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Dividend Proposal Rattles Renewables

by Keith Martin, in Washington

Energy companies initially embraced President Bush's proposal to eliminate taxes on dividends, but some pulled back after reading the fine print.

The proposal has the potential to reduce the value of tax credits that the US government offers as an incentive to invest in windpower, geothermal, landfill gas, synfuel and other alternative energy projects.

It could also complicate some debt restructuring talks of merchant power companies. The president asked Congress to limit the ability of companies with current net operating losses to use them as a carryback to recover taxes they paid the federal government in the past. Under current law, such carrybacks are permitted for up to two years in the past. Under the Bush proposal, losses could only be carried back one year.

News Coverage

News reports — including the first paragraph of this article — leave the impression that the president proposed eliminating taxes on dividends. In fact what he proposed is more complicated. Under current law, a corporation is taxed on its earnings and its shareholders are taxed again when the earnings are distributed as dividends. The proposal is to tax corporate earnings only once. Thus, to the extent a / *continued page 2*

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DEPRECIATION BONUS issues inch closer to resolution.

The US government began offering a 30% "depreciation bonus" last March as an inducement to US companies to invest in new plant and equipment. The bonus is available only for new investments during a "window period" that runs from September 11, 2001 through 2004 or 2005, depending on the investment.

Power plants and other infrastructure projects take a long time to build. Most projects that qualify potentially for a bonus were under development before September 11, 2001.

The Joint Tax Committee staff in Congress / *continued page 3*

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corporation pays taxes on its earnings, there would be no further tax collected from shareholders when the earnings are distributed as dividends.

This means that corporations would have less incentive in the future to invest in ways that the government encourages by offering tax credits. All the corporation will have succeeded in doing by reducing its taxes is to shift the tax burden to its shareholders.

There is a two-year lag between when the taxes accrue and when tax-free dividends could be paid. A corporation that paid $35 in taxes for 2002 could distribute $65 in tax-free dividends in 2004.

Many corporations retain earnings rather than pay dividends. The Bush administration tried to make the proposal neutral. If a corporation with $65 to distribute tax free in 2004 failed to distribute the full amount, then each shareholder would receive an equivalent benefit by increasing the basis in its shares at year end by the shortfall.

Corporations would have to send each shareholder a Form 1099 at the end of the year. The form would indicate the percentage of dividends that was tax free and how much the shareholder should adjust his stock basis as of the end of the year. If — in a later year — the corporation distributed *more* than it was entitled to distribute in tax-free dividends — suppose it could have distributed $65 tax free but distributed $75 — then its shareholders would not be taxed on the additional $10. Rather, they would have to *reduce* their stock bases by the $10 until the previous basis increases have been reversed. Any dividends after that would be taxed.

> The Bush dividend plan could deal a body blow to low-income housing, wind farms, geothermal power plants, methane gas recovery from landfills and similar projects.

Here is how the plan would work.

Suppose a corporation earns $100. It would normally pay $35 today in taxes and have $65 left over to distribute to its shareholders. (The US corporate income tax rate is 35%.) Under the Bush plan, the $65 could be distributed without shareholders having to pay any further taxes.

Each corporation would calculate the amount it can distribute tax free to shareholders by multiplying the federal income taxes it paid by 65/35ths. Thus, a corporation that paid $35 in taxes would be allowed to pay up to $35 x 65/35 = $65 in tax-free dividends to its shareholders.

It gets more complicated.

The calculation would be done each year on January 1 to show how much a company could distribute in tax-free dividends during the coming year. A corporation would start with the taxes it paid on a final tax return filed the year before. Most US corporations file their federal income tax returns on September 15 reporting taxes owed for the previous year. For example, a tax return filed on September 15, 2003 would reflect taxes owed for 2002. Thus, a corporation would use the taxes it paid for *2002* on a return filed in *2003* to calculate the amount of dividends that it could pay tax free in *2004*.

No basis adjustments would be made in preferred shares that are limited as to dividends.

The president wants the plan to take effect retroactively to the start of 2003. Corporations would calculate the amount they can distribute tax free during 2003 based on the taxes they paid for 2001.

Effects

Many economists like the proposal because it would help reduce some biases in the current tax system. The US Treasury Department listed as one of the benefits that the proposal would reduce a bias toward corporate borrowing. Since corporations can deduct interest paid on debt but not earnings paid out as dividends, corporations are more likely to borrow than raise equity. Heavy corporate debt loads lead to more bankruptcies during economic downturns.

The Bush administration also appears to be hoping that the proposal will lead to a boost in stock prices, thereby helping the economy. The newspaper columnist George Will called it an "exercise in mass psychotherapy."

However, at the same time, the proposal would deal a body blow to low-income housing, wind farms, geothermal power plants, methane gas recovery from landfills and other projects that rely on government help in the form of tax credits to be economic. In the typical wind farm, the sponsor essentially borrows against the value of the tax credits. If the institutional equity market will have less interest in tax credits, then windpower developers may have a hard time financing their projects. Many people worry that even if the proposal is not enacted, it will complicate financings this year while it is under debate in Congress. Opponents of the proposal in Congress have been asking for examples of new construction projects that have been placed on hold because of the uncertainty created by the plan.

Corporations would have less incentive to invest in ways that reduce their taxes. Congress enacted a 30% depreciation bonus as part of an economic stimulus bill in March last year. This would have less value as a stimulus.

Opinions differed over the effect on the equipment leasing market. More companies may find it advantageous to use lease financing for their projects because they will have less use for the accelerated depreciation or tax credits to which owners of equipment are entitled. At first glance, this should also mean fewer potential lessors. However, some argue that lessors are like addicts — they become addicted to the acceleration in earnings that they receive from use of lease accounting and must continue to do more leasing or suffer a dramatic dropoff in book earnings.

The proposal should make raising equity for corporations a little less expensive. There is a debate among economists about whether and how much the proposal might lift share prices. Higher share prices mean that a corporation can raise the same equity while offering fewer shares.

By the same token, if investors shift into the equity markets and away from debt, then corporate debt will be more expensive (unless corporations borrow commensurately less). This could be a concern for issuers of floating-rate debt.

Interest rates on tax-exempt bonds can be expected to increase because the pool of investors interested in tax-free returns will have a competing instrument in which to invest. This means that municipalities will have to pay more to attract the same amount of capital as / continued page 4

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answered some questions that power companies have about the bonus in a "blue book" in late January. The blue book suggests that most power plants will qualify for a bonus as long as construction did not start at the site before September 11, 2001. A question had arisen whether a project would qualify if the turbines were ordered before September 11. The blue book makes clear that a mere turbine order does not taint the project. The project will still qualify for a bonus. However, the blue book did not answer whether the bonus can be claimed on the turbine itself. Congressional staff could not agree.

The blue book also addresses what happens in a case where a project developer would not have qualified for a bonus on his project because work on it started too early, but the developer must sell the project before it is completed. Many merchant power companies are having to shed assets to pay down debts. The blue book says that a new purchaser who completes construction will qualify for a bonus on the project, assuming the project is completed before the end of the window period, despite the fact that the original developer would not have qualified for a bonus. Power companies had asked whether the new purchaser can claim a bonus on the full cost of the project — including what he pays to acquire the work in progress — or only on his spending to complete construction. The Joint Committee staff said the bonus can be claimed on the full cost.

However, the blue book indicates that Congress will adopt an "anti-churning rule" to prevent companies that do not qualify for a bonus from "churning" assets in order to give the bonus to someone else. An example of a churning transaction is where a project is sold and leased back by the developer or sold to a related party before construction is completed.

Meanwhile, the Internal Revenue Service has completed a first draft of regulations to */ continued page 5*

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before. Roads, schools, hospitals and other public facilities can be expected to cost more. Yields on municipal bond issues are measured as a percentage of the yields on Treasury bonds with comparable maturities. By early February, the yields on 30-year investment-grade municipal bonds were roughly 95% of the yield on 30-year Treasury bonds. Historical averages have been around 87%. On 10-year municipal bonds, the ratio in early February was 88% compared to an historical average of 77.5%. Some analysts attributed the higher yields to a record surge in new bond issues and said that the market was "concerned and confused" by the Bush dividend proposal, but that it had not yet affected rates.

The proposal could complicate any plans by companies that are losing money to get back cash from the US Treasury. Under current law, a company with losses can use them to get a refund of any federal income taxes it paid up to two years in the past. Under the proposal, losses in 2003 and later years could only be carried back one year. Some merchant power companies had been counting on the ability to carry back losses up to two years as a way to inject money into restructuring talks.

Wall Street expects a revival of interest in participating preferred stock. These are shares that entitle the holder to a certain amount in dividends before any distributions on the common shares and a preference at liquidation. The shares are "participating" because the holder would also have a limited upside out of additional earnings. Such shares would be more attractive because they would come close to an instrument that pays purely a tax-free return. The reason for "participating" shares is that corporations stand a better chance of avoiding taxes in a recapitalization in which existing shareholders would be given both preferred shares and new common in place of their existing shares.

Any analysis of the effects of the dividend proposal is complicated by a number of factors. The Bush administration is hoping that companies will have a greater incentive in the future to distribute their earnings as dividends rather than retain and reinvest them. The proposal is a form of shareholder populism offered in the same spirit that drives Republican administrations to cut taxes in the belief that voters should decide how to spend their own money rather than have the government or corporations make decisions for them. However, it is not clear how much pressure will be placed on corporations to pay tax-free dividends. According to Standard & Poors, 58% of shares are held today by pension plans and other tax-exempt entities. Even if there were pressure, corporate managers might have a perverse incentive to do things that reduce the "excludable dividend amount" as a way of easing the pressure on the company to distribute all its earnings.

Merchant power companies lack the cash to pay dividends. Some have speculated that this might open up a larger gap between the "haves" and "have nots" in the power industry, as the regulated utilities that have historically paid dividends would benefit from a boost in their share prices while the merchant power companies are left farther behind.

Other Energy Proposals

Ironically, the Bush administration called on Congress in the same budget that includes the dividend proposal to enact several new tax credits of interest to the project finance community.

The president urged Congress to extend a section 45 tax credit for wind farms. The credit is 1.8 cents a kWh for producing electricity from wind. The credit can be claimed on the electricity output for the first 10 years after a project is placed in service. Wind farms must be put into service by the end of 2003 to qualify under current law. Bush asked Congress to extend this deadline by another two years through 2005.

He also proposed to allow the credit to be claimed on electricity produced by burning most types of biomass. The exceptions — where the credit could not be claimed — would be power plants that burn old growth timber, wood waste incidental to pulp and paper production, municipal garbage, or post-consumer waste paper.

Under the Bush proposal, existing biomass power plants would also qualify — not just new plants built after the proposal is enacted — but only for three years of tax credits and then only at 60% of the normal rate. This potential windfall should be taken into account by anyone refinancing or selling an existing project.

Existing coal-fired power plants that co-fire with biomass would also get a credit, but only for three years and then only at 30% of the normal rate.

Finally, the president proposed to let lessees of wind farms and biomass power plants claim section 45 credits, but only where the lease is signed after this change is enacted. The wind industry has not been able to use lease financing for its projects in the past because such structures would result in loss of section 45 tax credits.

The president also called on Congress to extend the section 29 tax credit, but only for landfill gas. This is a credit of $1.082 an mmBtu to induce Americans to look in unusual places for fuel. Projects had to be in service by either the end of 1992 or by June 1998 — depending on the fuel — to qualify. Under the Bush proposal, the credit could be claimed on gas from brand new collection systems or from expansion wells that are added to an existing collection system during the period 2003 through 2010. However, landfills that are subject to new source performance standards that the US Environmental Protection Agency issued in 1996 would receive only 2/3rds of the normal credit. This haircut would not apply until 2008 to older landfills at which any part of the collection system was in use before July 1998. It would apply immediately at newer landfills.

The president also asked Congress — again — to enact a new tax credit for cogeneration facilities. The credit would be 10% of the capital cost of the project. Both the Clinton and Bush administrations have asked Congress repeatedly to enact this tax credit. It passed both the House and Senate last year as part of a national energy bill, but failed to make it to the president's desk.

Finally, the president asked Congress to extend a tax credit for producing ethanol and an exemption from federal excise taxes on gasoline sold with ethanol additives through 2010. Both the tax credit and the exemption are currently set to expire in theory after 2007 but, because of a quirk in the law, they would actually expire earlier after September 2005. Bush did not propose any change in the quirk that leads to earlier expiration.

Outlook

The dividend proposal has been met with a less than enthusiastic reception in Congress. However, it is too early to rule it out. The president has only just started to lobby for it. No one will really be able to gauge its prospects until mid- to late March when the House tax-writing committee is expected to "mark up" the president's tax plan and send it to the full House for a vote.

The chairman of the House tax-writing / continued page 6

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implement the depreciation bonus. The regulations are expected to be issued this summer.

REPATRIATING FOREIGN EARNINGS may become a lot easier.

Among the proposals that Congress is considering including in an economic stimulus bill this spring is a plan to give US companies a brief window during which they can bring back earnings they have parked in offshore corporations without having to pay full US taxes on the earnings. Under the plan, US companies would be able to exclude 85% of dividends received from "controlled foreign corporations" from US tax. This would only apply to dividends received during 2003 and the first half of 2004. A "controlled foreign corporation" is an offshore corporation that is owned more than 50% by US shareholders.

US power companies that own foreign projects have struggled to find ways to tap into earnings from their foreign projects without subjecting the earnings to US tax. Most such earnings are parked in offshore corporations. They will become subject to US tax if they are repatriated to the United States. The earnings have usually already been taxed abroad. The US allows a credit in theory for any taxes that were already paid on the earnings to another country. However, the foreign tax credit rules are so full of fine print that almost no US power company is eligible to use such credits.

Under the proposal, companies that take advantage of the new 85% exclusion for dividends from controlled foreign corporations would have to forego any use of foreign tax credits to offset US taxes further on the dividends.

Congress is about to get to work on an economic stimulus bill. The proposal is one of several that were listed in a Joint Tax Committee pamphlet for the Senate tax-writing committee in / continued page 7

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committee, Bill Thomas (R.-California), said publicly that the plan is "complicated" and he wants to explore the effects in hearings in early March before deciding what do with it. At the same time, he told lobbyists in private that its fate will be decided in the next few weeks by whether the Republicans on his committee take to it or not. Lobbying of the 21 Republicans on the committee (not counting Thomas) is in high gear.

a wind farm — for example — and then to pull back the carrot after the company is only five years through the tax credits.

There have been five serious attempts in the past 30 years to put legislation through Congress to reduce the double tax on corporate earnings. None of these proposals has ever gained much traction. The problem is that the business lobby has always preferred other forms of tax relief. Martin Sullivan, writing in *Tax Notes* magazine, said, "Perhaps dividend relief is like strawberry ice cream. Few would complain if offered it, but most would prefer vanilla or chocolate."

What distinguishes the latest effort is that Bush called for 100% relief from double taxation. Past efforts have been more modest. The big business trade associations were mobilizing in early February — spurred on by the Bush administration — to pressure Congress.

The proposal could also complicate plans by companies that are losing money to get tax refunds from the US Treasury.

The dividend plan faces a tougher test in the Senate where Republicans have only a one-vote majority of 51-49. Eight Republican Senators have said they have serious reservations about the plan, while only one Democrat appears on the fence and possibly ready to support it. The chairman of the Senate tax-writing committee, Charles Grassley (R.-Iowa), appeared in comments to the press on February 5 almost to rule out putting the plan through his committee. Grassley, who is already thinking about what package of tax proposals to submit to his committee, said, "I don't have the luxury of saying I've got to have the dividend deduction. The president is not going to get everything he wants."

Meanwhile, low-income housing developers and alternative energy producers have been lobbying to revise the proposal to treat corporations as having paid taxes that are offset through use of tax credits. Bush already proposed this approach for foreign tax credits, but not for any other credits. US Treasury officials said such a change would gut their plan.

However, the administration acknowledges the need for transition rules. Negotiations were underway about the scope of a possible transition rule as the *NewsWire* went to press. It would be unfair for the government to have held out 10 years of tax credits as a carrot to prompt someone to build

The politics of the plan are miserable. Most US states link their income taxes to the federal definition of taxable income. The dividend proposal would reduce state tax collections at a time when many states are already facing record budget deficits and are required by state constitutions to make either deep cuts in services or increase taxes to close the gap. The US government revised its own budget forecasts in late January and is now also projecting record deficits well into the future — and the latest projections do not take into account the costs of war against Iraq or the economic stimulus plan itself. The numbers have made many Republican members of Congress skittish. The distributional effects also do not help in Congress. One Arkansas Senator asked the incoming Treasury secretary at a hearing in early February how she can support a stimulus plan that spends nearly $400 billion of $665 billion in total on a dividend relief proposal that benefits few people in her state. Eighty-two percent of Arkansas residents own no stock in corporations.

The main debate will play out this summer in the Senate. The earliest real indication of the plan's prospects will come in mid- to late March when the House tax-writing committee takes up the plan. It may be as late as November before its fate is ultimately decided by Congress. ◎

Popular PUHCA Exemption Narrowed

by Lynn N. Hargis, in Washington

Enron lost the first round in a case that could have broad implications for power companies that operate in more than one state in the United States.

The chief administrative law judge at the US Securities and Exchange Commission said in a decision in early February that Enron subjected itself to potentially onerous financial and corporate regulation under a sweeping 1935 statute called the "Public Utility Holding Company Act," or "PUHCA," because of its ownership of Portland General Electric, an electric public utility in Oregon.

Single-State Exemption

Enron had gone to great lengths — even changing its place of incorporation to Oregon — in order to avoid regulation under the 1935 statute. This reincorporation was supposed to exempt it from the statute under a "single-state exemption" that exempts the owner of a power company that operates only in a single state.

However, the judge said that, even though the service territory of Portland General is confined to Oregon, the utility operates outside the state because of the wholesale electric sales that Portland General makes at interstate "hubs" that are across the Oregon border. Since the single-state exemption requires that a "material" utility and its parent must be "predominantly intrastate in character" and carry on their business substantially in a single state in which both are organized, the judge found that Enron's public utility, Portland General, does not qualify for the single-state exemption because too great a share of its revenue comes from out-of-state sales.

The judge's finding was made despite the fact that the Public Utility Commission of Oregon — which intervened in the case — insisted that it "effectively regulates" the effect of Portland General's out-of-state wholesale sales on retail rates and urged the judge to grant the single-state exemption. PUHCA was supposed to help the states by having the federal government step in to regulate electric and gas utilities that have expanded too much into interstate commerce for a state to regulate effectively. The */ continued page 8*

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connection with hearings on February 11 and 12 on possible stimulus measures.

CORPORATE TAX SHELTERS will have to meet stiffer standards under a bill approved in early February by the Senate Finance Committee.

The bill would apply to transactions entered into after February 14, 2004. The committee delayed implementation until early next year to give the IRS time to issue guidance.

Under the bill, transactions would have to have "economic substance" in order for the government to honor the tax results. Two things would have to be true about a transaction for it to have economic substance. First, it would have to change the taxpayer's economic position in a "meaningful way" apart from the tax results. Second, the taxpayer must not only have a substantial non-tax reason for entering into the transaction, but it would also have to show that the transaction was a reasonable way to achieve its objective. A taxpayer will not be able to do this for transactions that "do not appear to contribute to any business activity or objective that the taxpayer may have had apart from tax planning." There must be a link to its ordinary business operations or investment activities.

The Senate Finance Committee added a footnote to its report on the bill that should help future investors in synfuel, windpower, low-income housing, landfill gas and similar projects. The footnote says, "If the tax benefits are clearly contemplated and expected by the language and purpose of the relevant authority, it is not intended that such tax benefits be disallowed if the only reason for such disallowance is that the transaction fails the economic substance doctrine as defined in this proposal."

The reference to the "purpose of the relevant authority" leaves room for debate in resale transactions. The industry would be well advised to get */ continued page 9*

PUHCA Exemption

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judge found the Oregon commission's position to be "significant, but not controlling."

The single-state exemption has been used by many owners of power companies to avoid regulation under PUHCA. Anyone who did not get a formal order from the Securities and Exchange Commission confirming that the exemption applies, rather than simply relying on a filing with the SEC, and whose utility engages in lots of wholesale interstate sales should probably be nervous after the judge's ruling.

The ruling can still be appealed to the full Securities and Exchange Commission.

The ruling may complicate plans by private equity funds and Asian and European companies to buy US utilities.

Other Possible Exemptions

The judge also rejected Enron's claim that it qualified for two other exemptions from PUHCA. One of the exemptions — what the regulatory lawyers call a section 3(a)(3) exemption — would have been available if Enron could have proven it was only "incidentally" a utility holding company. The SEC staff took the position before the judge that Enron could not claim this exemption unless it could show that Portland General provided no material part of Enron's revenue and is "functionally related" to one or more businesses in which Enron is primarily engaged.

The other exemption — called a section 3(a)(5) exemption — would have worked if Enron could have shown that the revenues it received from Portland General were not "material" to Enron when compared to the revenue from Enron's other subsidiaries owning "utility assets" either in foreign countries or that had been specifically exempted from PUHCA by Congress, such as power plants to which one of three labels attaches for regulatory purposes: QF, EWG or FUCO. The judge found that Enron did not qualify for the section 3(a)(5) exemption on either substantive or materiality grounds.

Enron had essentially conceded that it could no longer meet the materiality requirements for these two exemptions, given the loss of its energy trading businesses and its bankruptcy, but asked the judge for a temporary exemption of two years or so until it could sell off Portland General and portions of Enron's other power plants that are known as "qualifying facilities," or "QFs," and which cannot be owned by Enron under federal regulations unless it has one of the latter two exemptions.

The judge interpreted more narrowly than expected the "single-state exemption" used by many owners of electric and gas utilities to avoid regulation under PUHCA.

Effects and Outlook

The decision could mean loss of QF status for some power plants in which Enron invested.

Numerous parties attempted to intervene in the proceeding because of the potential impacts on the other owners of the Enron qualifying facilities or on other utility parent companies that have a single-state exemption. Most attempting intervention were only allowed limited participation status, and the judge noted at the outset of her decision that "[t]he facts presented herein have not been tested by cross-examination."

The proceedings were on a fast track. They were initially held before an SEC commissioner, pursuant to an SEC order that immediately followed a Senate committee report criticizing the SEC's failure to exercise adequate oversight over Enron's filings under PUHCA. Enron argued to the judge that a finding that Portland General is not predominantly intrastate in character and does not carry on business substantially in a single state will make the single-state exemption irrelevant in the context of today's electricity industry. Enron also questioned whether the SEC intended to examine other utilities that have disposed of generation assets and increased their trading in electricity markets. The judge said that these were policy issues that deserved consideration in another forum, but were not relevant to a determination of whether Enron's exemption applications meet the statutory requirements and SEC precedent.

The initial decision will become a final SEC decision unless Enron or another party appeals the decision within 21 days, or unless the SEC itself decides to review the decision on its own initiative. The deadline to appeal should expire around March 1. If the judge's decision becomes final as issued, Enron will have to register with the SEC under PUHCA and submit to comprehensive financial and other regulation to which some 28 registered holding companies currently submit, until it is able to sell Portland General, although Enron's bankruptcy proceedings may affect what happened. Since the new owner of Portland General would also presumably have to register with the SEC, the ruling could limit the number of bidders for the utility. Indeed, the City of Portland found the decision encouraging, since it can bid for Portland General and not be subject to PUHCA as an agency of the state.

There will also presumably be issues raised as to whether Enron's QFs can maintain their QF status with Enron as an owner. This question is before the Federal Energy Regulatory Commission. A related settlement with Enron-owned QFs selling to Southern California Edison is pending.

Finally, there may be questions raised regarding other utility holding companies that are currently enjoying exemption from PUHCA pursuant to filings under SEC rules or as to the "good faith" of other pending PUHCA exemption applications that rely on arguments similar to those made by Enron and rejected by the judge, if the SEC affirms the initial decision or leaves it standing. A parent company is ordinarily allowed to rely on a pending application for exemption from PUHCA as long as the application was made in "good faith."

The SEC order originally called for a second phase of the hearing as to whether, even if Enron met the qualifications for an exemption, such exemption should nonetheless be denied under the "unless and except" clause of PUHCA. This clause allows the SEC to deny or limit an exemption if it finds it would be detrimental to the public interest or to the interest of investors or consumers. Since the judge found that Enron does not meet the statutory criteria, the second hearing phase does not appear to be required by the terms of the original SEC order.

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this phrase clarified — perhaps by way of example — when the bill is debated on the Senate floor.

TURKEY said again that some private power projects must renegotiate their contracts to sell electricity.

The prime minister, Abdullah Gul, said on January 16 that talks are underway to revise contracts held by five power projects that were built under the "build-operate-transfer" or "BOT" model. BOTs are "obliged to reduce their prices" and their power contracts may be "annulled," the prime minister said. He did not address whether these projects risk losing their licenses to operate if they refuse to reduce prices. Such licenses are required under new rules issued last August. A number of BOTs are challenging the new rules in a lawsuit filed in the constitutional court of Turkey last October. A decision in the case is expected in February.

VENEZUELAN PROJECT lenders may have to amend their mortgages as a result of recent devaluations in the *Bolivar*, the Venezuelan currency.

The mortgage may no longer provide enough security for loans made in dollars. Many mortgages are fixed in *Bolivares.* The *Bolivar* has lost 60% of its value against the US dollar since early 2001.

Mortgages — called *hipotecas* in Spanish — are a type of security that lenders take from borrowers in exchange for making a loan. If a borrower does not pay the total amount of a loan, then the lender can take over the asset secured by the mortgage and recover his losses, but only up to the amount of the mortgage. Mortgages are normally used in the United States only to secure real property, like buildings and land. However, in Venezuela, they are used also to secure equipment.

Venezuelan mortgage documents specify the loan amount being */ continued page 11*

Project Sales: Traps For The Unwary

by Allen Miller, in New York

Merchant power companies seeking to sell or refinance projects to increase liquidity face wary purchasers or lenders who are giving renewed scrutiny to a number of legal issues that extend the due diligence inquiry well beyond examination of the project and the contracts to which the project company is a party. In many respects, the law may not be what one thinks it is. What follows is a discussion of a few traps for the unwary.

1. *When Consent May Be Required Even Though It Isn't*. Every purchaser, lender, seller and borrower knows the importance of ascertaining whether contractual consents are required in order to consummate a transaction.

Typically, a review of contracts to which the project company is a party is made to determine whether any contract counterparty has a consent right, right of first refusal or other contractual right or encumbrance upon the transfer or assignment by the project company of its interest in the plant assets or contract rights. If the purchase of the project is effected through a sale of stock of the project company, then a similar contract review is generally made to determine if a consent or termination right is triggered by a change-of-control or comparable provision. If the contract in question does not contain a change-of-control or comparable provision, then the natural conclusion may be that the contract counterparty has no say in the sale of the stock of the project company and that the transaction may proceed without the seller having to obtain any consent.

The problem with this analysis is that there are troublesome court decisions that might be construed to impose on sellers the obligation to obtain consents to stock transfers in certain circumstances even though the contract by its terms imposes no such requirement.

Federal courts in the 9th circuit (which includes California, Oregon and Washington) appear to have concluded that the sale of 100% of the stock of a "shell" company that owns an equity interest in a lower-tier entity may be deemed the same as the direct sale of the equity interest in the lower-tier entity for purposes of analyzing consent or right of first refusal provisions, even though the relevant contract provisions are silent on the issue of change of control.

In effect, the courts have held that if a seller owns little more than an equity interest in another entity, it may not circumvent contractual obligations restricting the transfer of such equity interest by instead selling control of the seller. On the other hand, if there is a sale of 100% of the stock of a "real" entity —- that is, a company that has substantial assets in addition to the equity interest in its subsidiary company —- then the sale of stock would not be deemed the same as the direct transfer of the equity interest in the subsidiary for purposes of considering consent and right of first refusal provisions restricting a direct transfer of the equity interest.

The approach adopted by courts in the 9th circuit could have some superficial appeal to other courts concerned with the equitable rights of contracting parties, but it has the ill-advised effect of writing into contracts language that is not there. This makes for great uncertainty in determining whether, for example, the consent of a power offtaker may be required under a power purchase agreement -— a key point of analysis in any project company sale.

The concerns created by the decisions in the 9th circuit extend to all parts of the country, not just jurisdictions within the 9th circuit. This is because the case law has not been sufficiently developed in other parts of the country to make an informed decision as to whether the 9th circuit's analysis would be adopted or rejected.

2. *When Liabilities of a Limited Liability Company Aren't Limited*. The doctrine of "piercing the corporate veil" is an exception to the general rule that shareholders are not liable for corporate debts.

The veil of a corporation is pierced, and the shareholder is held liable for the debts of the corporation, when a court determines that the debt in question is not really a debt of the corporation and, in fairness, should be viewed as a debt of the shareholder.

The doctrine is most often invoked where the courts perceive that a fraud, or something akin to it, is being perpetuated on creditors by the shareholder of a corporation. However, some courts have held that the doctrine applies where the parent has treated its subsidiary as its instrumentality, where the subsidiary is in fact a mere "alter ego" of the parent, or where the parent has exercised such domination and control that the subsidiary lacks any real independence.

In making a determination whether to pierce the corporate veil, courts generally examine various factors considered to be indicia of control, including whether the parent and subsidiary boards are identical, whether the two entities have common officers, whether the directors and officers of the subsidiary take orders from the parent or act independently, whether corporate formalities have been observed, whether officers and employees are paid by the parent or directly by the subsidiary, whether the flow of funds has been properly recorded between parent and subsidiary as dividends, loans or other distributions, whether the subsidiary was adequately capitalized, whether assets of the parent and subsidiary were commingled without regard to true ownership, and whether the subsidiary is commonly referred to as a department or division of the parent.

Although the doctrine of piercing the corporate veil has long been in effect, people often are unaware that courts in some jurisdictions have applied the doctrine to limited liability companies.

That the courts have done so is a surprising development because the common perception is that most of the factors considered by the courts to determine whether to pierce the corporate veil are simply not relevant to limited liability companies. Limited liability company legislation was developed in many states to create entities with the tax characteristics and corporate governance flexibility of a partnership while preserving the liability limiting features of a corporation. However, the relevant statutes afford so much flexibility to limited liability companies that most state laws do not require that they have directors, officers or managers. There is also no requirement that a limited liability company adopt an operating agreement. In short, it is enough under most state statutes that the limited liability company have filed a one-page certificate of formation with the state secretary of state and that its affairs are governed by the members who own it.

It may be difficult at first blush to reconcile the statutory purpose to minimize and streamline recordkeeping and governance mechanisms of limited liability companies with the application to them of the corporate-veil-piercing doctrines. However, more than one court has found that the doctrine may indeed be applied to limited liability companies, with the result that the owner of a limited liability company may be liable for debts of the limited liability company.

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secured. This provision is known in Spanish as the *cobertura*. One of the purposes of the *cobertura* is to ensure that a lender will not recover from the mortgage more than he lent. The *cobertura* usually is fixed at an amount equal to or slightly higher than the total amount of the loan. However, the *cobertura* must be fixed in *Bolivares*, even if the loan itself is made in dollars or another currency. Otherwise, the mortgage could be held invalid by a Venezuelan court. The mortgage amount can be amended.

Venezuela abolished a registration tax last year for amending mortgages. The tax had been 0.25% of the amount covered by the mortgage. There is always a risk the tax will be reinstated. Thus, lenders should probably act quickly.

TEXAS is expected to make it harder to use an ownership structure that many companies with projects in the state use to reduce their taxes.

The state is facing a budget crisis. Governor Rick Perry (R.) told reporters in late January that it is "not appropriate and not right" for corporations to use the structure. "I think the legislature feels as I do — that it should be closed."

Texas collects a franchise tax from companies doing business in the state, but there is no tax on limited partnerships. Therefore, most companies own projects in Texas through limited partnerships. Any franchise tax in that case is collected from the partners. However, a "foreign" limited partner — for example, an out-of-state company — is not normally subject to Texas franchise tax because the state has conceded that such a partner has no "nexus" in Texas that would enable the state to tax it. Thus, most limited partnerships are set up with the limited partners owning 99.9% and a general partner owning 0.1%. This reduces the share of income subject to Texas franchise tax effectively to 0.1%.

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The issue becomes relevant to a buyer who purchases, for example, a holding company with two separate project subsidiaries, one of which is performing well, and one of which is a marginal performer with potential upside but also contingent liabilities. The credit analysis will be one thing if the buyer believes that the assets of the performing project may be vulnerable to creditors of the marginal project and quite another if the buyer believes that the two projects will be treated separately as standalone projects. The determination as to which approach is most appropriate will depend in part on a veil-piercing analysis of the relations between the projects and their common parent. The fact that the projects are held in limited liability form does not necessarily insulate them from a veil-piercing analysis.

3. *When the IRS May Attach Assets of a Company That Doesn't Owe Taxes*. A subsidiary that is a member of its parent's consolidated tax group has joint and several liability for taxes of the consolidated group. This liability continues for pre-departure periods even after a consolidated subsidiary leaves the tax group. The result is that the Internal Revenue Service can file a tax lien against the assets of a former consolidated subsidiary even after it has left the group via sale to an unrelated party. Therefore, it is not uncommon for a parent seller to indemnify a buyer against consolidated tax group liability. However, buyers may view the tax indemnity of a struggling seller skeptically, since the indemnification obligation will be an unsecured claim if the seller files for bankruptcy and the bankrupt seller is unable to satisfy the IRS out of assets of the bankrupt estate.

While a due diligence review of the parent's financial condition may provide some comfort, it is unlikely that the scope of review will extend to sensitive tax liability issues of the parent's consolidated group. The seller will not allow it due to legal privilege concerns. A buyer that is uncomfortable with a seller's overall financial condition may require that the equity purchase be restructured as an asset purchase as a condition to proceeding with the transaction.

While newer projects are typically held in partnership or limited liability company form, occasionally some older projects are held in corporate form due to regulatory or other restrictions. In secured lending transactions, these corporate-form projects present special reason for concern because foreclosure on the stock of a project company borrower (which may otherwise be more desirable for the lender than an asset foreclosure) will not insulate the project company from attempts by the IRS to attach "after-acquired property" of the project company. Under the tax laws, the holder of a perfected security interest in "property in existence" generally has priority over a subsequently filed IRS tax lien. The "property in existence" requirement has been construed by the IRS to mean that "after-acquired property" — that is, property acquired after the notice of tax lien is filed — is not protected by the security interest as against the IRS lien even if it is protected from claims by other creditors. The IRS has taken this position even where the contract rights pursuant to which the receivables are earned are subject to the security interest.

A project company with no pension plan may still be liable for unfunded pension liabilities.

The IRS has had a poor track record in defending this position in the courts. However, despite its lack of success, it has shown no sign of retreating from its position, and lenders may want to consider certain protective mechanisms to mitigate the risk.

4. *When a Project Company with No Pension Plan May be Liable for Unfunded Pension Liabilities*. Most project companies do not technically have employees. Typically, employment services are provided under an operations and maintenance agreement or a management services agreement. Therefore, employment related liabilities do not generally rank high on the list of concerns of buyers or lenders to a project company except in the context of reviewing the relevant contracts.

However, there are circumstances under which the project company may be subject to employment-related liabilities even though it does not have, and has never had, employees. Under the Employee Retirement Income Security Act of 1974, or "ERISA," each entity within a "controlled group" is jointly and severally liable for certain pension plan liabilities of related entities within the controlled group. A controlled group is generally defined as including chains of entities connected by at least 80% ownership (including indirect ownership through trusts and similar devices). Entities within a controlled group are often referred to as "ERISA affiliates."

Controlled group liability is generally limited to liabilities relating to failure to make required contributions to a defined benefit pension plan, failure to file timely premiums to insure the pension plan with the Pension Benefit Guaranty Corporation and underfunding of a terminated pension plans. ERISA affiliates are jointly and severally liable for such liabilities even if the member has no employees who participate in the controlled group pension plan. In certain cases, a former member of a controlled group may remain jointly and severally liable for pension plan liabilities of its former controlled group members for a period of five years after leaving the controlled group.

The issue of ERISA-controlled group liability can be readily dealt with if the due diligence review confirms that there is no defined benefit pension plan within the controlled group and that there has been none within the past five years. If there has been such a plan, then further due diligence, contractual representations and indemnities may be appropriate to provide comfort to the buyer of, or lender to, a project company that the project company will not incur liability associated with pension plans in which its employees never participated.

5. *When a Senior Perfected Lienholder May Not Be Able to Foreclose*. A senior lender to a project may require that a subordinated junior lienholder's lien be extinguished upon foreclosure by the senior lienholder in order to facilitate enforcement of the senior lienholder's remedies. Typically, this is a contractual arrangement that would be honored by a reviewing court. However, if the junior lienholder should itself file for bankruptcy, the automatic stay of the bankruptcy court may enjoin the senior lienholder's foreclosure where the junior lienholder's lien would be extinguished on the theory that the extinguishment of / continued page 14

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The Texas comptroller of public accounts warned on January 13 that the state is facing a budget shortfall of $9.9 billion.

Independent power companies that are locked into long-term contracts to sell their electricity at fixed prices are worried that they will end up with sharply higher tax costs without any ability to pass them through to their purchasers.

MUNICIPAL POWER DEALS remain a subject of active lobbying at the US Treasury.

Independent power producers who sell their electricity to municipal utilities under long-term contracts would like the ability to have the municipal utilities prepay for the electricity. The municipality would receive a discount in exchange for prepaying. The thought is that it would borrow in the tax-exempt bond market to raise the money for the prepayment. In effect, the independent producer would have had access indirectly to the tax-exempt bond market for funds to build his project. IRS regulations allow anyone who is prepaid for "goods" to report the income over the same period the goods are delivered as long as this is how the income is reported for financial purposes.

The problem is arbitrage restrictions in the tax-exempt bond area rule out this type of transaction — at least for electricity. The IRS made an exception in the arbitrage regulations last year for prepaid gas deals. The American Public Power Association — the trade association for municipal utilities — sent the Treasury a letter in December urging that it make the same exception for electricity.

There have been roughly 20 prepayment deals to date, mostly for gas. The Treasury argues that an exception for gas makes sense because the gas market is uniformly deregulated and municipal gas companies need to enter into long-term deals with gas suppliers in order to ensure stable prices. Treasury officials are less convinced / continued page 15

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the lien constitutes a taking of bankruptcy estate assets. There is inconclusive judicial authority going both ways on this issue.

In the typical financing context, lenders generally are more concerned about the effects of a possible project company bankruptcy than the effects of the possible bankruptcy of other lenders to a project. However, where corporate loans have been made by an affiliate to support a project, it may be appropriate for a senior lender to consider analyzing its rights and remedies in case the affiliated junior lender files for bankruptcy.

The five issues covered in this article are traps for the unwary. They show the need for buyers and lenders to do a careful analysis of whatever rights other companies with ties to the project company might have before closing. ◎

Tax Issues In Project Sales

by Keith Martin, in Washington

Many merchant power companies are having to shed assets in order to raise cash to pay down debt. Private equity funds are organizing and raising pools of capital with which to buy assets. However, sales are slow because there is still a general perception in the US market that prices for power plants will take another downward tumble before reaching bottom.

The main challenge for sellers is how to structure the sale so that there is not an immediate tax on gain. The seller wants to take away as much cash as possible after the sale to pay down debts.

In cases where the seller is expecting a loss on the sale, the challenge is how to structure the sale so that it produces an "ordinary loss" rather than a "capital loss." The problem with capital losses is they are harder for corporations to use.

Form of Sale

The starting point for any sale is to decide what is being sold — the project directly or the company that owns it?

It is easiest for everyone concerned to sell the company because a direct sale of assets would require getting consents to the assignment of contracts and permits that are held in the project company. Each one of these assets would have to be transferred separately. In some cases, a seller might also prefer to sell the company if it has a higher "tax basis" in its ownership interest in the project company. Assets are depreciated over time, meaning that the older the project, the lower the tax basis that the project company will have in the project itself. These reductions in asset basis may or may not be reflected in the tax basis that the seller has in his ownership interest in the project company. If not, then the seller will be better off selling the project company. The higher his tax basis, the less gain he has to report — or the larger the loss he can claim — from the sale. A sale of membership interests or shares in a project company usually also avoids state and local sales taxes that would be triggered by a direct sale of the project.

Buyers tend to prefer to buy assets. For one thing, buyers worry about inheriting a company with existing liabilities that may be hard to uncover fully on due diligence. Moreover, a buyer usually wants to make sure the price he pays for the project is reflected fully in his tax basis in the assets so that it can be recovered through tax depreciation. Shares in a project company cannot be depreciated. Only assets can.

The buyer's objectives are often best served by buying the project company, but treating the transaction as an asset purchase for tax purposes.

This occurs automatically in cases where the project company is a "disregarded entity" for tax purposes. An example of a "disregarded entity" is a limited liability company, or LLC, that has only one owner. Otherwise, an election would have to be made by the parties under either section 338 — in cases where a corporation is being sold — or under section 754 — in cases where the sale is of a partnership interest. These are sections in the US tax code. The election is made by filing a form with the Internal Revenue Service.

Another benefit from selling the project company but treating the transaction as a sale of assets is this avoids state and local sales taxes. Sales taxes are usually triggered by a sale of "tangible personal property." In some states, an existing power plant may be considered "real property" —

and, therefore, not be subject to sales taxes. There may be real property transfer taxes, although usually at a lower rate. Be aware that in California — and perhaps some other states — it is not a good idea to say in the transaction documents that the project is personal property for bankruptcy purposes. California courts have held the parties to this designation for sales tax purposes. Be aware that in some states sale of a project company may trigger state transfer or gains taxes if the project company is considered a real property holding company.

There are two kinds of section 338 elections. Section 338(g) elections are rarely made. A section 338(h)(10) election can only be made where the seller is selling a subsidiary corporation with which it files a consolidated return. The subsidiary is treated as if it sold its assets to the buyer. The seller ends up having to bear any tax triggered by this deemed asset sale. Both parties must join in making a section 338(h)(10) election.

Understand the state income tax consequences of making a section 338 election. Not all states recognize such elections. The state income taxes on the sale and going forward need to be factored into the sales price.

If the project company is a corporation and is included in the seller's consolidated federal income tax return, then the seller will usually be indifferent for tax purposes whether it sells the project company or the assets. Its tax basis in each of them should be the same. It should be willing to make a section 338(h)(10) election to allow the buyer to step up the asset basis. (An exception is where the seller acquired the project company from someone else earlier without making a section 338 election.)

In other situations where the project company is a corporation, but is *not* included on the seller's consolidated return, giving the buyer a step up in asset basis is a zero-sum game — or worse. The buyer can only get a step up in asset basis if the project corporation will pay tax immediately on gain. This is not a good exchange. The project corporation has immediate income. The buyer will have matching deductions, but over time through depreciation. The present value of the buyer's tax savings from the additional depreciation is less than the additional tax that must be paid on the sale.

The Bush dividend proposal could affect the decision what to sell in cases where the project company is a corporation. President Bush proposed in early / continued page 16

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of the need in electricity markets because many states still control prices. This reflects confusion about electricity deregulation. The wholesale power markets are deregulated. It is retail rates that remain controlled.

Memphis Light, Gas & Water tentatively struck a deal last fall with the Tennessee Valley Authority under which TVA would supply electricity for 15 years at fixed rates. Memphis would prepay $1.5 billion of the total cost by issuing tax-exempt bonds. TVA offered Memphis a 4% discount on electricity prices over the term of the contract, worth about $225 million, according to a report in The Wall Street Journal.

ADVANCE PAYMENTS FOR SERVICES do not necessarily have to be reported immediately as income, the IRS suggested.

The IRS proposed in December that companies would only have to report an advance payment for services in the year it is received to the extent the company treats the payment as book income that year. The rest of the payment could be reported the next year. The proposal is in Notice 2002-79.

POWER PLANT REPAIRS get attention from a task force of IRS and Treasury officials.

The task force is working on bright-line tests for distinguishing "repairs" from "improvements" at power plants. Repairs can be deducted immediately. The cost of any improvements must be added to the tax basis in the power plant and deducted over time as depreciation.

The task force hopes to have a draft revenue ruling ready in February to start circulating within the IRS and Treasury for signoff. The ruling will not address what is the "item of property" for purposes of assessing whether something is a repair. Obviously, if the item of property is the entire power plant, then $100,000 in spending looks less significant — and more like a / continued page 17

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January that corporate earnings should be taxed only once. To the extent that a corporation pays taxes on its earnings, then it would be able to distribute tax-free dividends to its shareholders. This means that the parties may be better off with a direct sale of the project rather than a corporation that owns it — at least in cases where the project company is an unconsolidated subsidiary. If the dividend plan passes Congress, it could take effect retroactively to the start of 2003.

Beware of the "loss disallowance rule." The seller may not be able to claim a loss on sales of shares in a subsidiary with which it files a consolidated income tax return.

Beware of the "consistency rule." The buyer will not be able to "step up" its tax basis in the assets if it buys some assets from a corporation directly and then also buys the shares in the corporation without making an election under section 338 to treat the purchase of shares as an asset purchase.

Buyer Strategies

Are there any strategies that a savvy buyer might use to win bids?

The best strategy is to be aware of what the seller needs to get out of the transaction and to try to present a structure that accommodates its needs.

There may also be peculiarities about the project or the bidder that can be factored into a bid. For example, it may be possible to qualify for some form of tax subsidy by switching fuels. The Bush administration is proposing to allow section 45 tax credits of 0.54¢ a kWh to be claimed by owners of existing coal-fired power plants for co-firing with biomass. It may be that the buyer can qualify for a 30% "depreciation bonus" on the project even though the seller would not. A buyer planning to sell the output to a municipal utility may be able to tap into the tax-exempt bond market for at least part of the purchase price. It may be that a particular buyer has an advantage over other bidders because it would be able to defer taxes in its home country on its future earnings from the project while other bidders would not. In bids for foreign projects, buyers sometimes present purchase structures that produce hidden benefits. An example is a so-called section 861 structure that allows a US bidder to treat future project earnings that go to pay interest on the acquisition debt as if they were a source of repatriated earnings to the US, but to do so in a way that does not create any taxable income in the United States and that puts the buyer in a better position to claim foreign tax credits from its other foreign projects.

There may be peculiarities about a project or a bidder that can be factored into an offer to make it the winning bid.

Another example is a structure that allows the interest on the acquisition debt to be deducted twice — once in the project country and again in the US or someplace else.

Seller Strategies

Many sellers in the current market are having to sell their projects at a loss.

Any seller expecting a loss will want to structure the sale so that it produces an "ordinary" loss rather than a "capital" loss. The problem with capital losses is corporations can only use them to offset capital gains. Corporations can carry unused capital losses back three years and forward five years. (The Bush dividend proposal may limit the carryback to one year. Not all the details of the proposal have been released yet.) It makes no difference how long the asset being sold was held: there is no difference for corporations between short- and long-term losses.

The key for projects that are already in service is to sell the assets — or sell the project company but in a manner that is treated as a sale of the assets for income tax purposes. Shares and partnership interests are capital assets, and their sale produces a capital loss. Depreciable property that a company is using in its trade or business is not a capital asset.

It is less clear that a seller can claim an ordinary loss when selling a project that is merely under development. The problem in that case is that the US tax code defines "capital asset" as all property other than certain categories of assets. The category into which the project would have to fall to avoid being labeled a capital asset is "property, used in [the seller's] trade or business, of a character which is subject to the allowance for depreciation . . . or real property used in [the seller's] trade or business." The IRS has ruled privately that property that is not yet in service is not yet of a "character which is subject to . . . depreciation," and it is unclear whether a project under development is real property for this purpose. There are arguments back and forth.

Any seller expecting a *gain* on the sale will want to try to sell in a manner that defers the tax on gain. Here are seven ideas for how to defer taxes on gain.

1. *Like-kind exchange*. The US tax laws do not require a company to pay tax immediately on gain when it is merely exchanging one asset for another asset of a "like kind." The company takes the same tax basis in the new asset that it had in the old one. The tax on gain on the old asset is merely deferred. It will be taxed in the future when the *new* asset is sold.

This approach offers little to a company that must shed assets to pay down debt. However, it should be considered when a company plans to reinvest the sales proceeds in another project. The old property can be sold for cash and the new asset purchased later. The company must identify the replacement property within 45 days after the old property is sold. The cash must be spent on the replacement property within 180 days. Most power plants are considered "real property." This is determined under local law where the power plant is located. In cases where "real property" is being exchanged, the replacement property does not have to be fully built. Thus, a company could take the sales proceeds and apply them against the cost of a project that is still under construction. Transactions that involve a sale of the old property for cash must be run through a "qualified intermediary," or broker.

2. *Hybrid lease*. The seller might avoid tax on gain by entering into a long-term lease of the asset to the "buyer." The buyer would prepay the rents. The / continued page 18

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repair — than if the item of property is a valve. The task force feels certain that the entire power plant is not the item of property. It believes each turbine — and perhaps even something larger — is a separate item of property. It cannot agree on where to draw the line beyond that.

Instead, the revenue ruling will address some common fact patterns that come up in utility audits. The task force is looking at nine fact patterns submitted by utilities.

CAPTIVE INSURANCE arrangements may be harder to make work after an IRS ruling in December.

US companies sometimes self insure. A company might set up an affiliate in a lower-tax jurisdiction, pay it premiums, and deduct the premiums. The parent company has a deduction. The income used to pay the premiums is shifted in this manner to the affiliate.

US courts have refused to recognize such arrangements as insurance unless there is truly a shifting of risks to someone else. Thus, no deduction could be claimed for a payment to a wholly-owned subsidiary that insures no one other than its parent company. There is no risk shifting in such cases.

The IRS drew a line of sorts in a ruling in December. The ruling addresses two cases. A US parent company forms a wholly-owned subsidiary to provide insurance. In one case, 90% of the premiums collected by the subsidiary and risks borne by it are from its parent company. In the other case, only 50% are. The rest of the premiums and risks are from unrelated parties. In both cases, the subsidiary is regulated as an insurance company in the states where it does business.

The IRS said the premiums could be deducted in the case where they accounted for only 50% of premium income and risks, but not so where they accounted for 90%. The ruling is Revenue Ruling 2002-90.

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seller would invoke special rules in section 467 of the US tax code to report the rents over the term of the lease, notwithstanding that the seller was paid virtually the entire rent at the start.

The lease must be structured so that it is a "true lease" for tax purposes. This means that the lease term could not run longer than 80% of the remaining expected useful life of the project or beyond the period when more than 80% of its value has been used. The seller might also want to structure the lease as a "capital lease" for book purposes. This would allow it to book its gain from the sale. Treatment as a capital lease requires either that the lease have a term at least 75% of the remaining expected useful life of the project or the rents have a present value of at least 90% of the fair market value of the project.

In such transactions, the "seller" will eventually get back the project at the end of the lease term. The "buyer" could always negotiate in the future to buy the residual interest (after the lease ends) for its market value.

3. *Installment sale*. Taxes on gain can always be deferred by providing for payment of the purchase price over time. In that case, the gain is reported as a fraction of each installment payment of purchase price — and the taxes are paid on each installment. A lot of the benefit of reporting a sale this way was taken away by Congress in 1987 when it required that interest be paid on the "deferred" taxes. Merchant power companies with junk ratings may find this a cheaper way to borrow. The current interest charge on the deferred tax liability is 5%. On the other hand, this offers little to such a company that is desperate for cash, since taxes are paid on gain at the same rate as the installment payments of purchase price are received over time. Beware that if the installment note is pledged as security for borrowing, then tax on the entire gain will come due.

4. *Leveraged partnership*. Several sellers have explored the following. At least two transactions have closed. The buyer and seller form a partnership. The seller contributes the project to the partnership. The buyer contributes assets that generate cash and have a value equal to the purchase price. The partnership borrows against the value of the cash-generating assets and uses the borrowed funds to redeem all but 10% of the seller's partnership interest. The seller guarantees repayment of the partnership debt. If it works, the transaction has the effect of giving the seller installment sale treatment, but without the interest charge and with all the cash received up front. The seller's tax on gain is deferred until the partnership debt is paid down. An internal IRS memorandum made public in November suggests a number of ways the tax authorities might try to attack the transaction.

A big concern of buyers who end up owning a project company that was included in the consolidated tax return of the seller is "-6 liability."

5. *Mixing bowl*. Partnership mixing bowls are a way to avoid tax on gain altogether, but they are hard to use. They work as follows. S contributes property it wants to sell to a new partnership that S forms with B. B contributes cash, marketable securities or other property that S wants. The partnership agreement gives S management rights over the asset that B contributed, and vice versa. There are "tracking allocations" where S gets 75% or 80% of the income or loss — and cash flow — from the property that B contributed, and vice versa. The problem with mixing bowls is the seller and buyer must remain joined at the hip and the seller does not get cash out immediately with which to pay down debt. The partnership must normally remain in place for seven years. There remains a risk — as in the leveraged partnership transaction — that the IRS will say that the seller made a "disguised sale" of the project.

6. *Tax-free reorganization*. If the project is held in a corporation and the seller is willing to take back stock in the buyer, then it may be possible to do a tax-free reorganization. There would be no tax to the seller upon receipt of the

new shares. The seller could spread the tax hit by staggering the sale of the shares over time.

7. *Foreign projects*. A seller might avoid immediate US tax on gain from the sale of a foreign project by structuring the transaction as a sale of assets (or of a project company that is treated as a "disregarded entity" for US tax purposes). US tax cannot be avoided if what is sold is a partnership interest or shares in a corporation. The IRS is challenging transactions on audit where the seller made a sale of the project company and took steps shortly before the sale to turn the project company into a "disregarded entity."

Indemnity Issues

A number of recurring issues come up when trying to negotiate tax indemnities in project sales.

One big concern of buyers who end up owning a project company that is a corporation and was included in the consolidated return of the seller is "-6 liability." The IRS can go after such a project company for any taxes that the seller consolidated group failed to pay during the period the project company was part of the seller group (assuming the statute of limitations has not run). The project company is "severally" liable for all the taxes of the seller consolidated group. This is referred to as "-6 liability" because the rules are found in the IRS regulations at section 1.1502-6. The IRS regulations go on to say that the IRS *may* limit any claim against the project company to its share of the tax deficiency rather than hold it accountable for taxes owed by the entire group. There is not much that a buyer can do to protect itself in practice other than get an indemnity from a creditworthy entity and do due diligence. It may be impossible to get a creditworthy indemnity in cases where the seller is in financial distress. On the other hand, the seller group may have had such large operating losses in recent years that it did not owe any taxes.

It is "market" for the seller to indemnify the buyer against any taxes for the period through closing and for the buyer to indemnify the seller against post-closing taxes.

Most parties agree in the indemnity to take the position that any indemnity payment is an adjustment to the purchase price. This is another way of saying that they will not report the indemnity as taxable income. However, there may be situations where the payment must be reported. In such cases, the indemnity payment should be "grossed up" for the taxes the indemnitee must pay on / continued page 20

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The IRS said separately that it will resume issuing private rulings to companies that want to know in advance whether their captive insurance arrangements work. However, it warned that some cases may be too factual on which to rule and suggested that companies should ask first whether a ruling is available. The announcement is in Revenue Procedure 2002-75.

CULM is not "biomass" for tax purposes, a federal appeals court confirmed in late December.

"Culm" is waste left above ground after coal is sifted from dirt brought out of underground coal mines in the anthracite region in eastern Pennsylvania. The same residue from bituminous mines is called "gob." If the material is biomass, then power plants burning it can be depreciated over five years for tax purposes. Such plants put into service before 1988 would also have qualified for an energy tax credit. "Coal" does not qualify as biomass. A federal appeals court said the material is coal. The case is *Gilberton Power Co. v. United States*.

LABUAN COMPANIES took another knock — this time from Korea.

Companies investing in projects in another country sometimes invest through an offshore holding company in order to benefit from tax treaties that reduce withholding taxes at the project country border when earnings are repatriated. For example, one might use a holding company in Mauritius or Holland to invest into India. Treaties also may reduce capital gains taxes in the project country upon exiting the project.

Labuan is an island off the coast of Malaysia. It is a tax haven. Malaysia has favorable tax treaties with many Asian countries, including Korea. Korea proposed an amendment to the treaty in / continued page 21

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the indemnity payment. Without such a grossup, the indemnitee will not truly be made whole for its loss. By the same token, any *benefit* that the indemnitee gets from being able to deduct taxes that triggered the indemnity payment should be taken into account in calculating the amount of the payment. The indemnity should address how grossup situations are identified. For example, the indemnitee might produce an opinion from outside tax counsel that it is "more likely than not" the payment must be reported as income.

The buyer will want the ability to participate in tax audits of the seller group in cases where what is decided on audit might affect the project company's tax position going forward. Sellers resist. Buyers are often given the right to participate if the issues can be isolated and handled in separate meetings with IRS agents. The parties argue about whether the seller can settle the issues without consent from the buyer. No seller wants the closing of a tax audit of its consolidated return to be held hostage to a small issue. There is no one "market" approach for the settling this.

Other Tax Issues

Here are other tax issues that make an appearance in many project sales.

In cases where the project company is a partnership, the parties will often go to great lengths to avoid terminating the project company for tax purposes. The main problem with a termination is the partnership must start over depreciating its remaining tax basis in the project. This has a present-value cost. A termination can also cause loss of "grandfather" rights to certain tax benefits. A partnership terminates if there is a sale of 50% or more of the profits *and* capital interests in the partnership during a 12-month period. The easiest way to avoid a termination is to stop short of selling 50%. It is enough to stop short of selling a 50% capital interest. The buyer can buy a much larger profits interest. His "capital interest" is the amount the buyer would receive if the partnership liquidated. It is popular lore that the buyer can agree at closing to buy an X% interest today and bind himself to purchase another Y% interest to take him up to 50% a year and a day later. However, there is not much authority for this. It would be better not to have a legal commitment to buy the second increment. Asset consistency rules in the section 338 regulations are a trap for parties trying to avoid a termination by having the buyer purchase less than a 50% partnership interest directly and buy the rest indirectly by purchasing shares in a corporation that is a partner.

There are seven ways a seller who expects to profit on a sale might defer taxes on the gain.

A question often asked is whether any part of the purchase price must be allocated to a power sales contract — for example, where the project has a long-term contract to sell electricity to a utility at above-market prices. The issue is whether the power contract merely adds value to the power plant or is a separate asset. The answer may have an effect on how quickly the buyer can recover its purchase price through tax depreciation or amortization. There is no clear answer. The law is clear that one ignores the market value of a lease in valuing a power plant — for example, where a lessor has leased the power plant to a utility at above-market rents. The rents are taken into account in valuing the power plant. The IRS takes the position that favorable financing terms to which an asset is subject are not a separate asset since "it is illogical to suggest that an obligation to pay money is an asset."

Sellers sometimes sell for a price that is partly contingent on future events. For example, a project under development might be sold for $X plus another $Y if the project reaches financial closing so that it can start construction. IRS regulations suggest the seller must take into account as income at closing the expected value of the principal amount of the contingent payment (as opposed to the embedded interest). In cases where the seller is selling at a loss, the fact that part of the purchase price is contingent does not prevent the seller from claiming a loss. If a different amount than the expected value is received later, then the seller reports the additional income or loss in that later year.

The purchase agreement will often hold the seller accountable for any sales taxes. However, beware that sales tax liability might follow the assets that were sold unless the buyer gets a certificate from the state tax authorities that the taxes were paid — at least that was the outcome in an appeals court case in California in late 2002. The case is a warning to buyers to insist on a tax certificate at closing.

Projects that were financed with tax-exempt bonds are often sold subject to the outstanding bonds — but not always. A project can be sold without the buyer assuming the obligation to repay the bonds. The bonds will not lose their tax exemption. However, this creates risk for the seller. If the buyer changes the use of the project — for example, if the buyer later permanently shuts down the project or the reason tax-exempt bonds could be used is the project used "culm" or "gob" as fuel and the buyer switches to run-of-mine coal as fuel — then money must be set aside immediately in escrow to repay the bonds at the first date on which the bonds are callable.

Congress and the IRS are still wrestling with the issue whether a purchaser of a project that is still under development or under construction can qualify for a 30% "depreciation bonus" on the project even though the seller would not have qualified. An economic stimulus bill in 2002 authorized companies making new investments during a window period that runs from September 11, 2001 through 2004 or 2005, depending on the project, to deduct 30% of the cost of the project in the first year. The Joint Tax Committee staff expressed the view in a "blue book" in late January 2003 that the buyer will qualify for the bonus, as long as he does not acquire the project in a "churning" transaction. A churning transaction is a sale-leaseback or other arrangement where the seller continues to use the project after the sale. There had been a debate about whether the buyer would qualify for a bonus on both its purchase price to acquire the existing work in the ground and also on its spending to complete the project. The blue book suggests a bonus can be claimed on the full amount. IRS regulations on the depreciation bonus are expected this summer.

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December that would exclude Labuan from the Malaysia-Korea tax treaty. The change is expected to be accepted.

Hooi Cheng Lee, a lawyer with Zaid Ibrahim & Co. in Kuala Lumpur, said, "We understand that certain countries — such as the United Kingdom, Netherlands, Switzerland, Sweden, Japan and Korea — have already informally excluded offshore companies incorporated in Labuan from taking advantage of the treaty benefits, but only Japan has formalized the exclusion of Labuan from its treaty with Malaysia." Lee said it is possible whenever a treaty is formally amended that existing Labuan companies will be "grandfathered," but this depends on the wording of the new treaty.

EUROPE proposed switching which country should collect "value added taxes" on electricity and on natural gas carried in pipelines.

VAT is collected currently by the country in which the electricity or gas is *produced*. The European Commission proposed in December to switch the tax to the country where the electricity or gas is *consumed*. Transmission and transportation services would also be taxed by the same country. Taxation Commissioner Frits Bolkestein explained, "It is difficult to determine where the place of supply of gas and electricity is located and this leads to differences in interpretation of the rules by member states and difficulties for traders supplying gas and electricity across borders."

The proposal must still be approved by the Council of Economic and Finance Ministers.

OPTIONS to purchase partnership interests may have tax consequences, the IRS said.

The agency has been studying such options for more than a year. It explained the tax consequences of "noncompensatory" options — or options that are most likely to be held by institutional / continued page 23

Lessons From Foreign Investment Disputes

by Peter F. Fitzgerald, in Washington

During the 1990s, there was a massive inflow of foreign investment into infrastructure projects in developing countries. Host country government contractual support for these projects and political risk insurance both played important roles in inducing companies to invest in power plants, toll roads, port development, telecommunications projects and other infrastructure projects. With political and economic crises erupting in Asia in the late 1990s and Latin America more recently, these foreign investment projects have come under stress and the value of both host government support and political risk insurance has been tested. What lessons have been learned?

Host Government Support

In the 1990s, host governments, with limited budgetary resources and borrowing capacity to develop crucially needed infrastructure, embarked on a process of privatization and invited foreign companies to build, own and operate infrastructure projects. In order to attract the massive investment needed, the risks associated with investing in the politically-volatile emerging markets had to be mitigated in a credible way. Host government support, backed with political risk insurance and guarantees often provided by development and export credit agencies of the home country governments, served as the basis for the necessary risk mitigation.

To illustrate both the type of support typically provided, as well as the types of problems that ensued when political and economic crises erupted, the case of the investments made by CalEnergy Company, Inc. (now MidAmerican Energy Holdings Company) in two geothermal power projects — the Dieng and Patuha projects — in Indonesia is instructive. The CalEnergy case has the added advantage of having been so well publicized that the facts are neither confidential nor in dispute.

The structure of each of the Indonesian projects sponsored by CalEnergy resembled the structure of most infrastructure projects developed in emerging markets in the 1990s. CalEnergy formed a special-purpose Indonesian company to build, own and operate its geothermal power project. This project company entered into a joint operating contract with Pertamina (the state-owned oil company that controlled the geothermal resource) and an energy sales contract with Pertamina and P.T. (Persero) Perussahaan Listruik Negara, or "PLN," a corporation wholly-owned and controlled by the government of Indonesia. Under the energy sales contract, the project company agreed to develop a geothermal power project and PLN agreed to a take-or-pay obligation pursuant to which it committed to buy all of the project company's available electricity for thirty years at a price denominated in US dollars. In addition, the Indonesian government, pursuant to an undertaking issued to the project company and signed by the Ministry of Finance, agreed that the Indonesian government would "cause PLN . . . to honor and perform" its obligations under the energy sales contract.

This contractual structure — that is, an offtake contract with a state-owned utility being the principal asset and source of all revenues of a special-purpose project company owned by a foreign investor, plus a guarantee of that contract by the host government — was the structure that marked most infrastructure projects during this period. It allocated the "commercial" risks of the project — for example, the risks of building and operating the project — to the equity investors and their lenders from the private sector, but allocated most of the "political" risks to the host government. Since the revenues under the energy sales contract were effectively guaranteed by the government of Indonesia, the energy sales contract provisions provided the contractual basis for allocating certain political risks to the host government. The risk of devaluation of currency, for example, was allocated to PLN through the denomination of payments under the energy sales contract in US dollars, and further allocated to the Indonesian government under its performance guarantee. Similarly, the risk that changes in Indonesian law might adversely affect the project was also allocated to PLN and the Indonesian government through provisions in the energy sales contract requiring PLN to pay an increased tariff for the power purchased if changes in Indonesian law increased the cost of production of the power.

The contractual allocation of political risk to the host government was not in itself sufficient, however, to induce the commercial banking community to lend the massive amounts of money needed for infrastructure projects in emerging markets. Foreign investors and their bankers came to the investment process in the 1990s with the experience of the Latin American debt crisis of the 1980s still fresh in their minds. Many bankers had held host government guarantees in connection with loans to Latin American parastatal companies, only to come to the painful realization when foreign exchange crises erupted in the 1980s that, although Walter Wriston may have been technically correct when he remarked that governments do not go bankrupt (because there is no bankruptcy process to manage the situation when governments cannot pay), governments certainly do run out of money and fail to meet their obligations.

Political Risk Insurance

With the international bankers still in the process of recuperating from Latin American debt crisis losses, it was clear to all that it would be difficult to raise the massive amounts of money needed for a large infrastructure project on the basis of host government commitments only; a creditworthy backstop to those commitments would be needed. Political risk insurance and political risk guarantees from development agencies (such as MIGA and OPIC), the export credit agencies (such as US Export-Import Bank) and, by the late 1990s, from the private sector political risk insurers (such as Sovereign, Zurich, AIG, and Lloyds), played a crucial role in providing this backstop.

The political risk insurers first had to grapple with two problems in determining how to provide effective political risk insurance coverage to an infrastructure project with a contractual structure such as CalEnergy's. First, political risk insurers traditionally covered the risk of expropriation — that is, the risk that the host country government would take action in violation of international law that would substantially deprive the investor of the benefits of its investment. Typically, this type of coverage would only be triggered if the host government took some kind of affirmative action to interfere with a project. However, the fundamental risk in 1990s infrastructure projects was the risk that the government would fail to pay when required to do so. Thus, the question arose as to whether expropriation policies covered this risk.

Also, policies required that the host government's action must violate international law. Under international customary law, it is not illegal for governments to */ continued page 24*

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investors — in proposed regulations in late January. Regulations on "compensatory" options that are given as compensation for providing services will follow later in the year.

The regulations address options issued directly by the partnership and that give the holder a right to buy an interest in the partnership (or to receive cash or property having an equivalent value).

In general, no income tax is triggered when such an option is exercised.

However, letting an option lapse without exercising it will have tax consequences. In that case, the holder of the option can claim a loss for whatever he paid for the option. The partnership must report the original payment for the option as income at that time. (It did not have to be reported as income earlier because it was viewed as part of an "open transaction.")

The capital accounts of all the partners will have to be adjusted so that they add up to the current fair market value of the partnership assets when the option is exercised. A partner's capital account is the claim he has on partnership assets if the partnership were to liquidate. In some cases, a disproportionate share of taxable income will have to be allocated to the new partner initially to set his capital account at the right level in relation to the other partners.

Careful tax counsel will want to keep an eye on options when assessing whether a partnership has terminated for tax purposes. That's because the IRS reserved the right to treat an option holder as already a partner if he has rights that are "substantially similar to the rights afforded to a partner." An example might be where he already has some voting rights and — because of infrequent partnership distributions — he is expected to have exercised the option in time to share in the economic returns during the option period. A partnership will terminate for tax purposes if 50% of more of the interests */ continued page 25*

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breach contracts. However, according to one authoritative source used in the United States (the "restatement" of US foreign relations law), a state *is* responsible for any injury caused by its breach of a contract with a foreign national if the foreign national is denied adequate channels to address his complaint, or is not compensated for any breach determined (by pursuing appropriate channels) to have occurred.

The experiences of CalEnergy, KBC and other investors in developing country infrastructure projects in the 1990's have taught some valuable lessons.

Therefore, the mere breach itself is not a violation of international law, but a violation of international law occurs if the host government frustrates the working of the dispute resolution process (typically offshore arbitration) in a manner constituting a denial of justice, or if the dispute resolution process yields an arbitral award or judgment in favor of the foreign investor and the host government refuses to pay it. Given the lack of clarity inherent in the international law violation requirement of expropriation policies, foreign investors sought political risk insurance coverage tailored to the precise risk posed by the infrastructure project contractual structure.

In responding to the needs of investors for coverage, OPIC led the way by modifying its traditional expropriation coverage to include a form of "disputes coverage," a variant of coverage that OPIC had long provided to US contractors with contracts to provide goods or services to host governments and that essentially underwrote the integrity of the dispute resolution process under these contracts. The disputes coverage provided that if the host government failed to pay under its contract, the insured obtained an arbitral award in its favor against the host government, and the host government failed to pay within an agreed time period, then OPIC would pay under its political risk insurance contract. By agreeing to backstop a host government's refusal to pay an arbitral award, OPIC served as a reliable and creditworthy backstop to host government obligations. Other development agencies and political risk insurers followed OPIC's lead and this structure proved to be a financeable way forward for the development of infrastructure projects.

The Indonesian Experience of CalEnergy

In connection with its investments in geothermal power projects in Indonesia in 1994, CalEnergy obtained expropriation and disputes coverage from OPIC and Lloyds. Pursuant to its coverage, CalEnergy would need to demonstrate that it obtained an arbitral award against both PLN and the government of Indonesia, the government failed to pay for 90 days, and the government's failure to pay was a violation of international law.

In the fall of 1997, Indonesia began a rapid descent into political and economic crisis, triggered by the Asian economic crisis, marked by a free fall in the value of the Indonesian rupiah, and resulting in the collapse of the Suharto regime. (When the energy sales contract was signed in 1994, the US dollar had a value of approximately 2,450 rupiah. Within months of the onset of the Asian economic crisis, the exchange rate plummeted to approximately 15,000 rupiah to the US dollar.) Having attracted a surge of foreign investment over the previous four years into 27 independent power projects being developed in response to Indonesia's growing electricity needs, in the fall of 1997 Indonesia was faced with the difficult prospect of having to pay the independent power producers for electricity in US dollars, notwithstanding that it could not pass on the large devaluation costs to the end users of the electricity. This is not to mention the fact that the economic crisis had led to a reduced demand for power in Indonesia. With a view to decreasing its foreign exchange outflows in the midst of this currency crisis, a series of presidential decrees were issued postponing, suspending or reviewing most of the independent power projects, including CalEnergy's projects.

By the summer of 1998, the situation had deteriorated to the point where the president of PLN was quoted in the press as saying that, if possible, all independent power producer contracts would be cancelled and challenging the independent power producers to sue PLN. With the completion of one of the CalEnergy projects in the summer of 1998, PLN failed to pay for power as required by the energy sales contract and PLN representatives informed CalEnergy that the plant was essentially being shut down for "political reasons." The Indonesian government also failed to pay under its performance guarantee.

With a clear breach of the energy sales contract by PLN and a failure of the government to honor the performance guarantee, CalEnergy commenced arbitration against PLN in August and obtained awards against PLN of more than $570 million in May 1999. (The energy sales contract provided for United Nations Commission on International Trade Law, or "UNCITRAL," arbitration in Jakarta.) CalEnergy then filed expropriation claims with OPIC and Lloyds claiming that the government of Indonesia had violated international law and deprived CalEnergy of the only asset of value to it —the energy sales contract.

Also in May 1999, CalEnergy commenced UNCITRAL arbitration in Jakarta against the government of Indonesia for breach of the performance guarantee. However, the following month, the Indonesian government sought injunctions to stop the arbitration from going forward. In July 1999, the central district court in Jakarta issued the injunction, purporting to suspend the arbitration against the Indonesian government and fining all participants $1 million a day if they continued with the arbitration.

In response, the three-member arbitral panel moved the arbitration hearings offshore to The Netherlands. The government, thwarted in its attempt to frustrate the arbitral process (it failed in an attempt to obtain an injunction from a Dutch court to enjoin the proceeding in The Netherlands), then resorted to coercing the arbitrator it appointed to the panel from participating in the proceedings. The arbitral tribunal nevertheless entered an interim default award against the government of Indonesia on September 26, 1999 and a final award on October 16, which the government then refused to pay.

With OPIC and Lloyds now facing what were clear violations of international law by the Indonesian government, an insured that had the full value of its project taken without any compensation, as well as arbitral */ continued page 26*

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in partnership profits and capital are transferred within a 12-month period.

The IRS said it is still studying whether to treat the holder of an option as already a partner in one other circumstance. This would occur where the option is in a limited liability company, or LLC, that has only one owner. If exercise of the option would make the LLC have at least two owners, then the IRS is considering treating the holder of the option as a partner even before the option is exercised. It has asked for comments.

AN EARNINGS-STRIPPING ARRANGEMENT reduced taxes in Missouri.

A company that made bricks reorganized and put all its trademarks in an out-of-state affiliate and started paying royalties to the affiliate for the use of the trademarks. It deducted the royalty payments in Missouri. More than $34 million had been paid in royalties by the time the state tax collector complained that the out-of-state affiliate should pay tax on them on grounds that they are income from Missouri sources.

The state supreme court disagreed. It said no tax can be collected because the affiliate has too little activity in Missouri to justify a tax. The court said the brick company and its affiliate are separate legal entities. The tax collector would have to prove that the affiliate has its own property, payroll or sales in Missouri to justify a tax. It could not. The affiliate has no property in the state, no employees or agents, and no sales. The licensing arrangement was negotiated entirely outside the state. The case is *Acme Royalty Company v. Director of Revenue*. The court released its decision in late November.

TAX OPINIONS from a law firm may have lost their "privilege" because the company shared them with its tax accountants, a US district court said.

It ordered the opinions */ continued page 27*

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awards that had been obtained and not paid, CalEnergy's claims were paid in full one month later in the amount of $290 million. It remains the largest political risk insurance claim paid to date. Thus, thanks to political risk insurance, CalEnergy was able to recoup its investment within one month of obtaining a final arbitral award against the Indonesian government and within approximately one and a half years from the initial payment default under the ESC.

The Experience of Other Investors

Although CalEnergy's experience was arduous, it ended with a recouping of its investment, which otherwise would likely have been lost. Other foreign investors in Indonesia (and elsewhere) have not had such positive results.

The facts surrounding the Kahara Bodas power project in Indonesia start out virtually identical to the CalEnergy situation. Much like the CalEnergy projects, the Kahara Bodas Company was formed in 1994, principally by Caithness Energy and Florida Power & Light (each of which owned 40.5% of the company), to develop two geothermal power projects in Indonesia. The contractual structure of the projects was similar to the CalEnergy projects. Disputes under its operating and energy sales contracts with PLN and Pertamina were to be resolved by UNCITRAL arbitration in Switzerland. The presidential decrees in the fall of 1997 unilaterally suspended the projects, and the project company, KBC, commenced arbitration against PLN and Pertamina in April 1998.

KBC obtained an arbitral award against Pertamina and PLN for $261 million in December 2000. The defendants then sought to appeal the award in the Swiss courts without success. KBC sought enforcement of the award against offshore assets of Pertamina in courts in the US, Hong Kong and Singapore. A US federal court in Houston confirmed the award and entered judgment against Pertamina for $261 million on December 4, 2001. Pertamina's appeal of this decision to a US appeals court is still pending. In February 2002, KBC filed garnishment and discovery requests with respect to Pertamina's US assets in New York, as well as in Texas and Delaware. (Among other assets, KBC is seeking to attach the proceeds of liquefied natural gas sales made by Pertamina that are paid into trust accounts at Bank of America in New York.)

Pertamina has vigorously defended these actions and KBC has been engaged in costly and time-consuming international litigation in its attempt to get paid. Although KBC was initially successful in freezing $320 million of Pertamina funds in the Bank of America accounts in New York, in April 2002 Pertamina obtained a New York federal court order holding that 95% of the funds held in the New York accounts belong to the government of Indonesia and not Pertamina. That decision was upheld on appeal, so it appears that only about $16 million of funds have effectively been frozen.

KBC also had some initial success with courts in Hong Kong and Singapore similarly freezing Pertamina assets. But in August 2002, Pertamina obtained an order from the central district court in Jakarta annulling the arbitral award, and Pertamina has sought to use the annulment order to its advantage in the proceedings in the US, Hong Kong and Singapore. It is arguing that those courts should refuse to enforce the award based on article V(1)(e) of the "New York Convention on the Recognition and Enforcement of Arbitral Awards." The New York Convention was designed to ensure that parties resorting to offshore arbitration need not relitigate the merits of the dispute when seeking to enforce the award in countries that are parties to the convention. It provides for few defenses to enforcement, but article V(1) (e) provides that the recognition and enforcement of an award "may be refused" if the award "has been set aside or suspended by a competent authority of the country in which, or under the law of which, the award

> If the host government cannot meet its contractual obligations, then why is it more likely to be able to pay damages awarded by an arbitral tribunal?

was made." As the agreements that provided for offshore arbitration were governed by Indonesian law, Pertamina seeks to persuade courts in these various jurisdictions that they should exercise their discretion and not enforce the award.

The KBC case continues to play out with complex litigation that has moved from Switzerland, through US courts in Texas, New York and Delaware, among others, and on to Hong Kong, Singapore and Jakarta. Although the ultimate outcome remains uncertain, one thing is clear: Cal Energy recouped its investment in full by payment from its political risk insurers within one month of obtaining an arbitral award; KBC has had its lawyers chasing assets worldwide for over two years now since obtaining its arbitral award in December 2000, and it still seems pretty far from recovering anything.

KBC is hardly alone. Investors in the other power projects in Indonesia have also run into difficult problems trying to recoup their investments.

The $2.9 billion Paiton power project has chosen to renegotiate its power purchase agreement rather than to pursue arbitration. Given the size and complexity of the Paiton project, too much may have been at stake for Paiton to pursue the arbitration and litigation route aggressively. (Prior to settling its differences through negotiations, a few litigation skirmishes were fought.) Press reports indicate that PLN has to date renegotiated 20 of its agreements with independent power producers, suggesting that most of the independent power producers in Indonesia determined that the arbitration and litigation routes were not in their interest.

Investors in projects in Pakistan, India and elsewhere have experienced problems similar to KBC in being thwarted by host governments when they attempted to exercise their contractual right to offshore arbitration of disputes. In the midst of a foreign exchange or other political and economic crisis, host governments have failed to honor the contractual obligations that are the linchpins of infrastructure projects and have attempted to frustrate the dispute resolution process by seeking to prevent the arbitral process from proceeding.

Lessons Learned

These experiences of CalEnergy, KBC and other investors in developing country infrastructure projects in the 1990's have taught some valuable lessons about polit- */ continued page 28*

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produced for inspection by the court.

Long-Term Capital Partners, L.P. hired Shearman & Sterling and King & Spaulding to render opinions about aspects of a transaction that produced a tax loss of $106 million in 1997. The IRS questioned the loss on audit. The partnership turned over the Shearman & Sterling opinions to the IRS, but refused to give it copies of the King & Spaulding opinions on grounds that they are protected by both the "attorney-client privilege" — for communications between a client and its lawyers — and the "work product privilege" — for work that its lawyers do in anticipation of litigation.

The court suggested that Long-Term Capital Partners waived any attorney-client privilege by sharing the gist of the opinions with its tax accountants and by giving the IRS the Shearman & Sterling opinions. The court said a company cannot selectively disclose opinions about a single transaction.

The court asked for copies of the opinions to determine whether they are covered by the work-product privilege. The case is Long-Term Capital Holdings v. United States.

NUCLEAR POWER PLANTS create interesting anomalies.

Entergy complained to the US Treasury Department in January that when Entergy buys nuclear power plants, the US tax rules require it to allocate purchase price first to securities held in any decommissioning fund that it inherits as part of the purchase. Decommissioning funds are set up to ensure there will be enough money when the plant reaches the end of its life to pay decommissioning costs. The fund should have no net value. However, the problem is the US tax rules do not allow the purchaser of such a plant to take into account the expected offsetting liabilities, Entergy said in a letter the Treasury made public. */ continued page 29*

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ical risk coverage.

Lesson number one: Political risk insurance coverage is valuable. The CalEnergy experience — especially in contrast to the experience of similarly situated projects like the Kahara Bodas or Paiton projects — demonstrates that political risk insurance may be of crucial importance in ensuring the integrity of contractual structures relying on host government support. The problem with host government contractual support is that it is most needed during periods of political and economic dislocation, but during such periods it is often unrealistic to expect that the host government will be in a position to meet its obligation. When countries experience political and economic crises, host government contractual obligations will be of uncertain value without the creditworthy backstop of a political risk insurer.

Lesson number two: Arbitrations against host governments are likely to proliferate. Foreign investment projects proliferated in the 1990s with the demand of emerging markets for infrastructure. Project agreements, concession agreements, host government guarantees and bilateral investment treaties that provide investors with protection against expropriation all generally provide for the arbitration of investment disputes. With political risk insurance contracts structured to protect investors against the failure by host governments to pay arbitral awards, we are likely to see more arbitrations against host governments than in the past.

Without political risk coverage, the foreign investor faces a threshold decision as to whether to take a host government to arbitration over a failure to pay or to renegotiate the obligation to its detriment. However, if the government cannot meet its current obligation, why is it more likely to be able to make the type of large buyout payment that would be awarded as damages by an arbitral tribunal? Moreover, the KBC experience suggests that even if the government can meet its obligation, the foreign investor may be facing years of complex and costly international litigation in order to compel the government to comply. Without political risk insurance coverage, an investor will often feel that it has no real effective dispute resolution alternative to accepting a unilateral renegotiation of its contract with the host government on terms imposed on it by the host government.

Political risk insurance makes arbitration of a dispute an effective option because the insured is assured of a creditworthy obligor once the award is obtained.

As political risk insurance coverage makes arbitration of the dispute an effective alternative (because the insured is assured of a creditworthy obligor once the award is obtained), host governments are likely to see a rise in arbitrations against them for breaches of their agreements. Since the insured investor's interest in the project company and arbitral award is assigned to the insurer as a condition to claim payment, host governments will also probably find themselves in negotiations with the home governments — for example, the US government to the extent the coverage is issued by OPIC or US Ex-Im Bank — or the World Bank Group in the case of MIGA coverage — rather than the foreign investor. The US ambassador played an important role in negotiations between OPIC and the government of Indonesia, for example, after OPIC paid the CalEnergy claim.

Lesson number three: Since governments can be relied on to attempt to frustrate enforcement of arbitral awards, it is important to draft the arbitration clause with the aim of making such frustration difficult. Whether CalEnergy or Kahara Bodas in Indonesia, Enron in India, or the Hub power project in Pakistan, when foreign investors have sought to enforce their contractual rights against host governments by commencing arbitration, the host governments have aggressively sought to enjoin the arbitrations from proceeding. As political risk contracts typically require the insured actually to obtain the arbitral award (in order that the insurer has salvage rights against the host government after payment of the claim), attention needs to be given to drafting the arbitration clause in a manner designed to overcome these likely attempts by governments to frustrate the process from continuing. In addition to providing for offshore arbitration in a New York Convention jurisdiction hospitable to arbitration, the arbitration provisions should provide, for example, that the parties shall have no access to the local court system with respect to a dispute under the agreement until after an award is made and then only for enforcement of an arbitral award.

Lesson number four: Here are some tips for managing the claim process. When pursuing claims against political risk insurers, a number of complex issues typically arise. First and foremost, it is imperative that the insured keep its insurers informed of problems and current developments as soon as it becomes aware that political problems may give rise to a claim. Most political risk insurance contracts require the insured to do so (as, among other things, the insurer may be in a position to use its influence to resolve the problem). Providing full and current information will, at a minimum, preclude defenses by the insurer and, at best, may actually lead to the insurer assisting on resolving the problem before it leads to a claim. (MIGA, in particular, has shown an ability to assist the investor in this manner.)

One thorny issue that sometimes arises is that political risk insurance contracts typically require the insured throughout the claim process to negotiate in good faith with the host government and generally to pursue all remedies as though it were uninsured. Although this provision is straightforward in its application in expropriation policies, it is less clear how this provision works in the context of disputes coverage. If the host government indicates a willingness to settle an arbitration at a low amount and the insured refuses to settle (since it has paid high premiums for a policy standing behind the arbitral award now within its grasp), does the insurer have a defense to claim payment? Having bargained with the insurer for it to stand behind an arbitral award, it would not seem appropriate for an insurer to try to defend on the basis of an unwillingness of an insured to settle for less in this situation. These clauses should probably be addressed when negotiating the policy. In this context, it is not reasonable to expect the insured to act as though it were uninsured.

Another provision that needs to be looked at carefully when negotiating the policy is the assignment requirement in connection with claim payment. Given */ continued page 30*

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The result is the entire purchase price is allocated to securities in the decommissioning fund, leaving nothing to allocate to the power plant.

Entergy complained about the same problem last year.

FOREIGN TAX CREDITS cannot be claimed for taxes that another country might waive if a company can prove that it will not be able to credit them against its US taxes, the IRS said.

Costa Rica collects withholding taxes on dividends, interest and other types of income leaving Costa Rica. However, by law, the tax authorities can waive all or part of the withholding tax in cases where the recipient of the income can prove that it will not receive credit for the taxes in its home country.

The IRS ruled in late January that foreign tax credits may not be claimed for Costa Rican withholding taxes in the United States. IRS regulations deny foreign tax credits for taxes that may or may not be levied depending on whether the taxpayer can get credit in the United States for having paid them.

The ruling is Revenue Ruling 2003-8. It is a reminder to check on due diligence whether the tax authorities in another country have the power to waive any taxes.

INDIA claimed the right to tax the owner of satellites on rentals it collects for use of its satellites by a television company that beams programming across Asia, including into India.

The satellite owner — AsiaSat — is based in Hong Kong. It has no other business connection with India. Nevertheless, a tax appeals tribunal in New Delhi said that AsiaSat had to pay tax to India because the television channels that paid for the use of its satellites were engaged in business there and were essentially paying "royalties" to AsiaSat for use of a "process" in India. The appeals tribunal treated the */ continued page 31*

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that most infrastructure projects are project financed and lenders will want a lien over all project company assets (including any arbitral award), it is important to make sure that all the insurer will require to be assigned is the insured's interest in the project company and arbitral award and not the award itself, which will likely be encumbered. The industry has had enough problems with the insurers' requirement that the insured's equity interest be delivered free and clear of liens. (This often requires a complex carve-out from the lender's pledge agreement.) It simply would not be possible or reasonable to expect lenders to relinquish their lien on an arbitral award in this context and care should be taken to ensure that the language in the policy does not appear to require this.

Lesson number five: Confidentiality agreements may pose a problem. Political risk insurance contracts have tight confidentiality clauses. One problem with these clauses is that if the insured feels the insurer is wrongfully denying its claim and unreasonably forcing it to a costly arbitration, it is deprived of its ability to complain to others in the market. As the ability to complain about perceived unfair treatment often serves as a moderating influence on market participants, consideration should be given to negotiating these clauses in a manner where the confidentiality requirement with respect to a claim would no longer be required after the claim has been denied. ◎

LNG Projects Helped in the US

by Daniel R. Rogers, in Houston

The US government moved at the end of 2002 to help prospective importers of liquefied natural gas, or "LNG," by adopting a new regulatory policy that expressly authorizes development of closed-access, "proprietary" natural gas and LNG import terminals and allows the owners of such terminals to charge for services at market rates rather than rates that are tied to the cost of service.

The government took two actions.

First, the "Maritime Transportation Security Act of 2002" enacted by Congress in November provides a new statutory framework for federal regulation of offshore natural gas and LNG terminal facilities. Second, the Federal Energy Regulatory Commission made a favorable preliminary decision in December to certify a proposed onshore LNG facility that Dynegy wants to build at Hackberry, Louisiana.

Both events reflect a US government response to the natural gas industry's pleas to reduce or remove regulatory barriers to new gas and LNG import facility investment by establishing a more flexible regulatory policy. Before these latest actions, developers interested in building LNG terminals were uncertain about some of the rules that would apply to them. Some of the uncertainties stemmed from the need to comply with FERC's open season/open access and cost-of-service tariff rate regulations in connection with shore-based terminals. There was also no gas-specific regulatory framework under which offshore natural gas and LNG terminals could be developed.

Offshore Gas

The "Deepwater Ports Act of 1974" and its implementing regulations have been in existence for some time and govern the development and operation of offshore oil receiving and storage terminals. However, it was not until November 2002 with the passage of the new Maritime Transportation Security Act, that a statutory framework existed for the development of offshore terminals to receive imported natural gas and LNG.

The new maritime statute amends the earlier Deepwater Ports Act to expand its reach to the siting, construction and operation of offshore natural gas and LNG import terminals (including any storage, sendout pipelines or other associated equipment) that are located seaward of the coastal high water mark. It also provides that licensees of offshore gas terminals are not required to offer service to the public on an open-access or common-carrier basis. In the event that third-party access is in fact provided, then the rates to be charged for such access may be privately negotiated, market-based rates as long as it can be shown that such rates are "reasonable" and such third-party use will not materially interfere with the licensee's intended use of the terminal facility.

In developing this approach, proponents compared offshore gas and LNG reception facilities to existing offshore natural gas production and gathering facilities — which are not currently regulated by FERC — and argued that an offshore natural gas or LNG reception facility is simply another mechanism to introduce new gas into the US market. Any gas imported would essentially be competing with other gas produced offshore. Any pipeline, storage or associated equipment located onshore of the coastal high water mark will remain subject to FERC regulation, including any applicable open season/open access and cost-of-service tariff rate regulation. (Some companies may be able to avoid this regulation by claiming an "intrastate facility exception.")

The new maritime statute makes the US Coast the "one-stop," single point of contact for purposes of all necessary federal agency authorizations. The Coast Guard must consult with all relevant federal agencies in connection with any offshore terminal license application. The final decision with respect to approval or denial of a license application rests with the US Secretary of Transportation (who oversees the Coast Guard).

Although the new law consolidates all federal-level activity with respect to the siting, design, construction, operation and safety of an offshore gas or LNG terminal, it is important to note that it does not supersede existing regulations that require a gas or LNG commodity importer to obtain a gas or LNG import permit from the US Department of Energy.

Under the new statutory regime, applications for licenses to build an offshore gas or LNG terminal must be made to the Coast Guard. The Coast Guard then has 21 days to review the application and determine whether the application is complete. The next step is for the Secretary of Transportation to publish a notice of the application in the *Federal Register*. This publication starts a 240-day time period during which any public hearings must be held. The Secretary of Transportation then has another 90 days from when any hearings conclude to grant or deny the application.

The Department of Transportation must make a decision on the application based on a number of listed factors, most of which center on national interest and national security considerations. The new maritime statute also requires the concurrence of the governors of all affected states before any terminal license can be issued. Presumably, this will be obtained within the time periods laid out in the statute for a final decision on the application. In practice, as long as a license applicant submits all necessary information in a timely manner, it appears that a final license determination should be in hand within 351 days from / continued page 32

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payments as for use of the intellectual property embedded in the satellites rather than for the equipment itself.

Meanwhile, the Hindustan Times *reported that the finance minister, Jaswant Singh, plans to announce in his budget speech to parliament this month that the government will abolish long-term capital gains taxes for foreign institutional investors.*

MINOR MEMOS. Entergy claimed a $2.316 billion tax deduction on its return for 2001 by "marking to market" a long-term contract it signed years ago to buy electricity from the Vidalia hydroelectric project in Louisiana. The tax deduction was expected to provide it with a cash flow benefit of between $700 and $800 million at the end of 2002, according to a US Securities and Exchange Commission order in December. Section 475 of the US tax code requires dealers in securities to mark their securities inventories to market at the end of each year for tax purposes. Dealers in "commodities" have had the option of doing so since 1997 . . . . Forty-six percent of IRS agents who audit large and medium-sized businesses are eligible for retirement within the next three years. The agency is worried about the brain drain. It takes years to train IRS agents in these positions . . . . The IRS announced a new approach to large corporate tax audits in January. It said that it would be willing to enter into formal agreements at the start of audits with large companies where each side agrees not to raise issues below a certain dollar threshold. The hope is to streamline audits. It remains to be seen how attractive this is to large companies. A company would have to have at least $10 million in assets to take advantage of the program. The ground rules are described in an information release IR-2002-133.

— contributed by Keith Martin, Helena Klumpp, Samuel R. Kwon, Kristin Meikle, Luis Torres and Merrill Kramer in Washington.

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the date the application was filed. This is a substantial improvement over the undefined 18-month to two-year period that it has typically taken to obtain final certification from FERC in connection with land-based LNG terminal facilities.

The Coast Guard is already at work on draft regulations to implement the new scheme. These regulations are expected to resolve a number of questions that were not answered in the maritime statute. At this stage it does not appear that any privately-negotiated terminal capacity agreement will be required to be filed with the government. However, this will remain an open issue until the final regulations are published. Of particular interest will be whether and how the statutory provisions relating to the reasonable rate requirement in connection with private third-party access arrangements will be handled, and how disputes over whether offered rates are reasonable will be resolved under a new citizen complaint procedure.

The new law raises a few interesting issues relating to marine transportation and delivery of natural gas or LNG into offshore facilities. First, all vessels calling at the offshore gas or LNG terminal are liable for any penalties imposed for violations of regulations governing operation of the terminal (apparently including the terminal owner's violations), unless it can be shown that the vessel owner or bareboat charterer was not a consenting party or otherwise involved in the prohibited conduct. An example of a violation might be the discharge of cargo into a facility that does not possess a valid terminal license.

Furthermore, foreign flagged vessels are not authorized to call on US offshore gas and LNG terminals unless the relevant flag state government has either directly consented to or acknowledged the jurisdiction of the US government over the activities of the vessel while it is in US waters. As a further condition to calling on US offshore gas and LNG terminals, foreign flag vessel owners and operators are also required to designate an agent for service of legal process in the US. This heightened attention to foreign vessels means owners of such vessels will have to adopt new compliance practices in order to ensure uninterrupted transportation services.

Onshore LNG Facilities

The second important development for the LNG industry came on December 18, 2002 with the FERC Hackberry decision. After initially failing to convince FERC that it would run a safe and economic LNG terminal, Dynegy was able to persuade the agency of the merits of its position.

The Dynegy application is important because it is the first time the agency has seemed willing to approve a closed-access, "proprietary" terminal that would charge for its services at market rates rather than rates that are tied to the cost of service. FERC made a preliminary decision that the Dynegy application is in the public interest. It was helpful that the proposed terminal is a new facility and thus there would be no adverse economic impact to existing users and also that Dynegy bears the entire investment risk of the terminal. FERC also noted that this approach is consistent with the existing "first-sale" exemption for natural gas sales, as well as the new closed access terminal service regime that was authorized for offshore terminals in the Maritime Transportation Security Act in November.

Importantly, FERC recognized that in the case of the Hackberry terminal, which is located near the inlet of a fluid and dynamic natural gas market where a number of supply options appear to be readily available, it is unlikely that Hackberry's closed-access import terminal would be in a position to exercise market power over the price of natural gas. It will be interesting to see whether FERC makes similar market power findings in the future in cases where facilities are located closer to the end market.

FERC made it a condition to final approval that the project must file a copy of its private terminal service agreement with its Dynegy affiliate prior to commencing construction. The Hackberry order is silent about whether subsequent amendments or modifications to the terminal service agreement must be filed. It also offers no insight into what FERC would do in a case where the project structure does not involve a separate terminal service agreement. For example, it is not clear what FERC would do with a project where the cost of terminal services is rolled into the price charged the consumer of the commodity.

While the Hackberry decision is notable in many respects for its lack of clarity as to future application, a few issues are fairly clear. First, in issuing the Hackberry decision, FERC did not concede or otherwise modify its jurisdiction over the siting, design, construction and operation of LNG facilities from a safety standpoint. The Hackberry decision only speaks to FERC's economic (rather than safety) regulatory powers. It does not supercede the open season/open access regulatory system or existing cost-of-service tariff rate regulation. It merely offers an alternative means of obtaining FERC certification in the case where the terminal developer finds it preferable to operate closed-access facilities on market-based service pricing terms. Nothing in the Hackberry decision appears to preclude a terminal developer from simply pursuing the more traditional FERC approval process, particularly where the eminent domain powers associated with authorization under section 7 of the Natural Gas Policy Act are key to developing the terminal. Finally, the Hackberry decision does not divest FERC of its well-established authority to remedy complaints of discriminatory or anti-competitive behavior, nor does it preclude FERC from making any supplemental order or otherwise conditioning its final certification of any LNG terminal.

Some of the more significant open issues left unanswered after the Hackberry decision include the following:

- Will FERC certify projects where the terminal capacity holder is not an affiliate of the terminal owner (and thus the "entire economic risk" is spread among the participants instead of placed on the terminal owner)?
- Will the fact that FERC has authority to impose new conditions after certifying a project to redress complaints of discriminatory treatment or anticompetitive behavior create any significant issues for lenders in connection with project financing or to LNG suppliers, who may worry about changes that could affect the economic viability of the LNG buyer or terminal owner?
- Is FERC being consistent when it claimed jurisdiction in the Hackberry decision over the associated natural gas sendout line for the project with its earlier decision in the Cove Point project? There, it declined a customer request to unbundle the cost of terminal service at the Cove Point LNG facility from the cost of sendout pipeline service on the basis that the pipeline was integrated with the terminal and to decouple the two could have led to under-utilization of the LNG terminal.
- Can the owner or operator of an existing LNG facility now use the policy and rationale in the Hackberry decision to apply for authority to run a closed-access facility and charge market rates? What about for expansion capacity at an existing terminal?
- To what extent is it desirable to bring the approval processes with FERC and the Coast Guard into harmony?

The Hackberry decision might be seen as a sign by FERC that it does not plan any broad regulations in this area but rather prefers to address issues as they arise in individual applications. If this is in fact the case, it is likely that there will be little concrete guidance for onshore LNG terminal developers until a consistent and reliable body of FERC precedent evolves.

Safety Plans

As should be expected, the good news from the government did come without at least one string attached.

The Maritime Transportation Safety Act requires LNG facility owners and operators to file a detailed LNG facility security plan within six months after regulations implementing the statute are issued by the US Department of Transportation. This requirement to file a security plan applies equally to FERC-certificated shore-based LNG facilities and Coast Guard-licensed offshore natural gas and LNG receiving terminal facilities. By law, the security plan must be approved by the US government within one year after interim regulations are issued or else the LNG facility will no longer be allowed to operate. Each security plan is to be developed on a location-specific, user-specific basis. Congress indicated that "boilerplate" security plans will not be viewed favorably. The regulations that will start the clock on submitting security plans are in the works at this writing. ◎

Mexico: Preparing For LNG

by Mario Juarez, in Washington

Developers have announced plans to build seven new plants to process imported liquefied natural gas, or "LNG," in Mexico to supply the growing demand for gas in the country. But before August 2002, Mexico did not have any specific regulation for LNG plants. How is Mexico getting prepared for LNG?

Background

Natural gas consumption in Mexico grew at an annual rate of 4.6% between 1993 and 2001, according to */ continued page 34*

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a recent Ministry of Energy publication called the "2002-2011 Natural Gas Market Perspective." Most of the growth was due to the greater demand for gas to run power plants.

Consumption of natural gas by the power sector alone grew at an annual rate of 12.1%. Power companies are becoming the largest single consumer of gas in the country. The growth rates in other sectors pulled down the average. The residential and services sectors had growth of only 1.2% a year. The main factor limiting gas consumption in these sectors is the limited gas distribution network in the country.

The Mexican government is projecting 10.2% annual growth in demand for natural gas over the next 10 years. The trend is for more imports as a share of total supply.

The future looks better. Since 1995, the Energy Regulatory Commission, or "CRE," has granted 21 permits for new natural gas distribution systems to be constructed in several cities. Some of the distribution lines authorized by these permits are still under construction.

In the 1990's, almost all the demand for natural gas was met out of domestic reserves. That is starting to change. By 2001, the country was importing gas to cover approximately 9% of domestic consumption.

The Mexican government is projecting 10.2% annual growth in demand for natural gas over the next 10 years. The trend is for more imports as a share of total supply. Demand for gas to generate electricity is expected to outstrip growth in other sectors. Growth in gas consumption by power plants is expected to increase by 12.6% a year over the next 10 years. This represents an increase from consumption of 1,156 million cubic feet a day in 2001 for electricity generation to 3,801 million cubic feet a day by 2011.

The government recognizes that the demand cannot be met without private investment in the oil and gas sector. Its current 5-year development plan has as a goal the construction of one or more LNG plants. The *Comisión Federal de Electricidad* put out a request for bids in late December for someone to supply an average of 425 million cubic feet a day of LNG over the next 15 years. The winner will be expected to build a new LNG plant in Altamira, Tamaulipas and to have the plant in operation by January 2006.

Regulation

Developers have been eying Mexico as a good place to put an LNG plant to supply the California market for at least the last three years. However, it has become clear with construction of new power plants in Baja on the Mexican side of the border that the increasing local gas demand is enough to justify such plants in Mexico.

This has led to a "Mexican LNG rush." It caused the Fox administration, in turn, to take steps to regulate — but at the same time promote — construction of LNG plants in Mexico. One of these steps was to propose amendments to existing gas regulations to impose standards for such things as storage and regasification of liquefied natural gas, including the transferring of LNG from vessels to plants and security measures that will be required to ensure safe handling. The proposed amendments would also have created a new kind of permit specifically for the storage and regasification of LNG. However, the Fox administration never moved forward with these amendments because it feared they would be contested by Congress after a Supreme Court ruling in April 2002 declaring unconstitutional certain reforms made by the government to the rules for cogeneration and self-supply projects.

In the meantime, the Fox administration published temporary "guidelines" for the construction and operation of LNG plants in an effort to dispel any legal doubts about the legality of private sector involvement. The guidelines are found in *Norma Oficial Mexicana de Emergencia* (NOM-EM-001-SECRE-2002). They are expected to be replaced by a set of new "permanent" guidelines later this year. Existing gas regulations are expected to be amended at the same time.

The guidelines explain the technical requirements for design, construction, operation and maintenance of LNG plants. They apply to onshore facilities of LNG plants, from the point where LNG is received from a vessel to the pipeline in which the vaporized natural gas is delivered. They also apply to all activities related to the LNG plant, including receiving, transferring, storage, regasification and delivery of LNG.

The guidelines require a developer to obtain from CRE a gas storage permit before he can build and operate a plant. The legal entity that will operate and maintain the plant must also be authorized by CRE.

Existing gas regulations explain how to obtain a gas storage permit. Gas storage permits are granted for a term of 30 years and can be renewed for one or more additional terms of 15 years each. A permit can be revoked in certain circumstances described in article 13 of the "Law Regulating Article 27 of the Constitution in Oil Matters."

The same legal entity the holds the gas storage permit might also hold another permit that will be required for the eventual transportation and distribution of the regasified gas.

Announced LNG Projects

There has been an overwhelming interest in the construction of LNG plants in Mexico. Currently, at least seven LNG projects have been announced. Four of these projects will be located in Baja California, one in Altamira, Tamauipas and two in Lázaro Cárdenas, Michoacán. Also Topolobambo, Manzanillo has been proposed as a site to install an LNG plant.

In Baja California, El Paso Global LNG and Philips will jointly develop an LNG regasification terminal that is expected to begin operating in 2006 and will have an estimated cost of US$500 million.

Marathon Oil Corp., together with Grupo GGS and Golar LNG Limited, plan to build an LNG regasification project that will also include a power plant, a water desalination plant, wastewater treatment facilities and the natural gas pipeline infrastructure. The estimated investment for this project is US$1.5 billion. Marathon Oil Corp. has already applied to CRE for the necessary permit to begin construction. It expects the permit to be granted during the first half of 2003.

A third project will be developed by CMS Energy Corporation and Sempra Energy. This plant will have a send-out capacity of approximately 1 billion cubic feet a day of natural gas and is expected to begin commercial operation in late 2005.

Finally, Shell Gas and Power also has expressed its interest in building an LNG plant in Baja California. The plant cost will be US$500 million and its completion is expected in 2006. For this plant, Shell has contracted for 7.5 million tons a year of LNG as the initial supply for the plant.

In Altamira, the most notable project is the LNG regasification terminal to be constructed and operated by El Paso Global LNG and Shell Gas and Power. El Paso and Shell have already applied for the necessary permit from CRE and expect to receive it during 2003. Initial investment costs are estimated to be as much as US$300 million, and the plant is scheduled to start operating in the first half of 2004.

The last two LNG projects that have been announced are being developed by Tractebel and Repsol-YPF with Gas Natural SDG. The plants will be built in Lázaro Cárdenas, Michoacán, and the estimated cost of each plant is approximately US$500 million.

Some analysts have noted that that there could be around 20 Mexican LNG terminals if all proposals are approved. Currently, 18 projects are under review. However, they believe that in view of the estimations of Mexico's gas needs for the next ten years and the possibility of supplying natural gas to California, it is more realistic to think on the installation of three or four LNG regasification terminals in Mexico over the next 15 to 20 years. ◎

Like-Kind Exchanges

by Daniel L. Feehan, with APEX Property Exchange, Inc. in Boston

Many companies have the impression that "like-kind exchanges" of power plants and other infrastructure assets are either irrelevant or too complex to arrange.

In today's energy market, companies are looking to sell assets and use the sales proceeds to pay down debt and maintain liquidity, not to acquire new assets. In the rush to do this, tax-saving strategies involving like-kind exchanges are often overlooked.

The combination of a like-kind exchange with other financing techniques can be used not only to generate tax savings, but also to create capital to purchase new property, reduce debt, enhance credit ratings and prevent tax bills from being passed on to ratepayers and investors.

Background

Tax-deferred exchanges have been in use */ continued page 36*

Like-Kind Exchanges

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for more than 80 years. Most property held for productive use in business, including office buildings, power plants, factories, mineral interests, and other real estate, equipment like aircraft, trucks, tractors, railcars, and transmission and distribution lines, and intangible assets like patents, contracts, trademarks, customer lists, and licenses can be a candidate for a like-kind exchange.

Taxpayers can create substantial savings by doing a three-way like-kind exchange where an intermediary acts as a go-between between the seller of the asset and the eventual buyer. Two kinds of entities may be involved: a "qualified intermediary" and an "exchange accommodation titleholder."

There are two basic types of transactions: forward exchanges and what the tax lawyers call a "parking arrangement" under Revenue Procedure 2000-37.

Forward Exchange

A forward exchange requires that existing property be relinquished first and that replacement property thereafter be identified within 45 days and purchased within 180 days. Taxpayers that acquire replacement property of equal or greater value to the relinquished property and invest all equity in the replacement property are generally able to defer federal tax fully on any gain, as well as avoid any "recapture" of depreciation claimed to date on the property being sold. If the transaction qualifies as a like-kind exchange, then the basis of the relinquished property will be carried over into the replacement property, and any gain from the sale of the relinquished property will be deferred until the replacement property is sold. However, where the relinquished property is considered equipment for tax purposes (rather than real property), special rules will apply and need to be considered.

Parking Arrangements

Companies often have trouble finding suitable replacement property and scheduling closings to comply with the tax code's requirement to sell first and buy second. However, in September 2000, the IRS issued Revenue Procedure 2000-37. It created creates a "safe harbor" permitting taxpayers to make a sale of property through an "exchange accommodation titleholder," or "EAT." This allows the seller more control over the timing of the disposition and replacement in order to complete a tax-deferred exchange. Under the parking safe harbor, the parked property must be conveyed from the EAT to the taxpayer (if replacement) or from the EAT to a third party buyer (if relinquished) within 180 days of parking. Further, although for most taxpayers it is a mere formality, the intended relinquished property must be identified within 45 days of parking a replacement.

The notion that like-kind exchanges do not work for power plants and other infrastructure projects is a myth.

The greatest benefit of the parking safe harbor is its flexibility in permitting various arrangements concerning the property during the parking period. For example, an EAT can acquire property and lease it back to the taxpayer or any other party. This allows the taxpayer to manage and operate the property while it is owned by the EAT. Additionally, the taxpayer can either lend money directly to the EAT to acquire the target property, or the taxpayer can be the guarantor of third-party loans obtained by the EAT.

As long as a taxpayer meets the requirements of the parking safe harbor, including keeping the parking arrangement from exceeding the time limit of 180 days, the IRS will not challenge the arrangement on grounds that the taxpayer failed to dispose of the relinquished property before acquiring the replacement.

The intricacies and pitfalls associated with entering into like-kind exchanges are best illustrated by two examples.

Example 1: Using credit tenant lease property to create capital.

An investor-owned utility plans to sell $2 billion of non-core real estate. Its goal is to defer the capital gains taxes on the sale of the real estate by acquiring like-kind replacement property of a type consistent with its desire to maintain liquidity.

The utility purchases replacement real estate that is already leased to an investment grade, single tenant (often called a credit tenant lease, or "CTL") which has a term of 20 years or longer. Much of the appeal for these properties stems from their high financeability: they are often packaged with 90% loan-to-value non-recourse debt. In this example, the taxpayer's advisors have concluded that this CTL also has certain characteristics that will allow leveraged lease accounting treatment.

Once this replacement property is located, the utility sells its original piece of real estate. The qualified intermediary takes an assignment to the rights in the purchase contract, but does not take title to the relinquished property. The utility transfers title to the buyer directly, and the sales proceeds are placed in an escrow account to which the qualified intermediary also signs. The utility then identifies its replacement property within 45 days, and enters into a purchase agreement with the seller of the replacement property.

The proceeds from the sale of the relinquished property (held in escrow) are used within 180 days to purchase the replacement property. The replacement property is transferred to the utility using the qualified intermediary in a manner similar to the first transaction. The type of CTL property and the duration of its lease allow the utility both to defer its tax liability through a like-kind exchange and maintain liquidity. Potentially, the utility may not pay any state or federal capital gains taxes or depreciation recapture on the sale. At some point in the future, the utility may sell the CTL property and purchase core property.

Example 2: Using parking arrangements to bring projects online. An investor-owned utility plans to sell $350 million in assets and intends to develop a greenfield power plant. The utility's development cycle for a new plant is typically 36 months or longer. The utility also desires to purchase equipment and other personal property for plants already under construction before disposing of its non-core assets.

The utility sets up two EATs: EAT 1 acquires and holds title to the future plant site, and EAT 2 acquires and holds new transmission and distribution assets. The utility guarantees the entire amount of a third-party loan granted to EAT 1 to acquire the new plant's site. EAT 1 holds title to the new plant's site and leases the site to the utility to manage the construction work at the new site.

The utility lends money to EAT 2 to purchase all new transmission and distribution equipment for both the new plant and for use by plants that are already in operation. The utility ensures that the new equipment being purchased is of a "like kind" to the equipment being sold.

Once each EAT acquires replacement property, the utility will have 45 days to identify the property it is selling and 180 days to purchase the replacement property from the EATs. The utility sells the relinquished property and all sale proceeds are directed into an escrow account through an unrelated third party known as a "qualified intermediary."

The utility exercises its option in the lease agreements to acquire the replacement property from EAT 1 and EAT 2. The intermediary sends proceeds from the escrow account to each EAT to purchase the replacement property. The intermediary transfers the replacement property held by each EAT to the utility and each EAT then pays off the loans used to acquire the replacement property.

The utility is able to sell its non-core property and defer all the gains taxes from the sale into new strategic property that will grow its business. The flexibility of the EAT structure gives the utility the ability to develop its parked property while maintaining the use of its relinquished property.

Longer Parking Arrangements

For transactions that take longer than 180 days to complete, Revenue Procedure 2000-37 says the IRS "recognizes that 'parking' transactions can be accomplished outside the safe harbor provided in this revenue procedure. Accordingly, no inference is intended with respect to the federal income tax treatment of 'parking' transactions that do not satisfy the terms of the safe harbor provided in this revenue procedure." However, many of the arrangements into which taxpayers enter with an EAT in anticipation of completing safe harbor parking within 180 days appear problematic from the perspective of, if not wholly inconsistent with, a parking transaction intended to satisfy the IRS. Strategic ownership structures are being developed to address instances when a property needs to be parked for an extended period of time. In the meantime, prior to parking, taxpayers should do their best to determine whether they will be able to find a buyer within 180 days of parking, and they should pay particular attention to its time constraints.

Dispelling the Myth

Like-kind exchanges are becoming essen- */ continued page 38*

Like-Kind Exchanges

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tial for companies that want to defer capital gains taxes or depreciation recapture on their dispositions. The assumption that power plant and infrastructure exchanges are difficult or have no place in the energy sector is proving false. Comprehensive and flexible like-kind structures can be successfully executed. With proper planning and the assistance of an experienced and knowledgeable intermediary, like-kind exchange structures can be used to acquire new core assets or generate cash.

Given the current marketplace, companies need to continue incorporating like-kind exchanges into their planning. With restrictive capital markets, such transactions can allow companies to recycle capital, maintain liquidity, and move toward financial solvency.

"New Source Review" Rules Bring Key Changes

by Roy Belden, in New York

After more than 10 years of rulemaking deliberations, litigation, more than 50 stakeholder meetings and public hearings, and consideration of more than 130,000 comments, the US Environmental Protection Agency finally issued important changes to the federal "new source review," or "NSR," air permitting program.

The new rules will take effect on March 3.

They were greeted with howls of protest from leading environmental groups and several members of Congress. The press labeled the new rules a "rollback" of more than 30 years of progress on clean air initiatives and nine attorneys general from northeastern and mid-Atlantic states filed a lawsuit challenging the rules on the day they were released. One Democratic candidate for president jumped into the fray with a highly publicized effort to delay implementation. (See *Environmental Update* in this issue.)

Contrary to the press reports, the new rules do not make sweeping changes to the NSR program, nor do they lead to a rollback of the program's fundamental tenets.

The new rules make critical improvements in the program that should help make the NSR permitting process a little less painful for companies. They will give companies more flexibility in making equipment changes and plant modifications in a timely fashion without undergoing a cumbersome permitting process.

However, companies must take proactive steps to incorporate the new measures into their existing air permits before they can benefit from the new rules.

Key Reforms

The new rules keep the general structure of the NSR program in place, but make key changes to the underlying rules. Under the program, most new major air emission sources and major modifications of existing major sources must undergo a permitting review before construction can begin. A plant modification will trigger NSR review only if there is a physical change or a change in the method of operation that would result in a "significant net emissions increase" in a pollutant regulated by the Clean Air Act.

The change that has generated the most controversy is a new formula to determine when a "significant net emissions increase" occurs.

The new rules adopt for all industrial facilities a rule of calculating significant net emissions increases that previously applied only to utilities — the so-called "WEPCO" rule, named for a 1990 case involving Wisconsin Electric Power Company. Instead of requiring companies to compare past actual emissions to future *potential* emissions associated with a modification, the rule allows a company to compare past actual emissions to future *projected actual* emissions. A company may choose to use the old actual-emissions-to-potential-emissions calculation, but many plants should find the new actual-emissions-to-projected-actual-emissions test much more representative of the emissions impact of the equipment modifications. This is because *potential* emissions are generally calculated based on the theory that the plant will operate every hour of every day and every day of the year. In reality, no plant operates continuously without some outages for periodic maintenance. Thus, calculating a plant's potential emissions based on the theory that it operates all the time will result in an inflation of a plant's expected emissions.

The new rules provide that in calculating the "projected actual emissions" increase, plants should exclude the emissions that the plant could already accommodate during a 24-month "baseline" period during the past 10 years and that are unrelated to the particular modification project. Sources using the projected actual emissions calculation must maintain records of the actual pollutant emissions for at least five — and in some instances ten — years following the modification. Sources must report these post-change emissions to the permitting authority within 60 days after the end of each year. If a company chooses to use the old actual-emissions-to-potential-emissions test, then these post-change monitoring and reporting requirements would not apply.

The second key change affects how "baseline actual emissions" are calculated.

Baseline emissions are the starting point for measuring how much a proposed plant's modification will increase emissions of a particular pollutant. Under the new rules, sources of pollution other than utilities will calculate pre-change emissions based on a baseline period of *any* consecutive 24-month period in the past 10 years, instead of the current practice of generally using the most recent two-year period of emissions. The current policy for electric utility steam generating units — a baseline of a consecutive 24-month period in the past five years — will become law. In general, sources are expected to use the highest two-year period of emissions as the period that is most representative of the plant's emissions. Emissions increases from equipment modifications will be measured against this baseline. In general, the higher the emissions baseline, the lower the projected emissions increase.

The third key change under the new rules is that sources that keep their emissions below a plantwide cap will be able to make operational changes and equipment modifications without undergoing a major source NSR permitting process.

A plantwide applicability limit, or "PAL," is a voluntary option that is intended to provide plants with greater flexibility to respond to market demands for increased output. EPA has been testing the PALs concept for several years, and a few major sources have been issued permits with plantwide emissions caps. Plants that take advantage of a PAL must monitor the emissions from all emissions units subject to the cap, maintain records of emissions monitoring, testing, and deviation reports, and report such monitoring results semi-annually to the permitting authority. Deviation reports must be submitted to the permitting agency promptly. PALs will be effective for an initial 10-year period and may be renewed.

Also under the new rules, plants that have recently installed state-of-the-art pollution control technology on new or modified emission units as part of an NSR or a federally-approved state permitting process — for example, by installing best available control technology or "BACT" — may make changes to the "clean unit" if two conditions are met. First, the project cannot require any change in the unit's emissions limits. Second, there cannot be any alteration of the physical or operational characteristics that formed the basis of the NSR control technology determination. Clean unit status will be valid for up to a 10-year period and may be lost if a modification requires changes in the emissions limits or alters the physical or operational properties of the unit that underwent an NSR or similar permitting review. An example is switching to a more polluting fuel.

Finally, EPA formally adopted its longstanding policy of excluding pollution control and prevention projects from NSR permitting review where such projects lead to a net benefit for the environment. The final rule contains a presumptive list of technologies that automatically qualify for the exclusion if there will be no adverse impact on air quality. This change provides some certainty to companies that are required to undertake emissions control projects to satisfy certain Clean Air Act requirements where there may be some collateral increases in other air pollutants. For example, installation of an incineration device to reduce air toxics may result in increased emissions associated with the incineration process. If the pollution control device is a presumptively-excluded pollution control project, then NSR permitting review would not be triggered.

The new rules are under attack by various interested parties. Nevertheless, they will become effective on March 3, 2003, and it seems unlikely that a US appeal court — where complaints about them will be heard — will find grounds to grant an injunction delaying their implementation. A court would require a showing of irreparable harm and a likelihood of success on the merits before it will grant an injunction, and based on the courts' traditional deference to agency rulemakings on complex issues within its areas of expertise, it is doubtful that the EPA rules will be struck down or that there will be any delay in implementation.

Routine Maintenance Proposal

At the same time that it issued the new NSR rule, EPA also proposed controversial changes in how the / continued page 40

New Source Review

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agency defines "routine maintenance, repair, and replacement."

Equipment modifications qualifying as "routine maintenance, repair, and replacement" are exempted from NSR permitting. The agency's interpretation of this key exemption is at the heart of the agency's on-going, high-profile enforcement initiative against older utility plants. The enforcement actions are based on the premise that these older power plants conducted major equipment modifications and upgrades over the years that did not qualify as exempted "routine maintenance, repair, and replacement" activities.

The new proposed rule sets out a range of options for identifying two types of qualifying categories of "routine maintenance, repair, and replacement." These categories are annual maintenance, repair and replacement allowances and equipment replacement.

Under the first category, the proposed rule will establish an industry-specific cost allowance, and certain types of activities that fall under the allowance cap will qualify for the exemption. The annual allowance may be based on a calendar- or fiscal-year basis, and it is intended to cover relatively small capital expenditures compared with the replacement cost of the facility. Certain activities would be excluded from the annual allowance, including the construction of a new process unit, the replacement of an entire process unit, and any change that would result in an increase in a source's maximum achievable hourly emissions rate.

Under the second category, most projects that replace existing equipment with functionally-equivalent new equipment will generally qualify for the exemption as long as a cost threshold was not exceeded. The cost threshold for the second category would generally be pegged to a percentage of the replacement cost of the particular process unit. EPA is seeking comments on whether one category is more appropriate than the other or whether both categories of "routine maintenance, repair, and replacement" should be adopted. Comments on the proposed rule are due by March 3.

Because it is only a proposed rule, the "routine maintenance, repair, and replacement" proposal will be subject to public notice and comment. EPA expects to finalize the rule before the end of the year. However, the proposal is highly controversial, and EPA's timetable may be pushed back. If the rule is finalized as proposed, it will be challenged by many of the same entities that are challenging the new NSR rule changes discussed earlier.

The proposed changes will only apply prospectively. Meanwhile, the US government is continuing to pursue lawsuits filed in 1999 and 2000 against US utilities alleging that several coal-fired power plants failed to undergo NSR permitting for major modifications that were not covered by the existing "routine maintenance, repair, and replacement" exemption. In addition, many EPA regional offices are continuing to issue notices of violation to certain older power plants for alleged NSR permitting violations. For example, last summer one EPA region issued notices of violation to three coal-fired plants in Colorado and North Dakota.

Several of the lawsuits are scheduled to go to trial later this year. Meanwhile, a US appeals court is expected to issue a decision shortly in *Tennessee Valley Authority v. EPA*, which is one of the first cases to be tried on the issue. If the government's interpretation of the "routine maintenance, repair, and replacement" exemption is upheld in the *Tennessee Valley Authority* decision, then the affected utilities may have little choice other than to settle the cases on as favorable terms as possible.

The decision in the case could also affect the proposed rulemaking on the "routine maintenance, repair, and replacement" exemption. If the government is successful in court, then it may come under pressure from environmental groups to avoid defining more clearly the scope of the "routine maintenance, repair and replacement" exemption.

Companies will have to make a conscious effort to incorporate the new measures into their existing air permits before they can benefit from the new rules.

Environmental Update

Clean Air Act Revisions

The Bush administration found a key ally in Congress for its "clear skies initiative." Senator James Inhofe (R.-Oklahoma), the new chairman of the Senate environment committee, said in early February that he will work to enact the clear skies plan. The plan is the top environmental priority for the Bush administration this year. The legislative language is expected to be introduced soon in Congress by Inhofe and others.

The clear skies initiative calls for substantial reductions in nitrogen oxides, or "NO_x," sulfur dioxide, or "SO_2," and mercury emissions from power plants in a two-phase process with specific reduction targets set for years 2010 and 2018. The proposal does not cover carbon dioxide, or "CO_2," emissions. The president's proposal would create a mandatory "cap and trade" emission allocation program similar to the federal acid rain program for the three pollutants. As a *quid pro quo* for having to meet new stringent emission reductions targets, the initiative would exempt power plants from having to comply with certain existing Clean Air Act programs that would be duplicative of the new legislation, such as the "new source review" permitting program and certain air toxics standards.

While the Republicans now control both houses of Congress, it is far from certain that Bush will be able to get the clear skies plan through Congress. He faces possible problems in the Senate. Republicans enjoy only a 51-49 vote majority. The Democrats have already gone on the offensive against the clear skies plan. The administration cannot afford to lose any Republican votes.

Global Warming

Three different high-profile bills were introduced in the US Senate in January to curb greenhouse gas emissions. The Bush administration remains opposed to mandatory greenhouse gas emission caps and favors only voluntary reductions.

It seems unlikely that the Republican leaders in Congress will let the greenhouse gas bills on the agenda. However, the issue may force itself onto center stage if several Democratic senators who are running for president make it an issue in the primary elections.

Two well-known senators — John McCain (R.-Arizona) and Joseph Lieberman (D.-Connecticut) — introduced a bill that would require reductions in greenhouse gases from four major sectors of the US economy — the electricity generation, transportation, industrial, and commercial sectors. These sectors cover approximately 85% of the greenhouse gas emissions in the United States. Their bill would create a greenhouse gas emission allowance system tied to mandatory reduction targets starting in 2010, with a second target commencing in 2016. By 2010, the greenhouse gases in the affected sectors would have to match the year 2000 levels of all greenhouse gas emissions in the US. The 2016 target would be set lower — at the 1990 US levels. The bill specifically excludes the agricultural and residential sectors.

The McCain-Lieberman bill would also establish a national greenhouse gas database that would have in it a registry to record greenhouse gas emissions by company and track greenhouse gas emission trades. An allowance-trading program would be created, and the US Commerce Department would be responsible for allocating allowances to existing sources and determining the amount of allowances that would be auctioned. Under the bill, up to 15% of a company's emission reduction requirements may be meet by obtaining allowances from another nation's greenhouse gas market, carbon sequestration credits (like reforestation to create "carbon sinks"), or US allowances from a non-covered company. Failure to meet a company's emission limits would potentially result in fines of up to three times the market value of the greenhouse gas tonnage shortfall.

Another Senate bill also calls for creation of a national greenhouse gas emissions inventory and registry. The bill — introduced James Jeffords (I.-Vermont) and Tom Daschle (D.-South Dakota) — would require greenhouse gas emitters to submit reports to the inventory, and they would have the option of also reporting emission reductions and emission trades with other companies. The bill would also require the federal government — not private sector companies — to reduce its greenhouse gas emissions to 1990 levels by 2013 and / *continued page 42*

develop a plan to reduce the federal government's net greenhouse gas emissions to zero by 2025.

Finally, Jon Corzine (D.-New Jersey) reintroduced his proposal from the last Congress to create a mandatory greenhouse gas emissions inventory and registry of emission reductions.

None of the bills can make it to the Senate floor without going through the Senate environment committee. James Inhofe (R.-Oklahoma), a Bush ally, controls that committee.

NSR Challenge

The new US Environmental Protection Agency rules for the "new source review" air permitting program sparked controversy both in Congress and in the courts, as Senate Democrats tried unsuccessfully to delay implementation and states and municipalities raced to file lawsuits to challenge them. (See related article.)

A proposal to delay implementation was defeated on January 22 in the Senate by a vote of 50 to 46. The proposal — offered by Senator John Edwards (D.-North Carolina) as an amendment to a omnibus appropriations bill — would have delayed the effective date of the new rules from March 3, 2003 to September 15, 2003 to allow time for the National Academy of Sciences to prepare a report analyzing their effect. Edwards is running for president. Five Republican senators from the New England states and Senator John McCain (R.-Arizona) voted for the amendment. Five southern Democrats voted against it.

The Senate adopted a compromise proposed by Senator James Inhofe (R.-Oklahoma). It calls for a National Academy of Sciences study of the rules, but does not delay the implementation schedule. Senator Edwards vowed to press on in his efforts to delay or kill the new NSR rules. He may try to amend other bills that are moving through the Senate.

In addition to the flurry of legislative activity, nine northeastern and mid-Atlantic states filed a lawsuit challenging the new NSR rules on the last day of December. Several environmental groups and other state and local entities are also expected to file their own lawsuits. Under the Clean Air Act, petitions to review a final agency rule must be filed with the US appeals court in Washington, DC within sixty days after publication of the final rule in the *Federal Register*. The new NSR rules were published in the *Federal Register* on December 31. Twelve Connecticut municipalities announced on January 16 that they would join the lawsuit filed by the northeastern and mid-Atlantic states. The South Coast Air Quality Management District in southern California also recently announced that it would file its own lawsuit. All the lawsuits will probably be consolidated by the courts. A decision on the merits is not expected until 2004.

Five large US utilities are facing shareholder resolutions seeking the disclosure of information on financial and environmental risks that may result from failure to reduce greenhouse gas emissions.

Air Toxics

EPA recently released proposals for three new air toxic rules that may affect electric generating facilities and other industrial pollution sources using industrial boilers or reciprocating internal combustion engines.

These proposed rules will set new maximum achievable control technology, or "MACT," standards for stationary combustion turbines, industrial boilers, and reciprocating internal combustion engines. The standards will apply only at major sources of hazardous air pollutants, or "HAPs." A source is a major HAP source if it has the potential to emit 10 tons or more of any one HAP or 25 tons or more of any combination of HAPs. The Clean Air Act has a list of 188 HAPs.

Under the Clean Air Act, the HAP emissions from all equipment at a plant are evaluated — not just the emissions from a particular piece of equipment — to determine whether the facility as a whole is a major source. For example, a plant may include utility boilers and stationary combustion turbines, and the HAP emissions from the boilers may make the entire plant a major source. In this scenario, even though the HAP emissions from the combustion turbines might be relatively minor, the plant would still potentially be subject to the stationary combustion turbine MACT standards.

EPA believes that its proposed MACT standards for stationary combustion turbines will affect about 160 existing sources and 155 new sources. The proposed standards are in the *Federal Register* for January 14. They focus on reductions of acetaldehyde, benzene, formaldehyde and toluene. Under the proposed rule, affected sources may install carbon monoxide catalytic oxidation systems or reduce formaldehyde emissions to 43 parts per billion. By reducing formaldehyde, EPA expects that other HAP emissions will be reduced to similar levels. Comments on the proposed rule are due by February 13.

EPA's proposed MACT standards for industrial boilers are expected to affect more than 58,000 industrial sources and potentially impose significant capital costs. The proposed rule calls for significant reductions in emissions of arsenic, cadmium, chromium, hydrogen chloride, lead, and other heavy metals. EPA believes that emission controls will be required at approximately 2,800 large industrial boilers generating more than 100 mmBTUs of energy and using solid fuels such as coal or wood. These sources will probably have to install scrubbers or fabric filters to remove heavy metals. The remaining affected sources will probably face new monitoring and reporting obligations under the rule. Comments on the proposed industrial boiler MACT standard are due by March 14.

The industrial boiler MACT standard has generated a fair amount of controversy, and the proposed rule will affect a substantially larger group of sources than the MACT standard for stationary combustion turbines. As a result, EPA is giving the regulated community 60 days to submit comments instead of the more customary 30 day comment period.

The proposed MACT standard for reciprocating internal combustion engines was published in the *Federal Register* on December 19. The standards will apply to combustion units above 500 horsepower that are located at major HAP sources. Approximately 37,000 reciprocating internal combustion engines are in use at power plants and other industrial facilities, and EPA believes that approximately 10,000 new and exiting engines will be affected by the proposed rule. The rule is intended to reduce emissions of acetaldehyde, acrolein, formaldehyde and methanol. Under the proposal, spark ignition four-stroke engines would be required to install non-selective catalytic reduction systems or reduce formaldehyde emissions to 350 parts per billion. New two-stroke and four-stroke engines would be required to install catalytic oxidation systems. EPA is accepting comments on the reciprocating internal combustion engines proposed rule until February 18.

Water Quality Trading

The US government wants states, multistate agencies and Indian tribes to consider implementing water quality trading programs.

The Environmental Protection Agency announced a new policy for voluntary programs to facilitate the trading of credits that would be generated by installing treatment technologies or implementing other mechanisms to "over control" so that discharges of nutrients, sediments, and other pollutant discharges into a water body are reduced below required levels. The pollutant trading concept is based on previously successful air emission trading programs such as the federal acid rain program. Connecticut also implemented a successful nitrogen trading program among publicly-owned treatment works discharging into Long Island Sound. The Long Island Sound program achieved required nitrogen reduction levels while saving more than $200 million in control costs.

Acceptable state and tribal programs will need to comply with the applicable Clean Water Act requirements, and the baseline for establishing tradeable water quality credits will be derived from the water quality standards that apply to the particular water body. The trading provisions may be implemented in individual wastewater discharge permits, watershed plans, or other water quality management programs. The trading of water quality credits is relatively untested, but it is based on the principle of providing incentives to entities that can achieve wastewater pollutant reductions most efficiently and cost-effectively.

Brief Updates

Canada and Poland became the latest countries to ratify the Kyoto protocol. Canada, which ratified on December 16, emits approximately 3.3%, and Poland, / continued page 44

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which ratified on December 13, emits approximately 3.0% of the carbon dioxide emissions released by industrial countries. The Kyoto protocol will enter into effect after it is ratified by 55 or more countries whose emissions represent at least 55% of the carbon dioxide emissions from so-called "Annex I" developed countries in 1990. Canada was the 100th country to ratify the Kyoto protocol, and the total emissions represented now stands at 43.7%. Russia — with 17.4% of the carbon dioxide emissions — is the key country that must still ratify in order for the Kyoto protocol to take effect. The Russian government has indicated that it expects to ratify the Kyoto protocol sometime in 2003. Once in effect, the Kyoto protocol will require the Annex I countries to achieve approximately a 5.2% reduction in greenhouse gas emissions during the first commitment period — 2008 to 2012 — compared to 1990 emission levels.

On January 16, 13 major corporations and Chicago announced the creation of the Chicago Climate Exchange market to which the members have each committed to reduce their greenhouse gas emissions by 4% by 2006 from baseline emission levels set during 1998 to 2001. The initial exchange members include DuPont, American Electric Power, Motorola, Ford Motor Company and the International Paper Company. Members may buy and sell verifiable reductions in greenhouse gases, and the exchange is expected to impose sanctions against members that do not meet the 4% reduction commitment.

Five large US utilities are facing shareholder resolutions seeking the disclosure of information on financial and environmental risks that may result from the failure to take action to reduce greenhouse gas emissions. The Connecticut state pension fund and two corporate responsibility organizations have filed the shareholder resolutions with American Electric Power, Cinergy, Southern Company, Xcel and TXU Energy.

Senator Tom Daschle (D.-South Dakota) and several other Senate Democrats have introduced a bill that would require certain industrial plants to implement enhanced security measures, including the preparation of vulnerability assessments and response plans. The provision is similar to the chemical security measure that was introduced by Senator Jon Corzine (D.-New Jersey) and defeated in the last Congress. Senator Corzine's bill would potentially affect about 15,000 facilities.

EPA announced on December 20 that it will withdraw the Clinton-era water quality rule that revised the total maximum daily loads, or "TMDL," program. The program limits the amount of pollutants that can be discharged into rivers, lakes, streams, and other water bodies. The Clinton TMDL rule was strongly criticized by agricultural interests, states and environmental groups, and Congress voted to bar implementation. In response, EPA undertook an 18-month review of the rule and must withdraw the rule by April 2003 or else the rule will take effect. EPA is currently working on an alternative "watershed rule" that would address the amount of total pollutant discharges into US water bodies. ◎

— contributed by Roy Belden, in New York.

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