in many states for taxes that their out-of-state owners fail to pay.

Most infrastructure projects are undertaken by a special-purpose subsidiary that owns just the project. In the United States, limited liability companies are favored for this purpose. LLCs give their owners limited liability. Thus, claims against the project company cannot be collected from the owners any more than a claim against IBM or General Motors — both of which are corporations — can be collected from shareholders of those companies. At the same time, limited liability companies offer greater flexibility than corporations. The owners can choose for US tax purposes whether to have the LLC */ continued page 11*

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gasoline excise tax is currently 18.3¢ a gallon. Blenders can forego the 52¢-a-gallon alcohol fuels credit and pay, instead, a reduced rate of excise tax on the blended fuel they produce — so-called gasohol. Gasohol that contains 10% ethanol is subject to excise tax at only 13.1¢ a gallon. Gasohol with less ethanol is taxed at higher rates. Most blenders choose the lower excise tax rather than the alcohol fuels credit.

Utilities have been given a limited time through the end of 2006 to shed transmission lines with favorable tax results.

The bill makes four changes.

It extends the alcohol fuels credits through 2010. The credits had been scheduled to expire at the end of 2007.

It also lets such credits be used for the first time by companies that are on the alternative minimum tax. This would be allowed starting in 2005.

It eliminates the lower excise tax for gasoline. The full excise tax will have to be paid in future in theory on gasohol, but blenders will have the choice of claiming a credit against the excise taxes of 51¢ per gallon of ethanol they use in making gasohol. The ethanol must be at least 190 proof. As before, a blender will have to choose either a savings on excise taxes or on his income taxes (by taking the alcohol fuels credit).

Finally, the bill also gives an excise tax credit for blenders who mix "biodiesel," a mixture of diesel fuel with vegetable oil made from such things as soybeans, canola, coconut or hemp or with recycled cooking oil from restaurant kitchens. The biodiesel credit is 50¢ per gallon of vegetable or cooking oil used in producing the fuel. It increases to $1 a gallon if the oil is "agri-biodiesel." The current federal excise tax on diesel fuel — that would be offset by means of the credit — is 24.3¢ a gallon.

The new biodiesel credit can only be claimed on sales of biodiesel during 2005 and 2006. Ethanol blenders will get the benefit of their excise tax credit through 2010.

Leasing

Congress reduced the tax benefits that a US lessor can claim on property that it leases to a foreign entity or to a US tax-exempt entity, government agency or Indian tribe. Any property that was leased at any time in the past to such a lessee also remains tainted. The changes are retroactive, and the announcement earlier in the year they were coming had already put a halt to a booming business in lease financing for municipal assets in the US and for electric and gas distribution systems, sewage systems, railroad cars and track and other assets in foreign countries, principally in Europe.

Lessors claim tax depreciation on their assets. That depreciation is less valuable in cases where the assets are leased to a "tax-exempt entity," defined broadly to include government agencies, universities and other tax-exempt organizations, and foreign entities that are not subject to US income taxes. In such cases, the assets must be depreciated on a straight-line basis over the "class life" or over 125% of the lease term, whichever is longer.

The bill changes current law in three important ways.

First, "lease term" has now been defined to include the term of any "service contract or similar arrangement" that the lessor enters into when the lease ends. An example is where a US institutional equity leases a power plant to a European utility and requires that the utility enter into or arrange for a follow-on power purchase agreement at the end of the lease term.

Second, certain high-technology computer-based equipment — like telephone switches — and software that could be written off in the past over three or five years is now subject to the 125%-of-lease-term override where the lessee is a tax-exempt entity.

Third, the bill bars US lessors from using depreciation and interest deductions from leasing transactions with entities that are not subject to US income taxes to shelter income from other sources if certain features are present in the lease like too much defeased debt or a fixed-price purchase option. Rather, they must carry any such losses forward to wait until income is generated in future years from such leases. This restriction is applied to each lease separately. Thus, losses from one leasing transaction cannot be used to shelter income from another such transaction. This rule also applies to depreciation and interest deductions tied to property that was once used under a tax-exempt lease. Such property remains tainted.

The new rules apply to leases entered into after March 12, 2004, with two exceptions. They apply to leases entered into with Indian tribes after October 3, 2004, and certain domestic rail leases in the United States are "grandfathered." Amending an existing lease may bring it under the new rules if the amendments are considered substantial.

Transactions with Coops

Congress opened the door to certain types of transactions that the rest of the power industry has been hoping to do with electric coops. At the same time, it also gave coops the ability to expand their reach by making electricity sales to persons who are not members to order to make up for the loss of members. This last item is a carrot to encourage coops to open their grids to other power suppliers. However, the changes in law are temporary, making them of limited value until the next Congress decides whether to extend them. They only apply through the end of 2006.

A coop must be careful to ensure that at least 85% of its income each year is receipts from members "for the sole purpose" of meeting expenses.

Congress directed that coops be allowed to ignore several types of income in future when doing this 85% calculation. One such type is wheeling charges that the coop collects from others for moving electricity across its transmission or distribution lines, but only — in the case of transmission — if the wheeling services are provided on a nondiscriminatory basis under an open access transmission tariff or independent transmission provider agreement "approved or accepted" by the Federal Energy Regulatory Commission. Another type of income the coop can ignore is gain from the transfer of the coop's interest in any nuclear decom- */ continued page 12*

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taxed like a corporation or treated as "transparent," meaning the company is not subject to income taxes and any taxes are collected from the owners directly.

Many states are moving to hold LLCs accountable for taxes that their out-of-state owners fail to pay. A survey in *Tax Notes* magazine in September done by the law firm Bradley Arant Rose & White LLP reports that 27 states now require transparent LLCs to withhold income taxes for their out-of-state owners. In some of the states, withholding can be avoided if the owner promises to pay the taxes himself. The states are Alabama, California, Colorado, Connecticut, Georgia, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maine, Maryland, Michigan (individual owners only), Minnesota, Missouri, Montana, Nebraska, New Mexico, North Carolina, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Vermont and West Virginia.

In three states, the LLC is contingently liable for taxes that out-of-state owners fail to pay. In such states, the LLC should get a commitment from each owner that he will pay his taxes. Otherwise, the burden may fall on the LLC and, indirectly, on the other owners. The states are Alabama, Idaho and Kentucky.

In Mississippi, the other owners are "jointly and severally liable" for any unpaid taxes — meaning that the state can collect the full taxes owed on the company's income from any one owner — unless the LLC withholds at least 5% of its income in taxes.

NEW YORK said a cogeneration project owes back taxes on the gas it imported for use as fuel.

A cogeneration facility is a power plant that makes two useful forms of energy from a single fuel. An example is a plant that burns gas in a combustion turbine and then uses the exhaust from the turbine to make steam and electricity in a heat recovery steam generator.

New York taxes gas */ continued page 13*

Tax Changes

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missioning fund. This should make it easier for coops to shed their interests in nuclear power plants. Finally, coops will be allowed to enter into like-kind exchanges of assets — for example, a swap of one power plant for another power plant — without affecting the 85% calculation.

The bill also allows coops to enter into "load loss transactions" in the future. These are wholesale or retail sales of electricity to persons who are not coop members. Income from such sales will be counted as good income toward the 85% test. Only coops who offer nondiscriminatory open access to their systems will be allowed to do this. There is a limit on the amount of electricity that such a coop can sell to nonmembers. The limit is the amount of its "load loss," calculated by adding up the shortfall in sales to its members each year over a seven-year period compared to a base year. The seven-year period starts with 2004 or, if later, the first year the coop offers nondiscriminatory open access. ◎

Wind Market Update

by Keith Martin, in Washington

The US wind market is expected to boom for at least the next 12 months now that the US government has extended a "production tax credit" that is essential for wind projects in the United States.

Projects must be put into service by December 2005 to qualify. The earlier deadline to complete projects had been December 2003, and there were questions about whether the extension — when Congress got around to passing it — would be retroactive so that plants put into service before the credit was extended in September 2004 would qualify for tax credits. They do.

The American Wind Energy Association estimates that wind developers will require another $2 to $3 billion in capital in the next 12 months to finance new projects.

The tax credit is 1.8¢ a kilowatt hour and can be claimed on the electricity sold to third parties from wind farms for 10 years after a plant is put into service. The tax savings from the credit are worth about 33.5% of the capital cost of a typical project in present-value terms. The credit is adjusted each year for inflation. The figure 1.8¢ is the credit for 2004.

In early October, Congress also eased a problem with the "alternative minimum tax." Corporations in the United States must compute both their regular income taxes at a 35% rate and "alternative minimum taxes" at a 20% rate but on a broader definition of taxable income. They pay essentially whichever amount is greater.

Production tax credits cannot be used to reduce a corporation's regular income taxes below the level at which the alternative minimum tax kicks in. This is now causing problems for some larger wind developers and is also a source of concern for potential equity investors in wind deals. Congress voted before adjourning for the US presidential elections to allow production tax credits to be used against minimum taxes, but only for the first four years after a wind farm is originally placed in service, and then only for projects that are put into service after President Bush signs the bill. He is expected to sign it in late October or early November.

Earlier Deadline

Wind developers are facing a deadline of December *2004* to qualify for a "depreciation bonus" on their projects.

The US government made a limited-time offer after the terrorist attacks on the World Trade Center and the Pentagon. Anyone investing in new plant and equipment in the United States during a "window period" that runs from September 11, 2001 through 2004 or 2005, depending on the investment, can deduct as much as 50% of the cost of new assets in the year they are put into service. The balance of the cost is deducted over the normal depreciation period.

Wind farms must be put into service by December 2004 to qualify. It is possible in a wind farm to put some of the turbines into service in 2004 even though others might not get into service until 2005. The federal tax savings from the bonus are worth 2.61% of the capital cost of a wind project. The bonus can also be claimed in some US states. At last count, 25 states that otherwise piggyback their income taxes on the federal system had "decoupled" and were not allowing the bonus, and another six states were only allowing a partial bonus.

Haircut

The Internal Revenue Service is reassessing whether any state tax credits cause a "haircut" in the federal production tax credit. It has committed on its current business plan to issue guidance by next June 30.

One of the most important questions for any investor in a wind project to ask on due diligence is whether the project benefited from government grants, tax-exempt financing, subsidized energy financing or any "other credit." If so, then the federal production tax credit is reduced by the portion of the capital costs of the project that were paid for with these benefits. For example, if 90% of the project costs were financed with tax-exempt bonds, then the federal tax credit is reduced by 90%.

The IRS has said in a series of private letter rulings that various state benefits do not require a haircut. The agency released the latest such ruling in early October involving a state program to encourage wind development, probably in Oregon. Utilities in the state are required to collect a "public purposes charge" as part of electricity rates to cover, among other things, the above-market costs of renewable energy. The money collected is paid into a trust fund, and a state agency has authority to direct how the money is spent. In the case addressed in the ruling, a partnership that is developing a wind project agreed to transfer all the environmental attributes from its electricity — for example, greenhouse gas credits — to the trust in exchange for an "advance payment." The advance payment "vests" — does not have to be paid back — as the project delivers electricity to an in-state utility that has agreed to purchase it. Any part of the advance payment that has not vested by year 15 must be paid back.

The IRS ruled that the advance payment is not a government grant, tax-exempt financing, subsidized energy financing or "other credit." It said the arrangement is not a "grant" because there remains a possibility that some or all of it might have to be repaid.

The partnership also qualifies for a "business energy tax credit" equal to a percentage of the capital cost of the project. (Wind projects in Oregon qualify for a 35% tax credit, but no more than $10 million per project. The credit is claimed over five years.)

The IRS declined to rule that the tax credit will not cause a "haircut" in the federal credit. It said the issue "cannot be readily resolved before published guidance is issued."

The ruling is PLR 200439038.

The director of the Oregon Department of Energy wrote Greg Jenner, the assistant Treasury secretary for tax policy, a letter on September 27 urging the US / continued page 14

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utilities on their sales of gas. The tax is passed through to consumers in utility rates. In order to prevent large industrial customers from avoiding the tax by purchasing their gas out of state, New York enacted a separate tax on gas importers in 1991. The tax made an exception for cogeneration facilities.

A partnership that owns a cogeneration facility at the Brooklyn Navy Yard bought gas directly at the field in Canada and the Gulf of Mexico and arranged with pipelines to bring the gas to New York. The partnership claimed an exemption from the gas import tax on grounds that it owns a cogeneration facility. The state tax department said on audit that the partnership owed about $7.3 million in back taxes for the period from December 1996, when the plant started operating, through November 1999, the end of the period covered by the audit, on grounds that it did not qualify for the exemption.

On appeal, the division of tax appeals said no exemption could be claimed for gas purchased before April 9, 1997, but an exemption was allowed after that.

The partnership had trouble getting an order from the Federal Energy Regulatory Commission that the project is a "qualifying cogeneration facility" under the Public Utility Regulatory Policies Act. FERC rejected the first application the partnership filed because the project had too much utility ownership. An electric utility cannot own more than 50% of a qualifying facility, or "QF." Projects do not need formal orders from FERC to be qualifying facilities. This one promptly amended its partnership agreement to address the utility ownership issue and sent a letter to FERC in February 1996 informing the agency that the project is a QF. It later asked FERC for a formal order. The order was issued on April 9, 1997.

A project must be either a QF under federal law or a "cogeneration facility" under New York law to qualify for the exemption. This one was not such a facility under / continued page 15

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government to issue the guidance quickly. He wants a conclusion that the Oregon business energy tax credit will not result in a haircut. Jenner used to be an aide to former Oregon Senator Bob Packwood (R).

The informal IRS position in the past has been tax credits that are tied to the cost of a project reduce the federal credit. Tax credits that are tied to the amount of output should not.

The IRS is reassessing whether state tax credits cause a "haircut" in the federal wind credit.

Thus, for example, 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 RECs are tied to output. The IRS ruled privately in 2003 that no haircut is required by a project that receives state tax credits that are tied to the amount of property taxes the project pays and how many workers it employs.

Oregon argues that when the US tax code says there is a haircut for any "other credit," Congress intended that a project would suffer a haircut only on account of other *federal* tax credits. IRS officials are still weighing the arguments. There is no clear evidence of what Congress intended. The IRS is looking at what inferences it can draw not only from the wording of the production tax credit, but also from a similarly worded statute that allows companies to claim tax credits for producing landfill gas and synthetic fuel from coal.

Old PPA

A company that bought a wind project recently in an asset sale by the bankrupt owner may not have done enough due diligence. The IRS said in a private letter ruling made public in early October that the new owner of the project is not allowed *any* production tax credits, at least until it amends the power purchase agreement to reset the price for a portion of the electricity sold to current market. The project is earning an above-market price currently for its electricity.

The ruling is PLR 200440001.

Congress voted in 1999, after lobbying by the California utilities, to deny production 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.

The provision comes into play when an existing wind project is sold to a new owner.

Nevada

Nevada requires electric utilities in the state to supply at least 5% of their power from renewables. The percentage is scheduled to increase to 15% by 2013. The two Nevada utilities have been unable to buy enough electricity from renewable suppliers to comply with the law because of impaired credit ratings. A project will have a harder time arranging financing without a creditworthy offtake contract.

The Nevada Public Utilities Commission voted on September 29 to order the two utilities to set up trust accounts. The commission will authorize the utilities to increase rates to cover their obligations to renewable suppliers plus set aside at least "three times the highest monthly payment" owed each eligible renewables supplier under its contract with the utility as a reserve.

Only projects on which construction started on or after July 1, 2001 qualify potentially for participation in the program.

The hope is the trust mechanism will allow such projects to obtain financing.

All payments under the power contract the project has with a utility will be made by the trust. The trust will remain in place at least until the utility has maintained an investment grade credit rating with Moody's or Standard & Poor's for 24 consecutive months. It will fall away earlier if the "original financing, including debt, equity, or both debt and equity, as applicable . . . has been fully satisfied pursuant to its original terms." The PUC will revisit the rates charged by the utility to its ratepayers once a year. Amounts remaining in the trust when the trust is extinguished will be returned to the utility, but will factor into what the utility is allowed to collect in rates going forward. The utilities will have to pay income taxes on the revenue they collect from ratepayers, even though the amounts are paid into trust, but they will receive offsetting tax deductions as amounts are paid for electricity.

It remains to be seen whether the trusts will satisfy the financial community. The protection the trusts provide is a reserve account equivalent to three months of power sales revenue. According to Ted Zink, a bankruptcy partner in the Chadbourne New York office, lenders to the power project remain at risk that the power sales contract with the utility might be rejected in bankruptcy.

Cash Investors

Financial officers at wind developers report that they are getting expressions of interest to invest in wind deals from institutional investors who lack a tax base to use production tax credits. This has put more pressure on whether a partnership that owns a wind project can distribute cash disproportionately to a cash investor while preserving the production tax credits for other investors who can use them.

IRS regulations require that partners share in production tax credits in the same ratio as they share in "receipts" from electricity sales.

Many tax counsel believe — at least until the IRS says otherwise — that partners can share in cash however they want without affecting tax credits.

The IRS national office has no position yet. IRS officials start with a sense of uneasiness with any notion that a developer or cash investor might strip out cash while leaving tax benefits for a tax-base investor.

Cash can be distributed to a partner as / *continued page 16*

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New York law because there is an 80-megawatt limit on size and the project has a capacity of more than 150 megawatts.

The division of tax appeals said, in a decision in September, that the project qualified for the tax exemption only from April 9, 1997.

Another requirement for the exemption is that the electricity or steam produced at the plant must be "supplied and used by a thermal energy host located at or near the project site." Most of the electricity from the Brooklyn Navy Yard plant is sold to Consolidated Edison, which resells the electricity to its ratepayers. The tax department argued that Con Ed was not a "thermal energy host," even though the utility also bought steam from the plant, and Con Ed is not "at or near the project site." It also argued that Con Ed does not "use" the steam and electricity since it resells them to ratepayers. The appeals division disagreed.

The New York legislature amended the exemption in 2001 to make it tougher to claim. Since 2001, gas used to generate electricity — but not steam — that is sold to a public utility no longer qualifies for the exemption. The case is In the Matter of the Petition of Brooklyn Navy Yard Cogeneration Partners, L.P. *It is DTA No. 819110.*

MANUFACTURING EXEMPTIONS may not be as broad as many power companies think.

And the fact that a sales tax had to be paid when an asset was purchased does not bar the state from treating the asset as "real property" when it comes time for collecting property taxes.

Most states collect sales and use taxes. The taxes usually apply only to sales of "tangible personal property." Thus, equipment is subject to tax. Some project developers try to have power plants classified as real property so as to avoid sales taxes when selling an entire plant. In many states, equipment purchased for use in "manufacturing" is exempted from sales and use tax. Use of equip- / *continued page 17*

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a "guaranteed payment" without affecting tax credits. "Guaranteed payments" are amounts that the partnership commits to pay a partner each year as a return on his capital or as compensation for services. An example is where a partnership agreement directs that $250,000 a year be paid to partner X out of the first available cash. Remaining cash is shared among the partners in a different ratio. If there is too little cash in a year to make the guaranteed payment, then the shortfall is made up in later years. Guaranteed payments have no effect on how tax credits are shared. The key to a guaranteed payment is the amount owed to the partner does not depend on how much income the partnership earns. It is treated for tax purposes like a payment to a third party — for example, the interest the partnership pays a bank. Payments to third parties do not affect how tax credits are shared among the partners.

Other Developments

A US wind developer announced a plan to put wind turbines on farms and to organize the farmers into an electric cooperative to own the turbines. Coops are effectively exempted from federal income taxes on the income that they distribute (or are deemed to have distributed) each year as long as at least 85% of the income comes from the provision of services to members. The developer said he plans to preserve the production tax credits for institutions that will provide the financing and to pay the farmers a 30-year annuity. The structure will be a challenge to make work. Coops in rural areas — whether are not they are tax-exempt — qualify potentially for loans from the US Department of Agriculture with terms as long as 30 years at rates as low as 1/8th percent above the rate charged by the federal financing bank for interagency borrowing.

A common question recently is whether wind farms on Indian reservations qualify for production tax credits. A Texas wind company announced projects on two reservations near San Diego in early October.

Wind projects on Indian reservations qualify potentially for depreciation over three years rather the five years used by such projects off the reservation. The tax savings from the faster writeoffs are worth about 2.27¢ for each dollar of capital cost. Such a project also qualifies for a wage credit tied to the number of Indians hired to work on the project. The deadline for placing projects in service to qualify for these benefits is December 2005.

Production tax credits may only be claimed on electricity produced "within the United States." Indian tribes are treated as sovereign nations for most tax purposes. There is some helpful case law that suggests a project on a reservation would qualify, but no clear answer.

Some US wind developers are looking at Canadian income funds and cross-border lease arrangements as a way to find cheaper capital.

A Canadian income fund is a trust formed in Canada that raises money in the Canadian capital markets and pools it for investment. Such trusts pay little US income tax on their earnings from US businesses in which they invest, and they are not subject to tax in Canada. This tax advantage means that the trusts can afford to pay at least 27% more than competing bidders for operating businesses. The problem US wind developers face when trying to tap such trusts is the trusts have no US tax base to use production tax credits, and the trusts are interested mainly in businesses that throw off a steady and predictable cash flow. The trusts may ultimately prove good cash investors alongside US institutions that can use production tax credits, at least for projects with long-term power sales agreements and a good operating history.

Cross-border leases, if they can be structured properly, involve ownership of wind turbines by an institution in another country and a lease of the turbines to a US wind company. The foreign lessor and the US wind company claim tax ownership of the turbines in their respective countries. This introduces an additional tax subsidy to the project. Such transactions only work with a lessor in a country that bases tax ownership largely on the form of the transaction. The foreign lessor advances the funds for the turbines and retains legal title to them during the lease term. The US wind company effectively prepays the rents and the exercise price for a repurchase option to be exercised when the lease ends. The prepayment is less than the full cost of the turbines; the difference is an upfront benefit to the US wind company. The US wind company remains the owner of the turbines for US tax purposes; the United States bases tax ownership on the underlying substance of the transaction. The structure leaves room for another financing — for example, to get value for the production tax credits — to be done in the United States.

Federal Regulatory Issues In Windpower Projects

by Adam Wenner, in Washington

The Federal Energy Regulatory Commission is charged with regulating wholesale power sales in all of the continental United States, except for sales in Texas. As a result, its policies significantly affect the prospects for the development of new wind energy projects. This article summarizes key FERC policies that affect wind energy development.

Regulatory Status

Project developers should try to have their projects qualify either as "exempt wholesale generators" or as "qualifying small power production facilities." These categories are important because they spare a project from potentially onerous regulation under a 1935 statute called the Public Utility Holding Company Act, or "PUHCA."

To obtain a FERC determination that a wind project is an exempt wholesale generator, or "EWG," the entity owning the wind project must be engaged only in the wholesale power business and must sell power only at wholesale — it may not sell power directly to end users.

To be a qualifying small power production facility, or "QF," a wind project cannot be larger than 80 megawatts in size, and no more than half the equity in the project can be owned by electric utilities. A project can obtain QF status simply by filing a notice with FERC or by having FERC issue a formal order granting certification.

Although an entity that owns a wind project that is an EWG is exempted from regulation under PUHCA as a utility holding company, it remains subject to FERC regulation under the Federal Power Act as a "public utility." As a result, before it can sell power, the project must obtain FERC authorization to sell its output at market-based rates. To obtain that authorization, the owner of the wind project must show that it lacks market power, or such a dominant position in the local electricity market that is can set prices. Because FERC regulations create a presumption that newly-constructed independent power projects do not possess market power, and because FERC has / continued page 18

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ment to generate electricity is often considered manufacturing.

A recent decision in Rhode Island is a warning not to assume that all equipment tied to a power plant is exempted from tax under a manufacturing exemption. A scrap metal company bought safety equipment and repair parts for cranes it uses to load the scrap metal, after processing, into trucks or ships for transportation to customers. The state said a sales tax should have been paid because manufacturing has ended by the time the cranes are put to use; the cranes are part of distribution and not manufacturing. A state tax tribunal agreed in a hearing in July. Its ruling is administrative hearing no. 2004-11.

Meanwhile, an Indiana tax decision involving Donald Trump is a warning not to assume that just because sales taxes were paid means that annual real property taxes can be avoided. Trump bought a riverboat to use as a casino. The boat was made in Florida and shipped to Indiana. Trump did not pay sales or use taxes in either state. He paid $1.1 million a year in real property taxes in Indiana. The state hit him with a $1.3 million use tax, and the Indiana Supreme Court upheld the assessment.

The court said the two statutes — the sales and use tax statute and the real property tax statute — have different definitions. Thus, the riverboat is subject to tax under both. The court rendered its decision in late September. The case is Indiana Department of State Revenue v. Trump Indiana, Inc.

PARTNERSHIPS usually designate one of the partners as the point of contact with the IRS in any tax audits.

That partner is called the "tax matters partner." Only general partners — not limited partners — can act as tax matters partners since the IRS wants someone who can bind the partnership.

The IRS said in August that a partnership whose sole general partner / continued page 19

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recognized that wind projects normally cannot profit by withholding power from the market, obtaining FERC authorization for market-based-rate sales is generally a straightforward process.

Interconnecting to the Grid

Wind projects must be located where there is sufficient wind. This is usually not where many people live, which means that the electricity must be moved long distances to bring it to market. As a result, the requirements for and pricing of interconnection facilities can be a key factor in the viability of a potential project.

Wind farms need to qualify as either "exempt wholesale generators" or "qualifying facilities" for federal regulatory purposes.

It has not been easy for independent generators using any fuels to connect to the grid. More than half of interconnection agreements between independent generators and utility are filed unsigned with the Federal Energy Regulatory Commission because the parties cannot agree on terms. Wind projects have an even more difficult time because the intermittent nature of wind generation creates additional engineering issues. FERC was so tired of mediating disputes between generators and utilities that it adopted a model interconnection agreement last year for the industry to use. The model agreement and a set of standard interconnection procedures are spelled out in two FERC orders — Nos. 2003 and 2003-A.

FERC rules establish two different types of interconnection service. "Energy resource interconnection service" enables the wind project to deliver its output to the utility grid and to transmit its output on the grid, but only to the extent that transmission capacity is available. "Network resource interconnection service" is a higher-quality service that enables the wind project to be designated as a "network resource." A network resource has the same claim on scarce transmission capacity on the grid as does electricity the utility generates itself; accordingly to provide this service, the utility must upgrade its system so as to permit the wind project to reach load in the same way that the utility integrates its own generators to service native load.

Regardless of which type of interconnection service a wind project takes, a key issue is who will pay for the equipment that is needed to permit the wind farm to interconnect and provide power into the grid. FERC rules focus on the "point of interconnection," which is the point where the wind project connects to the utility's transmission system. Under these rules, the wind project is responsible for the costs of "interconnection facilities" — facilities and equipment that are physically located on the generator side of the point of interconnection, regardless of who owns the facilities.

Facilities and equipment installed on the utility side of the point of interconnection are called "network upgrades." The utility is ultimately responsible for the costs of network upgrades, subject to an exception for utilities that have turned over operating control over their grids to independent system operators — called "ISOs" — or regional transmission organizations — called "RTOs." However, the generator must advance the cost of network upgrades, and it is repaid over time, with interest, as the utility is able to collect for the cost through wheeling charges from all users of the grid. This FERC policy is favorable to wind generators, as the costs of improvements to the transmission grid are borne by all grid users and not charged entirely to the wind project.

FERC permits an RTO or ISO to adopt, subject to FERC approval, alternative policies for the pricing of network upgrades. Several RTOs and ISOs, including PJM — which controls parts of the grid in Pennsylvania, New Jersey, Delaware, Maryland, Illinois, Ohio, Virginia, West Virginia and the District of Columbia — ISO New England, and the New York ISO, have adopted "but for" pricing for network upgrades. Under this approach, a "base case" transmission expansion plan is developed by the RTO or ISO. The cost of the new transmission facilities that would be added in the base case is compared to the cost of network upgrades that would be needed as a result of the interconnection of a wind energy plant. The generator is responsible for any additional costs. Because the generator is responsible for these costs, "but for" pricing is generally less favorable to wind projects.

In PJM, New York and New England, a generator that pays for expanding the transmission system by adding network upgrades is entitled to the financial or physical benefits of those upgrades. In these RTO or ISO regions, the RTO or ISO operates a power pool, or auction, that establishes electricity prices at locations throughout the market. When the transmission system is not being used at full capacity, the electricity price will be the same throughout the system. However, when transmission use is high, the quantity of electric power available to transfer from one location to another may exceed the ability of the transmission system to carry power and the system becomes constrained. In these constrained situations, the right to use the available transmission capacity or the financial benefits of having that right is valuable. Several ISOs and RTOs provide that "congestion rights" — the rights to use limited transmission capacity — or the financial benefit that the physical right would provide — are awarded to whoever pays for the grid improvements when a new generator connects to the grid. In these regions, by paying the cost of the upgrades, a wind generator receives the benefit of entitlement to the additional transmission capacity when the transmission system is overloaded. However, there is no guarantee that the value of these rights will equal the cost of the network upgrade; rather, the value depends on the cost of the network upgrade compared to the benefit of transferring power from a low-cost region to a high-cost region during periods when the availability of the transmission system is limited. In evaluating the feasibility of a wind energy project, the costs and benefits of any required network upgrades are clearly a key consideration.

Scheduling Issues

In order to function properly, supply on a utility system must equal demand, or "load," on an instantaneous basis. Most conventional forms of power generation can be operated to match a schedule that can be established before the fact. However, wind energy is only available when the wind blows. While wind availability can be forecasted with increasing accuracy, wind energy cannot be sched- / continued page 20

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is a "disregarded" limited liability company could only name the disregarded LLC as its tax matters partner, notwithstanding that the LLC is not considered to exist for tax purposes. The ruling is a breach in the rule that disregarded entities are treated as if they do not exist. It is Revenue Ruling 2004-88.

CREDITORS of foreign governments can "garnish" taxes and royalties that US companies owe the governments, a US appeals court ruled in late September.

The Republic of Congo defaulted on a loan from Equator Bank to build a highway. Equator Bank assigned the loan to the Connecticut Bank of Commerce, and the Connecticut bank sued in London and the US courts for repayment and then moved to enforce the judgment by seizing assets belonging to the Congo in the United States. A US appeals court held that among the assets subject to seizure are taxes and royalties that three Texas companies owe the Congo as participants in an oil joint venture with a state-owned Congolese company.

The Congo argued that its assets are protected from seizure by sovereign immunity — the right of governments to be insulated from suits. It had waived sovereign immunity in the loan agreement, but argued that it was nevertheless protected from suit under a US law called the Foreign Sovereign Immunities Act, under which a waiver of immunity is effective only against property that is "in the United States" and is being "used for commercial activity in the United States." The appeals court said both requirements were met in this case. The case is *Republic of Congo v. CMS Oil and Gas et al.*

Such decisions create practical problems for the US companies involved; they may find it hard to continue doing business in the country.

NUCLEAR POWER PLANT purchasers got relief from the US Treasury, but / continued page 21

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uled in the same way that conventional thermal generation is scheduled.

When FERC first required utilities to provide open access to the grid for independent generators in Order No. 888, it authorized utilities to require generators to schedule hourly energy deliveries and to impose penalties for deviations from the schedule. In order to facilitate the operation of wind energy and other intermittent resources, several ISOs and RTOs have eliminated scheduling requirements for these resources. For example, the California ISO permits wind generators to net out their deviations from the schedule on a monthly, rather than an hourly basis, and waives imbalance penalties. The ISO forecasts wind energy production and responds to its forecasts; wind generators pay a fee of 10¢ per MWh for this service. Monthly netting of imbalances should largely address the scheduling issue, as statistically "over" and "under" generation should cancel each other out over this longer period.

Another approach endorsed by FERC and adopted by several RTOs is the operation of "real-time" energy markets. FERC Order No. 2000, which establishes criteria that the government uses to approval applications for new RTOs, states that an RTO must ensure that its customers have access to a real-time balancing market — in other words, a market for the auctioning off of electricity — operated by the RTO itself or by an entity that is not affiliated with market participants. PJM, the New York ISO, and ISO New England operate real-time energy markets. When such a market is available, if a wind project generates less than its scheduled output, then it (or its customer) can purchase the difference at a price reflecting the then-current value of electricity. If it produces more than scheduled, then it can sell the excess into the market. The prices in that market reflect the value of the energy bought or sold and thus provide an economically fair compensation for the over- or under-generation.

Transmission Pricing Issues

Electricity must be wheeled across a grid to bring it to market. FERC's pricing of transmission, under which a transmission customer must make a fixed monthly payment for "firm" transmission service, can be problematic for wind developers since their projects must pay effectively to reserve transmission service on a "24/7" basis, but wind generators generally have a load factor of less than conventional thermal generation. As a result, a wind project that reserves firm transmission capacity ends up paying for capacity that is likely to go unused for significant periods. FERC also requires utilities to provide "non-firm" transmission service for which a transmission customer only pays on the basis of its actual usage. However, as its name implies, non-firm service is available only when the grid is not being used at capacity by firm service customers. Non-firm service is generally not a viable option for wind generators who need certainty that their electricity can get to market.

The intermittent nature of wind means that wind farms run the risk of paying for less or more capacity on the transmission grid than they need.

Relief from the problem of paying for more or less capacity on the grid than one actually needs may be found in the transmission pricing offered by some RTOs and ISOs, such as PJM. In PJM, for example, it is the utilities serving retail customers and, where retail choice is available, retail customers themselves who are responsible for the costs of the regional transmission system. By paying the embedded costs of the transmission system, a customer acquires the right for power to be transmitted to it from any point on the PJM system, without additional charge. As discussed above, separate from transmission charges, a customer who wishes to retain the physical or financial benefits of using transmission capacity during periods when the transmission system is constrained must acquire congestion rights.

Under this type of transmission pricing, since the cost of transmission is a "sunk" cost for which the customer is ultimately responsible irrespective of which generator it taps for electricity, a new wind project serving a customer located within the PJM system does not incur any additional transmission charges. A similar result occurs when a wind generator interconnects with a utility that is the purchaser of the project's power — since the utility has already incurred the cost of the transmission capacity used to serve its customer load, the wind generator does not incur a transmission charge for its sale of power to the utility. In contrast, where power from a wind generator must be transmitted across one or more utility transmission grids that are not part of an ISO or RTO, the generator can be assessed "pancaked" multiple transmission charges.

Other Interconnection Issues

In response to complaints that certain provisions in the model interconnection agreement and policies should not be applied to wind generators, FERC exempted wind projects from several of its generally applicable requirements, including the requirements to install power system stabilizers and to maintain a specified power factor. Wind projects use small, non-synchronous generators that respond differently to grid disturbances than do large synchronous generators. In Order No. 2003-A, FERC afforded the wind industry an opportunity to suggest other areas in which the unique electrical characteristics of wind generators call for adoption of different approaches for the interconnection of wind generation.

The American Wind Energy Association has proposed that FERC adopt a "low voltage ride-through standard" for wind farms. It also wants standards for projects to install remote supervisory control and data acquisition equipment (SCADA) that allows remote control of wind farms. According to AWEA, low voltage ride-through capability ensures that wind projects will remain on line during most power system disturbances and help support the stability of the grid. AWEA proposes that low voltage ride-through capability be required when it is found to be beneficial based on significant amount of wind project penetration on the system.

Regarding SCADA equipment, AWEA suggests wind farms should install equipment that would curtail output during system emergencies and provide bi-directional electronic communications between the grid operator and the wind farm to exchange information needed for forecasting and

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only for acquisitions on or after September 15, 2004.

Owners of nuclear power plants are required by federal law to set up decommissioning funds to cover the cost of decommissioning a plant after it reaches the end of its useful life. The liability for these costs is a significant figure. When someone buys a nuclear power plant, he acquires not only the power plant but also the decommissioning fund. US tax rules require the parties to allocate the purchase price among the various assets sold.

Under current allocation rules, a large share of the purchase price is allocated first to the decommissioning fund — without taking into account the liabilities for decommissioning as an offset against the value of the investments in the fund — before there is any allocation of remaining purchase price to the power plant itself. The result is a large share of the purchase price is allocated to the fund, and little is left over to allocate to the power plant. This makes it harder to sell nuclear power plants since the buyer will not be able to claim as much tax depreciation. Amounts allocated to the fund cannot be deducted until the fund is later resold or used to pay decommissioning expenses. The cost of the power plant can be deducted starting immediately through depreciation.

The Internal Revenue Service issued temporary regulations in September that will allow either party — the seller or the buyer of a nuclear power plant — to make an election to take the fund liabilities into account. This would let whichever party or parties choose to make the election allocate the purchase price among all the assets, including the fund net of liabilities, in relation to their relative values. The new rules are prospective in effect.

LEVERAGED PARTNERSHIPS continue to receive attention as a way to sell property without triggering a tax. This one failed, but not by much. */ continued page 23*

Wind

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scheduling. AWEA also proposes that wind generators be required to maintain a power factor of up to 0.95 leading and 0.95 lagging. Finally, it has asked FERC to require that engineering models used to determine interconnection requirements be current, and to permit wind generators to do their own feasibility studies of a proposed interconnection rather than having to submit a completed power systems load flow study as part of its interconnection request. Because the turbine selection decision is greatly influenced by the grid conditions at the utility interconnection point, until those conditions are known, the turbine selection and electrical design is not completed. However, in order to enter the interconnection queue, a wind developer must have a completed electrical design. To avoid this "Catch-22," AWEA proposes to permit the developer, upon payment of the appropriate deposit, to enter the interconnection queue, receive grid base case data, including load flow, stability and short-circuit base case data, and then present the utility with an electric design sufficiently detailed to enable the utility to conduct a system impact study.

FERC held a hearing on the AWEA proposals in mid September. The agency is expected to announce its decisions about them early next year. ◎

Biomass Projects in the UK and US

by Denis Petkovic, in London

Forty-five percent of all renewable energy used in the United States involves biomass, and 4% of all energy consumed in the United States is represented by biomass, according to the Global Energy Research Institute. These are staggering statistics in the light of the relatively dismal success of biomass projects in the United Kingdom.

This article discusses some of the key features of biomass financings, contrasts the UK support for such projects with the support in the US, and suggests steps to be taken in the UK to improve the odds for biomass projects to succeed. Biomass projects, in simple terms, involve combustion or other technologies that generate heat, and the heat is used to drive a turbine that generates electricity. Such projects raise four particular issues that, while shared by other projects, are unique in their application to biomass. These are fuel supply arrangements, environmental issues, technology risk and tax risk.

Fuel Supply Arrangements

Fuel supply contracts vary with the fuel type used. There are three broad types of biomass material: forestry materials (where the fuel is a by-product of other forestry activities), energy crops, such as short rotation coppice, willow or miscanthus where the crop is grown specially for energy generation purposes, and agricultural residues such as straw or chicken litter.

Whatever the fuel, one requires a lot of it to fuel a biomass plant because of the low calorific value of such fuels. The UK's leading renewables company, Energy Power Resources Limited, for example, which operates the ELEAN straw-fired plant at Ely, England, uses 230,000 tons of straw a year to generate 36 megawatts of electricity. In the same company's poultry litter plant located at Thetford, England, which generates 38 megawatts of electricity, 450,000 tons a year of poultry litter are required.

Project financiers will want to see a fuel contract with a term at least as long as the power sales agreements or financing arrangements. This must be executed prior to financial closing. There is a threshold issue to grapple with for long-term fuel supply contracts in the UK biomass sector. Generators are said to be unsure still how the "large combustion plant directive" will affect them, and this is one of the reasons why they are not prepared to offer long-term contracts to biomass suppliers. Moreover, to the extent that the sector requires energy crops to act as a fuel source, there is no national policy in the United Kingdom on setting aside land for this purpose. This is a fundamental issue given that some energy crops, such as miscanthus or willow coppice, require a three-year period to elapse before farmers see a saleable crop.

For a successful project, fuel should be available to the project in quantities sufficient to run the plant at full capacity when it is needed. If the power purchaser has varying power requirements, a connected consideration for any biomass project will be the availability of fuel in the immediate countryside. In the UK, forest wood, for example, is simply not available within a viable distance for many prospective generating plants.

The fuel supply contract must accommodate the project's needs with flexible delivery schedules. The pricing provisions of the fuel supply contract, including any increases in price to account for inflation or other factors, should match provisions under the power sales agreements that allow comparable adjustments to the power purchase prices. The quality of fuel to be delivered must be compatible with the project's construction, design and permitting requirements and restrictions, including air emissions restrictions.

Contracts for the transportation of fuel to the plant are equally important as contracts for the supply of fuel. Availability of rail transportation facilities may be an issue, or if fuel is delivered by truck, availability of roads for this increased traffic may be a problem. This is very much the case in the UK where the loss of national railways over generations now forces biomass transportation onto the roads system; roads are the most expensive mode of transport in the UK. Interconnection to transmission and distribution systems should be available.

Fuel storage arrangements or a back-up fuel supply may be necessary if satisfactory fuel supply and transportation arrangements are not available and, in any event, are matters with which the lenders must be comfortable.

Diversity of fuel suppliers may also be necessary to enable a successful project financing to take place. A project company should, ideally, maintain relationships with a variety of fuel suppliers rather than concentrate its inputs on one so as to minimize the likelihood of disruption to supply and to price changes.

In the case of biomass, fuel supply can be affected heavily by seasonal factors, and this must be addressed. For example, forest fuels such as wood wastes may become too moist in winter and other wet periods and can affect plant efficiency and supply and, for some types of biomass, like straw, wet weather will simply damage stocks of fuels held by the generator. If the plant is fitted with technology to supplement such fuel sources, like natural gas, for start up and combustion, this is beneficial. Another means of alleviating fuel supply price risk is to build up stocks of fuel on site or with near-site storage. Owing to moisture risk, plant storage arrangements need to be considered for any project as should the project company's policies / continued page 24

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Company A had property it wanted to sell. It contributed the property to a partnership with other partners. The partnership borrowed on a nonrecourse basis against the property and distributed the cash to Company A.

The IRS is always on the lookout for disguised sales of property to partnerships. Such a sale will be assumed when one partner contributes property and receives back cash from the partnership within two years. However, IRS regulations make a number of exceptions. One exception is where the partnership borrows against the property and distributes the cash to the partner whose property it was within 90 days. The partner may have gotten back cash within two years of contributing property, but he will not be treated as having sold the property as long as the cash he received is no more than his share of the loan the partnership took out to pay the cash.

What is his share of the loan? Most nonrecourse debt at the partnership level is considered borne by partners in the same ratio as they divide up the taxable income of the partnership. However, partners are free to agree on a different percentage as long as that percentage is consistent with how they share in some "other significant item."

In this case, the business deal among the partners is that Company A had a "senior preferred interest" in the partnership. It got cash equal to its preferred return each year before other partners were distributed any cash. It was also allocated an amount of "gross income" for tax purposes equal to the cash it was distributed each year before any income was allocated to anyone else.

The partners agreed on allocating 100% of the debt to Company A. This avoided a disguised sale. Company A argued that this was consistent with an "other significant item" — the fact that 100% of gross income was allocated to Company A each year up to a certain amount. / continued page 25

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toward fuel blending.

The heating value and moisture content of different types of fuel to enable the maximum level of power generation to take place will also be of interest to lenders. A connected topic is whether the plant requires drying technology to reduce moisture content of fuel. Where premium fuel is required by the plant, such as natural gas, then maintaining good fuel quality control becomes a key ingredient of assuring the profitability of a project. In this regard, wood fuel prices vary seasonally.

Environmental Issues

An issue that will be of great sensitivity to lenders (and project sponsors) is liability for environmental conditions at or from the site, including contamination at the site caused by the use, or misuse, of hazardous substances, air pollution and wastewater discharge to nearby water bodies. The transfer documents for the site or the site lease should, at a minimum, contain an environmental indemnity by the prior owner or lessor for pre-existing conditions on the site. An environmental site assessment should be performed (even if it is not legally required) before a site is finally chosen and any contamination or other potential liabilities, such as areas of historical, religious or archaeological sensitivity, potential contamination from neighboring land, or presence of endangered species or rare habitats, must be evaluated and, if possible, removed or the impact mitigated.

Project sponsors and lenders alike will want to be sure that the project and the site are properly permitted under all applicable laws and regulatory requirements. Air, water, waste discharge or storage and other permits will need to be obtained before closing. Any permit that is not final and non-appealable or is revocable prior to repayment of financing, or that contains requirements or conditions that are unduly burdensome, could delay financial closing or make the project financing more difficult without additional sponsor support. In some projects, permits relating to construction may be the responsibility of the construction contractor, but the project sponsors will be required to confirm early in the development process that all required permits will be available when needed.

Particular environmental issues raised by biomass projects concern air emissions. In the UK, the "waste incineration directive" sets strict emissions levels and can directly affect the operation of some biomass projects. Biomass plants must comply with the directive even though coal-fired plants, for example, that emit more carbon monoxide are unaffected by the directive. The fact that the introduction of the waste incineration directive (through UK regulations) commenced on December 28, 2002 has directly affected the profitability of some existing biomass plants owing to the compliance and regulatory costs.

Other environmental issues raised by biomass concern how waste ash byproducts are dealt with, how and where cooling water will be disposed, where the water supply is coming from, noise emission levels and the potential increase in road transport as fuel is transported to a plant.

Technology Issues

It is a given that commercial lenders will not assume the risk of unproven technology under traditional project financing theories. Biomass projects that have been unsuccessful in the UK have often breached this basic principle.

Two high-profile UK projects reflect this failing. The first is the case of the collapse, in 2003, of Border Biofuels Limited, which was described by *The Scotsman* newspaper in the following terms:

> A Scottish company given millions of pounds in grants from the [DTI] network has suffered a spectacular financial crash without creating a single job or starting any of its ambitious developments.

The company sought to establish a high tech venture using unproven pyrolysis technology. This technology involved heating timber, plant matter and organic waste at high pressure to produce a high-quality oil that can fuel a power plant. The £4.6 million project was funded 25% by grants from the Department of Trade & Industry. The remainder of the finance came from The Bank of Scotland, British Linen Bank, hire-purchase agreements and shareholder loans.

The project would not have been a candidate for a conventional project financing. The technology was unproven. However, the project company historically held interests in other ventures ranging from power generation development and biomass fuel supply to coppice production. A project financing would have imposed the discipline of total concentration on the project at hand and not permitted additional investments and diversification. Indeed, at the time of its collapse, Border Biofuels was reportedly considering developing huge biomass plants at Hexham in Northumberland, Carlisle, Ellesmere Port in Merseyside and Newport in South Wales.

A second, even more high-profile collapse in the UK owing to technology risk was the ARBRE project — a £30 million project funded from European Union grants and Department of Trade & Industry grants (a total of £13 million) and the balance from shareholders such as Yorkshire Water Plc (which company resold its interests to Energy Power Resources for £1).

Following the insolvency of ARBRE Energy Limited and sale of its assets to American interests, *The Guardian* reported (on May 31, 2003):

> The sale is a disaster for Britain's green energy policy . . . .

This project, which began in 1998, also involved previously unproven technology associated with gasification aimed at making combustion more efficient by converting short rotation coppice into gas that could then be used to fuel a gas turbine generator. The plant closed after eight days of operation (owing to deposits that failed and ultimately blocked the plant's heat exchangers). The plant's closure caused a crisis for nearby farmers who had planted 1,500 hectares of this crop for which there was no buyer after the company's collapse. The 2003 Royal Commission on Environmental Pollution said of ARBRE:

> [T]he loss of ABRE has . . . shaken the confidence of other investors and, equally importantly, of the farmers concerned.

The Royal Commission on Environmental Pollution also assessed that the "main problem" for the failure of biomass to become established in the UK is that the government capital grants schemes for biomass have focused on high technology approaches to "electricity-only generation" with a view to potential export development.

Demonstration schemes have not been based on established biomass technology and have consequently failed with a resulting loss of confidence in the sector. Basically, the Department of Trade & Industry has concentrated its grants for capital and research and development by backing the wrong technological horse in speculative demonstration plants for gasification and pyrolysis technology rather than proven technologies. / continued page 26

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The IRS said no in a "technical advice memorandum." A "technical advice memorandum" is a ruling by the IRS national office to settle a dispute between a taxpayer and an IRS agent arising from an audit.

The national office said a tranche of gross income or taxable income can never be a "significant item." Rather, the phrase refers to partnership income of a certain character type, such as gains from the sale of property or tax-exempt income. The ruling is TAM 200436011. The IRS made it public in early September.

RUSSIA is requiring foreign companies to reregister with the tax authorities by January 1 or risk having their bank accounts frozen.

EUROPE has created a new type of legal entity — a *Societas Europaea* or SE — that will be available from October 8. SEs are public limited liability companies. The Internal Revenue Service said in early October that SEs are corporations for US tax purposes.

HOLLAND is expected to cut corporate income tax rates. The latest budget proposed by the government in late September would cut the corporate tax rate from 34.5% to 31.5% starting January 2005 and reduce it further to 30% in 2007. The budget would also get rid of a corporate surtax of 20% on excessive dividend distributions next January rather than waiting until January 2006.

AUSTRIA will cut its corporate income tax rate from 34% to 25% next January 1.

It will also allow companies to join together in filing a group tax return. The common parent company must own more than 50% of each of its subsidiaries that joins in the group return. Joint ventures can also be included in a group return provided the parent company has at least a 55% interest. In most but not all cases, the *entire* profit or loss of a company must be reported / continued page 27

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The experience of ARBRE is in contrast to EPR Ely Limited's straw-fired power plant near Ely in Cambridgeshire. This £60 million, 31-megawatt straw-fired power station, which has the benefit of a power contract terminating in 2013, was funded with £52 million of senior project finance debt and £8 million of equity from Energy Power Resources Limited and Cinergy Global, Inc. The senior debt was provided by HypoVereinsbank of Germany and National Investment Bank of The Netherlands.

The developers of two unsuccessful British projects forgot that commercial lenders will not assume the risk of unproven technology.

The security taken by the banks in 1998 comprised a debenture incorporating first priority charges over all land owned by the project company, intellectual property, goodwill, consents and permits, contract and other rights. In 2004, the project's main sponsor, Energy Power Resources Limited, as a security trustee, took a second ranking debenture securing loan finance provided by it and other holders of loan stock.

The power station consumes 230,000 tons per year of straw that is collected from farms within a 50-mile radius in the form of Hesston bales weighing over half a ton each. The delivered straw must have a moisture content below 25%. This is automatically tested and weight-corrected and craned from delivery trucks, 12 bales at a time. The fuel is stored in two enclosed barns having a total capacity of 2,100 tons (enough for up to four days of operation).

The unloading cranes automatically feed a straw conveyor system, serving twine-cutters and bale-breakers that shred the bales *en route* to four screw strokers feeding individual burners. The straw is burned on a two-stage crate. The plant's operation results in byproducts, including fly ash and boiler grate bottom ash, that are collected, stored and form the basis of organic agricultural fertilizers.

Unlike ARBRE and Border Biofuels, the Danish technology used at the EPR Ely power station was proven in a number of European plants making it an appropriate candidate for project financing. Governmental estimates are that straw alone could, in principle, provide more than 3% of total electricity in the United Kingdom.

Tax Risk

To the extent that a biomass project relies on government subsidies to pay a large part of the project costs, then the project carries a tax risk that it will not qualify for such tax subsidies. For example, it might miss a deadline to be put into service or the mix of materials supplied to the plant as fuel might not qualify as biomass. Several US insurers are now selling insurance to protect against such tax risk which is expensive and, in some US states like California, subject to avoidance legislation. Lenders would generally expect the project sponsor to make payments to the project for the value of any proposed tax subsidies whether or not the project qualifies.

Contrast the US Experience

In the United States, the tax system has played a large part in the success of biomass projects. A number of key tax and like initiatives deserve mention. Section 29 of the US tax code has traditionally provided a tax credit for projects involving biomass that is converted into gas before it is used as a fuel. The credits can be claimed on gas produced from biomass through 2007. However the equipment used to produce the gas must have been put into service by June 1998 to qualify. Congress is debating whether to extend the deadline to allow additional projects to qualify for the tax subsidy.

Section 45 of the US tax code also specifically allows taxpayers a tax credit of 1.8¢ a kilowatt hour for electricity generated from "closed-loop biomass" for a period of 10 years starting when the power project is placed in service. Projects must be put into service by the end of 2005 to qualify. Closed-loop biomass refers to plants that are grown exclusively for use as fuel in a power plant. The US government had in mind "electricity farms" (similar to the short rotation coppice arrangement for the ARBRE project) where plants are grown specifically to be burned as fuel. The Internal Revenue Service said last April that there are no known closed-loop biomass plants in operation in the US Congress is debating whether to allow power plants that use other types of biomass as fuel also to qualify for the credits.

Equipment in a power plant or other facility that uses biomass or disposes of "waste" could also qualify for an unusually generous US depreciation allowance.

Certain equipment in an electric generating plant that uses biomass for fuel qualifies for depreciation over five years using a 200% declining-balance method, provided the plant is a "qualifying small power production facility" within the meaning of the Public Utility Regulatory Policies Act. The following equipment qualifies: boilers, burners, pollution control equipment required by law to be installed, and equipment for "the unloading, transfer, storage, reclaiming from storage and preparation" at the place where the biomass will be used as fuel. This is basically all equipment up to the point where electricity is produced.

The ability to depreciate an asset over five years is a valuable benefit. Equipment in a power plant is normally depreciated over 15 or 20 years. Each dollar of depreciation deductions spread over 20 years produces tax savings of 13¢ in present-value terms, while the same dollar deducted over five years produces a tax savings of 25¢ — almost twice as large. If the developer cannot use the tax benefits himself, he may be able to transfer the tax benefits to another company that can use them in exchange for equity to help finance the project.

The Energy Policy Act of 1992 also authorized a program of "incentive payments" of 1.5¢ a kWh by the US Department of Energy for power plants that use sunlight, wind, biomass or geothermal energy for fuel.

The incentive payments are subject to the following conditions. The power plant must be owned by a state or local government or nonprofit electric cooperative. The payments can be made to the owner *or the operator*. A project qualified for the payments if it was "first used" during the period October 1993 through September 2002. The electricity must be "for sale in, or affect, interstate commerce." Once approved for a project, the incentive payments continue for 10 years. Power plants that burn "municipal solid waste" are ineligible for the payments.

Power companies have historically */ continued page 28*

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on the group return — not just a share corresponding to the ownership interest.

"SUBPART F INCOME" had to be reported by a US company even though it could not have received it.

A US company owned common stock of a foreign corporation. Someone else owned preferred stock in the same corporation. The organizational documents for the foreign corporation barred it from paying any dividends to the common shareholders while the preferred shares were outstanding.

The United States looks through any foreign corporation that is more than 50% US owned and taxes any US shareholder who owns at least 10% of the foreign corporation on its share of the foreign corporation's earnings. However, not all earnings are exposed to tax like this. The US will look through and tax only the passive earnings — like dividends, interest, rents and royalties — earned by the foreign corporation. This is called "subpart F income."

In this case, the US company argued that it should not have to pay tax on any part of the foreign corporation's passive earnings because it could not receive them.

The IRS said no in a "technical advice memorandum," or ruling issued by the IRS national office. The national office called the circumstances that denied the US company access to the earnings a "voluntary" restriction. It was something to which the shareholders agreed when they set up the company. The IRS refused to give the restriction any significance, in part because the US parent company had the voting power to change the restriction if it wanted.

More importantly, the IRS said it would only have let the US parent company avoid reporting a share of the earnings if it was denied access by currency restrictions or other laws in the foreign country. The ruling is TAM 200437033. The */ continued page 29*

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been able to issue tax-exempt debt associated with "solid waste disposal facilities," notwithstanding that tax-exempt bonds in the United States are generally supposed to be restricted to financing for schools, roads, hospitals and other public facilities. Private companies that own "solid waste disposal facilities" have had access to the tax-exempt bond market for finance because the plants are thought to produce public benefits.

A power plant that burns solid waste converts disposes of the waste by converting it into electricity. In addition, pollution control equipment that traps ash and other solid particles at the back end of power plants that burn solid fuels (which can account for as much as 25% of the total cost of a power project) has, in the past, qualified for tax-exempt financing benefits.

The Internal Revenue Service is proposing to tighten the definition of solid waste. In the future, only material that has been discarded can qualify as waste. (It is enough currently to show that nothing was paid for the fuel; people pay for transporting and handling, but not for the fuel itself.) The more restrictive definition could take effect next year.

Finally, an additional boost is given to biomass projects in the United States through "renewable portfolio standards." Sixteen US states have adopted some form of renewable portfolio standard, or law requiring utilities either to generate a percentage of their electricity from renewables or buy it from independent generators who use renewable sources. In some of the states, the utility must have a certain number of renewable energy credits — called RECs or green tags. Anyone producing electricity from renewable fuels receives credits and can sell them in the market. This is potentially another source of cash for developers of renewable energy projects, although there is litigation at the state level over whether the generator still owns the green tags as a separate assets in cases where he has sold the electricity under long-term contract to a utility. The Federal Energy Regulatory Commission declined to settle the issue and threw it back to the states to address under their individual programs. Currently, there is no federal renewable portfolio standard.

The rules for what qualifies as a renewable vary from state to state, but biomass generally qualifies. A failure by a utility to buy the requisite electricity results in financial penalties unless the utility buys renewable energy credits from a third party — if applicable state law allows it to do so.

It will be seen that the US rules bear some strong resemblance to the UK renewables obligation, but operate in tandem with tax concessions supportive of biomass.

The UK Experience

The UK government's stated target is that 10.4% of licensed electricity supplies is generated from eligible renewable sources by 2010.

At the heart of this policy is the "renewables obligation," which now places an annually-escalating obligation on all licensed electricity suppliers in England and Wales to source a growing percentage of their total electricity sales from renewable sources. The procedure, introduced in April 2002, requires the supplier to present renewable energy certificates — called "ROCs" — representing one megawatt hour of electricity generated from eligible units to OFGEM, the Gas and Electricity Markets Authority, in respect of periods of one year. These certificates are issued to accredited generators for eligible renewable electricity generated within the United Kingdom and UK territorial waters.

The main eligible technologies are, in summary:

- Landfill and sewage gas,
- small hydro (under 20 megawatts declared new capacity), or larger hydro if commissioned after April 1, 2002,
- onshore and offshore wind, biomass (including, up until 2016, biomass co-fired in conventional fossil-fuelled plant),
- geothermal power,
- tidal and wave power, and
- solar power.

The renewables obligation replaced a former "NFFO regime" and its equivalent in Scotland that guaranteed generators fixed-price power sales contracts with the Non-Fossil Purchasing Agreement and that were popular with project financiers. The fact that changes in the renewables regulatory regime occurred underscores, for financing banks, that this sector is substantially at a high risk of legal change or "regulatory risk."

As an alternative to supplying renewable energy, suppliers may fulfill part or all of their obligations by paying a buyout price to Ofgem set a £30/MWh up until April 2003 and then adjusted in accordance with the retail price index. The proceeds will then be returned to suppliers by OFGEM in proportion to the number of ROCs that each supplier presents to discharge its obligation. Failure to pay the buyout price, in theory, leads to payment of a financial penalty.

Aside from the renewables obligation, the UK government operates as capital grants scheme aimed at wind and energy crops-based renewables.

In principle, the ROC regime has much to commend itself; however, some problems have arisen in practice.

First, there is no technology banding under the regime and, thus, biomass projects must compete in the market for capital against other renewables technology such as wind; being a more expensive technology, this result is very much to the detriment of biomass. Moreover, wind is the renewable technology that can be brought to market more quickly than any other meaning that it produces the earliest return on investment for investors. Further, the costs of collection, storage and transport of fuel place a heavy financial burden on biomass project generators. For example, in relation to the EPR Ely project, farmers receive £2 per ton for straw lying in the fields, but by the time it is baled, stored and transported to EPR's plant in Ely the cost is £35 per ton. Poultry litter plants raise similar issues.

Second, the buyout price has, in relation to electricity suppliers in financial distress, simply not been paid. Thus, three insolvent electricity suppliers have not paid their buyout price after entering into insolvency.

Name	Insolvency Date	Amount Outstanding
Atlantic Electric and Gas Limited	April 2004	£8.45 million
Maverick Energy Limited	June 2003	£642,110
TXU (UK) Ltd	November 2002	£22.5 million

The administrators, in each case, argued that compliance with the renewables obligation was incompatible with their duties and applicable insolvency law. There was little OFGEM could do in the circumstances, and reform of the rules associated with the buyout price is being considered. However, two steps that could be considered are reducing the period suppliers have to calculate and pay the */ continued page 30*

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IRS made it public in September.

WEST VIRGINIA needs to keep collecting a 14¢ per ton tax on coal mined in the state past March 2005. The tax had been scheduled to drop then to 7¢ a ton. The state Department of Environmental Protection made the recommendation in August. The tax proceeds are used for reclamation of old mines.

MEXICO is considering reducing the corporate income tax rate from 33% to 28% over three years starting in 2005.

This is one of several tax reform proposals that the Fox administration submitted to the Mexican Congress on September 8. The tax reform plan would also let companies deduct profit-sharing payments to employees before computing income taxes and impose "thin capitalization" rules that would deny a company deductions for interest payments to the extent its debt-equity ratio exceeds 2 to 1. There would be a five-year transition period for companies whose debt-equity ratios are currently too high.

The Fox administration has had trouble in the past putting its legislative program through Congress.

IRAQ AND LIBYA are no longer on a list of countries where US companies suffer a tax penalty for doing business.

US companies suffer two penalties for doing business in countries with which the US has severed diplomatic relations. Their earnings in the country are taxed immediately in the US as "subpart F income" without waiting for the earnings to be repatriated to the United States, and they are not allowed to claim income taxes already paid on the earnings in the rogue country as a foreign tax credit against further taxes in the United States.

The US Treasury Department removed Iraq from the list on September 27. The delisting is effective as of last June 28. President Bush informed Congress a week */ continued page 31*

Biomass

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buyout price (perhaps to monthly periods) and thereby reduce OFGEM's credit exposure to suppliers. Another alternative is to require buyout price payments to be "ring fenced" from the funds available to other creditors under insolvency laws (although this is against the spirit of insolvency reforms undertaken by the UK government in the Enterprise Act 2002).

Spain is considering removing the preferential pricing enjoyed by wind and increasing that enjoyed by biomass to redress an imbalance.

Third, it is not even clear that the UK government is really behind biomass. This statement from the Select Committee on Science and Technology's Fourth Report is breathtaking:

> Biomass . . . [f]uels have a low energy content compared with their bulk and it does not make economic or environmental sense to transport them long distances before using them. There are several biomass plants in the United Kingdom, but it is unlikely that there will be more in view of the unhelpful and confused regulatory environment and the lack of financial encouragement. However, making use of biomass, both indigenous and imported, could be a cost effective way of meeting the Government's targets for renewable generation. We understand that this is now the policy of the Danish government.

Regulatory charges in the form of the introduction of the New Electricity Trading Arrangements, or "NETA,") in 2001 (which put in place market-based trading arrangements for electricity) in England and Wales contributed to a fall in wholesale electricity prices, up until recently, to around 1.5p per kWh whereas 6 to 6.5p per kWh is effectively the break-even point for a profitable biomass plant. Even wind generators have struggled at times to generate electricity profitably under the NETA regime, so difficulties for biomass developers are likely to be greater.

In addition, the planning process in the United Kingdom is one of the most problematic areas for renewables developers. Small generators are approved by local planning authorities on a case-by-case basis rather than by the Secretary of State (as is the case for generators in excess of 50 megawatts). Amusingly, one of the most significant objectors to renewables projects in the United Kingdom is the Ministry of Defense — albeit to wind generators — on the basis that they may confuse radar. Nevertheless, the fact that two government departments, Defense and the Department of Trade & Industry, have contradictory policies towards renewables reflects the uncoordinated muddle that UK energy policy sometimes finds itself in and the perception that regulatory risk is an issue in UK power financings.

Conclusion

The upshot of this discussion is that biomass in the United Kingdom requires protection from the market mechanism imposed by the renewables obligation in favor of, say, large-scale wind projects. The previous government program — called NFFO — provided that protection and acted as a spur to some developments in this sector. The US experience of making biomass projects more economic through tax incentives and renewable portfolio standards is complimentary to this approach as would be the introduction of biomass RO certificates and requirements. What is necessary, under the current RO regime, then is technology banding of sorts. Even the Spanish authorities — a strongly green government — have recognized this. In that country, the tariff paid to biomass and wind is twice that of the market rate for fossil fuel-derived electricity. However, such pricing favoritism has not helped the biomass sector grow. Spanish authorities are now considering removing the preferential pricing enjoyed by wind and increasing that enjoyed by biomass in order to redress the situation. If similar biomass "nurturing" steps were to occur in the United Kingdom, including US-style tax system support for biomass project financings more projects, such as EPR Ely, should follow. The UK government needs to be far more consistent, coordinated and "mid-Atlantic" in its approach towards this sector. ◎

Power Contracts and Bankrupt Generators

by Joseph Smolinsky, in New York

US courts in different parts of the country have reached different conclusions about whether it is up to the bankruptcy judge or the Federal Energy Regulatory Commission to decide when a power contract with unfavorable terms can be canceled in a bankruptcy proceeding.

Also at issue is what standard a bankruptcy judge must use if it is his or her decision.

The cases are important because banks financing power projects wonder how secure are the long-term power purchase agreements, or "PPAs," against which they lend.

The NRG Energy and Mirant bankruptcies provided an opportunity recently to settle these questions. A federal district court in New York said it is up to FERC to decide when a power contract can be canceled. A US appeals court in the south central United States told Mirant that the decision should rest with the bankruptcy judge, but suggested he should use a stricter standard than is usual for bankruptcy proceedings when deciding whether to let such a contract be canceled.

The cases call into question the interplay between the US bankruptcy code and the Federal Power Act. The Federal Energy Regulatory Commission has exclusive jurisdiction under the Federal Power Act to regulate the transmission and sale of electricity in interstate commerce. FERC is also responsible for regulating prices, terms and conditions for the sale of electricity between states and regions.

A company in bankruptcy can sometimes reject or disavow contracts as part of a plan to restructure its finances.

Starting with the Enron bankruptcy filing in late 2001, four merchant power companies have been in bankruptcy. Two merchant generators — NRG Energy, Inc. and Mirant Corporation — tried to reject long-term / continued page 32

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earlier that he intends to grant a waiver from both penalties for Libya.

BULGARIA cut its corporate income tax rate from 19.5% to 15%. The new rate takes effect on January 1.

ROMANIA cut its corporate tax rate from 25% to 19% starting next January. The announcement appeared in the official gazette on August 27.

ESTONIA is moving to cut corporate income taxes. Corporations are not taxed on their retained earnings, but are taxed at a 26% rate on earnings that they distribute to shareholders. In late September, the government proposed a reduction in the tax rate to 24%. The proposal must still be approved by parliament.

GOVERNMENT GRANTS that supplement operating income are taxable, the IRS said.

The US government imposes duties on imports that foreign manufacturers are found to be "dumping" in the US market. Dumping is selling goods at less than their market value. By law, any such duties collected are distributed by the government to the affected industries in the United States as compensation for injury. The IRS is insisting on audit that such payments must be reported as income by the US companies that receive them. A "technical advice memorandum," or ruling, released by the IRS national office in one of the audits in late August explains the IRS reasoning. The ruling is TAM 200434019.

PROPERTY TAX ASSESSMENTS withstood challenges in two states.

In one case, the owner of a landfill in Virginia complained that the county should not have assessed the value of his property by discounting the projected net income the landfill was expected to earn over time. He argued that this was the / continued page 33

PPA Bankruptcies

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power purchase agreements, but their requests to the bankruptcy judge for approval were opposed by the contract counterparties, both regulated utilities. The utilities in both cases argued that only FERC, and not the bankruptcy court, has jurisdiction over the ultimate disposition of PPAs. The merchant generators countered that rejection of contracts is clearly within the exclusive jurisdiction of the bankruptcy courts. FERC, protective of its mandate, played active roles in both these disputes.

This article discusses the rights of a bankrupt company to terminate contracts generally and how the NRG and Mirant courts have reconciled these broad debtor rights to disavow contracts with FERC's need to ensure that consumers are supplied with stable and economical electricity. For independent generators and their lenders and other creditors, this developing law could greatly affect creditor recoveries and limit restructuring alternatives.

It is not yet clear who decides on when a power contract with unfavorable terms can be canceled in bankruptcy.

In General

Restructuring a business successfully in chapter 11 often requires not only a reduction in debts, but also a refocusing of business operations to more profitable pursuits. This operational assessment process necessarily includes a review of all outstanding contracts to determine whether the bankrupt company could become profitable again by rejecting certain of its contracts.

The ability to reject burdensome "executory" contracts under section 365 of the US bankruptcy code is one of the most valuable benefits from filing for bankruptcy. It permits a bankrupt company to pick and choose among its various leases and executory contracts. The term "executory contract" is not defined in the Bankruptcy Code, but the term is generally accepted to mean any contract where there are material ongoing obligations remaining by both parties. The decision whether to assume or reject leases of office space and other nonresidential real property must be made within 60 days, unless the court allows more time. The decision to assume or reject other contracts does not usually have to be made by the bankrupt company until it presents a plan of reorganization. However, many companies try to reject burdensome contracts early in the bankruptcy process because doing so brings immediate savings.

The bankruptcy code lets a bankrupt company *assume* an executory contract (other than an agreement to provide a loan or other financial accommodation) only if, at the time of assumption, two things occur. The company must cure past defaults and demonstrate its financial capability to perform the contract fully in the future. Section 365 of the US bankruptcy code provides a further benefit in that it permits a bankrupt company, as part of the assumption process, to assign a contract to a third party notwithstanding a prohibition against such assignments in the contract. Notwithstanding this, personal service contracts and certain intellectual property licenses cannot be assigned without consent.

A bankrupt company has the power to *reject* an executory contract if the contract is burdensome and, in the company's business judgment, rejection is appropriate. If a contract is rejected, then it is not terminated but rather the bankrupt company is considered to have breached its obligations under the contract as of the bankruptcy filing. This excuses the company from any further performance, but also exposes it to a claim for damages from the counterparty to the contract. The counterparty's damage claim is treated in bankruptcy as a "pre-petition general unsecured claim" for damages. This establishes its priority for payment. In contrast, if a contract is assumed by the company and then later breached, the counterparty has an "administrative priority claim" for damages. Such claims are ahead of general unsecured claims in line.

The standard a bankruptcy court applies in deciding whether to let a bankrupt company assume or reject a contract is the "business judgment" test. In general, a company's decision to reject an executory contract in its business judgment must be upheld, unless it is the product of bad faith, or of whim or caprice. Most courts disregard as irrelevant the harm caused to other parties to the contract as a result of a rejection. There are some courts that have modified the business judgment test to consider a balancing of the harms, but courts have only denied rejection in situations where general creditors of the bankrupt company would not be aided significantly by rejection and the rejection would result in substantially more harm to the contract counterparty than it would benefit for the bankrupt company.

Rejection of PPAs

Contracts in the project finance arena such as PPAs are unusual because of their long terms of 20 years or more. Contract pricing is based on long-term commodity market projections that could be extremely volatile and greatly affected by external forces. As such, these contracts are more susceptible than most to rejection by independent generators in chapter 11 proceedings.

Mirant and NRG both found their way into chapter 11 during 2003. Each was a party to one or more PPAs with regulated utilities, and each could no longer economically perform its contracts. Both companies recognized that as part of their overall restructuring efforts, they should take advantage of the chapter 11 filing to reject certain PPAs. In fact, for Mirant, rejection of its PPA with Potomac Electric Power Co. was said by the debtor to be one of the primary things it had to achieve for a successful reorganization. Mirant and NRG faced legal snags in implementing these restructuring initiatives as the courts struggled to reconcile the competing interests of the bankruptcy code and the Federal Power Act.

NRG

NRG Energy was party through a subsidiary to a 4-year PPA with the Connecticut Light & Power Company that required NRG to provide a fixed amount of energy to CL&P at a set price from January 1, 2000 through December 31, 2003. Immediately before filing for chapter 11 relief in a New York bankruptcy court on May 14, 2003, NRG gave notice to CL&P that it intended to terminate the PPA.

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way to value his entire company, but not the landfill. For one thing, he said the assessor's method also took into account the value of permits he needed to run the business. There is no property tax on intangibles.

The Virginia Supreme Court upheld the assessment in late September. It cited a treatise on property valuations suggesting the income forecast method is a reasonable approach. Comparable sales could not be used in this case because such sales are hard to find. The court disagreed that discounting expected income took into account any separate value for the permits. The case is *Shoosmith Bros. v. County of Chesterfield*.

Separately, USGen New England failed in its effort to set aside a $102 million value that a town in Vermont put on a hydroelectric facility on the Connecticut River. The plant was built in 1928. USGen bought it in 1999 from the New England Power Company. The plant straddled the river, with part of it in Vermont and part in New Hampshire. Vermont claimed the plant was worth $102 million and allocated 90% of the value to Rockingham, Vermont for purposes of collecting property taxes. The town used the income forecast method to assign a value. USGen wanted to throw out the testimony of one of three valuation experts — a power market expert on whom the town relied — on grounds that his use of one year of electricity price data to project electricity prices for the next 20 years was unreasonable.

The three experts who testified at trial assigned widely disparate values to the plant: $32.7 million, $76.5 million and $102.6 million. The Vermont Supreme Court declined to set aside the $102 million value, saying the trial judge who originally heard the case could rely on the expert he chose.

The case is USGen New England v. Town of Rockingham. *The court released its decision in mid-September.*

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Later that day, NRG formally filed for bankruptcy and filed a motion to reject the PPA. The next day, the Connecticut Department of Public Utility Control and the Connecticut attorney general asked FERC to "stay" the termination, citing harm to CL&P's customers. FERC issued an order staying the termination on May 16, 2003. On June 2, 2003, the bankruptcy court let NRG reject the contract under the business judgment standard, but said it would not overrule the FERC "stay" of the contract rejection. Thus, NRG had to continue performing the contract. The court told NRG that it would have to persuade FERC to drop the stay. NRG promptly asked a federal district court in New York to bar FERC from enforcing its stay. FERC responded by issuing a second order requiring NRG to comply with the rates, terms and conditions in the contract pending a FERC determination of whether NRG's proposed termination was consistent with the public interest.

The federal district court ruled that the issues that were pending before FERC — whether NRG could cease performance notwithstanding the Federal Power Act guidelines — fell squarely within FERC's regulatory responsibility. Moreover, the district court noted that section 8251 of the Federal Power Act provides that orders issued by FERC are to be reviewed only by a US court of appeals. Accordingly, the district court dismissed NRG's complaint. NRG then went on to settle its differences with CL&P, and the company emerged from chapter 11 a short time later.

Mirant

In 2000, PEPCO, a regulated utility serving the District of Columbia and Maryland, agreed to sell its power plants to Mirant. Mirant also agreed to replace PEPCO as the purchaser under a number of long-term power contracts that PEPCO had entered into with other electricity suppliers. PEPCO had trouble assigning two of the contracts under which it was an electricity purchaser to Mirant so Mirant agreed to enter into a new contract — called a back-to-back agreement — with PEPCO under which it promised to buy electricity from PEPCO at the same price that PEPCO had to pay under the two agreements that it was unable to assign. The rates under the back-to-back contract ultimately proved substantially higher than market rates, and Mirant was suffering substantial losses. At the time of the bankruptcy filing, the back-to-back agreement had a remaining term of more than 18 years.

Also at issue is the standard a bankruptcy judge must use if it is his or her decision.

In July 2003, Mirant filed for bankruptcy relief under chapter 11 in Texas. Mirant had seen the trouble that NRG caused itself by providing notice of termination of its PPA to CL&P and allowing CL&P to take preemptive action before FERC by getting orders against NRG directing performance. In an effort to avoid the same fate, Mirant asked the bankruptcy court in Texas for permission to reject the back-to-back agreement, and it also asked the court to bar FERC from taking any action to require Mirant to comply with the back-to-back agreement. The bankruptcy court granted a preliminary injunction in favor of Mirant in September 2003.

PEPCO then sought relief in a federal district court after the district court exercised its right to transfer the issue to it from the bankruptcy court. After extensive hearings and intervention by FERC, the district court found in December 2003 that FERC has exclusive authority to determine the reasonableness of wholesale rates for electricity sold in interstate commerce and that those rates can only be challenged in a FERC proceeding, not through a collateral attack in another forum.

Mirant appealed the decision to the US appeals court for the 5th circuit. The appeals court sided with Mirant. It said in August 2004 that the power of a bankruptcy court to authorize rejection of a PPA such as the back-to-back agreement "does not conflict with the authority given to FERC to regulate rates for the interstate sale of electricity at wholesale." The court said rejection of a PPA is a breach of the contract, and the Federal Power Act does not provide FERC with exclusive authority over the remedies for breach of a FERC-approved contract. The bankruptcy code does not let certain types of obligations be rejected in bankruptcy without approval of the interested regulators, but there is no such special provision for FERC contracts. However, the appeals court said the strong public interest in the transmission and sale of electricity suggests there should be a more stringent test than business judgment before Mirant can reject the back-to-back agreement. It directed the lower court to consider the impact of rejection upon the public interest as well as ensure that the rejection will not cause any disruption in the supply of electricity to other public utilities or consumers.

Mirant viewed the appeals court decision as a victory. The case is back in the district court for further hearings. It is still possible the district court could apply the same rigid standards FERC would have before allowing Mirant to terminate the contract. Given the more than 15-year term remaining on the back-to-back agreement, the final outcome could be significant for Mirant creditors.

Libya Update

by Nabil Khodadad, in London

Two important developments in the last few weeks should accelerate foreign investment in the Libyan oil and gas sector.

One is the lifting on September 20 of the remaining US trade sanctions against Libya. The United States released more than $1.3 billion in blocked Libyan assets and opened the door to air service between the US and Libya. The other development is the National Oil Company of Libya — called "NOC" — formally kicked off its long-awaited bidding round for exploration properties on September 5 and 14.

Libya is the only major oil producing country — apart from Iraq — that has the capacity to double its crude oil production over the next decade. This makes it a prime target for foreign investment. It has vast exploration potential, an ideal location on the doorstep of Europe and easy access to the United States, high-quality low-sulphur crude oil and low operating costs of $1 to $5/bbl. */ continued page 36*

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MINOR MEMO. A US appeals court decision in September is a warning that shareholders may be held accountable for federal income taxes that corporations fail to pay. A waste hauling company in Minnesota failed to report all its income over a three-year period. The company sold its assets at the end of the three years to Browning Ferris Industries in exchange for stock in BFI and the assumption by BFI of the company's debts. The company then liquidated and distributed the BFI stock to its shareholders. The IRS went after the president of the company for back taxes under section 6901 of the US tax code, which imposes "transferee liability" on persons who receive a company's assets when the company liquidates. The president owned 49% of the company. The court said whether the IRS can collect from shareholders turns on state law. In Minnesota, where the company was located, the state law let it do so. The case is *McGraw v. Commissioner*.

— contributed by Keith Martin, Samuel R. Kwon and Jana Dimitrova.

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US Sanctions

The United States began easing trade sanctions against Libya in early 2004. On February 26, it lifted a travel ban on US nationals visiting Libya. On April 23, President Bush lifted other sanctions against Libya under the International Emergency Powers Act of 1996 and terminated the Iran-Libya Sanctions Act of 1996 with respect to Libya. The Iran-Libya Sanctions Act had authorized the president to penalize foreign companies making investments of more than $40 million a year that "directly and significantly" contribute to enhancement of Libya's petroleum resources.

On September 20, President Bush lifted a few remaining trade sanctions against Libya under the International Emergency Powers Act by unfreezing more than $1.3 billion of blocked Libyan assets and permitting US carriers to resume air service to Libya. The following day, Continental Airlines applied for permission to fly from Houston to Tripoli via Amsterdam.

Libya still remains on a list of state sponsors of terrorism maintained by the US Department of State. Nations on this list are barred from receiving arms-related exports of US origin or US economic assistance. Libya is still awaiting the delivery of eight C-130 Hercules aircraft which it purchased in the 1970s. Those aircraft have been parked on a runway at Dobbins Air Reserve Base in Marietta, Georgia for more than two decades. While Libya remains on the list of state sponsors of terrorism, the US government is also barred from supporting loan requests by Libya to international financial institutions such as the World Bank, International Finance Corporation and International Monetary Fund.

Many observers believe that the removal of Libya from the list of state sponsors of terrorism is imminent. Once Libya is removed from this list, then the United States is expected to restore full diplomatic relations with Libya. Already the United States has opened a US liaison office in Tripoli as a first step toward the resumption of diplomatic relations. As a sign of the continuing thaw in US-Libyan relations, the US secretary of state, Colin Powell, recently met with his Libyan counterpart, which was the first time a US secretary of state and a Libyan foreign minister had met in more than three decades.

Libya is the only major producing country, apart from Iraq, that has the capacity to double its oil output in the next decade.

Bidding Round

Libya formally announced its new explorations bidding round on August 16. This is the first opportunity for US companies to invest in Libya in more than 18 years. In September, Libya gave technical presentations to potential bidders in Tripoli and London where it disclosed in more detail the rules, schedule and terms for the new bidding round. The terms are similar to the tentative terms previously announced by Libya in May 2004. These terms are described in an article in the June 2003 *Newswire*. However, the new terms revealed at the technical presentations are more detailed and in some ways represent an improvement over the terms previously announced. For example, the bidding round will now cover 15 exploration areas (10 onshore areas and 5 offshore areas) instead of only the eight areas that Libya had previously announced.

Tender Schedule

Under the tender rules, potential bidders must pre-qualify by submitting an application letter, audited financial statements for the last three years, activity reports for the last three years and copies of their constituent documents. These documents had to be submitted to the NOC by September 28, 2004. Applicants currently operating in Libya are exempted from the qualification requirement. The NOC has committed to inform applicants whether they have qualified by October 19, 2004.

Upon payment of the relevant data room fee, each qualified applicant is invited to visit the data room in Tripoli between October 20 and 29, 2004. The data room fees range between $12,510 and $129,565, depending on the exploration area. In the data room, each applicant will receive instructions and bidding procedures, technical data prepared by the NOC with respect to the relevant blocks (on a dvd), a model exploration and production sharing agreement (known as EPSA-4), a form of commitment letter, and a form of bid guaranty.

Applicants will have an opportunity to seek clarification of any terms in the proposed tender at meetings they can schedule with the NOC during the weeks of November 6 to 11 and November 21 to 25. If the NOC accepts any clarification comments, it will include them in a revised bid package and circulate the same to all bidders by December 12, 2004.

All bids are due in Tripoli on the morning of January 10, 2005, together with a bid guaranty issued in the form of an irrevocable letter of credit issued by the Libyan Arab Bank. The stated amount of the letter of credit must be equal to 10% of the minimum exploration program set out in the tender rules for the exploration area. It is permissible for companies to bid as a consortium as long as they give the NOC notice at least three weeks prior to the date that the bids are due. In order to ensure the transparency of the bidding process, all bids will be publicly opened on January 10, with the winner announced on the same day. The winning bidder is expected to sign an exploration and production sharing agreement with the NOC by the end of January 2005. The EPSA will become effective on the date that it is approved by the Libyan General People's Committee.

Commercial Terms

A minimum exploration program will be specified for each of the 15 exploration areas. During the exploration phase, a management committee consisting of two members appointed by the NOC and two members appointed by the international oil company will be established. In order for a discovery to be declared commercial, all members of the management committee must declare the discovery commercial. If the management committee members appointed by the international oil company do not approve the subsequent development of the discovery, but the management committee members appointed by the NOC do, then the NOC has the right to purse the development of the field at its sole cost and risk. However, the international oil company has the right to rejoin in the development of the discovery within one year of the NOC's implementation of the development of the field.

Libya plans to narrow the field of first-round bidders for oil exploration rights by October 19.

During the development phase, a joint operating company will be established to act as the operator of the field. An operating joint committee will be established to manage the joint operating company with two members appointed by the NOC and one member appointed by the international oil company. A shareholders' agreement will govern the relationship between the shareholders in the joint operating company. Based on various statements made by the NOC to the press, it appears that most, if not all, decisions of the operating joint committee must be by unanimous vote.

Following the exploration period, the term for the development phase shall be 25 years for crude oil and 30 years for the production of non-associated gas. The international operating company is not permitted to assign its interest in the EPSA until all seismic work has been completed and at least 50% of the wells have been drilled. */ continued page 38*

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The NOC has a pre-emption right with respect to any assignment by the international oil company.

During the exploration phase, the international oil company will be responsible for all exploration and appraisal costs, as well as training expenses for Libyan nationals. During the exploitation phase, all development costs (including those relating to pipelines, abandonment and site restoration) will be shared equally between the NOC and the international oil company. All operating costs shall be shared according to the "primary production allocation."

The "primary production allocation" will be determined by multiplying the "M factor" — a bidding parameter in the form of a constant multiplier equal to or less than 1 — by the primary production allocation to the international oil company that the NOC has pre-determined for each exploration area. The primary production allocation will prevail until the international oil company's costs are recovered. Thereafter, the oil company's share of "excess production" will be determined by reference to the ratio of its cumulative revenues to its cumulative costs, and the average daily production levels. Pricing of crude oil for cost recovery purposes will be determined by reference to the weighted monthly average of the market price for crude oil realized by the NOC.

The international oil company is required to pay a signing bonus equal to a signing bonus multiplier known as the "B factor" times a pre-determined amount for each exploration area. The B factor is a secondary bidding parameter. Production bonuses are also payable by the international oil company at pre-set production levels. Neither the signing bonus nor the production bonuses are recoverable from cost oil. The international oil company is also subject to tax on its net income and to royalties. However, the NOC is responsible for discharging these taxes and royalties and for procuring a receipt from the government confirming payment of the taxes.

The M factor will be the primary selection factor. The bidder with the lowest M factor will win the tender. In the event that the M factors for the two highest bidders are the same, then the bidder with the highest B factor will be declared the winner.

New Markets Tax Credits

by Samuel R. Kwon, in Washington

Up to $2.7 billion dollars worth of tax credits still remain available under a US government program designed to encourage the flow of capital into low-income areas in the United States. These "new markets tax credits" expire at the end of 2007.

Background

In 2000, the US government was looking for ways to stimulate business investments in impoverished urban and rural areas of the United States. Congress created the Community Development Financial Institutions Fund, or "CDFI" fund, that year to administer a new markets credit program. It authorized the fund to select entities that would devote themselves to making investments in low-income areas in the United States –- known as community development entities, or "CDEs" –- and to authorize them to capitalize themselves with funds from investors. In exchange, the investors would receive tax credits allocated to the CDEs by the CDFI fund.

In 2002, during the first round of the selection process, the CDFI fund selected 66 CDEs out of 345 applicants and authorized them to accept up to $2.5 billion in capital contributions from investors in exchange for tax credits equal to 39% of the contributions over seven years. The largest amount of investment a single CDE was allowed to accept was $170 million, and 20 CDEs were allowed to accept investments of up to $50 million or more. The smallest was $500,000, and the median investment size was $17.5 million. In 2003, the fund authorized another 63 CDEs to accept a total investment of $3.5 billion in exchange for tax credits. The largest investment allowed was $150 million. Fourteen CDEs were allowed investments of more than $100 million and 31 CDEs were authorized to accept more than $50 million. The smallest amount of investment allowed was $2 million, and the median investment size was $47 million.

The application process for 2004 was completed in September 2004. The CDFI fund is expected to authorize a large number of additional CDEs to accept up to $2 billion worth of investments in exchange for tax credits for 2004. The fund will authorize an additional $7 billion of investment into CDEs in exchange for tax credits over the next three years. Investors who want to take advantage of these credits must make a qualified investment in a CDE before the end of 2007.

Tax Credits

Any person who makes a "qualified equity investment" in a "qualified CDE" receives new markets tax credits each year for seven years as long as he holds the investment for those seven years. The investment must be made up front. The credit is 5% of the qualified equity investment for each of the first three years, and 6% in each of the next four years, for a total of 39%, or approximately 30% of the qualified equity investment on a present-value basis. The investment in a CDE may be sold and the new owner can claim the remaining tax credits so long as the investment qualified for the credits in the hands of the seller.

"Qualified equity investment" is any equity investment in a CDE whether in the form of stock in a corporation or capital interest in a partnership. Qualified equity investment includes, in addition to the investment into a CDE, any amount paid by the investor on behalf of the CDE such as underwriter's fees. Generally, an equity investment made in a qualified CDE before the CDE enters into an allocation agreement with the CDFI fund is not eligible for tax credits. However, there is an exception. If the investment is made after the Internal Revenue Service publishes a "notice of allocation availability" in the *Federal Register*, the CDE later receives an allocation of tax credits, and the investment otherwise satisfies other requirements for new markets tax credits, then the investment is treated as having been made on the effective date of CDE's allocation agreement. An allocation agreement is a contract a qualified CDE enters into with the CDFI fund under which the fund authorizes the CDE to issue an approved amount of ownership interests in it in exchange for new markets tax credits to investors.

An investor who makes a qualified equity investment in a qualified CDE receives tax credits as long as three conditions are satisfied.

The first condition is that the investment in a qualified CDE must be acquired by the investor claiming the credits at its original issue, directly or through an underwriter, solely in exchange for cash. The IRS clarified in 2003 that cash includes proceeds borrowed by the investor from a bank, regardless of whether the loan is recourse or nonrecourse. This provides an opportunity for investors to use borrowed funds to receive tax credits. The 2003 IRS announcement gives an example of two investors who form a partnership and capitalize it with $800. Then the partnership borrows $1,200 from a bank on a nonrecourse basis. The partnership, in turn, invests the $2,000 into a qualified CDE in exchange for an ownership interest in the CDE. The loan is secured only by the partnership's equity interest in the CDE. It is not secured by any assets of the CDE, and it is not convertible into an equity interest in the partnership. Under these facts, the partnership is entitled to new markets tax credit each year for seven years equal to a percentage of the full $2,000 invested (rather than solely on the $800). All of the tax credits may be allocated to the two partners as long as the allocation of the credits is in accordance with the tax rules.

The second condition for qualifying for new markets tax credits is that at least 85% (or 75% in the seventh year of investment) of the investment must be used by the qualified CDE to make a "qualified low-income community investment." The investment has to be made "directly" into the qualified CDE. For instance, if a CDE uses a line of credit from a bank to make a qualified low-income community investment, and then takes the equity investment later to pay off this line of credit, the investor may not be viewed as having fulfilled this "direct' investment requirement.

There are four types of "qualified low-income community investments."

The first is any capital or equity investment in, or loan to, a qualified active low-income community business. "Qualified active low-income community business" means a corporation or a partnership if for a year at least 50% of the total gross income of the entity is derived from the active conduct of a qualified business within any low-income community, a substantial portion of the use of the tangible property of such entity (whether owned or leased) is within any low-income community, a substantial portion of the services performed for such entity by its employees are performed in any low-income community, less than 5% of the average of the aggregate unadjusted bases of the property of the entity is attributable to collectibles other than collectibles that are held as inventory primarily for sale to customers, and less than 5% of the average of the aggregate unadjusted bases of the property of such entity is attributable to nonqualified financial property.

The second type of qualified low- / *continued page 40*

New Markets Credits

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income community investment is a purchase from another CDE of any loan made by such an entity that is itself a qualified low-income community investment.

The third type of a qualified low-income community investment is financial counseling and similar services listed in IRS regulations for residents of low-income communities. Low income communities are census tracts where the poverty rate exceeds 20% or the median income is less than 80% of the greater of statewide median income or metropolitan area median income. In addition, The IRS may designate an area within a census tract as a low-income community if the boundary of the area is continuous, the area would be a low-income community if it were a census tract, and there is inadequate access to investment capital in the area.

Up to $2.7 billion in tax credits still remain available under a US program designed to encourage investment in low-income areas.

Finally, the last type of a qualified low-income community investment is any equity investment in, or loan to, a qualified CDE.

The last condition before an investor can qualify for new markets tax credits is the qualified CDE must designate the equity investment as having been made for purposes of new markets tax credits on its books.

Because the new markets credit is in its infancy, there is not a lot of information on what types of investments the CDEs are making with the capital they are raising. Industry participants speculate that a large proportion of the investment will go into having the CDEs own real estate rather than into new business development, loan purchases or financing of other CDEs.

Recapture

The investor will lose all of the new markets tax credits –- whether already claimed or to be claimed –- if a "recapture event" takes place within seven years of the original investment into a qualified CDE. There are three types of recapture events.

First, the investor will lose the new markets tax credits if the CDE ceases to be a "qualified CDE."

A qualified CDE is a CDE that is any domestic corporation or partnership whose primary mission is serving or providing investment capital for low-income communities or persons, that maintains accountability to residents of low-income communities through representation on any governing or advisory boards of the entity, and is certified by the IRS as a CDE eligible for new markets tax credits. In addition, certain specialized small business investment companies and community development financial institutions under the Community Development Banking and Financial Institution Act of 1994 are treated as CDEs. CDE certification by the CDFI fund lasts for 15 years unless revoked or terminated by the fund. To maintain the certification, the CDE must certify annually during the 15-year period that it has continued to meet CDE certification requirements. One of these requirements is that at least 20% of its governing or advisory board must be representative of low-income communities within the selected service area. This means the members must reside in low-income communities within selected service area or otherwise represent interests of residents of low-income communities.

Second, both past and future credits will be lost if substantially all of the equity investment ceases to be used in qualified low-income investments. This suggests that the investor must make sure that the CDE has a pipeline of projects into which any repayments to a CDE of equity or principal from qualified low-income community investments can be reinvested. As long as such reinvestment takes place within 12 months of receipt by the CDE of a return of equity or principal, the CDE will be viewed as having kept the investment in qualifying investments for purposes of the "substantial investment" requirement.

Third, a recapture of the credits takes place if the CDE redeems the equity investment from an investor.

Upon a recapture, interest on the resulting underpayment is also incurred as if the investor should not have claimed any tax credits: this interest is not deductible, and other types of credits cannot offset the new taxable income. The CDE is required to provide a notice of recapture within 60 days to its investors.

Notably, a CDE's bankruptcy is not in and of itself a recapture event, and it does not prevent future credits from being claimed.

Related Issues

The US tax code limits the ability of an individual or a closely-held C corporation (in which five or fewer individuals own more than 50% of the stock) to make use of the new markets tax credits; unless such an investor "materially participates" in the CDE's business, it can only use the credits to offset income from "passive activities."

Any unused new markets tax credits can be carried forward for 20 years and backward for one year. If any credits remain unused after the expiration of the carryforward period, then the investor is allowed to deduct the unused amount in the following year. New markets tax credits cannot be used to offset a taxpayer's alternative minimum tax liability.

Generally, the "tax basis" of an equity investment in the hands of the investor is equal to the fair market value of the contribution the investor made in exchange for the investment. However, the basis of any qualified equity investment in a CDE for purposes of new markets tax credits is the fair market value of the investment minus the amount of the new markets tax credits he is allocated.

The amount of the new markets tax credits an investor can claim is not reduced even if the investor claims other tax benefits such as rehabilitation credits under section 47 of the US tax code. In addition to the credits, the investor may also be allowed a share of depreciation from the CDE where the investor is a partner of a CDE that is a partnership. Moreover, if the CDE's business is successful, the investor can expect a cash return on the investment, and may have an interest in the residual value in cases where the CDE invested in hard assets like real properties. The IRS is currently studying whether a reduction is appropriate if the investor claims low-income housing tax credits with respect to the same investment under section 42 of the US tax code.

Financing Gas Pipeline Expansions in Argentina

by Ignacio J. Randle, with Caparros & Randle in Buenos Aires

Argentina is hoping that a new "financial trust" mechanism can be used to finance expansion of gas pipelines and distribution networks.

The idea is to put licenses and other assets needed to operate the expansion project in a trust that would issue debt or certificates of participation in the capital markets. The government would authorize the trust to charge users of the new pipeline or distribution lines special tariffs above the regular tariffs in order to ensure that investors in the project will be repaid. Running the money through a trust is supposed to make the cash flow more secure. Federal, provincial and municipal governments would be barred from taxing away the cash from the extra tariffs. After the funds raised in the capital markets have been repaid, then the trust assets would be turned back over to the gas company that originally formed the trust.

The program is off to a slow start, but two gas pipeline projects are now underway using the financial trust mechanism.

Need

Argentina is suffering currently from gas and electricity shortages. The energy crisis had been expected not to worsen until later in the year, but the increase in demand generated by growing economic activity, the lack of investment and frozen tariffs have accelerated the problem.

The gap between energy supply and demand is mainly due to three factors. First, there is still price distortion caused by the freeze in gas prices to regulated customers that occurred when Argentina devalued the peso and broke from the link with the US dollar in late 2001. Second, there has been little new investment in gas transportation and distribution equipment due to the weak financial situation of the companies, low prices, low tariffs and regulatory uncertainty. Third, there has been a strong increase in natural gas and electricity demand — of 25% and 9% respectively — in the first months of 2004 compared to the same period in 2003. */ continued page 42*

Argentina

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From 1946 until 1992, the transportation and distribution of natural gas in Argentina was under the exclusive control of *Gas del Estado,* a gas pipeline company owned by the Argentine government.

In 1992, *Gas del Estado* was privatized under federal Law No. 23696 and No. 24076 and federal Decree Nos. 1189/92 and 1738/92. The assets of *Gas del Estado* were distributed at privatization among two gas transportation companies and eight gas distribution companies. The transportation assets were split into two pipeline companies, north and south, organized to connect the gas fields with the main consumption centers, including the metropolitan area of Buenos Aires.

The main legal framework governing the production, transportation, distribution, storage and trading of gas in Argentina is found in four places: the Hydrocarbons Act, federal Law No. 24076, the bidding documentation for the privatization of *Gas del Estado*, and the transportation and distribution license and transfer agreements entered into between the federal government and each of the operators.

Natural gas transportation and distribution companies operate under an open access system. Producers, large consumers and distributors have a right to free access to transportation and distribution pipelines under the licenses granted to privatized companies. Furthermore, under the Hydrocarbons Act, producers enjoy a concession regime for the transportation of their own gas output.

Under the current legal framework, there are certain limits on cross-ownership among large consumers, producers, distributors and transportation companies.

The *Ente Nacional Regulador del Gas* or "Enargas" is the federal enforcement authority that oversees compliance with the applicable laws and regulations.

Financial Trusts

One measure the Argentine government has taken to address the energy crisis is to create trust funds to finance gas and electricity investments, especially for transportation and distribution. Under federal Decree No. 180/04, such investments must be arranged with and approved by the Ministry of Federal Planning, Public Investment and Services.

Argentina is experimenting with financial trusts as a way to bring in money to pay for expanding gas pipelines.

The Argentine government wants financing for gas and electricity investments to come from the capital markets. Resolution No. 185/04 authorized the formation of financial trusts, subject to the terms and conditions of federal Law No. 24,441, that will issue securities representing debt or certificates of participation in the financial trusts up to a maximum of $3 billion.

Formation of a trust and the issuance of securities require authorization from the *Comisión Nacional de Valores* — the Argentine equivalent of the US Securities and Exchange Commission. Public offerings of securities require commission approval. Authorization must also be received from either the Buenos Aires Stock Exchange or the *Mercado Abierto Electrónico S.A.* — the Argentine over-the-counter securities market — before the securities can be listed.

The administrator for the financial trust program is the Ministry's secretary of energy and the co-administrator is the under-secretary of fuel. The administrator and co-administrator may modify non-essential terms of the prospectus and determine the procedures that will govern the negotiation and execution of the agreements for the work to be performed under the financial trusts.

The administrator will also execute agreements with different private or public entities in order to fulfil the aims of the program and provide clear, simple and efficient performance procedures. In addition, the administrator selects the trustee for each financial trust.

Resolution No. 185/04 provides the following terms and conditions for the program.

The "settler" of a financial trust can be any gas transportation or distribution licence holder, or any cooperative or other player in the gas industry. The "settlor" is the company that puts licenses and other assets that will needed for the expansion project in trust to form the trust.

A trustee is then appointed to run the trust. The trustee enters into all the necessary contracts for the expansion project — for example, purchase agreements for materials and equipment, service and lease agreements, transportation or distribution service agreements, and operation and maintenance agreements.

The trust then borrows against its assets in the capital markets. Such borrowing is permitted exclusively to finance projects enlarging gas transportation and distribution systems. The debt or certificates of participation are gradually repaid or redeemed out of operating earnings from the trust.

Each trust will be given special tariffs to be paid by the users of its regulated transportation or distribution services. Special credit programs are also envisaged with national or international institutions as another source of funds.

The trustee does not have to assume responsibility for the transportation or distribution of gas; the licence holder who formed the trust by contribution of its assets can choose to remain responsible by entering into an operation and maintenance agreement with the trustee, in which case it will remain the operator of the new installations and be paid a fee for its services.

Once the trust has repaid the capital markets debt or redeemed the certificates of participation, then the trust will be dissolved and the assets transferred back to the licence holder who originally put its assets in the trust.

Financial trusts are supposed to be a tool mainly for financing expansion of gas transportation and distribution facilities of the two transportation and eight distribution companies that emerged at privatization of *Gas del Estado*.

However, Resolution No. 185/04 does not prohibit the use of financial trusts for the construction of gas pipelines and the extension of existing gas systems owned by other private companies, provided that they secure the necessary approvals.

Slow Start

The financial trust program is in an early stage of implementation. It has not yet contributed to the financing of expansion of the transportation and distribution of gas industry as expected. The slow start for the program is due, among other reasons, to the heavy government role in the design of financial trusts, and the fact that gas distribution and transportation companies are still awaiting regulatory approval for an adjustment in their tariffs, which have remained frozen since abrogation in late 2001 of the convertibility regime that had pegged the Argentine peso to the US dollar.

Two pipeline expansion projects have been announced recently. One is expansion of the pipeline for the southern region operated by *Transportadora de Gas del Sur S.A.,* or *"TGS,"* to be financed by the Brazilian bank *Banco Nacional de Desarrollo Económico y Social,* or "BNDES," for $142 million. The other project is a pipeline the northern region operated by *Transportadora de Gas del Norte S.A.,* or "TGN," at a cost of $100 million to be provided by the Spanish oil company Repsol YPF S.A. and another $70 million to be contributed by BNDES, TGN itself and by means of an advanced reimbursement of the value added tax, called *Impuesto al valor agregado*.

The Argentine government must now figure out what "extra tariff charges" to allow the financial trusts undertaking these projects to collect to repay the above-mentioned investments and identify the customer categories that would be subject to such tariff increases. Preliminary calculations done by the gas enforcement authority Enargas suggest that both pipelines would be authorized to collect extra tariff charges of 30% to 47% above the current gas transportation tariff.

Investors in the two projects are demanding that the extra tariff charges be ratified by Congress so as to avoid the risks that could arise from potential attachments or threatened litigation against such the extra cash flow. Investors want an assurance the additional tariffs can only be used to repay their investments.

The financial trust mechanism is a good first step toward raising capital to finance gas infrastructure investments. However, the program could be improved by allowing more active involvement by the private sector and a more flexible framework to allow for tailor-made measures that address the needs of each specific project.

Environmental Update

Election 2004

Environmental issues have largely taken a back seat in the 2004 US presidential election as the candidates have focused the discussion on terrorism, the war in Iraq, and the US economy.

President Bush and the Democratic presidential candidate, John Kerry, have strikingly different priorities on environmental issues. President Bush, if reelected, is expected to stay the course and continue work on several proposed regulations. The Bush administration can be expected to finalize its proposed "clean air interstate rule" (formerly called the "interstate air quality rule") that will require significant reductions in nitrogen oxides, or NO_X, and sulfur dioxide, or SO_2, from power plants by 2015 and to finalize a separate "utility mercury reductions rule" that will require cuts in mercury and nickel emissions from coal and oil-fired power plants.

The Bush administration's legislative priorities are expected to include working with Congress to enact a comprehensive energy bill, a chemical plant security bill, and legislation to cap damages and set standards for awards in asbestos cases. In a second term, the Bush administration would also be expected to press for enactment of its "clear skies initiative" to require additional substantial reductions in NO_X, SO_2, and mercury from power plants. The clear skies proposal stalled in the current Congress. The two proposed rules on power plant emissions that the administration is working to finalize are designed to achieve similar levels of reductions in NO_X, SO_2, and mercury emissions from power plants that the administration would have gotten from the legislation. The legislation would more closely coordinate the required reductions in NO_X, SO_2, and mercury emissions from power plants and make the two rules less likely to be overturned in court.

Power companies operating in Europe, Japan and Canada will have to start reducing carbon dioxide emissions by 2008.

Not surprisingly, John Kerry has different environmental priorities. Kerry is a strong supporter of measures to reduce global warming. He would be expected to push for legislation to establish greenhouse gas emission reduction targets for US power plants and industrial facilities. Kerry would probably also roll back rules the Bush administration issued to relax the "new source review" program. Kerry has been especially critical of how the Bush administration defined the phrase "routine maintenance, repair, and replacement" of equipment that can be completed at existing power plants and other major emission sources without having to get a new preconstruction air permit. Regulations that the Environmental Protection Agency issued addressing this contentious air permit modification issue in October 2003 are currently being challenged by 14 states, 29 local jurisdictions, and several environmental and public interest groups. The rule has been "stayed" by a US appeals court in Washington, DC until the court can hear arguments in the case. A decision is not expected until 2005.

Kerry would also be expected to rework the proposed "utility mercury reductions rule" to establish stringent emission limits based on maximum achievable control technology, or "MACT," rather than the market-based "cap and trade" approach favored by the Bush administration. A Kerry administration would probably also require that reductions in mercury emissions be achieved within tighter time frames. The Bush administration proposes to phase in its mercury reductions through 2018.

It is less clear whether Kerry would follow through on implementing the "clean air interstate rule." He might implement the rule largely as proposed but with a shorter timetable to reduce emissions and with some ratcheting down of NO_X and SO_2 emission reduction targets to more stringent levels. Other Kerry environmental priorities include prohibiting any exploration for oil in the Artic National Wildlife Refuge in Alaska and reinstating the excise tax on the chemical industry to collect revenue for the Superfund trust fund that is used to finance cleanups of abandoned hazardous waste sites.

Climate Change

Russia took a significant step toward ratifying the Kyoto treaty that sets deadlines for reducing greenhouse gas emissions. In September, the 1997 treaty was forwarded to the Duma or the lower house of the Russian parliament by President Putin's cabinet with the recommendation that the protocol be ratified. If, as expected, the Russian parliament approves of the treaty, then it will enter into force 90 days after Russia submits its approval to the United Nations.

This will mean that power companies and other industrial facilities operating in most of Europe, Japan and Canada will have to take steps to limit carbon dioxide, or CO_2, a greenhouse gas. The first compliance period is 2008 to 2012.

The United States has rejected the Kyoto protocol on the basis that implementing dramatic reductions in greenhouse gas emissions would have a serious impact on the US economy. The Bush administration also refuses to commit to a program of controlling greenhouse gas emissions unless large developing countries, such as China and India, also commit to the same program. The Kyoto protocol will enter into force after it has been ratified by 55 or more countries whose combined CO_2 emissions levels represent at least 55% of the CO_2 emissions from the so-called "Annex I" western industrialized countries in 1990. As of September 15, 2004, 125 nations have ratified the treaty, and those nations accounted for 44.2% of the 1990 CO_2 emissions. Russia accounts for 17.4% of the 1990 CO_2 emissions, and the United States accounts for 36%.

Russia would be the 30th of the 36 Annex I industrialized nations to ratify. The Russian Duma is expected to approve the treaty before the upcoming December 6-17, 2004 meeting of signatory countries at the "Tenth Conference of the Parties to the United Nations Framework Convention on Climate Change."

In related news, five US power companies that were recently sued in two separate cases by the attorneys general from eight states and New York City and by three environmental organizations alleging that their power plants emit large quantities of CO_2 have asked the court to dismiss the cases. The companies involved include American Electric Power, Southern Company, the Tennessee Valley Authority, Xcel Energy, and Cinergy.

The states and environmental groups argue that the CO_2 emitted by the companies' power plants creates a public nuisance. The companies own or operate 174 fossil-fuel fired power plants in 20 states, and account for about 650 million tons of CO_2 emissions. The plaintiffs in the two suits are seeking an injunction requiring the power companies to cap their CO_2 emissions immediately and then reduce the emissions by a specified percentage each year over the next 10 years.

The companies argued in a motion to dismiss the cases federal "common law" has been preempted by a federal statute, the Clean Air Act, and by other federal actions. The companies also argue that the plaintiffs lack standing to sue in the federal courts. A decision on the motion to dismiss is expected later this year.

Mercury

A coalition of eight US and Canadian environmental groups filed a complaint under the North American Free Trade Agreement with the Commission for Environmental Cooperation — called the CEC — asking the commission to investigate the US Environmental Protection Agency's alleged failure to prevent increases in mercury contamination in US and Canadian lakes and rivers. The environmental groups charge that EPA has not been adequately enforcing the Clean Water Act against coal-fired power plants.

Under NAFTA, the CEC has the authority to investigate complaints and issue findings to the administrators of the respective environmental agencies in the US, Canada and Mexico. The groups charge that US power companies have an advantage over Canadian power companies because they are not being held to the same standards on clean water. The CEC secretariat, based in / continued page 46

Montreal, must decide whether to accept the complaint and launch an investigation. If the CEC accepts the complaint, the next step would be to ask the US Environmental Protection Agency to respond to the charges. The goal of the environmental groups is to attract public attention to mercury discharges from US coal-fired power plants and keep the pressure on the Bush administration to adopt stringent mercury reduction requirements. The utility mercury reductions rule already proposed by EPA would achieve approximately a 70% reduction in mercury air emissions from coal-fired plants by 2018. The environmentalists want substantially stricter mercury reduction targets to be achieved in a much tighter time frame.

Power plants in New York will have to reduce SO2 emissions 50% below federal limits over the next three years.

IFC Environmental Policies

The International Finance Corporation, the private lending arm of the World Bank, has embarked on an effort to update the IFC's social and environmental "safeguard" policies that were originally developed in 1998. These are policies that apply to projects in developing countries. The policies cover a number of issues, including impacts on indigenous people, forced resettlements, natural habitats, dam safety, international waterways, forestry and cultural property.

The IFC recently announced that it would engage in a four-month consultation process with meetings scheduled in Rio de Janeiro, Manila, Nairobi and Istanbul. The IFC said it hopes to revise and streamline the safeguard policies to make them clearer, more concise and easier to use. It also aims to incorporate performance standards and address identified gaps in coverage. The concept of sustainability will also be incorporated into the policies, which will be renamed as the IFC's "Policy on Social and Environmental Sustainability."

On a parallel track, the IFC has also launched a review of all of its environmental, health and safety guidelines published prior to August 1, 2004. The IFC intends to update the guidelines at the same time it overhauls the safeguard policies. The IFC is expected to present the new standards and polices to its management and board in February 2005.

New York RPS

New York became the 17th state to adopt a renewable portfolio standard. The New York RPS requires that at least 25% of electricity sold to New York consumers be generated from renewable energy sources by 2013. Earlier this year, Hawaii, Maryland and Rhode Island also adopted renewable portfolio standards. Several other state legislatures are considering whether to adopt RPS requirements.

The New York Public Service Commission adopted the RPS policy in mid-September, and implementation will start on January 1, 2006. The commission expects the state to have to add approximately 3,700 megawatts of renewable energy generation to meet the 25% goal. Once fully implemented, statewide air emissions are expected to be reduced by the following amounts: NO_x by 6.8%, SO_2 by 5.9% and CO_2 by 7.7%.

The New York RPS program will apply to two categories of power plants, including a "main tier" of medium-to-large generating facilities and a "customer-sited tier" of smaller scale projects. Renewable energy plants using wind, hydroelectric, biomass, biogas, liquid biofuel, and ocean or tidal energy sources are classified as main tier plants. The customer-sited tier will include fuel cells, solar power and smaller wind projects. The commission concluded that energy generated from the incineration of municipal solid waste was not eligible for the RPS program.

The state currently receives about 19% of its power from renewable energy sources.

New York Air Regulations

The New York State Department of Environmental Conservation took emergency action in mid-August to keep its ambitious program to reduce NO_X and SO_2 emissions from power plants on track. The rules will reduce NO_X and SO_2 emissions from electric generators to levels that are significantly below current federal requirements. The regulations, which implement Governor Pataki's acid rain initiative, were struck down on procedural grounds by a New York state trial court in May. The department has filed an appeal of the trial court decision.

The final NO_X and SO_2 regulations were issued in March 2003. Under the new Part 237 rules, current ozone season NO_X reduction requirements will be imposed year-round starting on October 1, 2004. The NO_X reduction rules will affect existing and new fossil-fuel fired power plants that have a nameplate capacity of at least 25 megawatts and sell any amount of electricity to the grid. The Part 237 NO_X reduction requirements apply to a control period of October 1 to April 30, and existing sources will be allocated NO_X allowances based on an allocation formula that considers the greatest heat input experienced for any control period by the unit during the past three control periods. The Part 237 rule will implement a statewide NO_X trading program with a program-wide cap of 39,908 tons. Under the trading program, one ton of NO_X will be equal to one NO_X allowance. There is a limited exemption available for facilities that accept a NO_X limitation of 25 tons or less during a control period.

New electric generating units may apply for an allocation of NO_X allowances from a set-aside account consisting of 5% of the total cap amount. The initial allocations for a new unit will be based on a unit's control period potential to emit. After the fourth control period, the new unit will be included in the existing source program.

The new Part 238 rules require SO_2 emissions to be reduced by 50% below current federal acid rain program levels starting on January 1, 2005, with full implementation completed by January 1, 2008. The SO_2 reduction requirements apply to electric generating units that qualify as "affected units" under the federal acid rain program. The New York program is separate and distinct from the federal acid rain program, and will create a new market-based program for trading in New York SO_2 allowances. Under the Part 238 SO_2 program, one ton of SO_2 will be equal to one SO_2 allowance. Like the Part 237 NO_X program, existing sources will be allocated SO_2 allowances based on a formula that considers the greatest heat input experienced for any control period by the unit during the preceding three years.

The control period for the New York SO_2 program is year round, and the statewide SO_2 budget is 197,046 tons for the 2005 to 2007 control periods, and 131,364 tons for each subsequent control period. There is also a new source set aside for the New York SO_2 program that consists of 3% of the statewide SO_2 budget.

Both the New York NO_X and SO_2 programs will also set aside 3% of the statewide NO_X and SO_2 budgets for energy efficiency and renewable energy projects. Additional allowances will be awarded to companies that reduce NO_X and SO_2 emissions through in-plant or end-use efficiency measures or generate energy from renewable sources. To the extent there are unused allowances from the set-aside accounts, the allowances will be distributed to the units in the NO_X and SO_2 budget programs on a proportional basis.

Brief Updates

The US Interior Department recently released a draft environmental impact statement that evaluates the potential environmental impacts associated with developing wind energy projects on public lands. Environmental impacts from wind projects include disturbance of cultural sites, noise, degradation of wildlife habitat, and harmful effects on migratory birds and bats. The draft environmental impact statement is an initial step in the Interior Department's development of a national wind energy development program.

In September, EPA published a final rule regulating air toxic emissions from industrial and commercial boilers. New emission limits to control carbon monoxide, hydrogen chloride, mercury and particulate matter will apply to certain large new and existing boilers. The rule includes an exemption for certain units that present a low risk to human health. The rule will take effect on November 12, 2004, and a legal challenge from environmental groups is expected.

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Environmental Update

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New Jersey is expected to propose revisions to its state air regulations in October that would classify carbon dioxide as an "air pollutant." The US government is taking the position that CO_2 is not an "air pollutant" under the federal Clean Air Act. Many northeastern states are moving on their own to control carbon dioxide. New Jersey would be the first state to classify CO_2 as an air pollutant, and it lays the foundation for future state regulatory efforts to impose CO_2 emission reduction requirements to address global warming.

Mexico has reportedly become the first country to adopt internationally accepted standards to measure and report greenhouse gas emissions as part of a voluntary national greenhouse gas program. Mexico is implementing a 2-year pilot program to track greenhouse gas emissions, and it will use a corporate accounting standard that is widely used by the international business community.

Five major industry trade associations recently filed a petition with EPA seeking reconsideration of the deadlines for compliance with the 8-hour ozone national ambient air quality standard. They want the affected states with ozone nonattainment areas to have more time to comply. The five trade associations argue that EPA's own data and analysis show that several nonattainment areas will have difficulty meeting the target dates. In separate legal actions, six northeastern states and several environmental groups are challenging the 8-hour ozone implementation rule in the court claiming that EPA's implementation of the 8-hour ozone rule is too lenient and falls short of what a US Supreme Court decision on the issue requires.

The Bush administration filed its response briefs in *New York v. EPA*, a lawsuit challenging a rule the Environmental Protection Agency issued in December 2002 to relax the "new source review" permit applicability provisions. Fourteen states and a coalition of environmental groups have challenged the rule. Oral arguments in the case are scheduled for early 2005, and a decision is expected later in 2005.

In September, EPA issued notices of violation to Northern Indiana Public Service Co. for an alleged failure to undergo new source review permitting before modifying three coal-fired power plants in Indiana. EPA charges that the modifications of boilers and other equipment at the plants was major enough to require a permit.

— contributed by Roy Belden in New York

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