CHADBOURNE
& PARKE LLP

PROJECT FINANCE

NewsWire

April 2004

Weather Derivatives as a Financing Tool

by James Scarrow, in Washington

Weather derivatives are starting to make an appearance in the project finance market. Energy finance professionals need to be familiar with these risk mitigation tools and the creative ways that they can be used. A large "monetization" transaction moving currently to market — and a debate about whether weather derivatives should be regulated as insurance — will determine the extent to which they will become a standard tool in the future financing of energy projects.

What is a Weather Derivative?

A weather derivative is a transaction through which payments from one party to the other are made based on weather-related measurements, such as temperature, rain, snow or wind speed. Businesses that bear weather-related risks can use weather derivatives to transfer, share or otherwise hedge against such risks.

Take the hypothetical example of a beer vendor and a cocoa vendor at the baseball stadium used by the New York Yankees. Each is concerned about how the unpredictable April weather in the Bronx could affect his respective beverage sales. In order to hedge against the risk that sales will be lower than anticipated due to unseasonably warm weather (in the case of the cocoa */ continued page 2*

IN THIS ISSUE

IN OTHER NEWS

CONTRACT BUYOUT PAYMENT recipients got good news.

The Internal Revenue Service ruled privately that the owner of a power plant who agreed to cancel a long-term contract to supply electricity to the local utility for a lump-sum buyout payment not only did not have to pay taxes immediately on the buyout payment, but also could use the payment to pay down debt on another power plant that an affiliated company had under construction at the time.

When utilities signed contracts years ago to buy electricity from independent power producers, electricity prices were much higher than they are today. Utilities chafe at the high prices */ continued page 3*

Weather Derivatives

continued from page 1

vendor) or unseasonably cold weather (in the case of the beer vendor), they agree that for each game during April, the cocoa vendor will pay to the beer vendor $10 for each degree Fahrenheit by which the temperature at game time is below 55 degrees and, conversely, the beer vendor will pay to the cocoa vendor $10 for each degree by which the temperature is above 55. They further agree that the maximum amount per game that either party would owe the other is $100, and that they will settle up on May 1.

As is the case with derivative contracts for more commonly-traded commodities like gold, platinum and pork bellies, weather derivative contracts can be structured in a variety of ways including swaps (as in the example above), futures, options on futures, collars, and so on.

Although weather derivatives share many of the attributes of traditional commodity-based derivative contracts, there are several important distinctions. First, derivatives contracts for physical commodities are used to hedge price-related risks (for example, the risk that gas prices will rise in the future) while weather, derivatives are typically used to hedge against volume risks (for example, the risk that because of cold weather, additional volumes of gas will have to be purchased). Second, derivatives contracts for physical commodities can require the actual delivery of the underlying commodity (gas, oil, etc.) at a pre-determined time, price and date. In contrast, weather derivatives never involve the physical delivery of the weather "commodity" (ambient temperature, rain, wind, etc.), and they are always settled financially. Finally, while there are speculators who bet on the future prices of physical commodities, industry sources indicate that, to date, weather derivatives have been used principally for hedging and not for speculation.

> A large monetization transaction currently in the market — and questions about possible regulation as "insurance" — will affect whether weather derivatives become a standard tool in project financings.

Temperature-Based Weather Derivatives

Weather derivatives based on temperature are by far the most common type of weather derivative, accounting for approximately 85% of all weather derivative transactions. Such contracts are typically based on the number of heating degree days — called "HDD" — or cooling degree days — called "CDD" — over the contract period (typically a month or a winter or summer season) at a specified location.

The number of HDD or CDD in any period is a measure of the amount by which each day's average temperature during the period deviates from 65 degrees Fahrenheit. For this purpose, the "average" is 50% of the sum of the highest and lowest temperature for the day. For example, during January 2004, Chicago had 1,385 HDD. Houston had 335 HDD and 16 CDD during that same period.

A business that would expect to suffer reduced revenue during an unusually cold December could mitigate its risk by entering into an agreement with a counterparty (such as Entergy-Koch Trading, Goldman Sachs, Deutsche Bank or XL Weather and Energy) under which the business would receive a payment if the number of HDD during that month exceeded the historic average of 800 but would not be required to make any payment to the counterparty if there were fewer than 800 HDD. The premium that the business would have to pay to the counterparty for this form of option agreement would depend on the perceived risks and the maximum payment that the business could receive under the contract. Typical premium amounts range from 10% to 30% of the contract payment limit.

In 1999, the Chicago Mercantile Exchange launched the first public exchange-traded weather derivatives, based on the number of HDD and CDD over monthly or seasonal periods for certain population centers. Futures and options on futures can be purchased on the Chicago Mercantile Exchange. Exchange-treaded weather derivatives based on temperature are now also offered on the London International Financial Futures Exchange and the Helsinki Exchange. There are no exchange-traded derivatives available for wind- or precipitation- based derivatives.

Wind-Based Weather Derivatives

Weather derivatives linked to wind have recently become available, allowing wind farm owners to hedge against the risk of sporadic winds.

These contracts (of which, to date, fewer than a handful have been executed in the US) are negotiated bilateral contracts in which both the wind speed and turbine power-production characteristics are taken into account. Entergy-Koch Trading has developed proprietary wind power indices for selected locations in the US and Europe. The index for each location is designed to reflect the amount of power that could be generated at that location, based on both wind speed data and a power generation curve that reflects a basket of typical turbines. (Because the amount of power produced by a wind turbine is not linearly proportional to wind velocity, the wind power indices are not simply the wind velocity.) The wind power index for each location is calibrated such that the index for each location will be 100 during a normal year. Thus, a wind farm with certain debt service obligations might enter an agreement that would generate sufficient funds to pay debt service during any contract period during which the wind index drops below 90.

Precipitation-Based Weather Derivatives

Rain-related contracts account for approximately 10% of weather-derivatives transactions. Typically, these contracts are based on the number of critical precipitation days — called "CPD" — that occur during the contract period — that is to say, the number of days during which precipitation exceeded a specified reference level.

Derivatives transactions based on precipitation can be used to hedge energy-related risks associated with reservoir levels at hydropower facilities. For example, the Sacramento Municipal Utility District, which relies on hydropower for approximately 60% of its generating capacity, entered an agreement under / continued page 4

IN OTHER NEWS

in such contracts. The power plant owner in this case eventually agreed to let the utility buy out its contract for a combination of cash and common stock in the utility. During negotiations, the utility proposed to its state regulators that it be allowed to take over power plants by eminent domain from any generators who refuse to restructure their contracts. The threats by the utility led the IRS to rule privately in December 1999 that the contract was "involuntarily converted" into cash. A taxpayer who is effectively forced under threat of condemnation to take cash for his property does not have to pay taxes immediately on the buyout payment as long as the money is reinvested within two years in other property that is "similar or related in service or use."

The IRS issued a series of rulings in the late 1990's confirming that a number of power contracts with utilities were involuntarily converted.

However, the agency declined at the time to address what the money could be reinvested in. Each of the bought-out contracts was tied to a particular power plant.

Some independent power companies used the money to pay down debt on other power projects and have been challenged by IRS agents on audit. One such case went to the IRS national office for resolution. The national office said in a private ruling — called a "technical advice memorandum" — that the buyout payment could be used to pay down debt in another power project that was under construction when the buyout payment was received.

The case involved in the audit raised two issues. One is whether a power plant is "similar or related in service or use" to a power contract. The IRS national office said yes. It views a power plant and contracts tied to it as a single economic unit. Compensation for any / continued page 5

Weather Derivatives

continued from page 3

which it would be paid up to $20 million if the local precipitation was below the 30-year average. In wet years, when SMUD enjoys more revenue from power sales, it would be required to pay up to $20 million to the counterparty.

Documentation of Transactions

Privately-negotiated weather derivatives contracts typically are based on the standard International Swaps and Derivatives Association, or "ISDA," Master Agreement, which is the same form agreement used for derivative agreements involving physical commodities.

In October 2003, in response to the growing volume of weather derivatives transactions, ISDA published a series of new template confirmations and appendices, including form confirmations for weather index swaps, put options and call options, as well as form appendices for CDD, HDD and CPD index transactions. The new ISDA forms will help bring uniformity to the structure of privately-negotiated weather derivative transactions and presumably reduce the costs of negotiating such agreements.

The ISDA forms now include weather index appendices for heating degree days, cooling degree days and critical precipitation days. ISDA has not published standardized forms for wind transactions.

Monetizing Weather Derivatives

The holders of large positions in weather derivatives can hedge their exposure in a number of ways, including covering their positions by entering transactions with other parties or, in the case of temperature-based derivatives, through exchange-traded transactions. Another way the risk can be transferred is through weather bonds.

A weather bond is conceptually similar to "catastrophe bonds," which have been used periodically since 1997 by reinsurers to transfer risks associated with catastrophic events such as earthquakes and hurricanes. When catastrophe bonds are issued, the sales proceeds are deposited into the account of a special purpose entity. Bondholders receive interest and principal payments from the premiums owed to the reinsurer. Depending on how the bond is structured, the bondholders lose all or a portion of interest and principal payments if a covered catastrophic event occurs. For example, in January 2004 a 5-year catastrophe bond was issued by a special purpose entity to transfer to bondholders the risk of windstorm damage to the electricity transmission and distribution system of Electricité de France. The bond uses a specially structured index that not only takes into account recorded windspeeds in the area of the covered transmission and distribution system, but also reflects the vulnerabilities of that system to wind-related damage. When the measured index exceeds the trigger point, payouts are made to EDF regardless of whether there was actual physical damage.

Koch Energy Trading borrowed $50 million against a portfolio of 28 weather derivative contracts based on temperatures in 19 US cities.

As with catastrophe bonds, weather derivative bonds can be used to transfer to bondholders weather risks associated with a basket of weather derivative positions. The first, and thus far only, weather bond was issued in 1999 when Koch Energy Trading worked with underwriter Goldman Sachs to structure a $50 million, 3-year 144A offering that transferred to investors the risks associated with a portfolio of 28 weather derivative contracts based on temperatures in 19 different US cities. The securities were offered by a special purpose Cayman company, Kelvin Ltd. The portfolio's aggregate temperature risk was modeled by a consulting firm, with such modeling presumably showing to the satisfaction of would-be bond purchasers that the portfolio of derivative contracts would support payment of interest and principal. If the aggregate position of the derivative contracts became out-of-the-money, the special purpose issuer would be required to make payments to Koch Energy Trading under the terms of a swap agreement. Although the Kelvin transaction eventually closed, it was not without difficulty and the $50 million offering was considerably less than had originally been contemplated.

Despite the challenges of closing the Kelvin bond issuance, within the last few weeks it has been reported that the Inter-American Development Bank is preparing to launch a $300 million weather-linked bond offering that would transfer to the capital markets a portfolio of derivative weather exposures believed to be held by Entergy-Koch Trading. Reportedly, the coupons will be linked to the performance of a wide array of global weather risks, ranging from wind speed in Spain to snow depth in Fukushima, Japan. The bond issue will be split into three tranches and offer a guaranteed coupon in the first year. Thereafter, the coupons are linked to the weather index and may fluctuate, but the principal is guaranteed by the IADB. The appetite of investors for these complex securities may be a good indicator of whether weather bonds will enjoy a robust future.

Are Weather Derivatives Insurance?

Weather derivatives are considered financial derivatives and in many cases regulated as such by the US Commodity Futures Exchange Commission. However, with the continued growth in volume and variety of weather derivatives, the line between capital market products and insurance products is becoming blurred.

In a September 2003 draft white paper circulated by a working group of the National Association of Insurance Commissioners, or "NAIC," it was argued that weather derivatives are insurance products and should be regulated as such: "businesses that are involved in accepting risk transfers for a fee are known as insurers and the fee paid by the entity seeking to transfer its risk is known as premium." Regulation of weather derivatives, the white paper argued, would protect consumers from unfair contractual terms, provide assurance that adequate reserves are being maintained and also provide a safeguard against the gaming of indices like those that allegedly have occurred in the natural gas market.

In a forceful February 23, 2004 response, ISDA urged NAIC to reject the draft white paper. */ continued page 6*

IN OTHER NEWS

part of the economic unit can be reinvested in property that is similar to another part of the unit. Therefore, a buyout payment for a power contract can be reinvested in a power plant.

The other issue was whether the independent power producer "purchased" replacement property with the buyout payment. The tax laws bar reinvestment in property acquired from an affiliate of the taxpayer, unless the affiliate acquired the property from a third party during the two-year period for reinvesting the buyout payment. The taxpayer acquired the affiliate's power plant by merger before the debt was paid down. The debt the buyout payment was used to repay was owed to the parent company of the taxpayer. Nevertheless, the IRS said the transaction qualified because — before the merger — the affiliate had paid a unrelated construction contactor to build the power plant. Thus, the power plant was purchased from a third party.

The ruling is TAM 200411001. The IRS made it public at the end of March.

A DEPRECIATION BONUS issue is causing controversy.

Some tax counsel worry that all power plants must be put into service by the end of this year to qualify for a bonus. Long-lived assets were supposed to have until the end of 2005 to be completed.

The depreciation bonus is a limited-time offer by the US government. Companies that invest in new plant and equipment during a "window period" that runs from September 11, 2001 through 2004 or 2005 — depending on the investment — can deduct either 30% or 50% of the cost of the equipment immediately. The remaining cost is deducted over the normal depreciation period. The plant or equipment must be put into service by the end of the window period to qualify. */ continued page 7*

Weather Derivatives

continued from page 5

Arguing that weather derivatives are not insurance, ISDA stressed that unlike insurance, weather derivatives do not require a party to have suffered a loss in order to receive payment; instead, weather derivatives are "simply contracts with contingent payment obligations."

As the weather derivatives market grows and matures in the coming years, the proper classification of weather derivatives will be a subject of continued discussion and debate. The resolution of this debate will have significant regulatory, tax and accounting implications that will probably determine the extent to which weather derivatives become standard tools used in the financing of energy projects. ◎

Institutional equity investors in wind farms can use weather derivatives to hedge against wind risk.

Merchant Plants Start to Sell

by Jeff Bodington, with Bodington & Company in San Francisco

Buyers and sellers of merchant power projects in the United States are beginning to overcome the many obstacles that have slowed sales of such projects during the last several years. Deals are nearing close and, pending various approvals, buyers are findings ways to manage market risk, and the gap between bidding and asking prices is closing.

Standing back, few sales during 2002 and 2003 involved projects with merchant risks. To date during 2004, several are pending and many are under negotiation. That said, most of these sales provide little or no market data on merchant plant values. Assignments to lenders, foreclosures, sales to contractors and contract buyouts imply little about the value of a project to an owner who must pay cash and take market risks.

A few arm's-length merchant project transactions have now been announced that provide early data on what such projects may be worth.

The number of merchant projects and megawatts that are now and potentially will be for sale is unclear. Lenders have taken over 14 projects with a combined capacity of more than 12,000 megawatts, and the sale of only one of these has been announced. Adding those still under the control of owners who have declared bankruptcy brings the totals to over 25 projects and 19,000 megawatts. Adding further those owned by companies under some financial pressure or looking for a strategic exit who have announced their intention to sell brings the total for sale to more than 33,000 megawatts.

Public data on three pending transactions illustrate the varied history of merchant projects and show a wide range in potential value.

One sale announced during 2003 involves an "accidental merchant" with a storied history. Frederickson was developed during the early 1990s by Tenaska and was supported by a power sales contract with Bonneville Power Administration. BPA terminated the contract while the project was under construction, years of litigation and restructuring ensued, BPA became the owner, and EPCOR Power Development of Alberta ultimately purchased the project from BPA. EPCOR completed construction and operations began during September 2002. Last year, Puget Sound Energy announced its intention to purchase an interest in this project for $76.4 million, and PSE will contribute another approximately $4 million for upgrade costs. Closing is contingent upon timely approval of full cost recovery by the Washington State Utilities and Transportation Commission. Subject to that now-controversial approval, Puget Sound Energys ratepayers will bear the risks associated with the acquisition, power values and fuel costs. Ratepayers will pay a total of $584/kW for 137 megawatts of Fredericksons capacity, and this is approximately 79% of actual original cost.

Mirant and CLECO began development of a peaker and combined cycle project in Perryville, Louisiana during the late 1990s. With the peaker in operation and the combined-cycle project under construction, Mirant sold its 50% interest in the project entity to its partner, CLECO. Construction was completed during June 2002; however, tolling contract and other difficulties plagued the projects, and the project entity, Perryville Energy Partners, filed for protection from creditors under chapter 11 of the US bankruptcy code. Then, during 2003, CLECO announced the sale of 100% of the 718-megawatt project to Entergy Louisiana for $170 million. The buyer plans to use 25% of the power for its own customers and to sell 75% under a new power purchase agreement with Entergy Gulf States. The transaction is pending, and Entergy awaits regulatory approval from the Louisiana commission to pass all costs through to ratepayers. A project that cost $451/kW was sold for 52% of actual cost on a net basis and, if approved, ratepayers will bear all risks.

Finally, Brazos Valley provides another example of merchant plant value. The project was developed by NRG Energy, and construction was well underway during 2002 when NRG became unable to meet its equity funding commitments. The lender group foreclosed during January 2003 and, following much evaluation and a restructuring of the group's interests, the lenders funded the completion of construction during mid-2003. An extensive marketing effort and several false starts ultimately led to Calpine's announcement during February this year that it would purchase the 570-megawatt project for $175 million, or $307/kW and approximately 68% of actual cost.

In contrast to these values, the average price paid for projects with contract-secured revenues during 2003 was approximately $750/kW. This average includes all technologies. The average for sales that involved primarily natural-gas-fired assets with contract-secured revenues was approximately $700/kW. This gas-only value is slightly below the average for all transactions due to the high prices paid for geothermal, wind and hydroelectric projects that have no fuel costs. */ continued page 8*

IN OTHER NEWS

Companies were supposed to have until the end of 2005 to complete long-lived investments like power plants, transmission upgrades and gas pipelines. However, some tax counsel read the statute granting this extra time to say that equipment qualifies only if it is subject to section 263A of the US tax code "by reason of" two clauses in that section. Energy projects are already subject to that section for other reasons.

US Treasury officials say this is one possible reading of the statute. Brian Meighan on the staff of the Joint Committee on Taxation in Congress said flatly that energy projects qualify for the extra year. "I wrote that; I know what was intended," Meighan said. Clarifying language has been added to a list for when Congress gets around to making technical corrections to the statute.

PUERTO RICO is debating whether to impose a 29% withholding tax on interest payments on some commercial bank loans.

The withholding tax is collected currently only on cross-border loans from related parties of the borrower. The governor is considering whether to propose also collecting withholding tax on loans from banks outside Puerto Rico. An aide, Genol Hernandez, said the governor is still collecting comments and has not decided yet what to propose. The Puerto Rican bankers association has suggested a compromise under which only a 10% withholding tax would be collected with "grandfathering" for existing debt. Owners of large infrastructure projects have complained that any tax that applies to existing debt would impose large unexpected costs on their projects. The EcoEléctrica and Guayama power projects have combined debt of $1.3 billion, much of it from nonresident lenders. Centennial, a large telephone company on the island, has complained to the governor that it has $825 million in debt that */ continued page 9*

Merchant Plants

continued from page 7

While $/kW figures are useful for comparison of a project's change in value and broad price levels, they are at best a signpost to the value of an individual asset. The cost figures in the table below are estimates because some costs are closely guarded and not all companies record and report costs the same way. Further, these $/kW sales values do not imply that all merchant projects have values in the same range. Only a valuation method such as discounted cash flow can be tailored to an asset's unique characteristics and then yield a well-supported, rational value. The high uncertainty associated with power values and fuel costs means that probabilistic analysis is often necessary and discounted cash flow provides a framework within which risks can be considered. Under these circumstances, rate-of-return requirements become fluid. A 10% after-tax return on equity may be acceptable for both an average-case project with contracted revenues and a conservative-case project that involves some merchant risk. As assumptions about performance for the merchant become more aggressive, return requirements can rise over 20%.

While each project is different and valuation demands careful analysis of many factors, the logic behind the prices reported in this article is evident after doing a few order-of-magnitude calculations. Assuming, for example, a risk-burdened 12% weighted average cost of capital and a 20-year time horizon, the present value of a net operating margin averaging $10/mWh is approximately $75. For a power project with an 80% capacity factor, that totals approximately $550/kW and is within the range of what a combined-cycle project costs to build. For a project that runs just half the year at rated capacity, the total is Approximately $325/kW. This latter figure is consistent with forecasts of near-term gluts, thin margins and is within the range of what buyers appear willing to pay in troubled markets.

The three transactions reported in this article illustrate two important trends. First, the Puget and Entergy transactions show that regulated utilities are potential buyers of some of the unsold merchant projects. Dominion and Southern California Edison are further examples of regulated utilities that are purchasing either uncontracted assets or buying into projects with which they have contracts. (See related article, "FERC Restricts Power Plant Sales to Utilities," starting on page 8 of this issue.) Second, merchant assets, for now, appear to be worth 50% to 70% of original constructed cost. Purchasing these assets and working to arrange power contracts or selling to regulated utilities are examples of ways to add substantial value.

Examples of Early Merchant Project Sales

	Frederickson	Perryville	Brazos Valley
Developer	Tenaska / EPCOR	Mirant / CLECO	NRG
Seller	EPDC	CLECO / PEP	Bank Group
Buyer	Puget Sound Energy	Entergy, LA	Calpine
Date announced	10/22/03	5/8/03	2/18/2004
Date closed	Pending	Pending	Pending
Share	49.85%	100%	100%
Capacity, net mws	137	718	570
CT, OEM	GE7FA CCCT	GE7FA CT + CCCT	2 GE7FA CCCT
Location, state	Tacoma, WA	Monroe, LA	Fort Bend Cty, TX
NERC Region	WECC	SERC	ERCOT
Total value, $mm			
Cost, est. $/kW	743	451	455
Sold For			
$mm	80	170	175
$/kW	584	237	307
% of as built	79%	52%	68%
Bears market risk	Ratepayers	Ratepayers	Calpine

B&Co data verified by public sources.

FERC Restricts Power Plant Sales to Utilities

by Robert F. Shapiro, in Washington

The Federal Energy Regulatory Commission is making it hard for franchised utilities in the United States to buy power plants from distressed independent power companies.

Two recent FERC orders show the difficulty that utilities are having getting approval for such transactions. The effect is to reduce the number of potential buyers for distressed assets. It is also a sign that FERC intends to keep fighting for a more robust competitive wholesale market in the face of an increasing trend toward reintegration of generation by franchised utilities.

Ever since Enron's demise and the virtual collapse of spot market trading in many markets, merchant generating plants have become uneconomic. Seizing upon the opportunity to acquire independent generation at a bargain price or to salvage a bad investment in generation from their own unregulated affiliates, franchised utilities have sought to acquire new capacity from the market in order to add to their regulated rate bases.

FERC must approve acquisitions of certain power plants, distribution lines and other utility assets. Until a couple of months ago, utilities had successfully convinced FERC that their acquisitions were in the public interest. An example was FERC's decision in 2003 to let PSI Energy, a regulated utility in Indiana, acquire two existing power plants in Ohio and Indiana from its unregulated affiliates. This trend appeared to dovetail with a national energy plan that narrowly failed to pass Congress in late November. The bill would have given franchised utilities the upper hand to place the needs of their captive customers over the needs of independent generators in the wholesale markets. Among other things, the bill offered vertically-integrated utilities the potential to manage their transmission systems to the detriment of their competitors.

Perhaps sensing that the bill's failure to pass offered an opportunity to reinvigorate the */ continued page 10*

IN OTHER NEWS

would potentially be affected.

The Puerto Rican Congress, which would have to pass the tax proposal, is expected to be in session this year only until late June. The governor is running for reelection in November.

WIND CREDITS will remain at 1.8¢ a kilowatt hour in 2004, the IRS said in late March.

Owners of wind farms whose projects went into service by the end of last year can claim a tax credit of 1.8¢ a kilowatt hour on the electricity generated and sold to unrelated parties. The credits run for 10 years after a project is put into service. The credits are adjusted each year for inflation.

The IRS said in late March that inflation has been too low to justify an increase in the credit amount. It also said the average price at which electricity from wind farms was sold in the United States last year was 3.24¢ a kilowatt hour. This is down from 4.85¢ the year before. Only sales under post-1989 contracts are taken into account. Spot sales through power pools are not counted.

SECTION 29 tax credits were $1.1036 an mmBtu last year.

The IRS announces the credit amount each April for the past year. Section 29 credits are tax credits that can be claimed by companies that are producing synthetic fuel from coal or landfill gas or other "gas from biomass." The facilities used to produce these fuels must have been put into service by June 1998. The credits run on output from such facilities through 2007.

CANADIAN INCOME FUNDS face new restrictions in the budget announced by the Canadian government at the end of March.

The main restriction is a limit on the extent to which Canadian income funds can tap into Canadian pension plans as a source of future capital. */ continued page 11*

Plant Sales

continued from page 9

effort to create workably competitive wholesale markets, FERC issued an order in late December that put franchised utilities on notice that it would view skeptically their efforts to acquire generating plants from their competitors. Most remarkable was a FERC decision to question an acquisition of a failing enterprise where the to-be-acquired power project was owned by a bankrupt independent power company. Even the US antitrust laws make an exception and let a strong player in the market acquire a competitor where the competitor is a "failing company." The "failing company" doctrine is included in the Department of Justice/Federal Trade Commission 1992 horizontal merger guidelines that the commission adopted in its "merger policy statement" as the basic framework for evaluating the competitive effects of proposed mergers.

Recent sales suggest that merchant power plants are trading for 50 to 70% of what they cost to build.

Oklahoma Gas & Electric

Oklahoma Gas & Electric, or "OG&E" sought to acquire the generating assets owned by an NRG Energy subsidiary called NRG McClain in Oklahoma. NRG McClain, like the NRG parent, had filed for bankruptcy, and OG&E was the winning bidder of a bankruptcy auction for the assets. As a vertically integrated utility, OG&E had captive customers and needed additional capacity to provide service to those customers. OG&E also had made a commitment in a settlement agreement with its state regulatory commission to acquire this amount of capacity within a specified time period or pay a penalty to its retail customers. The filing was opposed by several independent power producers.

FERC does a "competitive screen analysis" when asked to approve such transactions. This is a test to measure the effect of the proposed transaction on competition for wholesale electricity supply in the region where the power plant is located. This "competitive screen analysis" does not recognize that any portion of a utility's generation must be used to serve its native load customers. OG&E's study showed that the acquisition would lead to too much horizontal market concentration in certain time periods in certain markets. However, OG&E also presented evidence that there would be no impermissible market concentration if OG&E's native load requirements were considered. OG&E proposed mitigation measures to increase transmission import capability that would take 18 months to complete.

In a December 18, 2003 order, FERC found that the analysis showed excessive horizontal market concentration and vertical market concentration. It ignored the impact of OG&E's native load in examining horizontal concentration. With respect to vertical market concentration, FERC found that OG&E already had the ability to use its transmission system to frustrate competition, and that adding 400 megawatts of additional generating capacity would increase its incentive to do so, despite the fact that OG&E has an "open access transmission tariff" that is supposed to allow everyone equal access to the OG&E transmission grid. FERC set the matter for hearing to determine what interim and permanent mitigation measures would be required before the acquisition could be approved. Hearings have been scheduled for August, and a final decision would not be expected until mid-2005. However, OG&E has asked FERC to reconsider whether a hearing is necessary and has also made a unilateral offer of settlement with the presiding judge, offering additional transmission enhancements as mitigation measures.

The OG&E decision signaled strong FERC opposition to the acquisition by vertically-integrated utilities of independent power plants in the utilities' own service areas and has had a chilling effect on the industry.

Several major owners of merchant generating plants that are losing money have said publicly that they will not offer to sell those plants to franchised utilities in light of the current FERC position. The FERC's order showed a preference for utilities to purchase power from competitors rather than acquire them, particularly in areas where no regional transmission organization, or "RTO," has been established.

Mountainview Power

FERC also put franchised utilities on notice that purchases of power plants from their own affiliated companies would be subject to stricter scrutiny in the future.

In a case involving the Southern California Edison Company in late February, *FERC* approved a proposed power purchase agreement between Edison and an affiliate of Edison that had an option to purchase an unfinished power plant in the Edison service territory. The Mountainview project was owned by an independent power developer that ran into financial difficulty due to its inability to obtain a power contract for its output. The pricing under the power purchase agreement was on a cost of-service basis. Numerous independent power producers, who had also been unable to obtain contracts to supply power to Edison, challenged the proposed agreement between Edison and its affiliate, claiming that they could meet or beat the Mountainview deal and asking FERC to apply the so-called Edgar standard to the proposed agreement. The "Edgar standard" is a FERC policy that a utility applying to buy power using market-based rates from an affiliate must show that the electricity is reasonably priced compared to alternatives in the market. It came out of an order FERC issued more than 10 years ago in a case involving Boston Edison and its affiliate, Edgar Electric Company.

Edison argued that the Edgar test was inapplicable since the prices it proposed to pay for electricity from its affiliate, Mountainview Power, were cost-based, not market-based.

FERC said that it was concerned about granting undue preference to affiliates, but it nonetheless approved the proposed deal on the stated ground that a cost-based formula did not require an Edgar analysis under current policy. Perhaps a more forthcoming response would have been that FERC knew that the / continued page 12

IN OTHER NEWS

Canadian income funds are trusts formed in Canada that raise money in the capital markets to pool for investment. Many US power companies have been looking at them as a possible source of financing for acquiring distressed assets and cashing out existing projects in the United States. The trusts have seen phenomenal growth in Canada. They accounted for 86% of all the new capital raised through initial public offerings in Canada last year and now represent 7% of the aggregate capitalization of the Toronto Stock Exchange. Canadian businesses organized as trusts face only one level of taxation — to the unitholders in the trust — and, to the extent the unitholders are pensions, there is no current tax. The same math works when the trusts invest across the border into the United States. The tax advantage means that Canadian income funds can afford to pay at least 27% more than competing bidders for operating businesses.

The Canadian government is worried about the loss of tax revenue in Canada if pension fund managers move to invest large sums of money in the trusts. They have been slow to invest so far because of concerns about potential liability if the trustee of a trust were sued and were viewed, under Canadian law, to have been acting merely as an agent for the unitholders. Ontario and Alberta are moving to limit the liability by statute. After that happens, pension plan and other institutional money is expected to flow freely into the income funds.

The new budget would impose two new measures starting in 2005. First, business trusts would be defined as restricted investments. Tax-exempt entities, including pension plans, are barred from holding more than 1% of the book value of their assets in restricted investment property. Second, any one pension fund could not own more than 5% of the interests in any / continued page 13

Plant Sales

continued from page 11

California Public Utilities Commission had approved the deal and did not want to make waves. FERC certainly was not legally barred from applying a new standard to a contested case; only rulemakings must be applied prospectively.

However, FERC announced that future affiliate transactions with franchised utilities, even those using cost-based rates, will be subject to an Edgar test. The order was another sign that FERC has a strong predilection for power purchases from non-affiliated entities to promote wholesale competition.

FERC is making it hard for franchised utilities to buy power plants from distressed independent power companies.

What Could Happen

FERC's policy cuts both ways for the independent power industry. It helps in the longer term to have an agency strongly interested in promoting competition in the wholesale market. However, the short-run effect is to exacerbate the financial straits of merchant generators who find themselves in a severely-depressed wholesale market by removing likely buyers of troubled assets. The fewer buyers there are, the lower the prices for assets become. The two FERC orders could also have the unintended effect of promoting traditional, rate-based utility construction, since FERC has no jurisdiction over the construction of generating plants. That would lead to the very sort of non-competitive market concentration and reintegration that FERC has sought mightily to avoid. ◎

Carbon Sinks

by Roy Belden and Katherine Wich, in New York

If a mandatory greenhouse gas reduction program is ever implemented in the United States, carbon sinks will be an important part of the compliance equation for US companies.

The Bush administration is talking at the moment only about voluntary reductions. However, a number of US states are taking action on their own — without waiting for the federal government — to require power plants and factories to reduce their greenhouse gas emissions.

Greenhouse gases include carbon dioxide, or CO_2, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride. Reductions in these greenhouse gases are generally measured in "CO_2 equivalents." CO_2 is the largest source of greenhouse gas emissions and accounts for approximately 83% of the carbon dioxide equivalent emissions.

What Are Carbon Sinks?

A carbon sink is a forest or other vegetation that absorbs the CO_2 emitted by power plants, factories, automobiles and the other machinery that uses combustion to power itself. Carbon sinks exist in a natural state. They can also be created as a way of reducing CO_2 emissions, like a forest planted in Guatemala to offset anticipated emissions from a new power plant under construction in Florida.

Plants extract carbon dioxide from the atmosphere through photosynthesis, converting it to carbon, storing it in the form of roots, stems, trunks, branches, soil, or foliage, and releasing the oxygen back into the atmosphere. Examples of naturally-occurring carbon sinks include forests, plants, cropland, grazing land, peat and permafrost. The term "carbon sinks" has also been expanded to included geologic formations, ocean water and carbonate deposits in the deep ocean where the carbon is stored under pressure and is prevented from being released into the atmosphere.

If one wanted to create more carbon sinks, the most cost-effective way would be to plant new forests. Costs to plant forests to offset greenhouse gas emissions are generally in the range of $1 to $2 for each ton of CO_2 sequestered. Trees on average are about 25% carbon. The amount of carbon that can be sequestered depends on the type of tree and the age of the tree. For example, a large sugar maple is capable of absorbing more than 450 pounds a year of CO_2. While there are ongoing studies into other potential technologies to remove CO_2 from power plant emissions, including an amine-based adsorption process, integrated gasification and a high-pressure decarbonization process, these other technologies have not yet been proven to be cost effective.

Planting trees can be a contentious issue in some communities. Local ecosystems come under stress if fast-growing "tree farms" are seeded instead of trees indigenous to the environment. The overall effectiveness of forests as carbon sinks is also difficult to measure. Carbon storage projections vary depending on the methodologies used.

A US Environmental Protection Agency draft report entitled "US Inventory of US Greenhouse Gas Emissions and sinks: 1990 - 2002" says that US forests and farmlands offset about 10% of total US CO_2 emissions in 2002. Overall, in 2002, US greenhouse gas emissions were approximately 6,934 million metric tons of carbon dioxide equivalents, which is about 13% above the level in 1990.

Private Initiatives

In the last several years, several US power companies have planted thousands of acres of trees and spent money on other forms of carbon sinks in an effort to offset carbon from combustion processes. These companies have entered private-public partnerships to promote carbon sequestration projects not only in the US, but also in developing countries. The companies include AES, Duke Energy, DTE Energy, American Electric Power, Entergy, Cinergy and British Petroleum. A large number of power companies have also participated in joint initiatives with environmental groups, such as the Nature Conservancy, to organize forestry programs. / continued page 14

IN OTHER NEWS

one business income trust. These limits would not apply to the types of trusts that invest in oil and gas and real estate. The finance minister, Ralph Goodale, released the budget on March 23.

Reaction in the market was muted. The prices for units in some prominent income funds were down slightly after the announcement.

BRIBES paid by an American company to avoid sales taxes and customs duties in Haiti may be a crime under the US Foreign Corrupt Practices Act, a US appeals court ruled in February.

The decision reverses a ruling by a lower court that such bribes are not the type of payments at which the Foreign Corrupt Practices Act is aimed.

Officials of American Rice — a rice exporting company in the US — paid monthly retainers to Haitian government officials in exchange for letting the company underreport by a third the amount of rice it brought into Haiti. The Foreign Corrupt Practices Act makes it a crime for a US company or US person to give anything of value to a foreign government official in an effort to win or retain business. The lower court said bribes paid to reduce sales taxes or customs duties have nothing to do with winning or retaining business.

The appeals court disagreed. It said the lower costs could help the company to win more sales, but it was unwilling to find that this would occur automatically and sent the case back for a closer look at whether the officials paying the bribes intended to reduce costs in order to obtain or retain business. The case is *United States v.* Kay.

HOLLAND and the United States agreed in a treaty protocol on March 8 to eliminate withholding taxes on certain dividends.

The protocol must / continued page 15

Carbon Sinks

continued from page 13

Power companies have sponsored numerous carbon sequestration efforts. For example, AES planted forests in Guatemala and Paraguay to offset CO_2 emissions from new power plants. DTE Energy, Cinergy and Wisconsin Energy Corporation bought and preserved sub-tropical forest land in Belize that was in danger of being stripped bare by developers. The Belize effort is expected to sequester approximately 2.4 million metric tons of carbon over the next 40 years. American Electric Power is a founding member of PowerTree Carbon Company, LLC, a carbon sequestration initiative among power companies to create reforestation projects in Arkansas, Mississippi and Louisiana. More than 40 utilities created another reforestation initiative called UtiliTree Carbon Company to create eight domestic and international forestry programs. Many afforestation and reforestation projects have been targeted for warmer, tropical climates where trees can grow faster, such as in Central and South America and Australia.

The power industry is also partnering with other high greenhouse gas emission industries like landfills, farming and logging to promote more environmentally-conscious business practices. DTE Energy, Cinergy and Entergy collect the methane that would otherwise be released from landfills and abandoned coal mines and use it as a fuel to generate electricity. Power companies have also purchased greenhouse gas emission reduction credits that are created when local farmers use minimum-till and no-till farming practices. These practices reduce emissions by reducing the amount of carbon dioxide emitted when the soil is tilled.

Private industry is also exploring other forms of carbon sinks. One form uses technology to capture and inject CO_2 into naturally-occurring reservoirs like out-of-service oil or gas fields, deep saline-water reservoirs, sandstone or the deep ocean. One successful example is the deep saline-water reservoir under the North Sea that stores CO_2 extracted from the natural gas stream produced by Statoil.

A number of states are acting on their own to require power plants and factories to reduce greenhouse gas emissions without waiting for the Bush administration.

Power companies are also spending money on research for future carbon sinks and emission reduction techniques. The US Department of Energy has joined with a number of companies, including American Electric Power, in a research effort to determine whether CO_2 can be stripped from the emissions stream at AEP's Mountaineer power plant and injected into a nearby geological reservoir as a carbon sink. President Bush has asked Congress for more than $1 billion to spend on building an emission-free coal-fired power plant. The CO_2 would be removed from the emissions stream and stored permanently in a carbon reservoir. Cinergy has also announced plans to build an integrated gasification combined-cycle plant that will use a coal gasification process. IGCC technology has shown promise in reducing CO_2 emissions compared with traditional coal-fired plants.

Required Reductions

There is nothing in US federal law currently that requires anyone to reduce his greenhouse gas emissions.

However, several US states have decided to take action on their own without waiting for the federal government to act. Thus, some power plants, factories and other "sources" are already required by state regulation or regional plans to reduce emissions of CO_2 and other greenhouse gases.

New York is spearheading an effort by 10 northeastern and mid-Atlantic states to develop a "cap and trade" program to reduce CO_2 emissions from power plants. The participating states are Connecticut, Delaware, Maine, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island and Vermont. They are expected to use the federal acid rain program as a model. Agreement on a regional program is expected by April 2005.

Maine became the first state in June 2003 to adopt a comprehensive statewide climate change law. Maine has committed to reduce greenhouse gas emissions to 1990 levels by 2010, and 10% below 1990 levels by 2020. The Maine program will impose Kyoto-type reduction requirements and will apply to a broad range of facilities, including power plants.

Oregon has set CO_2 emission limitations for new natural-gas-fired baseload power plants and non-baseload peaking plants. Covered plants must meet an emission rate of 0.675 pounds of CO_2/kWh of net electric power output. Companies also have the option of meeting the CO_2 standard through offset projects or by paying a fee of $0.85 per short ton of CO_2. Washington state adopted a new law in March 2004 that requires new power plants to offset 20% of the CO_2 they emit through mitigation projects. Companies can either pay a fee of $1.60 per ton of CO_2 or finance mitigation projects on their own.

States such as California, Massachusetts, Oregon, New York, New Hampshire, New Jersey, Wisconsin, Illinois, Iowa, Michigan, Maine, Colorado and Washington have each established some form of greenhouse gas emissions registry. Nebraska, North Dakota, Oklahoma and Wyoming are all working on agricultural reforms to reduce CO_2 emissions and increase CO_2 sequestration. Other states, such as Minnesota, Montana and Oregon, have instituted tree planting and forestry programs to foster carbon sequestration efforts.

Kyoto

The Kyoto treaty that was supposed to commit a large number of countries to take concerted action at the international level to reduce greenhouse gas emissions has not yet been implemented. There are doubts about whether it will ever take effect.

The treaty was negotiated during the Clinton administration, and it set deadlines for reducing greenhouse gas emissions below a 1990 baseline. The United States signed the treaty in November 1998.

/ continued page 16

IN OTHER NEWS

still be ratified by the US Senate.

Under the protocol, there would be no withholding taxes on dividends received by a publicly-traded company that has owned directly for the last 12 months before the dividend is paid at least 80% of the voting stock of the company paying the dividends. Alternatively, a private company could qualify if it owned at least 80% of the voting stock at least indirectly before October 1998.

The protocol also addresses how the tax treaty applies to income received through a company that is transparent under the tax laws on either the US or Holland. For example, if a US company owned a Dutch company through a US limited liability company that is transparent for US tax purposes, then the US LLC receiving the dividend would get the benefit of the tax treaty so long as the dividend it receives will be distributed to US residents who are required to report the distributed earnings as income.

In another development, the Dutch tax court refused in February to treat a US limited liability company as transparent for Dutch tax purposes. The ruling meant that a Dutch company with interests in two hotel companies in the United Kingdom could not avoid Dutch income taxes on the dividends from the hotel companies. It might have avoided them under the "participation exemption" if it had owned the hotel companies directly. However, it held them through a US limited liability company, with the result that the dividends passed through the US limited liability company on the way to Holland. The limited liability company was transparent for tax purposes in the United States, but not in Holland, the court said.

Dutch lawyers caution that US LLCs may still be treated as transparent for Dutch purposes depending on the facts.

/ continued page 17

Carbon Sinks

continued from page 15

However, the Bush administration rejected it in 2001, citing concerns about the effect of the treaty reductions on the US economy. The Bush administration also complained that large developing countries, such as China and India, would not be obligated to cut greenhouse gas emissions under the treaty and criticized the treaty for not fully embracing carbon sequestration as an acceptable method for offsetting greenhouse gas emissions.

If implemented in its current form, the treaty would require the United States to reduce CO_2 emissions by 7% below 1990 levels by 2012.

Russia is now the key to implementation of the Kyoto treaty. The treaty will enter into effect after it has been ratified by 55 or more countries (including both industrialized "Annex I" nations and developing "Annex II" countries) whose combined CO_2 emission levels represent at least 55% of the CO_2 emissions from Annex I countries in 1990. As of the end of March 2004, 121 nations had ratified the treaty, and those nations accounted for 44.2% of the 1990 carbon dioxide emissions. Russia accounts for 17.4% of the emissions, and thus its ratification would put the treaty over the 55% implementation threshold. The United States accounted for 36.1% of 1990 CO_2 emissions.

At present, Russian intentions are in doubt. A senior aide to the Russian president, Vladimir Putin, said in late 2003 that Russia will not ratify the treaty in its current form because it has similar concerns as the US about how the treaty would affect its economy. However, President Putin has not yet formally rejected the treaty. He was just reelected in March.

In December, a subset of the Kyoto negotiators clarified how to quantify CO_2 emission reduction credits from carbon sequestration activities. The group drew up model tables for reporting land use, land-use change and forestry activities undertaken to sequester carbon. It agreed that a type of carbon sequestration called a "clean development mechanism" project would count toward greenhouse gas emission reduction targets. Such projects might be sponsored by developed countries in developing countries.

> Some utilities are under pressure from shareholders to report on the potential future costs if they are required to reduce emissions.

US Voluntary Reductions

In the meantime, the Bush administration is advocating a policy of encouraging US companies to reduce greenhouse gases voluntarily. A "global climate change initiative" announced by the Bush administration in February 2002 would set a goal of reducing the greenhouse gas intensity of the US economy, as measured against the gross domestic product, by 18% within 10 years. The goal would be voluntary. The current US rate of greenhouse gas emissions is 183 metric tons per million dollars of gross domestic product. Bush would set a goal of reducing this to 151 metric tons. The administration says that its goal equates to approximately a 4.5% reduction beyond business-as-usual forecasts.

The president also wants Congress to set aside more money for developing science and technology, conservation efforts, renewable fuels and sequestering carbon as part of a long-term strategy.

The plan would also direct the US Department of Energy to improve its voluntary emissions reduction registry and to develop a strategy to ensure that companies are not penalized for registering voluntary emission reductions under any future climate change program. The

Department of Energy recorded 369 carbon sequestration projects in 2001 in 31 states and eight foreign countries. A total of 7,956,823 metric tons of carbon dioxide are expected to be sequestered from these projects. The department is currently funding more than 80 active research and development projects involving carbon sequestration. Many of these projects are focused on new ways to remove CO_2 from the emissions of combustion sources and also the potential storage of captured CO_2 in geological formations or in the deep ocean.

At least for the near term, the US Congress is not expected to pass legislation requiring mandatory greenhouse gas emission reductions. The Senate rejected a bill offered by Senators John McCain (R-Arizona) and Joseph Lieberman (D-Connecticut) in October 2003 that would have required power plants and factories to cut back their greenhouse gas emissions to 2000 levels by 2010. The vote was 43 to 55.

Mandatory Reductions on the Horizon?

Nevertheless, many companies believe that it is only a matter of time before some form of mandatory greenhouse gas emission reductions are in place in the US. American Electric Power and Cinergy are expected to report to their shareholders later this year on the potential financial risks from future greenhouse gas emission reduction requirements.

Even if the Kyoto treaty is ultimately set aside, there is no going back for the European Union: some form of mandatory greenhouse gas reductions are expected in Europe. Each of the European Union countries was obligated to submit its national quota allocation plans by the end of March 2004. The allocation plans are an initial step toward a planned start to trading greenhouse gas emissions credits within the European Union in January 2005.

Some American companies are already taking steps to reduce their emissions or invest in carbon sequestration projects in anticipation of an eventual US program. It is possible that these early reductions will ultimately be rewarded in any federal greenhouse gas reduction program that is enacted. Some companies see a public relations benefit from such efforts. Another factor is shareholder groups that are forcing large publicly-traded companies to cover in their annual reports what efforts they are making to address global / continued page 18

IN OTHER NEWS

VENEZUELA said it plans to increase income taxes on oil and natural gas companies by $3 billion. Tax Commissioner Jose Vielma Mora made the announcement on March 30. Any increases will have to be approved by the national assembly.

PERU imposed a bank transactions tax on March 1.

The rate is 0.1%, but will drop to 0.08% in 2005 and 0.06% in 2006 and then disappear after 2006. The tax applies to most transactions run through the Peruvian banking system, including making deposits or withdrawals from bank accounts, borrowing money, cashing checks and using credit cards.

Peru also changed its laws for carrying forward net operating losses. The new rules apply to losses starting in 2004. A company has a choice of using the loss to shelter income in each of the next four years until it is fully used. Alternatively, it can use the loss against only half its income in each full year but without any limit on how long the loss can be carried forward. A company has the same options for losses in 2003 that it has not already started writing off.

BRAZIL may find that an increase of two taxes in 1999 was unconstitutional, requiring refunds of as much as $5.17 billion.

The taxes are a social security tax called COFINS and a separate levy called PIS that funds a savings program for employees. The COFINS tax was 2% of a company's gross receipts from sales of goods and services. The rate was increased to 3% and extended to other types of income — for example, interest and currency gains — in 1999. The PIS tax is 0.65% of the same tax base.

The country's second highest court found in early March that expansion of the tax base beyond operating income was unconstitutional. The Supreme / continued page 19

Carbon Sinks

continued from page 17

warming. More than 25 global-warming-related shareholder resolutions are pending at companies this year, including at ExxonMobil, Southern, TXU, and ChevronTexaco.

A growing market is developing in the trading of greenhouse gas emission reduction credits. Emission trading companies such as Natsource, Cantor Fitzgerald and CO_2.com already actively trade such credits. Several industrial companies, financial institutions, and not-for-profit corporations recently joined the Chicago Climate Exchange — known as the "CCX" — which commenced business on October 1, 2003 as an electronic exchange for trading greenhouse gas credits among companies that voluntarily choose to reduce their greenhouse gas emissions. The CCX has more than 20 members, including American Electric Power, the Ford Motor Company and International Paper. Each member has voluntarily committed to reduce its greenhouse gas emissions by 4% in 2006 from a baseline emission level that is tied to CO_2 emissions during the period 1998 to 2001.

The CCX held its first auction of CO_2 emission allowances last fall consisting of 100,000 metric tons of 2003 vintage CO_2 allowances and 25,000 metric tons of 2005 vintage CO_2 allowances. The average successful bid was $0.98 per metric ton CO_2 for 2003 allowances and $0.84 per metric ton CO_2 for 2005 allowances. ◎

Current Issues in Financing Ethanol Plants

by Chris Groobey, in Washington

Ethanol is a significant and growing part of the energy infrastructure of the United States. There are currently 73 ethanol production facilities in operation in the US. These facilities produced 3.1 billion gallons of ethanol in 2003, a 32% increase over the production level in 2002. Another 14 facilities are currently under construction and will add 500 million gallons a year to production capacity. Many more plants, in more than 20 states, are under development.

Ethanol is an octane-enhancing additive to gasoline. It increases the oxygen content of the fuel and reduces harmful emissions from internal combustion engines. Ethanol is now blended into 30% of the gasoline sold in the US.

Demand for ethanol is expected to increase significantly through at least 2010. Gasoline refiners currently add either ethanol or a petroleum by-product called MTBE to gasoline. However, California, New York, Connecticut and other states have either banned MTBE or are moving to do so. In addition, Congress has been debating a renewable fuels standard that would create a domestic market by law of at least five billion gallons of ethanol a year by 2012, a 60% increase over current production capacity.

Why Ethanol?

A series of federal, state and local incentives are key to making ethanol projects economic.

Chief among them is a federal ethanol tax incentive benefiting gasoline wholesale marketers that may be claimed in one of two ways.

The first method is a partial exemption from the federal gasoline excise tax. The US government collects a tax of 18.4¢ a gallon on gasoline. The tax is collected from the refiner or wholesale distributor that last handles the blended fuel in bulk form. However, the tax is reduced by 5.2¢ a gallon on gasoline that contains at least 10% ethanol. This gives the refiner or distributor an incentive to blend ethanol with his gasoline if the cost to him of doing so is less than 5.2¢ a gallon.

The second method is by claiming a credit against federal income taxes. The credit can be claimed by the company that blends the ethanol with gasoline. The credit is 52¢ per gallon of ethanol that is blended into the gasoline. This is economically equivalent to the 5.2¢-a-gallon excise tax exemption for 10% blend gasoline. However, the amount of the credit must be reported as income by the blender — which has the effect of clawing back part of the benefit — and a blender cannot use credits to reduce his regular tax liability by more than 25%. It cannot be used at all against liability under the alternative minimum tax. Blenders usually prefer the excise tax reduction rather than the tax credit because of these restrictions.

There is also a separate tax credit of 10¢ a gallon for small ethanol producers. A company can qualify if it produces fewer than 30 million gallons of ethanol a year. The credit is capped at $1.5 million per producer per year so it only applies to the first 15 million gallons of production. It may not be claimed by an entity that has already taken advantage of the excise tax reduction. In other words, if an ethanol producer also blends the ethanol with gasoline, he will have to chose the small producer credit or the excise tax exemption. He cannot have both. As with the blender credit, the small producer credit must be reported as income, and it cannot be used against liability under the alternative minimum tax. Most new ethanol plants are designed to produce more than 40 million gallons a year and some plants are owned by farmer cooperatives that cannot take advantage of this credit. Congress is considering legislation that would allow plants to produce 60 million gallons a year and still qualify as "small ethanol producers." The legislation would also enable farmer cooperatives to benefit from the credit.

Finally, businesses may take a credit of 52¢ for each gallon of ethanol (not blended with gasoline or other fuel) that is sold at retail for use as vehicle fuel or that the producer uses directly as fuel in his own business. Only specially-modified vehicles can use pure ethanol as fuel so this credit has a limited market.

The current exemption and credits expire in 2007, but a number of bills moving through Congress would extend them through 2010.

The federal government also supports ethanol projects through a federal grant program administered by the US Department of Agriculture. The Commodity Credit Corporation — which is part of the Agriculture Department — provides up to $150 million a year in grants to encourage increased ethanol production. To qualify for these payments, the ethanol producer must enter into an agreement with the CCC and report its production on a quarterly basis. The CCC makes payments to producers who increase ethanol production over the previous year. Proceeds are generally used to construct new ethanol facilities or to secure financing for new ethanol producers. Payments are pro-

/ continued page 20

IN OTHER NEWS

Court heard an appeal. Three of the 11 Supreme Court justices have found the changes were legal. The fourth justice to vote has asked for more time. The other justices are expected to render their decisions in late April. A decision against the government could require large tax refunds back to 1999 and reduce tax collections going forward.

In a separate development, the Brazilian tax authorities issued a "normative" on March 17 implementing new rules that require tax withholding when nonresidents sell assets in Brazil. The new withholding rate is 15%. However, it jumps to 25% when the seller is a company or other resident in a tax haven.

STRANDED COST RECOVERIES by utilities are taxable income, the IRS said in an audit.

A state allowed consumers to bypass the local utility and contract directly with independent suppliers for electricity. As part of this deregulation plan, the utility moved its power plants into an unregulated affiliate owned by its parent company. That left the utility owning only transmission and distribution lines. The state deregulation law authorized the utility to collect a "transition charge" from all of its distribution customers until it recovered its "stranded costs," or its unrecovered investment in the power plants. The utility borrowed against the transition charges it expected to collect in the future — so that it would have the cash value today — and then used the transition charges as they came in over time to repay the lenders.

The utility took the position the transition charges it eventually collected did not have to be reported as taxable income. (It is not clear whether the utility took the potential tax cost into account when it borrowed against the transition charges. Since the cash it collects goes to repay the lenders, it has little cash left over to pay any taxes.)

/ continued page 21

Ethanol

continued from page 19

rated at the end of the government's fiscal year so that the aggregate amount of the grants (including separate bio-diesel grants) remains within the $150 million budgeted. For fiscal year 2003, the CCC paid more than $130 million to 44 ethanol producers for an average payment of $2.95 million. Congress has authorized the CCC program through 2006.

Other, smaller USDA grants are available to defray costs incurred during the early stages of developing an ethanol plant. These grants are available through the rural development office in the US Department of Agriculture.

There are also various state and local incentives for ethanol projects. Some of these incentives are aimed at a larger class of infrastructure projects than just ethanol. They include tax-increment financing (which segregates property tax revenues for the benefit of a specific project), property tax abatements, assistance in obtaining suitable project sites and similar support. Other incentives are targeted only to ethanol. Examples of these include a production incentive of 1.9¢ a gallon for ethanol in Minnesota and a sales tax exemption for ethanol in Illinois. These types of ethanol-specific incentives are most common in farm-belt states, but other states — most notably on the West Coast and in New England — are aggressively courting ethanol producers to support their own agricultural economies.

The Ethanol Opportunity

Ethanol processing facilities have historically been owned by farmer-owned cooperatives or agri-tech conglomerates like ADM and Cargill. Farmer cooperatives build ethanol facilities to create a captive customer for their grain and to profit from the sale of the ethanol produced from the grain. Conglomerates view ethanol as another outlet for the grain they buy from farmers. Ethanol production is the third largest market for corn after domestic consumption and exports.

There are 73 ethanol plants in the United States, 14 under construction, and other projects under development in another 20 states.

Traditional project financing opportunities for facilities owned by cooperatives or conglomerates have been rare as cooperatives generally borrow from rural development banks, through municipal bonds or from government agencies, and conglomerates generally develop ethanol facilities on their own balance sheets.

However, this might change. Both the institutional equity market and private equity firms have started to take an interest. Ethanol projects are now seen as generating the same attractive returns –- generally 12% to 15% before taking into account mezzanine debt and sub-debt structures — as affordable housing, big-ticket lease transactions, wind projects and other alternative investments that rely on tax advantages for a part of their total return.

Institutional equity investors in ethanol plants prefer to leverage their investments and to do so within a non-recourse, project-finance structure. Developers are also starting to show an interest in mezzanine debt structures that have not been widely used to date for ethanol.

Project Finance

At first glance, ethanol facilities appear to be strong candidates for project financing. Among other attributes, the process for distilling ethanol is well understood, so there is no technology risk. The facilities themselves are simple to construct and operate, so it is likely that they will be delivered on time and operate on budget. Corn and other feedstocks are widely available and easily transported so "fuel risk" is minimal. The end products — ethanol, carbon dioxide and distillers' grains — are readily sold and have multiple current and future uses. For example, carbon dioxide can be used to make dry ice or carbonated beverages, and distillers' grains are valuable as livestock feed. The facilities are generally welcomed by the surrounding community and subject to minimal environmental and other regulatory oversight or potential liabilities.

However, some attributes of ethanol facilities give project finance lenders pause and prompt changes from the traditional project finance model. Of these, the most important factor is that long-term, fixed-price, single-counterparty contracts are generally not available for either the inputs into the facility (corn and other feedstocks) or the outputs (ethanol, carbon dioxide and distillers' grains). The lack of such contracts — and the liquidated damages provisions that are normally contained in them — introduce uncertainty into both the price and availability of the "fuel" and the price and customer base for the "products" of the facility. Given the inability to tie down future costs and revenues, and given banks' current aversion to "merchant" facilities of any sort, project-finance lenders have been relatively conservative in the pricing and terms offered to the developers of ethanol facilities.

Crossing the Open Water

The realities of the supply and offtake markets for ethanol facilities create challenges for developers and financiers of such facilities. Developers try to maximize their returns on investment by borrowing as much as possible against the project. Financiers are constrained by their relative unfamiliarity with such projects and their concerns about uncertain expenses and revenues. Both sides tend to focus on the following characteristics of the debt financing when determining whether a deal can be struck:

Equity Requirements: Debt-equity ratios for contracted domestic power plants can reach 80-20 for the strongest projects. Ethanol facilities are generally limited to no more than 60% senior debt and more likely 50% (all percentages being of the total cost to develop the project to commercial operations). Less leverage means lower returns on equity for the developers but greater certainty of repayment for the lenders. Developers can increase their returns by inserting a tranche of subordinated or mezzanine debt into the capital struc- / continued page 22

IN OTHER NEWS

An IRS agent flagged the issue on audit. The agent and the utility sent to the question to the IRS national office for resolution. The national office said in a private ruling called a "technical advice memorandum" that the charges are income.

The ruling is TAM 200411008. The IRS released the text in late March.

CALIFORNIA said that its limits on property taxes are applied over time rather than each year.

Proposition 13 rolled back property tax assessments to the value in 1975, fixed the property tax rate at 1% of assessed value, and limited increases in the assessed value to 2% a year until the property is sold.

A homeowner bought a house in Orange County in 1995. The county left the assessed value unchanged in 1996 and 1997 because of the weak real estate market. In 1998, it increased the assessed value by 4%.

A California appeals court ruled in late March that the increase in assessment was allowed. The cap of 2% a year on assessments is applied over time, the court said. The case is expected to be appealed to the state supreme court. Fifty eight California counties use the "recapture" method and could have been forced to refund as much as $10 billion in property tax collections if the decision had gone the other way. The case is *California v. Bezaire*.

INDONESIA told Mauritius that it plans to cancel a tax treaty between the two countries at the end of this year.

Many companies have made investments into Indonesia using holding companies in Mauritius, an island off the east coast of Africa, because of the reduced withholding tax rates on dividends and interest received by Mauritius companies and the bar against Indonesia taxing capital gains when a Mauritius company sells / continued page 23

Ethanol

continued from page 21

ture, but such debt comes at the cost of higher interest rates and increased bank and legal fees in order to reach financial close. Equity capital can also be contributed by, among other parties, the contractor that is constructing the project, thereby decreasing the initial cash outlays from the developers.

Construction Contingencies: In the lenders' eyes, developers consistently underestimate the cost of bringing a project to commercial operation. Developers should plan to include a budget line item of at least 5% of the project's capital cost for unspecified "contingencies," in addition to including the maximum amount of all potential incentive payments to the contractor and other amounts that could increase the delivered cost of the project. A lesser amount will draw the attention of the lenders' independent engineer (the opinion of whom lenders almost never overrule) and force a reworking of the capital budget for the project. Note that where the contractor is also an equity participant in the project, a lender might find it more acceptable to have lower-than-market holdback and punchlist reserves. However, lenders will expect that construction or design-build contracts will adhere to arm's-length standards (including fully-developed definitions of "completion" and other milestone definitions and well-defined performance standards) even when the contractor will benefit from the long-term operations of the project.

Coverage Ratios and Reserves: Developers should expect relatively stringent requirements relating to debt service reserve accounts and coverage ratios. Debt service reserve accounts will typically have a required balance equal to the principal and interest payable on the senior loan for the next 12 months. Debt service coverage ratios, which measure the relationship between project revenues and debt service both retrospectively and prospectively, will usually have a trigger level of 1.2:1 or higher for the suspension of dividends to equity and a level of 1.5:1 or higher for the resumption of dividends.

Collateral Issues: Lenders to ethanol facilities benefit from substantially the same collateral package as do lenders to power plants, including a mortgage on the project site, pledges of the equity in the project company, liens on all of the tangible and intangible assets of the project company, consents from the counterparties to the project's major contracts and a series of "locked" waterfall accounts through which all of the project's revenues must flow before being distributed to the developers. Ethanol projects do have one unusual asset that is important to capture in the lender's collateral package, namely the project company's license to use the specific process utilized to produce ethanol. This license is usually a companion document to the construction or design-build contract for the facility, but lenders should be certain to keep in mind that the license must be kept in effect for the full working life of the facility, in contrast to the construction contract that usually terminates relatively early in the life of the facility.

A series of federal, state and local incentives are key to making ethanol projects economic.

Working Capital Facilities: Working capital facilities, which generally take the form of an "evergreen" revolving loan, can be an important component of the overall financing package for an ethanol facility. Such facilities are unusual in other project finance structures but developers of ethanol projects often wish to be able to take advantage of unexpected (and unbudgeted) opportunities to purchase feedstock at lower-than-normal prices. A traditional project finance structure without a working capital facility would make this impossible as available cash is only distributed for budgeted expenditures or at the end of each quarterly or semi-annual payment period. However, for ethanol plants, a small working capital facility can be drawn upon from time to time at minimal cost to the project company to purchase low-priced feedstock as it becomes available and, therefore, improve the economics of the project in a manner that is beneficial to both the developer and lender.

Hedges: It is unlikely that an ethanol facility will benefit from long-term, fixed-price, single-counterparty contracts for the supply of feedstock and the purchase of ethanol and other products. This is the greatest source of concern to a lender. Feedstock can be plentiful, but there may be significant competition for the same feedstock from other potential purchasers (including other ethanol plants) and replacement feedstock from other regions can be prohibitively expensive due to transportation costs. Most lenders will require that developers retain the services of a commodities broker to source feedstock rather than rely on in-house personnel, and will also specify that forward contracts be entered into for at least a minimum percentage of the project's total requirements for any given year.

With respect to offtake arrangements (meaning the sale of ethanol, carbon dioxide and distillers' grains produced by the facility), lenders will generally include in their economic models only projected revenues from ethanol sales as it is rare to find a purchaser for the carbon dioxide produced by a facility. Similarly, distillers' grains — which are useful as livestock feed — are generally sold into the local spot market with unpredictable long-term economic results. Ethanol can be sold into local, regional and national markets, and lenders will prefer that the project company retain the services of a marketer to ensure relatively constant prices and distribution to the various markets. Lenders may also require that a minimum percentage of the ethanol output of the project be sold pursuant to relatively long-term forward contracts, even if such ethanol might be expected to command a higher price if sold purely on the spot market. Marketers charge roughly 3¢ to 5¢ a gallon of ethanol sold and their commissions must be included in the financial model. Finally, depending on the location of the ethanol project and its access to utility infrastructure, the lenders may require that the developers enter into long-term, agreed-price contracts for the electricity, natural gas and water required to run the facility if they are not available from municipalities or utilities at regulated rates. */ continued page 24*

IN OTHER NEWS

its shares. The treaty will have no further effect after December 31 unless the two governments are able to negotiate new terms.

Meanwhile, the Indonesian government is proposing to set a flat corporate income tax rate of 28%. The country currently has a three-tier rate structure for corporations with the top rate at 30%. It also proposes to collect a minimum tax from companies that continually suffer losses.

A LATE BANKRUPTCY CLAIM did not prevent the IRS from collecting back taxes.

A telephone company in Florida failed to collect a 3% federal excise tax on telephone services before the company filed for bankruptcy. The IRS filed a claim in the bankruptcy proceeding for $583,619 in back taxes by the "claim bar date" in September 1998 based on information that had been supplied by the company. The claim was marked "pending examination." The company later filed a plan of reorganization stating that it expected the total tax payments it would have to make would not exceed $300,000. The bankruptcy court confirmed the reorganization plan in June 1999, without any objection from the IRS.

Seven months later, the IRS increased its tax claim to $2.8 million based on additional information.

The court said the fact that both the "claim bar date" had passed and the reorganization plan had been approved did not bar the IRS from asking for more taxes. It said the issue was whether the telephone company was on notice of the IRS claim before the claim bar date. It concluded it was in this case because the increased claim was for the same tax as before and the telephone company should have known the proper amount it owed since it had all the information. The case is *In re The Telephone Company of Central Florida*. The */ continued page 25*

Ethanol

continued from page 23

State/Federal Incentives: Both lenders and developers will want access to the proceeds from grants and abatements associated with the project, especially as these generally become available early in the life of the project. For example, a project might expect to receive a "bioenergy" grant from the Commodity Credit Corporation or a rebate of local property taxes paid in connection with the purchase of the project site. Developers will want the payments for their own account so as to lock in a portion of the return they expect to receive on their investments. In contrast, lenders will want the proceeds of such grants and abatements applied as mandatory prepayments of the outstanding loans.

Basic Market Due Diligence: Due diligence is key to understanding the expected market conditions for the plant. For example, a for-profit facility owned by an institutional equity or private equity fund might be at a disadvantage to another plant owned by the local farmer cooperative. A project might expect to ship a significant portion of its ethanol to the new, seemingly insatiable markets of California, New York and Connecticut, only to have those needs met by future projects located in those states. Since the projects are dependent on government incentives, due diligence should also be done on the likelihood that such incentives might be withdrawn from the project. For example, the federal excise tax exemption is subject to periodic renewal. Project financings are an exercise in risk allocation. It is important to have a complete catalog of all the risks. ◎

New Credit Standards for Gas Pipeline Customers

by David Schumacher, in Washington

Interstate natural gas pipelines will be required to adopt standardized procedures for determining the creditworthiness of their shippers, or customers, under new proposed rules that the Federal Energy Regulatory Commission published in late February. Comments were due at the beginning of April.

The new procedures are important because they set uniform limits on when pipelines can refuse to do business with companies that want to ship gas on grounds of poor credit.

FERC took action after a number of pipelines tried to toughen the credit standards in their filed tariffs. The pipelines sought these modifications in response to the deteriorating credit conditions in the energy industry.

Each interstate pipeline includes in its tariff a description of the information that potential and existing shippers must provide to the pipeline to demonstrate the shipper's creditworthiness. The tariff also describes the type and amount of collateral that a potential or existing shipper that is not creditworthy can deliver to obtain or maintain service on the pipeline. The credit standards in these filed tariffs currently vary from pipeline to pipeline.

The new proposed rules would require the pipelines to adopt uniform credit standards. The rules address the following issues: the information that a potential or existing shipper can be required to provide to a pipeline to establish the shipper's creditworthiness, the objective and transparent criteria that a pipeline must apply when judging a shipper's creditworthiness, the collateral that a non-creditworthy shipper can be required to deliver to a pipeline to obtain or maintain service, remedies available to a pipeline if a customer defaults on its payment obligations or fails to deliver required collateral, and the credit standards that apply to capacity release transactions.

Establishing Creditworthiness

The proposed rules would allow a pipeline to request from each potential and existing customer certain information to enable the pipeline to judge the customer's creditworthiness.

This information includes audited financial statements, annual reports, a list of the customer's affiliates, parent companies and subsidiaries, publicly-available information from credit reports and rating agencies, bank and trade references, statements filed with the US Securities and Exchange Commission, interim financial statements, and such other information as mutually agreed by the pipeline and the customer. A pipeline does not have to ask for all of this information. The rules set a limit on the information it can demand.

FERC also would adopt certain creditworthiness standards developed by the North American Energy Standards Board, the standards organization for the energy industry. These standards establish additional procedural requirements that the pipelines must follow when communicating with potential and existing shippers regarding creditworthiness.

The proposed rules would require each pipeline to include in its tariff objective criteria that the pipeline would use in evaluating each potential and existing shipper's creditworthiness. FERC did not propose a uniform set of criteria applicable to all pipelines, instead opting for a case-by-case review of potential criteria that each pipeline proposes. However, FERC asked interested parties to comment on whether FERC should adopt uniform creditworthiness criteria.

Permitted Collateral

If a pipeline determines that a potential or existing shipper is not creditworthy, then the shipper could nevertheless obtain or maintain service by delivering collateral to the pipeline. The proposed rules describe the collateral that a pipeline can request from its non-creditworthy shippers.

A non-creditworthy customer can receive service on an existing pipeline by posting collateral in an amount equal to three months' worth of the maximum fixed reservation, or demand, charges that the pipeline can charge the customer. According to FERC, three months of reservation charges is a pipeline's maximum potential credit exposure before the pipeline can terminate service to a defaulting customer. In FERC's view, the pipeline assumes the risk of remarketing the capacity available after a firm transportation contract is terminated. Customers would still be able to provide parent or third-party guarantees as credit support.

FERC requested comment on alternative approaches. For example, FERC asked for comment on whether pipelines should be permitted to allocate capacity based on a customer's creditworthiness. If this were adopted in a final rule, then a pipeline could award capacity to a customer with a better credit profile than another customer requesting the same service / continued page 26

IN OTHER NEWS

bankruptcy court released its decision in March.

However, a court barred the IRS from making a late claim in another bankruptcy case. The IRS filed its claim four months after the claim bar date. It was late because it was not on the list of creditors who were informed of the bankruptcy, and it moved promptly after receiving notice. A bankruptcy court said in a decision in early April that the tax agency was out of luck. This case is In re Johnny Hernandez.

DENMARK made several tax law changes to reduce its attractiveness as a base for offshore holding companies.

The changes are in legislation that the Danish parliament approved on March 30. They are retroactive to tax years beginning on or after last January 1.

There are two main changes.

First, any Danish company that has a foreign parent company and is disregarded for tax purposes in the country where the parent company is located will also be disregarded for tax purposes in Denmark. The effect is to deny deductions in Denmark for interest and royalties paid to the foreign parent company. The change is targeted at holding companies owned by tax residents of other European Union countries or countries, like the United States, that have tax treaties with Denmark. However, it does *not* apply to any Danish holding company that is treated as a partnership — rather than a disregarded entity — for US tax purposes, at least in cases where the interest or royalty payments it makes to its US parent are taxable in the United States.

Second, interest paid by Danish companies to shareholders in other countries will be subject to a 30% withholding tax. However, the withholding tax does not apply to interest paid to share- / continued page 27

Gas Pipelines

continued from page 25

or to a customer willing to post more collateral than another customer.

If the potential customer is seeking service using new facilities, then FERC would allow the pipeline and the potential customer to negotiate the amount of the required collateral. For service using new mainline facilities, the pipeline's collateral requirement must reflect the reasonable risk of the mainline construction project, particularly the risk to the pipeline of remarketing the new capacity should the initial customer default. However, the amount of the collateral could not exceed the customer's proportionate share of the project's cost. The collateral requirement would have to be agreed upon prior to the initiation of construction. The collateral requirement imposed on the initial customer would continue to apply even after the new project goes into service.

If the new facility is a lateral pipeline that is constructed to serve one or more customers, then the pipeline can require users of the lateral to post collateral in the aggregate equal to the full cost of the lateral.

FERC also requested comment on the collateral that pipelines could request to cover the risk of "loaned gas," or gas that shippers borrow from a pipeline through imbalance mechanisms or park-and-loan services. Collateral for loaned gas would be in addition to the collateral that a pipeline could request for transportation service.

Cutting Off Service

The proposed rules also address suspension and termination of service to shippers that fail to pay or fail to provide adequate collateral when found not to be creditworthy.

If an existing shipper fails to deliver required collateral, then the pipeline can suspend service after giving the shipper five business days to provide an advance payment for one month's service and 30 days to satisfy the collateral requirements. If an existing customer breaches its payment obligation and the pipeline's tariff allows the shipper to continue service by delivering the required collateral, then the same timeline applies before the pipeline can suspend service.

Interstate gas pipelines have been handed proposed uniform standards to use for assessing the creditworthiness of companies that want to ship gas.

A pipeline that suspends service cannot continue to bill the suspended shipper for transportation charges. In lieu of suspension, the pipeline could sue the shipper for consequential, unmitigated damages caused by the shipper's breach.

Before a pipeline can terminate service to a shipper that either fails to pay or fails to provide the required collateral, the pipeline would have to provide the shipper and FERC with 30 days prior written notice. The proposed rules are not clear whether a shipper can cure a payment default or a failure to provide collateral during the 30-day notice period prior to termination or whether a pipeline can threaten to suspend and terminate service in the same notice. (For example, can the pipeline threaten to suspend service if a prepayment is not delivered within five business days and to terminate service if the payment or collateral default is not cured within 30 days?)

Capacity Release

Capacity release is the mechanism for a firm transportation customer to assign, or "release," its firm transportation capacity to a third party. Upon a capacity release, the new customer, or "replacement shipper," enters into a new contract with the pipeline for the released capacity. The existing customer, or "releasing shipper," remains liable for the reservation charges payable with respect to the released capacity, essentially acting as a guarantor of the replacement shipper's obligation to pay reservation charges for the released capacity.

The proposed rules also address issues that arise from the contractual structure associated with a capacity release.

Creditworthiness of replacement shippers would be determined using the same standards that a pipeline applies to all other shippers. Releasing shippers would not be able to impose, as a condition to completing a capacity release, credit standards that are different from those in the relevant pipeline's tariff.

The collateral required from a replacement shipper bidding for released capacity would have to be delivered to the pipeline before the released capacity is awarded through the capacity release bidding process, if the releasing shipper insists that potential replacement shippers must meet the pipeline's credit requirements prior to an award of released capacity.

Following an award of capacity and the posting of collateral, if the replacement shipper defaults, then the pipeline would be required to credit to the releasing shipper any collateral that the replacement shipper delivered to the pipeline and that is not used to defray the replacement shipper's obligation to the pipeline.

Because a releasing shipper remains liable to the pipeline under its contract even after a capacity release, the proposed rules address the rights of a replacement shipper if its releasing shipper is in default to the pipeline and the pipeline terminates its contract with the releasing shipper. In this circumstance, the terminating pipeline must allow the replacement shipper to continue receiving service using the released capacity if the replacement shipper agrees to pay, for the remaining term of the release, the lesser of three amounts. The amounts are 1) the releasing shipper's contract rate, 2) the maximum tariff rate applicable to the releasing shipper's capacity, or 3) some other rate that is acceptable to the pipeline. If the replacement shipper refuses to pay the lesser-of rate, the pipeline also may terminate the replacement shipper's contract. Alternatively, the pipeline can continue to honor the replacement shipper's original agreement following termination of the releasing shipper's contract at the rate agreed in connection with the initial capacity release.

Under FERC's current policy, if a releasing shipper executes a "permanent release" — that is, the releasing shipper releases its capacity at its */ continued page 28*

IN OTHER NEWS

holders in other European Union countries or in countries with tax treaties with Denmark, provided — in the case of a tax treaty — the parent company has owned at least 25% of the shares in the Danish company for at least a year.

A LUXEMBOURG HOLDING COMPANY qualified for a 5% withholding rate on dividends paid to it by a US subsidiary.

A parent company in Holland used the Luxembourg holding company to hold all of its subsidiaries outside Holland, including a subsidiary in the United States. Ordinarily, dividends paid by US companies are subject to a 30% withholding tax at the US border. The rate is often reduced by tax treaties. It is 5% under the US-Luxembourg tax treaty, but usually only for dividends paid to Luxembourg individuals, government agencies and publicly-traded companies. However, the IRS ruled privately in this case that the 5% rate would apply because of a special clause in the treaty that gives the benefit of the 5% rate to private Luxembourg companies in which at least 95% of the shares are "ultimately owned" by residents of other European Union countries with which the US has comprehensive income treaties. The US has such a treaty with Holland.

The IRS said that worked: the parent company in Holland was the "ultimate" owner of the shares so that it was not necessary to look through it to inquire about the tax residences of its shareholders.

The ruling is Private Letter Ruling 200409025. The IRS made the text public in March.

JAPAN denied a Japanese investor in a US limited partnership passthrough of losses from the partnership. It said the partnership is a corporation for tax purposes in Japan.

A president of a Tokyo */ continued page 29*

Gas Pipelines

continued from page 27

contract rate for the remaining term of its agreement — then the pipeline cannot unreasonably refuse to relieve the releasing shipper of liability under its contract. In other words, if the pipeline is not in a worse credit position as a result of the permanent release, then the pipeline cannot require the releasing shipper to remain the guarantor of the replacement shipper's reservation charge obligations. The proposed rules do not change this policy. ◎

The pipelines are concerned about deteriorating credit conditions in the energy industry.

FERC Reaffirms Its Lead Role in LNG

by Daniel R. Rogers, in Houston

A US government order in late March and an agreement reached among three federal agencies in February reconfirmed the supremacy of the Federal Energy Regulatory Commission over the permitting and regulation of onshore LNG facilities in the United States.

This is important because it means that developers should face a more streamlined process for getting approvals for construction of new LNG import terminals in the US. LNG is liquefied natural gas.

The Federal Energy Regulatory Commission, or "FERC," said in a declaratory order on March 24, 2004that regulatory authority for the siting, construction and operation of liquefied natural gas import terminals rests exclusively with the federal government. The order came in a dispute with the California Public Utilities Commission over who has jurisdictional authority over an LNG import terminal project under development in southern California.

A month earlier — on February 11, 2004 — FERC and two other US government agencies with regulatory jurisdiction over new LNG facilities in the US entered into an agreement that recognizes FERC plays a key role in the permitting and regulation of onshore LNG facilities in the US, and designates FERC as the "lead federal agency" for preparing the analyses and making decisions required under the National Environmental Protection Act for the approval of new LNG facilities.

FERC Supremacy

Developers of LNG import terminals must file an application with FERC for a certificate of public convenience and necessity under section 3 of the Natural Gas Act. This certificate is a requirement before the developer can start construction and later operate his terminal. The application requires extensive engineering design work and safety analysis, which can take six to nine months to complete before the application is ready to be submitted. Upon submission, FERC then corresponds with the various federal and state agencies that have permitting authority, as well as with interested citizens through a public comment process, in order to receive input and prepare an environmental impact statement as required under the National Environmental Policy Act.

The whole process of completing the environmental impact statement through issuance of the certificate of public convenience and necessity can take 12 to 18 months for a relatively straightforward application to which there is no significant regulatory or public opposition.

The California Public Utilities Commission recently challenged this arrangement by asserting exclusive jurisdiction over an LNG import terminal project being developed by Sound Energy Solutions, an affiliate of Mitsubishi Corporation, at the Port of Long Beach, California for the import of LNG and resale of vaporized LNG mainly into the California market. The CPUC argued that section 3 of the Natural Gas Act merely gives FERC jurisdiction over the decision whether to authorize LNG to be imported into the US, but it does not give FERC jurisdiction over the siting, construction and operation of the proposed terminal in Long Beach since the owners of the terminal plan to use it only in intrastate, as opposed to interstate, commerce.

FERC rejected the argument, comparing it to a similar, unsuccessful argument made by Dynegy in 2001. Dynegy asked FERC to disclaim jurisdiction over an LNG import terminal that Dynegy planned to build in Hackberry, Louisiana on grounds that terminals making only "first sales" in the same state as the terminal is located are exempted from federal purview.

In the California case, FERC conceded that much of the case law and legislative history supporting its claim to exclusive jurisdiction involved interstate commerce activities. However, it reminded the CPUC that while gas sales out of the terminal may well be made on a purely intrastate basis, the act of importing LNG still involves foreign commerce. FERC said the distinction between interstate and intrastate commerce is not relevant to the issue of jurisdiction over LNG terminals involved in foreign commerce, and it referred to a 1979 US Supreme Court case and a 1974 appeals court decision involving the Distrigas LNG facility in support of this conclusion.

The California Public Utilities Commission argued it should have a role in overseeing the project because FERC has less ability to regulate market power abuses and protect the physical safety of California residents. FERC said it was not persuaded. It reminded the CPUC of its longstanding experience in regulating LNG and natural gas activities and the considerable resources it can bring to bear, and it questioned the need for a state regulatory body with no experience in regulating LNG projects and limited resources to engage in largely duplicative regulation. At the same time, FERC reiterated the importance of cooperation between state and federal authorities and the critical role that state agencies can play in providing input in the assessment of certificate of public convenience and necessity applications under federal review. Despite this stinging blow, FERC strongly encouraged the continued participation by the CPUC / continued page 30

IN OTHER NEWS

Stock Exchange-listed company invested millions of dollars in a Delaware limited partnership that bought about 800 rental apartments in Texas, Arizona and Florida. The president claimed losses from the partnership; depreciation on the properties exceeded the rental income. The regional tax bureau denied the losses. In March, the National Tax Tribunal denied his appeal. The tribunal said that the losses belonged to the partnership and not the partners. US limited partnerships and limited liability companies are not treated as transparent for tax purposes as in the United States, but rather as separate entities.

DIRECT TAXES face a constitutional barrier.

Union Electric Company, a Missouri utility, tried to have a "special assessment" on uranium enrichment struck down on grounds that it was a "direct" tax. A US appeals court refused in early April.

The US constitution bars the federal government from collecting any "direct" taxes unless the tax falls on each state in proportion to its population.

In 1992, Congress imposed a "special assessment" on domestic power companies that "purchased [enriched uranium] from the Department of Energy for the purpose of commercial electricity generation, before October 24, 1992." The purpose was to raise money for shutting down and decontaminating the government's uranium enrichment facilities. The government estimated the shutdown would cost $2.25 billion. The tax on each utility was tied to the amount of energy required for processing the utility's uranium. The tax was to remain in effect for 15 years or, if earlier, when the government collected $2.25 billion. Union Electric paid $14.4 million in taxes, and then sued for a refund, charging that the tax was an unconstitutional direct tax.

A US appeals court / continued page 31

LNG

continued from page 29

and other state agencies in the certificate evaluation process, and it promised that legitimate concerns raised by state regulators will be adequately addressed.

The FERC order was not yet final as the *NewsWire* went to press. The CPUC has until April 24 to petition for a rehearing. It remains to be seen whether the California commission wanted simply to fire a "shot across the bow" of FERC in order to get more attention for its concerns about the Long Beach terminal in the environmental impact review process or whether the CPUC seriously intends to try to displace FERC in the regulation of LNG facilities in California that are engaged in foreign commerce.

Assuming FERC retains exclusive jurisdiction over LNG facilities, the agency will be kept very busy over the next few years. There are currently more than 40 planned or proposed LNG import terminal projects to serve the US market, and expansion plans are either under consideration or underway at another four existing US import terminals. Responding recently to concerns about the likely flood of applications this year, FERC spokeswoman Tamara Young-Allen said applications will continue to be treated on a "first-come, first-served, case-by-case basis," and FERC separately reconfirmed that it has no current plans to limit the number of facilities that are developed by turning away any applicants.

Mark Robinson, the director of energy projects at FERC, continues to encourage applicants to pursue a new environmental impact pre-filing process that involves a dialogue with regulators and the public seven to eight months in advance of the actual filing in order to identify the relevant federal and state regulatory agencies and key issues with the aim of streamlining the permitting process. Robinson emphasizes that the environmental impact pre-filing process is not a fast-track mechanism to shorten the time period required to obtain the required permits. It will still probably take one to two years from the date of application to receive the various required permits due to the long time periods to perform the necessary analysis and prepare and receive comments on the environmental impact statement. Rather, the hope is the pre-filing process will ease the burden on the applicant and the regulators during this one-to-two-year process and provide regulators with some extra breathing room to consider the increased number of applications that are likely to be made.

FERC told California that the federal government has exclusive authority over the siting, construction and operation of LNG terminals.

Federal Interagency Agreement

When more than one federal agency has permitting authority for an energy project, the agencies will often designate a lead federal agency to coordinate the preparation and review of the necessary environmental impact statement. In the past, federal agencies have allocated lead responsibilities either by way of a formal memorandum of understanding or through an *ad hoc*, informal understanding based on the agencies' good working relationships and mutual respect.

There are three key federal agencies with an interest in LNG facilities: FERC, the US Coast Guard and the Research and Special Programs Administration in the US Department of Transportation. The three agencies formalized their respective roles in oversight of onshore LNG terminals on February 11 by entering into an "Interagency Agreement for the Safety and Security Review of

Waterfront Import/Export Liquefied Natural Gas Facilities." The agreement designates FERC as the "lead federal agency" for the preparation of the analysis and decisions required under the National Environmental Protection Act for the approval of new LNG facilities.

The focus of the interagency agreement is US government oversight over land and marine safety issues tied to LNG facilities. The roles and responsibilities of the three agencies in connection with such matters as the siting, approval, operation and inspection of LNG facilities, information sharing, participation in safety and security studies, and resolution of any resulting interagency disputes, are described in a fair amount of detail. Among the topics discussed are LNG tanker operations and potential hazards, operating controls to mitigate hazards, project-specific operating plans, potential hazards and risks to the nearby population, marine terminal operation and risks, and land terminal operation and risks.

FERC will take the lead role. The other two agencies will participate as "cooperating agencies" in the environmental impact review process. Their charge is to ensure that the environmental impact statement conveys complete information to all of the interested stakeholders. The designation of lead and coordinating agency roles will help minimize duplication of effort and save time.

The interagency agreement and the FERC order in the California case in late March should clear up any remaining confusion over what authority FERC has over the siting, construction and operation of onshore LNG terminals in the US. The hope is it will help speed the construction of needed new terminals. ◎

IN OTHER NEWS

disagreed. It called the levy an "excise" tax rather than a direct tax. Examples of direct taxes that the constitution requires fall on the states in proportion to their populations are a capitation tax — literally a tax on each head — poll tax, or tax on land. The case is *Union Electric Co. v United States*.

MINOR MEMOS. The IRS put taxpayers on notice that it plans to deny tax deductions shareholders claim for the loss in market value of shares in corporations that disclosed accounting fraud or other illegal conduct. A deduction can be claimed for loss in share value, but only when the stock is sold or it becomes "wholly worthless." The announcement is Notice 2004-27 . . . . The Bush administration backed off rules the IRS issued in 1998 that would have denied US corporations foreign tax credits from transactions that are expected to produce an insubstantial economic profit in relation to the value of the foreign tax credits generated. The US Treasury said in Notice 2004-19 that it will apply general tax law principles to deny foreign tax credits in such cases without having to resort to a rigid mathematical test.

— contributed by Keith Martin, Heléna Klumpp, Samuel R. Kwon and Micaela Garcia-Ribeyro in Washington.

Environmental Update

North Carolina

North Carolina complained to the US Environmental Protection Agency in March that power plants in 13 states that are upwind from North Carolina contribute significantly to air pollution in the state. It wants the federal government to order reductions in nitrogen oxides, or NO_x, and sulfur dioxide, or SO_2, emissions in 13 states that it says contribute to fine particulate matter, or PM2.5, problems in North Carolina. It is also wants action to reduce upwind contamination from Georgia, Maryland, South Carolina, Tennessee and Virginia that it says contributes to ozone or smog.

The North Carolina allegations are in a petition filed under section 126 of the Clean Air Act, which authorizes EPA to take action against specific air emission "sources" — without working directly through the states — after the agency makes a final finding that upwind emissions make it harder for a downwind state to comply with the national ambient air quality standards.

The petition alleges that the upwind contamination will affect whether the state can comply with its expected obligations under standards issued in 1997 governing 8-hour ozone and fine particulate matter ambient air quality. After lengthy legal challenges to the standards, EPA is expected to issue final designations of new ozone nonattainment areas by mid-April. According to EPA, more than 500 counties are not meeting the new 8-hour ozone air quality standard. The final designations for PM2.5 nonattainment areas are scheduled to be issued in the 2004 to 2005 period. Once the new 8-hour ozone and PM2.5 nonattainment areas are established, states will have to propose rules designed to achieve reductions in ozone precursors (that is, volatile organic compounds and NO_x) and fine particulates in order to meet the standards. These new requirements, which will take effect over the period 2007 to 2021, may ultimately require upgrading or installing additional pollution control technology. North Carolina is anticipating that several of its counties will be in nonattainment with the 8-hour ozone and fine particulate matter ambient air quality standards, which will probably necessitate the imposition of costly emission reduction requirements on certain North Carolina air emission sources.

North Carolina is trying to get the US government to reduce air pollution from power plants in 13 states that are "upwind" from it.

The North Carolina action is essentially a preemptive strike that is intended to keep the pressure on EPA to take additional actions to regulate NO_x and SO_2. The filing came shortly after EPA proposed an "interstate air quality rule" in January 2004 that focuses on reducing the interstate transport of NO_x and SO_2 emitted from power plants and other sources that significantly contribute to fine particulate and ozone pollution in downwind states. The proposed rule directs 29 states, including all 13 states named by North Carolina, and the District of Columbia to develop new regulations that will require major SO_2 and NO_x reductions in a two-phase approach similar to the Bush administration's "clear skies" legislation that is currently pending before Congress. North Carolina and possibly other states are expected to use the section 126 petition process as a forum for advocating more significant NO_x and SO_2 emission reductions and faster implementation timeframes than proposed in the interstate air quality rule.

The interstate air quality rule would impose a 3.9-million-ton emission cap on SO_2 emissions by 2010, approximately a 58% decrease from current SO_2 emission levels, and a further cut to a cap of 2.7 million tons of SO_2 emissions by 2015, for a total reduction of about 70% from current SO_2 levels. NO_X emissions would be reduced to a cap of 1.6 million tons by 2010 under the proposed rule, with a further reduction to a cap of 1.3 million tons by 2015, for a total NO_X reduction of about 65%.

Cooling Water

EPA Administrator Mike Leavitt signed a final rule in February that affects cooling water intake structures at large existing power plants. The regulations could require significant upgrades to existing cooling water intake systems, particularly at plants withdrawing water from water bodies with sensitive aquatic habitats and species.

Plants that withdraw 50 million gallons a day or more of water from rivers, streams, lakes, oceans or other waters in the US and use at least 25% of the water for cooling purposes will potentially be affected by the new requirements. EPA projects that more than 550 existing power plants will be subject to the rule, and many plants may need to make new technology-based improvements to cooling water intake structures.

The new requirements will be implemented through the existing national pollutant discharge elimination system, or NPDES, program. Plants applying for reissuance of a NPDES permit will have to submit information demonstrating how the facility intends to comply with the new requirements. The reissued NPDES permit will incorporate a new section containing the cooling water intake structure provisions. The new regulations were issued under section 316(b) of the Clean Water Act, which requires EPA to develop rules requiring that the "best technology available" be used to protect aquatic organisms from being impinged or pinned against water intake screens or other parts of the cooling water system, or drawn into the cooling water system and subjected to thermal, chemical or physical stresses. Aquatic organisms such as fish, fish larvae and eggs, crustaceans, shellfish, turtles and other forms of aquatic life are frequently killed or injured in cooling water intake structures.

The EPA rule leaves room for creative solutions that achieve an equivalent level of environmental performance to the presumptive technology requirements. For example, plants with cooling towers will be deemed to be in compliance with the section 316(b) rule, but the rule does not require that cooling towers be installed to meet the performance standards.

The final rule will require all large existing power plants meeting the water withdrawal thresholds to meet certain performance standards. Under the technology performance standards, impingement mortality must decline by 80 to 95% and, depending on the location of the facility, the amount of water withdrawn and energy generation, entrainment must decline by 60 to 90%. Plants generally may choose one of three options to comply. Under the first option, the plant may demonstrate that the cooling water intake structure meets specified technology performance standards that are based on a closed-cycle recirculating cooling system (that is, a wet cooling tower). Under the second option, the plant may install new equipment and take operational or restoration measures to meet the technology performance standards. An example of an operational measure is a screen with a fish return system. Examples of restoration measures are restocking affected fish or creating alternative habitats for them. Under the third compliance option, a plant could make a site-specific determination of what is the best technology available. The conclusion may differ from EPA's if compliance costs are significantly greater than those considered by EPA. In addition, facilities may substitute restoration and other conservation measures to maintain fish and aquatic life in place of , or in addition to, technology measures. However, this "restoration alternative" will probably be subject to further EPA rulemaking.

The final rule is the second in a series of three rules intended to establish new cooling water intake structure requirements. The first rule addressed new facilities and was issued in December 2001. The third rule is expected in November 2004 and will apply to power plants and other industrial sources using smaller amounts of cooling water.

In related news, a US appeals court largely upheld the section 316(b) rule for new facilities that was issued in December 2001. The court rejected arguments from environmental groups that Congress intended dry cooling systems — such as dry cooling towers that use minimal water — to be the "best available technology." However, the court agreed with the environmentalists that using restoration measures as an alterna- / continued page 34

tive to complying with the performance standards is inconsistent with the Clean Water Act. EPA's "restoration alternative" was sent back to the agency for further rulemaking. A similar provision allowing for the use of voluntary restoration measures in the new second-phase rule will probably have to be revised to comply with the court decision. The court released its decision in February.

Mercury

EPA received a barrage of negative comments at the three public hearings held at the end of February on a proposed "utility mercury reductions rule" that would regulate mercury and nickel emissions from existing and new coal- and oil-fired power plants. At hearings in Chicago, Philadelphia and Research Triangle Park, North Carolina, numerous environmental and public interest groups, local and state agency air division officials and various politicians urged that the proposed rule be rewritten.

The major criticisms are that the "cap and trade" option under the proposed rule is not authorized by the Clean Air Act, the mercury reduction targets are not sufficiently stringent enough, the compliance deadline for achieving the emission reductions is too far off, and the proposal should regulate more air toxics than just mercury and nickel. EPA heard more of the same criticisms in letters earlier this month from 45 US Senators and 10 state attorneys general.

The proposed utility mercury reduction rule became a lighting rod for dissent when the government failed, as expected, to take a traditional "command and control" approach to regulating air toxic emissions from power plants under section 112 of the Clean Air Act. The agency was expected to propose a "maximum achievable control technology," or MACT, standard that would require compliance by December 2007. Instead, EPA proposed two alternative approaches for reducing mercury emissions from coal-fired plants and nickel emissions from oil-fired plants. It will choose one of the approaches by the end of this year.

One of the alternatives is a traditional MACT standard. The other approach is a "cap and trade" program. The MACT alternative uses a command-and-control approach that would apply to both new and existing coal-fired power plants. For existing plants, the MACT level is set at the average emission limitation achieved by the best performing 12% of plants in a particular category or subcategory of sources. For new plants, the MACT level must be set by law at the level of control achieved by the best controlled similar source. Under the "cap and trade" approach, EPA would implement a nationwide cap on mercury emissions. Coal-fired plants subject to the rule would be required to hold sufficient allowances to cover their annual mercury emissions. Each allowance would authorize the emission of one ounce of mercury. EPA is strongly leaning toward adopting a "cap and trade" program that it believes will achieve steeper reductions in a more cost-effective manner. According to EPA, emissions from coal-fired power plants would be reduced by 30% by 2007 under the MACT approach and by 70% by 2018 under the "cap and trade" option. Environmental groups are seeking at least a 90% reduction in mercury from coal-fired power plants.

Both EPA alternative proposals would apply to coal-fired power plants with a capacity of more than 25 megawatts that produce their entire output for sale and to cogeneration facilities that put more than one-third of capacity and more than 25 megawatts on a utility grid for sale. Given the uncertainties surrounding the technologies that will be available to achieve mandated mercury emission reductions, both EPA proposed mercury reduc-

US regulators are ordering power plants that draw water from lakes and rivers with sensitive habitats or species to make expensive upgrades in their cooling water intake systems.

tion rules include different emission standards depending on whether a plant burns bituminous, sub-bituminous, lignite or coal refuse. In the MACT standard approach, EPA proposes emission limitations for new and existing power plants based on five subcategories, including the four different fuel types and a separate standard for integrated gasification combined-cycle or IGCC units. EPA projects that mercury emissions would be reduced from 49 tons to 34 tons through implementation of the proposed mercury MACT standards.

Under the "cap and trade" alternative, EPA is proposing a 34-ton mercury emission cap for the first phase, which commences in 2010 and a 15-ton cap for the second phase, which starts in 2018. Mercury allowances would be issued to coal-fired plants based on a unit's share of the total heat input from existing coal units, multiplied by an adjustment factor that depends on the type of coal. The adjustment factors are 1.0 for bituminous, 1.25 for sub-bituminous and 3.0 for lignite coals. Under the "cap and trade" approach, EPA would set mercury MACT standards for new coal-fired plants at substantially the same levels as the mercury MACT emission limits proposed in the command-and-control approach.

On March 16, 2004, EPA published a supplemental proposal with specific provisions of a model "cap-and-trade" rule that states may adopt. The proposal spells out applicability requirements, allowance allocation formulas, emission banking, and compliance and enforcement mechanisms. The proposal also includes a "backstop" price of $2,187 per ounce of mercury that would cap the price of a mercury allowance under the trading program. EPA held a hearing on the supplemental proposal at the end of March in Denver.

Given the criticism, EPA has agreed to extend the public comment period on the rule from March 30 to April 30. EPA Administrator Mike Leavitt has also directed agency personnel to consider whether earlier cost estimates take into account the possibility that mercury control technology costs may decline over time.

Under a court-approved settlement, EPA must issue a final rule by December 15, 2004. The costs to comply with the new rule are expected to be substantial. Like many environmental regulations, the parameters of the final rule will probably be settled in court.

NO_X Emissions

EPA issued a"Phase II" supplement to its rule requiring most states east of the Mississippi River to adopt state implementation plan, or "SIP," rules requiring reductions of nitrogen oxides or NO_X. The "NO_X SIP call rule" was originally issued in October 1998, and the Phase II supplement responds to a court decision that struck down portions of the original rule. The original rule has already required a number of affected power plants owners to decide whether to install pollution control equipment, such as selective catalytic reduction systems, shut down particular units, or embark on a program to purchase sufficient NO_X allowances. The Phase II rules will have similar effects on power plants in Georgia and Missouri that are now subject to the NO_X SIP call rule.

The initial rule required 22 states east of the Mississippi River plus the District of Columbia to take steps to reduce NO_X to a specified level for each affected state by 2007. A federal appeals court largely upheld the NO_X SIP call rule in March 2000. However, the court disagreed with extending the rule to three states — Georgia, Missouri, and Wisconsin — on grounds that there was too little evidence indicating that NO_X emissions from these states contribute to ozone nonattainment in downwind states. The court sent this issue and two other key issues back to EPA for further proceedings.

In response to the court's ruling, EPA proceeded to regulate power plants and other large stationary sources within the remaining 19 states and the District of Columbia. Sources in these states are required to comply with the new NO_X SIP call standards by May 31, 2004. The NO_X SIP call standards apply during the summer ozone season that runs from May 1 through September 30.

The Phase II rule largely completes the agency's response to the court's decision. In the Phase II rule, EPA has concluded that power plants and other large industrial combustion sources in Wisconsin and portions of Alabama, Georgia, Michigan and Missouri that are classified as the "fine grid" modeling areas will be excluded from the NO_X SIP call. Georgia and Missouri will be required to submit to EPA their state regulations implementing the NO_X SIP call requirements by April 1, 2005 for approval. These two states will have

/ continued page 36

Environmental Update

continued from page 35

to comply with the NO_X SIP call rule by May 1, 2007.

Under the Phase II rule, EPA also set standards for natural gas-fired stationary internal combustion engines and diesel and dual-fuel combustion engines, and it revised the definition of "electric generating units" to exclude certain cogeneration units from the NO_X SIP call rule.

Brief Updates

American Electric Power and Cinergy announced plans in February to report on the potential financial burden of implementing future greenhouse gas emission reduction requirements. The reports are expected to be released to shareholders by September.

The state of Washington adopted a new law at the end of March requiring new power plants to offset 20% of the CO_2 they emit through mitigation projects. Companies can either finance mitigation projects on their own or pay a fee of $1.60 per ton of CO_2.

The US Senate defeated a proposal by Senator Frank Lautenberg (D–New Jersey) in March to reinstate a "Superfund tax" on chemical and petroleum companies that was used to finance the a federal Superfund trust fund for cleanups undertaken by the federal government. The vote was 43 to 53. Reinstatement of the Superfund tax is opposed by the Bush administration.

EPA increased its maximum penalties for civil violations of environmental laws in March by 17.3% to account for inflation increases since 1997. For example, the maximum penalty for most Clean Air Act violations has increased from $27,500 to $32,500 a day per violation.

The European parliament recently approved the first "polluter pays" liability law. The environmental liability plan is now cleared for final approval by the Council of Ministers, which is expected in the next few weeks. Once approved by the Council of Ministers, the European Union countries will have three years to implement the measure, which will penalize companies that cause environmental damage by releasing heavy metals or producing dangerous chemicals.

More than 125 environmental and public interest organizations petitioned the US Environmental Protection Agency in February to ask that the agency take steps to regulate the disposal of coal combustion waste in mines, quarries and surface impoundments. EPA is reportedly working on draft nonhazardous waste regulations that will establish standards for disposing of coal ash and other coal combustion wastes in landfills and surface impoundments.

Finally, EPA took action in late March to remove four subcategories of combustion sources from the list of sources of hazardous air pollutants, or "HAPs." These sources include new lean premix gas-fired turbines, diffusion flame gas-fired turbines, emergency stationary combustion turbines, and stationary combustion turbines operated on the North Slope of Alaska. EPA is also proposing to exempt these types of combustion turbines from the new HAP emission standard for stationary combustion turbines that was published in the *Federal Register* on March 5.

— contributed by Roy Belden in New York

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

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

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

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

Beijing Representative Office
Beijing Kerry Centre
1 Guang Hua Road, Chao Yang District
Beijing 100020, China
+86 (10) 8529-8892

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

11 Mykhailivska Street, 4th Floor
Kyiv 01001, Ukraine
Telephone +380 (44) 230-2534
Facsimile +380 (44) 230-2535

Chadbourne & Parke
Radzikowski, Szubielska and Partners LLP
ul. Emilii Plater 53
00-113 Warsaw, Poland
Telephone +48 (22) 520-5000
Facsimile +48 (22) 520-5001

Chadbourne & Parke
a multinational partnership
Regis House
45 King William Street
London EC4R 9AN
+44 (20) 7337-8000