CHADBOURNE
& PARKE LLP

PROJECT FINANCE
NewsWire

January 2006

Coal To Liquids: The New Black Gold?

by Todd Alexander and Jeffrey Harrison, in Houston

The prospect that oil prices might remain high for the foreseeable future is forcing both governments and the private sector to explore other sources of transportation fuels besides oil.

Two alternatives — converting corn into ethanol and soybeans into biodiesel — have been around for many years, but have only recently gained market acceptance.

Another alternative — converting coal to liquids, or "CTL" — is experiencing rapid growth overseas and renewed interest in the US. There are new federal incentives for such projects and new stringent environmental regulations that should also help make them economic. However, the projects face daunting challenges.

Potential Market

CTL projects typically, although not always, use a two-step process for converting coal into a liquid synthetic fuel. In the first step of the process, coal is exposed to steam and oxygen at very high pressures, yielding hydrogen and carbon monoxide. This step is called "gasification." It is the same process that is used in integrated gas combined cycle, or "IGCC," power plants.

Step two is application of the Fischer-Tropsch process, which */ continued page 2*

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A NEW TAX BILL signed by President Bush on December 21 will reward companies making investments in sections of Louisiana, Mississippi and Alabama that were damaged by Hurricane Katrina. It also affects paper mills and companies that produce synthetic fuel from coal.

The bill allows a 50% "depreciation bonus" on new plant and equipment put into service in the hurricane zone in Louisiana, Mississippi and Alabama by December 2007. The deadline for completing new office buildings is a year later. The bonus can also be claimed on improvements to existing facilities.

It is an acceleration of tax depreciation to which */ continued page 3*

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converts the gas produced in step one into a synthetic fuel that can be processed into a cleaner version of diesel fuel and several co-products.

The Fischer-Tropsch process was used by Germany during World War II to make fuel for motor vehicles. Germany had ample amounts of coal but negligible petroleum. The process was originally invented by Franz Fischer and Hans Tropsch in Germany in the 1920s. By 1944, Germany was producing synthetic fuel at the rate of more than 45 million barrels a year.

US developers are starting to look seriously at coal as a source of fuel for motor vehicles.

South Africa is the only other country to have employed CTL on a large scale. South Africa was driven to use of the process by trade embargoes during the apartheid era. Like Germany during World War II, it had abundant coal and little to no petroleum.

One consequence of extended use of CTL by South Africa is that SASOL, a South African energy and chemical firm, helped improve the technology. SASOL has produced more than 1.5 billion barrels of synthetic fuel from 800 million tons of coal in the past 50 years. It currently supplies about a quarter of South Africa's fuel needs through coal.

Despite the enormous potential of CTL technology, its use has been limited to date to situations when political necessities leave no other options.

The biggest hurdle to wide-scale commercial implementation of CTL has been the price of oil. The "break-even point," or the price that a barrel of oil must reach in order for it to equal the unit production cost of an equivalent amount of synthetic fuel using CTL technology, depends on coal prices. The current break-even point in the United States is between $20 to $40 per barrel of oil, according to John Doyle and Bob Kelly with DKRW Energy, a firm that is developing a CTL project in Wyoming. The reason for such a wide range is the coal used as a feedstock in such projects varies in price.

Despite the relatively high break-even point by historical measures, CTL projects are attracting attention. "The recent persistence of high oil prices has stoked significant interest in the CTL area from both industry players and financial investors," said Paul Ho of Credit Suisse. "Technology providers, coal companies and others see a great opportunity for working together, while financial investors find the upside very attractive."

There are currently no CTL projects operating on a commercial scale in the United States. At least three large projects are under development. In addition to the DKRW project in Wyoming, Rentech has announced plans to develop CTL facilities in Illinois and Mississippi.

One of the leading proponents of CTL is Governor Brian Schweitzer of Montana. Montana has the nation's second-largest coal reserves, an estimated 120 billion tons, or enough to produce an estimated 180 billion barrels of CTL fuel. To put this in perspective, the United States consumed 7.5 billion barrels of oil in 2004 of which 4.3 billion barrels were imported. Schweitzer argues that CTL projects could eliminate any need to import oil from abroad.

The United States lags behind other countries that are looking currently at CTL.

China, the world's top producer of coal, plans to invest $15 billion in CTL projects over the next several years. Royal Dutch/Shell and SASOL are building 10 CTL projects in China independently of the government effort. Two of the SASOL facilities illustrate the large scale of new CTL projects in terms of both cost and output: the projects cost $3 billion each and will jointly produce 440 million barrels a year at a projected cost of $15 a barrel. Additionally, China's largest coal company, which is state-owned, is currently building a project in Inner Mongolia that is projected to convert one million tons of coal a year into synthetic fuel in 2007, with plans to increase output to 20 million tons a year by 2020.

The Philippines are looking at building a CTL project that would produce as much as 60,000 barrels of synthetic fuel a day and cost an estimated $2.8 billion. The output from the project would supply about 15% of transportation fuel in The Philippines and save consumers $3.2 billion a year.

India, the world's third-largest coal producer, has taken initial steps toward developing a CTL project. The state-owned coal company and oil company have formed two joint ventures, one to develop a CTL project and the other to increase coal production to supply the project.

US Incentives

The new energy bill that President Bush signed into law in early August provides grants, government loans, loan guarantees and tax subsidies for CTL projects.

The bill authorizes the US Department of Energy to spend another $1.8 billion on a "clean coal power initiative." Seventy percent of the money must be spent on gasification-based projects. The Department of Energy is authorized to commit up to $200 million annually during the period 2006 to 2014 for loan guarantees, loans and direct grants to project developers for gasification-based projects. However, some of the funds have already been "earmarked" by Congress, or directed to named projects. The earmarks require that at least five of the projects that receive aid must use petroleum coke as a feedstock.

The energy bill also provides a 20% investment tax credit for spending on gasification projects, but only in the following industries: chemicals, fertilizers, glass, steel, petroleum residues, forest products and agriculture. The material being gasified can be any "solid or liquid product from coal, petroleum residue, biomass, or other materials which are recovered for their energy or feedstock value." The equipment must turn the material into a "synthesis gas" composed primarily of carbon monoxide and hydrogen. The gas must be used as gas or for "subsequent chemical or physical conversion." Anyone hoping to claim a tax credit for a gasification project must have his or her project certified by the Internal Revenue Service. Total credits for all projects are limited to $350 million. No more than $130 million in credits can be allocated to a single project. The / continued page 4

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the owner of a project would be been entitled anyway.

The owner gets a much larger depreciation deduction the first year and smaller ones later. His depreciation allowance in the year the project is put into service is 50% of his "tax basis" in the project (basically what the project cost), plus depreciation for the year calculated in the regular manner on the remaining 50% of basis. The remaining 50% of basis is depreciated normally.

The faster writeoff can be a significant benefit. The benefit is greater the longer the normal depreciation period for an asset. A 50% bonus reduces the cost of assets that are depreciated over 20 years — for example, transmission lines and coal- and combined-cycle gas-fired power plants — by 8.98%. It reduces the cost of gas pipelines and other gas-fired power plants that are depreciated over 15 years by 7.54%. The cost of a power plant that burns waste would be reduced by 3.61%. Wind farms and biomass projects would cost 2.61% less. These are the *federal* tax savings from the depreciation bonus using a 10% discount rate. There may be additional state tax savings.

The bonus cannot be claimed on a project if tax-exempt financing is used to pay part of the cost. It only applies to projects on which construction starts on or after August 28, 2005.

The United States already allowed a 30% or 50% depreciation bonus on infrastructure projects with at least two-year construction periods built during the period September 11, 2001 through December 2005. The bill gives the IRS the authority to extend the December 2005 deadline for selected projects that companies can show were delayed because of Hurricanes Katrina, Rita or Wilma. Thus, this relief extends also to projects in Florida and Texas.

The bill also allows each of the three Katrina states to issue tax-exempt bonds in an amount up to $2,500 times / continued page 5

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energy bill also authorizes $1.3 billion in spending from 2007 to 2013 on new projects under a "clean air coal program" and $500 million in spending from 2007 to 2011 to increase environmental performance at existing facilities.

The energy bill also authorizes an "incentives for innovative technologies" program through the Department of Energy that will provide federal loan guarantees of up to 80% of the cost of new gasification equipment at fuel manufacturing facilities.

Separately, a federal highway bill also enacted in August contains a 50¢-per-gallon tax credit for diesel fuel produced from coal using the Fischer-Tropsch process.

Finally, the US Department of Defense is moving to implement a "clean fuel initiative" under which the department will assess the feasibility of converting military ships, aircraft and vehicles to alternative fuels. The US military is the largest single consumer of imported oil in the country, consuming 300,000 barrels per day.

New low-sulfur diesel regulations are also providing another boost for CTL projects in the United States. New rules issued by the US Environmental Protection Agency reduce the maximum allowable sulfur content in diesel fuel from 350 ppm to 10 ppm starting in 2006. Refiners are scrambling to meet the deadline. CTL fuels could provide a partial solution. CTL produces a clean fuel: sulfur, mercury and arsenic can be isolated and removed during the Fischer-Tropsch synthesis and then sold for use in other industries. Additionally, the carbon dioxide byproduct can be collected and injected underground, which would help CTL projects comply with any future carbon dioxide emission limits. CTL fuels also produce significantly lower levels of carbon monoxide, nitrous oxide and particulate matter than even low-sulfur diesel.

Financing Challenges

The first CTL projects to be built in the United States will be constructed either by a well-funded multinational corporation with both the ability to absorb the full impact of any downturn in the price of petroleum and access to sufficient capital to complete construction, or by developers using traditional project financing techniques to mitigate the risks both to themselves and their financing sources of lower diesel prices, technology failures and construction delays. Developers will find it a challenge to devise structures that properly mitigate these risks.

The projects are being helped by high oil prices, environmental regulations and government incentives. They become economic as oil prices move across a range of $20 to $40 a barrel.

There are two main risks: commodity risk, and technology and completion risk.

Commodity risk is central to CTL projects. Developers, especially those seeking to finance on a limited-recourse basis, will have to address the risks that the price of oil will drop below the point where the project can break even economically or that the price of coal will increase making synthetic fuel uncompetitive with petroleum-based diesel.

There are several strategies used in combination to limit exposure to commodity risk. Starting with the risk of falling oil prices, one strategy is to enter into futures contracts based on the price of diesel. This would provide predictability to a portion of a project's revenue stream, although this strategy tends to be prohibitively expensive in volatile markets, such as the diesel market, if implemented for the longer term. Another strategy is to enter into long-term fixed-price contracts, similar to those used in the ethanol and biodiesel industries, for at least a portion of the facility's output. This approach has the benefit of providing a more predictable revenue stream, but would probably require the owners of the project to forego much of the upside potential of the project. A third method is to capitalize on the flexibility of the CTL process by designing the facility to produce co-products for which long-term fixed-price offtake contracts are available.

In addition to exposure to oil price risk, projects are exposed to the risk of rising coal prices. While a large component of the cost of synthetic fuel is the price of coal, the selling price of synthetic fuel is not highly correlated with the cost of coal. The independent power industry attempted to solve a similar problem caused by the lack of correlation between the price of natural gas and electricity by buying natural gas fields and entering into long-term contracts at fixed or capped prices to ensure a predictable price for gas. Similarly, CTL developers could obtain access to predictably-priced coal by purchasing a coal mine or entering into long-term coal supply contracts at a fixed price or with a cap.

Given that very few commercial-scale CTL projects have been constructed, the markets are likely to perceive a high degree of technology and completion risk for the first few projects that are built. Developers, especially those seeking to finance on a limited recourse basis, can limit their exposure to technology and completion risk by entering into lump-sum, fixed-price turnkey construction contracts. Such arrangements would probably be preferred by third-party equity investors and be required by project finance lenders. The construction contract would have to have performance and schedule guarantees, as well as a fixed price and a single point of responsibility for all contractor liabilities.

The performance guarantees would be comprised of guarantees of the quantity and the quality of output as well as the reliability of the production process. Lenders are likely to require quantity guarantees to ensure that projected revenues are sufficient to satisfy debt service and stringent quality guarantees because of the first-in-kind nature of the projects. As we have seen in the biodiesel and ethanol industries, quality guarantees may be essential to facilitate market acceptance of a new product like synthetic fuel. For instance, it will be essential that vehicle manufacturers warrant the performance of their vehicles on synthetic fuel and that existing distribution channels for diesel accept synthetic fuel.

The reliability guarantees would measure long-term availability of the facility to produce synthetic / continued page 6

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the original population of the hurricane zone to pay for renovating or rebuilding existing facilities belonging to regulated utilities or constructing new ones. The potential beneficiaries are electric, gas, water, steam and sewage utilities and gas pipeline and telephone companies. The bonds must be issued by December 2010. The facilities must be used to provide services at rates that are regulated on a rate-of-return basis.

The same utilities have also been given the right to carry casualty losses caused by Katrina back as many as 10 years. That could open the door to refunds of federal income taxes paid during the past 10 years. Such losses can usually only be carried back two years.

Congress also attached a series of "technical corrections" to recent tax legislation to the Katrina-relief measure.

Among the technical corrections is one that makes clear that "lignin" — a wood residue that is a byproduct from making paper — is "biomass" so that paper companies can burn it to generate electricity and qualify potentially for production tax credits of 0.9¢ a kilowatt hour on the electricity. Paper companies were worried that the IRS would rule out the credits on grounds that the material is not "waste" or that it is hazardous because of chemicals that are used in the papermaking process. Only electricity sold to third parties qualifies for credits.

Another technical change affects companies with plants that make synthetic fuel from coal. A JOBS bill in October 2004 authorized section 45 tax credits to be claimed on new plants for making "refined coal." The new plants must be put into service during a window period that runs from October 23, 2004 through December 2008. The credits are $4.375 a ton. They run for 10 years after a plant is put into service. The product must have a market value at least 50% higher than the raw coal used to produce it. It must also reduce nitrogen oxide emissions / continued page 7

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fuels and the other co-products. Reliability guarantees are especially critical in a CTL project, as it employs technology similar to that used in IGCC projects. IGCC projects have suffered from long-term reliability issues in the past. As such, the debt and equity markets are likely to scrutinize the reliability guarantees offered by the contractor. Fortunately, it appears that these reliability problems are being corrected and gasification technology licensors could be more willing to provide long-term performance guarantees.

The two main risks in such projects are commodity risk and technology and completion risk. The challenge is to find financing structures that mitigate them.

The schedule guarantees would obligate the contractor to pay the developer delay damages if construction has not been completed by a date certain. These damages, in conjunction with contingency funds, would be necessary to ensure the financing parties that the developer will be able to pay interest during construction and other fixed-cost obligations, including payroll, insurance and take-or-pay obligations, in the event of construction delays.

Moreover, even if the construction contract contains appropriate performance and schedule guarantees, obtaining meaningful guarantees could still prove to be difficult due to the mammoth size of CTL projects. Ordinarily these guarantees could be given by turnkey contractors and supported by guarantees from the process technology licensors, but technology licensors of the Fischer-Tropsch process tend to be too small to provide a creditworthy guarantee of the magnitude required, and even the largest turnkey contractors and the licensors of gasification technology, such as General Electric, Shell and ConocoPhillips, may be reluctant to accept this potential liability alone. As a result, developers may be forced to accept non-traditional construction arrangements that will require careful structuring and risk analysis.

Given the need to share this risk, one likely scenario is that the first projects will be constructed by joint ventures between two or more contractors. Although a joint venture approach may ultimately be the best alternative, developers should appreciate that there would no longer be a single point of responsibility on the contractor's side. The financing community tends to prefer a single point of responsibility to prevent finger-pointing issues. However, this obstacle has been overcome in the past either by a willingness of the parties to the joint venture to accept joint and several liability with respect to the project company or through a sensible construction coordination arrangement.

Finally, the construction contract should have a guaranteed maximum price or the equity should be willing to provide appropriate completion support. Debt sources will likely be concerned that project cost overruns could occur due to unforeseen circumstances that may arise in connection with the design and construction of any new facility, especially one that is the first of its kind. As a result, the lenders are likely to seek assurances that either the contractor is willing to absorb any unforeseen cost increases or that the equity has access to a reasonable amount of additional funds that could be used, if necessary, to pay for any cost overruns.

At the end of the day, CTL technology has the potential to provide an abundant supply of relatively clean energy. The primary obstacles to widespread adoption of CTL are the continuing uncertainty over the price of oil and the need to find a project structure that allocates risks in a way that is simultaneously attractive to the investing, lending and construction communities. ◎

A One-Time Investment Opportunity in China

by Hong Li, May Sun and Edwin Lee, in Beijing

Foreign investors have a rare opportunity during 2006 to profit by buying "non-tradable shares" in Chinese companies that are partly owned by the government while such shares remain undervalued and then benefit from securities market reforms that will lead to conversion of the shares into tradable securities.

Background

The Chinese securities market is expected to grow in the next decade with continual improvements in the trading platforms of Shanghai and Shenzhen Stock Exchanges. Since the securities market reforms in the early 1990s, the total market capitalization has grown from RMB 104.8 billion in 1992 to RMB 3,364.5 billion by the end of 2005. Currently, there are 1,381 companies listed on the Shanghai and Shenzhen stock exchanges.

Market analysts point to recent consolidation of the Chinese securities market as an indication that listed companies in China are becoming safer investments. The annual trading volume on the Shanghai and Shenzhen stock exchanges increased from 3.8 billion shares to 301.6 billion shares in just 10 years from 1992 to 2002. The 2002 figure represents RMB 2,799 billion in total stock turnover.

The Chinese securities market distinguishes between A-class shares and B-class shares. The distinction is that A-class shares are subscribed and traded in domestic currency and are predominately reserved for Chinese citizens, while B-class shares are traded in foreign currencies and are open to both foreign and domestic investors. Historically, the A-class share market was seen as more exclusive. It was launched in 1990, two years before the B-class share market, and it covers all common stock issued in mainland listed companies. The A and B markets differentiate investors according to the underlying currency of their capital contributions rather than whether they are domestic or foreign investors.

The A-class share market is expected to grow more rapidly in the next decade than the B-class share market due to recent reforms in the trading of A-class shares.

The A-class share market is / continued page 8

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and either sulfur dioxide or mercury emissions, when burned, by at least 20% compared to the raw coal.

The technical change clarifies that anyone making refined coal in the future does not also have to show that the output is a "synthetic" fuel. In other words, there is no need to prove that it differs chemically from the raw coal.

The credits phase out as coal prices move across a range of $8.75 above the 2002 coal price. Both the $8.75 range and the 2002 coal price are adjusted for inflation.

Owners of existing synfuel plants may be able to qualify for another 10 years of tax credits by rebuilding their plants enough to have them considered "new" for tax purposes. The IRS treats a rebuilt plant as new if the amount spent on upgrades is more than 80% of the value of the rebuilt plant.

ENERGY COMPANIES are jostling for awards of scarce new energy tax credits.

A new energy bill that became law on August 8, 2005 authorizes an array of new tax credits for investing in energy projects in the United States, but many of the credits are limited in amount.

For example, Congress authorized up to $800 million in tax credits to be claimed on new IGCC (integrated gasification combined-cycle) power plants. Credits can be claimed on only part of such a plant — the equipment that is "necessary for the gasification of coal, including any coal handling and gas separation equipment." The credit is 20% of the cost of such equipment. The Internal Revenue Service must decide how to allocate the credits among companies that apply for them.

The lobbying has already started.

Mitch Daniels, governor of Indiana, wrote a letter in December to the US Treasury secretary on behalf of Cinergy, a large utility with operations in his state. Cinergy wants a share of tax credits for an IGCC plant / continued page 9

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segmented into tradable and non-tradable shares.

Tradable shares are shares with legitimate exit rights and are reserved to domestic investors and qualified foreign institutional investors.

Non-tradable shares prevent holders from exiting through a public offering. There are three kinds of non-tradable shares: state-owned-enterprise shares, legal person shares and natural person shares.

State-owned-enterprise shares are shares in companies with assets partly or wholly funded by the state; the government owns an equity interest in the companies. For instance, if 5% of a listed company's total equity is funded by the state, then this 5% can be defined as SOE shares while the remaining 95% non-SOEs can be issued as legal or natural person shares.

Legal person shares are shares held by a legal entity. Natural person shares are shares held by individuals and usually refer to shares issued to employees under an employee stock option plan.

Foreign investors are allowed by law to acquire both A- and B-class shares, but entrance into the A-class share market has, until recently, been limited to the purchase of non-tradable shares. Non-tradable shares represent more than two thirds of the A-class share market.

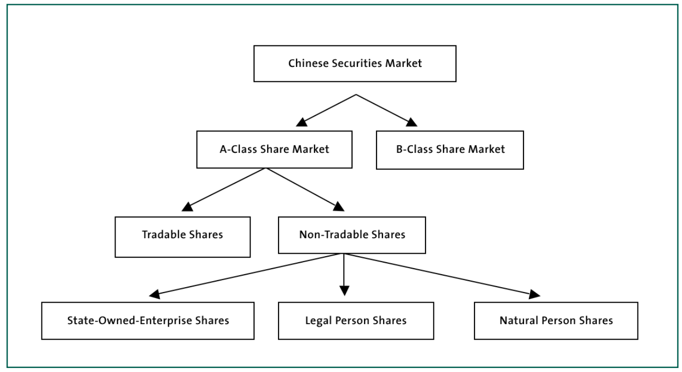
Recent Market Reforms

The original reason for segmenting the A-class share market was to protect state-owned enterprises from hostile takeovers by private investors. The State Council is gradually relaxing the restrictions as the Chinese securities markets mature.

The Chinese government first lifted the ban on foreign takeovers of Chinese companies in November 2001 in a joint release by the Ministry of Commerce and the China Securities Regulatory Commission called "Several Opinions on Relevant Issues of Listed Companies Concerning Foreign Investment." This was the first step toward moving from a fully state-controlled market to a more western market-based system.

On September 4, 2005, the government introduced further reforms in a bulletin called "Administrative Measures on the Share Separation Reform of Listed Companies." These latest reforms free up the A-class share market by removing the distinction between tradable and non-tradable shares.

Structure of Chinese Securities Market



Various laws, rules and industry codes have been adopted by Chinese policymakers in recent years to improve the transparency of the securities market. These rules are now continuously monitored by state agencies. There has also been greater cooperation between US and Chinese regulators to harmonize the securities practices of the two countries.

Chinese law recognizes the legal sanctity of transfers of listed shares. Shares purchasers have access to the Chinese courts to enforce their rights.

Practical Tips

Foreign investors thinking about buying shares in state-owned-enterprises — or companies that are owned partly by the government — should find the specific industry code for the company and comply with the relevant procedures for that category of company.

For example, all share purchases in SOEs are governed by the "Regulations on the Acquisition of Listed Companies," while specific share purchases may also be covered by the "Provisional Regulations on Mergers and Acquisitions of Domestic Enterprises by Foreign Investors." Each province also has its own codes that deal with specific cases of foreign investment.

In cases where there is a time lag between signing a purchase agreement and closing on the share purchase, the "Interim Measures for the Administration of State-Owned Assets" will apply. In cases where the legality of the share transfer is in doubt and there are guiding policies from government agencies, additional steps will have to be taken.

Five government agencies regulate securities transactions. The Ministry of Commerce controls foreign investment and must approve share purchases by foreign investors. The China Securities Regulatory Commission controls mergers and acquisitions of listed companies and approves foreign takeovers. The Ministry of Finance and the State-Owned Assets Supervision and Administration Commission jointly administer assignment of shares and must approve the transaction price. The State Administration of Foreign Exchange monitors foreign exchange risks.

Once a foreign investor has the necessary government approvals, the closing on the share purchase is straight forward. Settlement of the actual transfer and delivery of shares is done through the Depository Clearing Corporation system at the relevant stock exchange. Article 9 of the "Clearing Corporation Rule" stipulates that a settlement confirmation must be issued by the Depositary Clearing Corporation "within three working days after the receipt of the application." Share purchases paid in foreign currency must be registered with the State Administration of Foreign Exchange prior to the actual transfer.

It is in the interest of every foreign investor to register transactions so that he or she will have all available legal protections later.

Alternatively, a foreign investor may obtain protection by registering the change in shareholding with the State Administration for Industry and Commerce and then applying for a renewed business license for the target company to reflect the change. This has been a popular protective strategy for foreign investors.

Continuous disclosure requirements and corporate governance monitored by the various government regulatory agencies protect shareholders from corporate fraud, misleading information, abuse of minority rights and antitrust and monopoly issues. The new disclosure rules are aimed at protecting foreign shareholders. For example, article 6 of the "Clearing Corporation Rule 2005" facilitates e-disclosure, or public disclosure via the designated website of the stock exchange, and this gives foreign shareholders faster and cheaper access to public disclosures. This is expected to improve the speed and safety of international transactions in the Chinese securities market.

Investing in SOEs

The Chinese government announced / continued page 10

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the company plans to build. Daniels was head of the US budget office during the Bush first term.

Ken Kies, a high-profile Republican tax lobbyist, wrote the most senior tax policy official at Treasury in December asking for a meeting on behalf of SCANA Corporation, the parent of the South Carolina Electric & Gas Company. SCANA plans to build one or more nuclear power plants and is interested in a share of "production tax credits." The energy bill authorized anyone building a new advanced nuclear plant to claim tax credits of 1.8¢ a kilowatt hour on the output during the first eight years after the plant is put into service. However, there is a limit on the total number of projects that can qualify for credits of 6,000 megawatts. Kies is pressing Treasury to limit the credits to plants that file license applications with the US Nuclear Regulatory Commission by December 2009 and start construction by December 2015. Credits would be allocated ratably among eligible plants. The allocations would be made annually to plants that are operating during the year.

Agrium, Inc., a large Canadian fertilizer manufacturer, sent the IRS a memo in late December alerting the agency that it hopes to qualify for a tax credit on a new coal gasification facility that the company plans to build next to an existing fertilizer plant in Alaska. Agrium hopes to claim a 20% investment tax credit on the cost of the gasification facility. The energy bill limited the total dollar amount of such credits to $350 million. The memo comments on a number of technical issues that come up when trying to apply the statute.

CLEAN RENEWABLE ENERGY BOND applications must be filed by April 26.

Clean renewable energy bonds are a type of bond that municipal utilities, electric cooperatives and Indian tribes can use to borrow money for wind farms and other power plants that use renewable / continued page 11

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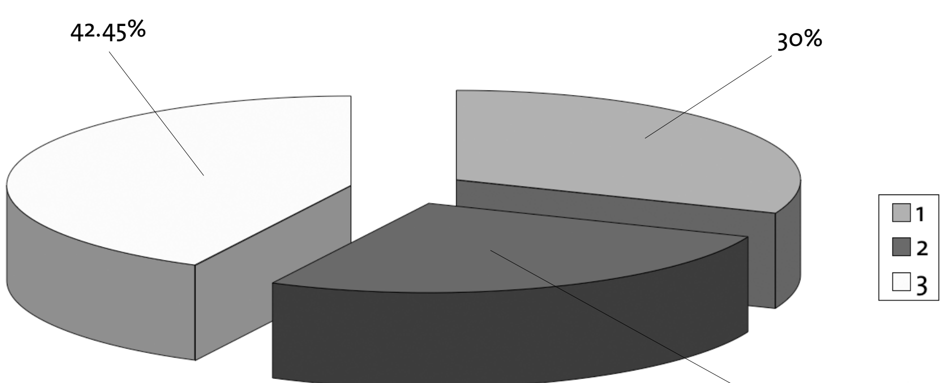
plans on August 23, 2005 to transform all tradable and non-tradable shares in the A-class share market. The reforms are expected to be completed by the end of 2006. The central government is actively encouraging provincial governments to cooperate with the reforms.

Non-tradable shares represent a significant percentage of the market capitalization of the A-class share market. The latest data suggests that only 30% of A-class market is tradable shares and remaining 70% is non-tradable shares. Since late August 2005, 26.55% of non-tradable shares have either been converted or are in the process of being converted into tradable shares. Chart 2 shows the relative percentages of tradable shares, non-tradable shares that have been or are in the process of being converted, and shares that remain non-tradable as of November 29, 2005.

Relative Ratio of Tradable and Non-Tradable Shares in A-Class Share Market



1. Tradable shares
2. Non-tradable shares undergoing conversion
3. Non-tradable shares yet to be converted

Foreign Investment Opportunities

Market analysts suggest that the remaining non-tradable shares may present a highly profitable strategy for foreign investors to penetrate the A-class share market at a fair market value.

There are various strategies.

An investor might acquire non-tradable shares to increase control over the existing share capital in a partly state-owned company. Greater control lets the investor improve the management structure and add value to the shares. Non-tradable shares can then be converted to tradable to increase the market capitalization of the underlying company. The conversion will also provide greater flexibility in hedging against currency risk through the B-class share market. Further, it gives the holder of the converted shares additional exit and entry rights in the A-class share market, thereby adding further to value.

Given the potential profitability of acquiring non-tradable shares before the A-class share market reform is completed, a foreign investor would need to consider how legitimately to acquire non-tradable shares. The new reforms set out the necessary procedural requirements. The transaction stages are summarized in the chart on the following page. It is important that the parties engage in a clear dialogue with the relevant authorities. Good legal advice can mitigate the risks of delay and information asymmetry at each stage in the transaction.

The successful entrance of Mittal Steel Co. in July 2005 into the Chinese steel market is an example of the advantages of acquiring non-tradable shares as a foreign investment strategy.

Mittal is a leading world steel company that is listed in The Netherlands and operates in India and the United Kingdom. Its objective was to expand its international presence and gain access to the vast Chinese market. In January 2005, Mittal engaged in negotiation with Hunan Valin Group, a leading state-owned steelmaker with an interest in expanding internationally. Mittal could offer advance technological and management expertise, while Valin offered a chance for Mittal to gain a foothold in the world's leading steel market. Mittal acquired a 36.67% stake in non-tradable shares from the parent company of Valin Iron and Steel Co Ltd. The price for the shares was US$338 million. The acquisition was expected to increase the value of both companies.

Transaction Stages When Buying Non-Tradable Shares

1. Negotiation of share purchase and internal valuation and net present value projections

2. Asset appraisal

   Relevant government agencies will screen the proposed purchase on the basis of
   (a) market value
   (b) shareholder protections
   (c) improvements in management

3. Submit purchase proposal for appraisal by regulatory agencies

4. Payment and registrations

The main challenge for foreign investors buying non-tradable shares is information asymmetry, which may lead to delays and deadlocks in the transaction. This information risk may be mitigated, where the parties have substantial market knowledge of the industry, by being careful to document everything properly.

Failure to deal prudently with regulatory risk can have a number of adverse effects on a transaction. Undervaluation of an A-class share / continued page 12

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fuels. The borrower does not have to pay any interest on the bonds. Rather, the lender is allowed to claim tax credits. Only $800 million in total in clean renewable energy bonds can be issued for all projects. All bonds must be issued in 2006 and 2007. The IRS will allocate the bond authority among interested projects if there is more interest in the bonds than there is capacity. Congress directed it to reserve at least $300 million of bond authority for electric cooperatives.

The IRS said in December that it plans to allocate the scarce bond authority by handing it out to the project that asks for the smallest amount of bond authority first — up to the full amount requested — and then to the next smallest, and so on, until all the bond authority has been used up. In so doing, the government rejected a request by the California state treasurer to allocate the bond authority among US states based on population. A list of the information that must be included in an application is in Notice 2005-98.

The American Public Power Association has been talking to the Treasury Department about how arbitrage restrictions will be applied to the bonds. The US tax code bars state and local governments from borrowing at tax-exempt borrowing rates — or, in this case, at a zero rate — and then reinvesting the proceeds in other securities, commodities or similar investments that earn a higher return.

BIODIESEL companies are angry about an apparent decision to allow tax credits on fuel made with imported biodiesel.

"Biodiesel" is processed oil from plants, like soybeans, sunflowers and rapeseed. It is then mixed with gasoline or diesel fuel to make a biodiesel mixture that can be used in motor vehicles. The US government rewards fuel blenders who mix biodiesel with vehicle fuel. It allows a tax credit of 50¢ or $1 a gallon to such blenders. The higher credit applies to biodiesel made from agricultural sources. / continued page 13

China

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company's assets can lead to rejection of the transaction price by the State-Owned Assets Supervision and Administration Commission as unfair. Chinese companies follow international appraisal standards. Therefore, the main difficulty foreign investors face at the valuation stage is largely informational rather than divergence in appraisal methods. This problem can be reduced through due diligence and an active dialogue.

Submissions for government approval to convert non-tradable shares to tradable shares must be accompanied by legal opinions, a feasibility study report and other materials.

Both the Ministry of Commerce and the State Administration for Industry and Commerce are actively engaged in screening out foreign investment aimed at gaining monopoly control over the Chinese market. Where a foreign acquisition represents a clear breach of antitrust and monopoly rules, it may be rejected as illegitimate after a public hearing. A foreign investor is provided with ample opportunity to challenge the basis of an administrative decision by providing additional material to rebut a claim of breach.

Anyone acquiring listed stock representing more than a 30% ownership interest must make a tender offer to all the existing shareholders. However, a foreign investor may apply to the China Securities Regulatory Commission to be exempted from this requirement. Where the share purchase can be viewed as improving the efficiency of the Chinese market or where it adds value to the internal management of a SOE, an exemption would probably be granted. ◎

Mexico Addresses "Earnings Stripping"

by Jose Ibarra, with Chevez Ruiz Zamarripa y Cia, in Mexico City

Mexico is continuing to tinker with strict limits it imposed a year ago that were supposed to limit the ability of Mexican companies to deduct interest paid to related shareholders.

The limits — called "thin capitalization" rules — prevent Mexican companies from deducting interest paid to anyone to the extent the companies have debt-equity ratios greater than three to one.

The thin capitalization limits took effect on January 1, 2005, but have been a source of controversy since then because key details about how to apply them remain vague. Suits are pending in the Mexican courts to have the limits declared unconstitutional. President Vicente Fox issued a decree on October 21, 2005 relaxing the restrictions by allowing money borrowed from financial institutions and spent on productive investments not to be counted as debt. Congress — at the request of the president — passed a new law in late November that broadens the exception. The new law, to be effective January 1, 2006, should permit a Mexican tax deduction for interest on most project financing notwithstanding the taxpayer's debt-equity ratio.

Background

The Mexican thin capitalization limits deny interest deductions on that portion of a taxpayer's debt that exceeds a 3-to-1 debt-equity ratio.

Equity for purposes of the ratio is probably shareholders' equity as reported for financial statement purposes.

The taxpayer's debt for the tax year is determined by taking the average of its debt on the last day of every month during the year. However, the word "debt" is not defined, and it is unclear whether accrued liabilities and trade payables are to be counted in determining the debt-equity ratio.

There is a five-year transition period that may enable taxpayers to avoid having their interest deductions denied if they are able to reduce excess debt "proportionately in equal parts" over the five-year period. It is unclear what the consequences are if the taxpayer reduces its excess debt more quickly than "proportionately in equal parts" over the five years.

The thin capitalization rules apply to all related-party loans and to third-party loans from creditors located in or outside of Mexico. Under the law as originally enacted, third-party loans are exempted from the 3-to-1 debt-equity ceiling only if the borrower obtains a ruling from Mexican tax authorities that all of its inter-company transactions are reasonably priced under approved transfer pricing methods.

The Fox administration proposed legislative amendments to the thin capitalization rules throughout 2005, concerned that the rules would impede the long-term financing needs of Mexican infrastructure projects and manufacturing operations. On October 21, 2005, the administration issued a decree that created an exception from interest deduction denial for debt incurred to finance qualifying projects.

The presidential decree allows debtors to exclude from their debt-equity ratios any financing obtained from the financial sector that can be allocated to the construction, operation or maintenance of productive infrastructure or the manufacturing of fixed assets. To qualify, at least 80% of the loan must be used in the acquisition or construction of fixed assets, land or engineering projects. There are some additional requirements that are designed to ensure that the financing is in the nature of a typical long-term infrastructure financing, one of which is the creditor must impose conditions on the borrower in order to conserve the borrower's financial resources. To qualify for the decree exception, the financing contracts must contain at least six of 16 specified creditor-friendly terms, such as a provision permitting the creditor to appoint a member of the borrower's board of directors and a provision prohibiting the borrower from entering related-party transactions without creditor approval. If existing loans are refinanced to comply with these requirements, then they can qualify for the exception from the thin capitalization rules provided by the decree.

At the same time that the decree was issued, several legislative proposals to change the thin capitalization rules were being considered. On October 28, the lower house of the Mexican Congress approved a tax bill containing a broad exception from the thin capitalization rules. The exception permitted the deduction of interest on third-party debt if it incorporated the restrictions on borrower behavior that are typically imposed by unrelated creditors. The proposed legislation was more generous than the presidential decree because it did not limit the thin capitalization exception to infrastructure projects or to financing from the financial sector.

On November 17, the Mexican Senate unanimously adopted a modified version of the proposed thin capitalization exception, along with several other tax changes. The tax bill — to be effective January 1, 2006 — is expected to be signed by the president. */ continued page 14*

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Ten US congressmen wrote the Treasury secretary in November to complain about an apparent IRS decision to allow blenders who use biodiesel from palm oil to claim the $1-a-gallon incentive. The congressmen complained that palm oil is not produced in the United States, and that the decision only benefits farmers in Ecuador, which is preparing to export three millions gallons of palm oil-based biodiesel a month to the United States.

US biodiesel production was 30 million gallons in 2005. It is expected to grow exponentially in the next few years.

PARTNERSHIPS with both US taxpayers and foreign or tax-exempt entities as partners got another reprieve from the IRS.

Congress appears inadvertently to have limited the ability of US taxpayers participating in such partnerships to take deductions from them. An example of such a partnership is where a US company owns a wind farm in the United States in partnership with a foreign wind developer or a municipal utility. Any deductions tied to "tax-exempt use property" can only be used to offset income from the partnership. They cannot be used as shelter for income from other sources.

The wind farm will be considered partly tax-exempt use property unless the parties 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 remain partners.

The limits on deductions are in section 470 of the US tax code.

IRS said in December that it is delaying enforcement of the limits in most partnership cases for another year. The announcement is in Notice 2006-2. The limits will now be applied for the first time to deductions in tax years that start in 2006.

The IRS acted 48 hours after receiving a letter from the chairmen */ continued page 15*

Mexico

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New Exception

Under the new rules, Mexican companies with debt-equity ratios above 3-to-1 will be permitted to deduct the interest paid or accrued on qualifying loans from third-party lenders. These qualifying loans are excluded from the calculation of the taxpayer's debt for purposes of the debt-equity ratio.

The exemption applies to all financing from unrelated parties that restricts the borrower's ability to do all of the following: sell fixed assets, reduce capital or issue new share capital, distribute dividends or profits, enter into new financing, and impede the lender's rights under the financing agreement.

The new legislation also spares taxpayers with excess debt who cannot deduct all their interest payments from having to include the excess debt in computing inflationary income (defined as the inflation effect for the year on average liabilities), thus eliminating a double hit to those taxpayers.

Unfortunately the new legislation fails to clarify some aspects of the thin capitalization rules that are not well understood. As originally enacted, the rules contained a five-year transition rule under which the interest expense on debt in excess of the 3:1 ratio does not become nondeductible unless the taxpayer's debt-equity ratio remains excessive for the five years. There is no penalty if the taxpayer is able to reduce excess debt "proportionately in equal parts" over the five years, but there is no guidance as to what this requires or whether a failure to reduce debt sufficiently in one year can be rectified by extra reductions in a subsequent year.

The new legislation also fails to clarify whether general trade payables and other accrued liabilities — for example, court-ordered damages — are "debt" for purposes of computing the debt-equity ratio.

Taxpayers can choose to apply the new tax legislation retroactively to January 1, 2005.

Meanwhile, a significant number of Mexican companies have taken legal action against the thin capitalization rules in general, going to the courts and filing "amparo" suits.

The courts have yet to rule, but there is a strong feeling among tax litigation experts that there are enough grounds for the courts to rule for the taxpayers. ◎

Electric Power Sector Reform in Russia: Where Are We Now?

by Christopher Owen and Oxana Gorshkolepova, in Moscow

Reform in the electric power sector in Russia has been a major work in progress for years. Under the most recent plan, RAO UES of Russia should itself be phased out at the end of 2006. But, according to the internal materials of RAO UES of Russia, this is now unlikely to happen earlier than 2008.

This article looks at the progress to date and what we can expect in the short and medium term.

Despite some delays in the implementation of certain elements of the future market model and a complex coordination process between the government and UES, power reform seems to be almost halfway there. The transition market model is scheduled to run through 2008. From the year 2009 onwards a free competitive market is expected to be in place.

Background

UES is an enormous electric utility. The company is a holding company that owns controlling stakes in 73 regionally vertically-integrated utilities in Russia. It owns 72.4% of the installed generating capacity in the country, 96.1% of the high-voltage grid, and 77% of the distribution network. It owns 100% of the Federal Grid Company and 100% of the System Operator, which operates the grid. The Russian government has been moving for some time toward privatizing UES.

The basic principles for reform of the Russian electricity market were legislated during 2001 to 2003. In July 2001, these principles were defined in a "Decree on Restructuring the Electric Power Industry of the Russian Federation." In mid-2003, a series of laws came into force, including the "Law on the Electric Power Industry." In connection with this decree and these laws, several regulations were adopted, in particular the "Rules of the Wholesale Electric Power Market (Capacity) During the Transitional Period." Rules on the operation of the electric power retail market should be adopted shortly.

The electricity market reforms envisage restructuring formerly vertically-integrated companies that combined all industry functions, by splitting them into a separate monopoly sector — electric power transmission and operational dispatcher control — and a competitive sector — electric power generation, sales, repairs and related services.

The end goal of power reform is a fully competitive wholesale market. However, a prerequisite for such a market to develop is the full de-monopolization of the electric power sector.

Electric power sale-purchases during the transitional period are to be made through two sectors: the free sector, launched on November 1, 2003, and the regulated sector. Within the regulated sector, there is also a trade in differential between the actual and requested capacity of electric power production or consumption.

Wholesale and Retail Markets

To be eligible to engage in electric power sale and purchase transactions, the administrator of the trading system — called "ATS" — must give a participant the status of a wholesale market participant, followed by subsequent registration with ATS. In addition, a participant must execute a standard agreement with ATS for access to the wholesale market trading system.

The functioning of the wholesale market depends on freedom for market participants to choose counterparties and the prices at which they want to buy or sell, and to enter into bilateral agreements for the sale and purchase of electric power.

For additional information, please refer to the table below.

Functions of the Sector's Key Institutions

1. The Federal Grid Company administers the unified national electric power grid.

2. The System Operator ("SO"):
   – is responsible for operating the grid,
   – provides technical grid connection of generating equipment held by any legal entity or individuals pursuant to their ownership or other rights, and
   – offers electric power transmission services.

Note: The reform proposals call for more than 75% of the Federal Grid Company and the SO to remain state owned.

3. ATS organizes electric power sale-purchases in the wholesale market. For example:
   – ATS, together with the SO, enters into an agreement with a new participant in the wholesale market regarding the terms and conditions of access to the trading system of that market, and
   – ATS registers electric power sale-purchase agreements between the supplier and consumer. */ continued page 16*

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and two "ranking" members of the House and Senate tax-writing committees asking the agency to delay enforcement in order to give Congress more time to fix the tax code so that the limits no longer apply to most partnerships. The letter said Congress is trying to rewrite section 470 so that it only catches partnerships that are used in "abusive" transactions. The delay in IRS enforcement does not apply to abusers.

An example of an abusive transaction is a "synthetic SILO" where a partnership is used to replicate the benefits that US institutional investors used to get from buying equipment from a foreign or US municipal user of the equipment and leasing it back to the user. The user would put most of the purchase price in a bank account, called a defeasance account, with instructions to the bank to pay rent when due and to pay a purchase option price at the end of the lease term if the user decided to buy back the equipment.

TELEPHONE COMPANIES are fretting about having to collect excise taxes on long-distance telephone calls after the US government lost for the tenth straight time in court in lawsuits by large customers to get their tax money back.

The latest losses were in suits by AMTRAK — which runs passenger trains in the United States — and OfficeMax, an office supply chain. Both decisions were at the appeals court level.

The US government is litigating another 19 cases. Taxpayers have won $12 million in refund claims to date.

The United States imposes a 3% excise tax on long-distance telephone calls. Telephone companies act as collection agents. The tax statute is badly out of date. The tax applies only to calls that are billed on the basis of time and distance. Almost all long-distance service in the United States is now billed at a flat, per-minute rate or by charging */ continued page 17*

Russia

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Participants in the wholesale market are free to determine the price for electricity based on a a so-called equilibrium price, which is a function of supply and demand and is arrived at either by comparing the bids of electric power providers with a selection process done by ATS, or the parties can fix the contract price on their own by means of a two-party agreement.

The retail market is more strictly regulated. To ensure stable power supply conditions and to prevent price escalations, the state introduced regulated bilateral agreements, in which capacity and price-related terms are set directly by the State.

To date, more than 30 regional generation companies — called "AO-Energos" — have been privatized. All seven wholesale generation companies envisaged in the reform proposals have been established, and the majority of 14 territorial generation companies envisaged have completed their state registration. By 2008, UES is intended to be phased out. Following the end of the transitional period, the majority of shares in the wholesale and territorial generation companies will be privately owned.

According to information available on the web-site of UES, the shares of the new companies will be proportionally distributed among the shareholders of the respective AO-Energos.

For political reasons, the state has been taking very gradual steps to exit the retail market. A transitional retail market, where part of the electric power supplied will be at competitive prices, is scheduled for 2006. However, the state will keep control over prices for individual consumers even when the transitional retail market is in operation.

An arbitration tribunal has been established within ATS. This is a permanent arbitration tribunal that considers economic disputes arising out of civil contracts in the electric power industry, provided the parties have agreed to submit to its authority. The tribunal provides the parties to a dispute with the following advantages: shorter periods for consideration of their disputes as compared with other arbitration courts, a simplified arbitration hearing procedure, the right of the party to select an arbitrator to hear a dispute and enhanced confidentiality.

Investments

In September 2005, the Ministry for Industry and Energy submitted to the Russian government a draft of a planned "Decree on Investment Guarantee Mechanisms for the Construction of Generation Facilities." The aim is to ensure that investors will be reimbursed for an amount equivalent to the difference between the market electric power price and the payback price for a fixed payback period. The draft is currently under consideration within the Russian government.

Under the terms of the draft, an investor will be selected through a tender to be held by the System Operator with the participation of representatives of the local authorities. Preferred projects will be those using state-of-the-art technologies for generating facility construction. According to the information available, the draft proposes to limit the aggregate capacity of the facilities built under the investment guarantee mechanism to 5,000 megawatts. The mechanism contemplated in the draft is planned as a transitional stage of reforming the power sector. It is a provisional measure providing for the construction of new generation facilities in certain regions with power deficits.

There is still a lack of investment into the Russian electric power sector in general. There are several underlying reasons, but the majority of large industrial consumers would expect to be served directly by generating companies, and distribution companies limit their focus to the retail market. Generation activities look more attractive to potential investors. ◎

Holland Opens for New Energy Investments

by Frederik Bernoski and Elizabeth van Schilfgaarde, with NautaDutilh in New York

A proposal for "unbundling" or separation of the regulated and unregulated gas and electricity businesses of Dutch energy companies is expected to be debated in Parliament at the end of January. If adopted, the proposal will open new investment opportunities in the Dutch energy sector. However, it is controversial.

Background

The Netherlands government sent a proposal to Parliament at the end of August 2005 for restructuring the energy market. The core element of the proposed legislation is the obligatory unbundling of all integrated energy companies into "network companies" that transport energy, on the one hand, and "commercial energy companies" that supply or produce gas or electricity as a commodity, on the other.

The government expects that the unbundling will create a level playing field in the commercial energy — or commodity — business by taking away from gas and electricity suppliers the advantages of the natural monopoly offered by also owning the network. It also expects that the increased cost transparency of the network managers will benefit consumers.

A further objective of the proposal is to give the present shareholders of Dutch energy companies the opportunity to divest their interests in the commercial energy business. Practically all integrated energy companies are owned currently by municipalities and provinces. Privatization of network activities is not allowed. Following implementation of the unbundling proposal, the current public shareholders will be able to sell their stakes in the commercial energy business, while maintaining, at least for now, ownership of the shares in companies operating the networks.

Two Dutch energy companies have already unbundled and sold their commercial energy subsidiaries in anticipation of the new legislation. On June 6, 2005, Intergas Energie sold its commercial energy company to the Danish DONG. The gas and electricity network remained with Intergas Energie. On September 14, 2005, the fifth largest energy supplier in The Netherlands, NRE Holding, sold its commercial energy companies to E.ON Benelux. The electricity network remained with NRE Holding. Most surprising was the acquisition by Macquarie European Infrastructure Fund of a 49% interest in the network company of NRE, conditional upon obtaining the required consent for such a sale.

The government expects to be able to debate the proposal in the second chamber of Parliament by the end of January 2006. If the proposal is adopted, it will have to be sent to the first chamber for final approval.

Unbundling

The proposed legislation prohibits the operation of gas and electricity networks and the commercial energy business within the same group of companies. Furthermore, network companies will not be allowed to hold shares of companies engaging in the commercial energy business, and vice versa. Therefore, if the proposed legislation is / continued page 18

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a fixed price for an unlimited number of calls. The Congressional Budget Office estimates that the tax brings the federal government $1.6 billion a year.

Twenty telecom companies and a trade association sent the US Treasury secretary a letter in December urging the government to drop the tax. The IRS put the phone companies on notice in late October that it expects them to continue collecting the tax. At least two long-distance carriers — AT&T and Cingular Wireless — reportedly remove the tax from monthly bills if requested by a customer.

Many large companies have been advised by tax counsel to file protective refund claims even if they do not intend to litigate in case the government decides to make refunds.

DOUBLE DIPPING is "alive and well . . . with a little bit of finesse," said one tax expert after a federal district court decision in late October.

He was not suggesting the company involved in the case was itself involved in double dipping, but that the court's reasoning opened the door to such transactions.

Berkshire Hathaway borrowed $750 million in four debt offerings in the late 1980's and used the money to inject capital into a reinsurance subsidiary, National Indemnity Company, in an effort to turn the company into a major player in the reinsurance market.

When a domestic corporation pays dividends to a US parent, the parent company does not have to pay income taxes on 70%, 80% or 100% of the dividend depending on the circumstances. That's often because the parent can claim a "dividends-received deduction."

Congress became concerned in the 1980's about situations where a corporation borrows to buy stock in another company. In such cases, not only does it not have to pay taxes in full on the dividends it receives from the company whose stock it purchased, but it also has a deduction for interest it / continued page 19

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adopted, the currently integrated Netherlands energy companies will be required to spin off either their energy networks or their assets and activities relating to the commercial energy business.

The energy companies will have two years to implement the required changes after the proposed legislation comes into force.

A proposal to force the "unbundling" of integrated electric and gas companies in The Netherlands should create new investment opportunities.

Municipalities, provinces and the state will not be affected by the unbundling requirement. They are allowed to continue holding shares in both network companies and commercial energy companies. However, these interests will have to be held through separate holding companies.

The unbundling requirement relates solely to energy companies that are active in the Dutch commercial market and are operating networks located in The Netherlands. It will remain possible for companies operating energy networks located outside of The Netherlands to hold shares in a company participating in the production, trade or supply of energy in the Dutch market and vice versa.

Spinoffs of the kind proposed would ordinarily lead to imposition of a real estate transfer tax on the immovable property involved, including the networks. However, the proposal exempts from real estate transfer tax all transfers of immovable property that take place in the course of the obligatory unbundling. In addition, the Tax Plan 2006 contains a more general exemption of networks from real estate transfer tax.

Investment Opportunities

The Dutch government envisages that, after the unbundling requirement is implemented, there will be two groups of energy companies in The Netherlands: companies in which one or more subsidiaries operate gas or electricity networks — called "network companies" — and companies engaging in the commercial energy business.

No further restrictions are placed on the ownership of commercial energy companies. Once the unbundling is implemented, the current shareholders can sell their stakes to private investors. In addition to the NRE and InterGas transactions that have already closed, there are many more transactions already rumored to be under negotiation.

The recent conditional acquisition by Macquarie of a 49% interest in the NRE networks can be seen as an indication of the appetite in the market for Netherlands energy networks. However, it is unclear whether private investment in network companies will be possible in the foreseeable future.

Netherlands law currently prohibits privatization of networks and network companies. Restrictions on privatization have been part of the Electricity Act since 1998 and part of the Gas Act since 2000. However, these restrictions were seen initially as temporary measures only, to be lifted in 2006 at the latest (when the energy supply market would be fully liberalized).

On or about March 2004, when obligatory unbundling was first raised by the government, the government indicated that the prohibition on the privatization of networks could be lifted, at least for minority interests in network companies, upon the unbundling requirement becoming law. Full privatization would be allowed, in the view of the government, upon full implementation of the law. When it released the legislative proposal in August 2005, the government indicated that it expects to be able to allow a minority privatization upon the law going into effect. However, an explanatory memorandum released at the same time did not directly address the timing for allowing full privatization.

More recently, on November 20, 2005, in its response to hundreds of questions submitted by Parliament about the proposal, the government indicated that it would allow privatization of a minority interest in network companies only after full implementation of the unbundling legislation: therefore, no sooner than two years after it comes into effect. According to the November 20, 2005 response, whether full privatization will ever be allowed remains to be seen.

Opposition to Unbundling

Although a majority in Parliament appears to be in favor of the unbundling proposal, there is strong opposition from the four largest Netherlands energy companies, from certain municipalities and provinces and from the Christian Democrats, a party that is a member of the governing coalition.

The energy companies claim the legislation "has the potential to create substantial inefficiencies in the Dutch energy sector, could jeopardize the reliability of the energy supply and could lead to considerable and unjustified costs for Dutch consumers, energy companies, the shareholders of the Dutch energy companies and the Dutch taxpayers." The provinces of Zeeland, Gelderland and North-Brabant, which hold shares in Delta, Nuon and Essent, respectively, are opposed to the proposed legislation. The provincial government in North-Brabant believes that privatization, with its loss of control over energy companies, would lead to loss of jobs in the province and less production of "green" power. However, the province of Friesland is reportedly very much in favor as is the city of Eindhoven, and they wish to sell their shares in Nuon and NRE, respectively, as soon as possible.

A major objection against the proposal raised by the energy companies is that the unbundling will make Dutch energy companies easy acquisition targets for other European energy companies that are not subject to similar restrictions and will also put them otherwise at a disadvantage when competing within the northwestern European market. However, the Netherlands government — or, more specifically, the Netherlands minister of economic affairs — is convinced that Europe will ultimately follow the Dutch unbundling model.

Although the European commissioner for competition, Ms. Smit Kroes, has openly supported the minister of economic affairs, the other members of the European Commission remain silent on whether the Dutch policy for unbundling should be implemented on a / continued page 20

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pays on the debt to acquire the stock. This leaves it with very little tax exposure.

Congress became unhappy about this "double dipping" of interest and dividends-received deductions after T. Boone Pickens used it to make a run at Gulf Oil. Congress tried to put a halt to the practice in 1984. Section 246A of the US tax code, enacted that year, reduces the dividends-received deduction to the extent that a corporation borrows money to buy stock in another corporation. The parent must own at least 50% of the other corporation for the limits to apply (except in some cases where the threshold is as low as 20%).

In Berkshire Hathaway's case, the IRS read a *Forbes* magazine article suggesting that the company uses its insurance subsidiaries to hold preferred stock and receive partially-taxed dividends. The IRS assigned an agent to the case. The agent spent three years purporting to trace the four borrowings in the late 1980's to stock that Berkshire Hathaway bought around the same time as the borrowing and directed the company to pay $16 million in back taxes and interest.

A federal district court rejected the IRS claim in late October. The agent basically assumed that the money went into shares in other companies that Berkshire Hathaway purchased around the same time on the theory that money is fungible and because the parent company was fairly diligent about keeping spare cash anywhere in the Berkshire Hathaway group fully invested. The judge said this was too thin a connection. Borrowing must be "directly traceable" to a purchase of shares in another company in order for section 246A to apply. The judge said he realized this reading of the statute makes it "virtually impossible" for the IRS to apply section 264A against big companies that have lots of transactions, but any decision to loosen the direct connection must come either from Congress or from the IRS through exercise of its authority to issue regulations. The / continued page 21

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European level. In this respect, it is interesting to note that according to *The Business Sunday*, the European Commission is currently in the process of reviewing the energy markets in Europe. It intends to impose fines on French and German energy companies for violating competition law, specifically for the lack of transparency between their commercial and network businesses. Although not explicitly named in the report itself, *The Business Sunday* suggests that the report is referring to EdF, RWE, GDF and E.ON. If this is indeed the case, then these companies in future might have to spin off certain of their activities. These developments would support the proposals of the Dutch government and take the discussion surrounding required unbundling of integrated energy companies to a European level.

Possible Amendment

The Christian Democratic party, which has so far strongly opposed the unbundling proposal despite participating in the governing coalition, announced recently that it might be willing to accept unbundling, provided privatization of network companies will not be allowed. It also insists on assurances that the issue will not be revisited until at least three years have passed after the legislation has been fully implemented by the energy companies. At that time, the effects of the proposal should first be evaluated. After the evaluation, Parliament will decide whether a minority privatization of 49% of the shares of network managers can be permitted. However, under the Christian Democrats' proposal, full privatizations would not be allowed at any time.

The largest opposition party, PvdA, has indicated that it looks favorably at the proposed amendment. As a result, the Christian Democrats' amendment, if submitted, has a fair chance of being accepted.

Outlook

The shares in most integrated energy companies in The Netherlands are held by provincial and municipal governments. These shares are currently locked up as a result of the prohibition on privatization of network companies.

If the proposed legislation becomes law, the energy companies will have to split up into commercial energy companies and network companies. Most likely a substantial part of the commercial energy companies will then be put up for sale (to the extent they are not already on the market).

Even if the proposed legislation becomes law, it remains to be seen whether network companies will be up for sale. The government's current position is that it would be in favor of allowing the privatization of a minority interest after the unbundling is implemented, which would be two years after the proposal comes into effect. However, a majority appears to be forming in Parliament that would not allow such a minority privatization until, at the earliest, three years after the implemented unbundling: therefore, five years after the law comes into effect.

More information on the extent of investment opportunities in the Netherlands energy market should become available in the coming months. ◎

FERC Moves to Implement New Energy Law

by Adam Wenner, Robert Shapiro and Donna J. Bobbish, in Washington

The Federal Energy Regulatory Commission began issuing final rules in December to implement parts of a new energy law that President Bush signed on August 8.

The new law repealed a 1935 statute, called the Public Utility Holding Company Act, or "PUHCA," thereby eliminating restrictions that currently prevent parent companies of utilities from owning non-utility businesses or owning utilities in other regions of the United States. Congress gave new authority to the Federal Energy Regulatory Commission over a larger group of "holding companies." It gave FERC expanded authority over mergers, securities and asset acquisitions under the Federal Power Act, or "FPA," and radically modified the rights of qualifying facilities, or "QFs," under the Public Utility Regulatory Policies Act, or "PURPA."

FERC has issued final rules relating to PUHCA and modifications to the FPA. Under those rules, there are significant book-keeping requirements for holding companies. Acquisitions, by public utilities and holding companies, of small voting interests in QFs and exempt wholesale generators, will now require FERC approval. In addition, in FERC's proposed rulemaking to revise the PURPA rules for QFs, FERC proposes for the first time to subject many existing and new QFs to rate regulation under the Federal Power Act.

Background

The utility industry has for decades insisted that any comprehensive energy bill include PUHCA repeal because regulation of holding companies under PUHCA was so restrictive. Under PUHCA, a company that owns or controls at least 10% of the voting securities of an electric or natural gas utility company is a "holding company." PUHCA requires utility holding companies to obtain advance approval from the SEC for their securities issuances and inter-corporate transactions, requires all utility subsidiaries of a utility holding company to be in the same area or region of the country, restricts companies not already in the utility business from becoming active owners of utilities in more than one state, and bars companies that own utilities from engaging in lines of business other than owning utilities and related businesses.

The new energy law removed these restrictions by repealing PUHCA and replaced SEC regulation of holding companies with "books and records" oversight by FERC and state public utility commissions. PUHCA will be repealed as of February 8, 2006.

With the repeal of PUHCA finally accomplished, holding companies had assumed that they would be relieved of the kind of regulation to which they had been subject under PUHCA, subject only to "books and records" oversight by the FERC, as required by the new law. Instead, over the objections of industry commenters and Representative Joe Barton (R-Texas), chairman of the House Committee on Energy and Commerce and a leading sponsor and drafter of the new energy law, who took the highly unusual step of filing comments, FERC in its regulations implementing PUHCA repeal subjects "holding companies," even entities that were exempt from regulation under PUHCA, to new reporting and recordkeeping requirements.

Books and Records

FERC issued new regulations in December that require holding companies and their affiliates to maintain and make available to FERC or to state commissions books and records that show the costs incurred by affiliated electric utility and gas companies that affect rates subject to FERC's or a state commission's jurisdiction. / continued page 22

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case is *OBH, Inc. v. United States.* It was one of first impression for the courts.

The IRS is currently proposing to change its regulations to adopt a pro rata *allocation rule to determine the use of borrowings that are not traceable to a specific use. It proposed the change in May 2004.*

TRANSMISSION GRIDS became a little easier to transfer.

The IRS told a group of municipal utilities that financed their transmission grids with tax-exempt debt, and then later put the grids under the control of an "independent system operator," that the action would not cause loss of the tax exemption on their bonds.

Tax-exempt debt cannot be used to finance equipment that will be put to more than 10% private business use. The independent system operator in this case auctions "firm transmission rights" in the grids under its control to the highest bidders. Whether bonds are tax exempt is determined based on the expected use of the equipment financed with them when the bonds are issued. However, a "deliberate action" later to allow private use will cause loss of the tax exemption.

The IRS regulations recognize that it is US government policy to require open access to the electricity grid. Therefore, use of a municipal grid by a private party is not considered impermissible private use to the extent the municipality is simply complying with US law. However, it is impermissible private use if the municipality makes a conscious "sale, exchange, or other disposition" of all or part of its grid to a private person.

The IRS ruled privately to a joint entity in which a number of municipal utilities participate that the transfer of operational control of their grids to the ISO and sale by the ISO of firm transmission rights are not a "sale, exchange, or other disposition" of the grids.

To have gone too far, the utilities would have had to transfer an */ continued page 23*

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The FERC regulations exempt from books and records review any entity that is a holding company solely because it owns qualifying small power production or cogeneration facilities under PURPA, known as "QFs," exempt wholesale generators, known as "EWGs," or non-US utility companies, known as "FUCOs." (Holding companies that own EWGs or FUCOs are exempted from FERC review, but not from state commission review.) FERC's new regulations also provide for possible exemptions from its books and records regulations, upon request, for several classes of persons and transactions, including passive investors, mutual funds, collective investment vehicles, utilities subject to FERC jurisdiction without captive customers, electric power cooperatives and natural gas local distribution companies.

Beyond these statutory requirements, however, and against the urging of numerous commenters, including Rep. Barton, FERC adopted "modified, streamlined versions" of several forms and regulations relating to recordkeeping, financial statements, accounting and reporting requirements that had been used by the SEC to administer PUHCA. In adopting these SEC regulations as its own, FERC rejected arguments that "PUHCA 2005" — or the part of the new energy law that replaces PUHCA — does not provide the FERC with authority either to require entities to file reports or to adopt the SEC regulations.

A number of entities are exempted from the requirements of PUHCA 2005 by statute. The new regulations also allow single-state holding companies, holding companies that own generating facilities totaling 100 megawatts or less used for their own load or sales to affiliated end-users, and investors in independent transmission companies to request a waiver of the recordkeeping and reporting requirements.

The SEC forms and regulations that FERC has adopted to implement its books and records oversight of holding companies previously applied only to registered holding companies. FERC will apply them more broadly than the SEC did. The agency decided it would not recreate the old PUHCA distinction between "registered" and "exempt" holding companies for purposes of future books and records oversight of holding companies. The new FERC regulations subject the new, broader category of "holding companies" that are not otherwise exempt to the books and records requirements of PUHCA 2005.

FERC is proposing to subject certain QF projects to ratemaking oversight. It could leave the projects in regulatory limbo.

All entities that meet the definition of a "holding company" under PUHCA 2005 on February 8, 2006 must file a form notifying FERC of their status as a holding company.

Furthermore, holding companies that qualify for an exemption from the books and records requirements of PUHCA 2005 must file a form notifying FERC that they qualify for an exemption. An entity that becomes a holding company after February 8, 2006 must file a form notifying the FERC of its status within 30 days after it becomes a holding company.

Formerly registered holding companies currently subject to the SEC's record-retention rules have the option of complying with the new FERC rules or continuing to comply with the SEC rules during 2006. However, they must begin complying with the new FERC rules by January 1, 2007. On the other hand, formerly exempt holding companies that currently do not follow either SEC or FERC recordkeeping requirements are not required to comply with new FERC record-retention requirements until January 1, 2007.

EWG and FUCO Certification

The new FERC regulations allow entities to continue to obtain EWG and FUCO status, but under new procedures. EWGs and FUCOs are legislative creatures of PUHCA, in that the 1992 legislation that created these classifications did so by adding amendments to PUHCA. The benefit of EWG status under PUHCA was exemption from the requirements of that law. EWG and FUCO status continues to be relevant under the new regulatory scheme for utility holding companies, because Congress required FERC to exempt from the new books and records requirements entities that are holding companies solely because they own QFs, EWGs and FUCOs.

The new FERC regulations establish procedures for both individual approval of EWG and FUCO status by FERC and "less burdensome" procedures for self-certification of EWG and FUCO status, similar to the options that have been available to entities seeking QF status under the Public Utility Regulatory Policies Act, or "PURPA." A self-certification filing made in good faith provides temporary EWG status as of the date of its filing. FERC has 60 days from the date of filing to act on the notice of self-certification; otherwise it is deemed granted.

Mergers and Acquisitions

The new energy law gave FERC broader authority to review electric utility mergers as a tradeoff for repeal of PUHCA. FERC had authority to review sales of "jurisdictional assets" even before the new energy law. This authority is in section 203 of the Federal Power Act. "Jurisdictional assets" include transmission lines and power sale contracts of traditional utilities, EWGs and power marketers that sell or transmit power "in interstate commerce." However, FERC jurisdiction did not extend to Alaska, Hawaii, countries other than the United States, or to the Electric Reliability Council of Texas, or the "ERCOT" region of Texas. Also, FERC approval was not required for the acquisition of a municipal or other utility owned by the United States, a state, or a political subdivision of a state, or of or by a cooperative with financing from the Rural Utilities Service.

FERC jurisdiction applied to transactions involving facilities worth more than $50,000. FERC lacked jurisdiction over transactions that involve only generating facilities. Historically, FERC has chosen to exercise policy initiatives through its "conditioning authority" by, for example, conditioning its approval of utility mergers on a commitment to join a regional transmission organization. By structuring sales of generating plants not to require section 203 approval, utilities have been able to avoid the imposition of these types of FERC conditions as the cost of obtaining approval for a transaction. / continued page 24

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ownership interest in the grids. They did not. The ruling is Private Letter Ruling 200542032. The IRS made the text public in late October.

CORPORATE-OWNED LIFE INSURANCE policies remain an area of controversy with the IRS.

Public Service of Colorado — which is now part of Xcel Energy — bought 2,435 life insurance policies on its employees in 1984 and 1985 — it said to help fund a benefits plan for workers that promised death benefits and life insurance coverage, but that was in danger of being underfunded. The holder of a whole life insurance policy can ordinarily borrow against it. The utility borrowed the cash value of the policies and paid interest. It had a choice of two interest rates. It chose the rate that was higher, and the insurance company credited part of the interest paid back to the cash value of the policies. The utility used at least some of the borrowed money to pay the premiums on the insurance policies.

Companies can deduct the interest they pay on borrowed money.

However, the IRS denied the interest deductions that the utility claimed in this case, charging that the insurance arrangements were a sham.

The case is now before a federal district court in Minnesota. Both sides asked the judge to decide the case for them on the basis of legal briefs without the need for a trial. In November, the judge rejected the government's argument that there were no real insurance contracts, but said he wants to hear the evidence at trial about whether the utility was entitled to an interest deduction.

Section 264 of the US tax code makes it difficult for corporations to deduct interest payments on loans under corporate-owned life insurance policies, but the interest is deductible on policies purchased before June 20, 1986 as long as the corporation paid the premiums using unbor- / continued page 25

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The new energy law raised the floor for dispositions of assets requiring FERC approval. A jurisdictional asset being sold must be worth more than $10 million in the future in order for the transaction to require FERC approval. Applicants will have to include an explanation showing that the proposed transaction will not result in cross-subsidization of non-utility affiliated companies or encumber utility assets for the benefit of an affiliated company. However, the most far-reaching change in the new energy law is the expansion of FERC authority to approve certain transactions not previously subject to FERC jurisdiction.

The repeal of PUHCA makes it possible for parent companies to own utility subsidiaries in different regions of the United States. It also allows non-utility companies, from Wal-Mart to Westinghouse, to own utility companies. In order to retain some federal regulatory supervision over these previously forbidden types of utility combinations, Congress amended section 203 to require prior FERC approval for the acquisition, by a "holding company," of several types of assets. Approval is required before a holding company can acquire more than $10 million worth of utility securities, including voting, non-voting and debt securities. Note that, under the new law, the owner of 10% or more voting securities of a QF, EWG or FUCO is a "holding company." Approval is also required before the direct or indirect merger or consolidation of a holding company with a "transmitting utility," which is a company that owns or operates transmission facilities that are connected to the interstate grid, or an "electric utility," defined as a person, including a corporate entity, or a federal or state agency, that sells electric energy. Approval is also required before a holding company can acquire another holding company that has a "transmitting utility" or "electric utility" subsidiary. Prior FERC approval is also now required for the acquisition of an "existing" power plant worth more than $10 million that is used for wholesale power sales to the interstate grid.

Rep. Barton said in comments filed with FERC that the amendments to section 203 in the new energy law "were not intended to expand significantly [FERC]'s jurisdiction" over mergers and acquisitions. He said Congress intended only to codify existing precedent, in which FERC has held that section 203 gives FERC jurisdiction to approve "changes in control" of public utilities subject to its rate jurisdiction, such as the acquisition of a holding company that has a public utility subsidiary. Therefore, Barton said, the new authority over acquisitions by and of holding companies "should be read in light of current commission practice and precedent and not viewed as a grant of extensive new authority." These comments were largely disregarded by the commission.

The agency abandoned a proposal not to allow new power projects to become EWGs or FUCOs.

The merger authority language in the new energy law was added at the 11th hour. There are drafting inconsistencies and omissions that cast doubt on whether Congress intended the results that would occur from a literal application of the terminology, or whether these results were simply the result of inartful drafting. Many utilities expressed concern that, read literally, the requirement for "holding companies" to obtain approval for the acquisition of public utility securities would mean that intra-system financing arrangements, such as the acquisition of notes and other evidence of indebtedness, would require transaction-specific approvals.

Private equity and hedge funds also complained that the new rules require many of them to seek prior approval for their purchases of public utility securities. The problem is the expansion of the companies that could be deemed to be "holding companies" and thereby subject to the requirement to obtain FERC approval for many types of acquisitions that previously were not subject to FERC jurisdiction under section 203.

In December, FERC moved to address some of these concerns. It issued regulations under section 203 giving blanket approval to certain types of transactions.

Non-voting securities in an electric utility or another "holding company" can be acquired in any amount without approval, and purchases of such securities do not have to be reported to the commission. FERC warned in a footnote that "it is possible, in some circumstances, for non-voting securities to convey sufficient 'veto' rights over management actions as to convey 'control' that triggers" the approval requirement.

Up to 9.9% of voting securities can be purchased without seeking approval. However, such purchases must be reported to FERC within 45 days. FERC will publish notice of such purchases for informational purposes.

Approval is also not required for purchases of securities — voting or non-voting — of a utility — including a QF or EWG — that operates only in ERCOT, Alaska or Hawaii, or in a local distribution company that is regulated by a state commission, or in a FUCO. However, a public utility or "holding company," which includes the 10% or more owner of voting securities of a QF, EWG or FUCO, must now get FERC approval to acquire 10% or more of the voting securities of a QF, EWG or FUCO or another "holding company."

Drastic Revisions to PURPA

The new energy law responded to utility concerns that FERC regulations and decisions allowed so-called "PURPA machines" — power projects that provide steam to an uneconomic or contrived use for the sole purpose of enabling the project to claim the benefits of QF status, which include the right to receive "avoided-cost" rates and exemptions from PUHCA, the Federal Power Act and state law. It also permitted FERC to eliminate the utilities' purchase obligation for QF power in workably competitive markets.

The new energy law amends PURPA by requiring FERC to add criteria for new qualifying "cogeneration facilities" — one of two types of QFs — to ensure that new such facilities are using their thermal output in a "productive and beneficial manner." The electrical, thermal, chemical and mechanical output of such new facilities must also be used fundamentally for industrial, commercial or institutional purposes. FERC is also supposed to use / continued page 26

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rowed funds in at least four of seven years and the arrangement is not purely a tax play.

The court said the issue is whether there was economic substance to the arrangements. In particular, it is interested in whether the utility expected a profit — apart from tax benefits — from its investment in the life insurance policies.

UTILITY RELOCATION PAYMENTS had to be reported as taxable income.

The IRS is making it harder for utilities to avoid taxable income when developers merely reimburse for the cost of moving gas mains and power lines out of the way of new construction. It addressed two fact patterns in private letter rulings that were released in late October.

In one ruling, the county government made a developer pay to expand a highway next to a site he was developing. The developer had to reimburse the local utility to move its power lines and poles. The lines and poles will be used to supply electricity to the developer's site. The IRS said in Private Letter Ruling 200541036 that the cost reimbursements had to be reported as income. In the other case, a developer had to pay the local utility to bury power lines along the perimeter of his site as a condition for a building permit. These lines were *not* used to supply electricity to his site. The IRS said in Private Letter Ruling 200541001 that the utility still had to report the cost reimbursements as income.

The rulings make for higher costs for developers, since the utilities will insist on "tax grossups" in addition to being reimbursed for their relocation costs.

The parties in such situations should explore whether it is possible the utility lines and poles were "involuntarily converted" into cash, as that would avoid tax. They may have been if the local government would have taken them had the utility failed to move them. / continued page 27

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the QF label to encourage continuing progress in the development of efficient electric generating technology.

The new energy law also eliminates the restriction on utility ownership of QFs, so that instead of being limited to a 50% interest in the equity of a QF, utilities may now own up to 100% of the equity interests in a QF.

FERC issued proposed rules implementing the new rules for QFs in October, with final rules to be issued by February 2006. These rules do little to advance the ball beyond the literal language of the statute with respect to new standards for new cogeneration facilities. Moreover, FERC has decided on its own to propose rules that would subject many QFs to FERC ratemaking jurisdiction. The result is to create uncertainty both for developers of new cogeneration projects and for existing QFs as to the degree to which they will be subject to regulation, including the possibility that many power sale agreements could be subject to modification under the same standards that apply to non-QF power sale contracts.

Observers of the multi-year process that led to passage of the new energy law understood that PURPA would be largely gutted at the end of the day. Existing QF contracts would be grandfathered from modification, but utilities would be freed from the mandatory purchase obligation, once FERC determined that certain regional markets — primarily those with mature regional transmission organizations or RTOs — are workably competitive. In addition, industry observers understood that Congress would allow the criteria for new "small power production facilities" — the other type of QF — to remain the same, but would require FERC to make it far more difficult for new cogenerators to qualify.

Many observers expected FERC to spell out in the new rulemaking what new standard it would expect new cogenerators to meet. For example, the operating standard might have been increased from 5% to 20%, or perhaps no more than 40% of the electric output could be sold to an electric utility. FERC did not do this; instead, it simply adopted the statutory language in its proposed regulations and said it would look at each potential project on a case-by-case basis. FERC's failure to promulgate specific new criteria does not allow the developer of a new cogeneration project to know the rules ahead of time and, consequently, hinders new project planning.

FERC is imposing burdensome reporting and recordkeeping requirements on a broad class of "holding companies" to fill what it perceives as a regulatory vacuum created by PUHCA repeal.

As if the new requirements would not be stringent enough, FERC now proposes to permit utilities to challenge the presumption of usefulness of the thermal output of a project. Under current precedent, if a particular thermal use has been established by FERC generally as "useful," then the thermal use could not be challenged in a particular project. Under the new rules that FERC proposed in October, assuming that a new cogeneration facility can get past the "fundamentally not for utility sale" test, and provided that FERC has not determined that the regional market is competitive enough to eviscerate the utility's obligation to buy QF power, the would-be purchasing utility can still tie-up the prospective QF seller by challenging the thermal use as unproductive and getting the FERC to set the matter for hearing.

Why QF Rate Regulation?

Even though the new energy law says absolutely nothing about eliminating the federal or state exemptions from utility regulation that existing QFs now enjoy, FERC took it upon itself to propose that certain QFs — those without long-term contracts blessed by a state as containing avoided cost rates — should be subject to FERC ratemaking jurisdiction. The rationale offered by FERC for its proposal is that "a large number of QFs make market-based sales, which are often referred to as 'non-PURPA sales.'" FERC also noted that the removal of the restriction on utility ownership of QFs would make it possible for a utility to obtain market power by acquiring 100% of a QF project.

The "large number of non-PURPA sales" assertion was made without any support whatsoever. In proposing to subject QFs to rate regulation, FERC has overlooked the fact that there are hundreds of QF contracts that have not received the avoided cost blessing of state commissions and that did not have to receive such a blessing under the current FERC regulations. Indeed, the FERC regulations expressly authorize QFs to enter into negotiated contracts, but allow the QF to petition the state commission to impose an avoided-cost rate on a utility as a "last resort."

Since most QFs were required to enter into long-term power sale agreements in order to obtain financing, and most QF investors and lenders relied on the QF's exemption from rate regulation when decisions to invest or lend were made, the FERC's proposal to impose rate regulation on existing projects is at best puzzling. Further, by proposing to remove exemptions to existing QFs in a new rulemaking, the FERC would appear to be applying a new rulemaking retroactively in violation of the Administrative Procedure Act.

In its proposed rule, FERC also suggests that rate regulation is warranted because Congress gave FERC new authority in the new energy law to address market misconduct. But that legislation did not signal to FERC that it needed to modify preexisting exemptions from FERC regulation. Allowing QFs to remain exempt from FERC regulation would put QFs in no different position than other currently exempted entities, like municipal utilities, cooperatives and federal power agencies, which are far more numerous and have far more generating capacity and market penetration than do QFs.

FERC also suggests it has market power concerns now that the new energy law removed the QF utility ownership limitation and will give traditional utilities the right to own 100% of a QF. If that is FERC's real concern, it could limit the requirement of section 205 and 206 filings to QFs owned by traditional utilities, that is, utilities with franchised service territories. Even that requirement, if implemented, could be limited to QFs that are selling within the region of the service area of that franchised utility to address any market power concerns.

The result of these proposals, if fully / continued page 28

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PARTNERSHIP ALLOCATIONS may be tested with a more jaundiced eye by the IRS, the agency warned.

Partners in corporate joint ventures or partnerships are given a fairly free hand by the US tax authorities in how they share cash, taxable income and other benefits from the partnership. In general, partners can do what they want as long as they maintain "capital accounts" — or a record of what each partner contributed to the venture and what each got out. If a partner has a negative capital account, then that usually means the partner took out more than his or her fair share. IRS rules require that the partner either indicate a willingness to pay back money into the partnership when the venture liquidates to eliminate the capital account deficit, or else the partnership must take steps during the life of the partnership to prevent partners from having negative capital accounts — for example, by reallocating amounts that would throw a particular partner into deficit to the other partners.

Tax lawyers call this ensuring that the business deal has "economic effect." The IRS makes it a condition to letting partners do what they want that their business deal must have "economic effect."

The IRS requires the economic effect must also be "substantial."

The agency has various ways of testing whether the economic effect is "substantial." One is to probe whether a particular allocation makes at least one partner better off after his or her tax position is taken into account while no one else suffers. The calculations are done using present values. Some companies have taken the position that they only have to look at the after-tax consequences at the level of the partners and not look higher up the ownership chain.

The IRS made clear in November that it disagrees.

It said in proposed / continued page 29

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implemented, will be to increase transaction costs for both existing and new facilities in order to comply with FERC rate filing requirements, and to create uncertainty for existing QF investors and lenders as to the rate recovery for power sales from projects that were always exempted from FERC rate regulation. It will also create uncertainty for developers of future cogeneration projects that believe they may be able to satisfy the new Congressional standards but have received no guidance from the implementing agency.

If FERC sticks to its guns and imposes ratemaking requirements on QFs, then there will be little reason for QFs to exist as a separate category of power producers. PURPA was originally designed to provide two specific benefits to QFs: first, encouraging utilities to buy QF power and, second, encouraging QF development by exempting them from federal and state regulation. The combination of the reluctance of most state commissions to enforce the utility purchase obligation in recent years, and the new law's authorization to FERC to eliminate the purchase obligation in workably competitive markets, effectively eliminates the first benefit. The creation of EWGs in 1992 and the repeal this year of PUHCA altogether, combined with FERC's proposal to regulate the rates of QFs, effectively eliminate the second benefit. State commissions (other than Texas, Hawaii and Alaska) generally do not regulate wholesale sales, and, in particular, most states do not deem wholesale-only generating entities to be utilities subject to regulation. ◎

Environmental Due Diligence: The Basics

Chadbourne conducts regular training sessions for young lawyers on issues that come up in project finance transactions. The following is the transcript from a training session last fall on environmental issues that need to be covered during the due diligence phase of a project. The speakers are Andrew Giaccia, an environmental partner in the Chadbourne Washington office, and Roy Belden in the New York office. Belden moved recently to GE Energy Financial Services as a senior vice president for environmental support.

MR. GIACCIA: We will cover four topics today. The first one will give you a sense of what we mean by environmental laws. Then we will proceed to a discussion of what a due diligence process could or possibly should include. We will then talk about provisions that you see across project finance agreements and then, finally, we will conclude with a few words about structuring around environmental risks in a transaction.

Key Environmental Statutes

MR. GIACCIA: Starting with the key environmental statutes, the top four are the Clean Air Act, the Clean Water Act, the Resource Conservation and Recovery Act, or "RCRA" —which is the hazardous waste law — and Superfund or "CERCLA."

Between RCRA and Superfund, you get most of your remedial obligations to address contamination under federal law — not all of them, but most of them. The Clean Water Act regulates discharges into "waters in the United States." The Clean Air Act provides for the comprehensive regulation of air emissions. It is also the statute that has received the most attention in the last 15 years in terms of new regulatory developments. It was renewed in 1990 with more than 800 pages of Congressional mandates, and it has taken quite a number of years for implementing regulations to be written.

Another significant statute is the National Environmental Policy Act or "NEPA." It provides a comprehensive procedural process that we will get into in a little more detail. NEPA may require that a detailed environmental impact review be done for a project. Developers try hard to avoid having to do such reviews because they are expensive and time consuming.

There are also numerous state and local environmental laws that may provide comparable protections as the federal statutes, but on a level closer to home. We spend so much time talking about federal environmental laws, but the framework for regulating air emissions, water emissions, hazardous waste management and hazardous substance cleanup is that the rules are implemented not so much by the federal government but by the state and local governments with some federal oversight. As a result, you will see repeatedly that the state and local environmental agencies are implementing these federal programs pursuant to approvals by, or delegation agreements, with the US Environmental Protection Agency.

Permitting Due Diligence

MR. BELDEN: I'm going to pick up here and talk first about the nature of permitting risk. Next, I will discuss the scope of the environmental compliance review that we typically go through in different project finance transactions.

Anything that could have an impact on the environment or human health is potentially covered by an environmental statute. You do not always need an environmental permit, but most often there is an environmental statute or regulation that covers an activity, such as air emissions or wastewater discharges.

What is a permit?

A permit is a document that gives permission from a federal, state or local government to undertake some action affecting the environment — either to emit air pollutants or discharge wastewater or dispose of ash at a landfill. It is generally not a property right. Permits usually have a condition in them that says that they do not convey any property rights. Without the requisite permits, a particular project cannot be built.

Permits are generally divided into two categories. There are construction permits and operation permits. In project finance transactions, the focus is often on obtaining the preconstruction approvals. Permits will also have numerous conditions and limitations. Look at those to make sure there are no specific conditions that will limit a plant's operations and affect the economics of the deal. For example, an air permit may have hours of operation limits that could restrict the plant's operation at different times.

There may be other permit conditions that, on their face, do not look like they will restrict plant operations, but look behind those conditions and review the permit application to get a sense of whether the conditions potentially restrict the plant's output. An example may be a gallon limitation on burning fuel oil as a backup fuel. That oil restriction could limit a plant's ability to operate when high natural gas prices make it uneconomic to run unless the plant can burn oil.

Very stiff penalties could be imposed for violating the permit conditions. Federal statutes typically authorize penalties of upwards of $32,500 a day per violation. An air permit with numerous emission limits in it could trigger multiple violations due to one excess air emission. In other words, you can have numerous violations for a relatively few number of exceedances that could add up to substantial fines.

Another area of permitting risk is the potential for changes in law that increase the costs of the project. Recent examples include the "clean air mercury / continued page 30

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regulations that the tax consequences to a partner that joins in filing a consolidated return with other corporations must be weighed by looking at the effect on the consolidated group. Thus, for example, if a corporate partner is allocated depreciation deductions that it cannot use as a standalone company, but that will be absorbed immediately on the consolidated return that it joins in filing, then the immediate benefit must be taken into account in assessing whether only the government loses from an allocation. If the partner is itself a partnership, then one should look higher up the ownership chain. If the partner is a foreign corporation that is owned more than 50% by US shareholders — a so-called "controlled foreign corporation" — then the tax effects on the US shareholders are also taken into account in the case of any dividends, interest or other types of income the partnership allocates that will pass through directly to the US shareholders under US "subpart F rules."

The IRS gave the following as an example of a case that bothers it. A and B form a partnership. A is a US corporation. B is a foreign corporation. They are both owned by the same US parent. The partnership allocates 90% of its income to B — the offshore company — and 90% of its losses to A for 15 years. Then it reverses the allocations. The income allocated to B is not "subpart F income" so it does not pass through immediately to the parent company's US tax return.

The IRS warned that it might also attack such cases by using its general authority under section 482 of the US tax code to reallocate income in transactions between related parties.

WEST VIRGINIA will continue collecting severance taxes on coal destined for export.

The US constitution bars states from taxing imports or exports without the consent of Congress. The West / continued page 31

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rule" and the "clean air interstate rule" that EPA promulgated in 2005. These rules will come into effect in the 2009 and 2010 time frame, and they could impose very significant costs on individual power companies.

Air Emissions

MR. BELDEN: Turning to air permit issues, the preconstruction air permit is probably the most important permit for a thermal power plant. Both major and minor emission sources will need to go through new source air permitting. Issuance of a preconstruction air permit is required before a developer can commence construction, and it often involves a complicated permitting process. Typically, major emission sources have to go through a control technology review, and the permitting agency will then decide what type of pollution controls may be necessary. The developer's consultant will prepare the initial control technology review document that will be submitted as part of the air permit application. In a control technology review, you are required to review the requested emission limits for the plant against the limits in permits that have been issued for other new plants. A new plant's air emission limits will be based on the limits that have been achieved by similar sources using state-of-the-art equipment.

Air permits typically have an appeal period, and there may be an automatic suspension of a permit when an appeal is filed. Some regulatory schemes allow permits to remain in effect when an appeal is filed. A lender will not want to close the financing if there is an appeal pending on a permit.

You may also need emission reduction credits in order to build a plant. The country is divided into two areas for purposes of the Clean Air Act. There are areas meeting the six national air quality standards, and there are other areas that fail to meet at least one of the six ambient air quality standards. There are separate ambient air quality standards for sulfur dioxide (or SO_2), nitrogen dioxide, particulate matter, carbon monoxide, ozone and lead. If a plant with significant air emissions is going to be built in a nonattainment area, then the applicant will need to purchase emission reduction credits to offset the new plant's emissions. This adds to the cost of the project.

There are emission allowance programs that are different from the preconstruction emission reduction credit programs. Depending on the type of plant and where it is located, a developer may need one allowance for each ton of a particular pollutant emitted by a plant. The most well-known allowance program is the acid rain program or the SO_2 allowance program. There is also a summertime "ozone season" NO_x allowance program that applies to 20 states east of the Mississippi that are subject to the federal limits on nitrogen oxide emissions called the "NO_x SIP call rule."

NO_x allowance prices have fluctuated, but they are currently around $3,000 per ton. SO_2 allowance prices have gone up steadily in the last year and hit $800 a ton earlier this year, which is an all-time high.

MR. GIACCIA: The peak in the SO_2 allowance market really started when people took seriously the prospect that EPA was going to cut back on the number of available allowances under the "clean air interstate rule," and people started to realize that SO_2 allowances that could be stockpiled this year and then sold or used in future years were going to have increasing value. The NO_x and SO_2 emission allowance markets exhibit volatility and, without advance planning, that volatility can lead literally to millions of dollars of extra costs. This is an increasingly important area of due diligence.

MR. BELDEN: To clarify the difference between an emission reduction credit and an allowance, emission reduction credits are also known as "offsets," and they are generally a right to emit a pollutant in perpetuity. Some states recognize a "discrete" emission reduction credit that allows a one-time emission of one ton of a pollutant. Emission reduction credits can be generated when an existing plant shuts down or ratchets back its emissions and accepts an enforceable limit to prevent emitting a pollutant above a certain level. Either of these actions will generate a tradable emission reduction credit that typically must be approved and certified by a state agency. A plant that is going to put on a new unit will basically take off line older, less efficient units and generate emission reduction credits that can be transferred to the new unit.

MR. GIACCIA: When the emission reduction credits are generated, they have to be registered and approved by the state. They do not exist legally until an application is filed and the state reviews, quantifies and approves the application. Then, once that happens, they are "banked." They are in a state emissions bank and are now tradable.

MR. BELDEN: The emission reduction credits are used for nonattainment areas. Those are essentially areas where the air is dirtier than in other areas. Under the Clean Air Act, the goal is to maintain or improve the air in an attainment area and to improve the air in a nonattainment area over time. In contrast, allowances are a going-forward operational requirement that you need every year. For example, under the acid rain program, a project must have one allowance for every ton emission of SO_2 that it emits in a particular year, and sometimes those allowances can be banked or carried forward so that the project can sell the surplus or use it in a future year.

Once a project buys or creates an emission reduction credit, it is a right to emit in perpetuity. An allowance, on the other hand, is not. An allowance is a discrete permission to emit one ton of that particular pollutant in a particular year or, if it can be carried forward, to emit one ton in a future year.

MR. GIACCIA: This is a very complex area. We can speak for an hour on this subject because there are so many nuances, but in terms of the geographic scope of the program, an emission reduction is only usable in the state where it was created unless there is an actual agreement between the two states to allow cross-border use. In the handful of states where those provisions exist, the states usually place a lot of restrictions on their use and ratchet them down, so it is typically not a one-to-one offset.

MR. BELDEN: You can trade SO_2 allowances under the acid rain program throughout the United States. The NO_X allowances are only good in the states that are affected by the NO_X SIP call rule. There are 20 eastern states in the NO_X SIP call program where you can trade NO_X allowances.

Other Key Permits and Approvals

MR. BELDEN: In addition to preconstruction air permits, there are a number of preconstruction approvals that may be required depending on the type of project. There are state and local land use approvals, which would include a zoning or subdivision approval and most local building permits. The next category to consider is power plant siting laws. There are a few states that have power plant siting laws that are meant to be a one-stop shop where you would get one permit or certificate that covers a number of different approvals that are required from state and local agencies. It does not mean that the applicable state and local agencies are not involved. For example, Florida has / continued page 32

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Virginia Supreme Court held in a 3-to-2 decision in December that the state is not barred from collecting a 5% severance tax on coal mined in the state, even when the coal will be sold overseas. The state was at risk of having to refund nearly $500 million in back taxes and interest to coal companies. Between 14% and 21% of coal mined in the state is sold abroad. The court said that the tax is collected on the activity of mining and processing in West Virginia, and coal does not enter the export stream until after processing. Eleven coal and steel companies brought suit seeking refunds.

The decision is expected to be appealed to the US Supreme Court. The case is US Steel Mining Company LLC v. Helton.

MINOR MEMOS. The IRS denied interest deductions on audit that a corporation claimed on its senior debt. The debt was linked to shares in a subsidiary that the corporation owned. At maturity, the lenders would receive back the principal amount of the debt, plus accrued interest or, if greater, the then-market value of the reference shares. A promoter had sold the company on the idea of issuing the debt as a way of monetizing the value locked in the subsidiary shares without triggering capital gains taxes and while still being able to use a "dividends-received deduction" to shelter most of the dividends the company received from its subsidiary from taxes. The IRS said on audit that the debt and the subsidiary shares were a "straddle." Section 263(g) of the US tax code bars interest deductions on debt that is part of a straddle. The case is discussed in a ruling — Technical Advice Memorandum 200541040 — that the IRS made public in late October . . . . The IRS told a US importer in another audit that the importer had taxable income when the US government refunded duties that the importer overpaid. The IRS suggested the importer might have avoided this result under a "tax benefit rule" in / continued page 33

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a power plant siting law, and the Florida Department of Environmental Protection issues a comprehensive certificate that covers most of the major state and local environmental requirements.

Wastewater discharge permits implementing the requirements of the federal Clean Water Act are typically issued by the states. In addition, some states also have their own wastewater discharge programs. For example, Arkansas issues a single wastewater discharge permit for both the federal and state programs. A wastewater discharge permit is an operational permit, but it is a major approval and a project finance transaction will not reach closing without having a wastewater discharge permit in place. Some wastewater discharge permits also address storm water. Other states provide coverage under general storm water permits. An applicant meeting the requirements for coverage under a general permit would simply need to file a "notice of intent" requesting coverage.

There are also section 10 and section 404 permits issued by the US Army Corps of Engineers. A section 10 permit is required for the installation of a structure in a navigable water such as a dock or water intake system. Any sort of filling in of wetland areas will require an Army Corps of Engineers section 404 permit. Some impacts on wetlands may be relatively minor, and the developer can get by under what they call a nationwide general permit. However, if the impacts are more significant, he or she will need an individual section 404 permit.

Another important permit is a water withdrawal approval. This approval is particularly important in the western, midwestern and mountain states where water is scarce. Sometimes these approvals can be difficult to obtain. Some states treat water withdrawal approvals as a property right that you need to apply for or have transferred. For withdrawals from a surface water body, a project will also need to construct a cooling water intake structure. That approval process is wrapped into the wastewater discharge permit, and there are new federal regulations that apply to clean water intake structures.

Archeological reviews and endangered species reviews are typically required when you have a federal permit like an Army Corps of Engineers permit. If there is a likelihood that you are going to kill an endangered species or destroy its habitat, you will need to get an "incidental take permit" from the US Fish and Wildlife Service. Incidental take permits are very difficult and time consuming to get; they require advance planning. Governmental rights-of-way and easements may also be needed for linear projects like pipelines and transmission lines. To the extent that you are going to run a pipeline under submerged lands, the states will issue a submerged lands easement for activities within state waters. There is new language in the Energy Policy Act of 2005 that authorizes the US Department of Interior to issue easements for projects on submerged lands on the outer continental shelf, or the area just beyond the three-mile limit of a coastal state's jurisdiction. If you are working with a project that is on the coast, the state will also need to issue a Coastal Zone Management Act approval.

In addition to the numerous preconstruction approvals, there are also separate operating permits that are typically obtained after the closing on the construction financing for a new plant. The most important is the air operating permit. Major emission sources must file an application for a title V operating permit within 12 months after the plant commences operations. Some states have different interpretations on when operations commence. Some take the position that it occurs at first firing, and other states view it as occurring after the completion of the shake-down period when the plant achieves its planned operating mode. The title V operating permit is intended to include all of a plant's applicable air emission requirements, including the conditions from the preconstruction air permit.

There are a lot of permits and approvals to think about and, if that is not enough, the project may also require an environmental impact review, which often involves a very time-consuming procedural review process.

National Environmental Policy Act

MR. BELDEN: A National Environmental Policy Act or NEPA review is required for any major federal action that will significantly affect the environment. It is not required for all projects, but only if you have a federal permit like a US Army Corps of Engineers permit or federal funding is involved.

Several states also have similar state environmental policy act requirements. California and New York, for example, have state environmental policy act processes that are fairly detailed. A NEPA review or similar state review is a precondition to most project permits. If a review is triggered, you will need to go through the environmental review process before the permits can be issued, and it is a very convenient forum for public opposition. The outcome of that process is either a short "environmental assessment" and a finding of no significant impact, or a finding of a significant impact, which will require preparation of a full-blown "environmental impact statement." The environmental assessment or environmental impact statement documents are intended to address all the environmental aspects of the project, and the public is invited to comment and attend a public hearing if an environmental impact statement is being prepared. Some of the key elements of that process involve the identification of the scope of the project, a cumulative impact analysis and a review of the alternatives. If the project involves a federally-permitted dock or transmission line, then the developer may be able to limit the scope of the project just to the dock structure or the transmission line instead of the entire project. For example, a power plant project may need an Army Corps of Engineers' permit for a dock structure to unload coal. The goal would be to limit the NEPA review just to the dock structure. In the alternative analysis, one alternative that is always considered is the effect of not constructing the project at all. The NEPA or state equivalent review is a comprehensive look at the project involving not only the air quality and water quality, but also the habitat, aesthetics, local environmental impacts, transportation impacts, the traffic congestion and other impacts.

MR. GIACCIA: The environmental impact review is such a time-consuming and costly process that in those states where it is not required by state law, projects will go out of their way to avoid it if they can, and they often can. The typical power project in a state that does not have a state environmental policy act review can avoid this whole process if it avoids wetlands areas and structural work in a surface water. Therefore, if you can build your plant to avoid wetlands, and if you can keep from having a wastewater discharge by building an evaporation pond rather than discharging into a river, then you can avoid NEPA. We have seen many projects go out of their way from a design standpoint just to stay away from it. It is not triggered by air permitting, and it is not triggered by some of the other basic permitting that you see for power plants.

MR. BELDEN: I want to touch on other types of permitting risks. The most important is the permit */ continued page 34*

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section 111(a) of the US tax code if it had shown that it did not benefit by deducting the overpayments in earlier years. The importer made no such showing. Duties paid on imported goods are normally offset against the sales price when the goods are sold. This reduces the income the importer must report on the resale. The case is discussed in Technical Advice Memorandum 200543051.

— contributed by Keith Martin and Laura Hegedus in Washington.

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appeal risk. You are not going to close a project if there is a pending appeal of a major preconstruction permit. There may be situations where a statutory appeal period is still open, but it really depends on the type of permit in order to determine whether you can close the transaction with an appeal period still open. I have not seen a project closed where a Clean Air Act permit has an open appeal period. The one exception was a situation where a lender was willing to close notwithstanding a pending certiorari petition before the US Supreme Court, and the lender was comfortable that it was highly unlikely that the petition would be granted to consider the permit appeal. Nevertheless, that deal ultimately closed after the court denied certiorari. Some projects have very long appeal periods. For example, the US Army Corps of Engineers permits typically have a statute of limitations under the federal Administrative Procedures Act of a six-year period. Other permits have a very short appeal period of 30 or 60 days. Another point is that some permits may have postponed decision making or a condition that requires resubmittal after a particular milestone. This may present an opportunity for public opposition when an agency makes a final decision on a post-closing submittal. And then there are often third-party approvals that are typically outside the control of the developer, but are nevertheless very important to the project. For example, if a local wastewater treatment authority is constructing a wastewater treatment plant that will be receiving wastewater from a power plant, then you need to know that the wastewater plant has its permits in place, and can actually be built.

A big risk in projects is that the environmental laws will change. New air pollution rules proposed in 2005 could impose very significant costs on individual power companies.

Environmental Compliance Review

MR. BELDEN: The environmental compliance review involves a review of a project's inspection reports, prior environmental audits and monitoring reports. Reviewing the air emission monitoring reports and wastewater discharge monitoring reports will give you a sense of how the unit has been operated. These reports may also give you an indication of whether the unit had to ratchet back its operations because the project is bumping up against a permit limit. We will also look at notices of violation, notices of noncompliance and correspondence with state and federal agencies to see if there may be compliance issues. We will also go through the conditions in each of the permits and, where available, review the history of past capital improvements at a facility to get a sense of whether those improvements should have gone through a permit modification or triggered a new permit.

Federal and state agencies may have different enforcement priorities, and one well-known initiative was the federal government's actions in 1999 to target coal-fired plants to review whether some such older plants made capital improvements that should have gone through new source review permitting for air emissions. In 1999 and 2000, the federal government filed several lawsuits against utilities with older coal-fired power plants. Many of those lawsuits are still in the courts and are in the process of being resolved. A number of the cases have also settled, and the penalties have been very significant. There have been fines of millions of dollars, and several utilities are spending hundreds of millions of dollars on pollution control equipment at the plants.

Federal and state agency enforcement practices may differ depending on the underlying statute and the agency's settlement guidance. The settlement guidance typically allows the agency to settle a pending lawsuit or an enforcement action for basically a fraction of the possible civil penalties. An agency's settlement posture may depend on which party is in power and the goals it is trying to achieve.

A number of the environmental statutes authorize citizen suits, and some state statutes do as well. If a citizen lives near an industrial source, many environmental statutes gives him or her the right to file an action for alleged violations. The person must satisfy "standing" requirements, including showing that he or she was harmed. Visual and other non-physical impacts may be sufficient.

Turning to environmental noncompliance, liability for noncompliance typically remains with the seller of a project unless there is a contractual shifting of that liability. Responsibility to pay the costs of site contamination liabilities and past noncompliance liabilities can be allocated contractually between a seller and buyer. What we have seen in some plant divestitures is that the seller will try to shift past noncompliance liabilities to the buyer. This was more common in the past three or four years when the market favored sellers. In more recent divestitures, sellers have retained most pre-closing environmental liabilities. In project finance transactions, the lender will require that the borrower absolutely comply with environmental laws, and the lenders will not take any noncompliance risk. A lender will have its independent engineer monitor that risk.

Environmental compliance liability differs from site contamination liability in that, particularly under Superfund, site contamination liability is often triggered based on a party's status as owner or operator. It does not matter if it had any role in causing a release of contamination. Under Superfund, just the fact that you are an owner or operator of a property that has had a prior release on it could lead to liability.

Site Contamination

MR. GIACCIA: Site contamination issues require a thorough review. As Roy Belden said a moment ago, this notion of status liability boils down to the fact that there does not have to be culpability. Cleanup can be very expensive. That said, cleanup costs have been coming down a great deal in recent years, probably the last decade. Ten years ago, virtually everything in an environmental remediation was handled in pretty much the same way. You dug up soil, and you pumped out contaminated groundwater and treated it. The technologies have been advancing rapidly so that there are various remediation options depending on the nature of the contamination. A lot of contamination can now be treated in place using anti-bacterials. States have also tried to simplify the remedial process. One of the things that has always led to significant increases in cost has been the bureaucratic oversight requirements. A majority of the states have issued "brownfield" laws that attempt to streamline the remediation process. "Attempt" is the operative word there. In reality, the practice has been that you still have the same bureaucrats administering those supposedly streamlined requirements and, therefore, similarly difficult bureaucratic bottlenecks are still present.

From a cost standpoint, you also have to consider the possibility of delay. If you are dealing with a new plant construction, it becomes an important issue even if the overall cost is not significant. The process of putting a slab-constructed plant on top of the contamination cannot begin until the government gets around to approving the capping remedy that has been selected for the site. This can lead to delays even though nothing is really being remediated and the cost is relatively minimal.

Toxic torts and property damage are always issues. We see this in cases of groundwater contamination and also airborne contamination or exposure, such as asbestos. The problem with those claims is that they typically have a very long lead time. Illnesses do not manifest themselves for years and, therefore, it is difficult to project the potential liabilities.

Property damage can occur to private property or to public resources, and this is a frightening area that continues to evolve from an environmental remedial standpoint. Both at the federal government level and the state level, there is an increasing emphasis on the recovery of the costs of the injury and the actual damage to natural resources. New Jersey has gone so far as to have a program where it charges for groundwater that was polluted, even if that groundwater is not being used by anyone. These charges are assessed on top of the cleanup costs. They are a penalty or natural resource recovery charge for the damage to the groundwater itself, based on the aerial extent of that groundwater contamination.

There is contamination and there is contamination — it cannot all be treated in exactly the same way. It is important to evaluate it. People think contaminated groundwater is unacceptable, but that is not true. There are federal drinking water standards that allow low levels of / continued page 36

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contaminants. Even some of the worst contaminants have a threshold that is allowed in drinking water. The level is very low, but there is a threshold. It really depends on the particular threat the contaminant presents. For example, No. 6 fuel oil, because it is so thick, basically does not get into groundwater and does not spread very much. A solvent, or something like a gasoline additive like MTBE, mixes with groundwater rapidly and spreads very rapidly. Finally, the issue comes up when you are dealing with contamination or potential contamination, in how much investigation should you engage.

Phase I and II Audits

MR. GIACCIA: The format of a phase I environmental audit has now been standardized by the American Society for Testing Materials, which is a standard-setting organization for all sorts of engineering applications. ASTM Standard 1527, which was written in 2000, is now the standard for phase I environmental site assessments. If you see a contract provision that says that a phase I assessment will be done, that contract provision should specify compliance with ASTM Standard 1527. That standard is tremendously detailed because it tries to address a large number of potential situations. It also calls for a number of basic investigative activities. Among them are a review of government regulatory files and databases. There are numerous databases that tell you all kinds of information both about the site and about what goes on in the surrounding area. As part of the phase I audit, a database radius search will be done, probably within a one-mile radius from the site, to find every hazardous waste facility, leaky tank, spill site and everything else you can imagine from an environmental husbandry standpoint.

A phase I audit will also involve an inspection of the site, but they are not walking around with shovels, testing equipment or anything of that sort. They are just looking for things that could be a problem. They will also look at past land use records to see whether years ago, although there is no evidence of it now, the site was a landfill or a more environmentally-sensitive type of industrial facility, such as a chemical plant or something of that nature. They will look into records, if they are available, of the existing facility or of operations that were formerly associated with the site, interview employees and neighbors, and then there will be a recommendation for further action. They will identify something called recognized environmental conditions or RECs. When RECs appear at the conclusion of one of these reports, you never just stop there. You must go on to the next level, which is a phase II environmental site assessment.

Lenders will not close on the financing while key permits can still be appealed.

There is also an ASTM standard for phase II audits. The size and scope of a phase II environmental site assessment can vary tremendously. Phase I site investigations can run \$5,000 to \$15,000. Phase II investigations are typically more expensive, picking up somewhere where a phase I left off. Maybe \$30,000 to \$35,000 is an average phase II audit, but they can be, depending on how much sampling you have done, much more expensive than that.

The areas of investigation in a phase II environmental site assessment involve intrusive physical sampling of the site. That includes samples of the soil, perhaps in areas where stains were observed or where sensitive activities were previously observed or known to have occurred. For the phase II investigation, the groundwater investigation may also be associated with particular areas of concern at a site, or groundwater sampling might be used to get a more complete picture of the site, because groundwater contamination spreads. If you can get the right number of wells in place, then you can get a broader picture of what might be going on at the site even though there is no indication on the surface that there is something to worry about.

An area of sampling that is increasingly important — it has really exploded in the last couple of years and will continue to take off — is soil gas sampling. There is a heightened sensitivity in environmental agencies to the cumulative exposure risks associated with volatile organic compounds that evaporate readily, which in the soil or groundwater may work their way up into the surface air, and, therefore, may be potentially inhaled by human beings, particularly if human beings are in an enclosed space sitting on top of the leaking contaminants. This is an area that states, particularly New York, are scrambling to address. New York announced last year that it was going to rethink every remedial site where there are volatile organic compounds. Soil gas sampling issues are a big deal.

Once the sampling is performed, the results are compared to regulatory standards. Some contamination is permissible, and higher levels are permissible if the use will be commercial or industrial, as opposed to something more sensitive like residential. A phase II site assessment report might recommend further action that could include additional sampling. There could be a phase III, IV, V or remedial action.

Superfund

MR. GIACCIA: We briefly talked about this concept of Superfund status liability. The operative terms are owner or operator, and you do not have to be culpable, but if you are the current owner of the site or the operator, or if you were a former owner or operator when a release occurred at the site, you have liability under Superfund.

Most state Superfund laws also generally have liability sections that are written the same way as the federal Superfund law. The liability is joint and several, which means that if you have liability for a little, you have liability for everything if you cannot find somebody to share it with. Case law has made that whole process of trying to allocate the liability a lot worse. There are some defenses. Those defenses are centered around due inquiry at the time of acquisition for the most part and, therefore, those phase I and phase II site assessments that we talked about earlier, particularly the phase I assessment, need to be done properly to have any chance of taking advantage of some of those innocent purchaser, bona fide prospective purchaser or contiguous properties defenses under the statute. Lenders should ensure that their borrowers investigate the site. There is a secured creditor exemption for creditors that went into the law years ago, but lenders still think potential risks exist.

The lender exemption is not tied to due diligence. It is tied to behavior. If the lenders simply conduct themselves as lenders, and do not get caught up in the day-to-day operations at the site and the decision making, then they are entitled to the exemption. They can even foreclose on the property and run it for a while and still be entitled to the exemption, at least to the extent that there is pre-existing contamination, as long as they sell the property the first time somebody makes a good faith offer for the property. So it is not about the diligence the lenders engage in. It is about behaving as lenders while the loan is outstanding. That last point is important by the way. The state brownfield laws and other remediation statutes can throw the whole thing out the window. The Superfund defenses are great, but they are not always reflected under state law and, therefore, they have to be looked into very carefully.

The law is very clear on the secured creditor exemption and so is the case law that, from a Superfund standpoint, the mere fact that the lender is in a position to control its borrower's conduct and even exercise that control, just in the way that lenders normally exercise their control, is perfectly fine. In every loan agreement, there is an obligation to do cleanups, and enforcing that obligation is not a problem. What you are really looking for from a liability standpoint is getting too involved in the conduct that caused the contamination. But the cautionary point is that the exemption is under the federal Superfund statute, and most, but not all, state Superfunds have adopted a similar lender liability exclusion. There are other state remedial statutes that are not Superfund models where a lender could get caught up, particularly in a post-foreclosure scenario.

A brief comment about parent-subsidiary liability: this comes up once in a while, and not often in a finance context. There is a 1998 case where the US Supreme Court in Bestfoods listed specific standards of conduct that a parent corporation can engage in that would define whether the parent corporation was so involved in the operation of the subsidiary as to have treated it as an alter ego or so involved as to be directly liable as an operator under Superfund. We will not get into too much analysis on */ continued page 38*

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that, but it is something to be aware of.

Project Agreements

MR. GIACCIA: Environmental provisions can pop up in most project agreements. You would expect to find environmental provisions in land-related project agreements, such as purchase agreements, lease agreements and easement agreements. It is not necessarily the case that a lessor, for example, will take responsibility for contamination on the site. It is a question of leverage. It is more often the case than not that the lessor will take responsibility for pre-existing contamination and for the migration of such contamination. It is best to discuss potential environmental liability in a lease. It is always much better to sue under a contract for cleanup costs than it is to try to pursue a common law or statutory remedy.

Another place to find environmental provisions is the engineering, procurement and construction or "EPC" contract. In the standard EPC contract, and it is rare to find anything differing from this, the construction contractor will not take liability for pre-existing conditions. It will not take liability for any conditions that it does not cause, and it typically will not take any responsibility even for dealing with something that it encounters during construction. The minute the contractor encounters it, the EPC contract usually says he is entitled to stop, let the owner-developer know about it, and the owner-developer must do something about it. The other place in the EPC contracts to look is the performance guarantees. There inevitably will be in either the EPC contract or in separate vendor agreements, particularly for thermal power plants, contractual guarantees that address air pollution performance. To a lesser extent, you will see wastewater pollution performance, and then you will also typically see noise performance standards. Air and noise are the two key ones.

In facility services and operation and maintenance agreements, environmental provisions will also pop up. A steam supply agreement frequently will have provisions in it about the quality of the condensate water returning or other related services. Water supply agreements are key agreements, particularly for thermal power plants with cooling water being in such a high demand. This is frequently an area that requires considerable analysis whether it is in the form of a water supply agreement or some sort of a tariff agreement with a public authority. There must be an analysis about the strength of those water supply arrangements and the quality of the water being supplied.

Finally, credit agreements, participation agreements and other types of transaction documents include environmental provisions. These agreements contain several basic types of environmental representations. While there are many variations on this theme, the level of detail in the representations may, in part, turn on the level of detail of the informational materials provided and the need to confirm that certain questions are asked and answered through the representation. Basic representations will include a compliance-with-environmental-laws representation. You want to look at both current compliance, and past compliance, because past compliance can point to chronic conditions or future penalties.

There will also typically be a representation regarding the completeness of the environmental permits, and that they are in full force and effect, and are not appealable. The full force and effect and nonappealable language is a standard representation in credit agreements. It is found probably less than 50% of the time, maybe even 25% of the time, in an M&A deal. Another representation will address the fact that the plant is not subject to any environmental enforcement action, prior claim, or notices of noncompliance. One of the big sticking points in purchase

> Be careful how "deductibles" in environmental indemnities are drafted. A project might have multiple environmental violations in one day, but no indemnity coverage because each separate violation is below the deductible.

and sale agreements is to what extent the seller is really willing to give essentially a guarantee that the site is not contaminated. There are many variations on the representation about contamination liabilities, both at the site and also off-site where materials may have been sent for disposal. In a credit agreement, the borrower generally has no option but to give a fairly complete representation that there are no on-site or off-site contamination liabilities.

There will also generally be a representation about the completeness and accuracy of the due diligence materials provided. In addition, in a purchase and sale agreement, we typically request a representation that the plant retains all of its emission reduction credits and allowances.

MR. BELDEN: You will also see some qualifiers in representations. For example, in M&A transactions, you will have disclosure statements from the sellers essentially carving out from the representations certain known conditions. There may also be knowledge qualifiers that are typically heavily negotiated, and there may be material adverse effect qualifiers. These limitations on the representations are all heavily negotiated.

MR. GIACCIA: From an environmental standpoint, the toughest ones to negotiate are the knowledge qualifiers, because you need to push knowledge down to get to a point where you can get a fairly high degree of certainty for a lender or a buyer. Lenders do not usually allow such qualifiers. A buyer will want to confirm that the company has enough knowledge to make the representations.

Environmental covenants might include maintaining permits and compliance with laws. Those are not unique to the environmental regime. Prompt notice is usually required of not only claims you get from the government or a third party like notices of violation or claims, but also of material releases or material violations of which the borrower becomes aware. A covenant requiring notice of a material release or violation is often a heavily negotiated provision because borrowers do not want lenders to be hovering over them, and there is always some sort of spill going on. There may be a covenant imposing an obligation on the borrower to investigate and remediate contamination and rectify any violations. In a sale transaction in particular, but sometimes in a loan transaction, there may also be a covenant requiring the plant to maintain its inventory of allowances or emission reduction credits and to prevent the sale of the allowances or credits so that value is not taken out of the project.

Project agreements will typically include environmental indemnities. In acquisitions, the past liabilities go with the seller, and post-closing liabilities with the buyer, but that can be shifted around. It is not against the law to shift. You can divide it up really any way you want, whether it be a compliance liability or a contamination liability. It is typical to subject them to the same dollar thresholds as the other indemnities or to have individual dollar thresholds for environmental claims. The important thing is the aggregation of claims. Roy Belden mentioned that, in environmental air emissions, you can have multiple violations in one day. Those might individually each garner a smaller penalty than your threshold, but this could go on for days or months. You could end up having a huge potential fine that if the provision is written incorrectly, and aggregation is not allowed, the fines could get swept out by the claim threshold provision.

Determination of which party controls the cleanup is oftentimes specified in the special environmental provisions in the indemnity. Environmental claims are not always like other types of litigation. An environmental claim can have an effect on how the plant is to be operated in the future. Certainly for remediation claims, somebody needs to control the cleanup and you could put in provisions about cleanups having to be reasonable and justifiable, et cetera, but there is no better way to save yourself money by making sure it is done economically than to do it yourself, and so who manages a cleanup becomes an important point of negotiation for the indemnifying party.

The last point is that there is no really meaningful statute of limitations under most environmental statutes. They exist under environmental laws for compliance issues, but because of the way they are worded and interpreted, a lot of times they do not begin to run for a long time and, therefore, it is unacceptable unless, of course you are the party benefiting from it, to subject environmental liabilities to a statute of limitations because the indemnification obligation may never go away. Typically, we see environmental indemnification obligations contractually limited to a specific term of years.

Structuring Around Environmental Risk

MR. BELDEN: We will finish up on structuring around environmental risk. We have separated the topic into two areas — one is new domestic projects and the other is existing domestic projects, which includes M&A transactions.

In financing a new project, you are definitely going to want to see a phase I environmental site / continued page 40

Environmental Diligence

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assessment at a minimum and, depending on where the project is located, you may need a phase II environmental site assessment. You may have a new project that is built on former farmlands, which is what is referred to as a "greenfield" project, or you can have a project built on what is called a "brownfield" site, which is an area where there is prior industrial use or near an industrial area where there may be contaminated groundwater near the site. If it is a brownfield location, you are definitely going to want a phase II environmental site assessment of the site.

As part of the transaction process, you need to identify the government approvals that will be required. In connection with a financing, there will be a governmental approvals opinion that is issued at closing by the borrower's counsel, and there may be a separate opinion issued to cover federal permits and then another opinion that covers state and local permits. The legal opinion is important in that it confirms that the project has all the permits that it needs to construct the plant, and it identifies all the permits the plant needs to operate. The legal opinion will also confirm that the applicable appeal periods for each permit have expired or, if not, then the opinion will identify the issues involved with an open appeal period.

On financing new projects, there may be post-closing risk that you will need to work with, for example, implementing a backup water supply plan. You want to make sure that such a plan can be readily implemented, if needed. Typically, a credit agreement would spell out the timing for the delivery of that backup water supply plan or backup wastewater discharge plan. In credit agreements, the indemnities will run in favor of the lender, and the borrower is on the hook for all environmental liabilities. There will be an independent engineer's report and you will want to make sure that the independent engineer has identified any issues that should be addressed.

For brownfield sites, there may be ongoing cleanup responsibilities or deed restrictions that apply to the site. Be fully aware of what those are and if there is a cleanup obligation, how that may affect the construction of the plant and the plant's operation. If there is existing contamination of the site, an environmental insurance policy may be an option. With environmental insurance policies, there are typically a lot of exceptions that apply. The utility of an environmental insurance policy is sometimes in doubt, but it may be useful for a very specific situation.

MR. GIACCIA: If there is a known issue, by the way, the insurance product that is relevant is called cost cap insurance. If it is an unknown issue, then there is environmental remediation liability insurance. With cost cap insurance, the insurance company is not interested in actually paying for the cleanup, but the policy caps the overall costs, basically at a number that reflects both the projected remedial costs plus an additional 10% to 15% buffer, and then above that, the insurance company is responsible.

MR. BELDEN: Now we will shift to structuring risks for existing projects. There is definitely more pressure for a phase II site assessment at an existing plant. As part of the power plant divestitures a few years ago, these were plants that had been in operation for 20, 30 or 40 years. The phase I reports identified areas of potential contamination at the plant sites.

For the acquisition of an existing plant, typically you will have some sampling done to find out what your contamination risks might be. You will also want to take a look at the operating permits of the plant. In general, construction permitting is not an issue since these plants have been in existence for a while. But you may need to anticipate what change-in-law risks exist. For example, in a divestiture of coal-fired plants, factor in the impact of the clean air mercury rule, the clean air interstate rule and possibly climate change risks. There may be mandatory carbon reduction requirements some day in the US, and, with an existing plant, you want to take a careful look at the compliance history and review any environmental liabilities the owners may have agreed contractually to cover.

In an asset sale, the mere fact that you are buying assets is not a shield against liability issues. With a divestiture, you want to try to have the seller provide a comprehensive indemnity. An alternative is to set aside part of the purchase price for possible environmental liabilities. Environmental insurance may also be an option.

MR. GIACCIA: I have to tell you that I can think of only two transactions in which I have been involved where an insurance product got us over an environmental problem. However, some people who do environmental transaction work believe in them as a useful tool. The variable may very well be your preparedness, the quality of the broker that you work with and your ability to negotiate a policy that is effective. Because if all you are planning to do is call an insurance company, get the basics done, and get a policy signed up, then you are kidding yourself that you are going to get something that is useful. It takes time to get an effective policy, and you can usually not get one at the 11th hour. If there is enough time and enough information about the site, then you may be able to negotiate an insurance policy that is useful. ◎

Toll Road Update

by Jacob S. Falk, in Washington

A number of US states that do not currently authorize significant private sector involvement in road projects are considering public-private partnerships for the development or operation of toll roads.

While some of these states are focusing on creating the necessary legislative and regulatory framework for private or public-private road projects, others are starting with an attractive project and working their way back to the necessary legislation.

Of course, whether you start with a framework or with a project, one of the key ingredients for jump starting any public-private partnership — or PPP — program is political support and, in a handful of states, recent gubernatorial elections brought in governors who support the use of PPPs to help solve their states' transportation problems.

Individual States

Private sector involvement in road projects has traditionally been limited in the United States to low-bid procurement of construction contracts. To involve the private sector in anything more than low-bid procurement requires legislation to change the rules.

Maryland is moving to create a PPP program for highway projects. Maryland has a PPP program authorizing transportation projects generally, which dates back to 1997, but the program specifically excludes highway projects. (The program is administered by the Maryland Transportation Authority, which is responsible for managing, operating and improving the state's toll facilities.) Maryland recently sent highway officials to Texas, Virginia and California to study the experiences those states have had with highway PPPs and, on August 11, the Maryland Transportation Authority released a report on highway PPPs titled "Current Practices in Public-Private Partnerships for Highways."

Maryland has not yet disclosed specific projects for which it would consider PPPs. Since Maryland already has a centralized and well-managed tolling authority, there is speculation that the state is considering PPPs for the development of new capacity rather than the operation of existing toll roads.

Utah is also considering PPPs for roads, but like Maryland, Utah has not yet identified a particular PPP project (or a group of projects) on which to focus. Utah needs $16.5 billion for road development over the next 25 years. It is studying what other states have done to encourage PPPs generally. A bill for PPP toll roads is expected to be introduced in the next session of the Utah legislature.

In Tennessee, the commissioner of the Department of Transportation recently suggested that the state will look at PPPs over the next couple of years as an alternative financing solution for road projects. The commissioner identified the proposed beltway around Knoxville — the so-called "orange route" — as one project that might benefit from private-sector help, but the state is expected to focus on authorization of PPPs generally.

Tennessee is looking at PPPs because high gas prices make it difficult to raise gas taxes to pay for highway maintenance. The state gas tax is currently 21.4¢ a gallon and has not been raised in years. The buying power associated with it continues to decline. The state is projecting a 5% to 10% percent decline in gas tax revenues in the near term as high gas prices cause people to drive less and buy more fuel-efficient cars.

In Nevada, the governor has established a task force that is supposed to report by the summer of 2006 on the potential for toll road PPPs. The state is facing a $2.4 billion shortfall in highway funding over the next six years. Raising gas taxes is difficult in Nevada. The state gas tax is 23¢ a gallon and the combination of federal, state and local gas taxes bring the total tax to 53.05¢ a gallon -– the highest in the nation, outside Hawaii.

Nevada has PPP enabling legislation for certain types of transportation projects, but toll roads and toll bridges are specifically excluded from the legislation. Nevada's enabling legislation cannot be amended until the legislature meets again, which is not scheduled to happen until 2007. Among the projects Nevada would like to complete, but cannot afford to complete out of current revenue, are the widening of I-15 and I-95 in the Las Vegas area and the construction of a bypass around Boulder City.

Indiana does not currently have statu- / continued page 42

Toll Roads

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tory authority for highway PPPs, but the governor suggested in August 2005 that the state consider PPPs generally. The governor said, in particular, that the I-69 extension from Indianapolis to Evansville would benefit from a PPP structure. Unlike the other states mentioned earlier, Indiana is not initially focusing on creating a broad regulatory framework for PPPs but approaching things from the other direction by focusing on privatizing a single existing highway.

At least another eight US states are moving to bring in private partners in highway projects.

The state is soliciting proposals for a 75-year concession agreement that will require the concessionaire to maintain the 157-mile Indiana turnpike, in exchange for which it will be allowed to collect tolls. The turnpike runs across the northern part of the state, starting in the east where the Ohio turnpike dumps cars into Indiana and connecting in the west with the Chicago Skyway. The governor is hoping that the state will receive proposals for this concession that are too attractive for the legislature to turn down. If the state is offered the kind of money that Chicago was offered for the Chicago Skyway, then the governor's gamble will have paid off. If not, the governor's gamble could turn into an embarrassing setback for the state's PPP program.

Another PPP project that may be in the works is the new $910 million Mississippi River bridge between Illinois and Missouri. A preliminary study by a St. Louis engineering firm, which will not be complete until sometime in 2006, found that a $1.00 toll each way could generate as much as $240 million per year, assuming an average of 66,000 vehicles crossing the bridge each day. Illinois does not currently have statutory authority for highway PPPs. (The Chicago Skyway was authorized by the City of Chicago under a home rule provision of the Illinois constitution.) Illinois transportation officials have said they would prefer not to collect toll on this new bridge. Missouri has legislation from 1990 authorizing not-for-profit state transportation corporations to implement PPPs, but Missouri does not have broader statutory authority in place authorizing the full range of PPP structures being used around the country.

The Florida Department of Transportation is moving forward on plans to begin a PPP tender process for the Miami port tunnel. The tunnel would link I-395 on Watson Island with the Port of Miami on Dodge Island. The tunnel would help accommodate port traffic, which is expected to increase, and would remove trucks and buses from Miami's crowded downtown streets.

Miami held a heavily-attended informational meeting on December 5, 2005 to solicit feedback from the private sector and share background information. Alternative scopes and project delivery methodologies were discussed. On December 13, the Federal Highway Administration signed a re-evaluation of an earlier environmental assessment, again accepting a recommendation for a bored tunnel. A request for proposals and an information memorandum are expected to be released in early February 2006, with the selection and award of a franchise or concession targeted for the end of 2006.

New Jersey

In New Jersey, where there is currently no statutory authority for private participation in road projects, the incoming governor, Jon Corzine, may face the same dilemma as the Indiana governor if he tries to privatize the New Jersey turnpike or the Garden State Parkway, a move New Jersey appears to be considering. Going to the legislature with a proposal in hand for a valuable concession (the concession has been estimated to be worth over $20 billion dollars up front) may help smooth the way for statutory authority. On the other hand, to ask private investment consortia to conduct the necessary studies and prepare proposals only to have these efforts set aside by a skeptical legislature could foreclose future private investment in New Jersey road projects.

New Jersey needs to find a new source of revenue for transportation projects. By June 2006, New Jersey's transportation trust fund, which funds capital improvements, will have $0.00 in revenue generating capacity for investment in new capacity and maintenance; it will be using all of its revenue for debt service on outstanding indebtedness. In addition, depletion of the transportation trust fund jeopardizes the approximately $1.2 billion that New Jersey receives from the federal government, which is only provided if the transportation trust fund provides matching contributions. Together, the transportation trust fund and the federal matching funds make up approximately 60% of New Jersey's transportation budget, and the loss of these revenue sources will force New Jersey to limit its transportation spending to operating expenses and emergency repairs.

The idea of privatization has been discussed for almost a year in New Jersey, but real political support has been elusive. There has been speculation that privatization will move forward now that Corzine has been elected, but a November 2005 report by the Regional Plan Association, a New Jersey, New York and Connecticut think tank, suggested that it would take one to two full years to negotiate a fair concession contract, and the "day of reckoning" for the transportation trust fund is expected on June 30, 2006 –- in six months.

New Jersey needs an estimated $2.7 billion a year in new transportation revenue. The Regional Plan Association's report suggested several alternative sources of funds that could be used in various combinations to satisfy this need. In addition to privatization, they include container taxes, corporation business taxes, motor fuel taxes, motor vehicle registration fees, personal property taxes on vehicles, petroleum gross receipt taxes, rental car fees, higher sales and use taxes, tolls and value-capture fees or mortgage recording taxes.

The report said Corzine must exhibit "rare leadership" and that a decision must be made within the next six months. A study commissioned by the New Jersey Department of Transportation speculating on how much might be raised by privatizing existing New Jersey toll roads was expected in late December.

Virginia

The new governor in Virginia, Tim Kaine, expects the transportation "crisis" to be the "most urgent issue" of his upcoming term in office. Kaine started, almost immediately after election day, hosting town hall meetings around the state to discuss Virginia's transportation needs.

Kaine supports PPPs. The town hall meetings are an effort to rally support for transportation initiatives. The state legislature has supported PPPs in the past, but the PPP landscape has been changing dramatically over the last year and the governor's support will be crucial, especially for the recent concession-style proposals being considered by the Virginia Department of Transportation, or VDOT.

VDOT is currently considering granting a long-term concession for the Dulles toll road similar to the one used for the Chicago Skyway and the one proposed for the Indiana turnpike. One bidder made an unsolicited proposal. The state is also reviewing four competing proposals. The initial unsolicited proposal would dedicate a significant amount of the concession price for development of a Metrorail extension from Washington, DC to Dulles airport. In late December, the state eliminated one of the competing proposals and the Metropolitan Washington Airports Authority, which operates the Dulles airport, submitted an additional competing proposal. The airports authority proposal relies on toll and bond revenues and does not contemplate any private involvement.

VDOT signed an agreement during 2005 with a private consortium for development and operation of two high-occupancy toll lanes in each direction on Virginia's 14-mile portion of the beltway that runs around Washington, DC. The project is expected to cost approximately $900 million. VDOT is also currently negotiating with a private consortium for an approximately $913 million concession for development and operation of high-occupancy toll lanes on a 56-mile portion of I-95 and I-395 south of Washington.

Meanwhile, Virginia and Maryland have been working together on adding new toll lanes to the two Potomac River crossings on the beltway. It is not clear whether the toll lanes would be developed or operated as PPP projects, or how a PPP could be structured between two states only one of which currently has a PPP highway program, but a study commissioned by the two states analyzing the projects is expected in the next 18 months.

The last year was an exciting year for private road projects in the United States, with the Chicago Skyway and the Trans-Texas corridor grabbing major headlines, but perhaps the most exciting development, as 2006 starts, is that a number of states without active PPP programs are talking about adopting them. ◎

Environmental Update

New Source Review

The US Environmental Protection Agency took another significant step toward a complete overhaul of the federal "new source review" air permitting program.

The agency proposed a new rule in October that would dramatically alter how it calculates an emissions increase due to a physical change or a change in the method of operation at existing power plants. The proposed rule responds to a decision by the US court of appeals for the 4th circuit, which held that the agency must define the word "modification" consistently for purposes of both the new source review or "NSR" program and the new source performance standards or "NSPS" program.

The proposed rule would clarify that power plant upgrades are not considered "modifications" for air permitting purposes unless they are considered modifications for purposes of the NSPS program.

The proposed emissions test would determine whether an emissions increase is expected to occur by comparing the maximum hourly emissions achievable at an electric generating unit during the past five years to the maximum hourly emissions achievable at the unit after the upgrades. Under the NSPS program, a "modification" occurs when there is an increase in the maximum achievable hourly emission rate.

This proposed approach is a significant development because it is much harder to trigger a "modification" at an existing power plant under the NSPS program than under the standard that EPA was using to calculate emissions increases under the NSR program. In the NSR program, a "modification" occurs when there is a significant increase in annual emissions at a plant compared to a base line of the plant's actual emissions during a consecutive two-year period within the previous five years. Under the new proposed rule, upgrades to a boiler that restore the unit to its original hourly emission rate would not be a modification, but they would probably have been a modification under the old EPA rules for the NSR program.

The issue of how to determine whether a "modification" has occurred under the NSR program has been a source of conflict among EPA, the regulated community and environmental groups, and the issue came to a head in 2005 when two federal appeals courts reached opposite conclusions on how a "modification" is calculated under the NSR program. The US appeals court for the 4th circuit held in *US v. Duke Energy Corp.* in June that "modification" has the same meaning for purposes of both the NSR and NSPS programs. However, the US appeals court for the District of Columbia circuit ruled nine days later in *New York v. EPA* that the agency is free to define the word "modification" differently for NSR permits.

Meanwhile, EPA also invited comments on an alternative approach for calculating emissions increases from modifications that is not quite as far reaching as its preferred approach described above. The alternative is to measure emissions increases by comparing the maximum hourly emissions achieved *before* the upgrades to the maximum hourly emissions achieved *after* the upgrades. EPA is also requesting comment on whether the emissions test should be changed from a kg/hr calculation to a mass-of-emissions-per-unit-of-output calculation, such as pounds per megawatt hour or nanograms per joule. EPA says that using an output-based calculation should help encourage the use of more energy-efficient units that displace older, less efficient units.

The new proposed rule is highly controversial, and it is attracting significant opposition from public interest groups. Environmental groups complain that EPA is retreating from its obligation to enforce the NSR program. EPA extended the comment period on the proposed rule from December 19, 2005 to February 17, 2006. A public hearing took place on December 9. If the proposed rule is adopted, then the attorneys general for several northeastern and mid-Atlantic states are expected to file suit to block implementation of the new rule.

In addition, the EPA administrator, Stephen Johnson, has directed the agency's enforcement personnel to "re-prioritize resources to other areas" rather than pursue new high-profile NSR enforcement cases. The agency will continue its ongoing NSR enforcement actions against several major utilities with coal-fired plants, but its focus in the future will shift to pursuing companies that violate the new proposed rule.

Mercury

The Environmental Protection Agency is reconsidering portions of two rules the agency issued in early 2005 to reduce mercury emissions from power plants.

Fourteen northeastern and mid-Atlantic states and five environmental groups sued to force the agency to reevaluate the clean air mercury rule and the so-called "section 112 revision rule" in which the agency reversed a December 2000 finding that the regulation of mercury from coal-fired plants is "necessary and appropriate." EPA concluded that more recent information demonstrates that it is not appropriate or necessary to regulate mercury emissions from coal-fired power plants under section 112 of the Clean Air Act. Section 112 requires use of a "command-and-control" approach to regulating air toxic emissions instead of a more flexible emissions trading regime favored by the Bush administration.

EPA is reconsidering two issues under the section 112 revision rule. First, it is assessing whether the public should have had a chance to comment on some of the legal interpretations that it adopted for the first time in the final section 112 revision rule; they were not hinted at in the proposed rule on which the agency had requested comments. Second, it is assessing whether the public should have been given an additional opportunity to comment on how the rule will be applied based on certain conclusions reached by the agency. The litigants have a particular gripe about how the government has chosen to measure the amount of mercury in fish due to utility emissions and the conclusion that such levels are not reasonably anticipated to be hazardous to public health.

EPA is also reconsidering seven issues tied to the clean air mercury rule. They are the methodology used to apportion the mercury budget to the individual states, the definition of "designated pollutant," EPA's basis for subcategorizing subbituminous coal-fired units, the statistical analysis used to establish the new source performance standards, the calculation of the highest annual average of mercury in coal used to derive the new source performance standards, the definition of covered units to include municipal waste combustors, and expansion of the definition of covered units to include some industrial boilers.

The clean air mercury rule has come in for heavy criticism, and a number of lawsuits have been filed challenging it. The parties filing these suits want strict technology-based emission standards for mercury emissions under section 112 of the Clean Air Act.

The clean air mercury rule applies to coal-fired steam generating units with capacities of more than 25 megawatts and that sell more than 25 megawatts to the grid. 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 capacity and more than 25 megawatts into the utility grid for sale.

Under the clean air mercury rule, EPA has adopted a two-phased "cap-and-trade" approach to reduce mercury emissions from coal-fired plants starting with the first phase in 2010 and the second phase following in 2018. "Cap and trade" means that power plants have a choice of reducing pollution or buying emission 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.

EPA has imposed a 38-ton mercury emission cap for the first phase and a 15-ton cap for the second phase. This is the amount of mercury emissions that would be allowed each year from all coal-fired power plants nationwide. US power plants emit approximately 48 tons a year of mercury in total. In both phase one and two, 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. One allowance will correspond to one ounce of mercury.

Even though the government has agreed with the northeastern and mid-Atlantic states and environmental groups to reconsider some issues behind its mercury rules, major changes to the rule are not expected.

The lawsuits challenging the mercury rules are moving ahead on a parallel track before the US appeals court in Washington DC, and a decision on the merits is not expected until late 2006 or early 2007.

In related news, an organization of state and local air pollution control officials unveiled a model mercury rule that states may consider as an alternative to the federal approach. Under the EPA rule, states have the option of participating in an EPA-managed cap-and-trade program or electing to adopt their own state programs. The model rule promoted by the state and local */ continued page 46* *continued from page 45*

officials organization provides two options. The first option calls for an 80% reduction in mercury emissions by 2008, followed by a 90 to 95% reduction by 2012. The second option would require coal-fired power plants to reduce mercury emissions by 90 to 95% by 2008 with a possible four-year delay if pollution controls to reduce NO_x (nitrogen oxide), SO_2 (sulfur dioxide) and particulate matter are also installed. The EPA clean air mercury rule requires approximately a 50% nationwide reduction in mercury emissions by 2010 and about a 70% reduction by 2018. New Hampshire, New Jersey, Pennsylvania and other states are moving on their own to adopt mercury reduction standards that are more stringent than the clean air mercury rule. New Hampshire, for example, appears to be heading toward adopting an 80% reduction target by 2013. New Jersey has already adopted a mercury reduction target of 90% or 3.00 mg per megawatt hour by the end of 2007.

Superfund

The Environmental Protection Agency released a final rule in November that explains what someone buying property must do to satisfy the "all appropriate inquiries" due diligence standard for recognizing certain defenses to potential Superfund liability associated with prior releases of hazardous substances. Under Superfund, liability may be imposed on a current "owner or operator" of a facility even if that entity did not contribute to pollution on a site.

The new "all appropriate inquiries" rule will take effect on November 1, 2006.

In the interim, EPA will recognize either compliance with the new rule or completion of a phase I environmental site assessment conducted as in the past.

There are three defenses under Superfund to potential liability based on satisfying the "all appropriate inquiries" due diligence standard. The defenses are provided for the following categories of landowners: "innocent landowner," "contiguous property owner" and "bona fide prospective purchaser."

Under Superfund, an "innocent landowner" may be protected from liability if he or she acquires property without the knowledge that it is contaminated or likely to be contaminated and the landowner is not affiliated with or a counterparty to a contract with the entity that caused the contamination (other than a contract for sale or a service contract). Likewise, a "contiguous property owner" who acquires property that is or may become contaminated by an offsite source may be protected from liability if he or she demonstrates not only a lack of knowledge, but also no reason to know that the property was or could be contaminated by a release of hazardous substances from a neighboring property. In order to meet the requirement that a contiguous property owner did not know about any potential contamination at the property, a phase I report satisfying the "all appropriate inquiries" standard must be performed.

The Environmental Protection Agency explained in November what someone buying land must do to escape liability under Superfund if the land turns out to be polluted.

Under the third available defense, a "bona fide prospective purchaser" must purchase the property after January 11, 2002, complete a phase I site assessment and not be affiliated with or be a counterparty to a contract with an entity that is responsible for the contamination. Nevertheless, a person may qualify as a bona fide prospective purchaser even if he or she purchases the property knowing that it is contaminated or might be contaminated from the offsite migration of contaminants.

In the preamble to the new rule, EPA confirmed that a phase I report meeting the "2005 ASTM phase I report standards" will fully comply with the new rule. Further, EPA also recognizes that phase I reports prepared in conformance with the rule will be valid for one year prior to the acquisition date. Phase I reports older than that will need to be updated within one year prior to the date the property is acquired.

Clean Air Interstate Rule

The Environmental Protection Agency announced in late November that it will reconsider four issues tied to the "clean air interstate rule." The clean air interstate rule requires 28 eastern states and the District of Columbia to reduce nitrogen oxide, or NO_X, and sulfur dioxide, or SO_2, emissions from power plants and other pollution sources by 2015.

Several states, utilities and environmental groups filed petitions for reconsideration with EPA. Many of these same parties also filed lawsuits in the US appeals court in Washington challenging the rule. EPA will generally grant a petition for reconsideration if the petitioner can demonstrate that the objection is of central relevance to the rule and that it was impractical to raise the issue during the public comment period.

The first issue being reconsidered with whether there were inequities in the method used to apportion SO_2 allowances to states that elect to use the EPA model SO_2 trading rule. One petitioner argued that the allocation penalizes utilities with units that have lower emission rates because they may end up buying surplus allowances from utilities with high emission rate units that install pollution controls.

The second issue concerns EPA's use of specific fuel adjustment factors to establish NO_X budgets for each state. Several utilities argue that states that rely heavily on natural gas and oil to generate electricity are being required to make more significant reductions in NO_X emissions than states that use coal. This is due to the way EPA granted greater weight in the fuel adjustment factors to states with more coal-fired units.

The third issue addresses the modeling inputs EPA used to determine whether Minnesota should be included in the PM2.5 portion of the clean air interstate rule. The fourth issue relates to whether Florida should be included in the ozone region under the rule.

The clean air interstate rule assigns each of the 28 affected states an emissions budget. Each state must comply in one of two ways. It can participate in an EPA-administered cap-and-trade program that ratchets down NO_X and SO_2 emissions from power plants in two stages starting with an initial NO_X cap in 2009 and an SO_2 cap in 2010 followed by lower caps for both pollutants in 2015. Alternatively, a state may propose other emission reduction measures, including roping in other sectors besides power plants to spread the reductions across a wider number of facilities.

EPA is accepting comments on the four issues through January 13, 2006. The agency expected to make decisions on the issues by March 15, 2006. Meanwhile, the lawsuits have been consolidated into a lead case titled *North Carolina v. EPA*, and a decision in the case is not expected until late 2006 or early 2007. The clean air interstate rule is generally expected to survive the legal challenges since it is modeled after a "NO_X SIP call rule" that remained largely intact after a protracted legal battle.

Wastewater Discharges

The Environmental Protection Agency took steps in October to clarify various provisions of the pretreatment discharge standards for wastewater that is sent by industrial users to local wastewater treatment plants. The pretreatment discharge standards require municipalities to set discharge limits to control industrial discharges into local sewage collection systems.

The new rule removes certain nonessential process requirements, including an order to sample for pollutants that are not present at a particular industrial facility. Instead, the industrial plant will be granted a monitoring waiver upon certifying that the pollutants are not present. Under the final rule, municipalities will have greater authority to grant general pretreatment permits covering a category of sources and the ability to use best management practices as an alternative to numeric discharge limits. Municipalities are also granted the flexibility to approve alternative sampling techniques.

While industrial discharges will still have to meet the same federal discharge limits in the locally-enforced pretreatment programs, EPA believes that the rule changes will substantially reduce the compliance costs for industrial facilities. The rule became effective on November 14, 2005.

Brief Updates

EPA released a new analysis in late October comparing the costs to implement the Bush administration's "clear skies initiative" to the costs of several legislative alternatives pending in Congress. The analy- / *continued page 48*

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sis showed the clear skies proposal is the least expensive of the proposals at $5.7 billion in 2020 with expected annual health benefits of $114 to $134 billion by 2020. The costs of competing pollution control measures introduced by Senators James Jeffords (I-Vermont) and Thomas Carper (D-Delaware) were $50.8 billion and $9.5 billion, respectively, by 2020 with generally much higher anticipated annual health benefits. The administration is hoping that the new analysis will prompt Congress to move on its clear skies initiative. The initiative has remained stalled, and action on it remains unlikely.

In California, two lawsuits were filed with the Alameda County superior court challenging the issuance of new conditional use permits for more than 3,000 existing wind turbines in the Altamont Pass area. The 13-year permits, issued by the Alameda County board of supervisors, imposed new conditions to reduce bird deaths, including the immediate shutdown of the most dangerous 2% of wind turbines and restrictions on winter operation when turbines pose the most danger to raptor and songbird populations. Environmental groups charge that an environmental impact review under the California Environmental Quality Act should have been completed before the permits were issued.

In Maryland, the public services commission took steps in October to implement a renewable portfolio standard that was enacted in 2004. The Maryland renewable portfolio standard separates renewable electric generation into two categories. Tier 1 facilities include solar energy, wind power, qualifying biomass and methane from landfills or wastewater treatment plants. Tier 2 includes waste-to-energy plants, the use of poultry litter as fuel and certain hydroelectric projects. Maryland utilities will be required to supply 1% of their electricity from tier 1 renewable fuels by 2006. The amount will increase to 7.5% by 2019. Utilities will need to provide 2.5% of their electricity from tier 2 sources by 2006.

A draft environmental impact statement completed in October recommends approval of a proposed liquefied natural gas terminal to be built at the Port of Long Beach in California. The Federal Energy Regulatory Commission and the Port of Long Beach jointly prepared the environmental study. The draft impact statement concludes that the proposed LNG terminal is environmentally acceptable. The terminal will have the capacity to supply 10% of the natural gas needs of California.

Finally, EPA published a proposed rule in October that would exempt the reporting of NO_X emissions in amounts less than 1,000 pounds per 24 hours under Superfund and the Emergency Planning and Community Right to Know Act, provided the releases are from combustion activities and not accidents or malfunctions. Under those laws, industrial facilities are currently required to report NO_X emissions if they exceed 10 pounds during any 24-hour period. Sources usually notify the government of any continuous emissions of NO_X that exceed this threshold. The proposed rule will provide some administrative reporting relief to facilities that emit relatively small amounts of NO_X. ◎

— contributed by Roy Belden in New York

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