CHADBOURNE
& PARKE LLP

PROJECT FINANCE
NewsWire

April 2005

US Limits Pollution from Power Plants

by Roy Belden, in New York

The US Environmental Protection Agency issued two new air emission rules in March that will require spending on costly new pollution control equipment retrofits at many existing power plants over the next five to 13 years.

The first rule — called the "clean air mercury rule" — would require reductions in mercury emissions from existing and new coal-fired power plants in a two-phased "cap-and-trade" approach starting with the first phase in 2010 and the second phase in 2018. "Cap and trade" means that power plants have a choice of reducing pollution or buying emission credits or allowances from other plant owners who have extra allowances. In addition to meeting the mercury emission caps, new coal-fired power plants that commence construction on or after January 30, 2004 will have to meet stringent "new source performance standards" for mercury emissions.

The second rule — called the "clean air interstate rule" or CAIR — would require 28 states and the District of Columbia to adopt rules that require substantial reductions in nitrogen oxide, or NO_x, and sulfur dioxide, or SO_2, emitted from power plants and other pollution sources. Each state has been told how much NO_x and SO_2 it is allowed. It must achieve the required NO_x and SO_2 reductions through one of two compliance methods. It can participate in an EPA-adminis- */ continued page 2*

IN THIS ISSUE

IN OTHER NEWS

TELEPHONE USERS continue to win lawsuits against the US government asking for refunds of excise taxes they paid on phone service.

In one of the latest cases, Fortis, Inc., a large diversified utility holding company that owns utilities primarily in Canada and the Caribbean, persuaded a US district court in New York in February that it should not have had to pay excise taxes on amounts the phone company charges it for 800 numbers that its customers can use to call Fortis toll free.

The US government collects a 3% tax on "amounts paid for communications services." The tax was originally enacted */ continued page 3*

Pollution

continued from page 1

tered cap-and-trade regime that caps power plant emissions in two phases starting with an initial cap in 2009 and then a lower cap in 2015. Alternatively, it can ask EPA to approve another method for achieving the reductions from in-state sources.

The two rules are intended to work in tandem and are expected to prompt significant investments in air pollution control equipment to meet the air emission reduction requirements. Both rules are closely modeled after a bill called the "Clear Skies Act" that the Bush administration has been trying to put through Congress for the past three years. The administration suffered a significant setback in March when the Senate environment committee failed to pass the measure out of committee by a 9-9 vote. Committee chairman, James Inhofe (R-Oklahoma), said the Clear Skies Act will not be reconsidered by the committee this year. The administration had threatened to take action administratively if it could not get the legislation through Congress. The main difference between the regulatory action EPA took in March and what the administration wanted from Congress is the clean air interstate rule only applies in 28 states and the District of Columbia. Any legislation that Congress passed would have applied to the entire country and would have been better insulated from the inevitable litigation that follows any EPA rules.

The administration is bracing for protracted litigation over the legality of the mercury rule. Although less controversial, the Bush administration also anticipates that lawsuits will be filed challenging certain aspects of the clean air interstate rule. Any legal challenge to the two rules must be filed within 60 days after the final rules are published in the *Federal Register*.

Environmental groups complain that the clean air mercury rule should have had stricter standards and a shorter compliance timeline. They are also unhappy with the "cap-and-trade" approach since companies have a choice of reducing mercury emissions or buying allowances, meaning that "hot spots" of mercury may remain where companies choose to purchase allowances rather than invest in new pollution control.

Power companies will have to spend $23 billion between now and 2010 on pollution control to comply with new limits the US government imposed on three pollutants.

During phase I of the mercury rule, the limit on mercury emissions from coal-fired plants is set at 38 tons annually for the entire country. EPA expects that coal-fired plants will be able to meet the phase I reductions as a byproduct of reducing NO_x and SO_2 emissions as required by the clean air interstate rule. Certain pollution control technologies used to reduce NO_x (such as selective catalytic reduction systems) and to limit SO_2 (such as flu gas desulfurization systems or scrubbers) achieve some limited reductions in mercury emissions. EPA predicts that most coal-fired power plants will not have to take additional steps to reduce mercury until the phase II mercury cap of 15 tons annually takes effect in 2018. Once the mercury rule is fully implemented, EPA predicts that mercury emissions from power plants will be reduced by almost 70% from the 1999 baseline level of 48 tons.

Mercury

Mercury is widely recognized as a highly toxic, persistent pollutant that accumulates in the environment. Mercury can transform into methylmercury and build up in the food chain. Humans may consume mercury by eating contaminated fish. Coal-fired power plants are some of the more significant mercury emitters.

EPA has already imposed mercury emission limits on certain municipal solid waste combustors and medical waste incinerators. In regulating mercury from coal-fired power plants, EPA has taken a laborious legal and highly-charged political path. The agency was sued in 1992 by the Natural Resources Defense Council, or NRDC, for not including power plants in the initial list of major stationary sources that were regulated under the hazardous air pollutants or HAPs section of the Clean Air Act — section 112. The Sierra Club then sued EPA in 1994 for failing to complete a study required by the 1990 Clean Air Act to determine whether it is "appropriate and necessary" to regulate power plants under section 112. Both lawsuits were settled in 1994, and EPA agreed to complete a "Utility Air Toxics Study" by February 1998. Based on the findings of the study, EPA concluded in December 2000 that hazardous air pollutants from coal-fired and oil-fired power plants present a public health concern and that regulating such emissions is "necessary and appropriate." As a result, coal- and oil-fired power plants were added to the Clean Air Act section 112 source category list.

Once a source category is listed under section 112, the Clean Air Act requires that a hazardous air pollutant standard be proposed within three years and a final rule issued within a year thereafter. With the clock ticking, EPA was obligated to propose a rule to regulate mercury from coal-fired plants and nickel from oil-fired plants by December 2003.

As the deadline for proposing mercury standards for coal-fired power plants rapidly approached, EPA faced a dilemma over possible options to regulate mercury without crippling the utilities and independent power producers that own coal-fired power plants. If the agency adopted the traditional "command and control" approach set out in section 112, then companies would have three years from the date of the final rule to implement stringent "maximum achievable control technology" or MACT standards. For existing power plants, MACT standards must be based on the average emissions achieved by the best performing 12% of plants in a particular category or subcategory of sources.

Imposing stringent MACT limits presented several problems. There is currently no "silver bullet" technology available to achieve substantial mercury air emission reductions from power plants. Some pollution control devices hold promise, such as activated carbon injection, but these technologies are still in the development stage and are not yet widely commercially available. (EPA believes that activated carbon injection and other mercury removal technology achieving reduction levels / continued page 4

IN OTHER NEWS

more than 100 years ago to help fund the Spanish-American War and, although it has been updated, the words in the statute are badly outdated to a point where the Internal Revenue Service is having trouble collecting taxes on many current forms of communications services.

The tax applies, among other things, to "toll telephone service," which is defined as including WATS-line type service where the user of the WATS line is charged a "periodic charge (determined as a flat amount on upon the basis of total elapsed transmission time)" for an unlimited number of phone calls to or from callers outside the local area.

Fortis is billed for its 800 number by the number of calls it receives. The court said the service could *not* be taxed because the company is not charged a flat rate or on the basis of time elapsed. The case is *Fortis, Inc. v. United States*.

Four days later, Honeywell International also won a decision in the US claims court ordering the government to refund taxes that Honeywell paid on regular long-distance telephone service from AT&T, MCI and Sprint. Honeywell is billed by the duration of each call. The US tax code says regular long-distance service is taxable when the phone charges are based on the "distance and elapsed transmission time for each individual communication." The key word is "and." The IRS argued the statute should be read as if the word were "or." The claims court disagreed.

The government is losing large dollar claims from phone customers seeking tax refunds. If the government wants to keep collecting these taxes, Congress should update the statute.

WIND CREDITS will be 1.9¢ a kilowatt hour in 2005, the IRS said in early April.

Tax credits may be claimed on electricity from geothermal and solar projects at the same rate. Tax credits for / continued page 5

Pollution

continued from page 3

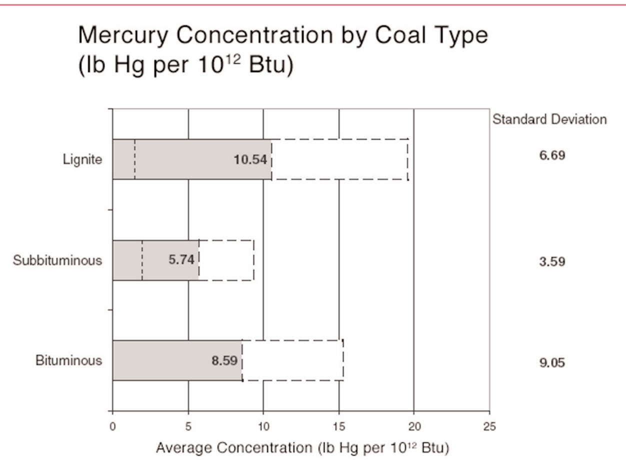
between 60% and 90% may be commercially available in the 2010 to 2015 time frame.) Another significant complication is that there are several different types of coal, including bituminous, sub-bituminous and lignite, and each of these types of coal has different levels of mercury content. The types of mercury within these coals also differ. For example, bituminous coal contains higher levels of mercury than sub-bituminous and lignite coals, but the mercury is much harder to remove from sub-bituminous and lignite coals.

Mercury is emitted either in a particulate form, a gaseous elemental form or divalent oxidized form. The particulate form is easiest to remove by using a baghouse or similar particulate control device. However, only small amounts of mercury are emitted as a particulate. Divalent oxidized mercury reportedly remains in the atmosphere for less than two weeks due in part to its solubility in water, and it can be deposited over 50 to 500 miles away from the source through rain, snow or dry deposition. This form of mercury can be captured by wet flue gas desulfurization systems. Elemental mercury is insoluble in water and is generally more difficult to remove. Elemental mercury can reportedly remain in the atmosphere for over a year before being oxidized.

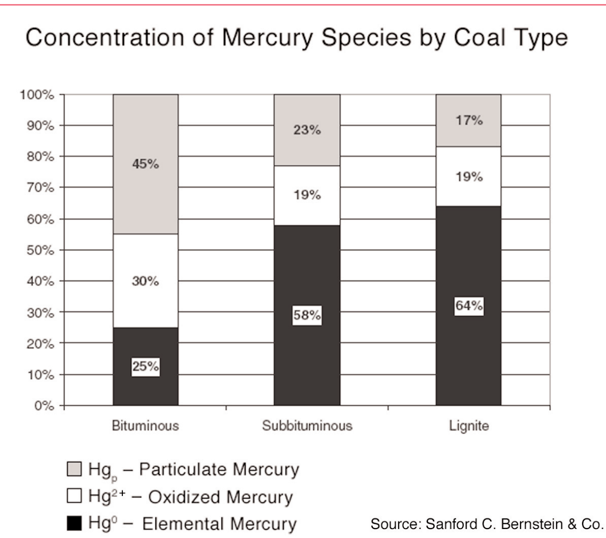
Wet flue gas desulfurization scrubbers are capable of removing mercury emissions from the burning of bituminous coal, and capture efficiencies range from about 20% to more than 80% depending on the amount of elemental mercury in the flue gas. Other conventional technologies include using a different type of coal, coal cleaning and certain particulate control devices (baghouses). Mercury removal efficiencies using conventional technologies are typically less when burning sub-bituminous or lignite. The chlorine content of coal also affects the form of mercury in the flue gas. Bituminous coals have higher chlorine levels and generally produce a flue gas that is higher in oxidized mercury. Most eastern coals are bituminous coals. The western coals are generally either sub-bituminous or lignite, which have a lower chlorine content, and the mercury is typically present in the harder-to-remove elemental form.

In searching for a workable solution, EPA evaluated whether a cap-and-trade regime could be applied to a mercury program. Similar cap-and-trade programs, such as the acid rain program and the NO_X budget trading program in the northeastern US, have afforded the regulated community a cost effective way to achieve required emission reductions. Under this approach, each existing power plant is given the right to emit a certain amount of mercury. Anyone who wants to emit more mercury than authorized must first purchase allowances from other plants that have them. Since section 112 of the Clean Air Act does not authorize emission trading, EPA had to find other statutory authority to support a cap-and-trade program.

In January 2004, EPA proposed two alternative



Source: Sanford C. Bernstein & Co.



Source: Sanford C. Bernstein & Co.

approaches for reducing mercury emissions from coal-fired plants and nickel emissions from oil-fired plants based on different sections of the Clean Air Act. The first alternative involved the "command-and-control" MACT standard approach under section 112. The second alterative was a cap-and-trade approach under section 111 of the Clean Air Act. That section is much less prescriptive and provides more flexibility in setting mercury and nickel emission standards.

In order to make the second alternative work, EPA also proposed in January 2004 to rescind the agency's December 2000 conclusion that the regulation of mercury and other hazardous air pollutants from coal- and oil-fired utilities is "necessary and appropriate" under section 112. The agency said the regulation of mercury from coal-fired plants and nickel from oil-fired plants under section 112 air toxic provisions is no longer "necessary."

EPA made these steps final on March 15, 2005. The acting EPA administrator, Steve Johnson, signed a final rule reversing the agency's December 2000 finding that the regulation of mercury from coal-fired plants is "necessary and appropriate." The agency said the December 2000 finding lacked foundation and more recent information demonstrates that it is not appropriate or necessary to regulate coal-fired power plants under section 112. The action paved the way for signing the clean air mercury rule on the same day that calls for a cap-and-trade regime as the mechanism to reduce mercury emissions from existing coal-fired plants. EPA is not moving under the clean air mercury rule to reduce nickel emissions from oil-fired power plants.

Nine states immediately filed a lawsuit challenging the EPA actions in the US appeals court for the District of Columbia. The states are New Jersey, California, Connecticut, Maine, Massachusetts, New Hampshire, New Mexico, New York and Vermont. The case will probably be consolidated with lawsuits being filed by other parties. A decision in the case is not expected until late 2006 or early 2007.

The mercury rule applies to coal-fired steam generating units capable of combusting more than 25 megawatts on an output basis and that sell more than 25 megawatts to the grid. These utility units typically consist of a furnace firing a boiler, which is used to produce steam that is run in turn through a steam turbine to generate electricity for sale. The mercury rule also applies to cogeneration units capable of combusting more than 25 megawatts on an output basis and that put more than a third of their capac- */ continued page 6*

IN OTHER NEWS

producing electricity from biomass will remain unchanged at 0.9¢ a kilowatt hour.

Owners of wind farms and geothermal and solar power plants in the United States can claim tax credits on the electricity they sell to unrelated parties. Projects must be put into service by the end of 2005 to be eligible. President Bush has asked Congress to extend the deadline for wind farms by another two years.

Credits may be claimed on the electricity output from wind farms for 10 years after a project is put into service. They run only five years for geothermal, solar and biomass projects. Biomass plants qualify for only half the normal tax credit, or 0.9 a kWh. The credits are adjusted each year for inflation. The IRS said inflation was enough last year to increase the credit slightly for wind farms and other projects, but not for biomass.

The credits will phase out if the average contract price for electricity reaches a high enough level that the tax subsidy is no longer needed. The IRS said that level is 10¢ a kilowatt hour for electricity sales during 2005. Separate average contract prices are computed for electricity sales from each type of "fuel." A phaseout would occur as the average contract price moves across a range of another 3¢ above the start of the phaseout range.

There is little chance of a phaseout during 2005; the IRS said the average contract price for 2004 sales in the wind market was only 4.85¢ a kWh. Only sales under post-1989 contracts are taken into account. Spot sales through power pools are ignored.

SECTION 29 tax credits were $1.13 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 */ continued page 7*

Pollution

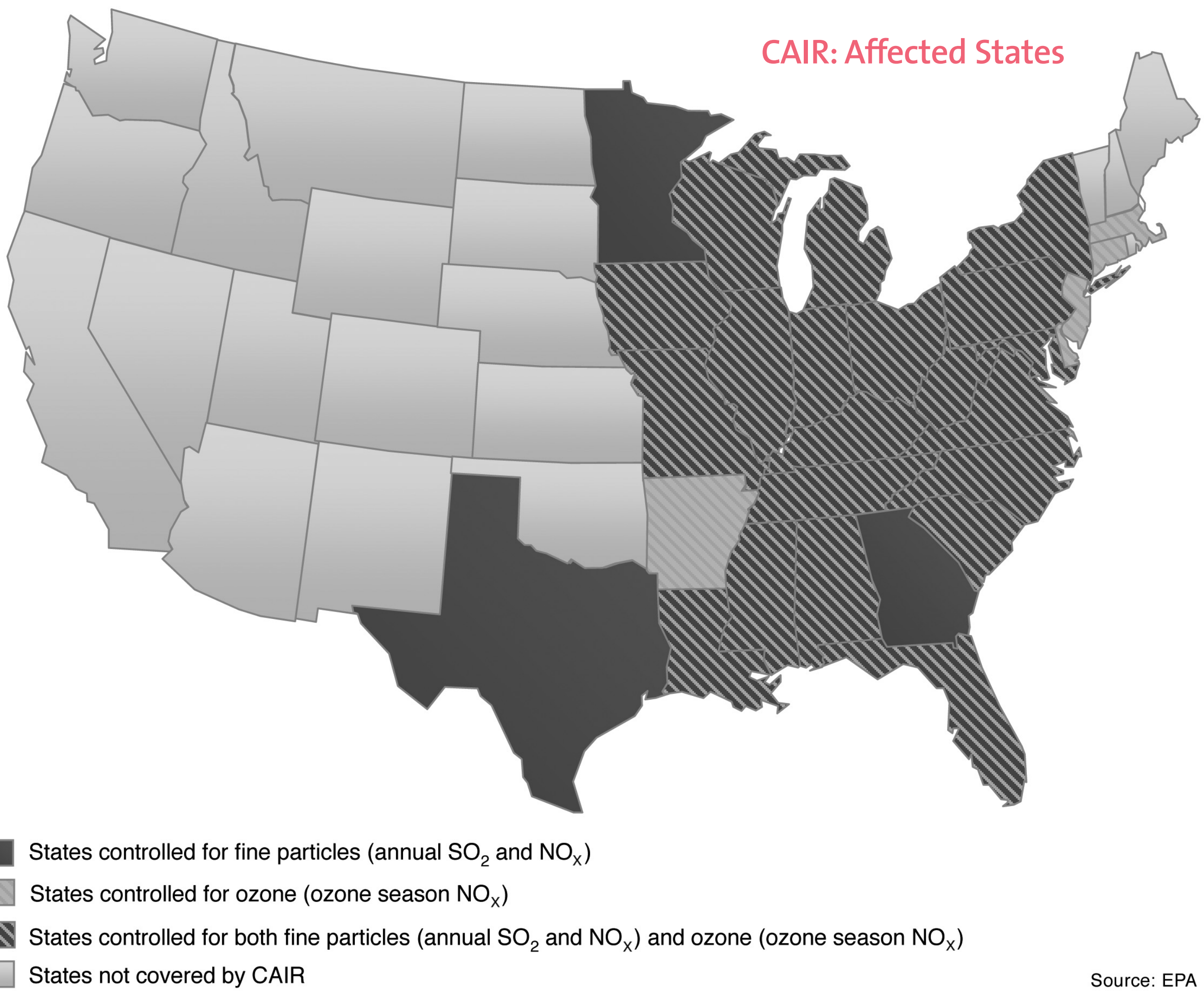
continued from page 5

ity and more than 25 megawatts into the utility grid for sale. (A cogeneration facility is a power plant that generates two useful forms of energy from a single fuel, such as burning coal to boil water and produce steam, some of which is used as steam to heat an adjacent building and the rest of which is run through a steam turbine to generate electricity.)

EPA has adopted a 38-ton mercury emission cap for the first phase commencing in 2010 and a 15-ton cap for the second phase starting in 2018. This is the amount of mercury emissions that would be allowed each year from all coal-fired power plants nationwide. In both phase I and phase II, 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 depending on the type of coal. The adjustment factors are 1.0 for bituminous, 1.25 for sub-bituminous and 3.0 for lignite coals. One allowance will correspond to one ounce of mercury.

States have the option of participating in an EPA-managed cap-and-trade program or electing to adopt their own state programs. Several environmental groups are encouraging states to adopt more stringent state rules to control mercury emissions from coal-fired plants. To date, four states — Connecticut, Massachusetts, New Jersey and Wisconsin — have adopted specific mercury emission limits that apply to older coal-fired plants in those states. For

CAIR: Affected States



Source: EPA

example, Connecticut moved in 2003 to require coal-fired power plants in the state to reduce mercury emissions by approximately 90% starting in 2008. The four coal-fired power plants in Massachusetts will need to meet an 85% mercury reduction level by January 1, 2008, and a 95% reduction level starting on October 1, 2012.

EPA agreed in the final mercury rule with the regulated community's argument that different mercury emission reduction targets should apply based on the type of coal being burned. Thus, allowances for existing plants will be weighted according to the type of coal burned. In the final rule, EPA set new source performance standards for *new* plants at levels that take into account the type of coal being burned. New coal-fired power plants that commence construction on or after January 30, 2004 must achieve the following output-based mercury levels: 0.0026 nanograms per joule (21×10^{-6} lb/MWh) for bituminous-fired units, 0.0055 nanograms per joule (42×10^{-6} lb/MWh) for sub-bituminous-fired units equipped with wet scrubbers, 0.0103 nanograms per joule (78×10^{-6} lb/MWh) for sub-bituminous-fired units equipped with dry scrubbers, 0.0183 nanograms per joule (145×10^{-6} lb/MWh) for lignite-fired units, 0.00017 nanograms per joule 1.4×10^{-6} lb/MWh for coal refuse-fired units, and 0.0025 nanograms per joule (20×10^{-6} lb/MWh) for integrated gasification combined cycle units. These limits are somewhat higher than originally proposed by EPA, and are based on an analysis of the "best demonstrated control technology" under section 111.

The regulated community does not need to take any immediate steps to reduce mercury emissions in anticipation of the phase I deadline, and potentially significant compliance costs will probably not be necessary until a few years before the start of the phase II portion of the rule in 2018. It is because of this long lead time that certain northeastern states and several environmental groups are lining up to challenge the mercury rule, and the fate of the rule will ultimately be decided by the US appeals court in the District of Columbia. In the meantime, it is possible that several other northeastern and mid-Atlantic states may take the initiative by adopting tougher mercury rules of their own for coal-fired power plants.

Interstate Rule

The clean air interstate rule signed in March focuses on reducing the amount of NO_x and SO_2 from power plants and other sources that blow across state lines where / continued page 8

IN OTHER NEWS

these fuels must have been put into service by June 1998. The credits may be claimed on output from such facilities through 2007.

High oil prices are spurring a lot of talk. Section 29 credits will phase out if oil prices return to levels reached during the Arab oil embargo in the mid-1970's. The phaseout is tied to the average wellhead price for domestic crude oil. The IRS said the average wellhead price was $36.75 a barrel last year, well below the phaseout range, which it said was $51.35 to $64.46 a barrel. Tax credits phase out as the domestic wellhead price moves across the phaseout range. Thus, for example, if the average domestic wellhead price had been the mid-point of the range last year, then section 29 credits on synfuel and landfill gas produced during 2004 would have been reduced by half. Both the bottom end of the range and the range itself are adjusted each year for inflation.

Meridian Investments, which has been helping synfuel plant owners "monetize" tax credits, studied the link between oil futures prices on NYMEX and the average domestic wellhead price that the IRS uses to determine whether the tax credits phase out. NYMEX prices had been more than $3 a barrel higher than the oil price used by the IRS, but John Boc, chairman of the company, reports that the gap is increasing. The IRS reference price was $40.24 a barrel in January this year, or 85.89% of the average NYMEX futures price for the same month.

> *Meridian calculates that NYMEX futures prices would have to average $64.02 for the rest of 2005 in order for the reference to reach the bottom of the phaseout range.*

PARTNERSHIPS with both US taxpayers and foreign or tax-exempt entities as partners may fall into a trap that Congress may have set inadvertently last October.

Congress passed a huge JOBS bill last October that, among other / continued page 9

Pollution

continued from page 7

it contributes to ozone and particulate matter pollution in downwind states. NO_X and SO_2 are precursors of fine particulates, or PM2.5, and NO_X is a precursor of ozone. NO_X, SO_2 and PM2.5 can travel for hundreds of miles and these pollutants have been linked to serious respiratory illnesses as well as having an impact on sensitive ecosystems and reducing visibility.

The final rule directs 28 states and the District of Columbia to issue new regulations that will require dramatic reductions in NO_X and SO_2 emissions by 2015 in a two-stage approach.

EPA determined that NO_X and SO_2 emissions from 23 states and the District of Columbia lead to unhealthy fine particulate levels in downwind PM2.5 nonattainment areas. It also identified 25 eastern states and the District of Columbia as contributing to ozone pollution in downwind areas that are not achieving the 8-hour national ambient air quality standard for ozone. These states are identified in the map on page 6.

The clean air interstate rule adopts a NO_X and SO_2 emissions budget for each state. States must comply with the allocated budgets either by participating in an EPA-administered cap-and-trade program that targets reductions from power plants in two stages or by proposing other measures, including requiring emission reductions from sources in other industrial sectors. However, the tone of the final rule strongly suggests that EPA expects states to adopt the cap-and-trade program.

Assuming most states go with cap-and-trade, EPA models suggests that the clean air interstate rule would bring about a 53% reduction or 1.7-million-ton decrease in NO_X emissions from 2003 levels by 2009. In 2015, the rule is expected to reduce power plant NO_X emissions by two million tons, which is a 61% reduction from 2003 levels. In 2010, the clean air interstate rule will reduce SO_2 emissions by a projected 4.3 million tons, a reduction of 45% from 2003 levels. By 2015, SO_2 emissions will have been reduced by 5.4 million tons or 57% from 2003 levels in the 23 affected states.

Each state must adopt its own regulations to implement the clean air interstate rule, and the regulations must be approved by EPA. For states subject to findings of significant downwind contribution for PM2.5, EPA is establishing annual budgets, and for states subject to findings of significant downwind contribution affecting compliance with the 8-hour ozone standard, the rule requires ozone season — May 1 to September 30 — emission budgets. States subject to findings for both PM2.5 and 8-hour ozone are also subject to an annual NO_X budget. The annual and ozone season budget caps are listed in the following chart.

The model cap-and-trade program incorporated in the clean air interstate rule uses a 25-megawatt cut-off to define affected sources similar to how affected units are defined in the so-called NO_X SIP Call rule and the acid rain program. The model cap-and-trade program also includes an exemption for small cogeneration units. Cogeneration units that generate more than 25 megawatts and supply more than one-third of their capacity and more than 219,000 megawatt-hours to the utility grid for sale would be subject to the cap-and-trade requirements.

Power plants located in states that are subject to the clean air interstate rule would be required to submit acid rain program allowances at particular retirement ratios to meet their SO_2 reduction obligations under the new rule. Affected power plants would be able to use pre-2010 vintage SO_2 allowances on a one-to-one basis. Vintage 2010 to 2014 SO_2 allowances could be used at a two-to-one ratio, and vintage 2015 SO_2 allowances and beyond would be retired at a ratio of 2.86 allowances for every one ton of SO_2 emissions. One effect of this SO_2 allowance retirement is that the value of post-2009 SO_2 allowances would be reduced in states

Emission Caps*

(million tons)

	2009/2010	2015
Annual SO_2 (2010)	3.6	2.5
Annual NO_X (2009)	1.5	1.3
Seasonal NO_X (2009)	.58	.48

**For the affected region.*

Source: EPA

subject to the clean air interstate rule SO_2 reduction requirements. There also may be a premium placed on achieving early SO_2 emission reductions since pre-2010 vintage year SO_2 allowances will be more valuable vis-à-vis 2010 and beyond allowances.

The clean air interstate rule has detractors, but it is not nearly as controversial as the mercury rule. It is much more likely to survive a legal challenge, since it is modeled after the NO_X SIP Call rule, which was largely upheld by a US appeals court after a protracted legal battle.

The clean air interstate rule will trigger installation of a new round of costly pollution control measures at some power plants and other industrial facilities, including selective catalytic reduction systems or selective non-catalytic reduction systems to reduce NO_X emissions to meet the 2009 deadline and flue gas desulfurization systems to limit SO_2 emissions starting in 2010.

Issues and Opportunities in Subsovereign Projects

An article in the June 2004 Newswire *reported on a new frontier for the international lending community working on projects in developing countries — the move to finance projects that have the financial backing of a municipal government rather than the national government.*

Chadbourne convened a conference call recently among representatives of several public institutions that have been substantial players in emerging market project financings to delve more deeply into the subject. The following are excerpts from that discussion. The speakers are Carlos Federico Basanes, adviser to the executive vice president of the Inter-American Development Bank, Christopher Bellinger, consultant with the office of co-financing operations at the Asian Development Bank and an alumnus of both the Multilateral Investment Guaranty Agency and the Overseas Private Investment Corporation (OPIC), Margaret Kostic, director for southeast Europe, and Paul Tumminia, director for Russia and the CIS, each with the Export-Import Bank of the United States, Henry Pitney, assistant general counsel at OPIC

/ continued page 10

IN OTHER NEWS

things, put a halt to cross-border leasing transactions called SILOs where a US institutional equity would buy equipment from a foreign user of the equipment and lease it back. The foreign user put most of the purchase price into a bank account, called a defeasance account, with instructions to the bank to pay rent when due and to pay the purchase option price at the end of the lease term if the foreign user decided to buy back the equipment. (In some deals, the foreign user would substitute financial instruments for the defeasance bank account.) Such deals were also done in the US between institutional equity and municipalities and other tax-exempt users of equipment.

Congress put a halt to the transactions last October, retroactively to March 13, 2004, by directing that the depreciation and interest deductions claimed by the institutional equity can only be used to offset rental income from the lease. The deductions cannot be used to shelter other income.

The trouble is that Congress defined the deductions that are subject to this limit as any deductions tied to "tax-exempt use property." Partnerships with both US taxpayers and foreign or tax-exempt entities as partners have "tax-exempt use property," unless they have a straight-up deal in which one fixed percentage is used for sharing all partnership items for the life of the deal — or at least for as long as the foreign or tax-exempt entities are partners.

Ironically, leasing groups that were fighting the SILO restrictions last year complained that the provision was too broad. Various groups have asked the US Treasury for an exemption for partnerships unless the partnerships are involved in SILO-type transactions. Accountants complained to the IRS that they could not figure out how to apply the rules in time to prepare Form K-1's that had to be distributed to partners in time to file 2004 tax returns.

Rather than try to sort everything out, the IRS said on March 10 that it */ continued page 11*

Subsovereign Projects

continued from page 9

and formerly with the Asian Development Bank, and Sumeet Thakur, an investment officer with the World Bank-IFC Municipal Fund. The moderator is Kenneth Hansen, formerly general counsel of the Export-Import Bank of the United States and an associate general counsel of OPIC. Hansen is a partner in the Chadbourne Washington office.

Receptivity

MR. HANSEN: Has your institution made or guaranteed loans to a local government authority without recourse to the credit of the central government?

MR. THAKUR: The Municipal Fund has closed two transactions, not direct loans but guarantees to local governments. One, in Mexico, is the Tlalnepantla transaction, which is for a public water company. With a partner, Dexia, IFC guaranteed a bond issued in the Mexican market. More recently we did a transaction for the City of Johannesburg. This, again, was a guaranty that was provided along with the Development Bank of Southern Africa. This supported a bond issue in the South African market. Both these transactions happen to be guarantees, but we could certainly do loans, and we are planning on doing loans in the near future.

I should mention that our unit is actually a joint World Bank-IFC unit so, although we're operating off IFC's balance sheet, the unit itself is a World Bank-IFC effort.

MR. BELLINGER: ADB has made an equity investment not directly into a subsovereign but into a guaranty facility that provides guarantees for municipal bonds. This is called the Local Government Unit Guaranty Corporation in the Philippines. As of January 21, ADB has invested $1.3 million for 25% of the equity. USAID is reinsuring them. They have not done many transactions, four for about $300 million. To date, their role is to provide comprehensive guarantees for municipal bond obligations.

MR. PITNEY: I was on ADB's credit committee when that was screened. Local Government Units have been established in the Philippines pursuant to a national law. As I recall, about 60 of them had been established, but only a small handful are creditworthy. The idea was to start with the creditworthy ones. It's reassuring to hear that this has actually progressed and that ADB has actually made the investment.

MR. HANSEN: So, ADB's support was by way of equity investment. That's an interesting variation of our theme of municipal project finance.

MR. BELLINGER: Yes. According to a press release just out, this is the first time this has been done. I'll quote it: "The investment in the Philippines marks the first time that ADB is assuming risk on a subsovereign commercial obligation without the backup of a central government guaranty." And, as you all know, ADB does not require government guarantees for its private-sector program.

MR. TUMMINIA: Ex-Im Bank authorized one project under the subsovereign program that was announced by the board in August 2000. The project was for the City of St. Petersburg. It was to be a $15-million project. It went about as close as it could possibly go to being operative. Then, there was a change in government, and the city cancelled the project.

That is our only experience to date under the subsovereign program where Ex-Im takes a direct risk of a city, oblast or region as opposed to asking for a guaranty from a bank or the sovereign or securing project revenues. In the case of the City of St. Petersburg, there was no bank or sovereign guaranty. There were no project revenues. It would have been pure city risk.

MR. HANSEN: How about a project revenue-based loan? Would you consider that?

MR. TUMMINIA: I think so. Ex-Im Bank has been trying. Margaret and I represent the Eastern Europe-Eurasia part of the world where we think that the subsovereign program is very appropriate and could some day be very, very important for exporters. It's a slow go, though. Jumping ahead to the question on what the problems are with municipal financings, I think the governments that we're dealing with are just not really used to this type of public-sector financing, so they are wary. They are suspicious. They think at some level that, if the project goes bad, Ex-Im's going to come hat in hand to the central bank and that they are going to be stuck for something they didn't approve. And that is understandable. We, of course, explain to them that is not how it works, but we think we would like to see projects based on the risk of the city, the oblast, and based on project revenues of some kind. We see it as a great future.

MR. HANSEN: It calls for the opposite of a central government support letter, perhaps a central government hands-off letter.

MR. TUMMINIA: Exactly.

MR. HANSEN: I understand that, at OPIC, there has been some debate over whether, in the non-honoring guaranty program, the guaranty that OPIC would be counter-guaranteeing had to be a guaranty of a central government, which was the original idea, or whether it could be a guaranty of some lesser public entity. With this approach the OPIC product could be very much like a partial risk guaranty program supporting subsovereigns. I've heard rumors of a couple of such deals in the pipeline.

Let's assume eventually you get to do a deal. What would you expect it to look like? Do you have any idea where the lower-hanging fruit might be?

MR. TUMMINIA: The types of projects that we see the greatest interest in from either the US exporter side or from the foreign buyer side have been in the areas of water, waste treatment, power, and then social services infrastructure like medical facilities and schools. The St. Petersburg transaction would have modernized the lighting in the city schools and done some other work around the city's primary and secondary schools. Lately it seems waste treatment and waste-to-energy have caught on. People are really very interested in that.

MR. HANSEN: It looks like IFC is leading this pack in closing such deals. Sumeet, where do you see your pipeline coming from?

MR. THAKUR: We're looking at deals in a number of markets. We're looking at follow-on transactions in South Africa and Mexico building on our experience there. We're also looking to do transactions in east Asia, south Asia, and a few more transactions in Latin America as well.

Obstacles

MR. HANSEN: May I ask you the other side of that coin? What are the high hurdles to getting those deals done?

MR. THAKUR: One of the biggest challenges that all of us face in this sector is that wherever possible these transactions should be local currency financed since clearly, the revenue streams are for the most part local. Unfortunately, local currency financing is not possible in all markets with the existing instruments. So that's an area where all of us have to think creatively to try and see if we can come up with solutions that really meet our clients' needs.

Also, it is important to distinguish between effective demand and potential demand. I think / continued page 12

IN OTHER NEWS

would not apply the new rules to partnerships before the 2005 tax year. It asked for comments on a number of technical issues in the meantime. The IRS announcement is Notice 2005-29.

HOLLAND plans to eliminate a capital tax on money injected into Dutch holding companies.

Multinational corporations usually own projects in other countries through offshore holding companies. Holland has been a popular location in the past for such holding companies because there is little tax on earnings passing through Holland, and it has a broad network of tax treaties with other countries that help in reducing withholding taxes collected by other countries where projects are located.

In recent years, Holland has had competition from Luxembourg, Denmark and other jurisdictions with their own treaty networks for holding company business.

Holland collects a 0.55% capital tax on money that a parent company contributes to a Dutch holding company — for example, to invest in an offshore project. The Dutch finance ministry said on March 24 that it plans to eliminate the capital tax effective next January 1. The proposal must still be approved by parliament.

WEST VIRGINIA may have to refund more than $400 million in severance taxes collected from coal companies that produce coal in the state, but sell it overseas.

The state Supreme Court agreed in March to hear claims by coal companies that the taxes on exported coal violate the US constitution because they interfere with foreign commerce, which only the US government has the power to regulate. The state collects a severance tax of 5% of gross receipts on coal mined in the state. Approximately 10% of West Virginia coal is exported abroad. State severance tax collections were / continued page 13

Subsovereign Projects

continued from page 11

the number of creditworthy municipalities and local entities that are willing to borrow on commercial terms while large, may be more limited than all of us think at the outset.

MR. BELLINGER: Ken, if I could just speak from my recent MIGA perspective. When I was based in Paris, we were trying to utilize MIGA's ability to cover subsovereign turnkey projects. I was personally involved with two waste-treatment projects in Cairo involving European concessionaires. We did three site visits. We had the benefit of USAID. The biggest problem we had was getting sufficient information from the Beautification Authority of Cairo to enable us to issue the guaranty. At the end of the day, we took comfort in a variety of other things and, from what I gather, MIGA in fact did issue insurance to the Spanish company called Drogados.

MIGA has also offered coverage for streetlights in the Czech Republic, two and a half years ago, taking the payment risk. Also in Gabon, one of the projects that I was working on was a vocational school where one was taking the payment risk of the school, which was a state-owned company. But we've also looked at airports in Syria, and dredging projects in a variety of African countries.

MR. HANSEN: In these projects, MIGA was typically insuring private equity investments or loans?

MR. BELLINGER: The coverage was requested by the commercial banks. They wanted payment cover so we were looking at covering breach of contract by projects that were 100% state-owned. There was no foreign equity.

MIGA's convention states that MIGA can provide coverage for turnkey projects under certain circumstances provided that the contractor is tied somehow to the performance of the project. So, whether with a performance bond or bearing responsibility for the success of the project three years after completion, MIGA management had agreed that in a number of projects, we could cover the fees under a turnkey contract that qualifies as quasi-equity. That enabled us to cover third-party debt.

As you can imagine, once it had been agreed that we could do this, there was a series of projects. There is a project in Russia for which MIGA has issued guarantees. And then streetlights in the Czech Republic and also the Drogados waste-treatment project in Cairo.

One growth area in financing by international financial institutions is lending to subsovereign projects, or projects that are supported by a municipality rather than the central government.

MR. HANSEN: This suggests that traditional lending is not the only option for municipal projects. Other support options may include putting in equity or providing a political risk guaranty.

MR. BELLINGER: Note that, at the end of the day, these "political risk guarantees" are, in effect, payment guarantees. MIGA's breach-of-contract coverage really becomes a payment guaranty. If you look at MIGA's annual report for the 100% state-owned hospital in Romania, MIGA's 100 million euro commitment was a payment guaranty. Technically, it is arbitration-covered, but it does cover nonpayment of the award. At the end of the day, you are covering nonpayment. It is arbitration-covered, but it does cover nonpayment.

MR. BASANES: To complement, we here at the IDB have not yet done operations with subnationals without a central government guaranty. We are exploring the possibilities. We are in a period of consultation within our institution and with different stakeholders, but we are trying to get into doing operations of this kind. Of course, we face the same impediments that have been mentioned, such as the inability to provide financing in local currency. We believe that is a big impediment. Politics and central government awareness are also concerns.

We think that the way to go, at least to start with a program like this, would be to rely on revenues generated by specific projects and not general revenues of subnationals. The projects that we are looking into for the time being are typically water and waste-treatment projects.

MR. HANSEN: It keeps coming up that it would be helpful to do these projects with local currency. Local currency financing to a municipal project would present two novel nuts to crack — subsovereign risk plus devaluation risk — but, if you can get comfortable providing local currency loans and guarantees, presumably you will be a step ahead in supporting subsovereign projects. So what's the problem with offering local currency financing?

MR. TUMMINIA: I think the first problem for Ex-Im Bank was payment of a claim. The payment process involved other parts of the US government like the Treasury Department. For years I think Treasury did not want to pay out a claim in a currency that was other than the US dollar. I think Ex-Im was only using a hard currency before 2003. So, though the loan might be made in francs, yen or marks, the claim itself had somehow to convert into a dollar.

That has since changed to some extent. Treasury has actually abdicated any role over this process, and so Ex-Im Bank now is in the position of actually figuring out on its own what the best way to do this is.

Unfortunately, we haven't fully resolved how to approach this, whether the claim should be converted to dollars or can be kept in the local currency. I think that we are moving that way. I think some of the currencies have been chosen. The hard currencies I don't think are a problem, but soft currencies like the ruble are more problematic.

I think that we are moving that way, although I don't think that Ex-Im has yet made a decision about some of the key aspects of managing local currency risk. That is one of the biggest problems. If we were to be able to offer a ruble-denominated loan and, in the event of a default, the loan could stay as a ruble loan, then I think it would be a little bit easier for us to get some of these deals through.

MR. HANSEN: Federico, what's keeping IDB from doing a local currency guaranty?

MR. BASANES: Well, we haven't done one yet. We are exploring the possibility. As a matter of fact, we had a workshop with some of the institutions on this call to discuss the way they are doing it.

Our charter allows us to do so, though we need board approval. We need to hedge the foreign exchange rates, of course, and we are looking into different / continued page 14

IN OTHER NEWS

$214 million in 2003. The plaintiffs in the case are seeking refunds for severance taxes paid as far back as 1997. They include CONSOL Energy, Arch Coal and Massey Energy. The case is *U.S. Steel Mining Co. v. Virgil T. Helton, Tax Commissioner.*

INVESTMENT INCOME might be shifted to a low-tax state.

The Missouri Supreme Court barred the state in January from taxing a Missouri subsidiary on income it earned from investing its overnight cash balances because its parent company in another state did the investing.

The decision opens the door to tax planning. Income might be shifted to a state where there is no income tax by means of an investment agreement. The court said the "brain" of the operation — and hence where the income was earned — was not in Missouri.

Most states collect income or franchise taxes from companies doing business in them, but the taxes apply only to the share of a company's income that comes from sources in the state. Most states make companies that are doing business in more than one state take their entire business income and apportion a share of it to the state. Many states do the apportionment using a three-factor formula. They look at the percentage of payroll, property and sales that a company has in the state. However, Missouri apportions based only on sales. Under the Missouri formula, a company multiplies its total income by a fraction. The denominator of the fraction is its total sales. The numerator is its Missouri sales plus half its sales that straddle Missouri and another state

A Missouri subsidiary had an "investment agreement" with its parent company in Ohio. The parent invested the subsidiary's overnight cash balances and paid the subsidiary 7.72% interest. The interest amounted to millions of dollars over the three tax years that were at issue in the case. / continued page 15

Subsovereign Projects

continued from page 13

ways of doing that. One constraint, of course, is the development of the capital market of certain countries. In order for you to be able to hedge the exchange rate risk, you need a swap market or you need to be able to issue in the local currency.

Still, we believe we are going to be able to move in that direction soon and, once we do, subnationals would be a natural client.

An obstacle is finding a legal borrower. For example, it is hard to find any local authorities in Russia, other than St. Petersburg and Moscow, with authority to borrow foreign funds.

MR. PITNEY: While I was at ADB, two things were done to address partially the funding problem that Mr. Basanes was describing. One was a US dollar-Philippine peso swap that ADB did with the central bank of the Philippines. ADB entered into a swap by which ADB provided US currency in exchange for Philippine pesos for a 10-year period at the end of which they would swap back into their currencies. The proceeds of the swap, the $200 million equivalent in pesos, will be on-lent by ADB to single-A rated foreign banks, and to Philippine banking institutions meeting other acceptable criteria. These participating banks will, in turn, make long-term, fixed-rate loans for certain categories of projects approved by ADB. The second thing that ADB did was to issue rupee bonds in India to finance the private sector loan and guarantee operations of ADB at a point when they had a reasonably robust private sector pipeline. So they solved the funding problem in those two ways in at least those two countries.

MR. BELLINGER: I think there hasn't been too much by way of either partial risk or partial credit guarantees of local currency loans. ADB can, however, make loans in local currency, as well as guarantee local currency loans. In fact, an internal paper was prepared late last year that identified some of the issues. I believe, however, that the obstacles can be overcome and am hopeful that, in the next year, we will see more of these.

MR. PITNEY: I know that, as of June last year when I left, ADB's first rupee loans were just waiting clearance of conditions precedent. I imagine that at least one or two of them by now have cleared those conditions precedent. Also there is an equity investment in local currency funded by a local currency issue that has been done already.

MR. HANSEN: Sumeet, the IFC lends local currency. Is that part of what you're doing in the municipal shop?

MR. THAKUR: We operate using all of IFC's product lines so, in whichever market that we can provide local currency financing, we can certainly use it to finance municipal projects.

MR. HANSEN: Yet the non-availability of local currency financing appears to be among the impediments to getting municipal deals done. If that is a broad issue, your municipal shop should be a big user of local currency financing. Is that true? Do you expect local currency financing to become an important part of what you will do?

MR. THAKUR: Absolutely. In some markets we may have no choice but to finance in hard currency, but I think that there should be well articulated reasons for going with a hard currency option.

There are two issues with regard to local currency financing. One is obviously the existence of a market that allows you to deploy local currency products and the second is local laws that in many jurisdictions require one to structure local currency financing because a lot of municipalities are not allowed legally to borrow in hard currency. So, it's not just a choice or a credit preference. In many markets it is a legal requirement.

MR. HANSEN: That's a good example of the special legal problems that sometimes arise when dealing with local governments. There is also the political risk of interference with local projects by the central government. For instance, you might think you are doing a revenue-based municipal project, but suddenly new legislation diverts those revenues to some other national purpose.

You mentioned before that the central governments feared that local projects could become a national burden. Has the other side of this coin been a problem, that local governments may not be autonomous enough?

MR. THAKUR: This is obviously a critical issue for us. In the transaction we have processed and are currently reviewing, we are clear that we are not relying on sovereign guarantees and that the decentralization framework is one that we are comfortable with.

MR. HANSEN: So you make them comfortable that you are not going to turn to them, but how do they make you comfortable that they aren't somehow going to undermine the project?

MR. THAKUR: That's part of the credit judgment that one is making and obviously one looks for the decentralization and broader institutional framework as part of the credit assessment. Where fiscal transfers play a major role, one looks at the past history of fiscal transfers and evaluates how predictable these transfers have been. That's a part of our due diligence

MR. HANSEN: Does anyone else have any experience with or perspective on whether central governments themselves are impediments to financing municipal projects?

MR. BELLINGER: MIGA requires host country approval when it issues cover for breach of contract for subsovereign risk. That document specifies what we are doing. In some countries, however, particularly India, we simply have not been able to get those country approvals. MIGA cannot issue the cover without that approval.

MR. PITNEY: In my experience, Ken, definitely, the central governments are sometimes part of the problem. Provincial authorities in China have a history of agreeing to particular project arrangements, sponsors or lenders clearing those things with the central government only to have the central government turn around three years later and say well, we know that we approved all those things but now circumstances have changed. This nearly scuttled a major provincial project.

So although that case did not involve a municipal authority *per se*, it did involve a local power bureau and what the central authorities unapproved was the so-called new tariff regime. They said circumstances have */ continued page 16*

IN OTHER NEWS

The Supreme Court said the subsidiary could exclude the interest from its total income to which it applied the apportionment fraction. The Missouri courts have historically let passive income that is earned from activity in another state escape any apportionment. In this case, the activity was in Ohio where the parent was located. The parent made the investment decisions.

The case is Medicine Shoppe International, Inc. v. Missouri Director of Revenue. *The Supreme Court released its decision on January 25.*

SALES OF INTERESTS in many partnerships and limited liability companies that own US property will have to wait in the future at least 30 days after reports are filed with US antitrust officials before the sales can close.

The filings are called Hart-Scott-Rodino filings. Until now, sales of less than an entire partnership or limited liability company — for example, a sale of a 99% interest — could occur without such filings. However, the Federal Trade Commission amended its rules on February 23 to require filings in cases where less than the entire entity is sold as long as the purchaser will have "control" of the partnership or limited liability company after closing of the transaction. The FTC defines "control" as having the right to 50% or more of the profits of the entity or having the right to 50% or more of the assets of the entity upon dissolution.

The new rules apply to sales that close after April 7, 2005.

The Hart-Scott-Rodino Antitrust Act is a 1976 law that requires parties to acquisitions of voting securities or assets meeting certain size thresholds to file notice and observe a waiting period before closing the transaction. Filings must be made with both the Federal Trade Commission and the US Department of Justice. The waiting period of 30 days after filing before a sale can */ continued page 17*

Subsovereign Projects

continued from page 15

changed and tariffs are too expensive; you will reduce them across China notwithstanding the contracts with independent power producers.

MR. HANSEN: Referring back to what Sumeet said, that's a case-by-case due diligence issue. But, in a place like China, it's probably a pretty big due diligence issue.

MR. PITNEY: This is a little bit off-piste because that's traditional project financing, but there is no reason it couldn't happen, for example, say, with water tariffs for municipalities, where project bankability is in part based on guarantees of tariff payments.

MR. HANSEN: How about the other side of the coin, which Paul raised, that problems that arise with municipal projects will become an albatross around the central government's neck? The question was raised over the weekend whether, as a legal matter the central government is responsible for local government financial obligations. I'm pretty comfortable the answer is "not necessarily" — that is, not unless the local actions somehow constituted violations of international law. The mere failure to make a payment doesn't do that. But a legal right to disavow responsibility is no assurance that the central government could do so without cost. So the question is whether central governments may be concerned that local projects will be more trouble than they are worth. Is it possible that a principal impediment to getting these deals done is preferences in the countries themselves?

MR. PITNEY: In China, municipalities are forbidden to take on debt. That is slowly starting to erode but it is still a significant impediment. The central government essentially allocates the municipalities' limited bond issue rights. Last time I looked, it was quite limited.

MR. HANSEN: How about rights to take advantage of the revenues of locally-organized projects? Is that also centrally regulated in China?

MR. PITNEY: I can't think of any specific national government stricture on getting the benefits from the local projects; however, there is the constant struggle between the central government and the provinces and the cities on how much of their revenues they get to keep, but that's a general budget thing rather than a project-specific thing.

MR. THAKUR: I don't usually work on China, but I do know that companies set up by local governments in some circumstances are allowed to borrow.

MR. HANSEN: This is something I keep hearing, that the ability of emerging market cities to be taken seriously in financial markets is new, but it's progressing.

I want to ask Paul and Margaret how this stands in the former Soviet Union.

MR. TUMMINIA: If we take away the Baltics, I think it's still fairly difficult for any local government, whether it's a city or whether it's an oblast or an autonomous region, to borrow. The Russian law makes it very, very difficult. And it has become more difficult recently, not less.

As far as we understand, the City of St. Petersburg and the City of Moscow are really the only two local Russian authorities that can borrow foreign funds, at least until the current law changes. Among any of the other 87 constituent local legal entities, I think you would be hard pressed to find a legal borrower.

MR. HANSEN: So, another reason to be focused on local currency lending as an option is that in some places it has the advantage of being legal?

MR. TUMMINIA: Yes, things get much easier if you can lend in rubles. There are a few other glitches, I think, under the Russian law. I recall not being able to accelerate a subsovereign loan upon a payment default.

In the other 11 former Soviet republics — with the exception of Ukraine and the City of Kiev — I think you would be hard pressed to be able to find the possibility of doing a subsovereign loan; you really cannot do it legally.

MR. HANSEN: Let's go to a different issue — the relevance of the multi-lateral development bank negative pledge obligations. Though made at the level of sovereign borrowing, do they interfere with municipalities offering collateral? Have you found negative pledges by central governments to stand in the way of municipal deals?

MR. THAKUR: We have no specific transactions where the issue has come up; however, I think that's an important issue.

MR. PITNEY: I would second that from my time at the ADB — particularly in the countries where foreign creditors have been very concerned about the bankability of deals and in countries that lack a strong, well-managed central bank. I know that the World Bank group has been very concerned that some of the former Soviet countries may be in breach of negative pledges. The ADB has also been quite concerned about negative pledges being breached in a number of projects in places like Laos, where theoretically everything is owned by the central government. ADB has been approached for waivers for Laotian projects. So the negative pledge has been an issue there generally. It has probably not been an issue in a municipal setting simply because, to my knowledge, ADB has not done any municipal deals in Laos.

MR. HANSEN: Has anyone had any sense of any willingness by the World Bank or other multilateral development banks to grant waivers in order to encourage successful financing of subsovereign projects?

MR. PITNEY: I think ADB was one of the most cautious at granting the negative pledge waiver. Part of the reason is because the US Treasury and, at times, other treasuries vehemently opposed waivers of the negative pledge. In fact, they forced a negative pledge policy from the World Bank and at times sought the same at the Asian Development Bank. They decided, however, that the ADB is more conservative than the World Bank's policy. I think, Ken, the answer is that the ADB would support a negative pledge waiver if it believed that there was a very significant developmental impact to such a municipal project.

Outlook

MR. HANSEN: Next question: is there a regional aspect to this? Are the prospects for these deals stronger in one part of the world or another?

MR. BELLINGER: I have seen projects in Colombia, involving water, quite a few from Algeria and throughout the Middle East, and in Africa. Again coming back to the MIGA payment guaranty product, once there was a sense that MIGA could insure turnkey operations with subsovereigns, there was a host of available projects in Africa, such as waste treatment and dredging. We saw in, I think it was Slovakia, something like 30 municipalities looking into doing streetlights. I think it's a question of, if you build it, they will come.

MR. HANSEN: It sounds like it could be responsive to circumstances that could erupt almost anywhere. The next point actually is implied by much of our conversation: what sectors are appropriate for municipal project finance? Water, obviously. Also, waste treatment. Any sense of other low-hanging fruit with respect to financeable municipal projects?

MR. THAKUR: We are looking at municipalities on a more corporate basis, so any creditworthy municipal financing for local roads, electricity or solid waste could be supported. Revenue-generating projects are in some / continued page 18

IN OTHER NEWS

close is supposed to give antitrust officials at the two agencies time to assess whether the sale has unfavorable antitrust implications. Most cases present no antitrust implications, and the parties can ask that the waiting period be shortened. However, even where early termination of the waiting period is granted, the parties still end up waiting about 20 days. The waiting period does not start to run until both parties — the buyer and the seller — make filings.

A Hart-Scott-Rodino filing is required only in cases where the value of the assets or voting securities being acquired is at least $53.1 million. The amount is adjusted each year for inflation. This is the figure for sales during 2005. The dollar threshold takes into account what the buyer already owns as well as any new interest he is purchasing.

A filing is required not only when someone buys an interest in an existing partnership or limited liability company from someone else, but also when a new partnership or LLC is formed — and ownership interests are issued — in exchange for capital contributions. A party acquiring "control" of the new entity in such a case must make a filing. The new entity itself must also file.

OUT-OF-STATE LESSORS do not have to pay income taxes in Alabama even though the leased property is used there, an Alabama judge ruled.

A leasing company leases specialty railroad cars. The company is headquartered in Illinois. It has no tie to Alabama other than that lessees who lease rail cars from it use the cars in the state.

The state tax department insisted that the leasing company had to apportion part of its rental income from leasing the rail cars to Alabama — and pay income taxes on it — based on the number of miles the rail cars traveled each year in Alabama as a percentage of total mileage. A number / continued page 19

Subsovereign Projects

continued from page 17

circumstances more appropriate and easier to do, but in many cases that may not be an option, so I think one has to look more broadly than just revenue-based projects and look at all municipal and other subsovereign infrastructure.

MR. HANSEN: Let's look introspectively for a moment. Are impediments to subsovereign lending to be found in the charters, policies, and procedures of your respective institutions that need to be addressed in order effectively to support subsovereign projects?

It sounds like the negative pledge is potentially one thing we've already identified. It sounds like MIGA has made real progress overcoming what could have been charter-based impediments to supporting financings of municipal projects.

MR. BELLINGER: Typically, however, MIGA projects have involved equity coverage. The only turnkey project that MIGA was working on was a school. In fact, if you look at MIGA's annual report, you have to read between the lines. Support may, for instance, be for a shareholder loan by a bank to its local subsidiary against the risk that a city fails to repay a loan to the subsidiary. The MIGA annual report would note that the breach-of-contract coverage is offered for a "banking project."

MR. HANSEN: So you insure the upstream loan against the downstream risk?

MR. BELLINGER: Correct, and that's been done on a number of projects.

MR. HANSEN: At Ex-Im, you mentioned that the institutional constraints to local currency lending posed by the Treasury Department's opposition have been resolved. How about the statutory requirement of finding a "reasonable assurance of repayment"?

MR. TUMMINIA: We're still working through foreign currency lending from the programmatic side, that is, what is the product that we can offer. Clearly the reasonable assurance issue is always going to be there. It is the 800-pound gorilla in the room. From the Ex-Im Bank side, what we decided is to look only at subsovereigns that are rated. We are only looking at a city, a region, a municipality or province that has a rating of B- or higher or B3.

MR. HANSEN: Federico, how about IDB? Is it just a business problem of finding reasonable terms for a reasonable project or are there also institutional barriers within the IDB to doing municipal projects?

MR. BASANES: We are in a dialogue right now internally within the institution. We are looking into what product we can offer. We are also in the process of talking about these things with our board. As far as I know, there are no restrictions in our charter that would prohibit us from doing any of this. It is just a matter of taking different things into consideration and putting out a product that we can deliver. So we are in that process right now.

MR. HANSEN: And OPIC?

MR. PITNEY: Last year OPIC's statute was amended specifically to allow local currency guarantees, provided that OPIC's eligible project and eligible investor requirements could be satisfied in a particular municipal project. I don't see anything that would preclude OPIC from doing them. In fact, we have been talking to a lot of different parties about doing this. I think our concern at the moment is that generally Treasury doesn't really want to get into the business of multi-currency risk. But that's just my sense on dealing with it for the last two to three months on an interagency US basis.

MR. HANSEN: For the final question, I'd like to ask each of you to look into your crystal balls and predict where your institutions might be a year from now. That is, how many subsovereign financings (without recourse to a sovereign) will you have closed by the end of the year? Sumeet, how about you? IFC seems to have a head start.

MR. THAKUR: Obviously I have to preface my remark with all the appropriate caveats, but we are fairly optimistic about doing a couple of deals this year.

MR. HANSEN: How about Ex-Im?

MR. TUMMINIA: I would guess that we might be able to see one or two, maybe not totally closed but authorized, by the end of the calendar year. Probably not in the former Soviet Union; I would say either Turkey or Central Europe would probably be the most likely candidates.

MR. HANSEN: OPIC?

MR. PITNEY: My sense is that the relevant project officers are optimistic that they will be able to get some approved this year. Whether they will actually go to closing by fiscal year end is another matter.

MR. HANSEN: Chris and Henry, how about ADB?

MR. PITNEY: Director General Robert Bestani is working on some of the institutional constraints. What he has to confront, frankly, are certain views about acceptable projects for the private sector operations group. In other words, there is a certain amount of resistance, for example, if something looks a little too "public sector" for the private sector to support, but he is doing his best to challenge these sorts of reservations.

I think with the public-private partnership dialogue in the last five or six years, these old notions of what's an acceptable project are being steadily eroded.

ADB's charter permits it to make guarantees with or without sovereign support and you can do everything under one roof. In other words ADB is not separated into three different groups like IFC, MIGA and the World Bank group, there is no constitutional impediment to doing something well structured on the subsovereign side. Chris mentioned at the beginning of the call the Local Government Unit project, but there they have invested in a corporation that guarantees, if I'm not mistaken, the Local Government Unit's bond issues. I think that's a small but interesting project that pushes the envelope responsibly.

MR. BELLINGER: The press release I referred to earlier says ADB plans on doing more private projects to help municipalities in ADB's developing countries gain access to private capital. Then it goes on to say that ADB expects to provide technical assistance to designated municipalities and local water utilities to prepare them for issuing bonds in the commercial markets, focusing on Thailand, India and the People's Republic of China.

MR. HANSEN: Federico, it sounds like IDB maybe has the longest horizon here?

MR. BASANES: I think so. Recognizing again all the caveats, now our expectation is that, within a year or a year and a half, we will get authorization to start doing local currency financing and subnational lending. But after getting the authorization, you still have to put together a few deals so I think it's a longer road for us. ◎

Regulatory Issues in US Utility Acquisitions

by Adam Wenner and Donna J. Bobbish, in Washington

Observers expect to see consolidation in the electric utility sector over the next five years and, as a result of a weakened US dollar, US utility assets are of renewed */ continued page 20*

IN OTHER NEWS

of states — for example, Massachusetts, Pennsylvania and Oklahoma — require such apportionment. However, an administrative law judge told the Alabama tax department that it could not collect income taxes in such cases. The judge said any effort to collect taxes from out-of-state lessors would be unadministrable. Rail leasing companies might require lessees to keep track of mileage, but for autos or other types of leased equipment, lessees could not be expected to keep such records. He said that in declining to tax out-of-state lessors, the state would be following Kentucky and Indiana.

The case is Union Tank Car Company v. Alabama Department of Revenue. *The judge issued a final order in the case in January.*

TEXAS is moving to close a loophole that allows projects in the state largely to avoid franchise taxes by operating as limited partnerships.

One sixth of businesses in the state avoid paying franchise taxes currently. The state House of Representatives voted on March 16 to increase business taxes. Businesses would have a choice in the future of paying a tax tied to payroll — the tax would be 1.15% of the first $90,000 in wages paid to each employee — or choosing to pay a franchise tax of either 4.5% of net income or 0.25% of capital. The measure goes next to the state Senate, where Senate staff say they expect action by the end of April. The current session of the legislature ends on May 30.

The House also voted to increase the state sales and use tax rate to 7.25%. That would make it the highest state sales tax rate in the nation.

CONTRACT CANCELLATION PAYMENTS can normally be deducted, but the IRS told one US company on audit that it had to treat such a payment as a cost of a new */ continued page 21*

Utility Acquisitions

continued from page 19

interest to foreign investors. The focus of this article is regulatory hurdles facing foreign investors who want to purchase US electric utilities. The article not only explains what the regulatory hurdles are, but also describes the experience of four non-US companies that cleared them.

At the federal level, acquisition of a US electric utility will require approval by the Federal Energy Regulatory Commission under the Federal Power Act and may also require approval by the Securities and Exchange Commission under a 1935 law called the Public Utility Holding Company Act (or "PUHCA").

Filings under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 with the US Department of Justice and the Federal Trade Commission will probably also be required. In addition, if the electric utility has a license to own or operate a nuclear power plant, then authorization for the transfer of that license will be required from the Nuclear Regulatory Commission under the Atomic Energy Act. Review of the transaction's effect on national security under section 27 of the Defense Production Act of 1950 — known as "Exon-Florio" — also may be required.

Federal regulators reviewing transactions under these statutes will examine the effect of a proposed transaction on competition, wholesale electricity rates and national security.

At the state level, the acquisition also may require approval of one or more state public utility commissions under state utility laws.

Four Case Studies

Four foreign companies acquired US electric utilities during a four-year period starting in 1999. The buyers decided that the prospect of US regulation was an acceptable price of owning a US utility.

Scottish Power plc acquired PacifiCorp in 1999. Through its operating company subsidiaries, Scottish Power is engaged in the transmission, distribution and power generation business in the United Kingdom. Although PacifiCorp operates in several states, it is organized as a single utility company with divisions, rather than separate companies.

National Grid Group plc purchased New England Electric System, or "NEES," in 1999. NEES is a "registered holding company" with utility company subsidiaries operating in Massachusetts, Rhode Island and New Hampshire, and other utility operations in Vermont and Connecticut. A subsidiary of National Grid, the National Grid Company plc, is a public utility company operating in England and Wales. National Grid also holds investments in transmission companies in Argentina and Zambia. National Grid subsequently acquired Niagara Mohawk Power Company, another US electric utility in upstate New York. Niagara Mohawk's system is directly interconnected with the NEES system in Massachusetts.

PowerGen plc acquired LG&E Energy in 2000. PowerGen is engaged in the generation and distribution of electricity in England and Wales through a subsidiary. It also is involved in the transportation, marketing and delivery of natural gas and the development of cogeneration and renewable energy facilities. LG&E Energy is the parent of Kentucky Utilities Company and Louisville Gas and Electric Company.

Subsequently in 2002, the German utility E.ON AG acquired PowerGen and, as a consequence, E.ON became a "registered holding company" subject to PUHCA regulation in the United States. At that time, E.ON, through its subsidiaries, had six business divisions: energy, chemicals, real estate, oil, telecommunications and distribution/logistics. E.ON was engaged in the ownership and operation of power plants and the transmission and distribution of electricity, gas, heat, water and water-related services. E.ON also held interests in regional electricity and gas distributors and in municipal utilities in Germany.

Each of these transactions was subject to federal and state regulatory scrutiny in the United States. Each transaction was approved. A foreign investor acquiring a US utility may have to deal not only with numerous federal and state regulatory bodies but also with other utilities and consumer advocates that might intervene in regulatory proceedings and have to reach an accommodation with such intervenors to remove opposition to a proposed transaction.

Federal approval of the Scottish Power, National Grid and PowerGen transactions was fairly straightforward. However, state approval was much more contentious, and the applicants had to enter in settlements with consumer advocacy groups and to agree to numerous conditions to get through them.

PUHCA

PUHCA is a 1935 law aimed at curbing abuses by large multi-state utilities that, because of their size and geographic reach, can evade state utility regulation. PUHCA is a significant inconvenience for a foreign buyer that is already in the electric utility business outside the US, but it is not an insurmountable barrier to entry. However, for other buyers, it is likely to be too much of an obstacle because PUHCA will require them to divest all of their non-utility businesses.

Who is subject to PUHCA?

The answer is anyone buying a US utility, but the pain hits under the statute only if the buyer cannot find a way to avoid status as a "registered holding company."

Any company that acquires 10% or more of the voting securities of an electric utility or a gas distribution utility (or of another holding company of such utilities) is automatically a "holding company." So is anyone buying a smaller voting interest but whom the US Securities and Exchange Commission concludes exercises management control over the utility. Once the label "holding company" attaches to a buyer, then the buyer must look for an exemption that will spare it from status as a "registered holding company." *Registered* holding companies are subject to extensive regulation by the SEC.

Since it is ownership of voting securities that triggers registered holding company status, a buyer might acquire non-voting stock or other types of non-voting ownership interests, such as passive limited partnership or non-managing member interests in a limited liability company.

Acquiring significant financial interests while limiting voting interests to less than 10% has become the standard way for US buyers to acquire utilities while avoiding PUHCA. The norm is to find a company that is willing to be subject to PUHCA to hold the voting securities, which can be common stock, a general partner interest or a managing member interest in a limited liability company. Alternatively, an individual might be found to play this role. An individual is presumed not to be a holding company. Several recent acquisitions of US utilities have been structured with an individual as the general partner of a limited partnership that indirectly owns the utility, while institutional investors avoid PUHCA regulation by participating as limited partners.

If the buyer cannot avoid status as a *registered* holding company, then it will be limited to owning one primary "integrated public utility system" in the United States, and the buyer will have to divest itself of other non-utility and non-utility-related businesses.

Unfortunately, none of the exemptions from registered holding company status is available to a / continued page 22

IN OTHER NEWS

contract the company signed around the same time.

The IRS action is described in a "technical advice memorandum," or ruling, that the agency released in March. The ruling is TAM 200512021.

Inability to deduct a cancellation payment makes terminating a contract more expensive. As a general rule, payments to get out of a contract can be deducted, but not if the payment is to modify the contract or replace it with another agreement. In the case under audit, a company entered into a merger agreement to be sold to a suitor, but later changed its mind after receiving a better offer from another suitor. It paid to terminate the original merger agreement and signed a new agreement to be bought by the new suitor. The IRS said the termination payment could not be deducted as it was a cost of the new agreement.

HYDROGEN PRODUCERS could get a tax break in North Dakota.

The state House of Representatives voted in February to exempt sales of hydrogen as well as equipment purchased to produce, store or transport hydrogen from sales and use taxes. The exemption would remain in place from July 1, 2005 through June 30, 2010. The measure passed the state Senate on March 23, but there remain some differences in language to work out.

ETHANOL incentives are costing Nebraska more than it expected.

The state enacted a tax credit of 18¢ a gallon in 2001 for producing ethanol at new plants that were put into service after September 2001 and that received state and federal approvals by June 30, 2004. The state expected that only two plants would qualify. Instead, 11 claim to have received the necessary approvals by the deadline. The tax credit is a nonrefundable, transferable tax credit that can be used to offset excise taxes on motor vehicle fuels. / continued page 23

Utility Acquisitions

continued from page 21

foreign buyer. Foreign buyers of US utilities cannot avoid becoming registered holding companies.

Therefore, as long as PUHCA remains on the statute books, the only potential foreign buyers of US utilities are foreign companies that are already exclusively in the utility business or are willing to divest their non-utility businesses. (Congress is debating whether to repeal PUHCA.) And any foreign buyer who buys more than one utility can only do so if the two are part of an "integrated public utility system."

An integrated system means the generation, transmission or distribution facilities must be physically connected and operated as a single integrated and coordinated system. In practice, this means a buyer cannot own more than one electric utility in the United States unless the utilities are confined to a single area or region and they coordinate their activities so as to function as a single interconnected system. If a buyer owns more than one US utility, then the utilities must be physically interconnected; however, interconnection may be achieved by reserving a firm transmission path between two utilities. Two utilities are considered physically interconnected if they are members of the same "tightly integrated" power pool, independent system operator (ISO) or regional transmission organization (RTO), such as PJM or ISO New England.

The SEC has applied the limitation of a "single area or region" liberally, permitting, in the most extreme case, American Electric Power, which operates in the Midwest, to acquire Central and South West Corporation, which operated in Texas, Oklahoma and Louisiana. Nevertheless, the SEC will not permit an east coast utility to acquire a west coast utility, and it is clear that PUHCA continues to prevent the development of "super-utilities" that, absent PUHCA, could take advantage of management and other scale economies by owning utilities throughout the US.

A 1935 law called PUHCA requires overseas buyers acquiring US utilities to shed their non-utility businesses.

EWGs and FUCOs

Historically, the SEC interpreted the "single integrated system" standard as applying to a US utility seeking to acquire a foreign utility, thus making it impossible for US utilities to acquire utilities in other countries unless the acquired utility was located in Canada or Mexico and could integrate its operations with those of the US utility. The result was that US utilities could not bid into the wave of utility privatizations abroad.

However, Congress amended PUHCA in 1992 to open the door to US ownership of foreign utilities — and vice versa.

First, the 1992 amendments created something called an "exempt wholesale generator," or "EWG." An EWG is a company that owns or operates a power plant used only for wholesale sales and that does not engage in any other activities. EWGs are not considered utilities for purposes of PUHCA. Thus, a buyer, irrespective of whether it is a US or a foreign buyer, is free to own EWGs without becoming a holding company. During the 1990's, many US utilities divested their generating facilities; the EWG exemption opened the door to foreign buyers that wanted to amass portfolios of generating assets in the United States.

A second exemption in the 1992 amendments proved helpful in an unforeseen way. Congress created another category of company under PUHCA called a "foreign utility company," or "FUCO." A FUCO is a company that owns or operates electric generation, transmission or distribution, or retail gas distribution facilities, and operates exclusively outside of the United States. FUCOs and their owners are exempted from PUHCA regulation. A FUCO, like an EWG, is not considered a utility under PUHCA, so that a company may own as many FUCOs as it wants without becoming a holding company. This opened the door for US utilities to make acquisitions overseas without subjecting themselves to regulation under PUHCA.

Although the 1992 amendments creating FUCOs were intended to assist US companies acquire utilities outside the United States, the legislation also works in reverse, enabling foreign utilities to claim FUCO status for their non-US utility operations and then acquiring a US utility company. Because the foreign buyer would own a US utility, the buyer would still become a holding company under PUHCA. However, it could own utilities outside the United States without having to show that they are part of a single integrated system with the US utility.

The "Two Bite" Rule

For foreign buyers who acquire interests in two or more US utilities, the single integrated system standard is enforced by a requirement in section 9(a)(2) of PUHCA known as the "two-bite rule." This provision requires a buyer to get SEC approval for any acquisition that would give it more than a 5% voting interest in more than one utility. No approval is required for the first utility acquisition (the "first bite").

The SEC may only approve the acquisition of a second or additional utility if the combined utilities will form an integrated system. A buyer is permitted to acquire or retain a "secondary" gas or electric utility system that is not integrated with the others it is acquiring if the secondary system would incur substantial losses if it were operated as a standalone company. Historically, a holding company could have either electric or gas utility subsidiaries, but not both. However, in recent years, the SEC has permitted holding companies that own electric utilities to acquire gas utilities as a secondary system, although this has generally been limited, in the case of electric utility holding companies, to acquisitions of combined electric and gas utilities or neighboring small gas companies.

In addition to barring a buyer from owning more than one utility unless the utilities are in a single area or region, PUHCA requires a foreign buyer to be involved only in the utility business or in related businesses. While the SEC has been expansive in its rulings on the types of businesses that qualify as appropriately related to the utility business, it has not and could not, under PUHCA permit, for example, an automobile manufacturer or a software / continued page 24

IN OTHER NEWS

In 2004, the state raised more funding for the program by increasing excise taxes on corn and sorghum, reducing refunds to people who put gasoline on which highway taxes were paid to off-highway use, and diverting money from a fund for cleaning up leaks from underground petroleum storage tanks. The additional funding is enough to cover the incentives for four plants. The state tax department estimates that there will be a funding gap of $200 million if all 11 plants operate at full capacity.

WYOMING properly charged severance taxes on coal-bed methane.

Minerals like gas from coal seams are taxed after they are "severed" from the ground. The tax is 6% of market value. The market value is determined at the point where the production process has been completed. The producer cannot deduct any expenses from the market value that are incurred before that point in the production process. However, expenses downstream from that point can be deducted.

The state Supreme Court said in March that coal-bed methane should be valued at a point just shy of when the gas goes into a triethylene glycol dehydrator, or TEGD machine. The Wyoming statute says the production process for gas is complete "after extracting from the well, gathering, separating, injecting, and any other activity which occurs before the outlet of the initial dehydrator." The gas producer in the case argued that the gas should be valued at a point farther upstream.

The case is Williams Production RMT Co. v. Department of Revenue. *The Supreme Court released its decision on March 2.*

GERMAN Chancellor Gerhard Schroeder proposed reducing the corporate tax rate from 25% to 19% in a speech in parliament on March 17. / continued page 25

Utility Acquisitions

continued from page 23

company to acquire a US utility. As E.ON found when it acquired Powergen, if a company engaged in non-utility businesses becomes a registered holding company by acquiring a US utility, then the SEC will require the holding company to divest its non-utility businesses.

Financing Hassles

Foreign buyers of US utilities should take note: any registered holding company — which a foreign buyer would automatically become — must get SEC approval before issuing any equity or debt securities (including guarantees). This approval requirement extends all the way up the ownership chain. Thus, if a foreign buyer forms a US holding company to acquire a US utility, not only would that US holding company need SEC approval for its equity and debt offerings, but so would the parent company outside the United States.

PUHCA requires that a security issued by a registered holding company or its subsidiaries be reasonably adapted to the earning power of the issuing company and to the capital structure of the holding company. Also, a registered holding company may not borrow or receive any extension of credit or indemnity from any of its utility subsidiaries. The SEC generally requires that a common stock equity ratio of 30% or higher be maintained for the utility company subsidiaries.

The SEC also regulates the sale of goods and services by affiliates to regulated utilities, generally requiring that goods and services be priced at "cost" so as to prevent artificial increases in the "cost-of-service" that the utility can pass through to its customers. The cost of services, sales and construction contracts between companies in the same holding company system must be equitably allocated among the holding company subsidiary companies.

PUHCA also specifically requires that a holding company must obtain SEC approval for the issuance of securities to finance the acquisition of FUCOs. There are also special rules on financing for acquiring EWGs.

The SEC has adopted Rule 53, a "safe harbor" rule for investments in FUCOs and EWGs, that provides the issuance of securities by a registered holding company — in other words, by any foreign buyer — to acquire EWGs is automatically approved if the aggregate investment does not exceed 50% of the holding company's consolidated retained earnings. The holding company must keep separate books and records for its FUCOs and EWGs in accordance with GAAP. To fall under the Rule 53 safe harbor, the holding company may not be the subject of bankruptcy proceedings, and its consolidated retained earnings may not have experienced significant reductions in recent years. The company also cannot have experienced operating losses related to its investments in FUCOs and EWGs.

Practical Experience

When Scottish Power purchased PacifiCorp, it acquired only one US utility and, thus, the acquisition did not require prior SEC approval under the two-bite rule.

Scottish Power became a registered holding company with the acquisition. That means it must limit its business activities to the utility and utility-related business, and it must comply with the provisions of PUHCA governing affiliate activities and the issuance of securities.

In its SEC filing, Scottish Power committed to maintaining its and PacifiCorp's credit ratings at an investment grade level and to maintain the capitalization of PacifiCorp at a 30% equity or higher level. Scottish Power already had investments in FUCOs and EWGs of approximately $3.2 billion, and it sought authority to finance up to $4.8 billion in such investments, which represented 148% of its consolidated retained earnings. PacifiCorp claimed FUCO status for its UK utility operations, thus rendering them "non-utilities" under PUHCA. Scottish Power committed to complying with the PUHCA requirement that services that its affiliates provide to PacifiCorp will be priced "at cost" and would be subject to review by all affected state regulatory commissions. The SEC approved the PacifiCorp acquisition on that basis.

In contrast to the PacifiCorp case, the New England Electric System acquisition by the National Grid involved the indirect acquisition of more than two US utilities and, therefore, required prior SEC approval under section 9(a)(2) of PUHCA. In its order approving the transaction, the SEC found that National Grid's utility operations in England and Wales, as well as its transmission businesses in Argentina and Zambia, qualified for FUCO status and therefore were not utilities for purposes of PUHCA. Since the only utilities for PUHCA purposes were the existing US NEES utility subsidiaries, which the SEC had previously found to satisfy the integration standard, the SEC approved the acquisition. Like Scottish Power, National Grid became a registered holding company when it completed the acquisition.

In considering National Grid's application, the SEC focused on whether National Grid's acquisition of NEES would impede state regulation of the NEES utilities. Helpfully, each of the state commissions involved advised the SEC that it had adequate authority and resources to protect customers of the NEES system. The SEC found that the National Grid had an investment in utility operations outside the United States of $3.5 billion, which represented approximately 202% of the pro forma consolidated retained earnings of NEES and National Grid. National Grid sought approval to invest an additional $874 million in EWGs and FUCOs, for an aggregate investment of 252% of consolidated retained earnings. National Grid committed to insulating the NEES utility subsidiaries from its investments in EWGs and FUCOs and agreed that none of the NEES utility subsidiaries would extend its credit or pledge its assets to any EWG or FUCO in which National Grid held an interest.

Because the acquisition of NEES required prior SEC approval, the SEC had to make certain PUHCA findings. It had to confirm that the consideration paid for the acquisition was not unreasonable, the capital structure of the merged company would not be unduly complicated or detrimental to the interest of investors or consumers, the corporate structure would not be unduly complicated or inequitably distribute voting power among security holders, and the transaction would result in economies and efficiencies. Like Scottish Power, National Grid committed to maintaining its long-term debt rating at an investment grade level. It also committed to maintaining a 35% equity ratio for NEES and its utility subsidiaries on a consolidated basis and to achieving a 30% equity ratio for National Grid.

Three years later, the SEC approved National Grid's acquisition of Niagara Mohawk. Niagara Mohawk is a member of a different regional transmission system (the New York ISO) than NEES (ISO New England). However, the transmission systems connect through a 230 kV intertie. The SEC found that the two ISOs engage in coordinated activities so that they function as a single market. Thus, Niagara Mohawk and NEES satisfied the integration standard.

PowerGen's acquisition of LG&E Energy also required prior approval by the SEC under section 9(a)(2) of PUHCA because the acquisition would make PowerGen the indirect owner of two utilities, Kentucky Utilities and LG&E.

PowerGen's non-US utility operations / *continued page 26*

IN OTHER NEWS

POLAND will reduce its rates for valued added tax and corporate and individual income tax to 18% in 2008, the finance ministry said in March. The value added tax rate is currently 22% on most items other than food, and income tax rates are 19% for corporations and up to 40% for individuals.

UKRAINE began collecting a 20% value added tax on oil imports on March 1.

INDIA will cut its corporate income tax rate.

The rate is currently 35%. The finance minister said in his budget message on February 28 that the rate would be reduced to 30%, but surcharges will increase from 2.5% to 10%, leaving the effective corporate rate at 33%. The changes are expected to be in effect from April 1. These are the rates for domestic corporations. Foreign corporations doing business in India will remain subject to income tax at a 40% rate.

In other news, the Authority for Advance Rulings said that a 20% withholding tax had to be collected on payments that an Indian subsidiary made to its US parent to pay for services the parent performed for the subsidiary outside India. The parent charged for the services at cost. Indian counsel advised that the parent could not opt instead to be taxed in India on a net basis and deduct its costs, which would have left it with no taxable income. The case is *Timken India Limited*. The rulings authority published its ruling on January 25.

BRAZIL bowed to pressure and withdrew a tax measure on April 4 that would have subjected foreign parent companies to tax on exchange rate gains in the value of shares in Brazilian subsidiaries.

The government said it would repackage the proposal. Any tax in the future is expected to be collected only when shares are sold.

The government has / *continued page 27*

Utility Acquisitions

continued from page 25

qualified for FUCO status. The application stated that the consolidated equity for PowerGen, following the acquisition, would be 29.2% of total capitalization. PowerGen committed that the common stock equity of LG&E and Kentucky Utilities would not fall below 35% of total capitalization. The combined LG&E Energy Group and PowerGen investment in EWGs and FUCOs was approximately $1.2 billion, representing 61% of PowerGen's consolidated retained earnings. PowerGen sought authority to finance investments in EWGs and FUCOs up to $1.9 billion, which represented 100% of the consolidated retained earnings of PowerGen. The SEC authorized the acquisition and the requested financing authority.

E.ON acquired PowerGen one year later. E.ON had to satisfy the PUHCA requirement limiting the activities of a registered holding company — which E.ON would become with the acquisition — to the utility and utility-related businesses. E.ON proposed to divest its chemical, real estate, oil, real estate and distribution/logistics operations. Consistent with its longstanding policies to avoid "fire sales" of divested companies, the SEC provided that these companies could be retained for periods of three to five years.

E.ON's existing investment in FUCOs, comprised of its utility operations in Germany, was $3.8 billion, and the combined LG&E Energy and PowerGen investment in EWGs and FUCOs was another $1.1 billion, representing 47% of the pro forma consolidated retained earnings of E.ON, PowerGen and LG&E Energy, which is above the Rule 53 safe harbor. The SEC observed that although E.ON's proposed investment in EWGs and FUCOs significantly exceeded the normal percentages for US registered holding companies, the US companies have significantly more assets invested in the US utility business, while E.ON's foreign operations are significant and its proposed FUCO investment is commensurately larger. Further, E.ON's debt-to-capitalization and interest-coverage ratios were shown to be within the ranges for US utility companies, and E.ON committed to maintaining its equity ratio at 30% or above and to maintaining its senior unsecured long-term debt rating at an investment grade level.

The lesson from these SEC reviews of the Scottish Power, National Grid, PowerGen and E.ON transactions is that PUHCA is not an insurmountable obstacle to foreign acquisitions US utilities, provided that the buyer limits its business to utilities and related businesses. Furthermore, the SEC is willing to allow significant time — up to five years — for a company to divest its non-utility businesses. Since PUHCA repeal is likely to be included in any US energy legislation in the next three years, a non-US company with unrelated businesses might take the risk that prior to the deadline for divestiture, PUHCA, and the requirement to divest, will have been repealed.

Federal Power Act

Another critical regulatory approval for a foreign buyer of a US utility is authorization by the Federal Energy Regulatory Commission under section 203 of the Federal Power Act. This requirement is not unique to foreign acquisitions of US utilities; *any* acquisition of an integrated electric utility, a generating company or a transmission company, whether accomplished through a stock purchase or an asset purchase, requires prior authorization by the FERC.

How long does FERC approval take?

Historically, one of the most vexing aspects of FERC's approval process was the length of time it took for the FERC to rule on an application. FERC has said that it can issue an initial order for most acquisitions within 150 days (five months) of receiving a completed application. FERC's ability to rule promptly on an application depends on the extent to which other parties oppose the proposed transaction. Once an application is filed, persons with an interest in the proposed transaction have the right to file comments either supporting or opposing the transaction. State public utility commissions have a right to intervene and frequently participate in merger proceedings before the agency.

FERC must approve a proposed acquisition if it finds the acquisition "will be consistent with the public interest." In making its public interest determination, FERC generally considers three factors: the effect of the transaction on competition, the effect of the transaction on rates, and the effect of the transaction on regulation. FERC also has the authority to attach conditions to its approval of a transaction to ensure that the transaction is consistent with the public interest.

FERC's objective in analyzing the effect of a proposed acquisition on competition is to determine whether the acquisition will lead to higher prices or reduced output in electricity markets. FERC also looks at the effect of the transaction on electricity rates. It expects applicants to try to resolve ratepayer protection issues with customers prior to filing an application. It looks at ratepayer protection mechanisms proposed by applicants for wholesale sales and transmission customers, such as "hold harmless" and "open season" provisions, rate reductions and moratoria, or a combination of such mechanisms.

The lesson that foreign buyers may take from the experiences of Scottish Power, National Grid, PowerGen and E.ON before FERC is that the first acquisition of a US electric utility will not face difficulties. However, any subsequent acquisitions may well raise competitive issues requiring considerably more scrutiny.

For example, in 2001, FERC authorized National Grid to acquire Niagara Mohawk Holdings, Inc., an exempted utility holding company under PUHCA that owns Niagara Mohawk Power Corporation, a combination gas and electric utility in upstate New York. Because National Grid already owned the NEES utilities by then, it had to persuade FERC that buying another US utility would not hamper competition in the relevant markets. FERC found that the proposed merger raised no competitive concerns. The key was that Niagara Mohawk lacked operational control over generation and, consequently, could not withhold resources to drive up market prices.

Other Federal Approvals

A Hart-Scott-Rodino notice must be filed with the US Department of Justice and the Federal Trade Commission, and the parties must wait 30 days after filing, before most acquisitions can close. Both parties to the transaction must file. The waiting period might be longer if the government asks for more information, called a "second request." On the other hand, the government also consents in some cases to cut the waiting period short.

Most acquisitions of US utilities will require Hart-Scott-Rodino filings. The government reviews the information in the filing to make sure the transaction will not lead to too much concentration of economic power.

If the utility being acquired owns or operates a nuclear power plant, then prior approval will be required under the Atomic Energy Act from the Nuclear Regulatory Commission. Such approval is unlikely unless the buyer can show that the board of directors of the US company owning or operating the nuclear plant has only US citizens as members. */ continued page 28*

IN OTHER NEWS

been attempting since 2002 to collect both income taxes and a social contribution tax on net profits — called a CSLL tax — from foreign parent companies on the appreciation in share value in their Brazilian subsidiaries caused by fluctuations in exchange rates. The US dollar appreciated 8.5% against the Brazilian *real* from January to June last year, but lost 7% in value measured over the entire year. The government based its past collection efforts on a directive that the Brazilian tax department issued in 2002. Most companies have been able to avoid payment because of court decisions that such taxes must be based on a law rather than a tax department directive.

The government moved at the end of December 2004 to provide a proper legal basis by imposing the taxes through a decree, number 232, that appeared in a special edition of the official gazette on December 30, but imposition of the taxes was delayed until April 2005 for CSLL tax and until January 2006 for income taxes.

NATIVE AMERICAN lands that an Indian tribe acquires on the open market remain subject to local property taxes, the US Supreme Court said in late March.

Indian tribes are treated as sovereign governments for many purposes under US law. State and local governments cannot usually make a tribe pay property taxes on its lands.

However, this case was different. The Oneida tribe originally controlled six million acres of land in upstate New York, but signed a treaty with New York in 1788 ceding all but 300,000 acres and, by 1838, when the tribe was forcibly moved west to Kansas, it had only 5,000 acres remaining. Members of the tribe had sold the rest.

In 1997 and 1998, the tribe repurchased some of the original 300,000 acres. The land in question had not been in Oneida hands since 1805. The local town of Sherrill, New York insisted that the tribe had */ continued page 29*

Utility Acquisitions

continued from page 27

Owners of nuclear power plants must obtain an operating license from the NRC and, by law, the NRC must approve any transfer (direct or indirect) of a nuclear power plant license. Foreign ownership of US nuclear facilities is prohibited. Section 103 of the Atomic Energy Act prohibits the transfer of a license to own or operate a nuclear plant to an entity that is owned, controlled or dominated by an "alien, foreign corporation or foreign government," and the NRC must reject any license transfer that would "be inimical to the common defense and security or the health and safety of the public."

The New England Electric System owns interests in two nuclear power plants: Seabrook and Millstone 3. The NRC approved the acquisition of NEES by National Grid and the concomitant transfer of minority ownership interests in the NRC licenses to foreign hands. Another New England utility, Northeast Utilities, intervened during the NRC review proceeding and raised the question whether the acquisition would result in impermissible foreign ownership of Seabrook and Millstone 3. The NRC established a hearing schedule that would have delayed the closing. In order to avoid the hearing, NEES agreed that all of the officers and board members of New England Power — the NEES subsidiary with the interest in the two power plants — would be US citizens. In return, Northeast Utilities agreed to withdraw its request for a hearing.

Exon-Florio

Section 27 of the Defense Production Act of 1950 — called "Exon-Florio" — gives the president authority to suspend or prohibit foreign acquisitions, mergers or takeovers of US companies upon a finding that the foreign interest might take action that threatens national security and there is no other way to protect national security than to block the merger. Authority to review foreign investment transactions has been delegated to an interagency group, the Committee on Foreign Investment in the United States. The committee is chaired by the US Treasury secretary and has representatives from 11 federal agencies.

Review under Exon-Florio is triggered by either a voluntary filing by a party to the transaction, or by notice of a transaction from an agency member on the committee. The committee can review a transaction even *after* it has been completed. The president is authorized to "direct the Attorney General to seek appropriate relief, including divestment relief, in the district courts of the United States." In other words, the parties might be ordered to unwind a transaction. Subjecting the transaction to an Exon-Florio review before closing insulates it from this risk.

The National Grid told the New Hampshire regulatory commission in 1999 that its acquisition of the New England Electric System had received clearance from the Exon-Florio committee and that the committee concluded that the proposed merger raised "no issues of national security sufficient to warrant an investigation."

State Regulatory Approvals

A foreign buyer purchasing a US utility must usually also get approval from the state regulatory commission in each state where the target utility conducts operations. Not all states approve mergers, but most do.

The criteria to be applied in reviewing a transaction differ from state to state. In addition to looking at the effect of the acquisition on retail rates and competition, state public utility commissions also consider the effect of an acquisition on a variety of local issues such as employment, the environment and low-income consumers. State public utility commission review of proposed acquisitions frequently involves evidentiary hearings. As is the case in proceedings at the federal level, interested parties, including state consumer advocates and other interest groups, may intervene in state regulatory proceedings. As a consequence, obtaining state approval frequently requires that applicants enter into settlements with these groups head off opposition to the transaction and avoid prolonged proceedings.

Scottish Power had to get approval or waivers from six state public utility commissions before buying PacifiCorp in 1999. The public utility commissions in Idaho, Oregon, Utah, Washington and Wyoming approved the merger, subject to numerous conditions and commitments. The California Public Utilities Commission said the transaction did not need regulatory approval, but made its exemption subject to several conditions.

California exempted the transaction because PacifiCorp had only 41,273 retail customers in California. It required Scottish Power to get California approval for any future sale of the distribution lines in California, to keep separate books of account for PacifiCorp from the Scottish parent, and to make the PacifiCorp books, records and employees available in the future to California regulators.

The Idaho Public Utilities Commission made its approval of the merger subject to conditions "considerable in quantity and scope." It imposed some 46 separate conditions on the merged company. These conditions included commitments that rates would not increase as a result of the merger, PacifiCorp would not seek a general rate increase for its Idaho service territory prior to January 1, 2002, and PacifiCorp would provide merger related cost-of-service reductions totaling $6.4 million through an annual "merger credit" over four years.

In order to get approval for the transaction in Oregon, PacifiCorp agreed to fund conservation programs at a level of $6 million a year for a period of three years, use shareholder funds for low-income initiatives in Oregon at a level of $400,000 a year over what was spent on similar programs in 1998, remove a $1,000 funding cap from its low-income weatherization program tariff, provide a "merger credit" of up to $51 million over a four-year period beginning in 2001, develop or acquire an additional 50 megawatts of system-wide renewable resources, and implement a "green resource tariff" that allows customers to purchase energy from renewable sources.

The Washington Utilities and Transmission Commission also imposed conditions. Among other things, PacifiCorp agreed to provide cost-of-service reductions of $12 million over four years through an annual "merger credit" and exclude from all future ratemaking treatment in Washington all transaction costs associated with the merger and the premium paid by Scottish Power for PacifiCorp. Washington also required Scottish Power and PacifiCorp to reflect in Washington retail rates savings from lower costs of capital and to bear the cost of any increased cost of capital of PacifiCorp electric operations directly resulting from the merger. The company also agreed to develop an additional 50 megawatts of wind, solar or geothermal resources at an estimated cost of approximately $60 million within five years, to make available $300,000 a year out of shareholder funds for a bill payment assistance and energy efficiency program, and to maintain the PacifiCorp Washington low income weatherization annual budget at least at the 1999 level of $560,000 for a three-year period following the merger. */ continued page 30*

IN OTHER NEWS

to pay property taxes on the land.

The US Supreme Court agreed, saying that the amount of time that had passed with the land in private hands "precludes the Tribe from rekindling embers of sovereignty that long ago grew cold."

The problem was the tribe bought the land on its own. The court said that if the US Interior Department had acquired the land in trust for the tribe, then it would have been exempted from taxes.

Congress provided an explicit exemption from state and local taxation for lands that the US government holds for native Americans in trust. The case is Sherrill, New York v. Oneida Indian Nation of New York. *The court released its decision on March 29.*

STAPLED STOCK structures can be unraveled without a tax cost.

The IRS told one US company that was unraveling such a structure that its plan would not trigger a US income tax. The IRS made the comments in a private letter ruling that the agency made public in late February. The ruling is PLR 200507009.

The United States taxes American companies on worldwide income. It tries to prevent double taxation of income from foreign sources by allowing a credit, in theory, for any taxes that had to be paid to another country, but the foreign tax credit rules are so full of fine print that few American companies are able to claim such credits in practice.

One problem is the IRS treats a US company's borrowing costs at home — even for purely domestic purposes — as a cost partly of its foreign operations. A portion of this domestic interest expense is allocated to foreign operations in the same ratio as the company's assets are deployed at home and abroad. The effect is that a company is not viewed as having earned much money abroad after this allocated interest expense is subtracted. Smaller foreign */ continued page 31*

Utility Acquisitions

continued from page 29

Wyoming imposed 36 negotiated conditions. They require prior notice to the utility commission of each debt or equity issuance by either Scottish Power or PacifiCorp of more than $75 million with a term greater than one year. Wyoming also required the companies to hold any diversified holdings and investments of Scottish Power or PacifiCorp in separate companies from PacifiCorp, with "ring fence" provisions for each diversified activity to prevent any financial problems from infecting the utility and to notify Wyoming promptly of any acquisition of a business representing 5% or more of the market capitalization of Scottish Power.

Utah imposed conditions, but many of them overlapped with the conditions imposed by the other states.

Other State Reviews

National Grid received relatively straightforward approvals at the state level for its acquisition of the New England Electric System. It got approvals in 1999 from utility commissions in Connecticut, New Hampshire and Vermont.

The Connecticut Department of Public Utility Control determined that it had jurisdiction over the merger by virtue of New England Power's minority ownership interest in the Millstone Unit No. 3, located in Connecticut. However, since the company had no ratepayers in Connecticut — just an interest in a power plant in the state — approval was easy. Connecticut decided the merger would not adversely affect electric service in Connecticut or affect Connecticut ratepayers.

The Vermont regulators concluded that the merger would promote the public good in Vermont, but reiterated a long-standing policy that above-book acquisition costs cannot be included in the rates charged Vermont consumers.

The New Hampshire Public Utilities Commission held a hearing about the merger. It approved the merger, applying its "no net harm" test that requires a proposed transaction be approved if the public interest is not adversely affected. It imposed minor conditions.

PowerGen had to get approval for its acquisition of LG&E Energy from state regulators in Kentucky and Virginia. Kentucky imposed numerous conditions. They included a requirement to keep the current officers in their current positions unless directed otherwise by the board of directors, keep the transaction costs and acquisition premium out of rates, continue to operate through regional offices with local service personnel and field crews, keep the headquarters of LG&E Energy and its utilities in Kentucky for a period of at least 10 years following the merger, and maintain a seat on the PowerGen board for a US citizen who lives in the LG&E service territory.

PowerGen promised not to claim in the future that Kentucky lacks the ability to deny rate recoveries for the cost of goods or services purchased from affiliates or to review transfer pricing on grounds that the state is "preempted" by US or UK government authority in this area. PowerGen also promised to maintain cordial relationships with the unions representing employees, remain neutral with respect to an individual's right to choose whether to join a trade union, continue to recognize the unions that currently have collective bargaining agreements with LG&E, and honor those agreements.

Virginia required PowerGen to commit to $2 million a year on average in investments over five years to enhance transmission, distribution and the general condition of the electric system in the service territory of Old Dominion Power, a subsidiary of LG&E Energy.

PowerGen received the state approvals for its acquisition in 2000. The next year, it had to go back to the commissions for approval of the E.ON acquisition of PowerGen. Virginia approved the E.ON takeover with 12 conditions. Kentucky approved it with 52 conditions. They included a promise that all corporate officers of LG&E and Kentucky Utilities would reside in Kentucky.

Conclusions

Obtaining the approval of US regulators has not proved a significant obstacle to acquisitions of US electric utilities by foreign buyers. At the federal level, the most complicated transactions are those where the buyer has other businesses besides utilities or where the target utility has a license to own or operate a nuclear power plant. In the first situation, the SEC will require divestiture of the non-utility and non-utility related businesses. In the second situation, the merged company may be required to commit that the board of directors of the US utility will consist entirely of US citizens.

However, state-level review presents a foreign buyer with the prospect of having to enter into agreements to address numerous local issues as the price of securing state commission approval.

Ethanol: Are Fears of Overcapacity Overblown?

by Todd Alexander, in Houston

The ethanol industry managed to grow profitably and quietly for half a decade while, for the most part, avoiding the attention of large institutional investors and money-center banks. That changed in 2004. Institutional investors and money-center banks moved in, attracted by record-high ethanol prices coupled with historically-low corn prices and the potential for extraordinary returns. The change was evidenced by the issuance of $160 million in bonds by Aventine Renewables, a $185 million B loan arranged by Credit Suisse First Boston for two projects sponsored by Whitney & Co., and by the attendance this year at the Renewable Fuels Association's national ethanol conference by several well-known institutional investors.

However, the continued growth and profitability of the industry have been called into question recently by some notable industry experts, including Edward Swinderman of Jim Jordan & Associates, LLP in a presentation at the national ethanol conference in February and in articles this year in *The Wall Street Journal* and *Project Finance* magazine and in reports on Bloomberg. The critics warn that production capacity is growing far more rapidly than demand. They also point to the unprecedented weakness in ethanol pricing, which started in February of this year when ethanol began trading at a significant discount to gasoline for the first time ever.

Although there is no denying that the critics have a point, the fundamental question for the investment community going forward is whether the growth in the industry's capacity should be cause for alarm.

There are several factors at work that could increase demand and several financing structures in use in the market that mitigate capacity risk. These two factors could alleviate many of the critics' concerns / continued page 32

IN OTHER NEWS

earnings mean fewer foreign tax credits. The calculations for companies that join together in filing a consolidated income tax return are done as if they were all one company. Most US power companies are in an "overall foreign loss" position, meaning that they have millions of dollars in allocated interest expense to burn off before they are viewed as having earned anything abroad.

Some US companies resort to self-help remedies. One such remedy was stapled stock. A US company might "staple" the shares of a foreign subsidiary to one of its US subsidiaries. This means that the shares of the two companies cannot be sold separately. It has the effect of subjecting the foreign subsidiary to US income taxes as if it were a standalone US company. The key word is standalone. Although the foreign subsidiary must pay US income taxes, it could calculate its own foreign tax credits unhindered by any allocated interest expense from its US affiliates.

The IRS said in Notice 2003-50 in July 2003 that it will require in the future that stapled foreign companies take into account allocated interest expense. This policy applies to foreign companies that were stapled to US companies after July 22, 2003. However, the IRS is also challenging *existing* stapled stock structures on audit. It warned in the 2003 notice that it will assert on audit that stock was not effectively stapled where there was nothing to prevent the US parent from breaking the staple at will.

The private letter ruling that the IRS released in late February involved a US group with a foreign subsidiary — FC1 — that it had stapled to one of its US subsidiaries. FC1 had, in turn, two other foreign subsidiaries — FC2 and FC3 — and it had recently reorganized them so that they were no longer brother-sister companies, but rather one was put under the other. Moving FC2 and FC3 around in this fashion could have triggered a "toll charge" in the US. The US collects a tax, or toll / continued page 33

Ethanol

continued from page 31

about overcapacity. In addition, the entry into the market during the past 12 to 18 months by participants with greater financial wherewithal will introduce for the first time the possibility of industry consolidation, which should also help rationalize production.

Is There Cause for Alarm?

Since 2000, fuel-grade ethanol use in the US has more than doubled while annual ethanol production has increased correspondingly from 1.63 to 3.41 billion gallons.

In 2005, fuel-grade ethanol demand is expected to approach an all-time high of four billion gallons, with ethanol being blended in more than 30% of all gasoline sold domestically.

This rapid growth can be traced to a great extent to the Clean Air Act, which requires the addition of oxygenates, such as ethanol, to gasoline and to the banning of methyl tertiary butyl ether, or "MTBE" — another oxygenated compound — in 14 states, including California and New York. To a lesser extent, it has also been driven by the use of ethanol as an octane enhancer and as a volume extender.

Ethanol is a useful octane enhancer because it has an octane rating of 113 while regular gasoline customarily has an octane rating of approximately 87. Ethanol is useful as a fuel extender because when blended with gasoline (usually in a 90:10 gasoline-ethanol blend), it increases the volume of fuel available at the retail level.

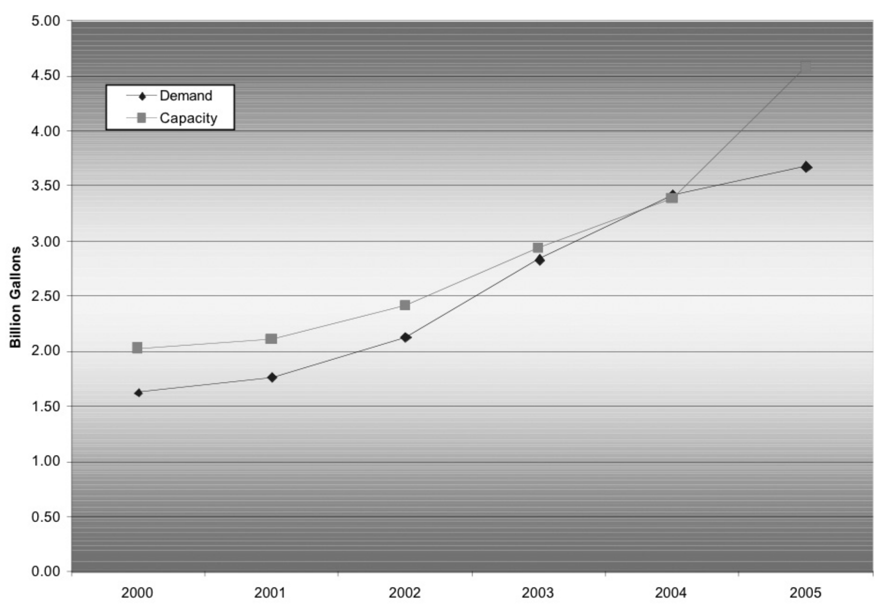
While demand for fuel-grade ethanol is expected to approach four billion gallons in 2005, domestic industry capacity at the end of 2005 is expected to exceed 4.4 billion gallons a year and five billion gallons a year by the end of 2006. Several major industry players have announced plans to move forward with the construction of new facilities in 2005 and 2006, including Morgan Stanley Capital Partners, Whitney & Co. and Fagen, Inc., and existing producers, such as Midwest Grain Processors, have announced plans to expand their current capacity.

Those are the bad facts. There are several promising developments at the same time.

First, Congress could adopt a renewable fuels standard sometime this year. Two bills that are in play in the House would require consumption of six billion gallons of renewable fuels, such as ethanol and biodiesel, a year by 2014, and require all gasoline sold in the United States to contain at least 10% ethanol by 2011. The Senate is also expected to debate whether to set a renewable fuels standard. One proposal in the Senate would require the use of four billion gallons of renewable fuels by 2006 and eight billion gallons by 2012, and another would require the use of six billion gallons of renewable fuels by 2012. Importantly, Congress could also ban the use of MTBE.

Second, there are several favorable developments at the state level that are expected to increase ethanol demand. For example, an MTBE ban has been enacted, but not yet taken effect, in another six states on top of the 14 states in which MTBE bans have already been implemented. These new markets for ethanol are Ohio, Kansas, Missouri, Kentucky, New Hampshire and Maine. In addition, Hawaii has recently implemented a rule requiring

US Ethanol Supply & Demand



Source: Jim Jordan & Associates, LLP

85% of its gasoline to contain at least 10% ethanol by April 2006, the governor of Minnesota proposed requiring the state's gasoline be blended with 20% ethanol rather than the 10% currently required by law, and the legislatures in Missouri, Wisconsin and Montana are all considering legislation that would require a 10% blend. Moreover, the Atlanta metro region may soon require approximately 250 million gallons of additional ethanol if the federal courts deny Georgia's bid to receive an exemption for the Atlanta metro area from the reformulated gasoline rules under the Clean Air Act.

Third, it is very likely that blenders will increase their ability to use ethanol as a fuel extender by retrofitting many of their distribution terminals in the Midwest and on the East Coast to accommodate additional ethanol deliveries and to allow for more blending and storage. Few blenders have taken these steps to date, but current prices provide an incentive to act. For instance, a blender today can purchase ethanol for less than $1.30 a gallon and blend it with gasoline that costs at least $1.50 a gallon. The blender is also entitled to a tax credit of 51¢ a gallon of ethanol used in blending. The large profits to be made from using ethanol as a fuel extender should lead to several million gallons of additional demand in 2006 and an even greater increase in demand thereafter, as refiners and other blenders modify their existing infrastructure to increase blending capacity and amend air permits to allow existing storage terminals to be converted for use as ethanol storage tanks.

Fourth, a sizeable share of the nation's ethanol is produced in older, smaller plants that do not benefit from recent technological improvements in the production process or from economies of scale. Ed Swinderman estimates that up to 15% of US production capacity has a marginal cost of more than $1.30 a gallon (assuming a price for corn of $2.10 a bushel and a fuel cost of $7.00 an mmBtu). If these estimates are correct, then the new ethanol plants under construction should displace existing capacity at these older plants rather than add to overcapacity.

Finally, the cross-border trade in ethanol should provide some relief to the industry. On the import side of the equation, it is estimated that the US imported 160 million gallons in 2004 from Brazil, Central America and the Caribbean basin. All of this imported ethanol was produced using sugar cane as the feedstock. These imports are not likely to be cost competitive with domes- */ continued page 34*

IN OTHER NEWS

charge, if it sees assets leaving the US tax net. Since FC1 was treated as an American company for US tax purposes due to the staple, this was a case where one of its assets was moving outside the reach of the US tax authorities. However, the company avoided a toll charge by entering into a "gain recognition agreement," or a promise to pay the toll charge with interest if FC2 failed to hold the shares in FC3 for at least five years. IRS regulations allow a toll charge to be avoided in certain situations by entering into such a gain recognition agreement.

Later, the group focused on undoing its stapled stock structure. It migrated FC1 to Delaware, thereby turning FC1 into a US corporation, and it dropped the staple.

The US parent asked the IRS whether the migration would blow the gain recognition agreement or, put differently, whether the fact that FC1 had turned into a US company meant it was no longer the same company so that a toll charge would be triggered. The IRS said it considers it still the same company.

SOUTH DAKOTA enacted two tax incentives to encourage power companies to build new plants in the state.

New power plants will be assessed for property tax purposes under a formula that arbitrarily values the plants at $500 a kilowatt. Thus, a plant with the capacity to produce 600 megawatts would be valued at $300 million. Property tax relief is also provided while the plant is under construction.

The other incentive is refunds of some of the sales and use taxes paid on the equipment that goes into the power plant. For plants costing between $60 million and $600 million, 75% of the sales and use taxes paid would be refunded at the end of construction. For plants that cost more, 90% of such taxes would be refunded.

The governor signed both bills on March 18. South Dakota is hoping to */ continued page 35*

Ethanol

continued from page 33

tic production in 2005 if sugar continues to trade in the neighborhood of 8.5¢ a pound. On the export side, US exports to Canada and Europe could increase by up to 100 million gallons in 2005 if US ethanol prices remain at current levels.

New Structures

Several new or improved financial structures are in use in the industry that mitigate exposure for owners and lenders to the risk of low ethanol prices, and they should make for a more stable industry than in past years.

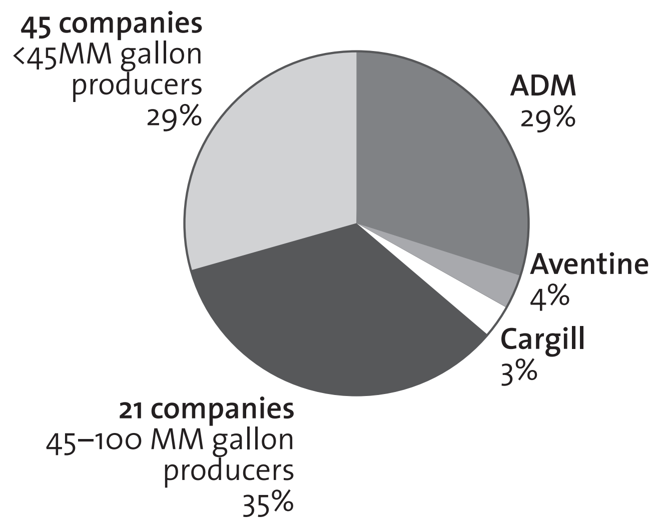
The newest financial instruments available to ethanol producers are the corn-based futures contracts, one of which began trading on the Chicago Board of Trade on March 23 and the other began trading on the Chicago Mercantile Exchange on March 29. Owners of corn-based ethanol plants will be able for the first time to use these futures contracts to hedge their exposure to the price volatility of ethanol. No one knows yet how liquid these contracts will become or how much interest there will be in the marketplace for trades more than six months forward.

Another way to mitigate price volatility is for the owners of an ethanol plant to share the risk of price movements with their major suppliers and marketers. For example, an owner can create a "collar" around ethanol prices by entering into corn supply and ethanol sales agreements. If structured properly, such collars should allow a project to operate profitably in any pricing environment. The tradeoff is that the equity may sacrifice a large portion of the project's upside potential in exchange for locking in a profit margin. If the sacrifice is too great, a project can also have its corn supplier and ethanol marketer agree to share a portion of its added costs or reduced revenues when prices move outside an agreed band. These types of partial hedges are available at a lower cost to the equity, and they preserve more of the upside earnings potential.

A third option is to arrange for a larger working capital facility. This gives the managers more flexibility to schedule purchases of feedstock and sales of ethanol on favorable terms by holding out until prices are most advantageous. Most lenders today recognize there is value in having an adequately-sized working capital facility since it can contribute to a more predictable cash flow in the long run.

A fourth option is to couple a cash sweep with an amortization schedule that permits the borrower to repay principal at low levels or in increasing amounts with a "bullet" at final maturity. These amortization schedules allow the borrower to prepay the loan during periods when market conditions are favorable while avoiding defaults when market conditions deteriorate. This structure was not commonly used in the market by plants financed prior to 2004, but is gradually becoming the preferred approach due to its inherent benefits where long-term, fixed-price contracts are not available and due to the higher returns it potentially offers to the equity.

Ethanol Producers



Consolidation

Regardless of whether ethanol demand increases commensurately with supply for the reasons discussed above or whether owners properly structure their contracts to mitigate their risks, the ethanol industry is likely to enter into an unprecedented period of consolidation as a result of the recent entrance of sponsors with greater financial backing and expertise. The process of consolidation should foster an environment in which production is rationalized and instances of long-term overcapacity are less likely occurrences.

Existing ethanol production is extremely fragmented because the industry has its origins as a means for domestic corn producers to hedge the price of corn against the price of ethanol. This meant most existing ethanol plants were designed to optimize a rural community's needs rather than to produce for a national ethanol market. Only one producer — Archer Daniels Midland Company — can claim today to have more than a 4% share of the market.

As with many maturing industries, this fragmented ownership structure appears to be changing. Several large agri-businesses and financial sponsors have plans either to build new plants or acquire existing ones with the aim of controlling at least 300 million gallons per year of production capacity. Several smaller plant owners who are inclined not to sell appear to have recognized that they will be too small to compete in the new marketplace and have made offers to purchase other small operations.

As the industry consolidates, the larger producers that remain will have several advantages that were not available to the fragmented industry.

The larger producers will be able to capitalize on economies of scale in all aspects of their operations, including with respect to grain procurement and scheduling and the marketing of ethanol and distiller's grains. These larger producers should be able to leverage their size into more favorable commodity prices and lower commissions. Second, the larger producers will be able to use arbitrage on a nationwide basis to ensure that they maximize their operating margins. Third, they will be able to attract and appropriately compensate a more talented class of management based on their higher revenues. Fourth, they will have access to lower-cost capital through their ties to the banking community and their ability to borrow on a portfolio basis. Fifth, many are likely to attempt to integrate their operations vertically to capture the full value of the ethanol manufacturing process at each point along the value chain. This will reduce the risk at the project level of potential disputes between the project and its various service providers and will ensure that the incentives of all parties involved in the procurement and marketing process are better aligned. Finally, many of the larger producers may be willing to infuse their operations with cash from their other businesses during lean periods, thereby creating a more stable investment climate and providing the petroleum industry and others who rely on ethanol with more certainty.

IN OTHER NEWS

set itself up as an exporter of electricity to other states.

Meanwhile, phone companies lost an effort to have a 4% gross receipts tax in South Dakota on cellular and other wireless telephone companies declared illegal. The state Supreme Court said in February that the ability of the state to levy such a tax was not "preempted" by federal law. The case is Dakota Systems, Inc. et al. v. South Dakota Department of Revenue.

MINOR MEMOS. German Gref, the Russian minister for economic development and trade, said he won a bottle of cognac by challenging two authors of the second half of the Russian tax code — the part that deals with business taxes — to interpret a chapter of the tax code that was chosen at random, and they gave "exactly opposite commentaries." Gref said this shows a lack of coherence in this part of the tax code and how badly it needs to be rewritten . . . . The US Tax Court said that the amount a real estate developer spent to persuade the city to change the zoning laws so that he could build two large office buildings in Los Angeles could not be added to his "tax basis" in the buildings and recovered through tax depreciation. It said the spending added value to the land. The cost of land is not depreciable. The case is *Maguire/Thomas Partners v. Commissioner.* The court released its decision on February 28 . . . . The IRS told an electric cooperative that in calculating its income for a year, it should take into account the actual amount the coop will pay to buy electricity from wholesale suppliers, even though it is 75 days after the year ends before the coop has the final figure on what it owes. The IRS said the amount is "knowable" when the tax year ended, even though the coop does not take time to calculate it. The coop pays its suppliers based on estimates and then does a reconciliation calculation within 75 days after the year ends. The IRS discussed this / *continued page 37*

Ethanol

continued from page 35

Outlook

Since 2000, the ethanol industry has both grown steadily and produced high returns on invested capital. This has brought both large institutional investors and money-center banks, on the one side, and more developers, on the other, into the market.

Although current production capacity appears to exceed demand, it remains to be seen whether this will hinder the growth of the industry in the medium term. There are several legislative initiatives at both the federal and state levels that would increase demand. A compelling economic case can be made that a new equilibrium in supply and demand will be achieved in part through increased use of ethanol as a fuel extender, the closing of older and smaller plants and cross-border trade. Moreover, the introduction of more sophisticated financial structures and the almost certain consolidation of the industry should help to promote stability and further rationalize production. ◎

Doomed to Invest in Russian Oil?

by Shane R. DeBeer, in Moscow

At a major oil and gas industry conference recently, Lukoil president Vagit Alekperov was asked about the prospects for foreign investment in Russia's petroleum sector. This question followed only five days after a public statement by Russian Natural Resources Minister Yuri Trutnev that auctions to develop certain major Russian oil, gas and mineral fields would only be open "to those companies in which not less than 51% of the share capital belongs to Russian participants."

No wonder then that Alekperov's response beginning with "[y]ou are doomed to invest in Russia" was greeted with appreciative laughter.

A very brief look at the recent legal history of foreign investment in the Russian oil and gas industry, as well as a look at a preliminary draft of a new law on underground resources, suggests that the conditions for such investment have not particularly worsened over the past decade. Meanwhile, the macroeconomic fundamentals suggest that, despite a flawed investment climate, international oil companies are indeed "doomed" to invest in the Russian petroleum sector, just as Russia is doomed to seek such foreign investment, at least in the medium term. Compared to other major oil-exporting nations that have shunned foreign investments in their petroleum industries, Russia has neither the historical imperative nor the geological luxury of going it alone.

Background

After the Soviet Union dissolved in 1991, international oil companies were keen to invest in Russia, figuring that Russia would welcome their capital and technology, and the oil companies were eager to add oil reserves to their balance sheets. Russia had significant potential to export more oil. Production peaked in 1988 and was falling due to lack of investment and declining domestic demand tied to the collapse of the Soviet economy.

While there had been no foreign investment in the Soviet petroleum industry, the Russian Federation had a variety of models to choose from. It could merely pay for foreign oilfield services and allow no foreign participation in the production itself (like Saudi Arabia or Mexico). It could license concessions (like Canada). There were various other forms of participation, including splitting the production with investors by means of production sharing agreements like those used in a variety of countries as disparate as Angola, Indonesia, Libya and other parts of the CIS.

A country's policy on a strategic resource like oil is rarely made on purely economic grounds, and specific historic factors are always at work. For example, both Saudi Arabia's and Mexico's oil industries were created from the nationalized assets of mostly American oil companies, in 1976 and 1938 respectively. Since then, both Saudi Arabia and Mexico have continued to develop their petroleum resources on their own, but in very different circumstances. Saudi Arabia's oil is relatively cheap and technologically simple to produce, much of it coming from the single enormous Ghawar oil field. Moreover the Saudis claim that production from this and similar fields could be easily increased if the market justified it. Mexico also produces the majority of its oil from one large field (Cantarell), but that field is offshore in the deep waters of the Gulf of Mexico, as are Mexico's more prospective undeveloped fields. There is a constitutional prohibition in Mexico on foreign investors having a participating interest in petroleum projects, although economics and geology might warrant otherwise. Saudi Arabia has a greater ability than Mexico to go it alone in the future. Saudi Arabia is also more heavily dependent on the petroleum sector.

In contrast, Russia's original great petroleum region in western Siberia was only discovered in Soviet times (excluding the Baku oil fields in what is now Azerbaijan, even though this was part of the Russian empire when the fields were discovered in the 19th century). If Russia's original petroleum region was developed under challenging climactic and geological conditions, then Russia's new prospective petroleum regions — in the Arctic, in eastern Siberia and offshore Sakhalin Island — are even more challenging.

In February 1992, as a transition from the Soviet command model, Russia adopted the current "underground resources law" that introduces a licensing regime. Under this law, the government owns all of the country's oil, gas and minerals, and licenses third parties (including state-owned Russian and foreign companies) to explore and produce them in return for payment of a fee to participate plus royalties, taxes and duties. The underground resources law does not prohibit foreign participation in tenders or auctions for licenses, but it contemplates that foreign investors may be excluded by other laws, such as the laws governing the maritime continental shelf or national security, or even local laws. Licenses can be transferred to related parties under limited conditions, but they cannot be sold or used as collateral to secure debt. By law, licenses are not property and are not protected, for example, from changes in the tax laws.

Russian domestic oil consumption continued to fall into the mid-1990s as did Russian oil exports. Some of the decline in exports was due to Russia's changing commercial relations with former socialist nations that had not paid for oil in convertible currency in Soviet times. Without a stable, transparent legal regime, it was argued, Russia would not be able to attract the investment needed to jump start production, much less to develop new prospects in remote and technically difficult areas, such as offshore Sakhalin Island. As a result, various experts, both Russian and foreign, joined with the oil companies in advocating that Russia adopt a new regime based on production sharing agreements.

A production sharing agreement — or "PSA" — is essentially an agreement between the govern- */ continued page 38*

IN OTHER NEWS

in a private letter ruling that it released in late March. The ruling is PLR 200510008 . . . . An Arizona appeals court said in late February that the starting point for valuing pipelines for property tax purposes is the original cost when the pipeline is first put into service — and not the amount a new buyer paid more recently for it. The difference meant a property tax valuation for an oil pipeline owned by a Kinder Morgan partnership of $121.8 million rather than $232.2 million. Pipelines and other utility property are "centrally" assessed by the state in Arizona, unlike other property that is valued by local property tax assessors. The statute providing for central assessment is particular about how valuations are supposed to be done. Kinder Morgan bought the pipeline in 1998 from the original developer, but it argued the property tax assessment should start with what the original developer paid to build it rather than the price Kinder Morgan paid. The appeals court agreed. The case is *SFPP, L.P. v. Arizona Department of Revenue.* The court released its decision on February 24. The court told the tax collector that if he has a problem with this result, he should complain to the legislature to fix the statute.

— contributed by Keith Martin, Jana Dimitrova and Neil Golden in Washington, and Brian Brick in New York.

Russian Oil

continued from page 37

ment and an investor under which the investor agrees to risk its money to explore and develop a prospective field, and if "commercial" (*i.e.*, enough) oil or gas is found, then the produced petroleum is shared between the government and the investor according to an agreed formula. Usually, a PSA provides that the first amounts produced (sometimes called "cost oil") are allocated to the investor to cover its costs. The balance, or "profit oil," is what is shared.

The biggest barrier to Russian oil exports is not production, but the lack of pipelines and port facilities needed to transport oil abroad.

While debate about a PSA law dragged on and Russian companies snapped up licenses, Russia eventually signed three *ad hoc* PSAs with international oil companies: the Sakhalin I project in June 1995, the Sakhalin II project in June 1994 (but which came into force after Sakhalin I) and the Kharyaga project in northeastern Siberia in December 1995. Not surprisingly, all of these PSAs concerned expensive and technically difficult projects outside the original western Siberian oil district. President Yeltsin signed the new PSA law in late December 1995, a few days after the Kharyaga PSA was signed and before any of them had come into force.

Far from accelerating the pace of foreign investment in the Russian oil sector, the new PSA law arguably slowed it, as oil companies complained that the new law was inconsistent with the tax code and lacked other provisions needed to secure the economics of PSA projects. The oil companies withheld investment in the hope that the PSA law would be amended. The PSAs for Sakhalin I and II (which came into force in mid-1996) and Kharyaga (which came into force in early 1999) were negotiated directly with the Russian government before the new law was written, and were thus "grandfathered," or protected from later changes in taxation and other economic parameter.

Other projects did not have the option of copying the PSAs for these three projects since their agreements had to be governed by the new law. Calls to revise the new law were countered by opponents, including domestic Russian majors such as Yukos, that lobbied against the PSA law on the ground that it unfairly favored foreign investors over Russian oil producers. Gradually the opponents prevailed. The PSA law was amended in 2003 to limit PSAs to a short list of fields approved by the Russian parliament, or Duma — and only where a licensing auction for the same field had already failed.

Russian production and exports of crude oil have increased significantly since the passage of the PSA law in 1995, despite the fact that not a single PSA has been entered into since its passage.

There are several reasons for this increase. One is skyrocketing oil prices. However, foreign investment in the form of portfolio and debt investment in Russian oil companies as well as mergers and joint ventures with Russian companies have also played an important role.

The Future?

The story of Russian production in the past decade has been increasing production, often by Russian companies making relatively inexpensive "brownfield" investments in existing oilfields. The era of increasing production through such brownfield investments is drawing to a close. Most analysts agree that the biggest barrier to Russian exports today is not production but export capacity, or the lack of pipelines and port facilities needed to transport the oil abroad.

There is reason to believe that neither the remarks by the natural resources minister about limiting foreign investment to minority positions in Russian oil projects, the new draft version of the underground resources law, nor the Yukos affair are likely to stem this flow of investment. Although the current underground resources law permits foreign licenses, most major project licensees are nevertheless Russian entities, with ultimate majority ownership by Russians. A big exception is TNK-BP, which is ultimately 51% owned by BP (with licenses held by subsidiaries).

In his remarks, the natural resources minister referred only to a specific group of fields, including Sakhalin 3 and some fields in the Barents Sea, as well as some mineral deposits. In the case of the oil fields he named (although not necessarily the mineral deposits), it has long been expected that those projects would be developed in partnership with Russian companies. In the case of Sakhalin 3, for example, subsidiaries of Mobil (now ExxonMobil) and Texaco (now ChevronTexaco) won the right to negotiate a PSA for that project in 1993. They were negotiating with Rosneft to form an alliance to develop the project 10 years later when the PSA law was undermined by the Duma. A new auction for the Sakhalin 3 project — for a license or a "right to use underground resources" as it is termed in the new draft underground resources law and not for a PSA — will determine how it is developed. In contrast, work has already begun on the Sakhalin 5 project, where a Russian company that is ultimately owned 51% by Rosneft and 49% by BP is the licensee.

This is not to suggest that the new draft underground resources law, at least in its present form, will be rapturously welcomed by potential investors. Some unwelcome changes for foreign investors are that the new draft underground resources law explicitly limits licensees (now called "users of underground resources") to Russian entities or individuals, and it explicitly grants the government the right to restrict the use of "strategic" assets. This was the likely basis of the natural resources minister's comment that certain fields will be restricted to minority foreign participation. Moreover, the liability of users for non-compliance is broad, with exceptions only for illegal acts of the government or due to *force majeure*.

Russian users of underground resources may be owned by foreign investors (with some exceptions), and foreign investors may welcome other provisions of the draft underground resources law, such as classifying the right to use underground resources as a form of "real property" that can be pledged or assigned (albeit only with governmental permission) and limiting the grant of the right to use underground resources outside of auctions. Existing licenses will remain valid, or may be converted to contracts to use underground resources (the new term), at the existing licensee's option.

So why are the IOCs "doomed" to invest in Russia's petroleum sector? Why shouldn't Russia follow Saudi Arabia's or Mexico's model?

Whatever the ultimate profile of the anticipated Gazprom-Rosneft merger, the new state-owned behemoth will not compare to a Saudi Aramco or Pemex, in the first case because Russia does not have one enormous and easily exploited oilfield as its cornerstone asset and in the second case because Russia is developing, and gives every indication of continuing to develop, its difficult offshore and remote reserves with the help of foreign capital and technology, whether through the existing grandfathered PSAs or through joint ventures such as the Sakhalin 5 project.

It is no coincidence that the head of the Russian Federal Energy Agency — former Rosneft executive Sergei Oganesyan — said recently about the slowing pace of production increases that the lack of significant investment in developing production must be reversed if Russia is to continue increasing oil output at a steady rate. In Russia, a variety of private companies continue to function well, many with substantial foreign ownership. The PSA law, however disabled, remains on the books and could be revived for the appropriate project, while the new draft underground resources law does not represent a significant departure from present practice. Russia will continue to need capital and technology, not to mention additional export capacity, to maintain and increase the increasingly important income it derives from oil exports, while the oil companies will still want to add reserves wherever they are available. Taken in context, neither the natural resources minister's remarks nor the Yukos affair gives any indication of changing that situation.

Project Financing of Cross-Border Pipelines

by Nabil L. Khodadad and Rubin Weston, in London

Oil and gas reserves closest to traditional markets are being depleted, while new discoveries are being made in more remote locations. In order to link oil and gas markets to reserves, substantial investment in cross-border pipelines will be required over the next several decades.

Even where pipeline development is */ continued page 40*

Pipelines

continued from page 39

not strictly necessary in order to enable hydrocarbons to be delivered to market, individual countries and aligned groups of countries, at both ends of the supply and demand chain, are increasingly concerned to diversify their transport options (in order to avoid over-reliance on a single market, transit country or source of energy). For example, one of the reasons why Transneft recently built a Baltic pipeline was to establish a new export port for Russian oil at Primorsk on the Baltic Sea and, thereby, reduce Russian dependence on transit through Latvia, Lithuania, Estonia and Finland.

The very nature of a cross-border pipeline renders its project financing inherently difficult.

A pipeline requires a high level of initial investment and does not generate any revenue to finance debt repayment until the pipeline is completed. For example, the Chad-Cameroon pipeline (a 1,070-kilometer pipeline that transports crude oil from three fields in the Dhola basin in southwestern Chad to a floating facility 11 kilometers off Cameroon) was completed in July 2003 at a cost of $2.2 billion.

Adding to the complexity, most cross-border pipelines involve a number of parties with diverse interests. Cross-border pipelines almost invariably involve both the public and the private sectors. There is an inevitable divergence of interest between these sectors. Within the public sector, the country of production usually wants the highest price for the exported hydrocarbons, the country of transit wants the highest tariff and the country of receipt wants the lowest price and the lowest tariff. A similar divergence of interests arises in the private sector, to the extent that different entities are involved in the supply, transportation and purchase of the relevant hydrocarbons.

However, it has been possible to effect successful project financings in this sector. For example, Chadbourne acted recently for the European Bank for Reconstruction and Development on its financing of the participation by the State Oil Company of the Azerbaijan Republic (SOCAR) in the south Caucasus gas pipeline, which will run from the Shah Deniz gas field off the coast of Azerbaijan, through Azerbaijan and Georgia, before discharging into the Turkish gas distribution system. In addition, the BTC pipeline, which will link the Azeri, Chirag and deep water Gunashli oil fields, off the coast of Azerbaijan with the Port of Ceyhan in Turkey, attracted over $1.5 billion of bank debt, and the Chad-Cameroon pipeline raised $1.4 billion of debt from banks and the capital markets.

There are nine main risks in pipeline projects that lenders will insist be addressed before they will provide financing.

Risks and Mitigants

An analysis of risk is fundamental to any decision to provide financing.

When considering whether a risk can be borne, a lender will take account of factors that might serve to mitigate that risk. The lender's perception of certain risks may depend on what type of institution it is. For example, international financial institutions (like the EBRD and International Finance Corporation) tend to be more comfortable taking political risks from which commercial banks might shy away.

The following is a catalog of key risks that apply in a cross-border pipeline financing followed, in each instance, by examples of how these risks have been successfully mitigated.

Upstream. The establishment of sufficient reserves underpins any successful pipeline project. If a pipeline is being developed to transport existing production, this risk is less important. Greater care will be required in circumstances where a pipeline is being established to transport the production of a specific upstream project. Any analysis of this risk will not simply end with a reserve report showing sufficient development potential. It will also extend to an analysis of the ability of the relevant producer effectively to develop the field and, in the case of offshore reserves, to consideration of delineating national borders to make sure the country purporting to grant the license to develop the field has jurisdiction.

Concerns about the extent of upstream reserves are usually addressed by obtaining a reserve report from a recognized and respected source. For example, the Chad-Cameroon Pipeline was underpinned by proven plus probable reserves of 917 million barrels in the three fields that were to be developed in the Dhola Basin.

Completion. Pipelines are an enormous engineering undertaking involving considerable technical challenges. Until the pipeline is completed, no revenues will be generated to service any project debt.

Ideally, the project should be implemented by means of a construction contract with an experienced contractor on "turnkey" terms that provide for liquidated damages if the contractor fails to deliver. In the case of the BTC pipeline, the Turkish government partially underwrote construction of the Turkish section by guaranteeing its completion under turnkey terms for a fixed price.

Turnkey terms are not often available, and other contractual means to address completion risk will usually have to be sought (for example, express commitments from the project sponsors). In addition, any lender will want to make sure the contractor uses proven technology.

Banks are very unlikely to take completion risk on such complex engineering projects; thus, recourse will be to the balance sheets of the sponsors until completion has occurred.

Operating. Another risk is, even though the pipeline has been successfully completed, it will not operate efficiently or at all. Lenders will want evidence of some guarantee of throughput. Any lender will be anxious to ensure that the length of this commitment extends several years beyond the duration of the scheduled loan repayments and that the amounts generated by shipment at the committed levels will generate enough cash flow to meet scheduled debt service. On the CPC pipeline project (completed in 2000 to link the Tengiz oil field in Kazakhstan with the Russian port of Novorossiysk), the fact that the oil producers refused to sign throughput and deficiency agreements (which would have constituted a commitment to ship a specified level of oil), appears, according to a joint UNDP/World Bank report in June 2003, to have played a part in the initial construction of the pipeline proceeding without bank financing.

For pipelines (especially gas pipelines) that are being developed in conjunction with a specific upstream project, this risk will tend to be less significant, as the pipeline may well constitute the only available means for the export of the reserves of a designated field. There is a tendency for the same commercial parties to be involved at the upstream and the midstream level. For example, ExxonMobil, Chevron and Petronas participated in the same equity proportions to each other in the upstream and midstream project companies responsible for the development of the Dhola Basin oil fields and the construction and operation of the Chad-Cameroon pipeline. The result was there was minimal risk that the upstream parties would choose an alternative export route. In contrast, the participants in the construction of the BTC pipeline were not identical to the participants in the development of the Azeri, Chirag and deepwater Gunashli fields.

Market. Any bank lending money for construction of a pipeline will want to make sure that there is a viable market for the relevant hydrocarbons. If no established market exists, or there is uncertainty about the ability of the market to consume the piped hydrocarbons, then the debt might not be repaid. This issue is of particular concern for a gas pipeline. Gas is much harder to transport than oil; it can only be piped or transported as LNG. For example, in the 1990's, a large pipeline was constructed across Poland to supply gas from Russia to the German market. It was intended that substantial volumes of the transported gas would also be made available to Poland. However, the Polish market has been able to absorb very little of this gas because Poland relies heavily on local coal to generate electricity. In the context of an oil pipeline, the presence of an immediate market is less significant, as the nature of oil renders it much easier to transport to alternative markets.

It will often be the case with a new cross-border gas project in a less developed gas market that the market will be constituted by a single counterparty. For example, most of the gas piped through the south Caucasus gas pipeline will be sold to BOTAS, the Turkish state gas company, which is then responsible for its wider distribution through the Turkish market. In these circumstances, a bank's analysis of risk will focus primarily on the counterparty's creditworthiness and the terms of the contract. However, the viability of the market as a whole will remain a

/ continued page 42

Pipelines

continued from page 41

relevant consideration, as, if the designated counterparty can not resell the gas, it is more likely to default. In the Bolivia-Brazil gas pipeline, which was completed in March 1999, potential lenders were very concerned about the ability of the underdeveloped Brazilian gas market to absorb gas that would be piped from Bolivia. As a consequence, Petrobras (Brazil's state-owned oil and gas monopoly) effectively underwrote performance of the pipeline by contracting to take enough gas to ensure its profitability.

Multilateral lending agencies will also want to know the environmental, social and economic impacts on the region the pipeline will traverse.

Legal. Any potential lender will want an assurance that all countries through which the pipeline will run have a secure legal framework to facilitate its construction and operation. Lenders will want to know that a viable forum exists for the settling of any disputes. The analysis of both of these issues will be complicated by the fact that cross-border pipelines, by definition, involve multiple legal regimes.

In the south Caucasus gas pipeline, each of the countries through which the pipeline would run (Azerbaijan and Georgia) entered into host government agreements with the project company. These host government agreements override all local laws (other than the constitution) and addressed such key legal issues as the grant of exclusive rights to develop and implement the project, protection from expropriation and the guarantee of the free movement of goods, services, personnel and currency. In addition, each of Azerbaijan and Georgia agreed to submit disputes arising under the host government agreements to international arbitration.

Tax. Local taxes should not impair the ability of the project to service any bank debt. In general terms, lenders prefer a situation where taxes are levied on the profit of the pipeline company, rather than the throughput of the pipeline, as the former can only reduce the amounts available to repay bank financing, while the latter could prevent it. In the south Caucasus gas pipeline, the tax risk was addressed by means of host government agreements granted by each of Azerbaijan and Georgia. Each of these documents set out the tax regime for the project and imposed limited direct taxation which would only apply on profits. In addition, only nominal customs duties were imposed.

Regulatory. A potential lender will want to ensure that there is a viable regulatory regime in each relevant country. The key requirement for the producing country will be the unfettered and absolute grant of relevant permits and licenses to enable development of the field.

With respect to any country of transit, regulatory concerns will relate to pipeline transportation charges and, as a pipeline is a natural monopoly, any regulations designed to promote competition. In certain countries, the regulatory environment is complicated by a requirement that all pipelines operate on a "common carrier" basis with third party rights of access. In other words, pipelines cannot be reserved for the product of specific fields. This is the case in Russia, although this requirement was waived for the CPC pipeline.

Turning to the country of discharge, the focus will be on the regulation of prices. In the context of an oil pipeline, the ability to transport oil relatively easily to an alternative market renders any price regulation of less relevance than would be the case for a gas pipeline.

What constitutes a viable regulatory regime will vary depending on the status of the project. In order to encourage initial investment, the investors need to be given assurances that they will be able to operate the pipeline without undue interference from regulatory bodies for a long enough period to guarantee an appropriate return on their investments. The regulatory risk in the south Caucasus gas pipeline was addressed by the host government agreements, each of which contains an exemption from competition, monopoly and similar legal restraints. In addition, the state authorities were compelled to provide a full list of any required permits and approvals, which they would then be obliged to issue on a priority basis.

The regulatory situation is complicated because the countries through which the pipeline passes usually have different regulatory systems. This concern was addressed in the West African gas pipeline by establishment of a single regulatory regime across all of its countries of operation (Ghana, Togo, Benin and Nigeria).

Political. The political situation can change in a way that is detrimental to development or operation of the pipeline. For example, a radical change in a regime may lead to detrimental changes in state policy. This problem hampered the Iraq Petroleum Company (IPC) pipeline from Kirkuk in Iraq to Banias in Syria. The project was completed in 1952. In 1966, a new extreme wing of the Ba'ath party took over the Syrian government and demanded that the transit fee be renegotiated. The pipeline was shut for several months while this process took place. Further demands for renegotiation led to the pipeline being rendered inactive from 1976 to 1979. Lenders should also consider the risk that the pipeline could be subject to political violence. In 1969, the Tapline crude oil pipeline from the Gulf to the Mediterranean via Jordan, Syria and Lebanon was closed for 112 days following sabotage in the Golan Heights by the Popular Front for the Liberation of Palestine.

An important generic mitigant of political risk is stable governments. However, the nature of the countries where many hydrocarbon deposits are discovered, and through which they must be transported, does not usually allow lenders this luxury. Often, the best mitigant of political risk is naked self-interest. In general, any producing country will be strongly motivated to ensure the success of a pipeline which, in effect, converts its natural resources into cash. Thus, European buyers of Soviet gas in the 1980's were prepared to lend capital to the USSR for the construction of massive inter-continental gas pipelines. The view was taken that, regardless of the political risk involved in advancing funds to the other side of the "Iron Curtain," the need of the USSR to sell its gas would ensure the successful performance of the pipeline.

The situation with transit countries can be more complex. The benefits on offer to any transit country must be sufficiently enticing to prevent it from interfering with transit. Georgia, as the transit country for the south Caucasus gas pipeline, has been rewarded by the ability to take gas at greatly reduced prices. Georgia is currently troubled by electricity outages due to a lack of money to pay for gas. Georgia also signed an inter-governmental agreement with Azerbaijan that confirmed its commitment to uninterrupted transit.

Another mitigant can be involvement of a local partner. A domestic partner who stands to benefit from the successful operation of the project might use its political clout when the government tries to alter tax and royalty structures. For example, in both the BTC pipeline and the south Caucasus gas pipeline, the lenders took comfort from the fact that SOCAR would be a participant in both the upstream and the midstream projects. However, the involvement of a local partner can weaken the quality of any completion guarantee provided by the project sponsors. Furthermore, in both pipelines, comfort was obtained from the direct commitments provided by Azerbaijan and Georgia in the host government agreements.

As a measure of last resort, pipelines have been routed to avoid political risks that cannot be addressed by other means. For example, a bypass was added to the northern route export pipeline, which is being used to transport oil from the first stage of the development of the Azeri, Chirag and deepwater Gunashli fields to Novorossiysk on the Black Sea coast of Russia, in order to avoid Chechnya. In addition, it was decided to route the BTC pipeline and south Caucasus gas pipeline to avoid Armenia.

Conflict. Pipeline projects involve numerous and diverse entities in both the public and private sectors. In a worst case scenario, if a conflict cannot be resolved, a key party could simply refuse to participate further. While the replacement of a private sector participant may be possible, if one of the states involved in the project decides that it no longer wishes to participate, the pipeline will be rendered impotent. For example, Syria closed down the IPC pipeline in 1982 when Iran agreed to supply it with oil instead of Iraq. Lenders will want evidence that all of the parties are motivated enough to ensure success throughout the period of scheduled repayment of the loan.

The best mitigant of the risk of conflict is the creation of as many factors as possible that bind all of the key parties to a successful conclusion for the project. / continued page 44

Pipelines

continued from page 43

These factors can be both inherent and contractual. For example, in the CPC pipeline, Russia, Kazakhstan and the commercial participants were all inherently interested in the success of the project. However, this unity of interest was further strengthened by the division of the equity interests in the pipeline company itself, which, apart from providing shares for the commercial participants, gave 24% and 19% of the shares to Russia and Kazakhstan, respectively. In the south Caucasus gas pipeline and the Chad-Cameroon pipeline, the risk of conflict between the commercial parties at the upstream and the midstream level was mitigated by the fact that the commercial participants are identical at each level.

The respective needs of the states involved can encourage compliance with their respective obligations. In the south Caucasus gas pipeline, the planned restructuring of the Azeri economy depends on the successful export of its oil and gas reserves. Georgia will greatly benefit from the cheap gas that the pipeline will produce. Turkey has a large and developing gas market. The natural unity of interest that these economic factors creates is strengthened by the intergovernmental agreements under which Turkey and Georgia separately agreed with Azerbaijan to take the steps necessary to implement the pipeline. In the Chad-Cameroon pipeline, Chad and Cameroon expect to generate income of $2 billion and $500 million, respectively, during the 25-year life of the project. In addition, the project employed more than 13,000 local people and presented more than $740 million in procurement to local contractors in such activities as construction, truck transportation, civil works, vehicle maintenance and catering.

The risk of conflict will be reduced if the initial contractual framework is reasonable and allows for a degree of flexibility for changed circumstances. A major reason for the poor performance of the IPC pipeline was the failure of Syria to negotiate favorable terms when the pipeline was established and the fact that legitimate means did not exist to reopen the commercial terms. As a result, the Syrian government constantly closed the pipeline in order to force renegotiation of its transit fees. In contrast, there is a tendency for the more successful cross-border pipeline projects to link the rewards given to the participants to market indices.

Beyond Risk Analysis

It is increasingly the case that a simple analysis of risk is not enough, on its own, to decide whether to invest or provide financing. The general impact of the pipeline on the environment, society and economy must also be considered.

In this area, the multilateral financial institutions lead the way. However, even commercial banks no longer operate in a vacuum where financial return is the sole factor in the decision to lend. They are subject to scrutiny from non-governmental organizations and the media, and the concept of corporate citizenship has become a central facet of business credibility. Thus, the tendency is for the standards imposed by the multilaterals to be adopted by the commercial banks. This is best illustrated by the adoption in 2003 of the "Equator principles" by commercial banks representing more than 80% of the project loan market, under which they agreed to abide by the environmental standards of the World Bank for projects costing more than $50 million. The export credit agencies, which, as agencies of governments, are subject to great public scrutiny, are also becoming increasingly sensitive to these issues.

The involvement of the World Bank and International Finance Corporation in the Chad-Cameroon Pipeline was predicated on provision of sustainable long-term development to both countries. In Chad, the situation was of particular concern due to its record of political instability and widespread corruption. The World Bank addressed these concerns by insisting on establishment of a revenue management program to support direct economic and social benefits for the poor. To this end, all government revenues will be deposited in a dedicated offshore escrow account from which their application will be audited by an independent oversight committee. This nine-member body has been drawn from local civil society, religious organizations, women's groups and the parliament. It has been charged with ensuring that, after 10% of the funds in the escrow account have been channeled into a future generations fund, the remaining funds are allocated as follows: 80% to education, health, social services, rural development, infrastructure and water management, 15% to the Chad treasury and 5% for regional development in the area of the Doba oil field itself. The committee is being advised and monitored by the World Bank and the US Treasury. To ensure transparency, its reports are disclosed publicly. In addition, environmental concerns were addressed by the establishment of two new large national parks in Cameroon, to compensate for the loss of forest caused by construction of the pipeline.

The Chad-Cameroon pipeline is probably the best illustration of the current trend towards a more holistic approach to pipeline financing. However, the themes of sustainability and transparency that it illustrates will be relevant to any future cross-border pipeline financing in developing economies. Thus, for example, the participants in the BTC pipeline instigated environmental and social impact assessments in each of Azerbaijan, Georgia and Turkey. Their preparation involved in-depth discussions with local landowners and communities. A community investment program was implemented to effect infrastructure improvements such as improved roads, new school equipment and clean water supply. (Steps were also taken to ensure that not a single household was displaced by the pipeline, even to the extent of tunneling underneath a village that could not be bypassed.) In addition, to increase transparency, the governments of Georgia and Azerbaijan have agreed to publish full details of the revenues derived from the pipelines. ◎

Toll Road Update

by Jacob Falk, in Washington

The United States would like to see more roads built in the future by public-private partnerships, but this will happen only if states allow private sector participation. Are states willing to open road development to the private sector? Increasingly, the answer is yes, and state initiatives are also beginning to venture beyond public-private development of new roads to privatization of existing highways.

Federal Actions

Congress has struggled to renew federal spending authority on road projects since the authority expired in October 2003. State governments have complained that the delay is affecting major state projects since such projects rely partly on federal funding. Congress has extended the spending authority at existing levels for short periods six times since October 2003 while it argues about what to write in the new bill. The most recent extension expires on May 31, 2005. A new spending bill passed the House on March 10. A new bill had not yet passed the Senate as the *NewsWire* went to press, but was scheduled to be debated the first week in April. A conference committee made up of senior members from both houses will eventually also have to iron our differences between the House and Senate versions of the bill.

The Bush administration is urging Congress to include several provisions in the final transportation bill to encourage public-private partnerships, or "PPPs." One provision would allow up to $15 billion in tax-exempt "private activity bonds" to be issued for construction of private road projects. Use of tax-exempt bonds is usually limited to public projects. The administration wants to make an exception. This provision did not make it into the House bill, but was included in the bill that the Senate approved last year. (The House and Senate both passed bills last year that are the starting points for the bills being considered this year.) Private activity bonds are controversial because expansion of tax-exempt bond authority is unpopular with the tax-writing committees in Congress, and there is also controversy surrounding whether the Davis-Bacon Act, which requires payment of prevailing wages on federal transportation projects, should apply to road projects that are funded with tax-exempt debt. Another provision supported by both houses of Congress and the Bush administration would reduce the required minimum project cost necessary for a project to be eligible to participate in the federal TIFIA program from $100 million to $50 million. TIFIA — the "Transportation Infrastructure Finance and Innovation Act of 1998" — provides public and private sponsors of road projects with supplemental subordinated credit, loan guarantees or loans of up to 33% of project cost from the federal government.

The US Department of Transportation recently issued a "Report to Congress on Public-Private Partnerships." The report, which encourages PPPs, responds to a request from Congress to explain the impediments preventing the implementation of more PPP schemes and what can be done with states to eliminate the impediments.

State PPP Initiatives

Texas is near the front of a line of states developing road projects using PPPs. The state has started implementing an ambitious plan to build a 4,000-mile transportation corridor of superhighways and pipelines called the Trans-Texas Corridor. The cost is expected to reach $180 billion. The state took the first step toward implementation in December when it chose Cintra to develop a new */ continued page 46*

Toll Roads

continued from page 45

$7.2 billion superhighway along the I-35 corridor connecting Dallas and San Antonio. The highway will stretch from the Oklahoma border in the north to the Mexican border in the south. Texas will give Cintra a 50-year concession to operate and maintain the corridor and to collect and keep tolls. The I-35 corridor is the first project with private financing to be approved in connection the Trans-Texas Corridor. On March 11, Texas and Cintra formalized their partnership by signing an agreement authorizing Cintra to move forward with the master development and financial plan.

The arrangement with Cintra on the I-35 corridor also is expected to serve as a blueprint for development of the I-69 corridor and for other corridors that the Texas Department of Transportation has designated as "high-priority." The Texas work on the I-69 corridor will be part of a national plan to develop more than 1,600 miles of proposed or existing connector highways from Port Huron, Michigan, on the Canadian border, to the Mexican border in Texas. The I-69 corridor will be developed as part of the Trans-Texas Corridor network with private financing. Additional corridors are planned and requests for proposals for additional routes will be assigned priorities based on the needs in Texas.

The TTC envisions each corridor having separate lanes for cars and trucks (as many as six for cars and four for trucks), high-speed commuter railways, freight railways, oil and gas pipelines, water lines, transmission lines for electricity and telecommunications and even broadband lines. The proposed corridors, which may be as wide as a quarter of a mile, will connect every corner of the state while skirting the perimeters of major urban areas. Most state road projects have been funded in the past out of revenues from fuel taxes. In contrast, the TTC website says, "We have purposely left project funding flexible to encourage creative ideas that will maximize revenues and ensure significant private participation in financing the TTC. We want to combine the best of private sector business practices with the best in government to deliver a world-class transportation system."

In the last couple months, several other states have also moved to encourage new road construction using PPPs.

A bill before the California state assembly (AB-850) would amend existing toll road enabling legislation in California that expired on January 1, 2003. The expired legislation has been criticized for being too restrictive and for putting too much responsibility on the private sector without guaranteeing enough state support. The expired legislation limited the number of projects that could be developed; initially only four pilot projects were authorized and this number was subsequently reduced to two pilot projects. The old legislation also required that the authorized projects be developed by the private sector without significant cooperation from the state. AB-850 would not limit the number of projects, but permitted "transportation projects" would be limited to toll lanes, mixed-flow toll lanes and free lanes, "dedicated exclusive truck lanes" and shared High-Occupancy Vehicle (HOV) lanes (although HOVs must be given free passage under the proposed legislation). AB-850 also allows for more cooperation between public and private partners. For qualifying projects, AB-850 would authorize "comprehensive development franchise agreements" among the California Department of Transportation and public and private entities.

The bill expressly permits the use of non-compete provisions in comprehensive franchise development agreements to protect authorized toll roads from competing state facilities, but California would be able to buy its way out. This part of the bill is probably a response to an impasse that developed in connection with the SR-91 express lanes, a project developed under the old legislation. In the SR-91 case, the Orange County Transportation Authority was forced to buy out the project after a non-compete provision in the concession agreement limiting further development along the route led to public criticism of the project. Under the new bill, the department's ability to open competing state highway facilities within the same transportation corridor as the toll facility may be limited, but this ability is qualified by a provision allowing the state to open competing facilities if the state exercises its police power to acquire by condemnation or negotiation the remaining net fair market capitalized value of the toll franchise period.

Oregon plans on issuing requests for proposals on April 8 for three separate public-private partnership transportation projects: the Sunrise limited access road facility, improvements to the south I-205 corridor and the Newburg-Dundee alternative corridor (bypass). These three projects will be the first projects implemented under the Oregon innovative partnerships program. The program was created to solicit proposals and accept unsolicited proposals from private entities to partner with the state on development of transportation projects. The initial RFPs are expected to be for "pre-development services," which, if delivered satisfactorily for the relevant project, would qualify the private partner to enter into negotiations for delivery of the project. Oregon accepted comments on a draft RFP through March 24. The expected due date for proposals is July 7, 2005.

The Colorado House passed a bill on February 8 centralizing regulation of toll rates for private toll roads. The Colorado Senate killed the House bill on March 22, but made private toll roads the focus of a summer legislative study committee. The House bill would have given the Colorado Tolling Enterprise, a branch of the Colorado Department of Transportation, the responsibility for regulating tolls for private toll roads that are located in more than one county. (Each county can regulate tolls for private toll roads that are wholly within county lines.) The bill would have applied to private toll roads, but would not have applied to toll roads financed, constructed, operated or maintained under the Colorado public-private initiatives program or pursuant to the statewide tolling enterprise program, both of which already contemplate statewide regulation of tolls.

The driving force behind the legislation was the development of the Front Range toll road by the Front Range Tolling Co. along the eastern edge of the Front Range. The Front Range Tolling Co., which acquired rights to develop parts of the Front Range toll road in the 1980's under an old law that has since been changed, would have been able to start construction of the Front Range toll road within months of the new law being passed. The company already has private financing lined up for the project. While Colorado killed this bill, the decision to set up a summer legislative study committee emphasizes the state's willingness to consider private investment in road projects.

Privatization

A hot topic currently in the US toll road market is privatization of existing toll roads. The Chicago-Skyway deal recently grabbed a significant amount of attention and has left a number of states thinking about their own privatizations.

In the Chicago-Skyway deal, Chicago leased the Chicago-Skyway toll road to a Cintra-Macquarie consortium for 99 years in exchange for $1.82 billion. The consortium will be responsible for operation and maintenance (including future improvements, but excluding policing and plowing snow), and the city will get the full $1.82 billion up front. The consortium is confident that the right to collect and keep future tolls, which the consortium has been given limited rights to increase, makes this investment worthwhile. Privatization of an existing road is generally less risky than development of a new road because traffic can be forecasted more accurately.

Other states are exploring the Chicago-Skyway model, and several state proposals for privatizing major toll roads have been issued recently.

Indiana Governor Mitch Daniels recently suggested selling the state-run Indiana toll road to private interests. Critics of the proposal argue that the toll road is used primarily by residents of northern Indiana and proceeds from the sale of the toll road should not be used to support projects elsewhere in the state.

In New Jersey, acting Governor Richard Codey is considering leasing the New Jersey turnpike to private interests. Codey asked the state treasurer to look into whether leasing the New Jersey turnpike would create surplus cash. State officials are concerned about public backlash to leasing the turnpike, but the New Jersey turnpike is a huge, statewide project that could probably generate several billion dollars for the state treasury. The state is facing a $4 billion budget shortfall this year.

New York Governor George Pataki also recently proposed privatization as a means of alleviating budgetary constraints. Pataki did not mention specific facilities, but his proposal suggested that privatization would be most appropriate for roads and bridges that currently charge tolls or for facilities that undergo substantial improvements to increase capacity.

In general, US states have been trying to involve the private sector in road development for almost two decades. However, only in the last few years have states begun to explore the PPP model seriously. The federal government might help push this along through the transportation bill, but the success of existing initiatives, like those in Texas and Chicago, will go farther in creating the necessary public and private confidence in the PPP model.

Environmental Update

Clear Skies Setback

Republican leaders have largely given up on trying to pass a "Clear Skies Act" in the US Senate this year after the measure failed on a tie vote to clear the Senate environment committee in March.

The "Clear Skies Act" would require reductions in three pollutants — nitrogen oxide, or NO_x, sulfur dioxide, or SO_2, and mercury — nationwide from power plants. The bill was controversial because Democrats also wanted reductions in carbon dioxide, which contributes to global warming, and Republicans were unwilling to go along. Republicans hold a majority on the Senate environment committee, but one Republican — Senator Lincoln Chafee (R-Rhode Island) — voted with Democrats, and the Republicans were unable to persuade at least one Democrat to break ranks and support a bill without carbon dioxide limits.

The US Environmental Protection Agency then finalized a "clean air interstate rule" that is described in a separate article in this issue of the *NewsWire*. This rule will achieve many of the same reductions in NO_x and SO_2 contemplated by the Clear Skies Act; however, the new regulation is limited in scope to 28 eastern and midwestern states. The Clear Skies Act would have applied to the entire country and a new statute would have been less susceptible to the inevitable litigation that follows any major EPA rule.

The Senate environment committee chairman — James Inhofe (R-Idaho) — said the Clear Skies Act will not be reconsidered by the committee this year. Nevertheless, several lawmakers still hold out hope that a compromise measure can be passed by the full Congress later in the year. Now that the clean air interstate rule has been finalized, there is less urgency to act, and it would be surprising if the bill receives any further serious consideration by this Congress.

Clean Air Settlements

The US Environmental Protection Agency reached noteworthy settlements with two utilities in March to resolve alleged violations of the Clean Air Act.

The utilities were accused of making major modifications to coal-fired plants in the late 1970's through the early 1990s without getting the necessary "new source review" permits from the permitting authorities. The crux of the issue is a dispute over what constitutes a "major modification" that triggers a permit review.

A settlement that a utility reached with the US government may provide funding for windpower and landfill gas developers.

The first settlement involved five power plants owned by Illinois Power and the second settlement covered four plants owned by Ohio Edison. Both Illinois Power and Ohio Edison were sued by the US government as part of a large-scale EPA enforcement initiative launched in the late 1990s. To date, the US government has entered into nine settlements to resolve issues raised in the coordinated federal enforcement initiative.

In the Illinois Power settlement, the company agreed to spend as much as $500 million by 2012 to install new pollution controls and upgrade existing pollution equipment at five coal-fired power plants. Illinois Power will install flue gas desulfurization systems on four units at the Baldwin and Havana plants over the next seven years, and NO_x controls will be operated year round at these two plants. The five plants will be subject to declining systemwide NO_x and SO_2 emission caps, which will result in emission reductions of 15,000 tons a year of NO_x and 39,000 tons a year of SO_2. In addition, particulate matter controls are required to be installed or upgraded at each of the plants. The company also agreed to pay a $9 million civil penalty and to spend at least $15 million on environmental mitigation projects. Illinois Power is also required to retire 30,000 SO_2 allowances under the federal acid rain program each year, and NO_x allowances allocated under the NO_x SIP Call rule are also reduced. The settlement resolves the US government's pending case against Illinois Power with respect to alleged new source review permitting violations at the Baldwin station. The other four Illinois Power plants were not implicated in the original lawsuit against the company.

Ohio Edison agreed to spend approximately $1.1 billion to reduce NO_x and SO_2 emissions from four coal-fired plants, and it will install state-of-the-art pollution controls at all seven units at the W.H. Sammis generating station, and the plant will be subject to declining plant-wide NO_x and SO_2 emission caps. The two largest units at the W.H. Sammis plant will be required to install flue gas desulfurization systems and selective catalytic reduction systems by December 2011. Emissions from the W.H. Sammis plant are expected to decline by a total of 28,567 tons a year of NO_x and 134,500 tons a year of SO_2. An additional 49,000 tons per year of NO_x and SO_2 emissions reductions are expected to come from the other three plants. As part of the settlement, Ohio Edison is required to retire a certain percentage of its SO_2 allowances under the federal acid rain program each year, and its NO_x allowances allocations under the NO_x SIP Call rule will also be limited. Ohio Edison also agreed to an $8.5 million penalty and will set aside $25 million for environmental mitigation projects. Of this amount, $14.385 million will be allocated for 20-year power purchase agreements with windpower or landfill gas projects from Connecticut, Pennsylvania, New Jersey or New York. While EPA has a long history of including environmental mitigation projects as part of its settlements, this appears to be the first settlement where renewable energy purchases were required as part of the agreement.

The settlement resolves the ongoing enforcement lawsuit against Ohio Edison. In August 2003, a federal district court in Ohio ruled that Ohio Edison violated new source review permitting requirements when it made major modifications to its W.H. Sammis station without first obtaining the requisite permits. The *United States v. Ohio Edison Co.* case was a major victory for EPA. New York, New Jersey and Connecticut had also filed suit separately against Ohio Edison and were parties to the settlement.

In a related development, EPA issued a notice of violation to the Big Cajun 2 power plant in Louisiana in March charging that the facility violated new source review permitting requirements by replacing boiler elements in units 1 and 2 in the late 1990s without going through the requisite review. The EPA action does not signal a new round of targeted utility enforcement actions, but confirms that the agency is continuing to pursue suspected violators of the new source review program.

Also in March, the Grand Canyon Trust and the Sierra Club entered into a settlement with the Public Service Company of New Mexico resolving a Clean Air Act citizen suit filed against the 1,600 megawatt coal-fired San Juan plant. The environmental groups alleged that the plant was exceeding its applicable emission limits. In the settlement, the Public Service Company of New Mexico agreed to spend an estimated $110 million in capital costs to install state-of-the-art pollution control technology to reduce NO_x, SO_2, particulate matter and mercury emissions from the plant over the next four and a half years. A portion of these costs will be used to install activated carbon injection systems to reduce mercury by as much as 80% from each of the plant's four units.

Regional Haze

EPA suffered another setback in its efforts to regulate regional haze when a US court of appeals in Washington invalidated an SO_2 emissions trading program that five western states adopted in an effort to reduce haze-forming air emissions from power plants and certain other industrial facilities built between 1962 and 1977. The ruling closely follows the logic the same court used in 2002 to invalidate a key provision of a federal regional haze rule.

In the 2002 regional haze rule case, the court said that before the federal government can impose best available retrofit technology or BART requirements on a power plant or other industrial source, it must first find that a particular source contributes to visibility impairment in a so-called class I area, such as a national park or federal wilderness area. The court rejected an EPA plan that would have allowed states to impose BART pollution control requirements on a group of sources instead of individual sources.

/ continued page 50

Even though the EPA rule was rejected in court, states still had the option of adopting an alternative means of reducing haze-forming emissions so long as it was "better than BART." Arizona, New Mexico, Oregon, Utah and Wyoming adopted a SO_2 emissions trading program to implement the regional haze rule, which was approved by EPA. However, in determining whether the rule was better than BART, EPA used a methodology that was substantially similar to the "group BART" approach that the court rejected in 2002. The similarity brought down the regional approach, and the five states must go back to the drawing board to develop an acceptable haze rule. In the meantime, EPA is expected to propose its own rewrite soon of BART requirements for individual sources. EPA is expected to require states to identify facilities that will be subject to BART by January 2008. The required emissions reductions are anticipated to take effect in 2014, with full implementation anticipated before 2018. The new EPA rule is expected to affect a number of older power plants and industrial facilities that have not previously been required to install or upgrade pollution controls to reduce NO_X, SO_2, particulate matter and VOCs.

Renewable Energy

Senator James Jeffords (I-Vermont) proposed in March that utilities should supply at least 20% of their electricity from renewable sources by 2020. Jeffords would define "renewable energy" to include wind, ocean waves, biomass, solar, landfill gas, incremental hydropower and geothermal. The bill would create a national renewable portfolio standard or RPS starting with 5% in 2006 to 2009, and increasing to 10% in 2010 to 2014, 15% in 2015 to 2019, and 20% in 2020 and beyond.

The Jeffords bill would also create a federal renewable energy credit or REC program. Entities generating electricity from renewable energy sources would be able to apply to the Department of Energy for RECs based on the amount of power produced. One REC would be issued for each kilowatt hour of renewable electricity generated. The Department of Energy would also be authorized to issue three RECs for each kilowatt hour of so-called distributed generation, which is defined as reduced electricity consumption from the grid due to the use of renewable energy generated at a customer's site.

Prices for SO_2 allowances increased by 250% in the past year, judging from prices at the latest US government auction.

The failure of a retail electric supplier to submit a sufficient number of RECs to cover its RPS requirements could trigger a civil penalty based on the number of RECs not submitted multiplied by the lesser of 4.5¢ or 300% of the average market value of a REC for the compliance period.

The Senate passed a similar RPS requirement in each of the past two Congresses as part of a comprehensive energy bill. An RPS requirement of 10% was dropped from the final bill in negotiations with the House in 2003 (and the energy bill was never enacted). The Senate is expected to try again as the energy bill moves through Congress this year.

In related news, Illinois Governor Rod Blagojevich announced plans in February for an RPS in Illinois. Blagojevich asked the Illinois Commerce Commission to write regulations that will require utilities in the state to supply 8% of their power from renewable sources by 2012. The regulations would also require that 75% percent of the renewable energy be generated by windpower.

Global Warming

The US Department of Energy released interim guidelines for the voluntary reporting of greenhouse gas emission reductions in March.

The department is required by the Energy Policy Act of 1992 to maintain a voluntary registry of greenhouse gas emission reductions that are submitted by various power generating and industrial companies. The interim guidelines make one significant change from an earlier proposal by allowing companies to register greenhouse gas emission reductions occurring outside the United States.

The guidelines create a two-tier process of *reporting* of emissions reductions *versus* the *registering* of emissions reductions. Companies will be able to *register* emissions reductions achieved after 2002 if they also provide entity-wide greenhouse gas emission inventory data. Entities registering emissions reductions would be recognized for net reductions in their entity-wide emissions.

The guidelines do not create a transferable credit program. In the preamble to the rule, the energy department suggested that registering greenhouse gas reductions would serve as a building block for recognizing such reductions in any future climate change program adopted by the United States; however, the agency acknowledges that it does not have the legal authority to create a transferable credit program that would be binding in any future mandatory climate change program.

The guidelines also explain how to measure or estimate greenhouse gas emissions. There is a 60-day public comment period ending on May 23, 2005. The guidelines will take effect on September 20, 2005. Companies will continue to have the flexibility to report greenhouse gas reductions on a plant-specific or project-related basis. Third-party or independent verification of emissions reductions is "strongly encouraged," but is not required. While companies are under no obligation to comply with the guidelines, companies may get a public relations benefit by participating.

Brief Updates

The US Environmental Protection Agency held the annual acid rain program SO_2 allowance auction in late March. The agency offered 125,000 vintage 2005 SO_2 allowances and another 125,000 allowances for the 2012 seven-year advance market. The auction prices for 2005 SO_2 allowance were more than 250% higher than prices paid for 2004 SO_2 allowances in last year's auction. The average auction price of a 2005 allowance was $702.51 compared to an average auction price of $272.82 for a 2004 allowance last year. The spot market price of SO_2 allowances traded by private brokerage firms has been steadily increasing over the past year, and this dramatic price increase appears to be largely driven by the new clean air interstate rule that EPA issued in March.

Local environmental groups filed a lawsuit in mid-March challenging the air permit issued for the proposed 1,500-megawatt coal-fired Thoroughbred generating station in Kentucky. The citizen suit alleges that the US Environmental Protection Agency failed to consult with the US Fish and Wildlife Service under section 7 of the Endangered Species Act before deciding whether to object to the dual pre-construction and air operating permit issued by the Kentucky Environment and Public Protection Cabinet. The environmental groups charge that emissions from the plant will adversely affect several endangered species. The complaint could set a new precedent for raising Endangered Species Act issues as a way to challenge air operating permits.

The US Environmental Appeals Board rejected a pre-construction air permit issued by the Illinois Environmental Protection Agency for the 1,500 megawatt coal-fired Prairie State generating station at the request of the Sierra Club and various public interest groups. The board concluded that the Illinois EPA violated applicable federal procedures when it issued the air permit. The board told the Illinois agency it had to consider comments submitted by interested parties before deciding whether to reissue the permit.

The US Environmental Protection Agency issued two orders in March directing the Illinois Environmental Protection Agency to rewrite portions of air operating permits that were issued to two coal-fired power plants in Illinois. EPA said that the air permits included a number of deficiencies, including the lack of sufficient monitoring to demonstrate compliance with certain emission limits, and several permit conditions contained language that was not practically enforceable.

EPA said in March that the draft environmental impact statement prepared for the Cape Wind windpower project in Nantucket Sound off the coast of Massachusetts was inadequate because the report failed adequately to analyze the potential environmental impacts from the project. The agency reaffirmed its strong support for renewable energy such as wind, but said the draft impact statement should have done a better job of evaluating the potential impact of the project on aquatic habitat, threatened and endangered species, eelgrass / continued page 52

Environmental Update

continued from page 51

and migratory birds. EPA also commented that the Army Corps of Engineers — which wrote the report — failed to address why a smaller scale project, such as a 25% to 75% smaller than proposed, was not considered. The ball is now in the Army Corps court to decide whether to go ahead anyway with a section 10 permit authorizing construction of the project.

EPA issued two proposed rules in the *Federal Register* in February that establish revised "new source performance standards" for various boilers and combustion turbines. The first rule would establish NO_X, SO_2, and particulate matter or PM new source emission limits for large utility steam generating units constructed, modified or reconstructed after February 28, 2005 and PM new source emission limits for large and small industrial-commercial-institutional steam generating units constructed, modified or reconstructed after the same date. The second rule proposes new NO_X and SO_2 emission limits for stationary combustion gas- and oil-fired turbines constructed, modified or reconstructed after February 18, 2005. The new source performance standards program applies technology-based standards as a backstop to emission limits adopted in the pre-construction permitting process. The new rule for large utility steam generating units would limit NO_X emissions to one pound per megawatt hour on a gross energy output basis, SO_2 emissions to two pounds per megawatt hour on a gross energy output basis, and PM emissions to 0.015 pounds per million Btu heat input. For large and small industrial-commercial-institutional steam generating units, the PM new source emission limit would be set at 0.03 pounds per million Btu heat input. The proposed NO_X new source standard for stationary combustion turbines would be set at one pound per megawatt hour for gas-fired turbines under 30 megawatts and 0.39 pounds per megawatt hour for over 30 megawatts. The SO_2 limit for all gas- and oil-fired turbines would be set at 0.58 pounds per megawatt hour. EPA is accepting comments on the first proposed rule until April 29, 2005. The comment period on the second proposed rule expires on April 19, 2005.

— 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
Suite 26, Plaza Business Centre
3rd Floor, North Tower
Beijing Kerry Centre
1 Guanghua Rd, Chaoyang 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