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Financing Pollution Control

by Keith Martin, in Washington

Any power company planning to install new pollution control equipment should consider whether it is possible to get the US government to pay part of the cost.

US power companies are expected to have to spend between $40 and $60 billion on additional pollution control between now and 2015 to comply with rules announced this past year by the US Environmental Protection Agency to reduce three pollutants. The new rules require reductions in sulfur dioxide, nitrogen oxide and mercury emissions from power plants by as much as 70% between now and 2018.

If, as expected, the United States also eventually takes steps to reduce greenhouse gas emissions from power plants, then the cost will be much more.

The US government pays part of the capital cost of new pollution control through tax subsidies. The tax benefits can cover as much as half the capital cost.

One problem with tax subsidies is that they are sometimes a challenge to use. US utilities and other companies in capital-intensive industries often lack the tax base to use them effectively because of the tax depreciation and other benefits to which they are already entitled from past investments.

This article explains the various tax subsidies that a power company might tap to bring down the cost of pollution control. Broadly speaking, there are four. It also discusses how to share in the value indirectly if the company is not in a position to use them effectively because of an inadequate tax base. */ continued page 2*

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CANADA has stopped issuing tax rulings for Canadian income trusts and other flow-through entities.

Some project developers in the United States have looked at the trusts as a way to raise cheaper money for their projects or as a potential buyer for existing assets that they want to sell. A Canadian income trust can afford to pay at least 27% more for US assets than can a taxable US bidder. The trusts look for businesses with predictable cash flows. Some have bought US independent power plants, particularly ones with long-term contracts to sell their electricity to creditworthy utilities. */ continued page 3*

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Rapid Depreciation

The first step is to figure out how rapidly the new pollution control equipment can be depreciated for tax purposes. The faster the cost can be written off, the greater the tax savings from the depreciation deductions on a time-value basis.

Most pollution control equipment is depreciated like the power plant to which it is attached.

Thus, equipment at power plants that burn biomass can be depreciated over five years using the 200% declining-balance method. That means that a larger share of the cost is deducted in the first two years than in each of the remaining years. Five-year depreciation is worth 29.8¢ per dollar of capital cost. That is the present value of the tax savings from the depreciation deductions for a company that is subject to a 35% tax rate; the calculation uses a 10% discount rate. "Biomass" for this purpose means all organic material — for example, wood, manure, rice hulls — but it does not include coal, oil or gas or products of such fuels. The power plant must be a "qualifying small power production facility" for regulatory purposes. That means that it must be no more than 80 megawatts in size. It would be a good idea for the plant owner to certify the plant as a "small power QF" with the Federal Energy Regulatory Commission. The plant must burn biomass directly rather than gasify it or convert it to some other form of "synthetic fuel" before use as fuel.

US power companies will have to spend between $40 and $60 billion on pollution control in the next 10 years.

Other power plants are depreciated over seven, 15 or 20 years depending on the fuel and whether the electricity is primarily for sale to third parties or is used by the power plant owner to power his or her own factory. Depreciation over seven years is worth 27.8¢ per dollar of capital cost. Seven-year depreciation is available for pollution control equipment at power plants that burn refuse or other solid waste. Depreciation over 15 years is worth 19.9¢ per dollar of capital cost. It applies to simple-cycle gas-fired power plants and to plants at factories that generate electricity for use by the factory. Depreciation over 20 years is worth 17¢ per dollar of capital cost. Combined-cycle power plants and plants that burn coal are depreciated over 20 years.

The next step is to figure out whether it is possible to write off the cost faster than the rate at which the power plant is depreciated.

This might be true in two situations.

One is where the pollution control equipment can be amortized separately on a straight-line basis over either 60 or 84 months under special rules in section 169 of the US tax code. "Straight-line" amortization means the cost is deducted in equal amounts each month during the period. Amortization over 60 months is worth 27.3¢ or 24.6¢ per dollar of capital cost, depending on whether the equipment is added to a simple-cycle gas-fired power plant or to a coal plant or combined-cycle gas plant. The amortization is worth the most at a simple-cycle gas plant. The amortization is worth 23.2¢ per dollar of capital cost if taken over 84 months.

Pollution control equipment can be amortized over 60 months only if installed at a power plant that was in operation before 1976. Both air and water pollution control equipment qualifies.

Amortization over 84 months is available at newer power plants, but only for coal-fired power plants and then only for equipment that controls air pollution. The plant must be "primarily" fueled by coal, and the pollution control equipment must be new equipment that was acquired after April 11, 2005.

Equipment does not have necessarily to trap pollution at the back end of the power plant. Equipment at the front end that prevents pollution also qualifies, but if the equipment has multiple functions, then the cost must be allocated between pollution control and other functions, and only the cost allocated to pollution control can be written off over 60 or 84 months.

There are three other hoops through which a power company must jump before it can claim rapid amortization.

First, both the state and federal environmental agencies must certify that the equipment complies with their environmental standards. (A taxpayer argued in court in 1978 that it was entitled to rapid amortization even though it failed to get its pollution control properly certified. The US Tax Court said no.) Second, the equipment cannot significantly "increase the output or capacity, extend the useful life, or reduce the total operating costs of the plant" or "any unit thereof" or alter the nature of the production process. Finally, the Environmental Protection Agency — one of the two environmental agencies that must certify the project — cannot certify it "to the extent" that the plant owner will recover the cost of the pollution control through recovery of wastes — for example, by using ash for paving roads.

Only part of the cost qualifies for rapid amortization — 80% at most — and it is only 60% for pollution control at a combined-cycle gas plant or coal-fired power plant. The remaining cost is depreciated normally. Thus, for example, 60% of the cost of pollution control at a new coal-fired power plant might be amortized over 84 months, while the remaining 40% of the cost is depreciated over 20 years.

The other situation where it may be possible to write off the cost faster than the rate at which the power plant is depreciated is where the equipment can be depreciated separately. That may be true where the equipment recovers usable material — in addition to trapping pollutants — or where it is owned by a separate company that either leases the equipment to the power plant owner or uses it to provide services in a pollution control business for hire.

Ordinarily, the way US tax depreciation allowances work, a company must decide what business it is in, and then most of its assets are depreciated over the same period. The Internal Revenue Service publishes tables that show the depreciation periods for different industries.

However, certain equipment can be depreciated separately. This is true of equipment that qualifies as a "waste reduction and resource recovery plant." The limits of what qualifies are unclear. Pollution control is most likely to fit under this heading if it is at a coal- / continued page 4

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The Canadian government is concerned about the loss of corporate tax revenue as more and more Canadian businesses convert to trust form. The trusts are not taxed. Investors in them are in theory, but a significant percentage of the money raised by such trusts comes from retirement savings accounts. The government estimated in a consultative paper released on September 8 that the conversions cost the government C$300 million in corporate tax revenue in 2004. The market capitalization of Canadian companies organized as pass-through entities was only C$18 billion in December 2000, but it had jumped to C$119 billion by the end of 2004. Income trusts accounted for 70% of the C$2.6 billion raised in the Canadian capital market in the first half of this year. Another C$3 billion in trust offerings are currently in the pipeline.

The government had hoped that release of the consultative paper on September 8 — with a list of possible tax changes to discourage businesses from converting to trusts — would be enough to slow the market. When it did not, the finance minister, Ralph Goodale, announced on September 19 that the government would stop issuing tax rulings on pass-through structures until it decides what to do about the situation. The process is expected to take at least a year.

Prices for trust units on the Toronto Stock Exchange dropped roughly 5% after the announcement, but they had rebounded by early October. The announcement has put a chill on conversions of Canadian companies to trust form, but "doesn't seem to have materially affected the ability of existing trusts to raise capital," according to one manager whose income fund has been active in the US energy market. One fund raised money in late September to acquire a natural gas storage facility in the United Kingdom. Most trust investments to date have been in North America, but as private / continued page 5

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fired power plant and is used for "material recovery," meaning that it not only traps pollutants, but also recovers usable material from them. However, there is also room for argument that mere waste reduction is enough. The IRS description of what qualifies mentions equipment used for "ash handling." Regardless, the equipment must trap "solid waste." Therefore, equipment to deal with waste gases does not qualify. Qualifying equipment can be depreciated over seven years using the 200% declining-balance method. The tax savings from this depreciation are worth 27.8¢ per dollar of capital cost.

Another way to get faster depreciation for pollution control equipment than the depreciable life of the power plant is to have a third party own the equipment and use it in a pollution control business. It would either lease the equipment to the power company or use it under contract to provide pollution control services. The equipment should be depreciable in such cases over seven years. However, the challenge is to find a way to structure the arrangement so that the lease or service contract is respected for tax purposes. The IRS might recharacterize the arrangement as something else. This challenge in discussed in more detail below.

Other Possibilities

Some power companies may be able to get money back from the US government that they paid in taxes as far back as 1998 to cover part of the cost of new pollution control. A massive energy bill that President Bush signed on August 8 lets any power company that had tax losses in 2003, 2004 or 2005 use the losses in one of the years to get a refund of federal income taxes that the company paid within the five years before the loss year.

An election to do this must be made between 2006 and 2008.

The company must spend the money on pollution control (or electric transmission assets). It can only elect to carry back losses equal to 20% of the amount it spent on such property *the year before* the election is made. The refund must be spent on property that the taxpayer will own.

The US government pays as much as half the cost of new pollution control equipment through tax subsidies.

Some pollution control equipment can be financed at reduced interest rates with tax-exempt debt. State and local governments can finance roads, schools, hospitals and other public facilities — including municipal power plants — using tax-exempt bonds. Private projects are ordinarily not supposed to be financed in this manner. However, Congress made exceptions for 15 types of projects that it considers quasi-public in the sense that they provide some public benefit. One of the 15 is "solid waste disposal facilities." Power plants that burn solid waste fit in this category; tax-exempt financing can be used to pay for the cost of equipment through the stage at which the plant produces its first marketable product. Pollution control equipment to trap ash and other solids at the back end of a coal-fired power plant also qualifies. It is not uncommon to see 10% to 25% of the cost of such a power plant paid with such financing.

There is a tradeoff. Equipment financed with tax-exempt debt must be depreciated more slowly — on a straight-line basis over a longer "class life." It is a math exercise to determine whether the savings on interest costs are worth the loss of tax savings from having to use slower depreciation. A rough rule of thumb is that the tax-exempt interest rate must be at least 100 basis points less than the taxable rate to make the tradeoff worthwhile. However, there is *no* tradeoff to the extent pollution control equipment qualifies for rapid amortization over 60 or 84 months.

Each state has a limited capacity to issue tax-exempt debt to finance private projects. The developer must secure an allocation of scarce "volume cap." States are limited to $75 times population or $225 million a year.

It may also be possible to claim a federal tax credit — in addition to rapid depreciation or amortization — by tackling pollution control at the front end before the fuel is burned. This applies only to coal-fired power plants. Either an existing coal plant would have to be retrofitted or a new plant built. They would have to use an "advanced" technology for burning coal. The tax credit is 15% of the capital cost of the new equipment installed. To be considered an "advanced" technology, the project must have a design net heat rate of 8,350 Btus/kWh or better with 40% efficiency of energy conversion. (A majority of the energy in fuel is lost as the fuel is converted into electricity.) The plant must also be designed to meet certain pollution standards, including at least 99% removal of sulfur dioxide and 90% removal of mercury. The US tax code describes a series of assumptions that should be made in calculating the heat rate.

The IRS must certify that a project qualifies. The fuel must be at least 75% coal. The plant must have a nameplate capacity of at least 400 megawatts. No more than $500 million in total tax credits can be taken nationwide for advanced coal projects; the IRS will have to allocate the credits among competing applicants.

The "basis" used to calculate depreciation on the power plant must be reduced by 15%. In other words, in cases where a tax credit is claimed, only 85% of project cost can be depreciated.

Structured Finance

Not all power companies are in a position to use tax subsidies. Any company in this position should consider whether it would do better to have a third party that can use the tax breaks own the pollution control equipment and share the benefit in the rent it charges for use of the equipment or the fees it charges for contract services to control pollution at the plant.

Even if the power company can use the tax breaks, a third party owning the equipment can probably get a faster tax writeoff for it — depreciation over seven years using the 150% declining-balance method — while the power company would be stuck in many cases */ continued page 6*

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equity capital drives up the cost of energy assets in the United States and Canada, the trusts have been looking farther afield.

In another development, Canadian utilities are exploring whether they can use the North American Free Trade Agreement to force their way into "renewable portfolio standard" programs in states along the US-Canadian border. The utilities want to supply electricity from large hydroelectric projects. Some border states exclude such projects from the definition of what qualifies as a "renewable." RPS programs are state-level programs in the United States that require utilities to supply a certain percentage of their electricity from renewable energy. The utilities can either generate the electricity themselves or buy it from other suppliers.

The North American Free Trade Agreement bars discrimination, on grounds of national origin, against Canadian and Mexican companies trying to compete in the US market. The Canadian utilities charge that the RPS definitions favor small local suppliers.

A NOVEL THEORY for reducing pollution cleanup costs failed in a US court.

Reynolds Metals Co. had to spend $110 million to help clean up a US "Superfund" site. The company had spent money on waste disposal continuously from 1940 to 1987 — the period the government charged that its manufacturing activities contributed to contamination at the site. However, standards changed, and what the company had done in the past was no longer good enough.

The company had treated its earlier spending as a cost of the goods it manufactured each year and offset the spending against its sales revenue for the year, thereby reducing the amount of income it had to report from sales.

However, rather than deduct the $110 million in additional cleanup spending today against *current* sales revenue, */ continued page 7*

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using 15-year or 20-year depreciation. The difference is worth another 8¢ to 11¢ per dollar of capital cost in additional tax subsidy.

Both approaches present special challenges.

The "lease" of the pollution control equipment might not be viewed as a real lease by the IRS. That would prevent the third party from claiming the tax depreciation. This is a problem in any case where the IRS considers the equipment "limited use property," meaning that it is like a chimney on a factory. It is hard to see the third party having any ability in practice to remove the equipment at the end of the lease. Concerns about limited use property are more likely to be an impediment to leases of pollution control equipment at coal-fired power plants than at gas-fired plants, since the scrubbers, baghouses, electrostatic precipitators and other equipment used to control coal emissions are more likely to be custom designed and constructed.

The reason the IRS has a problem with leases of limited use property is it believes the lessor is a hostage of the lessee. The lessor has no other use for the equipment than to leave it in place at the lessee's plant, with the result that the equipment will be used in practice for its entire economic life by the lessee. Pollution control leases compound this likelihood. The power company cannot operate its plant without the equipment, which tends to compel it to buy the equipment at the end of the lease if given an option to do so. The IRS has trouble with leases where the lessee is certain to end up with the equipment at the end of the lease term.

Another hurdle to overcome is that the lessor must expect a meaningful "residual" interest in the equipment after the lease ends. It may be hard to show such a residual if there is no market — including no rental market — for used equipment.

An alternative is to have the third party own the equipment but use it to provide services to the power company. The special challenge in that case is to show how the "service contract" differs from a situation where the power company is using the equipment itself to provide the services (in which case the power company would probably be viewed as the owner). Section 7701(e) of the US tax code has a list of six factors that the IRS uses to evaluate purported service contracts. The challenge is difficult, but probably not insurmountable.

The third party would need to finance the equipment. A lender will think hard about how it can realize on the collateral if the third party defaults. There is not much of a market in used pollution control equipment, and the lender may not want to put the power plant out of compliance with its air or water permits. Also, loan documents usually require that any "improvements" to the power plant must become part of the collateral package for the debt secured by the power plant. A bank lending to a third party that will own just the pollution control equipment would be wise to get the power plant lenders to acknowledge that the pollution control is not part of the collateral for their loan.

Another structure that has potential, but that is complicated to implement, is to have the power company admit the third party as a partner in an entity that owns the power plant. The third party contributes the capital cost for the new pollution control equipment. It is allocated the tax depreciation from it and an amount in taxable income and cash that corresponds to what it would have received from a long-term lease of the equipment to the power company. However, partnerships are not the same thing as direct ownership of the pollution control equipment by the third party. The third party would also have an interest, as a partner, in the power plant. ◎

Biodiesel Roundtable

Chadbourne hosted a discussion in New York on September 28 on the growing interest in biodiesel projects in the United States. "Biodiesel" is fuel made from plant oils, like oil from soybeans, sunflowers or rapeseed. The following are excerpts from the discussion. The speakers are Richard Fumoso, business manager for biodiesel at Lurgi PSI, Dave Fennema, vice president of biofuels at Marathon Capital, LLC, Gene Gebolys, president of World Energy Alternatives, LLC, Jerome Peters, managing director of Hudson United Capital, and Jonathan Phillips, a lawyer in the Chadbourne office in Houston. The moderator is Todd Alexander, who is also with Chadbourne in Houston.

MR. ALEXANDER: Richard Fumoso, what is biodiesel?

MR. FUMOSO: Biodiesel is a methyl ester, and it is produced primarily from vegetable oils. In Europe, rapeseed oil is the primary feedstock. In Malaysia, it is palm oil or palm kernel oil. In the United States, soybean oil is the predominant vegetable oil used.

MR. ALEXANDER: How is it made? How do you convert the feedstock into motor fuel?

MR. FUMOSO: It's a very simple, benign chemical reaction. I say "benign" because it is low-pressure and low-temperature simple gravity separation.

MR. ALEXANDER: The technology to do this has been available for many years. There is more than one kind of technology. What are the differences?

MR. FUMOSO: There are two basic technologies — the Lurgi process and a centrifuge process. Centrifuges are expensive mechanical equipment that Lurgi stays away from. Lurgi has been building biodiesel plants for decades because they were part of the oleo-chemical technology sector.

Market Size

MR. ALEXANDER: Gene Gebolys, how large is the biodiesel market today?

MR. GEBOLYS: The US market for biodiesel in 2004 was just over 19 million gallons. We know that with a fairly high degree of certainty because virtually every gallon produced in the United States is subsidized. The total subsidy paid can be confirmed in the US Department of Agriculture records. The market has grown. US output was about 37 million gallons through the first three quarters of 2005. Note that this is the figure for the government's fiscal year 2005 that started on October 1, 2004, so the figure is production through June.

MR. ALEXANDER: Just to give our audience a frame of reference, let me put these numbers into context. Biodiesel output in 2004 was almost 20 million gallons. Roughly 36 *billion* gallons of over-the-road diesel fuel is used each year in the United States, and 55 *billion* gallons of distillates are used each year. So biodiesel in the sub-100 million range is undetectable. What people are interested in is the rate of growth in the market. My guess is growth will be something on the order of 100% again next year. If the market went from 19 to close to 53 million gallons this year, I would expect it to go from 53 to something to close to 100 million gallons next year.

Gene Gebolys, who is buying biodiesel today?

MR. GEBOLYS: The vast majority of / continued page 8

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Reynolds argued that it should be able to treat the amount as additional costs of the goods sold earlier — in effect, deduct the $110 million against the higher tax rates that the company faced during the period 1940 to 1987. Section 1341 of the US tax code allows this approach in some situations by allowing a company to credit the amount it overpaid in taxes in earlier years against the taxes it owes today.

A US district court rejected the argument. The court said this was not a case of the company overstating its earlier earnings. Rather, the company faced new environmental clean-up costs after Congress adopted more stringent standards. The case is *Reynolds Metals Company v. United States*. The court released its decision in late August.

HOLLAND unveiled a new budget in September that cuts the corporate tax rate to 29.6% from the current 30.5%. The budget also gets rid of a 0.55% capital tax that is collected currently on capital contributions to Dutch companies and that has been an impediment to using Dutch holding companies. The capital tax will disappear next January 1.

INDIA ordered an Indian company to withhold income taxes from payments to a foreign consultant.

The consultant was in the United States and was hired to help the company secure orders for its products in the United States and also help it with strategic planning generally. The consultant was paid a monthly fee plus commissions on the sales he secured for the Indian company in the United States. The parties argued that no withholding taxes should be collected because the payments were for services performed outside India. Taxes are normally assessed only on income from Indian sources. However, in a September ruling, the Authority for Advance Rulings — or "AAR" — disagreed.

The case has implica- / continued page 9

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biodiesel use in the United States to date has been in what is known as the EPAct fleets. These are the original 1992 Energy Policy Act regulated fleets. There are government fleets and utility company fleets that use biodiesel as a mechanism for complying with the Energy Policy Act. That is a pretty boring little market, and it is not growing very much.

All the new growth is in lower blends. EPAct fleets use a 20% blend. The fuel put into their cars is 20% biodiesel and 80% regular diesel fuel.

The real growth is in lower-blend applications — 2% to 3% blends. For example, Minnesota requires a 2% blend for all diesel fuel. Illinois encourages production of an 11% blend. At that level, biodiesel becomes less expensive than diesel fuel. Texas has an incentive to make a 20% blend, which makes biodiesel significantly cheaper than diesel fuel. At those levels you no longer need a government incentive to get consumers to buy the fuel. The market is becoming more mainstream. We are starting to sell a lot into heating oil applications in the northeast for this winter. Power generation is also a huge opportunity. The thing that makes this fuel attractive is that it is extremely versatile, and it can go into a lot of different applications pretty seamlessly.

Attracting Financing

MR. ALEXANDER: Dave Fennema, on what should developers focus who want to raise private equity for their projects?

MR. FENNEMA: There are parallels between the ethanol industry and the biodiesel industry. Everyone assumes that biodiesel is kind of the kid brother following down the same path. I think the industry will learn a lot and quickly get up to speed. That said, I don't see the private equity or the large institutional players getting involved immediately in biodiesel with a full head of steam. If they get involved today, it will be on a one-off basis, and on more of a corporate basis for plants and groups of plants that have a creditworthy developer behind them. The overall capital costs for biodiesel are lower than ethanol. One of the reasons that ethanol is really showing up on the radar screen for the big private equity firms and for the bankers is that the dollars are getting big enough. The dollars are not as big yet for biodiesel.

> The market for biodiesel fuels in the United States is expected to more than double this year, and to double again next year.

MR. ALEXANDER: How much does a typical plant cost?

MR. FENNEMA: In the ethanol market, a fifty million gallon plant is a fairly standard plant. Hard and soft costs might be in the $80 to $85 million range. Biodiesel will be in the range of $10 to $40 or $50 million.

MR. ALEXANDER: How many million gallon plants are there?

MR. PHILLIPS: The average plant being proposed is 20 to 30 million gallons.

MR. ALEXANDER: What building blocks must a developer put in place to bring equity and debt into his deal?

MR. FENNEMA: An investor will want to get comfortable that there will be a market for the ethanol. Ethanol today is becoming a fairly mature market. On the biodiesel side, every time you do a 20 or 30 million gallon plant, you are just about doubling the capacity for the entire industry. Investors must be careful. They will want to confirm that there will be a market for the output, whether it is in the United States or in an export market like Europe. I am guessing that most people in the audience are here today because they believe the US market has incredible potential. But that does not mean an investor can just assume the output from a plant built today can be sold.

MR. ALEXANDER: Gene Gebolys, what do you think as a marketer?

MR. GEBOLYS: Must an investor know exactly where the biodiesel will be sold before putting dollars into a project? I agree completely that if you are going to build a 30 million gallon plant in an industry that produced 20 million gallons last year, you had better know where the additional output will go.

The key is to manage risk and diversify your markets. We see lots of people that come through with the great wisdom and idea of taking cheap palm oil from southeast Asia, producing biodiesel in Texas, and then exporting the biodiesel to Europe so that the same gallon gets subsidized through the US machine and then gets subsidized again through the European machine. That's great, but you had better make an awful lot of money in a short period of time because that play is ripe for being shut down.

MR. ALEXANDER: Because the government sees it as manipulative?

MR. GEBOLYS: No. There is a significant regulatory risk. Where World Energy sees the critical path to success is through diversifying your markets. Yes, the European play is great for now, and the Illinois play is great when it is available, and the Minnesota play is great when it is there, and the Texas play is great when it is there. The Canadians are working on incentives that will be really attractive, particularly for plants built in Ontario. Those are all excellent plays, but in any market that has been created by government, you had better diversify quickly so as to reduce your exposure to any one government decision maker.

MR. ALEXANDER: Richard Fumoso, how do Lurgi and other construction contractors minimize the construction and technology risks? Also, talk about the differences in the feedstock so that our audience understands what factors go into the decision which feedstock to use.

MR. FUMOSO: First, there is no technology risk. We have been doing this for decades, so I believe that it is a non-issue. The construction risk is handled by our company. We are a direct-hire construction company. We look at the site specifics, the labor pool, the productivity of that labor pool, and before we put out a fixed-price bid, we fully understand how best to mitigate the risks.

MR. ALEXANDER: Does Lurgi offer a turnkey contract with a guaranteed schedule and guaranteed performance?

MR. FUMOSO: We provide a guarantee / continued page 10

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tions for infrastructure projects in India. Many project developers divide the construction work for their projects into two separate contracts. One contract covers the engineering work and procurement that will be done outside India. The other contract covers the work that will be done at the construction site in India.

The case addressed in the AAR ruling is called *Wallace Pharmaceuticals Pvt. Ltd*. Indian lawyers advise that the rulings tribunal failed to consider whether India is barred from collecting taxes by the US-India tax treaty. A tax treaty may prevent a tax, depending on the facts.

Meanwhile, the Indian government is again pressing Mauritius to renegotiate the tax treaty between the two countries. Nearly 40% of foreign direct investment into India is run through Mauritius. The investors set up holding companies in Mauritius. As long as the holding companies qualify as "tax residents" in Mauritius, then they benefit from a tax treaty provision that bars India from taxing them on their capital gains.

India wants the treaty rewritten to include a limitation-of-benefits clause that would prevent Mauritius companies that are merely shell entities from claiming treaty benefits. It put similar language in a new tax treaty with Singapore. The language in the Singapore treaty denies treaty benefits to anyone who structures a transaction with a "primary purpose to take advantage" of the treaty and to any "shell companies" with "negligible or nil business operations" and "no real and continuous business activities" in Singapore. Mauritius has not yet responded to the latest demands.

In a related development, the Indian government is studying whether to treat income from the sale of shares in Indian companies as "business profits" rather than "capital gain," at least for large institutional investors who buy and sell Indian shares. The AAR ruled that a US-based / continued page 11

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based on our technology, a performance guarantee based on feedstock and utility costs, a date-certain completion and a parent guarantee. We are one of the few companies in the industry that has the financial ability to provide a parent guarantee.

MR. ALEXANDER: Jerry Peters, assuming the developer has raised the required equity, at what point should he or she approach you about the debt?

MR. PETERS: When a project comes to us with the equity already embedded, it may be tough to kind of stuff the debt in and make it fit with what the equity expects as a return. It is often too late. In every transaction that I have been involved in as a construction lender and term lender, we have negotiated the deal from the very beginning with the construction contractor, with the equity, the feedstock provider and the ultimate marketer so that all the pieces fit together properly at the end of the day. It takes a long time to do that. I have had several transactions that were a year to a year and a half in the gestation period. It takes a long time, but at the end of the day, you have an integrated transaction that makes sense from a lender's standpoint.

MR. ALEXANDER: Dave Fennema, what should the equity do to leave room for debt in the deal?

MR. FENNEMA: The equity should have some flexibility, as Jerry Peters said. It is a chicken-and-egg issue. The debt and equity go together. As the debt structure alters a little, it affects the equity. The equity should make sure that it has taken care of the feedstock appropriately, it knows as much as possible about where the output will be sold, it understands the working capital requirements for that the project — in other words, the equity should have addressed as much as it can everything that might affect revenue from the project before approaching the lenders.

MR. ALEXANDER: How much competition is there for equity? Is there a lot of equity ready to invest in biodiesel or is there a fairly small group of potential investors?

MR. PHILLIPS: The energy bill that President Bush just signed and the booming ethanol market have certainly peaked the interest of potential equity investors, but this is still an immature market.

The typical new biodiesel plant costs $80 to $85 million.

MR. ALEXANDER: Jerry Peters, I have heard people say that you are one of the few lenders with a keen interest in financing biodiesel plants. Is there a lot of competition to lend to these projects, and how do you see the terms for debt evolving over time as this market matures?

MR. PETERS: That is the key. There have not been many potential lenders. Biodiesel projects have a lot in common with ethanol projects. The agricultural banks understand the commodity nature of the business. They know from ethanol that this is a petroleum market price commodity, and they get comfortable with that. It should be fairly easy for them to get comfortable with biodiesel. The problem is that there are still plenty of ethanol deals to do, and why learn something new when you are already busy with ethanol? Going forward, many of the agricultural banks that have done ethanol will eventually do biodiesel, but I don't think you will to see a CSFB doing a B loan deal on biodiesel any time soon.

MR. ALEXANDER: Gene Gebolys, you are out in the market, with plants, working with people. How deep a market is there currently for debt?

MR. GEBOLYS: It is a pretty small market. A couple of plants have had debt components in them, but not so much to fund construction as to provide working capital. In biodiesel, the working-capital-to-original-construction-capital ratio is much higher than for ethanol.

MR. PETERS: It is one to one or better.

Commodity Risks

MR. ALEXANDER: Explain this further — how the price of feedstock is not necessarily correlated to the price of biodiesel?

MR. GEBOLYS: This gets to the heart of any financing. It is the intersection of risk. You are taking an agricultural commodity and selling it in an energy market. Those commodities don't necessarily trade in any relationship to each other, and so managing that intersection properly is the key to success in both financing deals and maintaining commercial success in the business. Biodiesel is different from ethanol. Biodiesel can be made from an array of feedstocks, and many plants are being designed specifically with feedstock flexibility built into them. A plant can use cottonseed oil, palm oil, rapeseed oil, soybean oil, animal fat, poultry fat and other products.

MR. ALEXANDER: What is the relationship between the amount of working capital needed and the feedstocks the plant plans to use?

MR. GEBOLYS: The capital costs are relatively low to get into the biodiesel game, but the operating costs are reasonably high. Focusing on feedstock, if you take 25¢ a pound soybean oil on any given day, that translates into almost $2 a gallon. You are almost $2 a gallon into the product before you have even converted the feedstock into biodiesel. Also, the downstream subsidies don't come back to the ultimate seller for almost 100 days after the biodiesel is sold. B99 is emerging in the marketplace. B99 has a very small blend percentage of petroleum fuel; actually it is B99.9. It has a very small amount of diesel fuel in it so that it can be sent out with a blender's credit. It comes to the marketplace with the blender's credit already embedded in the price. This means that you are waiting for a very good receivable from the federal government; you are waiting for it for 100 days. Make 30 million gallons on an annual basis, and you end up having higher and higher operating costs. A lot of the deal flow you see today is very small guys who are strapped for cash.

MR. PETERS: I think the length of the supply and delivery chain is also a factor. Take a highly flexible plant that is going to source low-cost palm stearin from Malaysia. The feedstock will come on a slow boat. Then the biodiesel made has to be put back on another boat for shipment to Europe because that is where biodiesel fetches the highest price today. You may have up to a third or a / continued page 12

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fund — Fidelity Advisor Series VII — earned "business profits" from its trading in Indian shares. The ruling means that Fidelity does not have to pay Indian income taxes on its gains as long as it is careful not to operate through an office or other "permanent establishment" in India. The government is examining how broadly this principle should apply.

If the review leads to widespread adoption of the principle, then foreign institutional investors would no longer have to invest through Mauritius or Singapore in order to avoid taxes when they sell their shares.

FRANCE is considering an "exceptional tax" on oil company profits if oil companies refuse to reduce prices, the French finance minister said in September.

A FOREIGN DEBT-SWAP PLAN was a headache for a US company, but the company eventually won in court.

Mexico tried, starting in 1985, to reduce its heavy debt burden through an ingenious plan where it encouraged foreign companies with subsidiaries in Mexico to buy government bonds being held at the time by foreign lenders. The bonds were trading at a steep discount because of market fears about Mexico's ability to repay its debt. Mexico lacked the foreign exchange reserves to keep paying its debts. Under the program, a foreign company would buy the bonds at a discount in the market and then trade them to the Mexican government for a larger sum in Mexican pesos than the company paid to acquire the debt. The company had to spend the pesos in Mexico with local vendors.

Kohler, a US manufacturer of plumbing fixtures, bought $22.4 million in Mexican government debt from Bankers Trust in 1987 for $11.1 million, or a 50% discount off the face amount of the debt. It then traded the bonds to the Mexican government for what was nominally the equivalent / continued page 13

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quarter of your total annual production in transit at any one time.

MR. FENNEMA: Let me add to what has been said about flexibility to use different feedstocks. I think it is a misnomer to talk about flexible feedstock when the point is the plant might be using soybean oil on Monday and rapeseed oil on Tuesday and so forth. It is not a faucet. Here is what flexibility to use different feedstocks gives you. Right now, we have a glut of crushing capacity for soybean oil and an abundance of soybean oil in the market. The great thing about biodiesel is that might not always be the case. Any plant built today may use soybean oil, but at some point when the numbers change, the plant has the ability to change feedstocks. A key factor in plant economics is overall crush spread.

Transportation can be a significant operating cost. The plant oil used as feedstock may be shipped from Asia, and the biodiesel may be reshipped to Europe for sale.

MR. VICTOR: My name is Adam Victor from Trans Gas Energy. I have two questions directed mainly to Richard Fumoso. I have no interest in subsidies. I want to know what the real cost is per million Btus for biodiesel assuming today the soybean price is about $450 a metric ton. I assume that feedstock is about 80% of the cost, and I assume that the capital cost is about $1 per gallon per year. Based on that, what do you believe is the real all-in cost assuming you can lock in the soybean oil for 10 years, what would the cost be for Btus for soybeans and for canola oil? And second, how much of that cost is offset by pharmaceutical glycerine that you can produce from the biodiesel plant? You said that it is 100% efficiency in the sense of one gallon in and one gallon out, but I know that there is some glycerine produced. How much subsidy does that glycerine give you for your Btu cost?

MR. FUMOSO: Our responsibility is to establish a capital cost of a facility. We provide you with the energy inputs required. Your cost structure for that energy is going to determine your cost of producing the profit. It is specific to each site. I can't answer your questions in the abstract.

Glycerine

MR. VICTOR: The question is, you mentioned that you have 100% efficiency. Actually, some glycerine comes out of your plant. What do you find — if you're just doing an average in the United States — what are you seeing at today's prices? What does it cost a million Btus for biodiesel? Forget the subsidy. And how much of that can be subsidized by glycerine? The next question I was going to ask somebody is whether you can get a blender's credit if you are using the biodiesel for power generation so that you are not putting it into the automotive market but you are consuming it yourself? Will the federal government give you an incentive for consuming this in a power plant?

MR. GEBOLYS: I can answer the easy one. Yes, you can go into off-road, and you can go into power generation. It doesn't affect the blender's credit.

MR. PHILLIPS: Gene is correct. The credit is not use specific.

MR. ALEXANDER: Why are we even talking about glycerine?

MR. PHILLIPS: Glycerine is a byproduct of production. In other words, if you produce biodiesel, you get a natural byproduct, which is crude grade glycerine unless you have the ability to refine the glycerine further. There is a big question as to what you do with the crude grade glycerine. My experience is that projects try to market it on a long-term basis. I believe it may be 5% or less of the revenues of the project on a long-term basis.

MR. GEBOLYS: That's about right.

MR. ALEXANDER: Jerry Peters, what do you do with the glycerine, and what happens if we have a 300 million gallon biodiesel market?

MR. PETERS: Crude glycerine is like crude oil. You really can't use it; you can't put it in your car. So you have to do something with it; you have to refine it; you have to put it into other products. There is a finite market for crude glycerin. It has to be refined for the downstream markets.

MR. ALEXANDER: What are people using it for?

MR. PETERS: Soaps, surfactants.

MR. GEBOLYS: Lipstick, cough syrup, you name it.

MR. PETERS: It makes things thicker. And think if you have a large amount coming into the market, as we had with DDGS in the ethanol market, you should expect the price to fall. Now, there is something that is a mitigant to that, and that is that glycerine can be used in a lot of other things for which it is not used currently because it's too high priced. As the price falls because of the additional supply, we anticipate that the market will find other uses for glycerine. That said, if, as a lender, you don't forecast in your model a falling price based upon the current market, then I think you will be in trouble.

MR. ALEXANDER: Gene Gebolys, do you agree?

MR. GEBOLYS: Yes. Directionally, that's absolutely right, but I think the key thing isn't to pick a point in time and conclude that 12% of total revenue will come from glycerine, or 15% or 8%, because these are just wild guesses and they will inevitably look wrong at some point in the future. The challenge is to come up with durable strategies to deal with the day when it is 8% and deal with the day when it is 15%. Going back to what this means for plant design, obviously if you have a glycerine refinery, you have two products that will be a source of revenue for the plant. You will have both a refined product and a crude product. If the refining spread takes a beating, then you can put out crude if you feel it is a better alternative. A lot of people have opted against putting in the refining capability for fear that there will be an oversupply of glycerine. That philosophy leads to one revenue stream when the plant could have two.

Core Competencies

MR. ALEXANDER: Do you need to hire a third-party operator, or can you find a project manager with the experience? Since this is an infant industry, I assume there are not many experienced operators.

MR. GEBOLYS: There are a lot of capable people in the oleo-chemical world that have transferable talent. It is not necessary that the person have experi- / continued page 14

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of $19.5 million in pesos. The Internal Revenue Service charged that the company had an $8.4 million gain.

Kohler asked a US court to rule in 2003 on "summary judgment" — that is, solely on the basis of legal briefs filed by the parties — that it had no gain. The court refused, saying that it was not persuaded by Kohler's arguments. However, the company went back again with new arguments, and this time the court agreed that Kohler had no gain. It said the best evidence of what the pesos Kohler received were worth was the amount it paid Bankers Trust for the "property" it traded a short time later for them. The court said the two amounts might not always be equivalent, but the US tax authorities failed to offer compelling evidence that the pesos were worth more.

The case is Kohler Co. v. United States. *A US district court in Wisconsin released its decision in September.*

SECURITIZATION TRANSACTIONS by utilities are okay in some circumstances, the IRS said, but the agency said it will not rule on others.

Many utilities in the United States were left with "stranded costs" when US electricity markets deregulated in the 1990s. Utilities recover the costs of their assets over time through the rates they charge their customers. Electric and gas utilities have historically had a monopoly on the supply of electricity or gas in their service territories. As part of deregulation, some states let customers buy from other suppliers. This left the utilities with too little base to collect fully for existing assets. Some states let utilities add surcharges to utility bills to collect for their stranded costs. The utilities converted these future revenue streams into cash immediately by borrowing against them.

One issue in such transactions is whether the utility must to report the accelerated rate recovery — through the securitization transaction — as income. The IRS said no in a series of private letter rulings to / continued page 15

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ence in the biodiesel world.

MR. FUMOSO: I can help him with that. These plants are very simple to operate. They involve a gravity reaction. The main thing you need is pump maintenance and instrumentation. If you have those two skill sets, you can operate a plant.

MR. ALEXANDER: Gene Gebolys, if you have a 20 or 30 million gallon plant, which is a fairly sizable plant in today's market, do you need to hire a marketer?

MR. GEBOLYS: That is a good question. The market for biodiesel is very, very small. World Energy has sold one out of every two units of biodiesel since 1998. We pulled from nine plants over that time period and made both short-term and long-term sales. We believe strongly that somebody that is in the business of moving product through the distribution supply chain downstream adds significant value to a project. Others have basically taken the view that if they build a plant, consumers will come. Time will tell. We can get some insight based on what is happening today with ethanol where more and more gallons are going through fewer and fewer outlets.

MR. ALEXANDER: Let me ask Jerry Peters as a more objective observer. Someone comes to you seeking financing with a business plan that suggests the developer plans to market the output himself. Would you make a loan?

MR. PETERS: I would have to know a lot about the marketing plan. Look at the ethanol industry and how ethanol is marketed. There are so many more users of ethanol — the market is well established — but you need infrastructure to deliver product. You need railcars; you need contacts. If you don't have those and you expect to reach the widest market to get the highest price, then I think you need a marketing group with access, ability, transportation assets and storage assets to get the job done.

MR. PHILLIPS: Gene Gebolys, you are marketing biodiesel for third parties. Are you insuring the biodiesel for risk of loss?

MR. GEBOLYS: The way that World Energy does it is different than what is commonly done in the ethanol industry where somebody represents someone else's materials. We just do a long-term type of pay agreement. Generally, those are indexed to feedstock. We focus on what the plant can control, which is the cost of manufacturing, and the more efficient the plant operates, the more profitable it is. Our cost is set at the beginning of the contract.

Crude oil prices probably need to move above $80 or $90 a barrel before biodiesel is economic without government subsidies.

MR. ALEXANDER: Jerry Peters, to follow up on the last question, are you seeing the biodiesel industry move toward long-term fixed-price contracts?

MR. PETERS: I wish, but not really. The industry is still in its infancy. The only thing that I see is, in some cases, the same entity that provides the feedstock also markets the end product, but in most cases, there is no linkage whatsoever. In most deals, you have the full commodity risk on the supply side as well as the sale side. From my standpoint, the only way you can protect yourself in such circumstances is a thing called equity — a lot of it.

MR. ALEXANDER: How much leverage can developers expect to achieve in a project?

MR. PETERS: It depends on what kind of plant. A developer should not expect much more than 50% leverage. I have to tell you, I know of several deals with 100% equity.

MR. ALEXANDER: Is the working capital line included in those percentages?

MR. PETERS: Quite honestly right now, I would prefer to put working capital into a biodiesel plant than a lot of debt.

Investment Returns

MR. DEVINENI: Prasad Devineni from Green Catalysts. I have two questions for the panel. One is about blending. What other states are expected to adopt incentives for blending biodiesel? The second question is, what returns should one expect on a biodiesel investment?

MR. FENNEMA: There is a great deal of variability in returns. We are in a world today when the crush spread is pretty attractive and the returns look great. But it takes time to construct the plant and then to start benefiting from that crush, and nobody knows where it is headed. Without fixed-margin contracts, which do not exist on a long-term basis today, you can reach a return of 30%, but just keep in mind the return will be highly variable.

MR. PHILLIPS: Let me tackle the other part of the question. One thing on which we have not touched today is mandated low sulfur diesel. The law requires fuel suppliers to reduce the sulfur content in diesel fuel from 500 parts per million to 15 parts per million by mid 2006. One way to reduce the sulfur content is to add hydrogen, which is a much more cost-intensive process than blending in biodiesel. So there is a ready-made market in some sense across the United States for blending. It is hard to say what other states might enact incentives for blending. Some states will no doubt move to mandatory blending. Some may adopt incentives that may or may not be funded or appropriated. I have not seen a list of states.

MR. GEBOLYS: I'm the regulatory director for the National Biodiesel Board. We are not actively pushing states to follow the Minnesota lead. The sleeping giant is the fact that the renewable fuel standard now includes biodiesel. I expect that as petroleum companies have to add ethanol and biodiesel to progressively larger shares of the fuel they supply, biodiesel will account for a significant percentage. I also expect that future state action on biodiesel will be more incentive-oriented and less mandate-oriented. That is true of Europe as well.

MR. PHILLIPS: Are you putting much emphasis on blending ultra-low sulfur diesel?

MR. GEBOLYS: That is just one more reason that a blender will move to biodiesel, because ultra-low sulfur diesel has lower lubricity characteristics. Biodiesel has good lubricity characteristics. If somebody is going to get renewable fuel standard credit and also get lubricity enhancement, a lot of dots start to connect and using biodiesel / *continued page 16*

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individual utilities and then ultimately in a "revenue procedure" in 2002 on which all utilities could rely.

The IRS revised the revenue procedure in August.

The new revenue procedure makes clear that securitization transactions can also be done on other types of charges that utilities are allowed by their regulators to collect, but the IRS said the transactions must be structured to fit in a "safe harbor." Transactions that fall outside the safe harbor are out of luck; the IRS will not issue any more rulings.

To fit in the safe harbor, the securitization can only cover specific charges that the utility has been authorized by a state legislature in special legislation to recover. The special legislation must say five things described in the new revenue procedure. In addition, the financing entity set up to borrow under the securitization must be wholly-owned — directly or indirectly — by the utility. The utility must have an equity interest in it of at least 0.5% of the money raised. Debt service payments on the securitization loan must be made on a quarterly or semiannual basis. The new rules are in Revenue Procedure 2005-61.

FOREIGN TAX CLAIMS cannot usually be pursued in the US courts.

Under a longstanding "revenue rule," the courts of one country usually refuse to enforce tax judgments on which another country may be trying to collect. Thus, for example, if a US company was found to owe back taxes in Brazil, the US courts would not help the Brazilian government collect on the judgment in the United States.

The US Supreme Court appeared earlier this year to chip away at the revenue rule in a case called *Pasquaranto v. United States*. The case involved a defendant accused of smuggling liquor into Canada to avoid liquor taxes. The defendant argued that he could not be charged in the United States with / *continued page 17*

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starts to make sense.

MR. RAKOWSKI: Richard Rakowski, Kidd & Company. I'm kind of a novice to this area. Focusing on the relative Btu value of biodiesel versus sugarcane-based ethanol versus gasoline, what price does crude have to reach before the alternative fuels become attractive even with the subsidies?

MR. FENNEMA: This is an area of heated debate. Most people believe that crude ethanol survives pretty well on its own when the price moves above $50 a barrel. On the biodiesel side, Gene is probably —

Vehicle engines do not have to be modified to burn biodiesel. The biggest issue is local outdoor temperatures.

MR. GEBOLYS: The situation is worse than ethanol.

MR. FENNEMA: It is probably $80 a barrel.

MR. GEBOLYS: Continuing with a back-of-the-envelope analysis, the feedstock costs $2 before you transport it to the manufacturing plant, and before you convert it to biodiesel and transport the biodiesel back into the marketplace for sale. So on the back of the envelope, you can figure out that you need a price of at least $2.50 for diesel fuel. We are currently at $65 a barrel for oil, and the price of diesel fuel with oil at that level is $2.12 a gallon. Therefore, rough numbers suggest you need oil prices to reach $90 or $100 a barrel before biodiesel will be economic on its own.

MR. ALEXANDER: Dave Fennema, what expected returns are developers assuming in their business plans?

MR. FENNEMA: I have yet to see a pro forma that assumes an inadequate return. One thing we try to do is create some flexibility so that there is room to appeal to different investors and lenders. Everyone has his own idea about where the market is headed. The truth is, no one should view the future as doom and gloom. The biodiesel market relies today on subsidies. There is no need to apologize to equity investors or lenders for that. We have to model it. There is a lot of data available about soybean oil prices. The wild card is the petroleum industry. No one believed a year ago that we were going to have sustainable $40-plus barrel crude. Now most people will not go below $50 in their long-term assumptions.

MR. PETERS: When you consider that the capital cost per gallon of annual production runs between 50¢ and $1.25, depending on whether you have a single-feedstock-batched plant or a multiple-feedstock-continuous plant like Lurgi makes, and you consider the very aggressive pro formas that we see, most of the pro formas show $1 a gallon of profit. I am not buying that. I assume when lending that the profit will be 80% less than that, but that's just my philosophy.

MR. PHILLIPS: Gene Gebolys, do you sell your crude on a short-term, long-term or spot basis?

MR. GEBOLYS: We have done it all three ways.

MR. PHILLIPS: Is it possible to get a long-term contract for the glycerine?

MR. GEBOLYS: Yes. I wish I had done more of it.

MR. GARDINER: I'm Kevin Gardiner from the UConn Biodiesel team with a question for Gene Gebolys. Does World Energy do some work with state and city departments of transportation?

MR. GEBOLYS: Yes.

MR. GARDINER: Do you have any statistics on the diesel needs or consumptions of any cities or states that you could share with us today?

MR. GEBOLYS: Is your question where they use a lot of it?

MR. GARDINER: Yes.

MR. GEBOLYS: We have contracts with state transportation departments in Ohio, New York, New Jersey, Connecticut, with Boston, and we also do a lot with the US military. The US Navy is the single largest diesel consumer in the world. The overall size of the diesel market — whether your focus is a state or a city or the federal government — isn't the key. The key is finding a fit in subsets of that market.

The diesel market is huge and getting bigger every day.

MR. KAUFMAN: Uri Kaufman, Evergreen Power. I have a question for Richard Fumoso. How much of the cost of biodiesel is the heat or steam that you use in the refining process, and could you put a biodiesel refinery next to a power plant and use the waste heat for that purpose? How much of a savings would there be if you do that?

MR. FUMOSO: It depends on what you have. It takes a lot of steam to do the distillation process. We can use the heat loss from a power plant to do that. There's no question about that.

MR. KAUFMAN: If you make a gallon of biodiesel, is 5% of it steam or is it 10%?

MR. FENNEMA: It is a very small percentage. The best analogy is ethanol, where up to 30% of your variable costs might be natural gas today, maybe even higher with gas prices at $13. Biodiesel is a different process. It is a very low pressure, low temperature process.

MR. KAUFMAN: What are the emissions from biodiesel compared to ethanol and compared to natural gas? How clean is the fuel? Assume you are using a clean feedstock such as virgin soybean oil?

MR. GEBOLYS: It is a great fuel. It reduces greenhouse gas emissions that don't matter today in the United States but eventually will. It reduces fine particulates very well, so that it reduces the asthma impact of diesel. It is a fuel that makes diesel engines run cleaner. How much cleaner? First of all, we would not compare it to ethanol because they're not competitive technologies. Second, any emissions are based on a combination of three factors: the engine, the fuel, and then the condition of the engine and the condition of the fuel.

MR. KAUFMAN: There is not any particular NO_X problem?

MR. GEBOLYS: Biodiesel used in an internal combustion engine increases NO_X just slightly. In an external flame, like a boiler or burner, it reduces NO_X. The jury is still out on gas turbines. There has not been enough research done on gas turbines yet.

Quality Issues

MR. ALEXANDER: Gene Gebolys, explain in more detail the quality issues that we have seen and what people are doing to eliminate them so that biodiesel can be adopted more uniformly.

MR. GEBOLYS: There is no way to make / continued page 18

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using the interstate telephone lines to defraud Canada of property, since the case was in substance an effort to enforce a Canadian tax statute. The US Supreme Court disagreed. It said that Canada had been defrauded of "property" — its right to collect liquor taxes — and the theft of property is a crime. It allowed the prosecution to continue. The key for foreign countries trying to catch tax evaders seemed to be to find grounds to charge there was a US crime.

The case caused nervousness in some quarters.

However, in mid-September, a US appeals court in New York drew the line. The European Union, various individual countries in Europe and Colombia have been trying to collect taxes from US tobacco companies that these governments charge the companies avoided by helping smuggle cigarettes across their borders. The countries brought a civil suit in the US courts charging that the companies violated a US racketeering statute called RICO. The RICO statute allows victims to sue directly without waiting for the US government to bring charges.

The appeals court said the case was nothing more than an effort to collect tax revenue, and it blocked the suit. The case is European Community v. RJR Nabisco.

FOREIGN TAX CREDITS cannot be claimed in the United States for taxes that a US company pays voluntarily to another country.

One US company had to go to unusual lengths to prove that the taxes that one of its offshore subsidiaries paid were not voluntary. The subsidiary was a "dual-resident company." It claimed it was a tax resident of two different countries outside the United States. The subsidiary paid taxes on interest it earned from bank accounts in one of the countries in which it claimed tax residence, country X. The subsidiary might have avoided taxes on this interest if it claimed / continued page 19

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good business out of bad quality. So what that means in terms of where the business is and where it is headed is this. There is currently a very low barrier to entry, with the result that there are some very small plants — 500,000 to 1,000,000 gallons a year — and they are far too small to afford the fully-equipped laboratory that it takes to ensure quality. Therefore, they go without. This is a recipe for disaster. There is no way to make quality biodiesel without an appropriate plant.

Demand for crops used to make biodiesel will eventually drive up commodity prices.

MR. ALEXANDER: Is quality a major issue?

MR. GEBOLYS: Yes. It is a business issue. If somebody is going to buy from a 500,000 gallon plant, it looks like a 500,000 gallon plant. It is buyer beware. Bad product is never a good thing for any industry. We deal with relatively sophisticated fuel buyers, and relatively sophisticated fuel buyers understand that if they want quality, they must buy quality. There is something called a BQ-9000 program that is being rolled out in biodiesel. It is a pretty sophisticated voluntary quality program for plant owners to participate in, and have their plants vetted through that process, and vetting runs all the way down through the distribution chain. There is not yet widespread participation in the program. But over time, I think that quality is just a business issue. If you do not produce a quality product on a consistent basis, the market will deal with you. Poor quality is not a long-term threat.

MR. ALEXANDER: Is there an issue beyond initial quality?

MR. PETERS: Biodiesel will degrade, so you can't store it forever. And it certainly makes a big difference if you have a multiple feedstock plant. Are you going to use one feedstock if you are delivering everything in Arizona, and are you going to use a different feedstock, a blended feedstock, if you deliver into Maine? The biggest problem is the temperature at which biodiesel gels. It gels — depending upon which feedstock it is — at a heck of a lot higher temperature than petrodiesel. Clearly you can use lower cost feedstocks, palm stearin or others, that you can get for a couple of pennies a pound less than you buy soy, but you better not use them in Maine in the wintertime.

MR. ALEXANDER: What about differences in quality standards for a producer in the United States who wants to take advantage of the higher prices for biodiesel in Europe and other export markets?

MR. PETERS: You had better meet the EC spec, because if you don't do that, you can't get the product into Europe. It is a pretty tough spec to meet. Some people say you can only meet it using rapeseed. I would say most of the plants in operation today in the United States can't meet that spec.

MR. ALEXANDER: Does meeting the European standards require paying more for your feedstock or does it require a more sophisticated process, or both?

MR. FUMOSO: We don't change our process.

MR. PAYANO: My name is Miguel Payano. I'm from Canal Step Management. Why buy a diesel blend if we can get away with straight vegetable oil?

MR. PETERS: Let me speak from the practical standpoint of a guy who used to take vegetable oil and stick it in his diesel engine versus somebody who only runs biodiesel today. If I am living in Arizona, I would feel a heck of a lot more comfortable heating up my vegetable oil to get it to the viscosity level that it will flow through my fuel filter and into my injectors and thus into my engine. If I have the chance, at any time, that the heating system will break down and can no longer heat the vegetable oil, then I have a car that potentially can't operate unless I run fully redundant systems.

MR. PAYANO: The other question was, who owns the CO_2 credits if there are any from blending or production?

MR. GEBOLYS: It is a matter of contract. We are working on a deal in Canada where CO_2 credits are with the lender. In the US, they really don't matter right now, but in the Canadian deal, it is just worked out contractually where they end up.

MR. HOAG: David Hoag, Capital International Research. This is probably for Jerry Peters and maybe Richard Fumoso. You suggested earlier that a certain level of biodiesel blend with diesel can run in engines without modifying the engines. With respect to a truck engine or other large-power engine, what are the quality issues or the viscosity issues or other issues that make it necessary to modify the engine at certain blends of biodiesel but not at lower blends? There was also a question about Btus earlier that I don't think got answered.

MR. PETERS: I don't think — with the larger scale engines — that you have to do any engine modifications at all to burn the entire range from 1% to 100%. There are plenty of large-scale engines that have operated, and continue to do so, at 100% biodiesel. I think that the biggest concern is the gel point of the biodiesel. It is that, rather than a matter of the engine needing much modification at all. That said, I don't think you will see many engine manufacturers offer a 100% warranty on their engines no matter what you burn, because they are a conservative lot. But I don't think any of the testing that has been done on reciprocating engines suggests that any modifications are required to burn 100% biodiesel.

MR. PHILLIPS: Gene Gebolys, do you know any manufacturers who are honoring warranties for biodiesel use?

MR. GEBOLYS: This is the central thrust of why biodiesel exists. Nobody is modifying engines to use biodiesel, and that goes back to the question about straight vegetable oil as well. Zooming way back, it appears to me and many others that the technologies of the future in the energy sector are hybrid technologies, whether they're hybrid vehicle technologies or they're hybrid fuel technologies. The only way a hybrid fuel works is if it works seamlessly in the fuel stream. Biodiesel at up to 20% can work seamlessly in the fuel stream. To my knowledge, nobody has ever voided a warranty for B20 use. There are engine manufacturers that don't recommend using biodiesel blends above 5%, and there is still a fair amount of dancing that goes on between the engine manufacturers and the fuel suppliers. But it is a dance that has been going on for decades and / continued page 20

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benefits under a tax treaty between country X and its other country of residence, country Y.

The IRS said the company had to ask the governments of the two countries for a ruling on whether it could use the tax treaty before the IRS would accept that the taxes on the bank interest were involuntary.

The IRS discussed the case in an internal memorandum that the agency made public in August. The memorandum is ILM 200532044.

FOREIGN DIVIDENDS were a problem for Amerada Hess Corp. when paying state income taxes in North Dakota.

North Dakota taxes large companies doing business in the state under the unitary method, meaning that rather than try to sort out which subsidiaries of a large corporate group earned what income in the state, it lumps the income of the parent and all the subsidiaries together and then apportions a share of the *group* income to the state based on the ratio of the group's total payroll, property and sales that are in the state.

Companies have the option of doing this calculation on a "water's-edge" basis, or a basis where only the income earned in the United States is subject to potential apportionment to North Dakota.

Dividends that the group receives from subsidiaries outside the United States are taken into account, even in the water's-edge calculation. However, only 30% of such dividends are taken into account. The state has a "partial exclusion" for foreign dividends.

Amerada Hess has lots of foreign dividends. When it comes time to pay its federal income taxes, the company claims foreign tax credits. The United States taxes US companies on their worldwide incomes, but it allows them a credit for any taxes that were already paid on the income to other countries. In many cases, a condition for claiming foreign tax credits is the company / continued page 21

Biodiesel

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decades between those two groups. The bottom line is you can certainly use biodiesel blends up to 20% throughout most of the developed world wherever distillate is used currently. And that is the fundamental reason why this technology has a future — because it is easy to use.

The Future

MR. ALEXANDER: Where do our panelists see this market going?

MR. GEBOLYS: That is the million dollar question. Is there any room for anybody between big oil and big agriculture?

MR. ALEXANDER: Maybe you could frame the issue for people who are not familiar with the industry.

MR. GEBOLYS: Why would energy majors get into this? The main play for energy majors is they need to have access to biodiesel and ethanol over the long haul. Do they need to be in it to have access? That has yet to be seen. Do they have core competencies that translate well for biodiesel? That has yet to be seen. The distribution channel for biodiesel is very different than the distribution channel that the major oil players use, and the skill sets for this business are very different than the skill sets that make somebody successful at the high end of energy wholesale.

MR. FENNEMA: I would say that anytime you have an industry that still has this much of a subsidy base built around it, neither big oil nor Cargill nor ADM want to be the whole market. I don't think the market is big enough for big oil to come in and take over yet. There are not enough dollars in it for big oil to get excited.

MR. GEBOLYS: If you are in the crush business, what you need to ensure is that there is a biodiesel industry. You don't need to ensure that you are in the biodiesel industry. If you are, you have to have core competencies that lend themselves to being better than the next guy in that business. Clearly being basic to feedstock is helpful, but one of the keys to success in the biodiesel business is distribution. And being basic to feedstock doesn't necessarily give you a significant strategic advantage in the marketplace. I ultimately think that the large crushing operations will do what they can to ensure there is a healthy business in the United States, and they will be very active in supporting biodiesel producers both in Washington and from a supply-of-oil point of view. Will they stake out sole participant status in that business? I don't think so. In fact, I expect them to focus hard on core competency, which is in crushing, and not on downstream energy distribution.

MR. KAUFMAN: Uri Kaufman, Evergreen Power. What have you heard about research into cheaper feedstocks, and in particular have you heard anything about algae being a viable feedstock?

MR. PETERS: I have heard of acid breakdown systems. I have heard of gasification. It turns it into gas and then into biodiesel. A conventional edible oil-based biodiesel project is hard enough to get financed. So to take it one step further and suggest there is the possibility anytime soon that something using other than edible oils can be used to produce biodiesel, I don't think there is any money yet to finance that.

MR. ALEXANDER: Studies suggest that biodiesel demand will grow to more than a billion gallons a year. How do we find enough feedstocks to produce that much biodiesel?

MR. PETERS: It is the same issue as with ethanol. We are quickly approaching the limits of corn as a viable feedstock at an economical price to make ethanol. Where do we go from there? We go to cellulosic ethanol. No large-scale plant has been built yet, and ethanol is five years ahead of where biodiesel production is today. Will it happen? Of course you will have, at some point, to find alternatives to edible oils in order to be able to be the low-cost producer of biodiesel. I have to think that the problem is five or 10 years away.

MR. GEBOLYS: Agricultural markets will shift around to opportunity, and as that surplus starts to go away, the soy complex today is driven by a meal-driven demand, not an oil-driven demand. Depending on what happens to demand for oil, the soy complex shifts around to that. There will be alternative feedstocks as a complement to soybean oil. Soybean oil is going to be the baseload feedstock in this country for the foreseeable future, but there will be alternative feedstocks. Over time, people will move to higher-oil-yield varieties of beans. There are lots of responses to a macro-economic model that has more than 240 million gallons of biodiesel demand in it.

MR. McKENNA: John McKenna. I'm with Hamilton Clark. We are an investment bank for energy technologies. When we make investments in hybrids and drive systems and diesel engine efficiencies, we talk to the fleet managers at FedEx and Pepsi/Frito-Lay. Have you had any experience with the fleet managers with centrally-fueled vehicles that are the ultimate big market for this, and if so what kind of reaction have you had?

MR. GEBOLYS: Great question. I suspect that I am the only one who has spent countless hours with these guys. World Energy is a company that is driven by backwards revenue streams. We exist to catch revenue streams and then supply those revenue streams. The fleet managers make those decisions. The original driver for the industry was fleet requirements, and transportation is still the vast majority of the market. Increasingly, energy companies matter, but this business was built going directly from biodiesel supplier to fleet manager, and then almost by accident energy companies have emerged in the middle. When you're selling a BTU at a premium, somebody had better value that. For a long time, biodiesel has been a premium market in the United States over the price for diesel fuel.

MR. ALEXANDER: Where are the best places in the United States to build a new biodiesel plant?

MR. PHILLIPS: That's an age-old question. Biodiesel has a lot of parallels with ethanol. Do you build the plant near the feedstock, or do you build the plant near the destination of its end use, or do you put it somewhere in between that can take advantage of its location to both the feedstock and the end product? There is no right answer. We see plants being built right in the middle of the most intense soybean production in the United States, and we see them being built where no soybeans are grown within 500 miles.

MR. PETERS: Biodiesel is a little less dependent than ethanol. Corn is a little harder to move than soybean oil. But these are both highly logistical decisions. No matter where you are, transportation of either the feedstock or the output will be a significant factor. ◎

"Pivot Points" in the New Energy Bill

Chadbourne hosted roundtable discussions in New York on August 24 and in Houston on September 14 about the massive new 1,724-page energy bill that President Bush signed into law on August 8.

Americans pride themselves on having a free market economy, but the truth is the government / continued page 22

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must "gross up" the dividend, or report the taxes that it is claiming as a credit as additional income. However, even with this gross up, the company comes out ahead since a dollar of foreign tax credit reduces US taxes by a full dollar while having to report the foreign taxes as income only adds 35¢ to the company's US tax bill.

North Dakota told Amerada Hess that it had to include the full gross-up amounts in its income.

The company objected. It argued that if the underlying dividend qualifies for a partial exclusion, then the gross-up of the dividend must qualify, as well. It lost before the state supreme court. The court said that the state legislature had consciously decided against treating dividend gross ups as part of the dividend.

The case is a warning to be aware of the potential issue in other states. The case is Amerada Hess Corp. v. North Dakota. *The court released its decision in late August.*

MINOR MEMOS. Another company got back the federal excise taxes that were included on its phone bill for long-distance calls. Hewlett-Packard won a $6.4 million refund from the IRS in a federal district court in California in August. The US government collects a 3% excise tax on long-distance telephone calls, but the statute is outdated, and the tax no longer applies to most long-distance service because of the way it is worded. The IRS won one key case and has lost a series of others. Congress has done nothing to update the statute. The latest decision was in the case *Hewlett-Packard Company v. United States*. The refund covers taxes the company paid during the period 1999 through 2002 . . . . A state legislator in Delaware, who opposes plans by the state to experiment with private toll roads, wrote the IRS in late September to question whether toll road developers can recover their investments in road / continued page 23

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creates new opportunities, alters existing markets, and shifts capital through changes in law. People who were smart enough to understand the opportunities created by the new Public Utility Regulatory Policies Act in 1978 made fortunes. That statute created the independent power industry in the United States. The question is whether there are similar opportunities in the new energy bill.

The following are excerpts from the discussion. The New York transcript is first, and it is followed by excerpts from the roundtable discussion in Houston.

The speakers in New York were Jay Worenklein, president and CEO of US Power Generating Co., Jonathan Weisgall, the chief lobbyist in Washington for MidAmerican Energy Holdings Company, Roger Gale, president of the consultancy GF Energy, and John Veech, managing director and head of global project finance at Lehman Brothers. The speakers in Houston were Peter Gaw, global head of utilities and power for ABN AMRO Bank, Dr. Robert Kelly, a principal with Houston energy firm DKRW and a former senior Enron executive, and Donald Kendall, managing director and CEO of Kenmont Capital Partners, a hedge fund. Two Chadbourne lawyers, Robert Shapiro and Adam Wenner, joined in the discussions in both New York and Houston. Keith Martin moderated both sessions.

MR. MARTIN: What types of deals will people do more of as a consequence of this bill?

Utility Consolidation?

MR. WENNER: The biggest opportunity is for utility acquisitions and mergers. The Public Utility Holding Company Act has been repealed effective next February. This opens the door to two types of transactions — combinations of utilities that are not in the same geographic region and takeovers of utilities by companies, like Microsoft or Starbucks or General Electric, that either are not already in the utility business or have diverse interests beyond utilities. It was possible in the past to merge utilities that are geographically connected — for example, because they sell into the same power pool — but PUHCA repeal has opened the door much wider.

MR. MARTIN: John Veech, will we see a lot of US utility mergers or acquisitions in the next few years?

There will be a gradual move toward utility consolidation in the United States, but not the "land rush" that many on Wall Street expect.

MR. VEECH: I think a couple things. First, PUHCA repeal will help the three high-profile mergers that have already been announced reach closing. Second, I think you will see some transactions, but not the land rush that some on Wall Street are predicting. The transactions still need to make strategic sense, and you will still have to deal with state regulators who may have a more prominent role now that PUHCA has gone. The questions will be whether there are enough synergies to justify the transaction, and whether the state regulators will approve the deal. You will have at least two sets of regulators where two utilities are merging. Each of them will want 75% of the synergies shared with local ratepayers.

MR. SHAPIRO: Not only do the states have jurisdiction over utility acquisitions, but the federal government also retains jurisdiction. The Federal Energy Regulatory Commission has authority to review utility mergers. This authority has been slightly expanded under the new legislation. The only thing that was eliminated was the need for approval for the deal from the US Securities and Exchange Commission under the Public Utility Holding Company Act, and frankly, in the last 20 years, that has not been difficult to obtain.

MR. MARTIN: Is there anybody on this panel who thinks there will be a rush of utility consolidations?

MR. WEISGALL: No. I tend to agree with John Veech. We are going to see a greater role being played by state regulators now that PUHCA has been repealed. It is not clear that state regulators will entertain companies like Microsoft and Starbucks coming into the utility marketplace. Oregon turned down a bid by the Texas Pacific Group to acquire Portland General. The decision was that ownership of an electric utility by a hedge fund may not be in the best interest of the local ratepayers.

MR. WORENKLEIN: We should temper our expectations and recognize that we are not likely to have the floodgates open with deals. That said, there are opportunities, in theory, for cost efficiencies through consolidation. Whether they can be achieved in fact through mergers, and how long it will take to realize them, are another matter. All of this leads me to believe some deals will be done that make a lot of sense. The good news is that companies no longer have to twist themselves into pretzels to get such deals done. We will inevitably see deals slowly coming to market, and the utility landscape in this country will be changed as a result.

MR. WEISGALL: There are almost 4,000 entities in the United States that sell electricity. That is the sum of investor-owned utilities, about 2,000 municipal utilities, about 900 electric cooperatives, and a large number of power marketers. Japan has seven to nine utilities. Are we going to see some consolidation? Yes, we will. How much? We are not going to get down to nine.

There is one other point about opportunities created by the new energy bill. There may be some secondary M&A activity as a consequence of utility mergers. Utilities that merge may have to divest some of their assets in order to gain regulatory approval.

MR. WENNER: I worked a number of years ago with Enron when it was trying to sell Portland General. The first thing we did was draw a circle around the possible buyers. Because of PUHCA, we were limited to potential buyers who were already in the utility business and who could buy a utility in the Pacific northwest without running afoul of PUHCA. Had the PUHCA constraint not been there, any utility in the country would have been free to acquire Portland General, and the Oregon commission at that time would have been very happy for that to happen.

Remember that competitive analysis is a problem when neighboring utilities merge. However, if an Exelon or a Duke proposes to buy Portland General, there is no concern about too much market power. More distant */ continued page 24*

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projects through depreciation deductions. Private roads can normally be depreciated over 15 years. The legislator asked whether this is true if there are federal funds involved or the developer holds the road under a concession agreement with the state. Many states are considering giving private developers the right to collect tolls on major highways in exchange for paying the cost to repair or upgrade them. The states are hard up for money. . . . Florida Power & Light lost a claim in the US Tax Court in August that it was entitled to millions of dollars in "investment tax credits" under transition rules in the Tax Reform Act of 1986. The United States used to allow companies to claim as much as a 10% investment tax credit on the cost of new equipment as an inducement to spend money in ways that might create jobs. The credit acted like a 10% rebate on the cost of new equipment. Congress repealed the benefit at the end of 1985, but with generous transition rules that allowed credits to be claimed at a reduced rate on investments that were considered already in the works as long as the investments were completed by 1990. An investment was considered already underway in 1985 if the equipment was needed in order to perform a "service or supply contract" under which the company had promised to do something for a third party. The utility argued that several of its obligations were such service or supply contracts, including its tariff to supply electricity to the public at particular rates and interchange contracts with neighboring utilities under which it agreed to connect to their grids. The US Tax Court disagreed. The case is *FPL Group v. Commissioner.*

— contributed by Keith Martin in Washington.

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suitors may have an edge in this sort of competition.

MR. MARTIN: John Veech, if Adam Wenner is right and PUHCA repeal means that a lot more companies are now potential suitors for US utilities, wouldn't you expect stock prices for utilities to go up in anticipation of this demand? Has that occurred?

MR. VEECH: Logic would dictate that if you increase the number of bidders while the supply of potential targets remains unchanged, then prices will increase. However, we have not seen any clear movement in utility stock prices since the bill was enacted. If you look at the utility index for the period starting a month before the bill passed through today, the prices for utility stocks have been remarkably stable.

MR. MARTIN: Have we opened up a Pandora's box? Is it better to have one federal statute or 50 different states moving in to fill the void? Will utilities come eventually to regret PUHCA repeal?

MR. GALE: On balance, there is no regretting. PUHCA should have been repealed a long time ago. Repeal is in the public interest. We have had consolidation in virtually every other industry, and there have been benefits from greater cost efficiencies. This is the only major industry with such a vulcanized structure. At the same time, it is clear that the states are not going to roll over. Consolidation will not be easy to achieve.

MR. SHAPIRO: The states retain full authority over changes in control of utilities in their jurisdictions. They have always had this power. They may be a little more demanding in the concessions they want to approve mergers in the future. They hold all the cards at the end of the day in what costs they will allow utilities to pass through in rates and what return they will allow on rate base.

MR. MARTIN: Bob Shapiro, you mentioned earlier that the Federal Energy Regulatory Commission will have broader authority to review proposed acquisitions. Do you see FERC exercising this authority aggressively, and is its exercise of the authority likely to change many outcomes?

Utilities are poor candidates for hostile takeovers. They tend to have the support of local political leaders.

MR. SHAPIRO: No, I don't think it will change many outcomes. But the bill does expand FERC authority to review a group of transactions that the commission lacked jurisdiction previously to review. For example, much of the generation that was spun off in California by Pacific Gas & Electric and Southern California Edison was done without FERC approval because the utility sold only its generating assets and retained the interconnection lines. Such a sale will not avoid FERC review in the future. Many power plant sales may require FERC approval in the future, but, at the end of the day, I don't see FERC being an obstacle to such sales.

MR. MARTIN: One more quick question — there has been a lot of talk about private equity money coming into this sector. Are private equity funds appropriate bidders for utilities? They have short time horizons to hold assets and high hurdle rates, certainly higher than the regulated rates of return allowed in this sector. Jay Worenklein?

MR. WORENKLEIN: That's a tough question. It depends on the situation. Some private equity funds have time horizons as long as 10 years. A private equity fund may be able in that time to fix a lot of problems and leave the utility in better shape with a significantly higher enterprise value.

Transmission

MR. SHAPIRO: You have to wonder about the returns that people can reasonably expect from a regulated enterprise, particularly in the distribution area, which is really what

PUHCA frees up for acquisition. States control those returns. They are not as high as the returns in other sectors, and certainly not at the hurdle rates set by private equity and hedge funds.

Private equity funds may be better off focusing on transmission rather than electric and gas distribution companies because, with transmission, you have only to contend with federal regulation, and the federal government is rewarding transmission investment with higher returns. Returns are in the 13% or 14% range on invested equity, which is 3% or 4% better than the returns that state regulators allow for a distribution company.

MR. WEISGALL: Following up on that, another reason we may see more investment in transmission companies is the energy bill gives the federal government a power of eminent domain that it can use to push through new transmission projects in areas of the country where there are transmission bottlenecks. I believe this is the first time that the federal government has been given this power in the electric transmission area. The government has had similar authority to help with interstate gas pipeline projects for a long time because such projects were seen from the start as involving interstate commerce. The specter of federal authority — rather than the actual exercise — may spur states to move more quickly on transmission projects on their own. This will help with investment.

MR. MARTIN: Let me explain for the audience. The new energy bill gives the federal government a year to take an inventory of where transmission is constrained, and the government will then have the power in the regions it identifies to take property through eminent domain proceedings to make room for new transmission lines. Is that right, Bob Shapiro?

MR. SHAPIRO: It is a little more cumbersome than that, unlike the Natural Gas Policy Act where the Federal Energy Regulatory Commission can exercise eminent domain authority immediately upon application. The US Department of Energy must first do a study. The study will identify specific corridors where exercise of federal eminent domain authority is needed. Then a project developer must petition a state to move on his project. If the state fails to act within a year, then the Federal Energy Regulatory Commission can use the federal eminent domain power. This is a more cumbersome process than developers go through to build an interstate gas pipeline.

MR. GALE: I agree with my colleagues that we will see a lot more investment in transmission in the future. An additional catalyst to such investment will be utility consolidation because, as utilities merge, they may be forced by market power concerns to shed their transmission lines, opening the door for others to get into this sector.

MR. MARTIN: John Veech, Lehman looks for opportunities in the market and tries to figure out how best to spend its time. Is transmission an area where Lehman is putting its resources?

MR. VEECH: Yes, I agree with the others on this panel. Transmission is one of the big winners in the bill. Other reasons to expect more investment in transmission, besides the ones already mentioned, are this is an area where utilities have seriously underinvested for the past 20 years, and there are new tax incentives in the bill to invest more. There are also tax benefits for utilities to shed their transmission lines. Finally, there is a huge appetite potentially from both private equity and strategic investors. If FERC gets the tariffs right for transmission, it will encourage a lot of people to jump all over this opportunity.

We took the International Transmission Company public a short while ago. This is the old Detroit Edison transmission system that was bought by Kohlberg Kravis Roberts & Company and Trimaran. The equity markets loved the story. The International Transmission Company is trading at 25 times earnings on a forward earnings basis compared to about 15 times earnings for more traditional utility stocks.

What the markets loved about it really were two things. One is the stability of earnings, because you can basically figure out the future earnings on your pocket calculator from the tariff. The other is the clarity of earnings growth. You have a transmission system that requires a lot of additional investment. The new owners plan to make those investments over time, and they will be allowed to earn a return on the additional capital expenditures. The company has a clear growth story. It is a perfect example of how, once the government gets the tariff right, the capital will follow.

Renewables

MR. MARTIN: So far, we have talked about two regulated businesses that may be interesting targets for additional investment. Roger Gale, does the new energy bill create other opportunities?

MR. GALE: I think there will be an / continued page 26

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additional shift of capital toward the renewables sector, but I don't think it will be huge because there are significant limits on what we can do with renewables in this country. They are a single digit — 4% or 5% — source of electricity supply. I am skeptical whether they can get to 10% in the next 20 years. There is a limit on the extent to which we can rely on wind turbines for our basic power needs. The bill throws significant money at renewables through tax incentives. This will spur more interest in the short term; the tax incentives are temporary. Congress has yet to address the problem of long-term continuity and strategy.

MR. WEISGALL: I think the bill is a mixed bag when it comes to renewables. On the plus side, Congress extended a production tax credit for renewables. It gave developers another two years to put renewables projects in service to qualify for five or 10 years of tax credits on the electricity output. If I am not mistaken, this is the first time that Congress has extended the deadline for putting such projects in service before the tax credit expired. There has been a boom-and-bust pattern to development of renewables projects in this country because the tax credits keep expiring and then time passes before they are renewed.

Also on the plus side, if you add up the dollars in the tax title, fully 20% of the tax subsidies are going to renewables, which make up about 2% of the US power sector.

The minus side is that Congress gave developers only another two years to complete their projects. That works for wind farms, which take only six months to build, but it is a tough timeline to meet for biomass, geothermal and other projects, even if you already have a permit to start construction.

Congress failed in the energy bill to adopt a federal mandate for renewable electricity. Twenty states and the District of Columbia require utilities within their borders to supply at least a minimum percentage of electricity from renewable sources. Congress could not agree on a national standard. It may be just as well because many of the existing state standards are already well above the national target that was under discussion. Any federal mandate would have turned into just another area for federal-state tension, a recurring theme in all the subjects we have discussed so far today.

Consolidation may create opportunities to buy assets that merging utilities are required by their regulators to shed.

MR. MARTIN: There is also an opportunity to take existing renewable plants and rebuild them so that they qualify for another five or 10 years of production tax credits. The credits can only be claimed on new projects. However, an existing plant is considered brand new if it is substantially rebuilt.

MR. WEISGALL: By the way, the bill creates a new acronym CREBS, for clean renewable energy bonds.

MR. MARTIN: Explain what those are.

MR. WEISGALL: I was afraid you would ask. The bill allows municipal utilities and electric cooperatives to issue bonds to finance renewables projects. No interest has to be paid on the bonds. The lenders get federal income tax credits in place of interest. There are a lot of municipal utilities in California looking at renewable energy. The federal government subsidizes private projects through production tax credits, but municipally-owned projects do not share in this subsidy. Clean renewable energy bonds are a way to let municipalities share in the tax subsidies for these types of projects.

MR. MARTIN: You make an interesting point. Institutional investors who are looking to invest in renewables projects and who are able to take part of their returns in the form of tax benefits now have two ways to invest in such projects. They can put equity into private projects, or they can lend to municipal projects. Either way, they get tax credits.

MR. WEISGALL: Congress chose in the energy bill to use a carrot rather than a stick. It gave institutional investors tax credits to encourage them to invest in renewable energy projects, but it declined to follow the states in ordering utilities to supply a certain percentage of their electricity from renewable sources.

Coal

MR. MARTIN: Roger Gale, are IGCC plants another opportunity as a result of this bill and, if so, why?

MR. GALE: IGCC is a stalking horse. It is a big leap in technology. It has wonderful promise. It is a way to sequester carbon dioxide emissions if we ever get to the point of ordering US industry to reduce greenhouse gas emissions. It is a way to beautify coal. However, I think we are going to see a lot of traditional coal plants built with huge capital expenditures on scrubbers and other pollution control equipment before we see many IGCC plants built. The problem with IGCC plants is they are more expensive than nuclear plants to build.

MR. MARTIN: Bob Shapiro, explain what an IGCC plant is.

MR. SHAPIRO: The acronym stands for integrated gasification combined cycle. Basically, you take coal, turn it into gas, run the gas through a gas turbine to generate electricity, use the exhaust from the gas to heat water to produce steam and then run the steam through a steam turbine to make more electricity. IGCC plants do not lend themselves easily to project finance because of their high costs. They are more likely to be built by regulated utilities, with approval from their regulators to put the cost into rate base, than by independent power companies.

MR. MARTIN: There are a lot of incentives in the bill for IGCC — a 20% tax credit as well as federal grants and loan guarantees.

MR. WEISGALL: I am looking at $3 billion in authorizations. We are throwing a lot of money at this particular type of project, but I agree with the other speakers. It is an old joke that soccer always has a great future in the United States. We may be saying the same thing about IGCC for decades. I am not sure, but if the technology fails to take hold, it will not be for lack of government subsidies.

MR. MARTIN: Congress spends money through a two-step process — it first authorizes the money to be spent, and then it appropriates it. You said there are $3 billion in authorizations in the bill, but the money will not truly be available until it is appropriated. When do you see that happening?

MR. WEISGALL: The appropriations bill for the US Department of Interior has already passed Congress. The energy and water appropriations bill is in a conference committee. Those would be the two logical places for the appropriations. My guess is we are not going to see funding until next year's appropriations cycle.

MR. WORENKLEIN: Let me add just one point on IGCC. The technology should not be viewed simply as gasifying coal and then running the gas through a turbine, because many IGCC projects are essentially complex chemical facilities. The real benefits of the IGCC plants that are being proposed in many parts of the country are production of other products — diesel fuel, carbon sequestration and numerous other energy-related outputs that go beyond the question of power. That is where I think the real benefits are. I disagree with some of what has been said. Some of the projects that have been proposed make tremendous sense, particularly if you view them as industrial plants that turn out an array of products. My view is you will see a real takeoff of this technology.

MR. GALE: I think the reality is that we will see a lot of additional coal-fired power plants built. The costs will be higher than we expect. The cost of IGCC is in the stratosphere, relatively speaking. We will find it hard enough to build traditional coal.

MR. WENNER: What about the discounting for the cost of anticipated carbon control? Won't that be a compensating factor in favor of IGCC?

MR. GALE: This is going to sound like a ludicrous statement, and perhaps you would say it is, but the best way I think to reduce carbon dioxide emissions in the medium term is to build pulverized coal plants that replace the existing fleet. Those new plants would be 15% or 20% more efficient, you would get a 10, 20 or 30% reduction in CO_2 emissions and, by doing something traditional, you would get a very big bang for the buck.

Other Opportunities

MR. MARTIN: Let's move to three other opportunities briefly and then on to a different topic. John Veech, are nuclear power plants an opportunity as a result of this bill?

MR. VEECH: There are obviously some intricate political dynamics to take into account; it is not / continued page 28

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enough to look solely at the subsidies for new nuclear plants in the bill. I think it is unavoidable that the country will need more nuclear capacity. If gas prices stay at $10 or $12 an mmBtu and oil is at $60 or $70 a barrel, then people will start to look at building new nuclear plants quite apart from any government subsidies.

MR. MARTIN: Jon Weisgall, you teach a course at Georgetown law school in energy law, and you told me before the session today about a question that you ask your students.

Transmission companies may make the best targets because they are allowed to earn higher returns on equity, and they are subject only to federal regulation.

MR. WEISGALL: I have taught the class now for 15 years. I tell my students you can live in one of two places — within three miles of a coal slurry plant or within three miles of a nuclear power plant. Which would you choose? Class after class, year after year, they vote to live near the coal slurry plant. We all know the health risk. They would rather risk lung disease from coal dust than the far more remote, but potentially more catastrophic, harm caused by a nuclear plant disaster.

MR. MARTIN: Does this suggest that the climate isn't right yet for new nuclear plant construction?

MR. WEISGALL: Perhaps. Congress has done all it can in this bill to say we want to change the climate. The amount of money potentially thrown at nuclear in the bill is staggering. Nuclear plant owners get a production tax credit like the credit given to renewables projects. They get massive loan guarantees and even delay risk insurance.

MR. GALE: We have done a survey since 1992 of the power industry. When you ask senior executives at US utilities whether they think any new nuclear power plants will be built, the percentage who answered yes as recently as 1997 was in the single digits. Last year, more than 60% said yes. The climate is changing, but the reality is it is an evolutionary process. We are still buying and selling used nuclear plants in this country; that is a much safer bet for anyone who wants to invest in nuclear. I don't think the engineering firms that would build the next generation of nuclear plants are ready yet to take on this challenge.

MR. MARTIN: Can a nuclear plant be built before the nuclear waste issue is addressed by Congress?

MR. GALE: That will be 50 years from now.

MR. WEISGALL: I would ask whether we are going to export our nuclear waste; will that be the answer?

MR. VEECH: On the nuclear waste issue, it will ultimately be a question of which party in the transaction must bear that risk. If you can structure a deal where waste disposal risk is not on the utility, then I think nuclear plants will be built before there is a complete solution to the waste disposal problem. The waste disposal problem must be solved, but it is going to take some time.

MR. MARTIN: Pollution control. John Veech, you see this as a potential opportunity.

MR. VEECH: Yes. There will be increased spending on pollution control. When you look at oil and gas prices, it is clear that there will have to be heavier reliance in the US on coal. Coal cannot be used without significant spending on pollution control. The energy bill encourages such spending with a couple tax subsidies — faster depreciation and the ability to get a refund of taxes paid in the recent past if the money will be put toward pollution control. Utilities will probably pay for pollution control on a corporate finance basis, but it is clear there will be an increase in spending in this market segment.

MR. MARTIN: The bill encourages more use of coal. Isn't one consequence of that the need for more spending on pollution control?

MR. SHAPIRO: Perhaps by regulated utilities, but not by independent power producers. Independent power plants facing a soft market are more likely to shut down than put in additional pollution control, since they have no ability in such a market to pass through the costs. That may be what Mirant is thinking with its plant in the Pepco service territory. The bottom line is that whether we are talking about IGCC, new nuclear power plants, retrofitting of existing coal plants or pollution control, it looks like the regulated utilities are in a better position to take advantage of the tax and spending subsidies for these activities in the bill.

MR. MARTIN: Another thing the bill encourages is production of ethanol and biodiesel fuels.

MR. WEISGALL: The bill requires US refineries to double the amount of ethanol that they blend currently with gasoline. Given the wind and ethanol incentives in the bill, the midwest comes off as a very big winner. The ethanol market is already booming, at least judging from the number of new plants under development to make ethanol using corn as the raw input. Probably the greatest new opportunities are in biodiesel and production of cellulosic ethanol, both of which qualify for tax credits.

MR. MARTIN: The debate in the ethanol market is whether, with all the new plants under development, we risk having the same over-build situation we had a few years ago in the merchant power market. That is not yet a concern for biodiesel. We do not produce much biodiesel in this country.

MR. WEISGALL: Very low numbers, but biodiesel output is expected to increase 10- or 20-fold in a relatively short period of time.

MR. MARTIN: Are there any other opportunities that we have not mentioned?

MR. VEECH: One thing no one has mentioned is the bill improves the siting process for liquefied natural gas receiving terminals. This could have a significant effect on the gas equation in this country. There is already enormous upstream and midstream investment around the LNG business, but siting of receiving terminals — particularly in North America anywhere near population centers — has been a vexatious issue. The bill should make it easier to build new terminals. That will have an effect, in turn, on longer-term gas prices.

If you look at domestic gas production in the United States, most of it is either mid-continent or along the shelf. Projections show a significant decline in output within the next five to 10 years. There are not a lot of alternatives in the medium term other than to increase imports of LNG. We may ultimately build a ton of new coal-fired power plants, but that is 10 to 15 years down the road. It is the period five to seven years out where there is clearly a gap around natural gas, and LNG will have to be a part of the solution.

Fuel Prices

MR. MARTIN: What effect will the bill have on fuel prices? If the bill encourages greater use of coal, then won't that cause coal prices either to increase or at least remain on their current upward trajectory? If it will lead to construction of more LNG terminals, will that lead to a decrease in the price of gas?

MR. WEISGALL: This winter, natural gas and home heating prices will go up 30 to 60%, which will make the gasoline spike look like a walk in the park. So short term, no, but perhaps yes in the longer term.

MR. MARTIN: Any other effects on fuel prices? Nobody has mentioned oil. High oil prices were one of the driving forces behind this bill.

MR. WEISGALL: The bill does little to affect oil prices.

MR. MARTIN: Adam Wenner, in some parts of the country, one fuel sets the electricity price and, in others, a different fuel sets the price. Is there an opportunity for windfall profits for people, in regions where coal sets the price, who are using a different fuel?

MR. WENNER: Yes, in areas where electricity is priced in a real-time or day-ahead market. The amount an electricity supplier who is selling into the spot market receives is set by auction. As the price of coal rises, everything else rises along with it. Electricity suppliers who rely on other fuels will benefit.

MR. SHAPIRO: I think you have to look at the bigger picture. In New England or New York state, gas is on the margin, and existing coal plants in those areas make money. The problem is those plants are very old and will need to be retrofitted. The cost of the retrofits will have to come from somewhere.

MR. VEECH: Also from a Wall Street perspective, it's an interesting question what will happen if, as Exelon predicts, it is able to increase the efficiency of the PSE&G nuclear plants. Does the additional return from greater efficiency end up getting passed through to the ratepayers in lower rates, or does it end up benefiting the shareholders of the company?

MR. MARTIN: John Veech, looking at */ continued page 30*

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the bill as a whole, who comes out ahead — independent power companies or utilities?

MR. VEECH: That's a tough one. I think there are some important provisions that will help generators, because the main thing that a generator needs is a customer, which means the generator needs either a contract or a very vibrant liquid market. One impediment that generators face when trying to reach customers is transmission, which is to say a generator may well have customers, and it may well have power, but it also needs a significant enhancement to the transmission system. The enhancements will not happen overnight, but perhaps over a five or even 10-year period, you are going to have better markets as a result of this bill. You will have a generator with plants in one region and customers in another region. If you fix the underinvestment in transmission, that ultimately will be a great benefit for generators. It won't happen overnight.

MR. MARTIN: One more topic — PURPA changes. Bob Shapiro, an audience member who is watching over the web asks what effect the PURPA changes in the bill will have on merchant wind projects. Perhaps you can explain what the bill does on PURPA and then answer the question.

MR. SHAPIRO: The bill relieves utilities of any legal obligation to buy electricity from cogeneration facilities and small power plants that use waste or renewable fuels. It does so only in some parts of the country — those places where such generators have another outlet for their electricity besides selling it to the local utility. Any generator with an existing PURPA contract to sell his output to a utility is not affected. Existing contracts are grandfathered.

The utility purchase obligation is most likely to disappear in markets that are served by regional transmission organizations, or RTOs. Wind projects that are under 80 megawatts in size will still have the ability to force utilities to buy their output in areas where PURPA remains intact because there are no alternative outlets for the power. One potential problem is that states have been reluctant, for the last 10 years, to force utilities to sign long-term contracts, at least in states where the state is not otherwise trying to force utilities, through renewable portfolio standards, to supply a certain percentage of their electricity from renewable sources. PURPA has not been a terribly effective tool, as a result, in getting utilities to sign long-term contracts.

It is a major shift in US energy policy that Congress and the Bush administration found it palatable politically to promote nuclear power.

MR. WEISGALL: PURPA repeal doesn't change much. One benefit of being a qualifying facility under PURPA was that it exempted the project from regulation under PUHCA. However, in 1992, Congress created another way to avoid such regulation — by making an independent power plant into an EWG, or exempt wholesale generator. Many new projects were developed after 1992 as EWGs — rather than PURPA qualifying facilities — because that let them avoid some of the restrictions that applied to QFs. The projects had no trouble getting long-term contracts to sell their electricity to utilities.

Today, both QF and non-QF projects have trouble getting long-term contracts. That's because, in a partially-deregulated world, utilities are reluctant to sign contracts when they cannot be sure they will have an outlet for the power. The wild cards for the utilities are consumer retail choice in many states and possible cost issues with the local regulators.

MR. MARTIN: John Veech, does it matter any more whether a project is a QF?

MR. VEECH: I would think it doesn't matter all that much. The real challenge for anyone developing a plant is getting a long-term contract, and his ability to do so has been driven more by economic forces more than legal regulation. The lessons of the late 1990s, when too many merchant power plants were built and wholesale power prices collapsed, are still resonating with the regulators. I do not think we will see a return to a situation where utilities are forced to sign long-term contracts.

Most Interesting

MR. MARTIN: My next-to-last question is for each of you — what did you find most interesting about the energy bill? Jay Worenklein, let's start with you.

MR. WORENKLEIN: I found it interesting that the Senate, the House and the Bush administration found it palatable politically to affirm the importance of nuclear power as a critical part of our future energy policy. That, in my mind, is revolutionary. What the bill basically says is it may take 10 years or it may take 20 years for us to see really a number of nuclear power plants on line, but we will see them. Now, that begs the questions of how we go about financing them and whether there is any board of directors brave enough to take on the challenge. My guess is the answer is no, because boards will remember that in the mid-1980s, we saw several utilities on the brink of bankruptcy, or specifically in bankruptcy, because they put on line nuclear power plants. These concessions of $500,000 or so, they are not enough. We had $5 billion problems in the 1980s. So we have a big issue still about how we are going to do this. But the fact that it is politically palatable to do it in principle means that the field is open for discussion.

MR. MARTIN: Jon Weisgall, what was the most interesting part of the bill for you?

MR. WEISGALL: There were two things. Number one is the fact that this is a significantly greener bill than I would have thought. The energy bill that Congress very nearly passed in 2003 was a fairly green bill, but it failed to cross the finish line. Beginning in 2005, Pete Domenici, the Senate Energy Committee chairman, said whatever we pass must be a bipartisan measure. Every single staff meeting on the Senate side included both Democrats and Republicans, and the result was 71 votes in the Senate for the final bill. In that sense, this was a defeat for Tom DeLay. The bill was legislators legislating, making compromises, and the sausage that results from that kind of process is pretty ugly.

The second thing I find interesting is the acronyms that are not in the final bill. CAFE, or fuel economy standards for automobiles, did not make it. There is nothing in the bill to decrease US reliance on imported oil. ANWR, or drilling in the Alaskan national wildlife refuge, is not in the bill but will be addressed in a later budget bill. RPS, or a federal renewable portfolio standard, is not in the bill. A lot of these items were dropped in the give and take of legislative compromise. But, in the end, the bill is a decent step forward.

MR. GALE: Let me also mention two things. I bumped into a Senator the other day and wound up sitting with him on the plane while we talked about the energy bill. He called it a potpourri, which is a surprising thing for a member of Congress to say about a measure that was sold as a national energy plan for the United States. But he is right. The bill has a little of everything. If you look at the bill from the point of view of those who had to pass it, they were worrying about whose interests they were going to serve. It is nearly a miracle that, on some level, it serves just about everybody's interest, with a few notable exceptions like the MTBE lobby. It gives extended tax credits to renewables, even though the renewables community failed to get a national renewable portfolio standard. There is a little for everyone — the American way.

The second, related observation is that we have not collectively been able to say in one sentence what this bill will do for the energy market because the bill lacks cohesion. There is no strategy in it. We do not have the leadership nationally on these issues that one would need to have any real sense of direction. And that is a real tragedy. The tragedy is that we were unable to have some semblance about where we want to go and how we want to spend our capital to get there and how we do it while minimizing the harm to the environment.

MR. MARTIN: Adam Wenner, what did you find most interesting about the bill?

MR. WENNER: I also have two items. The first is that Congress has been moving to repeal PUHCA since 1981. Repeal measures have passed in one or the other house several times. But after all that time, the draftsman still managed to screw up the merger provisions of the Federal Power Act that were added as part of the PUHCA repeal so that the new law, read literally, now requires the parent company of an Afghan utility that wants to acquire the Pakistani parent of a utility to ask the US Federal Energy Regulatory Commission for approval. That's a power grab! It will require a technical correction.

The second thing I found interesting is that now, with PUHCA repeal, you could have a merger among utilities that take you from the redwood forests to the / continued page 32

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Gulf stream waters to the New York islands.

MR. SHAPIRO: I think the most critical shortage in the power industry is transmission. Everyone has recognized this for many years, and I am heartened by the fact that there is finally — although it is not strong enough — some federal fact finding that will lead to federal siting and eminent domain authority and that may lead ultimately to construction of needed transmission lines. The places where the coal is and where the wind is are not where the load is, so you have to build massive amounts of transmission, and the federal authority might finally be the thing that helps.

MR. VEECH: The bill, as I see it, should be effective in directing flows of capital to discreet areas that were beneficiaries. Let me list them in order of priority. Renewables and wind, in particular, are big winners under the bill. Transmission is number two. Coal generally and LNG are my numbers three and four.

The Future

MR. MARTIN: Now to the final question — is this energy bill just the beginning of the energy policy debate in this country? Is it even the end of a big chapter in that debate? I read in the Wall Street Journal yesterday that Republicans are already talking about giving states the ability to override a federal prohibition on offshore drilling for oil and gas, and they will be looking for a legislative vehicle for such a measure this fall. The subject of drilling in the Alaskan national wildlife refuge will also come up for debate this fall as part of a budget reconciliation package. Jon Weisgall, are we going to see another energy bill in short order?

MR. WEISGALL: ANWR will happen because there is an agreement to deal with it in the budget bill. However, beyond that, I am of two minds. On the one side, it is so difficult for Congress to pass energy legislation that there is a part of me that thinks there is no way Congress will be able to put together another energy bill in the short term. For example, the Republican leaders may want to revisit the federal ban on offshore drilling, but if Virginia wants an inventory and Florida doesn't and New Jersey doesn't, well, we had that vote already. I don't see Congress reopening a lot of these issues.

On the other side, as we continue to see natural gas prices rise in the short term and have this oil problem, there will be continued pressure to do something more significant on energy. Therefore, we may see action sooner than a veteran lobbyist thinks.

The other point is I do feel that, no matter what happens in the larger energy debate, we are going to move very quickly to a debate on climate change and global warming. It will start soon and, in that sense, we are at the end of one chapter and the beginning of another.

Finally, let me respond to Roger Gale. It is probably a good thing that we can't say in one sentence what is in a 1,700-page bill. It is not unlike the report of the Cheney task force that said we have to develop all our energy resources in environmentally responsible ways. The bill has 17 titles. We have talked today about the stuff for coal, LNG, renewables, transmission and the overall electric sector, but it is a big bill. The markets move forward. We will move on to another act in this drama pretty soon.

MR. MARTIN: Have the rest of you seen people with whom you deal starting to worry about carbon emissions, and how is this affecting their behavior? Roger Gale, you are nodding yes.

MR. GALE: I think there is a general recognition that was not evident a year ago — and it wasn't a consequence of the energy bill — that we are going to have carbon issues. My company did a survey of utility executives recently, and the one question on which more people agree — 93% of the

> Many Americans still say, if given the choice, that they would rather live near a coal slurry plant than a nuclear power facility.

respondents — is that the climate issue is going to become more important.

MR. MARTIN: John Veech, are carbon emissions a topic at Lehman for your clients?

MR. VEECH: Yes. I think people are very focused on carbon emissions. There is a consensus that regulation is inevitable. There will be winners and losers. People are already thinking about how the coming regulation will affect the economics of their deals. People are baking their expectations about what will happen into their projections.

MR. SHAPIRO: California already has in its procurement requirements for utilities and adder of sorts, so that people who bid and will emit CO_2 or other greenhouse gases will be at a disadvantage to other bidders whose technologies don't.

* * *

Houston

MR. MARTIN: Joe Kelliher, the new FERC chairman, said that new energy bill is the most significant piece of energy legislation to become law in the last 70 years. Do you agree with that assessment?

MR. SHAPIRO: It is a very significant bill for people who want to buy utilities. It is a very significant bill for the franchised utilities. For wholesale generators, I think the Public Utility Regulatory Policies Act in 1978, and the Energy Policy Act in 1992, were more significant.

MR. MARTIN: Are there any dissenting views? PURPA, the 1978 statute that Bob Shapiro just mentioned and that was a foundation for the independent power industry, caused a seismic shift in the shape of the power business in this country. Will this bill do the same?

MR. GAW: The 1992 act had a much more significant shift in the profile of the utility industry. It created a partially competitive marketplace. A partially competitive marketplace led to the issues that we all faced three years ago. Outside of PUHCA repeal, which I think is a very significant step, this latest energy bill looks like a bill that took about four years to come together. It is more like a Christmas tree than a bill. I do not believe it will lead to a significant change in the landscape, but we will find out in the next five or so years what the impact will be on investment decisions. I doubt the legislators who passed this realize fully what the impact of those decisions will be.

MR. MARTIN: Bob Kelly, is this bill an energy policy?

MR. KELLY: It is not a policy in any great sense. The repeal of PUHCA will lead to some consolidation of the electric power sector. I don't think the consolidation will be easy to achieve because of the state impediments. The bill is an effort to shift capital into particular sectors, like coal gasification. The bill is not very comprehensive. It is not very strategic.

MR. MARTIN: Don Kendall, you made an interesting point when I spoke to you before this session about the contrast between this bill and PURPA.

MR. KENDALL: I think the main change is repeal of the Public Utility Holding Company Act, but the effect will take a long time to be felt fully. One should expect major consolidation of utilities in the long run and a handful of new issues around that consolidation.

PURPA had a much more dramatic impact, but no one understood in 1978 when PURPA was enacted how it would reshape the US market.

This new bill is clearly not an energy policy act. It is a grab bag of stuff related to power. The impact will be piecemeal. It will have nowhere near the ripple effects of PURPA.

Most Significant Legacy?

MR. MARTIN: PURPA changed the landscape. There was one thing that came out of PURPA. It was the independent power industry. Is there one thing that we will be able to say 10 years from now came out of this bill?

MR. WENNER: I'll call it the Starbucks of utilities. I am a little more bullish that there will be real consolidation of electric utilities now that the Public Utility Holding Company Act has been repealed. There are still barriers at the state commissions, but just look at the MidAmerican-PacifiCorp, Exelon-PSE&G and Cinergy-Duke mergers that have been announced recently. Duke and Cinergy said in their testimony to the regulatory commissions, for example, that this is just the beginning, and they view the merged utility as a platform on which to expand further.

MR. MARTIN: So you think the one thing that we will be able to say 10 years from now came out of this bill is fewer utilities. Does anyone else see one thing?

MR. WENNER: Or bigger utilities.

MR. GAW: I think the other thing we will be able to say was the result of this bill is the construction of new nuclear power plants. My first financing as a / continued page 34

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banker was to refinance the Three Mile Island nuclear plant. I have often said that the next Gaw who finances a nuclear plant will be one of my grandchildren. About three years ago, that changed to the next Gaw will be one of my daughters. Now, I have changed that to the last deal that I will do in my career will be a nuclear power plant financing. The nuclear provisions in the bill are a very important watershed moment in this country.

The dark horse may be how much penetration solar energy gets by mid-century.

MR. MARTIN: I noticed the Joint Tax Committee staff estimated that it would be 2013 before there will be any revenue loss from the tax incentives for nuclear in the bill. When do you expect to see the first nuclear plant built, and when do you expect to retire?

MR. GAW: I have three daughters, and three college educations and three weddings to look forward to, so I have plenty of time. No one knows how long it takes to build a nuclear plant in this day and age. I doubt we will see any new plant in commercial operation before 2015. It may even be 2020. Six plants have been identified already as possible candidates for construction. However, I do know we will see development work done on them. For example, British Fuels is looking today to divest Westinghouse Electric's nuclear division. If it had tried to sell the same subsidiary three years ago, there would have been a very limited response. I think you will see some large players start to become more prominent on the nuclear side of the business.

The United States is not the only place in the world that is taking a renewed interest in nuclear. There are other countries that have always been more comfortable with nuclear power — countries like France and Korea. I do not see nuclear turning suddenly into a bonanza for developers or bankers or equity investors, but there will be a gradual renaissance worldwide.

MR. MARTIN: Don Kendall, there has been a lot of discussion about whether Wall Street is impressed enough by the incentives in the bill for nuclear to finance new nuclear plants. What do you think?

MR. KENDALL: They will get funded, but a lot of the risk will have to stay with regulated utilities. They will require significant amounts of equity to finance. This will be a long process. The last such projects to be financed were 15 years in gestation.

MR. MARTIN: Adam Wenner or Bob Shapiro, I think Don Kendall just suggested that the next wave of nuclear plants will have to be done on a rate base because these are pretty risky ventures. They take an enormous amount of time. Will the state regulators allow such risky ventures to be put on the backs of the ratepayers?

MR. KENDALL: Let me interrupt. I didn't necessarily say "rate base," but I think a creditworthy entity will have to stand behind any new nuclear plant. It could well be a utility making the assessment. A regulated utility can get such a project financed. But I think the financings will be different. They will be more like we did at the end of the last wave of nuclear plant financings where lease financing was used. This had the effect of levelizing the payments and avoiding the shock of putting the entire cost into rate base with a commensurately large immediate increase in rates.

MR. MARTIN: So there may be new demand for all the leasing experts at banks who have been laid off?

MR. KENDALL: I don't necessarily think it will be third-party leasing. I think it will be inter-company leasing, like you are going to see for some of the large advanced coal plants for the purpose of smoothing the revenue stream.

MR. SHAPIRO: I agree nuclear will not be a developer play. It will be a utility play because of the risks and potential delays in permitting. There is some coverage in the new energy bill for the cost of delay, but it is for just the first few plants, and the amount of money is limited and the coverage is available only for a limited period of time. These are risks that can only be borne by captive customers of utilities. Considering the long lead time from development to completion, that is a very long time for a developer to carry that kind of risk without repayment.

MR. WENNER: Let's not overlook the intersection of the two themes about which we have been talking — the possible revival of interest in nuclear at the same time that utilities are consolidating. My view, exemplified by the Exelon-PSE&G merger, is that we will have a handful of large, nuclear-focused utilities that are in a better position to undertake these risks.

MR. GAW: I think you are absolutely right, but I will tell you not only are the lenders going to demand some assurances on cash flow stream and payment, but the equity holders are going to demand it, too. Some of us are old enough to remember the disallowances the last time around. It was a fairly big club that suffered. Especially big bites were taken out of the shareholder positions. I don't think you will have a deal until it is wrapped on the financial side through a lease arrangement or a large safety is provided by the federal government.

Let me tell you this: Don Kendall is right. This is a 2020 prospect. Who knows what the constituency is going to look like in 2020? Who knows what ratepayers are going to be paying for electricity in 2020? Who knows what the price of natural gas is going to be in 2020? It may be that the legacy of this energy bill will be several new nuclear plants that are costly in relation to other power stations. I doubt that, but it cannot be ruled out as a possibility.

MR. MARTIN: Bob Kelly, do we have any choice on nuclear? If we're going to bring greenhouse gases under control, don't we have to turn to nuclear?

MR. KELLY: I think there are other options. The dark horse is how much penetration solar energy gets by mid-century. There may also be new ways to sequester emissions from coal. My problem with nuclear is its high cost. There is also the problem of the nuclear waste. You still have a lot of opposition not just from local communities on siting, but also from shareholders. These are huge impediments. Unless the federal government becomes a lot more proactive on siting, nuclear is not going to happen.

MR. MARTIN: That's an interesting point. There is the so-called Yucca Mountain dispute in Congress about what to do with the nuclear waste. Congress has not been able to settle it. Can you have a nuclear plant before we know where the waste can be deposited?

MR. KELLY: I don't think so. Congress will have to come up first with a policy for nuclear waste disposal for the existing waste, let alone the new waste from incremental investments in nuclear power.

Takeover Targets

MR. MARTIN: So, here may be one place where the energy bill did half the job? Congress put some incentives in place. Maybe they are enough. Maybe they are not. But the waste issue must still be tackled.

Let me move back to something on which Bob Shapiro and Adam Wenner touched, and that is consolidation of US utilities. Don Kendall, you have scoured the market for opportunities for investment. Presumably one of those opportunities is utilities that are potential takeover candidates. How do you spot such a candidate?

MR. KENDALL: First, let me comment on the speed with which I see the sector consolidating. I think it will happen gradually. I think you are going to see virtually no hostile takeovers in the utility industry, because utilities tend to have the support of the local politicians. This means the acquisitions need to be friendly transactions. The two private equity firms that were bidding recently on utilities — KKR and Texas Pacific — both failed because they were unable to muster local support for their bids.

In terms of scouring for opportunities, we tend to like opportunities where utilities are mismanaged. The difficulty there is dumb management is not often smart enough to sell the company when it should. Those are the companies that should be taken over by a better-managed company, because the takeover is a win-win for the shareholders and potentially also for the ratepayers.

More often, I think what you will see are situations where a CEO who is close to retirement and thinking about his legacy is willing to be taken over by somebody.

MR. GAW: I agree on the speed issue because, in all honesty, PUHCA has been Swiss cheese for the last five to 10 years. It did not prevent utilities that are determined to merge from doing so.

I think mergers are based on value. I don't think anyone here believes we will be down to 50 utilities in the United States within the next five years. I don't see it happening because of the constituencies behind the various electric utilities. Many utilities are electric / continued page 36

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cooperatives or municipally-owned utilities. Those of us who have spent time with them know it is a religion. It isn't a business. These people are very fervent about what they are doing and about control over their assets.

At the end of the day, value must be created for the shareholders. There must be real synergies. One of the obstacles for global foreign players thinking about coming into the US market is they don't understand our regulatory framework. The new energy bill solves only part of that problem. It sweeps away some federal regulation but leaves 50 different state regulatory schemes intact. Second, they really cannot get to the same level of synergy that the utility next door can.

MR. KELLY: Don Kendall made the point that the types of firms that you would look to acquire are poorly-run firms that have undervalued assets. But typically in the utility business, if a company is poorly run and not performing well, chances are that it is at odds with its rate makers. And if the company is at odds with its rate makers, then it is going to be a damn hard thing to come in as a new investor and get a good deal on rates.

MR. KENDALL: What I think makes sense is more like the Exelon acquisition where you take two utilities that have a particular expertise — nuclear, for example — or two utilities trying to become the market leaders in a new coal technology. You may well see combinations to form larger transmission companies.

MR. MARTIN: Have you bought any stock of a utility that you expect to be a target?

MR. KENDALL: We are much more on the fixed-income side, and generally we wait until a deal is announced, if we are in that business, as opposed to trying to speculate. My view is these are going to take an awful lot of time. I think I would be too impatient to buy a stock in somebody that should be taken over, because I just don't think the consolidation will happen quickly.

MR. WENNER: I have been reading a lot of testimony lately in proposed utility mergers. Here's a dichotomy that, I think, is a useful way to look at them. The pros are economies of scale, and I think such economies are real, even if the two utilities are not contiguous, because of back-office operations, reduction in number of officers and other things like that.

But there are no economies of scale, as PacifiCorp found out, in dealing with regulators. The fact that you know how to deal with one regulatory commission does not mean that you will be able and equipped to deal with another.

MR. GAW: It is obvious that everybody will have his home market, including US utilities. But when I talk to European utilities, perhaps they are trying to be polite because I'm an American, but some say that they have a keen interest in investing in the United States. They just don't know how to make it work.

I agree. The likelihood of somebody coming in and buying something is low, but utilities around the globe face the same challenge, especially in OECD markets. They have very limited capacity for growth in their home territories. They have growing cash balances, and they are looking for alternative investments. So, either you go buy drug stores and real estate and all the other things that people did in the 1970s that proved unsuccessful, or you stick to what you know best.

I think there will be a shift at some point. I don't know when that inflection point will occur. You will see people starting to venture again into markets with which they are unfamiliar. At least they will be remaining in a business with which they are familiar even if the market is different.

Lobbyists who worked on the energy bill are already gearing up for the coming debate on global warming.

MR. MARTIN: Does anybody foresee a private equity fund taking over a utility in the next year?

MR. GAW: Maybe you should ask the opposite question. Do we not foresee that? I think one of the things we haven't talked about is the role of private equity and financial sponsors. I think the more interesting question is not so much which utilities will buy other utilities, but really which financial sponsors will play in this space in a big way. I do think you will see private equity come. It may be very targeted. It may be in the transmission business where although the returns are regulated, they are higher. Or it may be the renewable sector. I expect private equity to play a fairly significant role.

MR. SHAPIRO: I agree. I think transmission is particularly well-suited for private equity and not only because the allowable returns will be higher. A transmission-only entity is a federally-regulated entity that can get out from under the state control that we have said is a problem for mergers or acquisitions of distributions companies.

MR. KENDALL: The only way transmission works for private equity is with double leveraging. If you have FERC looking through to the holding company, you are going to have problems. However, as long as FERC continues to permit double leveraging, which is what the CIBC entity did with KKR — the actual rates of return on the deal are pretty rational. The reason you can do that, again, is through the right capital structure. But if there is a piercing of the structure — and that was one of the issues with the Texas Pacific acquisition of Portland General — once the regulators saw the internal documents and how much the bidder was making on leveraged equity, what the bidder said about lower returns and helping the ratepayers didn't ring as true. The same issue is present in transmission projects. If FERC decides some day to look at the actual leveraged equity in terms of transmission, there could be some real pressure to get the regulated return down.

MR. MARTIN: Is another way of describing double leveraging that you are allowed to earn a regulated return on a hypothetical capital structure?

MR. KENDALL: Exactly. In effect, you are showing more or less a 50% equity capital structure and 50% debt. The 50% equity is leveraged further at the level of a holding company.

MR. MARTIN: What returns are transmission companies allowed to earn?

MR. KENDALL: Independent transmission companies are allowed something like a 13% return with the hypothetical 50% leveraged capital structure. There is something like a 1% adder for independent companies. ◎

Are Subsidiaries Really Bankruptcy Remote?

by N. Theodore Zink, Jr. and Christy Rivera, in New York

A US appeals court decision in August is a reminder to lenders that there is a danger that even a "bankruptcy-remote" borrower can have its assets swept up in a bankruptcy proceeding involving a parent company or other affiliate.

A bankruptcy court might "substantively consolidate" the borrower with the company in bankruptcy.

That is what happened initially in a bankruptcy case involving Owens Corning. Fortunately for lenders, the appeals court reversed the lower court decision that the entities should be consolidated. At the same time, the court reaffirmed that anyone advocating substantive consolidation has a significant evidentiary burden to bear when requesting a bankruptcy court to disregard the boundaries between separate, but related, legal entities.

Substantive Consolidation

A corporation is a recognized legal entity distinct from its owners and other affiliates. This separateness, a recognized feature of corporate law, is generally respected by courts.

However, in a variety of contexts, courts may conclude that the principle of corporate separateness should give way to right some wrong or to achieve some other benefit. In bankruptcy cases, substantive consolidation developed to overcome corporate separateness.

A primary goal of the US bankruptcy code is equality of distribution. The primary purpose of substantive consolidation is, likewise, to ensure the equitable treatment of all creditors. Substantive consolidation allows bankruptcy courts to combine the assets and liabilities of separate (but related) legal entities into a single pool and treat them as though they belong to a single entity. / continued page 38

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Creditors of the various entities must then look to the consolidated pool for the repayment of their various claims.

Substantive consolidation does not necessarily benefit all creditors. Because different debtors within a related group are likely to have different asset-liability ratios, substantive consolidation may significantly disadvantage creditors holding claims against the financially stronger members of the group. Courts have recognized that substantive consolidation may often result in a harsh redistribution of value to some creditors at the expense of others and, therefore, substantive consolidation is an extraordinary remedy that must be exercised sparingly.

The courts have developed several principal frameworks in which to consider whether substantive consolidation is appropriate in a particular case. A line of cases decided shortly after the enactment of the bankruptcy code relies primarily on the presence or absence of certain "elements" that are identical or similar to factors relevant to "piercing the corporate veil" and "alter ego" theories. More recent cases take such elements into account within the context of a balancing test in which the interests of those parties objecting to substantive consolidation are considered. In a balancing test analysis, creditors may defeat substantive consolidation by demonstrating they relied on the separate credit of each debtor and would be prejudiced by such consolidation. The adverse effect on creditors who oppose substantive consolidation appears to have a greater degree of significance than mere proof of the substantive consolidation "elements."

The most stringent test, and that recently adopted by the appeals court in the Owens Corning case, provides the following alternative tests to determine whether substantive consolidation is appropriate. One test is whether creditors dealt with the entities as a single economic unit and did not rely on their separate identities in extending credit. The other is whether the entities' affairs are so commingled that substantive consolidation will benefit *all* creditors. This formulation is discussed in more detail in the following discussion about the Owens Corning case.

Owens Corning

Owens Corning and 17 of its wholly-owned subsidiaries filed for chapter 11 bankruptcy protection in October 2000 in the case of mounting asbestos claims. The creditors in the case included, among others, asbestos claimants, bondholders, and bank lenders under a $1.6 billion credit line.

Several years after the bankruptcy filing, Owens Corning (together with asbestos claimants and others) proposed a reorganization plan conditioned on court approval of the substantive consolidation of 18 related debtor and non-debtor entities. The motion sought consolidation for chapter 11 plan voting and distribution purposes only, thus preserving the corporate structure for all other purposes. The banks objected to the proposed consolidation.

At the crux of the consolidation issue was the undisputed fact that Owens Corning's "significant subsidiaries" — those domestic subsidiaries having assets with an aggregate book value of more than $30 million — gave the banks guarantees when the credit line was first extended in 1997. As a result of the guarantees, while asbestos claimants held claims only against either Owens Corning or one other entity, and holders of Owens Corning's public debt held claims only against Owens Corning, the banks held claims against each of the separate guarantors as well as Owens Corning. Accordingly, if the assets were substantively consolidated and the guarantees thereby nullified, the banks would be forced to share in the common pool of assets with asbestos and other claimants.

In concrete financial terms, the banks believed they would lose more than $1 billion in recoveries if the assets of all the companies were substantively consolidated.

A federal district court — the first court to hear the case — found that substantive consolidation was warranted. There are 13 federal judicial circuits — or regions — in the United States. The district court adopted a test for substantive consolidation that was developed by the US appeals court for the District of Columbia circuit, which covers the nation's capital.

That test requires someone seeking substantive consolidation to demonstrate both substantial identity among the entities to be consolidated, and substantive consolidation is necessary to avoid some harm or realize some benefit. If this showing is made, then the burden shifts to the party opposed to consolidation to show that it relied on the separate credit of one of the entities to be consolidated, and it will be prejudiced by substantive consolidation.

The district court that heard the Owens Corning case is in the third judicial circuit. In August, the US appeals court for that circuit rejected the test the district court used to decide on consolidation. It turned instead to the test used in the second circuit.

Under that test, anyone seeking substantive consolidation must demonstrate that *either*, before the bankruptcy, the entities disregarded separateness so significantly that their creditors relied on the breakdown of entity borders and treated them as one legal entity, or the entities' assets and liabilities are so hopelessly commingled that the expense of separating them would adversely affect the recovery of *all* creditors.

The appeals court also reviewed several "principles" that it suggested substantive consolidation, if used, should advance. The court said that a "fundamental ground rule" is to limit the cross-creep of liability by "respecting entity separateness." It directed courts to "respect entity separateness absent compelling circumstances." It called substantive consolidation a remedy of "last resort after considering and rejecting other remedies." It said substantive consolidation should typically address harm caused by the debtors (and not harm caused by the creditors) and that mere benefit to the administration of the case is not sufficient to invoke substantive consolidation.

After establishing the framework for its review, the court addressed the first test by asking whether there was disregard of corporate separateness. It found that there was no such disregard because Owens Corning and the banks negotiated the original lending transaction premised on the separateness of all the Owens Corning subsidiaries. Owens Corning cannot create the ground rules on corporate structure one day and ignore them the next, the court said. The fact that the banks did not require a review of individual internal credit metrics for each Owens Corning subsidiary was not determinative of the issue. The banks premised their credit extension on facts they knew about the guarantor subsidiaries as a group. The banks knew, for example, that each guarantor subsidiary had assets of at least $30 million, that collectively the guarantor subsidiaries had assets worth more than $900 million, and that the guarantor subsidiaries had little or no debt. At the end of the day, it was irrelevant that the banks did not receive independent financial statements for each guarantor.

The appeals court also said it was irrelevant that the banks did not request a legal opinion from counsel that substantive consolidation was unlikely to occur were any of the borrowers subject to bankruptcy. This type of lending with subsidiary guarantees is common. The court said the banks' requirement of guarantees from certain subsidiaries was evidence that the banks actually relied on the separateness of the entities in making the loan.

The court then turned to the second prong of the analysis and addressed hopeless entanglement. The standard is that "commingling justifies consolidation only when separately accounting for the assets and liabilities of the distinct entities will reduce the recovery of *every* creditor." The court easily found that hopeless entanglement did not exist here. The court was not impressed by the argument that the companies had not always accounted accurately for intercompany transactions. It said, "imperfection in intercompany accounting is assuredly not atypical in large, complex company structures."

Analysis

The district court's opinion seemed born of necessity — as the only way to get an Owens Corning plan confirmed — and not of thorough legal analysis.

The judge ignored the fact that Owens Corning strictly adhered to corporate formalities, that application of the harm/benefit analysis should have disregarded the potential salutary effect of consolidation and that a $1 billion loss to the banks was certainly prejudicial. In reversing the substantive consolidation ordered by the lower court judge, the appeals court gave weight to each of these facts and validated the lending and due diligence practices of the banks.

Although the appeals court adopted a more stringent substantive consolidation test, we believe the specific test applied is less important than a thorough and thoughtful analysis that pays appropriate deference to the corporate form. We believe that the test applied by the appeals court and the general principles enunciated by that court are consistent with the overwhelming majority of reported decisions on substantive consolidation.

Lenders should draw comfort from the appeals court's opinion. Among other things, the court validated the current day practice of obtaining subsidiary guarantees in connection with lending arrangements and limited the due diligence that lenders need to be able to demonstrate if faced with a request for substantive consolidation. For / *continued page 40*

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example, lenders need not obtain independent financial statements for each guarantor to demonstrate they relied on the corporate separateness of entities so long as they can demonstrate that they received detailed information from the parent about the subsidiaries. ◎

Asian and European Oil Companies Outbid US in Libyan Tender

by Nabil L. Khodadad, in London

The state-owned National Oil Company of Libya announced in early October the results of a licensing round it launched in May 2005 for oil and gas in 26 contract areas. The contract areas are divided into a total of 44 blocks.

The contract areas auctioned included three in the Cyrenaica basin, four in the Ghadames basin, six in the Sirt basin (Libya's most prolific basin), six in the Murzuq basin, two in the Kufra basin and five offshore in the Mediterranean.

This was the second competitive tender organized by the National Oil Company, or NOC, under its new model exploration and production sharing agreement called "EPSA-4."

Second Round Results

There was keen interest in the second round, with 50 companies from six continents submitting a total of 97 bids for the contract areas on offer. In the second round, companies from Asia were particularly successful. Japanese companies such as Japex, Nippon, Teikoku, Inpex and Mitsubishi won, or were in consortia that won, six of the contract areas; the Indian state-owned ONGC and the consortium of Oil India-India Oil each won a contract area; the Indonesian state-owned Pertamina won two contract areas; and the Chinese state-owned CNPC picked up a contract area. European companies also did well, with ENI, BG, Statoil, Total and Norsk Hydro winning most of the remaining contract areas. Russian oil company Tatneft and Turkish state-owned TPAO each picked up a contract area. Unlike the first round where US companies won, or were in consortia that won, 11 of the 15 exploration areas, ExxonMobil was the only US company to win a contract area.

Both the first and second rounds have been widely praised for their transparency. As in the first round, the bids from each bidder in the second round were opened in front of representatives from all bidders and were broadcast live on Libyan television. After all the bids for a contract area were announced, the winning bidder was immediately declared.

The winning bids for the second licensing round are shown in the table. (A more detailed description of the business deal offered by the NOC in the first and second licensing rounds can be found in "Libya Launches Second Exploration Tender" in the June 2005 *Newswire*.)

The company (or consortium) that bid the lowest production allocation, or "X factor," was declared the winner. The X factor is the percentage of oil production allocated for the recovery of the international oil company's costs and for the profit split. The international oil company will receive a percentage of production equal to the X factor until its costs are recovered. Thereafter, the oil company's share of excess production, or "profit oil," is determined in accordance with the following formula: the amount of profit oil multiplied by the "base factor" multiplied by the "A factor." The base factor is expressed as a percentage and can vary with the average daily production of oil. The base factor for oil produced from onshore blocks declines as the average daily production exceeds certain levels, but the base factor for oil produced from offshore blocks, and gas produced from all blocks, is set at a constant 100%. The A factor is also expressed as a percentage and varies with the ratio (commonly known in the oil industry as the "R factor") of cumulative revenues received by the international oil company to its cumulative capital and operating costs. As the R factor increases, the A factor decreases in a manner predetermined for each contract area.

As there were no bids for three contract areas, the NOC awarded 23 contract areas.

The total in signature bonuses for all 23 contract areas awarded was $103.4 million, with an average of about $4.5 million per contract area. The amount bid for the signature bonus was a secondary bidding parameter used to break a tie for lowest X factor, but in the second round there were no ties.

Comparison with First Round

The results of the latest bidding round confirm the keen interest of international oil companies in Libya and show the aggressive bids received in the first round were not a fluke. The average winning X factor was about 13.2%. This compares very favorably to the average X factor of 19.5% in the first round. In the first round, the lowest bid was 12.4%, with most of the winning bids between 15% and 20%. In the second round, 11 out of the 23 successful bids had an X factor of less than 10%. As the X factor just determines the amount of oil available for purposes of cost recovery and the profit split, it understates the take of the NOC and the Libyan government since the NOC is entitled to share in profit oil. These are considered excellent results for Libya.

The results of the second licensing round may foreshadow the emergence of Japanese, Indian and Chinese companies as key players in upstream oil and gas. With soaring demand for oil and gas in China and India, and with Japan appearing to slowly recover from its prolonged economic slump, we are likely to see Asian countries and their national oil companies compete more actively for upstream assets.

The aggressive bidding in the second round also appears to confirm the market's expectation that oil prices are likely to remain high for quite some time.

With the successful conclusion of the first and second EPSA-4 licensing rounds, Libya has confirmed its poll position as one of the leading destinations for foreign investment in upstream oil and gas. ◎

EPSA-4 Round 2 Results

Area	Winner	Production Allocation to International Oil Company (X Factor)	Signature Bonus (USD)	Number of Bids
Offshore				
2-1,2	Nippon (leader) Mitsubishi	8.0%	2,500,000	10
17-3	Pertamina	11.7%	8,009,000	6
17-4	CNPC	28.5%	6,000,084	1
40-3,4	Japex (leader) Nippon Mitsubishi	8.0%	1,700,000	10
44	ExxonMobil	28.3%	1,500,000	1
Sirt				
102-3	No offers			0
102-4	Oil India (leader) Indian Oil	10.5%	3,101,000	4
121	No offers			0
123-1	BG	10.9%	7,501,000	1
123-2	BG	14.2%	7,501,000	2
123-3	Pertamina	8.8%	7,009,000	8
Kufra				
171	Statoil (leader) BG	19.8%	1,001,000	1
186	ENI	15.4%	1,100,000	2
Cyrenaica				
42-2,4	Total (leader) Inpex	27.8%	1,801,000	1
42-1,3	No Offers			0
94	Statoil	24.9%	2,950,000	1
Murzuq				
146-1	Norsk Hydro	7.0%	7,068,000	8
147	TPAO	9.7%	7,262,000	4
161-1	ENI	8.5%	3,100,000	2
161-2,3	ENI	7.9%	4,000,000	6
176-3	ENI	9.8%	3,300,000	5
176-4	Japex	6.8%	3,000,000	5
Ghadames				
81-1	ONGC	11.8%	6,000,000	1
81-2	Teikoku (leader) Mitsubishi	7.5%	6,000,001	8
82-3	Teikoku (leader) Mitsubishi	7.5%	6,000,001	6
82-4	Tatneft	10.5%	6,000,000	4

China Moves to Encourage Renewables Projects

by Hong Li, in Beijing

A new law to encourage investment in renewable energy projects will take effect in China next January 1.

The Chinese government is expected to provide a range of financial incentives for such projects, including government grants to help with development costs, below-market loans and special tax treatment. The law also requires state-owned utilities to buy electricity from renewables projects, although the price they will pay for the electricity is one of a number of important details about the new law that remain to be worked out.

Electricity Shortfall

China is struggling with an inadequate supply of electricity. Current estimates are that the current Chinese electricity shortfall is 80 billion kilowatts a year, with actual demand at 2,456 billion kilowatts. Demand continues to rise and is outpacing reliable supply. In terms of supply, at least 70% to 80% of electricity is generated by coal and other depleting fossil fuel sources.

The Chinese government is trying to move quickly not only to increase electricity output, but also to diversify the sources of supply. Two fuel sources that are attracting increasing attention in China are solar and wind.

The National People's Congress adopted a "Renewable Energy Law" last February that is scheduled to take effect next January 1. The government is expected to fill in detail this fall through release of implementing regulations.

The new law defines the types of renewable energy that the government is now hoping to encourage as wind, solar, water, biomass, geothermal, ocean energy and "etcetera." The use of the additional word "etcetera" leaves the door open to developers using other technologies to apply for the same benefits for which the main renewables sectors will qualify.

Although "water" is one of the energy sources the government wants to encourage, it remains unclear whether the new incentives will be available for all forms of hydropower, since hydropower is already a common and traditional method of generating electricity in China. The best guess is that new small- and medium-sized hydropower plants with capacities below 50 megawatts will benefit from the new law. Older and larger hydropower facilities are likely to be excluded.

Benefits

There are three main benefits for projects that are covered by the new law.

Article 24 provides funding for a new "renewable energy development fund" that will make grants to pay for feasibility studies into the prospects for renewable energy in rural areas, cover early-stage research and development costs for projects in all areas, and help fund construction of renewable projects on islands. The government has not said yet how large the grants might be for any individual project. More details are expected by year end.

Article 25 of the new law directs Chinese banks and other financial institutions to provide low-interest loans for renewable energy projects. In order to qualify for such a loan, a project will have to be listed on a "national renewable energy development guidance catalog" that will be published in the future by the government. Some renewable projects have already received such loans under a circular — called the "Circular Regarding Issues on Further Supporting the Development of Renewable Energy" — that was published in January 1999 by the National Reform and Development Commission and the Ministry of Science.

Banks making the new loans are expected to be reimbursed for the interest-rate subsidy by either the central or local government, depending on which government approved the project for construction. Banks are also being urged to lend for longer terms than for other power projects. The interest rate subsidy is expected to be larger under the new loans than it was for loans made under the 1999 circular.

Projects that make it into the central government catalogue — or the listing of projects that qualify potentially for low-interest loans — will also qualify for special tax treatment, but the government has not announced any details yet. They are expected later this year. Any new tax breaks will be in addition to an exemption that wind developers enjoy currently from import duties on equipment for wind farms.

Developers of renewable energy projects in China must get an administrative permit or undergo a "registration for filing" procedure for their projects. If there is more than one applicant to build a project in a particular location, then the state is required to open the project rights to public tender.

Competition issues are also relevant to any renewable energy plant after construction is completed. One goal the government has set for itself is to ensure that renewables projects have an outlet for their output at prices that will make it possible to finance the projects. Under the new law, the state utilities that control access to the grid will be required to sign interconnection agreements with any renewables projects in their service territories that have received all the government approvals required to start construction. This mandatory purchase regime is similar to a regime already in place for gas and heat produced from biological resources.

Opportunity

The enormous market in China will create many opportunities for foreign investors looking to develop renewable energy projects. Industries are divided into three categories by the government, depending on the priority the government assigns to investment and whether it is prepared to let foreigners play a role. There are "encouraged foreign investment industries," "restricted foreign investment industries" and "prohibited foreign investment industries." Renewable energy is an encouraged foreign investment industry.

China has a current population of 1.2 billion. Demand for renewable energy is expected to grow to a US$12 billion market in the near term. The most established renewable sources currently are hydropower, wind and solar electricity. Total capacities this year for these three energy types are 110,000 mws of hydropower, 760 mws of wind farms and 60 mws of solar power.

Overall, the market share of renewable energy consumption in China is only 7%, and in comparison to some of its neighboring countries, China has lagged behind. Taking wind power as an example, China just barely registers in the top 10 countries in the world in terms of domestic consumption of wind power (well behind neighboring Japan and India).

The rate of increase in renewable energy consumption in China is currently 25% a year.

Consumption of electricity from renewables is expected to reach 15% of total consumption by year 2020, according to government figures. By then, capacity is expected to reach 300,000 mws of hydropower, 30,000 mws of wind farms, and 1,000 mws of solar power. The expected rate of increase in wind is staggering.

Although the new renewable energy law is expected to help, the major uncertainty remains the on-grid price of power generated by renewable energy and the ability for developers to generate "base rate" profits.

The National Reform and Development Commission issued a regulation in March this year on the reform of electricity prices in China. The report distinguishes among three types of electricity prices: the on-grid prices, the transmission price and the sales price. It recommends that a competitive pooling system be established that will allow the on-grid price to be determined through a bidding system. Any on-grid price established in this manner will still have to be approved by the price administration authority, but electricity from renewables projects is expressly excluded from this regulation. Rather, any review of on-grid prices for renewable electricity will be done on a different basis. Government regulators have been instructed to ensure that the price is set at a level that encourages both development and consumption of renewable energy. It remains to be seen how this standard will be applied in practice. Detailed rules on prices are expected, at least in draft form, in November.

The government is aware that any on-grid price set must afford a reasonable profit to investors. It is expected that on-grid prices for solar power are likely to be approximately RMB¥ 4 per kWh, and that prices for wind power are likely to be above RMB¥ 0.5 per kWh.

Some provinces have come out with their own rules without waiting for the central government to act. For example, Jiangshu province said in regulations in June 2005 that on-grid prices will be set at a level that provides reasonable compensation to cover higher generation costs, but the price must also ensure a fair sharing of costs between developers and consumers. The province said the on-grid price will be set through a tendering process, with any profit margin to be higher than the average profit rate earned on investments in other fields. ◎

SEC Takes Aim at Lease Accounting

Many US companies use lease financing rather than borrow from a bank to buy new equipment. The equipment must be returned to the lessor at the end of the lease term, unless the lessee exercises a purchase option to retain it. There are various reasons why a company might prefer lease financing. One is that it lacks the tax base to use the tax depreciation and any tax credits to which it would be entitled as the owner of the equipment. In a lease, the lessor claims these benefits and shares the value with the lessee in the rent it charges for use of the equipment. Another reason is that companies would rather not have to show more debt on their balance sheets. A lease can be a form of off-balance-sheet financing.

The staff of the US Securities and Exchange Commission said in a report in June that the accounting rules that allow this off-balance-sheet treatment for leases should be rewritten. The rules are in the hands of the Financial Accounting Standards Board. The SEC staff called on the accounting board to act.

The following is a conversation with Henry Phillips, an expert on leasing with the accounting giant Deloitte, about what is likely to come out of the SEC report. Phillips is the professional practice director of the national mergers and acquisitions practice for Deloitte. He also heads the subject matter team at Deloitte on leasing, and is part of a team at Deloitte that fields questions about entity consolidation. The questioner is Keith Martin.

MR. MARTIN: The Securities and Exchange Commission staff said lease accounting lets publicly-traded companies keep $1.25 trillion in future cash obligations off their balance sheets. The staff thinks this makes the financial statements of these companies misleading. Are you familiar with the report?

MR. PHILLIPS: I am. This is a report that the SEC was required by the Sarbanes-Oxley Act to write. It looks broadly at the use of off-balance sheet accounting.

The SEC staff identifies four goals in the report for those involved in financial reporting. One is to discourage companies from structuring transactions with the aim of producing favorable accounting rather than real economics. Another goal is to prod the Financial Accounting Standards Board to adopt more principle-based standards rather than hard-and-fast objective tests around which it is easy to plan. Another goal is to make financial statement disclosures more relevant to investors. The last goal is to focus financial reporting on communication with investors rather than rote compliance with the rules.

The staff made a number of recommendations. It urged the Financial Accounting Standards Board to reconsider its accounting guidance for leasing transactions. That is not a new SEC position. The report also urges the accounting board to reconsider how companies are required to account for defined benefit retirement plans. It wants FASB to require companies to report all financial instruments at fair value and abolish the notion of hedging and deferring costs on the balance sheet.

Finally, the SEC wants the accounting board to improve or redo FIN 46, which addresses when companies must consolidate special-purpose entities. FIN 46 was adopted in the wake of the Enron debacle. It has proven too easy for companies to structure around and, as a consequence, it has not had the desired effect.

MR. MARTIN: Come back to lease accounting. What is lease accounting?

MR. PHILLIPS: Accountants consider a transaction a "lease" if someone has been given the right to use a specified asset for a stated period of time. How that transaction is reported on a company's books depends on whether you are talking about the lessor or the lessee and what type of lease is involved.

Lessors

MR. MARTIN: Let's start with the lessor side of the transaction. If the transaction is reported using lease accounting, then the lessor would show itself as the owner of the asset and any debt used to acquire it would appear in the lessor's balance sheet. Is that correct?

MR. PHILLIPS: That's true when lessors account for leases as "operating leases." You will often find that the lessor and lessee use asymmetrical accounting. In many cases, the lessee will report a transaction as an operating lease, and the lessor will treat it as a "capital lease."

MR. MARTIN: A capital lease means the lessor views himself merely as financing a purchase of the equipment by the lessee?

MR. PHILLIPS: That's right. An example of an operating lease is where a business traveler rents a car at the airport. In an operating lease, the lessor has a hard asset — the car — on its books. It is the owner. The lessor reports the rental income on a straight-line basis over the lease.

However, in most big-ticket lease transactions — especially where a financial institution is the lessor — the lessor prefers to account for the lease as a capital lease. The most common subcategory of capital lease is a "direct finance lease." The lessor does not treat itself as owning the hard asset. Rather, what it shows on its books is ownership of a lease receivable.

MR. MARTIN: A note?

MR. PHILLIPS: A note receivable. The best of all worlds for a financial institution is a "leveraged lease." In a leveraged lease, the lessor collapses the transaction and reports it on a net basis. The only thing it shows on its books is its equity investment in the deal. The nonrecourse debt at the lessor level and the lease receivable are a wash to the extent rents will be used to pay off the lease debt.

MR. MARTIN: Back up one step. You said there are two types of leases, broadly speaking — capital leases and operating leases, and within the capital lease classification, there are subcategories of capital leases. There are a direct finance lease, a leveraged lease and — are there others?

MR. PHILLIPS: There are three types of capital leases from the standpoint of lessors.

The first is a sales-type lease. These are most common where the lessor is the manufacturer of the equipment being leased. It is really a form of sale. The lessor reports immediately the same profit that it would have had from a direct sale. The lessor also has lease income over the lease term, but a sales-type lease is really a financing and the only further income that the lessor reports from the transaction — after the profit is reported up front — is the interest income that it earns from financing the purchase.

The next type of capital lease is a direct finance lease. An example is where a financial institution acquires an asset directly from the manufacturer and immediately leases it to the lessee. It is merely a financing transaction. The lessor recognizes interest income over the term of the lease.

MR. MARTIN: And then there is a leveraged lease where the lessor shows just the equity investment it has after netting out the amount it borrows and the amount it is viewed as on lending?

MR. PHILLIPS: Right. A leveraged lease must first meet the requirements to be classified as a direct finance lease, and then there are some additional tests. First, there must be three parties to the transaction — the lessor, a lessee and a lender. Second, there must be substantial leverage in the transaction, meaning more than 50% nonrecourse financing from a third party. There are a couple other tests. The bottom line is the only thing a lessor shows on its books is its net equity investment.

MR. MARTIN: Why is that the best result for the lessor?

MR. PHILLIPS: Because the lessor does not have to show the debt. Contrast a leveraged lease with a direct finance lease, where the lessor has an interest-bearing asset on its books in the form of a lease receivable, but it also has the related borrowing on its books.

A leveraged lease also gives the lessor special accounting for when income is reported from the deal. Income is front loaded in a leveraged lease. The lessor reports his entire profit in year one and then only financing — or interest — income in later years. These are entirely form-driven standards.

Actually, what I just said on timing is an oversimplification. The reporting of income from a leveraged lease gets quite complicated. You need to determine the interest rate over the life of the investment that will yield a constant rate of return. In the early years of the deal when the lessor still has a positive net investment — after taking into account the tax benefits it is receiving — the constant yield is applied each year to that positive net investment. The net investment declines over time and, in some deals, actually goes into a negative position, and the lessor ceases to recognize any income for a period of time. There may be some additional income in the out years. The point is that most of the book income is usually recognized in the first several years under leveraged lease accounting.

MR. MARTIN: What is the timing of the income with a single investor lease or direct finance lease where there is no leverage?

MR. PHILLIPS: It is like the income that a lender reports when it makes a loan. The income each year is the rate of return times the outstanding principal balance. A portion of each lease payment will go to reduce principal and the rest is interest. The payments are more interest in the early years when a large principal balance is outstanding and then in later years, the situation reverses and each payment is considered more principal. / continued page 46

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MR. MARTIN: So you have a natural acceleration, but you do not have the pattern in a leveraged lease where there is extreme acceleration followed by . . .

MR. PHILLIPS: In some periods, the lessor in a leveraged lease may have no income.

Lessees

MR. MARTIN: Let's turn to the lessee side of the equation. With an operating lease, a lessee does not have to show any future financial obligation on its books, right? It just pays rent and deducts it each year?

MR. PHILLIPS: Right. There are disclosure requirements under the accounting standards that require the lessee to show in a table in the footnotes to its financial statement how much rent it expects to have to pay in the next five years. If the lessee has guaranteed the lessor a minimum residual value for the equipment at the end of the lease term, that must also be included in the footnotes.

In deals where there is a residual value guarantee, the guarantee shows up as a future liability offset by prepaid rent. The lessee is treated as having given something of value to the lessor at inception. That value is prepaid rent. That value is also the measure of the future liability the lessee must show on its books.

Residual value guarantees are more common in "synthetic leases" — transactions that the parties report as a loan even though they are set up as leases in form — than in "true leases." The trouble with residual value guarantees in true leases is they may make it harder for the lessor to claim that it is the tax owner of the asset. The guarantee puts the risk on the lessee that the asset will be worth less than expected at the end of the lease term. This is normally a risk that comes with owning the asset.

MR. MARTIN: The choices for the lessee are whether to report the transaction as an operating lease or a capital lease. A lessee likes an operating lease because he shows five years worth of rent in a footnote as a future obligation, but otherwise just deducts his rent each year as it is paid. The lessee is not viewed for financial reporting purposes as having a long-term obligation like a debt owed to someone. Contrast that with a capital lease. With a capital lease, the lessee is viewed as if he bought the asset. He has an asset on his books, but he also must show the full stream of rents that he must pay as an obligation. Is that right?

MR. PHILLIPS: Yes. An operating leases gives a lessee two things. One is the asset and liability are off the books from an accounting standpoint. I think the rating agencies are well aware of this. They tend to add back the future obligations, so I am not sure how much benefit lessees get today from operating leases.

The other point about operating leases is there is an income statement pickup. In an operating lease, rents are deducted from book income on a straight-line basis over the term of the lease. In a capital lease, the lessee has an asset on its books that it must depreciate. Each rental payment is treated as part interest and part principal. The part interest is deducted immediately. The lessee also has to depreciate the asset for book purposes. The combination of an interest and depreciation deduction each year is dilutive. Earnings are reduced more in the early years with a capital lease than with an operating lease. The expenses in a capital lease tend to be more front loaded.

MR. MARTIN: In the early years of a capital lease, more of each payment is considered interest than principal. So you get a large interest expense and a straight-line depreciation deduction. That is why the expenses are front loaded. In an

The Securities and Exchange Commission staff believes lease accounting lets US public companies keep $1.25 trillion in future cash obligations off their balance sheets. It wants the rules rewritten.

operating lease, the expenses are reported on a straight-line basis? There is no acceleration?

MR. PHILLIPS: That's right.

MR. MARTIN: What is the key to treatment as an operating lease versus a capital lease if you are a lessee? Are there a series of bright-line tests to pass and, if you pass them, you are home free? No further analysis is required?

MR. PHILLIPS: This is where the criticism of lease accounting takes hold. I am not sure anyone would disagree with the SEC's charge that it is absurd that whether a transaction is an operating lease or a capital lease can turn simply on the identity of the lessee. The two transactions can be otherwise economically similar.

A lessee will have a capital lease if one of four things is true about the transaction. First, title will transfer automatically from the lessor to the lessee by the end of the lease term. Second, the lessee has an option to purchase the asset from the lessor at a bargain price. Third, the lessee has the right to use the asset for more than 75% of its expected economic life. Fourth, the present value of the minimum lease payments that the lessee is obligated to make exceed 90% of the estimated fair market value of the asset at inception of the lease.

Any one of these attributes will make the transaction a capital lease. This is where the regulators chafe at the form-driven nature of the rules. Two lessees may use different discount rates with the result that one has an operating lease because the present value of his minimum lease obligations is 89.9% of the value of the asset, and the other lessee has a capital lease because his slightly lower discount rate gives his rents a present value of 90.1%.

MR. MARTIN: What discount rate does FASB require lessees to use?

MR. PHILLIPS: If known, the lessee must use the implicit interest rate in the lease. You determine that rate by solving for the discount rate to set the expected rent payments equal to the lessor's estimate of the residual value the asset will have when the lease ends. In most leases, the lessee cannot compute the implicit interest rate because it does not know what estimate the lessor has made of residual value.

In such cases, FASB requires the lessee to use its incremental borrowing rate — or the rate it would have to pay to borrow from a third party on similar terms — as the discount rate for applying the 90% present-value test. Lessees' borrowing rates vary.

MR. MARTIN: So you could have an identical transaction that would be booked as an operating lease by one company and a capital lease by another just because the two lessees' borrowing rates are different.

MR. PHILLIPS: Exactly.

Outlook

MR. MARTIN: Come back to what the SEC staff said. Did the SEC staff recommend to FASB that it get rid of lease accounting?

MR. PHILLIPS: I wouldn't put it that strongly. The staff recommended that the Financial Accounting Standards Board reconsider the accounting for leases. This is not a new position for the SEC. The SEC has urged the board for several years to take on leasing as a project. FASB has had it on the agenda to take on, but it has put off opening such a project for at least the past 10 years because other matters always seemed more pressing. Leasing has never been a priority. I think that is partly because FASB is moving toward greater harmonization of US and international accounting standards, and it has been waiting for the International Accounting Standards Board to address leasing, but the IASB has also viewed leasing as a second-tier priority.

MR. MARTIN: Do you think FASB is likely to take action on leases in the next couple years?

MR. PHILLIPS: The SEC report could be just the spark that moves leasing up on the FASB agenda, but I think FASB is constrained by its desire to make this a joint project with the IASB. I think you could see FASB open a project on this in the next couple years. In the next five years, we could see a new standard.

The process of coming up with a new standard is a long one. FASB has a healthy deliberative process with release of exposure drafts and plenty of opportunity for comment. The leasing industry is a very large industry. It is an effective lobbyist for its interests.

Most people are on board that lease accounting needs to change. It will take time for people to get comfortable with whatever FASB proposes and to assess the impact on their businesses.

MR. MARTIN: Let me just insert this background. FASB Chairman Robert Herz said three years ago: "My personal view is that lease accounting rules provide the ability to make sure no leases go on the balance / *continued page 48*

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sheet, even though you have the asset and an obligation to pay money that you can't get out off." He said that if companies don't capitalize leased assets on their balance sheets, something is wrong. David Tweedie, who is the International Accounting Standards Board chairman, said during Senate testimony in the wake of the Enron scandal, "A balance sheet that presents an airline without any aircraft is clearly not a faithful representation of economic reality."

It seems that those two gentlemen are interested in changing lease accounting, although — for reasons you point out — it may not happen very quickly. What is the International Accounting Standards Board treatment of leases? Does it mirror the FASB treatment?

MR. PHILLIPS: It is similar to the US standards, but there is a bit more substance. IAS-17 is the leasing standard. You should not have a situation, under the IAS rules, where characterization turns on whether the present value of the minimum required lease payments is 89.9% or 90.1% of the estimated value of the leased asset. However, the IAS rules are based generally on the same tests as in the United States. It is just that the tests are not applied as rigidly.

MR. MARTIN: In a case where you have a cross-border lease, say, between a European country and the United States, do both IAS and FASB standards come into play? Is the US party regulated by FASB, and would the European party be looking to IAS standards?

MR. PHILLIPS: Possibly yes, but some European companies ultimately reconcile to US GAAP because they are SEC reporting entities.

MR. MARTIN: If someone is in the midst of doing a large deal and relying on lease accounting, is there anything he or she should do in anticipation of possible changes in the accounting standards while structuring the transaction?

MR. PHILLIPS: My advice, given the current reporting and regulatory environments, is to structure the deal so that it aligns with the economics. When you apply the form-driven standards to get to operating lease or capital lease treatment, be reasonable in your judgments around those tests. Don't push the envelope.

For example, I don't think it makes sense for public companies with independent audit committees to move forward with a transaction as an operating lease if the present value of the minimum lease payments is close to the 90% line. In the current environment, I would be very conservative and stop at 80 or 85%. Give yourself a margin for error because there are judgments in applying the standards, and you don't want to end up losing if someone challenges your judgment. You don't want, as a lessee, to have to have change the reporting later on transactions that you thought were operating leases to capital leases.

My second bit of advice is that accurate disclosure is critical in these transactions because it can be material to investors, rating agencies and others who rely on the company's financial statements. Be sure accurately to disclose the obligations and risks and rewards associated with the transactions.

MR. MARTIN: If you had to guess at what new standards might come out of any FASB or IASB reworking of lease rules, in what direction do you think those boards will move?

MR. PHILLIPS: I think that there is a lot of support for an older accounting model called the G4+1 McGregor report. What that report said is that a lessee should put the present value of its lease obligations on the books as both an asset and a liability if the lease term exceeds one year. If you had a three-year lease, you would show three years of rentals as an obligation and an offsetting leasehold interest in the asset for a term of three years. If you had a 15-year lease, you would show 15 years of rentals.

MR. MARTIN: So no more off-balance sheet?

MR. PHILLIPS: That's right, but I think most people are reconciled to that result. It raises a number of other complex issues in terms of both recognition of assets and liabilities as well as de-recognition of assets and liabilities for both lessors and lessees. Some people struggle with having the same asset on both parties' books. Some of these finer points will have to be worked out as the accounting boards develop the new standard.

MR. MARTIN: I was going to ask you for an example of a complication. That is the main complication — the possibility of the asset being on two companies' books at the same time?

MR. PHILLIPS: That's right.

MR. MARTIN: What would happen, if the accounting boards move in the direction you suspect, to existing operating leases that lessees have in place when the new rules take effect? Will lessees have to make an immediate financial statement adjustment?

MR. PHILLIPS: The transition is always interesting when you have a new standard. FASB could mandate a number of things. It could require companies to apply the standard retroactively to existing leases, which might require restating earnings in prior years. It could require a cumulative catch up in the current period. It could "grandfather" existing leases. I suspect it will require a retroactive restatement because, otherwise, financial statement periods would not be comparable. Comparability is one of the things with which the accounting boards always struggle when adopting a new standard.

MR. MARTIN: Let me ask two other questions based on things you said earlier. You said it is not uncommon for the lessor to report a lease one way — for example, as a capital lease — and for the lessee to report it a different way — for example, as an operating lease. What percentage of big-ticket leasing transactions have this bifurcated treatment?

MR. PHILLIPS: This is only a guess, but I would venture to say in the majority of transactions where the lessee is accounting for them as operating leases, the lessor is accounting for them as capital leases or direct finance leases. One reason this happens is the lessee is using its incremental borrowing rate to apply the 90% present-value test, and this rate is usually higher than the rate the lessor uses as the implicit rate in the lease. That's because the lessor can usually borrow at lower rates than the lessee. Thus, the lessor may discount the minimum lease payments at a 4% rate and find they exceed 90% of the value of the equipment, while the lessee uses 6% and gets a different result. People are not playing games. It is just how the current rules work.

MR. MARTIN: The SEC report estimated that only about 22% of public companies report the lessee position as a capital lease while 63% book their transactions as operating leases.

The other question is you said rating agencies are focused on the off-balance sheet aspects of operating leases and are not really giving lessees full off-balance sheet treatment. Is there some way to quantify how much off-balance sheet benefit someone gets today from an operating lease?

MR. PHILLIPS: I am probably not the best person to speak to that, but I have heard that the rating agencies discount back the lease payments and treat the lessee as if he had a debt on his balance sheet equal to the present-value amount. So perhaps lessee gets about 10% off-balance-sheet treatment. I am just not sure. ◎

Toll Road Update

by Jacob Falk, in Washington, and Tracy Horton, in New York

The federal highway bill signed by President Bush in August earmarks $833 million for projects within 100 miles of the US borders with Mexico and Canada.

The measure should spur new highway construction in the border states, but the $833 *million* is paltry in relation to need. There is growing concern that unless new roads are built, border crossing points will soon be too congested for efficient use. Transportation officials, wary of the governments' ability to pay, are turning to private sector development as the best alternative for getting the necessary border projects done.

NAFTA

The US Federal Highway Administration and the Mexican Secretariat of Communication and Transport sponsored a "Border Finance Conference" in San Antonio, Texas in August. The focus of the conference was how to get new roads built along the US, Canadian and Mexican borders. Traffic among the three countries is booming thanks to the free trade zone created by the North American Free Trade Agreement — called NAFTA — and it is expected to increase as the countries approach a deadline of 2008 for full implementation of NAFTA.

Jeffrey Shane, a US undersecretary of transportation, said at the conference that the value of freight shipments among the US, Mexico and Canada increased an average of 8% a year since 1990 and is now more than 170% of what it was in 1990. "Mexico and Canada are the top two trading partners [of the United States], and trade among [these] countries is expected to keep growing," Shane said. "In 2004, the US traded $711 billion in goods with Canada and Mexico," which is almost $2 billion in goods and services a day. "Every year, some 350 million people legally cross the border between the United States and Mexico, and more than 200 million people cross the US-Canadian border."

The increasing traffic is a problem because there are too few suitable border crossings to handle the growing truck traffic, no viable "straight-shot" highways from Mexico to Canada, and insufficient government funding to build them. The US interstate highway system was designed almost half a century ago in the 1950s at a time

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when significant cross-border trade on the scale generated by NAFTA was unimagined. Mexican highways are similarly deficient. The main crossing points, like the border station at Laredo, Texas, are overcrowded while other crossings are underused because the roads leading in and out of them are not equipped to handle large volumes of commercial traffic. Trucks moving north from Mexico into the US interior end up adding to the congestion on already clogged roads in San Antonio, Austin, Dallas and Houston. What are needed are straight-shot highways that would let them bypass these cities.

The United States knew when NAFTA was ratified in 1994 that this would be a problem. It had originally planned to build a "NAFTA highway" that would run 1,600 miles from Laredo, Texas to Port Huron, Michigan at the US border with Canada. Part of this highway already exists as Interstate 69 between Port Huron and Indianapolis, Indiana. This part was built as part of the original interstate highway system in the 1950s. The rest was authorized by Congress in 1998 in the "Transportation Equity Act for the 21st Century" — called "TEA-21" — but construction has yet to start. The completed interstate would continue south from Indianapolis to the Mexican border through Indiana, Kentucky, Tennessee, Mississippi, Arkansas, Louisiana and Texas. Most states in the corridor have begun the environmental studies needed to move forward with design and construction of their portions of I-69.

Construction of I-69 will help alleviate the effects of NAFTA congestion, but the problem is much larger than one highway. The US border with Mexico is approximately 2000 miles long. A joint working committee of US and Mexican transportation officials has identified 311 significant road projects that need funding in the border areas

The US-Canadian border is more than 3,000 miles long. A similar joint working group of transportation officials from the two countries has identified 224 significant road projects that need funding.

NAFTA is forcing construction of new highways. US states along the planned route of I-69, which will run from Texas to Michigan, are having to turn to private developers to get their sections of road built.

The estimated total cost for projects along the US-Canadian border is $13.4 billion, and the funding shortfall for projects along the US-Mexican border is estimated at $10.5 billion. Government funding, which in the US is traditionally based on the collection of gas taxes, is unable to pay for these projects now and is unlikely to be able to pay for them any time soon.

US Actions

The amount of money the US government is able to provide is limited.

The federal highway bill that President Bush signed on August 10 authorizes $1.948 billion for road projects over the next five years through a "national corridor infrastructure improvement program." Congressional spending is a two-step process. Congress first "authorizes" spending, but the money cannot actually be spent until another bill is passed formally "appropriating" the money. Congress still needs to appropriate the highway funds that were authorized in August.

The money set aside for the national corridor infrastructure improvement program is supposed to be spent in ways that "promote economic growth and international or interregional trade," including NAFTA trade. However, Congress left federal highway officials with little discretion, choosing to "earmark" a lot of the funds. For example, Congress directed that $50 million must be used for general construction of I-69 in Texas, Louisiana, Arkansas, Mississippi, Tennessee, Kentucky and Indiana, $75 million for specific I-69 projects in Arkansas, $100 million for specific I-69 projects in Tennessee and additional amounts for various improvements to existing highways that will become part of I-69.

The highway bill also authorizes $833 million for NAFTA projects near the US border. This is the amount that Congress suggested the federal government would spend over the next five years under a "coordinated border infrastructure program." This money will be apportioned among the US border states based on the ratio of incoming commercial truck and personal motor vehicle traffic, the amount of incoming truck cargo and the number of border points of entry in each state. Some of the money may be used for qualifying projects on the Canadian or Mexican side of the border where such spending would help to ease congestion in the United States.

The sums that the highway bill authorizes are a drop in the bucket compared to need. Government officials attending the border finance conference in August agree that federal funding will be insufficient and spent most of the conference talking about how to get the private sector involved in road projects.

State Actions

Texas has already taken steps on its own to deal with NAFTA congestion. The state is implementing an ambitious plan to build a 4,000-mile, $180 billion transportation corridor of superhighways and pipelines called the Trans-Texas Corridor, or TTC, with private funding. The pressure placed on Texas highways by NAFTA traffic is one of the main drivers for the state's move toward innovative financing solutions. Texas selected a Cintra-Zachry consortium to develop the first stage of the project — a new $7.2 billion superhighway along the I-35 corridor, which stretches from the Mexican border in the south to the Oklahoma border in the north. The I-35 corridor will allow traffic to bypass San Antonio, Austin and Dallas while heading north.

The I-35 corridor in Texas is expected to serve as a "blueprint" — or test run — for development of the Texas portion of the I-69 NAFTA highway. The environmental studies for construction of I-69 in Texas got underway in early 2004 and are expected to conclude in 2006. Further environmental studies will be necessary if a preferred corridor is selected. No contracts have been awarded for the development or construction. The state expects to have to rely largely on private funds.

Meanwhile, in Indiana, Governor Mitch Daniels is proposing to use a public-private partnership to accelerate the state's construction of its remaining portion of I-69. Indiana does not currently have legislation authorizing use of PPPs to build road projects. The governor has asked the state transportation department to work on bill language to present to the legislature. If the plan passes, then the remainder of I-69 in Indiana may be built as a public-private toll road.

The remaining section of I-69 in Indiana will run 142 miles from Indianapolis to Evansville. Construction had been scheduled to begin in 2017, at the earliest, but under the governor's plan, construction will begin sooner. The estimated cost of the I-69 extension is $1.8 billion, with $700,000 to be spent over the next 10 years. The estimated savings to the state if the I-69 extension is built as a state-owned toll road is $700,000. If the I-69 extension is built as a PPP, the estimated savings to the state is between $900 million and $1.5 billion. The current round of environmental studies on the six sections of the proposed highway is expected to be completed by the summer of 2007.

Mexico

The United States is not the only NAFTA country looking at private ownership of roads to break the developing gridlock along the US-Mexico border. Mexico is doing so as well.

Mexico currently has 116 active public-private highway projects, and is expecting to develop more under a new national PPP program. Mexico has had a PPP toll road program since the mid 1990s, but the existing program has been a disappointment. The Mexican transport ministry announced a new program in 2003 that set aside $1.2 billion for nine concessions of varying length and size. The new program appears to be better thought out than the old program, and Mexico expects to put a number of other toll roads out to bid in the near future.

One of the proposed toll roads that is expected to go to bid as a PPP project this fall would connect Monterrey, a major industrial city, to the NAFTA highway on the Mexican side of the border. The NAFTA highway in Mexico is Highway 57 and runs between Mexico City and Laredo, Texas. North of Monterrey, Sabina Hidalgo may get an 88-mile PPP toll road to connect it with Colombia, a border-crossing point upriver from Laredo. Another border project proposed by Mexico would be a privately-built and operated highway and border-crossing bridge. The bridge would be located approximately 19 miles upriver from Reynosa, and would help alleviate overcrowding and delays on two bridges. ◎

Environmental Update

Climate Change

Nine northeastern and mid-Atlantic states released an outline in late August of a regional "cap-and-trade" program to reduce carbon dioxide, or CO_2, emissions from power plants.

This is the first effort by states to require mandatory CO_2 reductions on a regional basis. Massachusetts and New Hampshire have already moved within their own borders to require CO_2 reductions at specific coal-fired power plants.

The nine states announced a two-phase program that will cap CO_2 emissions from power plants starting in 2009 at approximately 150 million tons a year. That is based on an average of the highest three years of emissions reached in the region during the period 2000 to 2004. The first phase limit is a cap on emissions from 2009 through 2015, and the second phase limit will be 10% less than the limit during the first phase. The second phase limit will be in effect during the period 2015 to 2020. The affected power plants have generating capacities of 25 megawatts or more.

The initiative started with a proposal by New York Governor George Pataki in 2003 to address global warming on a state level since the Bush administration remains opposed to any action at the federal level. The nine states are working to achieve a consensus on the details of the program. It is expected to be memorialized in a memorandum of agreement among the states. The nine states are Connecticut, Delaware, Maine, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island and Vermont. Maryland, Pennsylvania, the District of Columbia, the eastern Canadian provinces and New Brunswick are participating as "observers."

Under the plan, states will be allowed to allocate up to 75% of the available CO_2 allowances to power plants directly. The signatory states will agree to set aside 20% of the allowances for public benefit purposes, including promotion of renewables and energy efficient projects and efforts to mitigate ratepayer impacts. States will also be required to set aside 5% of the allowances for a regional "strategic carbon fund" that will be used to encourage developers of new projects to achieve supplemental CO_2 reductions and to sequester carbon beyond what is required by the cap. States will also have the discretion to create a CO_2 allowance set-aside program for new sources.

The program is expected to allow the use of "offset credits" from qualified projects within the nine-state region, including from producing landfill gas, reforestation and certain energy efficiency projects. The nine states may also expand the use of offsets to include European Union greenhouse gas allowances that are traded to comply with the Kyoto protocol requirements, and offsets generated by Kyoto-approved "clean development mechanism" projects in emerging market countries. The states are expected to place a cap on the number of offset credits that can be used for compliance purposes.

One issue that will need to be addressed is how to account for potential emissions "leakage" by utilities agreeing to purchase electricity from generators outside of the nine states. Environmental groups charge that as much as 40% of the expected CO_2 reductions might be undermined by "leakage" where utilities look outside the region to buy power. This just shifts CO_2 emissions to other states. The nine states have decided to revisit in 2015 whether mitigation measures are needed to address the "leakage" issue.

The CO_2 reduction plan is expected to be finalized before the end of this year. A more detailed implementation rule will follow. The nine states are then expected to seek approval of the plan from their legislatures. California, Oregon and Washington are also reportedly considering a similar CO_2 cap-and-trade regional program in the Pacific Northwest.

In related news, a federal district court in New York rejected a lawsuit filed by eight states, New York City and several environmental groups against five power companies charging that their power plants emit large quantities of CO_2. The defendants in the suit were American Electric Power, Southern Company, the Tennessee Valley Authority, Xcel Energy and Cinergy Corporation. The petitioners claim that the five utilities account for about 650 million tons of CO_2 or about 25% of all CO_2 emissions from US power plants. The companies own or operate 174 fossil-fuel fired power plants in 20 states.

The case was based on a seldom-used legal theory that CO_2 emissions from the plants cause a "public nuisance." The judge said the case would require the court to rule on a "political question" that is not an appropriate "case or controversy" for the courts but rather should be addressed by Congress. The petitioners are expected to appeal.

Canada released proposed "offset system" rules in August as part of its effort to comply with its obligations under the Kyoto protocol to reduce greenhouse gas emissions. The draft rules explain how to create verified offset credits that can be sold to the Canadian Climate Fund or to other companies. Canada agreed in the Kyoto protocol to reduce greenhouse gas emissions by 6%, compared to 1990 emissions, by the period 2008 through 2012. The proposed rules give the following examples of projects that qualify for offset credits: demand-side management programs that reduce energy consumption, reforestation, landfill gas projects, agricultural carbon sequestration and renewable energy projects. The proposed offset credit rules are expected to be finalized by the end of 2005.

Energy Legislation

Congress is moving, in the wake of hurricanes Katrina and Rita and soaring gasoline prices, to pass legislation that would help expand gasoline refinery capacity in the United States and increase domestic oil and gas output. A bill reported to the full House by the House Energy and Commerce Committee in late September includes several controversial environmental provisions.

It would let state governors ask the US Department of Energy to oversee environmental permitting in their states for construction of new or expanded refineries. DOE would coordinate all permitting for siting, construction, expansion and operation of a refinery under the federal environmental laws, including the Clean Air Act, the Clean Water Act and the Safe Drinking Water Act, regardless of whether permits under these statutes are normally issued by state agencies. The bill also requires President Bush to designate at least three former military bases as locations for new refineries. The bill would also consolidate permitting for oil pipelines under the Federal Energy Regulatory Commission.

While the main focus of the bill is oil and gas, the measure also would rewrite the rules for when permits are required to make upgrades to existing power plants under "new source review," or NSR, procedures in the Clean Air Act. Section 106(b) of the bill would clarify that an upgrade is not considered a "modification" to a power plant for air permitting purposes unless it rises to the level of a modification for purposes of the "new source performance standards," or NSPS, program. This is significant because it is much harder to trigger a "modification" under the NSPS program. Under the NSPS program, a modification occurs when there is an increase in the hourly emission rate. In the new source review program, a modification is triggered when there is a significant increase in annual emissions at a plant compared to a baseline of the plant's actual emissions during a consecutive two-year period within the previous five years. For example, modifications to a boiler that restore the unit to its original hourly emission rate would not trigger a modification under the NSPS program, but they would probably trigger a modification under the NSR program.

There is a split in the federal appeals courts on the issue of how significant an upgrade must be to be considered a "modification" under the new source review program. The US appeals court for the 4th circuit held in *US v. Duke Energy Corp.* in June that "modification" has the same meaning for purposes of both NSR and NSPS permits. However, the US appeals court for the District of Columbia circuit said in *New York v. EPA* nine days later that the Environmental Protection Agency is free to adopt a stricter view of what is a "modification" for NSR permits.

The House bill also would codify a key portion of a controversial rule the Bush administration proposed in 2003 on the types of "routine maintenance, repair, and replacement" of equipment that can be completed at existing power plants without the need for a NSR permit. The Bush administration has been barred by a US appeals court from implementing its rule until the court rules on the merits. The House bill would write into the law a bright-line test that spares power plant owners from having to get permits to replace equipment where three conditions are met. First, the owner must be replacing an existing component of a unit (for example, a boiler or turbine) with identical components or components that serve the same purpose. Second, the fixed capital cost of the replaced component and any other costs associated with the replacement activity must / continued page 54

not exceed 20% of the current replacement value of the unit. Third, the equipment replacement must not alter the basic design of the unit or cause it to exceed any emission limitations.

The House bill would also authorize the US Environmental Protection Agency to extend the deadlines for areas that are downwind from "nonattainment areas" to comply with the national ambient air quality standards for ozone. This provision could have the effect of delaying currently required reductions in NO_X and VOC emissions in certain downwind nonattainment areas.

The refineries and oil pipeline bill remains controversial. It is expected to pass the House, but the outlook in the Senate is unclear. The best guess, as the *NewsWire* went to press, is that the controversial environmental provisions will end up being dropped.

Meanwhile, the Environmental Protection Agency is reportedly preparing to embrace the decision in *US v. Duke Energy Corp.* that "modification" has the same meaning for both NSR and NSPS permits without waiting for legislation from Congress. It would be a reversal of a longstanding EPA policy. If EPA goes forward with a proposed rule, a period for public comment can be expected later this year.

Mercury

The US Senate failed narrowly in September to overrule the "clean air mercury rule" that the Environmental Protection Agency adopted in May 2005. The clean air mercury rule uses a two-phased "cap-and-trade" approach to reduce mercury emissions from existing coal-fired power plants instead of the "command-and-control" regime that would typically have been imposed under section 112 of the Clean Air Act. The vote was 47 to 51. It marked one of the few times that the Congressional Review Act of 1995 procedures were used to try to overturn an EPA rule. That statute lets Congress overturn an agency regulation by a majority vote.

Meanwhile, the clean air mercury rule is being challenged in a federal appeals court in a case brought by 11 states and several environmental groups. They want the government to adopt strict technology-based emission standards for mercury rather than leave power plant owners with the flexibility either to reduce mercury emissions or buy allowances from others who have done so. The petitioners claim that simply ordering reductions would probably lead to as much as a 90% reduction in mercury emissions at most coal-fired plants. Under the clean air mercury rule that the Bush administration issued, the first phase of the mercury reductions commences in 2010 with a 38-ton cap followed by a reduction to a 15-ton cap in the second phase starting in 2018. Approximately 48 tons a year of mercury are emitted by US power plants today.

Nine US states are moving on their own to a "cap-and-trade" system to control carbon emissions from power plants.

The appeals court for the District of Columbia circuit declined to "stay" implementation of the clean air mercury rule while it hears the case. In order to grant a stay, the court would have had to conclude that the petitioners are likely to win the case on the merits and there is a likelihood of irreparable harm if the rule is not stayed. Since the first phase of the mercury reductions will not occur until 2010, the petitioners could not show the risk of irreparable harm if the court waits to hear the merits of the lawsuit. A decision on the merits is not expected until late 2006 or early 2007.

In related news, the Environmental Quality Board in Pennsylvania agreed in August to a request by a coalition of environmental and public interest groups to impose mercury emission reduction requirements on coal-fired power plants that go beyond the federal clean air mercury rule. The Board's action gives the Pennsylvania Department of Environmental Protection the authority to require 39 coal-fired power plants in the state to reduce mercury. The petitioners asked for mandatory reductions of at least 90% or a limit of 3.00 mg/MW-hr. Pennsylvania is expected to adopt a standard by November 2006.

Toxics Release Inventory

The Environmental Protection Agency took steps in September to streamline reporting requirements under the "toxics release inventory program." The "Emergency Planning and Community Right to Know Act" requires factories to make annual reports on the location and quantities of chemicals stored on-site to state and local agencies in order to help communities better prepare for chemical spills and other emergencies. Reports are filed with EPA each year for nearly 24,000 facilities and 650 chemicals. Most information is submitted on a five-page "Form R." EPA is proposing to let some companies use a shorter "Form A."

Under the proposal, Form A could now be used for persistent, bioaccumulative and toxic, or PBT, chemicals, except for dioxin and dioxin compounds, provided the facility manufactures, processes or otherwise uses no more than one million pounds of the chemical, there are no releases of the PBT chemical to the environment, and the plant does not manage more than 500 pounds of waste toxic chemicals at the facility by treatment, energy recovery or recycling. PBT chemicals include mercury, lead and other toxics. Current rules bar companies from using Form A to report PBT chemicals.

EPA also proposes that plants with non-PBT chemicals would be able to use Form A for a toxic chemical if the facility manufactures, processes or otherwise uses no more than one million pounds of a chemical and the facility manages no more than 5,000 pounds of waste toxic chemicals at the plant by treatment, energy recovery, recycling, disposal or other releases to the environment. The current threshold for non-PBT chemicals is a total annual reportable amount of 500 pounds that are treated, recovered, recycled, disposed or released. Comments on use of the new forms are due by December 5, 2005.

In a separate but related action, the Environmental Protection Agency notified Congress in early October that it plans to let power plants and other industrial plants report every other year — rather than annually — under the toxics release inventory program. EPA must wait 12 months after notifying Congress before it can initiate a rulemaking process to change the reporting frequency.

Particulate Matter

The Environmental Protection Agency explained in September what states must do to reduce fine particulate matter, or PM2.5, to meet the national ambient air quality standard for PM2.5. The PM2.5 standard was imposed in July 1997, and litigation challenging the rule was resolved in 2002. The affected states and the District of Columbia have until April 2008 to submit their plans to the federal government for approval.

Earlier this year, EPA identified 224 counties in 20 states and the District of Columbia that fail to meet the PM2.5, national ambient air quality standard. The nonattainment areas are mainly in the midwest, the mid-Atlantic states, the southeast, and California, with Ohio (31 areas), Georgia (28 areas), Pennsylvania (23 areas) and Indiana (19 areas) having the highest number of PM2.5 nonattainment areas. States must meet the PM2.5 standard by 2010; however, states may request an extension of up to five years for areas where there are more severe PM 2.5 problems and emission control measures are not feasible or available.

Particulates are particles found in air, including dust, dirt, soot, smoke and liquid droplets. The primary sources of fine particulates are motor vehicles, power plants, wood-burning stoves and forest fires. The proposed PM2.5 implementation would authorize states to regulate PM2.5 direct emissions, SO_2, NO_X, VOCs and ammonia. Fine particulates are believed to pose a health risk, particularly to older individuals and children, because their small size (less than 1/30th the size of an average human hair)lets them lodge deeply in the lungs.

The proposed rule contains some controversial exemptions that may trigger a lawsuit from environmental groups. In particular, the proposed rule would exempt power plants subject to the clean air interstate rule from complying with "reasonably available control technology" standards to reduce fine particulate pollutants. These standards require a minimum required level of emission reductions, but are not as stringent as the technology-based standards imposed on new and */ continued page 56*

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modified sources under the new source review program. The proposal would also set the "major source" threshold for new source review at 100 tons a year of PM2.5 for nonattainment areas as compared to the PM10 threshold of 70 tons a year for areas classified as serious PM10 nonattainment areas. The PM10 standard applies to larger "coarse" particulates. The EPA proposal will be subject to a 60 day public comment period after the proposal is published in the Federal Register.

The PM2.5 implementation rules may require existing power plants and factories to install costly new pollution control equipment or to upgrade existing controls to reduce fine particulate emissions.

Brief Updates

Industry groups representing utilities and coal producers are challenging the "clean air visibility rule" in the US court of appeals. The rule requires states to identify older power plants and factories that were built between 1962 and 1977 and have the potential to emit more than 250 tons a year of NO_X, SO_2, PM2.5 or volatile organic compounds that affect visibility in so-called class I areas, such as national parks or federal wilderness areas. The rule requires these facilities to install "best available retrofit technology." The industry groups that are in court argue that the clean air visibility rule runs afoul of prior court decisions on how states are supposed to identify who must comply. EPA adopted the rule that is now under challenge in July.

EPA published a final rule in late August exempting Georgia from complying with the "NO_X SIP call" rule. The NO_X SIP call rule imposes ozone season (May 1 to September 30) NO_X emission reduction requirements on sources in 20 states east of the Mississippi River. Georgia was originally required to comply with the NO_X SIP call rule starting on May 1, 2007. However, EPA has now concluded that emission sources in Georgia do not significantly affect ozone attainment in downwind states. North Carolina is objecting to the decision to exempt Georgia and is expected to file a lawsuit.

The New Jersey Board of Public Utilities voted to increase the amount of electricity that utilities in the state must supply from "class I" renewable resources, including solar, wind, landfill gas, geothermal, wave and tidal and sustainable biomass, from 4% by 2008 to 20% by 2020. The proposal would require that 2% of the amount come from solar energy.

Finally, the US House of Representatives passed significant revisions to the Endangered Species Act in September. It authorizes conservation grants and financial awards to private property owners to compensate for the loss of use of their property where the Department of Interior has concluded that there would be a "taking" of the property under the Endangered Species Act. The measure also establishes new financial incentives for private landowners who agree to enter into voluntary species recovery agreements and species conservation contract agreements to protect or restore habitat for covered species. The Senate has yet to act.

— contributed by Roy Belden in New York

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