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A New Dawn?

Too many new power plants were built in the United States in the 1990's and that led, together with the slowdown in economic activity, to a slump in wholesale electricity prices from which the merchant power industry has yet to recover. By 2003, some regions of the United States, like the Entergy service territory, had more than a 60% reserve margin — or spare generating capacity above what was required to satisfy electricity demand during peak hours — and even the area with the least capacity — Florida — had almost a 20% reserve margin. Predictions varied about how long it would take to work off the excess to a point where additional power plants would be needed.

Chadbourne hosted a roundtable discussion in late January about the outlook for domestic electricity prices with three prominent forecasters. The following are excerpts from the discussion. The speakers are Mark Griffith, a vice president with Global Energy Advisors, Art Holland, director of forecasting for Pace Global Energy Services, and Steve Dean, president of DAI Management Consultants. The moderator is Keith Martin.

Reserve Margins

MR. MARTIN: Where are reserve margins highest and where are they lowest today in the United States?

MR. GRIFFITH: The highest reserve margins today are in the ERCOT market in Texas and in the southeastern United States. Measuring reserve margins is always tricky, but I would say the lowest is in the Long Island area and New York City.

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RELOCATING POWER LINES can lead to tax complications for utilities.

The person asking the utility to move its lines often reimburses the utility for the cost. The utility then wonders whether it must report the cost reimbursement as taxable income. The Internal Revenue Service has been taking a hard line in such cases in the last year.

An electric utility moved a transmission line at the request of a state university that was expanding its campus. The transmission line cut across the new area the university planned to use as a campus. The utility moved it to the perimeter, and the

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That seems to be the area with the most urgent need for additional capacity.

MR. MARTIN: And what percentage reserve margins are we talking about in places like the Entergy service territory versus New York and Long Island?

MR. GRIFFITH: The last time I looked, the Entergy reserve margin was still close to 60%. In the New York City and Long Island area, if you just look at indigenous resources, the reserve margins are negative. It is actually planned that way. The region expects to rely heavily on imports to meet peak loads, and the reserve margins are currently in the range of minus 10 to 15%. That is not necessarily a bad thing. Many cities rely on imports. However, there is pressure to reduce the shortfall, and you will see some projects in 2005 and 2006 like East River and Astoria coming on line to help.

MR. MARTIN: Does everyone agree with that ranking of reserve margins?

MR. HOLLAND: I agree in general. I do want to caution, though, that it is not a good idea to use the reserve margin as a sole indicator for the need for new capacity. You are looking at a measure of supply and demand imbalance that focuses on a single hour during the year.

That said, in general, I think that the assessment was accurate. The reserve margins in ERCOT are high. Entergy remains very high. You have some parts of the Midwest that are still fairly high. Maine has a fairly high reserve margin still. You also have, by that measure, a fairly high reserve margin still in most of New England, or NEPOOL.

You also have to be careful with measuring capacity. For example, you don't want to apply all of your hydroelectric capacity to your reserve margin. Hydroelectric power is not so much a capacity-limited resource as an energy-limited resource.

MR. MARTIN: What does that mean?

MR. HOLLAND: It means that you don't necessarily want to rely on all of a hydroelectric facility that is rated at 500 megawatts to be available during the peak summer demand period. The water supply might not be adequate with the result that the plant might be unable to produce 500 megawatts when you need it.

US demand for electricity grew faster than supply last year for the first time since 1999.

MR. DEAN: I generally agree with the other commentators, but would like to point out a couple things. It is very difficult in most regions of the country to make unqualified statements about capacity factors. In the late 1990's, many more gas-turbine combined-cycle power plants were built than were needed. Many of these plants were halted in mid-construction and have sat idle. The reported figures mask this underutilized capacity. For example, in the southeastern United States — the area called SERC — we estimate that there is probably 20 to 25% additional capacity than you see in the reserve margins people quote due to unfinished plants or plants that have been mothballed. This is due partly to spiraling natural gas prices. They have gone up faster than most people predicted 12 or 18 months ago. Electricity prices have also increased in most regions of the country, but not enough to draw gas turbines into operating longer hours. In other words, fuel prices are increasing faster than electricity prices. The capacity factor for gas turbine projects is actually going down.

The one positive development is the growth in demand for electricity exceeded the additions to capacity in 2004 for the first time since 1999.

MR. MARTIN: In which regions of the country is the demand growth outstripping supply growth?

MR. DEAN: I think that is a general statement that is true basically in all regions of the country. As the economy has picked up, so has demand for electricity. And we have not seen a corresponding growth in supply.

MR. GRIFFITH: The one exception is the western United States where we are seeing a construction boomlet. We expect to add something on the order of 4,000 to 5,000 megawatts a year for the next two years — 2005 and 2006 — in the WECC, which is the western part of the US.

MR. HOLLAND: Mark, I suspect you are talking more about California and Utah than the entire WECC.

MR. GRIFFITH: Most of the activity is in California and some of the adjacent states, as opposed to the Rocky Mountain states. Arizona has also had a building boom and is trying now to figure out how to get the power to market.

Areas of Need

MR. MARTIN: Art Holland, what are the important factors in assessing whether there will be a need for more power plants — reserve margins, spark spreads, electricity prices, fuel prices, what?

MR. HOLLAND: In general, it is some measure of reliability. Despite my earlier comments, reserve margins are used as shorthand for that. Other organizations that are still under a more regulated type of a structure might use a loss-of-load-probability-reliability standard.

In more competitive markets, it may be useful to look more closely at prices and the point at which prices will start to justify new construction. Current prices do not justify new construction in the southeastern United States and perhaps not quite yet in the Midwest, but they are more competitive in the Northeast and California.

MR. MARTIN: Those areas offer perhaps the greatest opportunity for new construction. What is next on the list — Florida?

MR. HOLLAND: Florida is a unique situation. In Florida, you cannot build a power plant with a steam turbine in it over a certain size unless you have a contract with one of the local utilities. That was the issue surrounding the New Smyrna Beach Duke project, where the Florida Supreme Court sided with the utilities by confirming that you have to have a state permit in order to build a power plant with over a certain size steam turbine. Florida is in a fairly tight supply-demand situation, but there are legal impediments to new construction.

As far as working off the excess capacity most rapidly, you are already seeing pockets of need in New England. Boston and southern Connecticut are in need of capacity now and, as was already mentioned, New York City */ continued page 4*

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university reimbursed the utility for the cost.

The utility took the position that it did not have to report the cost reimbursement as income on grounds that the amount was a "nonshareholder" capital contribution. The IRS has often allowed such treatment in the past, but this time it insisted on audit that the utility had to report the reimbursement as income. The case went to the IRS national office, which confirmed in a "technical advice memorandum" — or ruling to settle a dispute between a taxpayer and an IRS agent — that the utility could not avoid reporting the payment by claiming it is a capital contribution. The agency said the problem in this case is the university received a direct benefit from the payment. The case is TAM 200450035. The IRS released the text in mid-December.

The utility should have claimed it had no income under a different theory. Companies that incur moving costs can ordinarily deduct them. However, that is not true in cases where a company is assured of reimbursement by a third party. In that case, the moving costs cannot be deducted, but the reimbursement does not have to be reported as income, either. The courts were describing this principle as "well settled" as early as the 1930's.

STATE TAX INCENTIVES to locate new businesses remain under a cloud.

A US appeals court in Ohio declined in late January to reconsider its decision that it is unconstitutional for a state to offer a company an investment tax credit in exchange for building a new factory in the state. DaimlerChrysler built a new automobile factory near an existing plant in Toledo, Ohio in 1998 at a cost of $1.2 billion. The state offered anyone investing in new plant and equipment at the time a 13.5% investment tax credit. The company also received a property tax exemption */ continued page 5*

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and Long Island have a continuous need for new capacity. The earliest other places where I would expect to see an early need for new capacity is Oregon and Washington. This might be less for energy requirements as for reliability requirements because of the high level of hydroelectric dominance there. The ECAR region — the "rust belt" states and, in particular, Michigan or what they call the MECS subregion — may be affected by Ontario's announcement that it will try to retire about 7,500 megawatts of coal capacity, some of which is old, but quite a bit of which is baseload capacity. That could create an imbalance between demand and supply in Michigan. You are seeing a similar situation in what used to be call MAPP, which is further west, and is now called MRO. This is the Dakotas, Minnesota, Wisconsin, and Nebraska. Xcel has already said that it needs several thousand megawatts of capacity.

MR. MARTIN: So we are beginning to see need.

MR. HOLLAND: Yes. We have been saying at Pace Global for a couple years now that you will start to see a recovery from the wholesale suppliers' perspective as early as next year. The market will not have recovered, but we will start to see signs of a recovery from the overbuild.

MR. MARTIN: As recently as a year and a half ago, forecasts were that you would start to see a recovery in places like Florida first, but it would be as late as 2015, or even later, before the recovery would reach places like the Entergy system. Has that time period shortened? Are people more optimistic about a recovery than they were even a year and a half ago?

MR. HOLLAND: Entergy is an extreme situation for a number of reasons. One is it was very easy for suppliers, private investors and development companies to get into certain parts of the Entergy service territory. There were no regulatory impediments. They were welcome to come build plants. The result was the area was extremely overbuilt. There is also some question about how much transfer capability in terms of transmission exists between Entergy and the surrounding area, which may make it difficult for that power to find a market outside of the Entergy area. You have a regulatory situation that is not conducive to competitive power, where you have very strong incumbent utilities, and the wholesale competitive market does not provide liquidity. It does not provide visibility in terms of price formation. There is not a lot of opportunity for non-utility suppliers to sell their power there. And they are in a highly overbuilt area.

> The merchant power industry is starting to emerge from the "bust" portion of the business cycle. The next "boom" should peak around 2010 to 2012.

MR. MARTIN: Steve Dean, do you want to comment on what we have been discussing?

MR. DEAN: Yes. Let's note that we are seeing some fairly substantial development activity taking place with respect to coal-fired generation. More than 100 new coal-fired plants are in various stages of development currently in the United States. Several coal-fired power plants in such places as New Mexico and other western states have been financed recently and started construction. In my mind, the question is not only where the areas are where reserve margins or capacity factors or even spark spreads support new capacity, but also what type of capacity should be built. I think we are seeing the answer to that question is that many of the new plants will burn coal. That is certainly true if you believe that natural gas prices will remain in the $5 or $6 an mmBtu range and you believe that electricity prices will not increase significantly in the near term.

MR. HOLLAND: I agree that is an extremely important point. The economics of coal-fired generating capacity are more attractive now than they have been in years. However, I would caution that coal is not a solution for every part of the country. It is difficult for me to imagine that we will see a lot of coal capacity built in very regions that we have said are likely to offer the earliest opportunities for new construction. Boston, southern Connecticut, New York, Long Island — I have a hard time imagining that you will see a coal-fired power plant built there. However, having said that, one of the technologies that looks like it may be starting to catch fire is IGCC technology. I don't want to suggest that we will see a large number of new integrated gasification combined-cycle power plants built soon, but the technology is starting to look more attractive.

MR. MARTIN: And the reason that it is more attractive is the capital cost per megawatt of capacity is far more expensive than for other types of power plants, but it is a cleaner way of using coal?

MR. HOLLAND: It is more expensive than a gas-fired combined-cycle power plant, but it may be comparable in cost to a conventional coal-fired steam-type power plant.

MR. GRIFFITH: We planned originally on this call to talk about the electricity price outlook and the parts of the US where they might be price opportunities, but the discussion broadened quickly to cover a lot of other topics — local reliability, the resource mix, the need for energy versus peaking capacity — and this gives you a sense of the overall complexity of the problem.

One of the things we have seen is that, as various regions recover from the supply overbuild, the transmission system is not allowing you to move the spare capacity around freely. There is a limit to how much electric transmission capacity exists in places like the upper Midwest, and this creates a need for new construction even in the face of a continuing oversupply in the southeastern United States.

If you look at a map to see whether you can move electricity between regions, the answer is you can 80% or 90% of the time, and this is one the factors contributing to depressed wholesale electricity prices in the Midwest, but you cannot move it during peak hours. That means you still have to build to maintain local reliability. It is the need for reliability that is behind the pockets of opportunity in places like Florida and the upper Midwest. There is a real need in these places, but it is due to the fact that they cannot get the capacity from other regions where there is still an overbuild. It makes for an interesting dynamic. It also shows that price alone is not what is spurring new construction, at least not at current energy prices.

We are struggling as a nation with / continued page 6

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for 10 years from the two local school districts. The tax benefits were worth $280 million.

A US appeals court held last September that "locational" incentives like investment tax credits are unconstitutional because they are an effort by a state to redirect interstate commerce. It let the property tax exemption stand. Ohio quickly asked the court to reconsider its decision. The court declined at the end of January. An appeal is expected to the US Supreme Court.

The decision casts a cloud over tax credits and similar benefits at the state level for wind farms, clean coal technology plants and other projects.

UNDIVIDED INTEREST STRUCTURES may be taxed differently by US states than by the federal government.

Municipal utilities and tax-exempt electric cooperatives who are approached about buying electricity from independent power companies sometimes ask to own an interest in the project and take a share of electricity in kind rather than buy the electricity under a power contract. One reason is the municipal utility or coop usually tap cheaper sources of money than the private developer can to finance its share of the project. The developer retains an interest in the project. It and the municipal utility or coop own the project as "tenants in common," meaning that each has an interest in the whole plant but the plant cannot be easily separated or divided. If two parties owned a chair this way, then each could sit in the whole chair, but they must share its use.

In order for such an arrangement to work, the parties must file a "section 761 election" with the Internal Revenue Service. The election ensures that the arrangement will not be treated as a partnership for federal income tax purposes.

A Louisiana appeals / continued page 7

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how to fund construction of this new capacity when there are still adjacent overbuild markets in this country. What is happening is utilities with a need for additional capacity to satisfy reliability needs are entering into bilateral contracts with independent power producers to provide specific identified resources that are used to satisfy the need. This is not the competitive model that people were envisioning 10 years ago, but it is a response to the reality on the ground.

The forecasts are based on assumptions about pollution controls, LNG terminals and nuclear power. These assumptions are the key variables to watch.

Locking in Supply

MR. MARTIN: Electricity prices are still low but are expected to increase. Are you seeing a greater willingness on the part of utilities nationwide, or just in particular regions, to sign contracts to lock in supply at current prices?

MR. GRIFFITH: Somewhat. The utilities with whom I have been working on integrated resource planning projects realize they need to sign some contracts to demonstrate that are not just interested in building power plants themselves. However, they have a concern about how long-term power purchase agreements affect their capital structures. When they build on their own, some of the capital comes from debt and some of it comes from equity. But when they sign a contract to purchase power, there is no chance to invest any equity. The demand charges under the purchase power agreements are treated like debt. This makes their debt-equity ratios look worse and is a concern when they come up for review by the rating agencies. Any utility that sign a lot of power purchase agreement might be asking for a downgrade in its credit rating, which would increase the cost of its debt. Utilities are struggling with this.

MR. MARTIN: Art Holland, are you seeing utilities under pressure in any parts of the county from their regulators to lock in long-term supplies of electricity while the prices are still relatively low?

MR. HOLLAND: Not directly. What I am seeing is utilities must show a level of prudence in their resource planning. Regulators are not saying prices are low so go out and buy, but they are insisting that utilities demonstrate prudence in their decisions whether to buy power from wholesale suppliers or to build their own power plants.

MR. MARTIN: Steve Dean, do you think it would be sensible for utilities to lock in supply at current prices? Are prices basically going to go up here?

MR. DEAN: Duquesne Light, which divested itself of all its generating assets, went to the Pennsylvania Public Utility Commission with a plan to purchase electricity, I believe, on a six-year contract. The commission rejected the plan. It wanted to shorten the contract period.

I think it makes sense to try to lock in long-term supplies because electric prices over the past year or so have been at historic lows, but as the experience in Pennsylvania shows, utilities in some cases are being prevented from doing so.

MR. MARTIN: Art Holland, would utilities be prudent to lock in supplies at today's prices?

MR. HOLLAND: The expectation in general is that prices will increase. I want to be careful that I don't say prices, but spark spreads. Prices tend to follow the general direction of fuels. As natural gas prices go up or down, you will see a corresponding change in the price for electricity. What is important is the spark spread, or the difference between the cost of inputs and what a generator can get for his electricity. The question isn't whether it would be wise to lock in prices when they are expected to increase. Utilities have to answer to their public utility commissions. They have to put together integrated resource plans that are consistent with the goals and objectives of the utility commission. The commission is interested in more than just the cost of electricity. The plan must also be consistent with the type of market that the commission is trying to encourage in the state.

That said, I think that it would be very prudent for large industrials with access to wholesale power to take a serious look at the prices in their area, and coupled with prudent risk management practices, look at entering into some longer-term contracts.

Trends

MR. MARTIN: Let me circle back to a question I asked Art Holland, but ask it this time of Mark Griffith. Are things looking rosier today for merchant generators than they were just a year and a half to two years ago?

MR. GRIFFITH: Rosy is a relative term. Things are actually playing out pretty much as expected. Go back two years. There was an expectation that prices would begin to recover as early as 2003 to 2004. What we saw was that most of the power plants that were under construction were actually completed, with the result that the overbuild got extended for another year or so. Now it is 2005, and we are seeing a recovery in the spark spread and it is not far off from what we were expecting.

The capital for investing, for refinancing, and for picking up distressed assets and keeping them in the market is much greater than we were anticipating. We thought that there would be more of a pullback from investors, especially the banks in New York who would not want to play in this game. What we see instead is a lot of money available for investment. It is not coming from traditional bank sources, but from private equity firms.

MR. MARTIN: Steve Dean, is the market recovering, in your view, faster than people were anticipating even a year or two ago?

MR. DEAN: I would argue that it is not, and the reason is clear if you look at the economics of gas-turbine combined-cycle plants. With gas at $6 an mmBtu and a 7,000 Btu-per-kWh heat rate, the owners need $42 an mWh just to cover their fuel prices, and electricity prices are currently in the $40 an mWh range. For these plants to be profitable, prices will have to move above $50 an mWh. We are not projecting that in the near term. The point is it remains a very tough environment for owners of gas-turbine combined-cycle plants, and it will remain tough for the next several years.

MR. MARTIN: Calpine, which is heavily invested in gas, says it expects the next wave of power / continued page 8

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court said in late December that such an arrangement was still a partnership for some state tax purposes. A Louisiana taxpayer, Unocal, owned a 2% interest in the trans-Alaska pipeline. The pipeline is owned by an "unincorporated association"; the owners opted out of partnership treatment at the federal level.

Louisiana allocates income earned from a partnership to the state where the partnership has its business operations. Thus, in this case, none of Unocal's income from the Alaska pipeline could have been taxed in Louisiana. However, if the pipeline project was not a partnership, then the income would be apportioned among all the states where Unocal does business, and part of it would be taxed in Louisiana.

The state argued that the pipeline project was not a partnership. It said it would follow the federal treatment. Unocal wanted the project treated as a partnership, at least for purposes of determining to which state to attribute its share of the pipeline income.

A Louisiana appeals court sided with Unocal. It said that even the federal tax code says that a joint undertaking among several parties to do a project remains a partnership for some federal tax purposes notwithstanding an election to opt out of such treatment. The court said this venture remained a partnership when it came to deciding where Unocal's share of income should be taxed. The case is *Unocal Pipeline Co. v. Kennedy*.

AN EARNINGS STRIPPING STRATEGY for British companies with US subsidiaries is under attack in the pages of *Tax Notes* magazine.

The magazine is popular with policymakers in Washington. "Earnings stripping" refers to what happens when a parent company pulls earnings out of a foreign subsidiary in a deductible form. For example, a parent company might capitalize / continued page 9

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plant building around 2008 or 2009. Is that consistent with your projections?

MR. DEAN: It depends on the region of the country. The most likely places where there will be such opportunities are in Florida, the New York ISO, and maybe some parts of the Midwest — for example, west of Chicago — as well as California, but with California, the question is how much of the need will be met through imports from the surrounding states.

MR. MARTIN: Art Holland, each of you seems to agree that the best opportunity by fuel type in the short term is coal. Is that because coal prices have not risen as rapidly as gas prices?

MR. HOLLAND: I'm not sure that I agree completely with that statement. In the parts of the country where you will see the need for additional capacity the soonest, coal may not be the best answer. While over the longer term, you do see an increase in the opportunities for new coal-fired power plants, I think that you have to temper that with environmental concerns and the longer lead times associated with coal. It takes longer to develop a coal plant than it does a gas plant.

MR. MARTIN: Well, that leaves a fairly confused picture, because the greatest demand is in regions where coal doesn't work. Why does coal get built then in parts of the country where the demand is not so great, and what gets built in the places where it is great?

MR. HOLLAND: The proximity to coal resources is conducive to construction of coal-fired power plants, as is the lack of proximity to densely-populated areas, which generally gives rise to heightened concerns about the environment. The environmental barriers to coal may eventually be overcome with IGCC plants, although I am not saying that we are throwing our hat into that ring just yet. We are looking at IGCC, and it is certainly looking more and more attractive.

MR. MARTIN: Mark Griffith, going back to you — Chadbourne had a conference in San Diego two years ago, and we talked about renewable portfolio standards, now in 18 states, that require utilities to generate or buy a certain percentage of their electricity from renewable sources. Is it possible that all the additional capacity required in the country, at least in the near-term, will be taken up by wind, geothermal and other renewable suppliers, and there won't be much room for more traditional merchant power companies?

> Large industrial users of electricity should think seriously about entering into long-term contracts to lock in supply at current prices.

MR. GRIFFITH: That's an interesting way of putting the question, Keith. Wind generation is a different type of capacity than a coal- or gas-fired power plant that is dispatchable. Early in this discussion, the point was made that you must be careful with counting capacity from hydroelectric generation due to its unique characteristics. The same thing is true for wind capacity, and even more so.

The renewable portfolio standards in 18 states plus the tax credit that the federal government offers wind generators is creating a building boom. You asked what the near-term opportunities are. Wind generation is definitely a near-term opportunity. Some electric utilities are also putting wind generation into their resource plans, even without being required to do so under a state renewable portfolio standard, because they want to take the lead on environmental activism and bluntly offset some of flak they expect to receive in the regulatory arena as they build a traditional fossil fuel plant. We are tracking renewables at Global Energy. We are expecting at least 10,000 megawatts in additional renewable capacity to be added in the US in just the next few years, and it could be a lot more than that.

However, all that aside, the capacity is generally not counted toward the capacity needed in reserve margins. The wind generation is not coincident with the peak demand for power in most regions, with a few exceptions like in California where there is a closer correlation between when the wind blows and periods of peak demand.

MR. MARTIN: So load growth will not be taken up by renewables for the reason that one cannot count on wind as baseload power?

MR. GRIFFITH: That's right. It is generally not baseload, with the possible exception of California. In other parts of the US, you often find the best wind resource is in the spring and the fall and not during summer when the loads are the highest. It is also not dispatchable. You have to take it when it is there. You are glad to have it because it is incrementally at a very low cost, but it is not a reliable resource.

The bottom line is if you end up putting in 10,000 megawatts of wind resources across the US, you will probably put in at least another 9,500 megawatts of some other type of resource, typically something that burns fossil fuel, in order to back it up.

MR. DEAN: The electricity center at Carnegie Mellon University did a study of how deployment of a large number of wind turbines would affect weather patterns in the United States. It found there would be a potentially significant effect. A large deployment would change the air flow and velocity and, therefore, the weather patterns. The study has not received much attention. Wind has a lot of momentum and political support at the moment, but it could become more controversial as wind farms become more widespread.

MR. MARTIN: That's very interesting. Is Washington, DC expected to be warmer or colder?

MR. GRIFFITH: I can't answer that question off the top of my head.

The Next Peak

MR. MARTIN: New direction — the merchant power market in the United States is characterized by periods of boom and bust. It is a little like the farm sector before the 1930's where every farmer had an incentive to maximize output, but if everyone pursued that strategy, the entire sector would be impoverished. We just went through a bust that started in 1999 and lasted at least through 2002 or 2003. Art Holland, if you were plotting a / continued page 10

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its foreign subsidiary heavily with debt. The subsidiary has earnings, but they are paid to the parent as interest on this debt. This reduces the subsidiary's taxable income, since the interest payments are deductible.

British parent companies have been using "deferred subscription agreements" to strip earnings out of their US subsidiaries. In the simplest form of such arrangements, a US subsidiary might sign a contract to subscribe for shares in a sister company in Britain. The two subsidiaries — the US subsidiary and its British sister — have the same British parent. The subscription agreement requires the purchase price for the shares to be paid over a number of years.

Another British subsidiary with the same parent takes assignment of the share subscription agreement from the US sub.

The US sub gives it a note to compensate it for taking on the obligation to pay the share subscription price. The US sub deducts its interest payments on the note. This reduces or eliminates the US tax base. The US-British tax treaty waives any withholding tax that might otherwise be collected by the United States on the cross-border interest payments. Meanwhile, the British subsidiary receiving the "interest" report it for tax purposes in Britain as a tax-free return of capital.

Recent versions of the strategy interpose an additional "hybrid" company in the transaction underneath the US subsidiary — a company that is ignored for US tax purposes because the US subsidiary has elected to treat it as a "disregarded entity" while Great Britain views it as a corporation.

Lee Sheppard, a contributing editor of Tax Notes, *has been urging the US Treasury Department since early last year to crack down on the transactions. The IRS says it is still "gathering information." Her attacks on other foreign tax planning strategies in the past have not always led to IRS action.*

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line, would it show the market now moving back in the direction of a boom and where would be put the next peak?

MR. HOLLAND: Yes. We are starting to breathe again. We are coming out of our coma. I would put the next peak somewhere around 2010.

MR. MARTIN: It will be upward from here until 2010, and then back down again?

MR. HOLLAND: Let me give a little broader range: 2010, 2011, 2012, I think will be a good range for when there will be a peaking out. Several parts of the country will need new capacity by then that have not been mentioned, including most of ECAR — the rust belt states. ECAR will start to need capacity by the 2012 to 2013 period. PJM may be looking for new capacity as early as 2012. We will see a general need for new generating capacity by about that period.

MR. MARTIN: Mark Griffith, if you were plotting the bust and boom, where would you put the peak of the next boom, and do you agree that this industry will continue to be characterized by boom-and-bust cycles?

MR. GRIFFITH: I agree that it is a boom-and-bust-cycle industry. It has that characteristic in common with many industries where a very large capital outlay is needed to bring new production capacity online. You see the same cycles across many industries. The period 2010 to 2012 is a pretty good time to be thinking about a peak in terms of when things will be from a supplier's point of view.

There should be a little more discipline on the financing side this time to help keep the boom under control. The risk is that everyone is anticipating this peak at about the same time. The resources are already lining up to meet the demand. There is certainly the risk for project developers to create another bust cycle pretty quickly. A lot of the new generation under study is gas-fired combustion turbines and combined-cycle units that have relatively short lead times to build. You can build such a plant in a two- or three-year period, depending upon how far along you are in your permitting. Developers are in a position to respond quickly to improving market conditions. If they start building such plants on balance sheets with the hope of lining up a power contract near the end of construction, we could see another bust cycle take hold quickly.

> Although wind projects may supply a lot of the additional demand, there is still room for fossil-fuel power plants because wind capacity is not counted fully in utility reserve margins.

MR. MARTIN: Steve Dean, do you agree with that time horizon? And do you agree with the last statement about the potential for a fairly rapid bust after the next peak?

MR. DEAN: I think the next development cycle will be very different from what we saw in the 1990s. There has been a lot of discussion about nuclear power. The economics for nuclear power plants are advantageous today in relation to gas-turbine combined-cycle plants. If gas prices remain high and if the regulators allow new nuclear plants to be permitted fairly quickly, I think you will see the large utilities start to build nuclear plants here in the United States. And if that happens, it will create a bust for the independent power producers because nuclear plants are now the low-cost producers in the United States.

MR. MARTIN: But surely that cannot happen within the time horizons we have been discussing? Nuclear takes so long to permit and build.

MR. DEAN: That was true during the 1980's and it is the key question today: can the time horizon be shortened to the point where nuclear plants could be put into service and meet some of this projected demand by 2008 to 2010? A lot of people are starting to look at that question. If they succeed at shortening the timelines, it will have a significant impact.

The next boom will not be the same kind of cycle that we saw in the 1990's. It will be a competition along gas-fired, coal-fired, nuclear and maybe some wind, but whichever fuel prevails will be the key to who benefits most from the next boom.

Possible Unexpected Turns

MR. MARTIN: You anticipated my last question, which is that if this were a presidential election, the commentators would be asked, before the results come in, what should television viewers watch for tonight? What one or two assumptions are key to the current projections that, if they turn out wrong, could turn the world upside down? Art Holland, let me start with you.

MR. HOLLAND: I would keep a close eye on what happens in the legislature with environmental controls. Most of our pricing projections today are based on the expectation that something close to the Imhofe "clear skies" initiative will pass Congress with the Environmental Protection Agency continuing down the same path on which it embarked last year. That means that power companies will be under orders to reduce NO_x and SO_2 emissions, and possibly some mercury, but nothing as dramatic as what you see in some of the other competing bills from Senator Jeffords or Senator Carper. If you see something akin to Carper or Jeffords signed into law, which we don't expect, but if you do, then you are likely to see wholesale retirements of existing power plants. You will see a need for immediate construction of new power plants. And under some of the terms of the Jeffords bill, you would probably see construction of new nuclear facilities because those are the only power plants that would be able to comply easily with the new emissions limits.

So, the short answer to your question is keep an eye on what type of environmental legislation comes out of Washington.

MR. MARTIN: If a Democratic administration replaces the Bush administration in the next election cycle and signs the US up to the Kyoto treaty, would that also be a factor that would speed up the recovery?

MR. HOLLAND: Very possibly because CO_2 is extremely difficult to mitigate. We would have to reset our thinking on the need for new plants in light of the potential for a large number of retirements.

MR. MARTIN: Mark Griffith, what should bankers sitting over in Europe, but financing power plants in the US, keep an eye on? What are important assumptions / continued page 12

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BRAZIL moved in December to tax foreigners on gains in the value of shares in their Brazilian subsidiaries caused by fluctuating exchange rates.

The government has been attempting since 2002 to collect both income taxes and a social contribution tax on net profits — called a CSLL tax — from foreign parent companies on the appreciation in share value in their Brazilian subsidiaries caused by exchange rate variations. The US dollar appreciated 8.5% against the Brazilian *real* from January to June last year, but lost 7% in value measured over the entire year. The government based its past collection efforts on a directive that the Brazilian tax department issued in 2002. Most companies have been able to avoid payment because of court decisions that such taxes much be based on a law rather than a tax department directive. Therefore, the government moved last month to provide a proper legal basis by imposing the taxes through a decree, number 232, that appeared in a special edition of the official gazette on December 30.

Under the decree, CSLL tax must be paid on capital gains due to exchange rate variations starting in April 2005. Income taxes will also have to be paid starting in January 2006.

The government also moved in December to stimulate investment in new plant and equipment. Law No. 11,051, enacted at year end, increased the depreciation rate for machinery and equipment from 10% a year to 25% a year. The faster writeoffs only apply to machinery and equipment purchased between October 2004 and December 2005.

MEXICO has started collecting a 25% withholding tax on certain payments by Mexican companies to foreigners.

Local lawyers advise that the tax is probably unconstitutional, but anyone paying it must file a separate court / continued page 13

Electricity Prices

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in these projections that could change?

MR. GRIFFITH: I agree with Art that one of key signposts will be environmental regulation. It affects not only the timing, but also the type of resources that will be built in the next round and the type of resources that are retired.

The other signpost for which bankers should be looking is how many liquefied natural gas terminals get permitted and built in the United States or in areas adjacent to the United States that can serve the US market. On the one hand, if we succeed in developing even a fraction of the 40-plus LNG terminals that are under development, that will have a material impact on natural gas prices and change the dynamic as to what type of resource is most economic in terms of new generation capacity. On the other hand, if none of the LNG projects is successful, then the gas price forecasts that we have been using have gas prices at too low a level, and the dynamic will shift in the other direction.

MR. MARTIN: How many new LNG terminals do current forecasts assume?

MR. GRIFFITH: Probably fewer than 10 new terminals out of the 40 that are under development. With 10 new terminals, LNG will no longer be the marginal supplier and will not set the price. The gas price will be set by the new marginal suppliers from frontier sources like offshore gas and newer fields in Canada and Alaska. The price may be something in the order of magnitude of $4 an mmBtu.

MR. MARTIN: So if more than 10 LNG terminals are ultimately built, then gas prices will be lower than expected. I don't know if you are projecting gas prices to decline in any event?

MR. GRIFFITH: Our projection is gas prices will decline in the next four to five years in response to development. We think that there will be a supply response.

MR. MARTIN: With what consequence?

MR. GRIFFITH: The consequence of lower gas prices than expected is a shift in the balance between gas-fired resources and coal-fired resources. Cheaper gas squeezes that coal-to-gas spread and makes it a little harder to justify the coal plants.

More than 100 new coal-fired power plants are currently in various stages of development in the United States.

MR. MARTIN: Lower gas prices than expected would mean a different mix of new construction, but would they mean a change in the total volume of new construction?

MR. GRIFFITH: They would affect the mix rather than change the absolute numbers.

MR. HOLLAND: We assume in our power projections and electricity and gas price forecasts a certain amount of LNG being available to the market. I can't tell you off the top of my head the number of terminals. However, I will say that making LNG a prominent and important aspect of our energy future is extremely troubling to me from a national security perspective. It is troubling to me that what was once thought to be a fuel that we had in abundance in the United States will now have to be imported in large quantities from places like Indonesia and Nigeria.

MR. MARTIN: Steve Dean, what would be an important change in the base assumptions that forecasters are making today?

MR. DEAN: I would echo what the others have said. A significant change in environmental regulation or a significantly larger or smaller number of LNG terminals from what we have assumed would upset the price forecasts. The other big change in assumptions would be if the United States were truly to take a position that it is going to reduce reliance on foreign oil. It would have a tremendous impact on the power industry.

MR. MARTIN: What effect would it have on the pattern of power plant construction in the US?

MR. DEAN: The United States has oil-fired power plants that run during peak periods. Those plants would be dropped from the system almost immediately. More effort would also be put into developing alternative domestic sources of energy and would have repercussions for the electric utility industry.

MR. MARTIN: You would have a different mix of new power plants, but no change in the overall capacity?

MR. DEAN: Right. Much different types and much different technologies. Our industry ranks today as one of the lowest industries in the United States in terms of R&D funding for new technologies. Most of the R&D work today is funded by the federal government.

Let me make one other point: I think we are at a fragile stage in the rebounding of the power industry. Anyone who rushes to take advantage of rising prices or margins by adding new capacity is taking a pretty bold step. He would be taking a fair amount of risk. There are a lot of unknowns as one moves three, five or 10 years into the future.

MR. HOLLAND: I think the days of estimating what the price of electricity will be in July 2010 are gone. The industry is a lot smarter today, and what forecasters do today is give decision-makers a range of confidence bands around our expectations for future commodity prices so that they can see how much uncertainty is embedded in the estimates.

Lower Taxes For US "Manufacturers"

by Keith Martin, in Washington

The Internal Revenue Service answered questions in late January about a new law that will let companies pay taxes at a lower rate on income from "manufacturing" in the United States.

US power companies would be well advised to pay close attention to how "tolling agreements" are drafted.

Generating electricity is considered "manufacturing," but not if the power plant supplies electricity under a tolling agreement where a fuel supplier pays to have his gas converted into electricity. The IRS said it would look at the underlying substance of the arrangement. The issue is whether the power plant is selling

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action within 15 days to have any hope of getting his money back.

Fees for services or rents paid by Mexican companies to foreigners in other countries that have tax treaties with Mexico are usually immune from withholding taxes if the foreign company receiving the payments has no "permanent establishment" in Mexico. However, a new law enacted on November 13 purports to override these treaty provisions. The law would subject to such payments to withholding taxes at as much as a 25% rate.

Ordinarily, a US company that must pay income taxes to another country would receive a credit to use against its US taxes. However, some of the withholding taxes in this case will not be creditable in the US. For example, where withholding taxes are collected on fees paid to a construction contractor, no foreign tax credit could be claimed to the extent the fees are for work performed physically in the United States. Foreign tax credits can only be claimed for taxes paid to another country on "foreign source income." In this case, the income would be considered from a US source.

The new Mexican law may ultimately be found to be unconstitutional. However, taxpayers must challenge it promptly in separate court actions to get their money back, according to Jose Ibarra, a tax lawyer with the firm Chevez, Ruiz, Zamarripa y Cia in Mexico City.

> *"Considering that residents of Mexico that make such payments will probably take the safe position of making tax withholdings based on local law provisions, without regard to any treaty, thus not risking a challenge by the tax authorities, it will be up to the nonresidents to take their case to a mutual agreement procedure or to the Mexican constitutional courts within 15 working days from the date in which they suffer the 'undue' withholding for the first time," Ibarra said.*

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Domestic Manufacturing Income

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electricity or merely providing services. Only income from electricity sales qualifies potentially for the reduced income tax rate. The provision of services is not considered "manufacturing."

Income from manufacturing in the United States will be taxed starting this year at a lower rate. The rate reduction is as much as 3.15%, but it phases in. Even a reduction of 1% can be worth millions of dollars to US utilities and other energy companies.

Income from "manufacturing" in the United States will be taxed starting this year at a lower rate. Generating electricity and producing natural gas are considered "manufacturing."

Background

Congress reduced US income taxes on domestic manufacturing income in a so-called JOBS bill that President Bush signed into law on October 22.

The United States was under orders from the World Trade Organization to repeal a tax break for companies that export US-made products. The export tax relief was worth $50 billion to US industry. Congress decided to give an equivalent amount of tax relief to US manufacturers. Defining what qualifies as US manufacturing is a challenge. The IRS made an initial stab at it in late January in "interim guidance," but asked for comments on its approach by the end of March. The guidance is in Notice 2005-14.

Congress did not actually prescribe a lower tax rate, but rather let companies deduct — or avoid paying tax on — as much as 9% of their domestic manufacturing income. With the corporate tax rate at 35%, this equates to a 3.15% reduction in tax rate.

The deduction is phased in. Only 3% of domestic manufacturing income may be deducted in tax years beginning in 2005 or 2006. The figure is 6% in 2007, 2008 and 2009. The full 9% deduction takes effect in 2010. Thus, any company with a November 30 tax year would not get any benefit from the deduction until its tax year that starts December 1, 2005.

The amount of deduction a company is allowed each year is capped. The limit is 50% of wages reported on Form W-2 for the year for its employees. The IRS said there is no single box on the W-2 form that will tell a company its wages for this purpose and suggested three ways it can derive the information. Companies taking on more employees during the year through acquisitions of new business divisions will not be able to count the wages paid during the year by the company that sold it the division.

"Manufacturing"

Domestic manufacturing income is broadly defined. The Senate floor manager of the JOBS bill, Senator Charles Grassley (R.-Iowa), grumbled at one point that every industry with a Republican lobbyist managed to have its activities defined as "manufacturing."

Qualifying income includes gross receipts from the "lease, rental, license, sale, exchange, or other disposition" of "tangible personal property," computer software, sound recordings and films (but not those with explicit sex scenes) "manufactured, produced, grown, or extracted *by the taxpayer* in whole or in significant part within the United States."

Companies producing electricity, natural gas or potable water in the United States are considered engaged in manufacturing.

In cases where a company owns a power plant, but hires a contract operator to run it, the power plant owner is ordinarily entitled to deduct part of its receipts from electricity sales on grounds that they are domestic manufacturing income. The contract operator cannot do so with his fees because he is providing services. However, the IRS said it would look at who has the "burdens and benefits of ownership" of the electricity, and only one party on "contract manufacturing" arrangements is entitled to the deduction. It is possible that some contracts might unwittingly shift the deduction to the operator.

Tolling agreements are a bigger issue. The classic tolling agreement is where a farmer pays a mill a fee to grind his wheat into flour. Tolling agreements in the power industry have a fuel supplier paying a power plant owner — at least in form — a fee to convert the fuel into electricity. However, many such contracts are power sales agreements rather than tolling agreements in substance. The distinction in particular deals will determine which party — the power plant owner or the fuel supplier — can claim the deduction. The IRS will not let both do so.

Companies that produce natural gas are engaged in manufacturing. Manufacturing continues through the point of processing to put the gas in a pipeline. However, the IRS said that landfill gas is not "natural" gas because it is not gas from a natural deposit. Therefore, landfill gas companies will not get the benefit of the lower tax rate.

Gas pipeline companies, local gas distribution companies and electric utilities with transmission or distribution lines are not engaged manufacturing, unless they also produce gas or generate electricity. Companies that do both must allocate not only their receipts, but also their expenses between the activities that qualify as manufacturing and those that do not. The IRS declined to specify how companies should allocate receipts. It said it has "not identified a single method that would be appropriate for all taxpayers," and simply directed that the method used should be "reasonable." The method is more likely to be reasonable if it is used for other business purposes and not strictly for taxes and the company uses it consistently from year to year. Receipts must be allocated item by item, meaning, for example, for each electricity or gas sale. In general, the IRS wants accuracy, but suggested companies — particularly smaller companies — could take into account the cost of tracking data and use another method where item-by-item accounting is prohibitively expensive.

If more than 95% of the gross receipts in a year come from domestic manufacturing, then the company does not have to bother with an allocation. Its entire income qualifies.

Construction contractors also qualify as "manufacturers." However, engineering and architectural services qualify as manufacturing only if they relate to "real / continued page 16

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DEPRECIATION BONUS issues continue to receive attention.

Companies that invest in new equipment in the US during a "window period" that runs from September 11, 2001 through the end of 2004 or 2005, depending on the equipment, receive a "depreciation bonus," or the right to write off as much as 50% of the cost of the equipment immediately. The equipment must be new.

The IRS told an air charter company that bought an airplane that had seen some use that it could treat the plane as new. The manufacturer had used the aircraft as a demonstrator and also to fly company executives around on business. It also loaned out the aircraft twice for periods of less than a month each time to customers who were awaiting delivery of their own planes. The IRS told the charter company in a private letter ruling made public in January that it could treat the plane as new.

The key was that the manufacturer continued to hold the plane out for sale while it was using it for other purposes. The ruling is PLR 200502004.

OUT-OF-STATE LIMITED PARTNERS may be taxed on their partnership incomes, even if they have no other ties to a state.

An Alabama circuit court said in November that a limited partner who lived in Georgia had to pay Alabama income taxes on his income from an investment fund based in Alabama. The taxpayer held an interest in the investment fund as a limited partner. A lower tribunal had concluded the state could not tax the income because the US constitution bars it from taxing anyone with so little "nexus" with the state, but the circuit court disagreed. It said ownership of the partnership interest was enough since this gave the partner a "purposeful connection" with the state. The case is *Department of Revenue v. Joe E. Lanzi III*. / continued page 17

Domestic Manufacturing Income

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property, inherently permanent structures other than tangible property in the nature of machinery, inherently permanent land improvements, and infrastructure." Since most power plants are considered almost entirely machinery, work done on the "E" portion of an EPC contract — an engineering, procurement and construction contract — for a power plant would not qualify. "Infrastructure" is defined as "roads, power lines, water systems, railroad spurs, communications facilities, sewers, sidewalks, cable, and wiring" and "inherently permanent oil and gas platforms."

The actual construction work should qualify whether or not the project is real property.

To get to manufacturing income that is taxed at the lower rate, a company must reduce its gross receipts from domestic manufacturing by related expenses, including depreciation on the assets used in manufacturing. Thus, for example, power plant depreciation will offset income that is taxed at a lower rate in the future. Companies running *pro formas* on power deals should take this into account in their projections.

A company that is carrying forward net operating losses does not have to reduce its domestic manufacturing income by them when it eventually uses the NOL deductions.

Many project finance deals are conducted through partnerships (or limited liability companies treated as partnerships). The IRS said that each partner should calculate separately its domestic manufacturing income that is taxed at the lower rate. The Form K-1 that partnerships give partners to tell them their shares of partnership items will get longer in the future as partnerships will have to let each partner know his share of W-2 wages paid by the partnership so that the partner can calculate his wage cap. Each partner will also be allocated a share of gross receipts from domestic manufacturing and related expenses so that he can do his own calculations.

Sale of a partnership interest does not produce domestic manufacturing income, even if the partnership is engaged solely in that activity, with one exception. The exception is US tax laws treat the partner as having sold a share of any "hot assets" in the partnership directly. Gain from the sale of hot assets is potentially domestic manufacturing income. Examples of hot assets are receivables or gain that is attributable to tax depreciation claimed earlier on the partnership assets.

US power companies would be well advised to pay close attention to how their "tolling agreements" are drafted.

Expanded Groups

One potentially significant new rule — and potentially a source of enormous complication from a business perspective — is all corporations that are part of an "expanded affiliated group" — must compute the total domestic manufacturing income of the expanded group and then allocate it among the group members. Expanded group means not only companies that join in filing a consolidated US income tax return, but also other companies that are owned at least 50% by vote and value by a common parent company.

Once the domestic manufacturing income of the expanded group is calculated, it is then allocated among the group members in the same ratio as they contributed domestic manufacturing income to the group calculation. Suppose a group has three corporations in it. Two have domestic manufacturing income for the year and the third has a domestic manufacturing loss. The loss reduces the group's total domestic manufacturing income. That total is then allocated to the two group members who contributed positive income in the ratio of their positive incomes. At the end of the day, less of their income will qualify for the lower tax rate than if they did the calculations separately.

Whether a company is part of an expanded affiliated group must be checked on a daily basis and the calculations must take into account its income or loss for the portion of the year it was part of the group.

Only manufacturing done in the United States is rewarded. "United States" in this context means just the 50 states and the 200 miles out to sea that the US considers territorial waters. Activity in Puerto Rico or other US territories and possessions does not qualify for the tax break.

The tax deductions can be claimed by companies that pay "alternative minimum taxes." The United States has essentially two corporate income tax systems. A company must compute its taxes at a 35% rate and then compute what the taxes would be at a 20% rate but on a broader income base and pay essentially whichever amount is greater. ◎

Wind Market Roundtable

In an otherwise soft project finance market, windpower deals are a bright spot. More than 180 people attended a roundtable discussion that Chadbourne hosted in mid-January in Houston. The discussion focused on what is new in the market. The following are excerpts. The speakers are Keith Martin, editor of the NewsWire and a tax lawyer with Chadbourne in Washington, Adam Wenner, a federal regulatory lawyer with Chadbourne in Washington, Marianne Carroll, a regulatory lawyer with Carroll, Gross, Reeder & Drews, L.L.P. in Austin, Edwin Moses, a former developer of windpower projects who is now with Marathon Capital, and Paul Weber, a project finance lawyer with Chadbourne in New York. The moderator is David Schumacher, managing partner of the Chadbourne office in Houston.

MR. SCHUMACHER: Keith Martin will talk first about new developments in how wind deals are being structured.

Deal Structures

MR. MARTIN: Since I have only five minutes, let me make just a few points.

If you asked people a year and a half ago where the market was headed on deal structures, they would have said the market was moving toward guaranteed-return structures. There was a general perception that / continued page 18

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WEST VIRGINIA has been collecting too much in severance taxes from some coal producers, the state's highest court said.

US states usually collect taxes from mineral producers on the right to "sever" minerals from the ground. In West Virginia, the severance tax on coal is 5% of gross value. Gross value is defined as the market value of the coal determined after the raw coal has been processed to put it in a commercially-marketable form.

The state supreme court said in December that the state overcharged a coal producer by not letting him subtract transportation charges to move his coal from a preparation plant to a loading dock on the Kanawha River. He claimed the coal was in a commercially-marketable form once it left the wash plant. The state argued that since he owned both the wash plant and the river dock, the processing was not completed until the coal reached the river dock.

The court disagreed. It said the cost to move the coal to the dock could be subtracted from the sales price of the coal before severance tax was applied. The court said, "[F]reight charges paid by a coal producer to a third party to transport fully-processed clean coal from the coal preparation plant to the point at which title passes to the buyer are costs which are deductible from the gross proceeds of coal sales for purposes of assessing the severance tax."

It helped that the moving costs in this case were paid to a third party, CSX railroad. The case is Kanawha Eagle Coal LLC v. Tax Commissioner.

COMMUNICATIONS EXCISE TAXES may not apply to yet another type of phone service.

The US government collects a 3% excise tax on "amounts paid for communications services." The tax was originally enacted more than 100 years ago to help fund the Spanish-American War and, / continued page 19

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there were too few equity — perhaps only a dozen — who were willing to put money into wind deals. This year, the market has turned upside down. No one is really working seriously on guaranteed-return structures. There are more equity chasing deals than there are deals available.

What you have this year are not only many more institutional equity with a tax base who want to invest, but also other equity who lack a tax base and want solely a cash return. Thus, some project partnerships now have three parties — the project developer, an institutional equity with a tax base and a cash investor. The cash investor, in order to play, really must come into the deal before the project reaches construction. He must be offering cash during the development phase.

The barrier to cash investors in the past was a fear that cash distributions by the project partnership to the cash investor would drag production tax credits with them. Production tax credits are supposed to be shared among the partners in a wind deal in the same ratio they share in "receipts" from electricity sales. However, in the last year or so, many tax counsel have concluded that a cash investor can be given preferred distributions of cash without also having to give him the same share of tax credits. The IRS has not said anything about the subject, but the market has persuaded itself that this works.

My second point is you have a lot of institutional equity crowding into the market this year who have been accustomed to investing in big-ticket leasing transactions. They had been putting money into highly-structured cross-border lease deals with high returns. Congress and the IRS have put a halt to those transactions. These lease equity are looking to put capital into the next most vibrant part of the market, which is wind deals.

It will be interesting to see how this works. There are accounting issues for these institutional lease investors. They are used to leveraged lease accounting, which they will not get by investing in a wind partnership. Also, the returns are lower than they have been accustomed to in the cross-border lease market.

The influx of lease equity participants into the wind market could affect how wind deals are structured.

The way deals are structured could be affected. Lease investors may ask for more expansive tax indemnities than the traditional energy investors. Traditional energy investors tend to be satisfied with representations about facts that go to whether a project qualifies for tax benefits, and they make up their own minds about how much risk they are taking. Lease investors may be more likely to demand warranties of tax benefits. They may also want step-in rights to take over the project after a debt default.

The third development is French leases. There is a window, through the end of this year, where a French double-dip lease might be used to help finance US renewable energy project. A French bank would own the asset for French tax purposes and lease it across the Atlantic. A separate partnership transaction can be done in the US to transfer the US tax benefits. The French lease produces a 4% or 5% net-present-value benefit. The French bank "expenses," or deducts, the entire cost of the renewable project in the first year.

It is a restricted market. There is scarce tax capacity for such transactions in France. The big banks with such tax capacity tend to be willing to do such deals only with existing customers.

Let me mention two other things briefly.

If President Bush has his way and truly overhauls the US tax code, then the production tax credits that are driving the wind market may be at risk, depending on how extensive the tax overhaul is and what form it takes. There is little one can do to protect against this. I have been asking audiences at speeches recently how many people think there will be significant tax reform in the second Bush term, and in an audience of 200 or 300 people, maybe three would raise their hands.

Finally, the question is always asked at workshops like this whether the production tax credit will be extended. Wind projects must be in service by the end of this year to qualify for tax credits. The odds are about 80% that the deadline will be extended, but not necessarily this year. Congress might have to extend it retroactively.

Advice for Developers

MR. SCHUMACHER: Eddie Moses, how about five minutes on the wind market from the perspective of a former project developer who has moved to the equity side?

MR. MOSES: Absolutely. Let me tell you my background so that you know what experiences I bring to the topic. I joined Enron out of the University of Texas MBA program in 1998. I spent my first two years in Tehachapi, California. I started early learning about regulatory and tax transactions. I went on to become director of project finance for Enron in Europe. That was about four or five years total. After Enron, I joined Clipper Windpower and closed that company's project with PPM Energy. I also worked on developing a wind project in Mexico until August 2004. I joined Marathon Capital fulltime last October for the purpose of raising passive tax equity for the windpower market. I am a managing director of the Marathon Tax Advantage Renewable Fund, which we are in the process of closing. The fund will be approximately $500 million in size. About 50% of the fund will be invested in wind energy.

So on to my talk: I want to talk mainly about what it takes to have a bankable project. There is a minimum list of ingredients to become bankable. However, the fact that a project is bankable does not mean that it will be profitable. Profitability depends on the quality of the inputs. If a project is not profitable, then it will not be built.

Wind energy tends to be very thin in competitive energy markets, so thin that it comes as a surprise to people with long experience in the power market but little experience with wind deals. While I was at Clipper, we talked to the International Finance Corporation about providing financing for our project in Mexico. The IFC tried to knock $10 million off a $50 million deal without realizing / continued page 20

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although it has been updated, the words in the statute are badly outdated to a point where the IRS is having trouble collecting it on many current forms of communications services. On November 30, a federal district court in Pennsylvania delivered the latest blow. A company called Reese Brothers bought long-distance phone services from three long-distance carriers: MCI, Quest and LCI. The phone companies collected federal excise taxes on top of the fees they charged. Reese Brothers sued the IRS for the money back on grounds that its type of phone service is not described in the excise tax statute.

The excise tax applies, among other things, to "toll telephone service," which is defined as telephone calls for which the phone company charges based on the "distance and elapsed transmission time for each individual communication."

Phone companies in the US have abandoned mileage bands and now treat the entire US as a single band. Thus, charges for interstate calls no longer vary by distance. The statute says to be taxable, the charges must be linked both to distance *and* elapsed time.

Perhaps taking its cue from former President Clinton, the IRS argued that when the statute says "and," it really means "or." The court declined to go along. The case is *Reese Brothers v. United States*. However, the IRS won a similar case in a federal district court in Florida last January. That case is *American Bankers Insurance Group v. US*.

The agency said in a notice last August that it intends to continue taxing long-distance calls, but there are questions about whether the IRS can expand the scope of the tax administratively or whether Congress must rewrite the underlying statute.

TELEPHONE COMPANIES provide a service rather than sell a product, a Kansas court said. The distinction is / continued page 21

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the margin was not a matter of smaller profits but life or death for the project.

To be a profitable project, the market value must be greater than the project cost, and the quality of the inputs given to investors is directly related to market value.

Developers are in the business of assembling documents and data that can be presented to raise financing for the project.

Many wind projects this year have three partners — the developer, a cash investor and an investor with a tax base.

Developers ask investors to write checks for millions and millions of dollars, basically in exchange for a tall stack of papers.

My advice to developers, having now switched to and having seen the equity side, is try to think like an investor. Try to help him or her sell your project internally, and you will be both profitable and successful.

Always ask three questions while developing a project. The first question is, "Am I giving an investor the ingredients to invest?" The necessary ingredients are secured and predictable revenue, predictable and manageable expenses, stable regulation and taxes, and experienced owners and operators.

Question two is, "Has this been done before?" I have a saying, and I use it often. If this has not been done before, then it will cost extra money. Many developers do not realize that. The easiest thing for a banker to sell internally is to say "I did the same deal six months ago with the same company and this contract language has been financed before." But the lesson applies to everything, not just the financing documents. Has the jurisdiction accepted wind energy before? Has the zoning or transmission authority been applied to before and, more importantly, has it delivered? Has the turbine model been implemented in this wind regime before?

Question number three: project value must be greater than project cost. This may be obvious, but it is easy to take your eye off the ball.

Developers live by faith, hope and perseverance, while bankers live by contracts, documents and legal opinions. Successful developers help their financiers sell the project by focusing on the inputs that a banker needs.

Let me give a couple examples. Looking at the ingredients to invest, you will see security, stability, predictability and experience. That is not an accident. Each of these has a positive effect on project value. If you have a question yourself, work on getting more data. It will be a good investment. Answer the question ahead of time. I suggest you start with your pro forma and ask yourself if you can supply a document to back up every single line and cell in the spreadsheet: insurance, property taxes, turbine expenses, use of electricity. Developing a project takes a lot more than a power purchase agreement and a wind study.

I can't stress enough, documents, documents, documents. Every question will have an answer, and every answer will have a document.

Your legal advisers can be a great help in this process. Use them to assemble a list of closing documents that will be required as early as possible. Investors understand that not everything will be completed right away, but a comprehensive directory will give confidence and improve the ability to sell your project. Legal advisers that have done this before have a positive effect on market value.

Wind data is golden. Your wind data quality is the greatest determinant of project value. I know that managing a fleet of meteorological towers is a big expense, and I have seen this expense go to waste through poor data collection and poor management of that data. Recently I met a developer who was a client of a law firm I know very well. The first thing he started talking about was the added expense and added time he put into his wind-energy analysis. There were two positive factors right there. He was already helping me sell his project internally.

My last point is "has this been done before" works both ways. You should critically assess the capabilities of your investors to close deals. For example, consortia bring added complexity, which could ultimately cost you money. Sometimes they bring additional value so that the additional cost is worthwhile. Weigh the two sides carefully.

In fairness to the International Finance Corporation, we had a lot of project-quality issues with our project in Mexico, and IFC's participation on balance was very positive. However, we knew in advance that the IFC had never closed a wind deal before. This lack of experience became a factor in the process.

To sum up, every action that a developer takes has either a positive or a negative effect on project value. Balancing the value versus expense is hard, but in many cases, gathering the information and documentation really does not involve significant expense. It involves just thinking like an investor.

Regulatory Developments

MR. SCHUMACHER: Thanks, Eddie. Adam Wenner, tell us what new developments on the federal regulatory front are affecting the wind market.

MR. WENNER: What is new with the Federal Energy Regulatory Commission? FERC officials would probably say, "We're from the government, and we're here to help." You can probably believe them this time.

FERC is expected shortly to propose revisions to its transmission rules that should have the effect of making transmission more wind-friendly. FERC has recognized that the open-access transmission tariffs that all utilities in the United States, except those in the ERCOT region in Texas, are required to have are not friendly to wind. They are around power plants that control their level of output and can schedule a day ahead and do so effectively.

FERC now recognizes that windpower projects cannot do this and that the imbalance penalties imposed on dispatchable resources make no sense when applied to wind projects.

What FERC will do shortly is propose new rules to take effect by next spring in time to help wind projects that are being put into service this year. The agency will propose that all utilities are free to, or may be even / continued page 22

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important because most states collect sales taxes on equipment purchased for business use, but not on equipment that will be used to manufacture "tangible personal property." The question which is it also comes up in the power industry.

Five telephone companies sued in Kansas to get back sales taxes paid on telephone switches, computers and other equipment used to provide phone service in the state on grounds that the equipment is used to manufacture a product — phone calls — and phone calls are no different from electricity, which the state acknowledges is "tangible personal property," because calls are basically transmission of electrical impulses. The Kansas supreme court disagreed. It also said it saw no violation of the "equal protection clause" of the US constitution by treating power companies and phone companies differently.

The case is In re Sprint Communications Company, L.P. *The court released its decision on December 17.*

MAURITIUS continues to receive barbs from the Indian government for its favorable tax treaty.

Foreign companies with projects in India usually own them through a Mauritius holding company. That's because a tax treaty between Mauritius and India limits the withholding taxes that India can collect on payments to anyone who is a Mauritius tax resident to 5% on dividends and 0% on capital gains. India responded several years ago by dispensing altogether with its withholding taxes on dividends and imposing an additional tax instead on the Indian company that makes the dividend payment. This is in addition to the income taxes that such a company would have already paid on its earnings. However, foreign investors still hold their investments in India through Mauritius to avoid taxes / continued page 23

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required to, adopt a Pacificorp-like tariff. What this will do is lead utilities to have more of a dead band for deviations in their scheduling. Basically, the FERC standard in effect today allows a generator to deviate by plus or minus 1 1/2% from its schedule without a penalty. The Pacificorp tariff allows deviations of as much as 5%.

More importantly, under the standard tariff today, a generator who deviates outside the dead band for transmission can be penalized up to $100 per megawatt hour of the difference. When you are going through the documents that Eddie Moses mentioned, be sure to check the transmission tariffs. They could be a deal killer.

If you're lucky enough to have a Pacificorp tariff or a newly-designed tariff under the new rules FERC is expected to propose shortly, it will permit imbalances to be made up at market rates — for example, you will pay or be paid 10% more or 10% less than the market price for imbalances from your production.

FERC will probably also support proposals like one that the California ISO recently put into place and that is very wind-friendly. It permits imbalances to be made up on the basis of monthly deviations — not hourly ones. In other words, all the project's over generation and all of its under generation is netted on a monthly basis — statistically, it should average out — and there is a settlement based on market, rather than penalty, rates.

FERC will also propose a form of conditional firm transmission, recognizing that wind projects find it terribly burdensome to pay fixed rates for transmission when their average capacity factor is only 32%, but also recognizing that interruptible transmission will not satisfy investors.

This type of transmission will have a specified limited period of curtailment and allow a wind project to pay a lot less for the firm portion of its transmission.

There are a couple of other issues before FERC that are also expected to be addressed.

FERC is considering what to do about trunk lines. For example, Southern California Edison has proposed a new 500-kv line going to an area like Tehachapi, where the California ISO believes there is potential for 4,000 megawatts of wind. Ordinarily this might be treated as a radial line, the cost of which would have to be borne by the developers in that region. However, Southern California Edison has proposed, and FERC will also propose, that this type of line — called a trunk-line facility — be put into the utility rate base, which means its cost would be charged to all users of the gird and not just the particular generators helped by the trunk line.

The thin profit margins in wind deals come as a surprise to anyone new to wind but with long experience in the power business.

FERC will also continue its favorable interconnection policies that require the utility ultimately to bear the cost of network upgrades — or improvements to the transmission grid — necessitated by the addition of another power plant. It will continue to push for formation of RTOs — or regional transmission organizations — that eliminate rate pancaking where multiple transmission fees must be paid today to move electricity across the individual grids belonging to different utilities.

The FERC proposals in this area should be posted to the agency's website. You will be able to find them at www.ferc.gov.

Texas

MR. SCHUMACHER: Excellent. Marianne Carroll, tell us about regulatory developments affecting wind projects in the ERCOT region.

MS. CARROLL: I would be happy to. The name of the game for wind in ERCOT is — just as in real estate — location, location, location — and also transmission, transmission, transmission.

There is a renewable portfolio standard in Texas that was adopted as part of the 1999 electricity restructuring legislation. That legislation turned into a Christmas tree. This was the renewables ornament.

The renewable portfolio standard is 2,000 megawatts of new capacity by 2009. In 1999, when this goal was set, the state already had 823 megawatts. There are currently 1,187 megawatts of capacity, mostly wind, in service, with another 194 megawatts expected this year. The point is we are ahead of the trend line that would put us at 2,000 megawatts by 2009.

The problem is much of that capacity was built in the same part of Texas, the McCamie area in west Texas. That's where the wind blows. There is insufficient transmission.

The way transmission is paid for in Texas is the developer pays only the cost of the step-up transformer and a circuit breaker, and everything else to interconnect the generator to the grid is paid for by the utility. If a project will require a long transmission line, there is a regulatory proceeding, called a certificate proceeding, that will be required, and the project timeline should take it into account.

The cost of the remaining equipment and upgrades needed to interconnect is put into an ERCOT-wide pool and allocated back out for payment on a load-ratio share to loads. What that does is make it easy for generators to come in, plop their plants down, and force the local utility to build the transmission. There is a standard generation interconnection agreement that can be found on the ERCOT website. The generator does not even have to negotiate.

There is open access to the grid in ERCOT. The theory is all generators should be allowed access. However, if there is too little capacity to accommodate everyone, a generator may be asked to reduce its output. That is what has happened to wind generators in west Texas.

If another power project comes along — for example, a fossil-fuel fired power plant might be built and interconnect to the grid between you and the load — that will restrict the wind generator's access to the load, as well.

The McCamie area generation has really suffered. ERCOT has looked at a policy for building new transmission out to that area — everyone knows it is needed — but ERCOT is going only for short-term fixes for now. / continued page 24

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on capital gains when they dispose of the investments.

The Indian finance minister suggested in response to a question in parliament in December that the government plans to rework the treaty so that India can tax capital gains and prevent foreign investors from treaty shopping by putting shell companies in Mauritius. It also wants the ability to collect more than a 5% withholding tax on dividends.

This is not the first time the Indian government has tried to rework the treaty, and no timetable has been given for any negotiations.

TURKEY reduced its withholding taxes on interest payments by Turkish companies to foreigners and on capital gains earned by foreigners on the sale of Turkish shares to 15% from current rates that reach as high as 24%. The change will take effect next January 1. The government also said that it expects this year to cut the corporate income tax rate from 33% to 30% retroactively to last January 1.

ROMANIA replaced its 25% corporate income tax with a 16% "flat" tax, effective on January 1.

KAZAKHSTAN adopted a 10-year income tax holiday in December for new business ventures undertaking projects in parts of the country where the government would like to encourage economic development. The normal corporate income tax rate is 30%.

MINOR MEMOS. Montana is moving to reduce property taxes on wind farms. Land and equipment used for windpower projects would be taxed at a 1.5% rate compared to 6% for other power projects. The state Senate voted for the rate reduction on January 25. The proposal goes next to the House . . . . The IRS told a US company on audit that it should not have used tax-exempt / continued page 25

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ERCOT is waiting for another 1,500 megawatts of new interconnection agreements to be signed before it will start on a new 345-kv line.

Construction of a new line will take time with the certificate requirements and the expected opposition — for example — of industrial customers in Houston, who don't give a fig about renewables and don't want to pay for transmission out to west Texas. The certificate proceeding will be contested.

In its last session, the state legislature gave the Texas regulatory commission explicit authority to order transmission to relieve congestion. The issue for the commission is whether to wait for the congestion to occur and then issue an order — in which case we would be looking at another five, six or seven years for the additional transmission capacity to be built — or whether to be proactive and order new transmission capacity to be built based on the knowledge that this is where the wind is.

The commission knows that more projects will be built in the McCamie area. It could go ahead and certify a line and order it to be built in an effort to anticipate need.

To date, the commission has not been in an anticipatory frame of mind. It is business as usual. The state representative who heads the regulated industries committee in the House of Representatives filed a letter in that docket saying, "That's not what I meant when I drafted the bill to give you this explicit authority." The commission is considering now whether to adopt the business-as-usual approach proposed by the staff or to act in the manner that this powerful representative would like to see. And there's more, but that's my five minutes.

Risk Allocation

MR. SCHUMACHER: Thank you. Paul Weber, talk to us about risk allocation in wind projects.

MR. WEBER: I will skip over things like transmission risk and tax risk, because there are others on this panel who are far more eloquent on those subjects than I am.

Eddie Moses touched on the first and foremost risk — wind risk. These are energy projects. You sell electricity when the wind blows, but if it doesn't blow, you are out of luck. In this area, knowledge is really power. As Eddie Moses indicated, the better your data, the more you collect, and the better the quality of the data you collect, the better your forecasts are going to be. You want to collect it at various heights and locations on your site, and you want to collect it over a substantial period of time.

> Developers live by faith, hope and perseverance, while bankers live by contracts, documents and legal opinions.

A wind consultant takes all this information and comes up with wind forecasts. The forecasts are expressed in terms of probabilities: a P50 case, maybe a P75 case, P90, P95, and in some instances, P99. These cases are plugged into your financial model and hopefully you will find you have a project that will make you some money; if not, you are out of luck. Most importantly, this will tell a lender how much leverage your project can support.

Another way of handling wind risk that has not caught on in the United States is through wind derivatives. They are in somewhat greater use in Europe. They are not as common here in large part because, if you are going for long-term financing, a wind derivative, which tends to max out at around five years, is not of much help. Wind derivatives are also expensive. If you are an equity investor and your margins are thin, you are essentially trading some of your upside to make your lenders more comfortable.

Another set of risks are construction and technology risks. There is nothing new or exciting about wind construction risk relative to other power plants. You want to have a good EPC contract that lays off as much risk as possible on the EPC contractor.

One wrinkle in the wind market is projects are often pressed up against a deadline to qualify for production tax credits. It is very important that construction finish on time. The current deadline is December 31, 2005. Developers should try to lay off as much completion risk as possible on the construction contractor. Projects are not technically complex to put together. The construction periods tend to be about six months. Completion risk is not a huge issue in many projects, but it must still be addressed.

Technology risks are a greater concern. The great news in wind projects, and I think the reason that we are all here, is that the price of producing a kilowatt hour of electricity from wind has come down about 90% in the last 20 years. To accomplish that, though, has required huge technological leaps — two generations of wind technology over the last 10 years — and there are sometimes glitches with the latest machinery. Lay that risk off on the turbine supplier. Make a decision whether you want the latest and greatest or something that is tried and true. Technology risk is laid off through a set of warranties. I will skip most of them, but there are two warranties that are key and that set wind projects apart from other projects. They are an availability warranty — a warranty that the project will be available at least 95% to 97% of the time — and a power curve warranty that the project will produce a certain amount of output at specified wind speeds.

What is unique about these warranties is what happens if they are not met. Ultimately, the vendor has to make you whole from a financial standpoint for the lost revenue under your power purchase agreement, lost revenues from loss of production tax credits, and lost revenues if you are in a state with renewable energy credits.

O&M risk: on the one hand, wind farms are not terribly complicated to run; on the other hand, individual turbines tend to have mechanical problems. You handle an O&M risk through traditional means. You hire a qualified operator, or if you yourself are a qualified operator, you run the wind farm yourself. Often the operator will be the turbine supplier. A good O&M contract is essential, and you typically try to line up a long-term service agreement as well.

A big question when using a new technology is whether the machines will still work well after seven, eight or nine years.

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bonds to finance a facility for storing spent nuclear fuel rods. Tax-exempt bonds can be used to finance facilities that dispose of "solid waste." The agency said in a "technical advice memorandum" — or ruling to settle a dispute arising out of an audit — that a comment by Congress when it wrote the law that solid waste "does not include most hazardous waste (including radioactive waste)" rules out spent fuel rods. The ruling is TAM 200452034. The IRS made it public on Christmas Eve.

— contributed by Keith Martin, Samuel R. Kwon and Jana Dimitrova in Washington and Jose Ibarra with Chevez, Ruiz, Zamarripa y Cia in Mexico City.

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Let me talk briefly about environmental risk. Everyone thinks wind power is environmentally friendly. There is a limited set of problems. One is noise concerns. The blades make harmonic noises. These can be addressed by noise warranties from the turbine supplier that the turbine not surpass limits in local noise ordinances. It also helps that most wind farms are in sparsely populated areas. Visual impacts are an issue. Remoteness helps.

The quality of the wind data for a project is the greatest determinant of project value.

Finally, bird and bat fatalities are also potentially a problem. The old-style turbines had lattice construction. The lattices were great bird perches. The birds not only perched but ran into the turbine blades. This problem has been principally addressed through technological advances. Wind turbines today are on unipoles. You also address this through studies of migration patterns of birds. To the extent bird fatalities of endangered species are expected, the project will need a permit from the US Fish and Wildlife Service.

Let me say just a few words about renewable portfolio standards. These are laws at the state level that require utilities to supply a specified minimum percentage of their electricity from renewable sources. Eighteen states have renewable portfolio standards. Six of them adopted their standards in just the last year.

Wind qualifies as a renewable resource in all 18 states. The definition of "renewable" varies in other respects from state to state.

The key to a good RPS program is to set the right target. In some states — in Maine, for example — what looks like a very high target was set, but it is really a chimera since the state already had a lot of eligible power coming across the border from Canada. A good RPS statute is one that requires broad participation by utilities and that sets meaningful penalties for utilities that fail to comply. Such statutes help set a market price on the intrinsic environmental value of renewable energy.

Eleven states, including Texas, have, or anticipate, rolling out, renewable energy credit programs. In such states, generators get a credit for each kilowatt hour or megawatt hour of renewable energy they produce. The credit is separate and apart from the energy itself. There are manifold benefits to this, but I will mention only two. First, when done right, these programs create efficiencies. Those people who are best at creating renewable energy and earning credits build wind farms. The incumbent utilities, who may not want to build wind farms and may be transmission constrained, buy renewable energy credits. Such programs create opportunities for independent power companies. Second, the programs create a third revenue stream for wind projects in addition to PPA revenues and PTCs: RECs.

Market Drivers

MR. SCHUMACHER: It is obvious there are differences between wind farms and other types of power projects. What would you tell an experienced power developer or investor who has never done a wind farm are the key differences? Keith Martin, let me start with you.

MR. MARTIN: I think the main difference is the government pays as much as 65% of the capital cost of a wind projects. About a third of the cost is paid through production tax credits. The balance is paid through generous depreciation allowances and, until last year, a depreciation bonus. State tax benefits add on average another 10%.

Thus, the challenge in wind deals, which isn't always present in other types of power projects, is to make effective use of the tax subsidies. Many wind developers are either too small to benefit from them or they are European companies that lack a US tax base. The challenge is how to share in the tax subsidies indirectly. It is this challenge that has driven how wind deals are structured.

MR. SCHUMACHER: Then who ends us investing in wind deals? Who can use the tax benefits?

MR. MARTIN: The users of the tax benefits are traditional, large institutional equity investors. They are not individuals. Individuals have a hard time using production tax credits and tax depreciation. So do closely-held corporations. This has presented a challenge for European wind companies that bring loads of experience to the US market but have a hard time playing here because they are not efficient users of tax benefits. They must find a partner to play in this market.

MR. SCHUMACHER: Eddie Moses, given this, why are there so many small developers in this market?

MR. MOSES: It is a question of what the alternatives are. There are usually four or five big companies in the market interested in buying projects that are ready for construction. The names keep changing, but there always seem to be four or five. Smaller developers push projects along to a point where they can be sold. These four or five will buy 100%. They do not want a partner. The developer takes a developer fee and is out of the deal. The alternative is to find partners to put up the equity to see the project through construction.

MR. SCHUMACHER: Paul Weber, since tax benefits pay a large part of the cost of projects and Congress must keep renewing the production tax credit, there is political risk. How do lenders want this political risk covered?

MR. WEBER: What lenders require is that someone else take the risk, and that someone else is the sponsor with the tax appetite. The lenders will take the risk that the wind will not blow and, thus, there are no production tax credits for lack of wind, but if the law changes, the sponsor will still be obligated to add the value of production tax credits into the project. This is typically done through capital contribution agreements. The sponsor is required to make capital contributions to the project partnership for the assumed value of the production tax credits on whatever electricity is generated. A sponsor may not actually have to put the cash back into the project to the extent that the debt coverage ratios are being met.

MR. SCHUMACHER: Eddie Moses, is the institutional equity market prepared to take the risk that the tax benefits will be denied due to a change in law?

MR. MOSES: Absolutely. The four or five big companies that are buying up projects from smaller developers turn around and leverage the projects. There is a lot of project debt. A lot of that is basically securitized borrowing against the production tax credits.

MR. MARTIN: David, I would add that the traditional investors in wind deals feel they can accept the tax risk. They ask for factual representations from the project developer. The tax risks are not usually significant, except for projects that are built close to the deadline for placing projects in service. The fact that there is not a great deal of risk is evident from the small number of private letter rulings that the Internal Revenue Service has issued in this area. Most rulings deal with whether renewable energy credits or various forms of state or utility financial assistance will cause a haircut in a project's production tax credits. A project will not get the full production tax credits to the extent that its capital cost is paid in part with government grants, tax-exempt financing or subsidized energy financing or with help from other tax credits.

MR. SCHUMACHER: Is there a real risk that the production tax credit will disappear?

MR. MARTIN: The biggest risk is fundamental tax reform. If Bush succeeds in scrapping the current income tax system and replacing it with something else, there are sure to be transition rules but they are unlikely to provide adequate protection for the remaining production tax credits for a project that has already been built. The conventional wisdom at the moment is that there will not be any fundamental tax reform. The conventional wisdom is that the Bush administration will crash on the shoals of social security reform.

MR. SCHUMACHER: Eddie Moses, you said earlier that the returns are low in this business. Why is that?

MR. MOSES: The barriers to entry are very, very low.

It is not like the geothermal market where test drilling costs a million dollars a hole. All a small developer has to do is put up a few towers and sign a few lease agreements and compete in utility RFPs. Some of these developers do not really know the whole game. They agree to supply electricity at an unreasonable price and the project is never built. What that does to medium-sized or more experienced developers is it hurts their deal flow. It makes it tougher to win electricity contracts.

MR. SCHUMACHER: Talk more about what is suitable wind data.

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MR. MOSES: We would typically invest on no less than two years of wind data. The developer puts up a very tall tower on his site. The tower should be tall enough to be at the nose cone of the wind turbine. Wind turbine towers can be 100 meters high today. Wind speeds vary at different levels. That's called sheer. You measure in a broad area because wind has a mind of its own. It can be vastly different 30 yards away. The developer then finds data at a reference point like an airport or NOAA station that has been cranking out public information for 20 or 30 years. He then does a lot of complicated correlations and hires rocket scientists to make the investors feel comfortable. The conclusions are almost always wrong by definition, but you do the best you can.

MR. WEBER: Lenders lend against the various probabilistic cases. Lenders try to protect themselves by requiring 1.5 coverage ratios on a P50 case and a 1.0 coverage ratio on a P95 or P99 case.

AUDIENCE MEMBER: I'm Eddie Daniels from Reliant. Paul Weber said that lenders count on staged equity contributions over time to help repay the debt. I assume many investors are corporations that put in money at the start of a deal and are not prepared to make other assets available. How do the banks count on the equity to pay off? Is it by creating a bucket to keep some of the revenue in the project?

MR. WEBER: That's one way to do it. But, as Keith Martin mentioned, the equity investors are usually large institutions that are creditworthy and that don't need to post cash collateral to secure their equity contribution obligations. From a lender's perspective, this is not staged equity as much as another revenue source. The revenues from the production tax credits accrue at the sponsor level rather than at the project level, so the lender thinks about how to get the revenues down to the project if they are needed to cover debt service.

MR. MOSES: That's by contract between the sponsor and the bank. You do not have to do it the way Paul describes. A developer can keep the production tax credits out of the waterfall and just borrow against the electricity revenues.

> Most of the wind projects in Texas have been built in an area — the McCamie area — with inadequate transmission capacity.

MR. MARTIN: It is a question of how much the sponsor wants to borrow. He must have enough revenue coming into the project partnership to support whatever level of debt he requires. If he requires more debt than the electricity revenues alone will support, then he agrees to make ongoing capital contributions for all or some portion of the production tax credits.

MR. MOSES: It definitely affects your return. Some people choose to have both senior debt and PTC debt, and some people choose to have no debt at all.

AUDIENCE MEMBER: Doug Whiting with T-3 Energy Services. I have seen suppliers of other types of turbines shying away from giving availability guarantees unless they get a piece of the action through an O&M contract or a long-term services agreement. Is wind significantly different in this respect from other technologies, or do you have to prepare to play that game with equipment suppliers?

MR. WEBER: Turbine vendors who are asked for long-term warranties will want to operate the plant or have a long-term services agreement. There are some developers who feel very comfortable operating wind projects on their own — an FPL Energy for example. They may be reluctant to pay money for an extra degree of comfort that they do not think they need.

AUDIENCE MEMBER: Alfredo Cahuas from USA Gamesa. The reason turbine vendors want to be involved in operation is the warranty. They want to make sure any turbine for which they are responsible is maintained properly. It is just like a car manufacturer — for example, the warranty on a BMW will be void if you take the car to another shop.

MR. WEBER: These agreements tend to be coterminous with the warranty. There will be a five-year agreement coupled with a five-year warranty.

AUDIENCE MEMBER: I am John Calaway with Superior Renewable Energy. I would like to make a comment on EPC contracts, as my company has been going through this recently. You have to be realistic about the profit margins that the contractor will earn on contract. Suppose you sign a $15 million EPC contract and the contractor has a 10% profit margin. That is the limit to the liquidated damages that the contractor will be prepared to pay.

The point is damages can only go so far. At the end of the day, you had better be comfortable with the track record and history of that contractor in meeting deadlines and building sound projects or equipment.

AUDIENCE MEMBER: My name is Mathis Conner with Chiron Financial. What kind of tenors are you seeing on project debt?

MR. MOSES: In 1999 and 2000, the banks were prepared to lend as long as 17 years. Then they became worried because of the collapse of the power market and the tenors went down to about 12 or 13 years. Today they are about 15 and 15 is fairly easy to achieve. Institutional money is also available for a term two years less than the power purchase agreement, but it could go longer than that depending on the project.

Transmission Capacity

MR. SCHUMACHER: Let me shift attention back to the regulatory front. In order for many of these projects to be viable, someone other than the wind developer will have to assume the capital cost of expanding transmission lines. Will that happen?

MR. WENNER: At a recent FERC conference in Denver, there was uniform agreement that the general body of ratepayers should pay the cost of additional transmission capacity to accommodate wind projects. No one objected. Of course, look who was in the audience. It was all wind developers.

People are going to have a view — whether it is consumer groups, industrial groups, and every other consumer of electricity who should pay the cost. Chances are there will be few volunteers.

From a policy perspective, it is in everyone's interest for there to be the equivalent of a national interstate highway system that is paid for by everyone; in this case, we are talking about a transmission network. Everyone benefits from having it available. The other policy is the extent to which consumer groups buy off ultimately on wind or are turned off by environmental and other factors. Is it worthwhile to pay the cost of transmission, which might not be incurred if a gas-fired power plant was built closer in? The gas-fired power plant would not require the same upgrades to the grid.

The jury is out.

MR. SCHUMACHER: Marianne Carroll, how is ERCOT dealing with the question whether it is fair to have the public at large basically subsidize wind projects?

MS. CARROLL: When Pat Wood was chairman of the Texas commission, which was from 1995 to 2001, he wanted to make the transmission grid the equivalent of a highway so that all electricity generators would be able to compete equally. Utilities that generate their own electricity would be on the same footing as independent power companies. The utilities put the cost of grid improvements into a pool and basically shared the cost of that highway system if you would. And that was fairly uncontroversial, once the utilities got over the initial shock.

But transmission is clearly a bigger issue for wind than for fossil fuels. There was one rate case recently in Texas for a utility that had to build a major transmission upgrade where people who would not normally have intervened did. We are beginning to see more activity by the industrial coalition. It has an able counsel. It is intervening more regularly.

A related issue is how quickly the utilities can recover their costs. Pat Wood understood that if you are going to require utilities to make substantial outlays for new transmission capacity, you have to allow fairly rapid recovery of those costs. He allowed mini rate cases. A utility that made new investments could adjust its rates in an annual mini rate case without having to go through a full-blown rate proceeding.

We have new commissioners now. We have also had a huge turnover in staff. Some of the utilities that have been the most active in building additional transmission capacity to west Texas have just been through / continued page 30

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rate cases, and it has been a bloodbath at the commission. This is a looming concern.

MR. WENNER: At some point, you are going to have the irresistible object pitted against the irresistible force. Under the renewable portfolio standard, a utility must, by year X, have a thousand more megawatts of renewable electricity, and yet the developers are unable to get their power to market because the transmission lines cannot be built. Which is a worse alternative for the utility — failing to meet the standard or the opposition it faces on the transmission front?

MS. CARROLL: There is no penalty on the utility for failing to meet its obligations under the RPS. Retail electric suppliers have to amass a certain number of renewable energy certificates, or RECs, each year. The curtailment problem has affected those utilities because they do not get RECs that they contracted to purchase, since if a wind generator is forced to reduce his output, he has fewer RECs to convey. The commission has had to revise its rules at least once to give utilities a bye, if you will, on meeting some of the REC standards.

MR. WENNER: There is another type of cost that we have not discussed called a system-integration cost. It is the cost to the utility system having a lot of intermittent or nondispatchable generators — that is, wind generators — connected to the grid.

Xcel and Minnesota did a study of that, because there have been charges that it costs more to operate the Xcel system than other utility systems because of the large number of wind generators in the area. The Xcel study looked at adding 1,500 megawatts of wind to a 10,000-megawatt system. It found that the utility would have higher operating costs for regulation control and for imbalance.

It is no surprise that when the wind is dropping or increasing rapidly, to maintain load-serving requirements you need to turn up or down some other unit, and that can be more costly than it would without the wind projects on the grid. But the total cost found by that study only came to $4.60 per megawatt hour, which is not out of hand if you consider power is selling at $40 or $50 a megawatt hour. And, again, this was assuming 1,500 megawatts of wind on a 10,000-megawatt system.

> Wind generators could face an assessment for system integration costs when connecting to a utility that already has a lot of wind on its grid.

The point is to keep in mind that wind generators could face an assessment for system integration costs when connecting to a utility that already has a lot of wind on its grid.

MR. MOSES: Let me just add some context. Wind energy in west Texas is cheap. We built a project and sold energy at $25 a mWh about five years ago. Of that amount, $10 was the REC value, so it was $15 electricity. You are competing against grandfathered coal at that point. I believe TXU is more than doubly oversubscribed for its REC quota, because it likes the cheap power and it likes to make the REC market as well.

AUDIENCE MEMBER: I'm from Southland Energy Works. I'd like to ask the panel what its view is on the prospects for offshore windpower here in the US.

MR. MARTIN: Offshore has decent prospects long-term but faces short-run political flak. Both Senator John Warner from Virginia and Senator Ted Kennedy from Massachusetts tried, at the end of the last session of Congress, to insert language in an appropriations bill to place a moratorium on any further offshore development until the government can come up with a national policy.

MR. MOSES: Are you for or against it?

AUDIENCE MEMBER: It just seemed like a potential growth area for wind. There have been offshore projects in Europe but they do not seem to be taking hold here in the US.

MR. MOSES: I financed a project in Sweden for Enron. We called it the first offshore wind project because you couldn't swim home from it. It was about 10 kilometers offshore, while the other ones were close enough to shore that you could hit them with a rock.

Offshore wind is really expensive. It is at least one-and-a-half times as expensive as onshore wind. In Europe, they are running out of land and, with the exception of Spain and maybe Italy and parts of Scotland, the wind speeds in Europe on land tend to be much lower than in the US, so offshore makes a lot of sense for Europe.

In the US, we have land. We have plenty of unused land in places like west Texas and Montana where the wind blows. What is needed is a transmission line backbone. You can get a lot of cheap energy all over the country on land. There might be pockets in some more crowded parts of the country — like Long Island where electricity prices could reach $100 a megawatt hour — where it makes sense to build wind farms offshore. But that is also where one runs into the most severe local opposition.

Mexico

MR. MARTIN: Eddie Moses, since you are on a roll, do you want to address another question I know was asked by someone in the audience, and that is what potential is there for building wind farms in Mexico to serve the US market?

MR. MOSES: The problem in Mexico is unstable regulation and land. The regulation is undefined. I worked on a project in Greece where the title to land was informal. You could not check the land records to confirm the real owner. Disputes are inevitable. German banks could not take that risk. There are some land disputes that go back 4,000 years. In Mexico, the land disputes go back only 250 years and some of it is communally owned. Transmission constraints are also an issue just as they are in west Texas, with the possible exception of projects near Tucson and San Diego. All of that said, people are looking at putting projects in Mexico.

MR. MARTIN: Adam Wenner, are there any regulatory issues with bringing electricity across the border into the US?

MR. WENNER: The US Department of Energy has jurisdiction to approve a cross-border interconnection. The standard environmental impact study would also be required, but it should not be a big issue because you would be importing clean energy.

MS. CARROLL: I would say that it is a technology issue. The state of the transmission over the border is not what it is over here and interconnecting the two systems is a challenge.

MR. MARTIN: And there are no production tax credits for US owners of such a project. They can only be claimed on electricity generated in the United States.

MR. WENNER: What about Texas RECs? Do they apply to non-Texas generated electricity?

MS. CARROLL: That's an interesting question. I haven't looked into it.

AUDIENCE MEMBER: No, they don't. They have to be inside of Texas.

MR. SCHUMACHER: One thing we have not talked about is power purchase agreement. You will need electricity sales to finance a project. What is pushing the utilities to enter into power contracts with wind developers and what leverage do wind developers have to extract a reasonable price?

MR. WENNER: Number one in 18 states is the utility has to fulfill its renewable portfolio requirements.

Another point to be emphasized is in many states, when the contract is approved by the state commission, it is approved for cost-recovery purposes, allowing the utility to pass through its costs of purchased power to its ratepayers. That may be one reason some utilities are indifferent to renewable portfolio standards since they can satisfy the requirements without having to eat the cost.

MR. WEBER: I read a statistic that during the period 1999 through 2003, two thirds of wind generation was in an RPS state, which means one third was in states that do not have an RPS. I believe the percentage in 2003 was 59%. I think it is principally, but not solely, the RPS.

MR. MARTIN: Perhaps we should wrap up. Are there any remaining comments from anyone on the panel or in the audience?

MS. CARROLL: I just have one issue that I did not mention, and it is a fairly large one. We are going through a process here in ERCOT where we are looking at changing the wholesale market structure. The market design today is a zonal market design. It is simpler than the nodal markets that you see up in the PJM area and the rest of the eastern interconnect. The Texas commission has not made a final decision whether to switch and probably will not until sometime later this year. However, if it decides to go to a nodal market, one of the things that developers have to factor into their calculations, in addition */ continued page 32*

Wind

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to where the wind blows, what transmission is available and what curtailments are possible due to grid congestion, is what prices are likely under a nodal market. Congestion would be factored into prices.

Tax Break For Repatriated Earnings

by Keith Martin, in Washington

The US government is hoping that US companies will bring back billions of dollars this year from overseas to take advantage of a special 5.25% income tax rate on repatriated earnings.

The Internal Revenue Service explained in mid-January what a company must do to qualify.

The tax break is expected to create a bonanza this year for banks since many US companies will have to borrow outside the United States to enable their foreign subsidiaries to pay dividends. The earnings must be repatriated in cash. The subsidiaries in most cases have undistributed earnings recorded on their books, but the cash has already been redeployed and is not available to pay dividends.

The IRS still needs to address at least one more issue before some US companies will be able to act. The special tax rate only applies to "excess" earnings that a company repatriates this year above what it repatriated on average each year during a five-year period that for most companies runs from 1998 through 2002. The IRS said it is working on a notice that will explain for companies that merged or that acquired or disposed of subsidiaries during this period how to calculate their base-period repatriations.

The details the IRS has released so far about the tax break are in Notice 2005-10.

There is no deadline for reinvestment. However, the agency established a "safe harbor" under which companies will not have to keep filing progress reports with the IRS if they have committed at least 60% of the repatriated funds to investments within three years.

Background

Many US companies with business operations or investments outside the United States own them through offshore holding companies in Holland, the Cayman Islands or similar jurisdictions. Income from the offshore operations accumulates in the holding company and is reinvested offshore. This lets the US company defer US taxes on its offshore earnings until they are brought back to the United States. Estimates of the amount of earnings parked in offshore holding companies run into the hundreds of billions of dollars.

Congress hoped that a lower tax rate would induce US companies to redeploy some of this money in the United States.

A so-called JOBS bill that President Bush signed on October 22 would let US companies deduct 85% of the dividends they receive from some foreign subsidiaries. Thus, only 15% of the dividends would be subject to US income tax. This translates into a 5.25% effective tax rate on the repatriated earnings (or a 3% effective rate for companies on the alternative minimum tax).

It is a limited-time offer. The lower tax rate will only apply to earnings that are repatriated during a one-year period. A company must choose either its tax year that straddles October 22, 2004 or its next tax year (for example, 2005).

A company must bring back more earnings than it did on average each year during a "base period" to benefit from the lower rate. The lower rate would only apply to the "excess" repatriation. The base period is the five tax years ending on or before June 30, 2003, but two years are dropped from the calculation: the years in which it repatriated the highest and lowest amounts. Thus, for example, a company that pays taxes on a calendar-year basis would look at the period 1998 through 2002. It must count as earnings repatriated during the base period not only the cash dividends it received from offshore, but also certain other amounts like distributions of property in kind, distributions of cash that did not have to be reported as dividends because the earnings were taxed in an earlier year, and any "section 956 inclusions." An example of a "section 956 inclusion" is where a US parent borrowed against cash that was parked in an offshore holding company with the result that it had effective use of the offshore earnings in the US. Such borrowing would have triggered a US tax on the offshore earnings that served as collateral for the loan to the US parent.

Only dividends from certain foreign subsidiaries qualify potentially for the 5.25% tax rate. The subsidiary must be a "controlled foreign corporation," meaning that it must be owned more than 50% by vote or value by US persons. Shareholding by a US person does not count unless the person owns at least a 10% voting interest in the subsidiary. In addition, the US company repatriating the earnings must itself own at least a 10% voting interest in the subsidiary.

Earnings must be brought back in cash to benefit from the lower rate. The low rate would not apply to other types of offshore earnings on which the US parent company must pay tax during the year. An example is passive income — like dividends or interest — earned by its offshore subsidiaries but taxed directly in the United States. Such passive income is taxed immediately to the US parent under "subpart F" of the US tax code without waiting for the money to be repatriated to the United States.

A company cannot lend its offshore subsidiary money to pay the cash dividends. However, it can borrow from a bank. Any increases in shareholder or other related-party debt of offshore subsidiaries between October 3, 2004 and the end of the tax year in which the lower rate is being claimed are potentially a problem. A technical corrections bill introduced on November 19 in Congress would also bar a US parent from effectively funding the dividends back to itself by making capital contributions or through other means.

The US company must reinvest the repatriated earnings in the United States "pursuant to" a reinvestment plan. The reinvestment plan must be approved by the company president, CEO or someone comparable before the repatriation occurs, and the plan must also eventually be approved by the board or a similar body. The plan must provide for reinvestment of the earnings in the US "including as a source for the funding of worker hiring and training, infrastructure, research and development, capital investments, or the financial stabilization of the corporation for the purpose of job retention or creation."

A company cannot use net operating losses or most tax credits to shelter the earnings from the 5.25% tax.

Foreign tax credits are an exception. Suppose a foreign subsidiary distributes its earnings as a cash dividend. Income taxes were paid on the earnings to other countries. The income taxes are released with the dividend for use as a foreign tax credit in the United States, but 85% of the taxes will never be creditable against these or any other income in the US. The other 15% can be used as shelter against the 5.25% tax on the repatriated earnings in the US. This is true of both "indirect" foreign tax credits — for income taxes paid by the foreign subsidiary or other companies below it in the ownership chain — as well as "direct" credits for withholding taxes collected by another country when the cash dividends are paid to the parent company in the US.

There is a dollar limit of $500 million on the amount of earnings on which the company can pay tax at the special low rate. However, if the company can produce financial statements proving that it had more than $500 million in offshore earnings "permanently reinvested" outside the United States, then its cap is the higher figure. It must use a particular financial statement for this purpose: the last audited one it had certified or filed with the US Securities and Exchange Commission on or before June 30, 2003.

Reinvestment Plan

Companies flooded the US Treasury Department with questions soon after the earnings repatriation provision was enacted. The IRS released the first set of answers in mid-January.

It said that the reinvestment plan that must be in place before the earnings are repatriated must describe the planned use of the earnings in the United States "in reasonable detail and specificity." The plan must provide enough detail for the company to be able to prove later on audit that the earnings were in fact used as originally contemplated. The plan will not pass muster if it merely refers to generic categories of spending or provides a laundry list of possible uses.

It should state dollar amounts, but they do not have to be detailed. For example, it can say that $X will be spent to pay down debt on project X and $Y will be spent to develop project Y. Spending can be shifted later among the uses specified in the plan. Thus, money could be shifted from project Y to pay down more debt on project X. The plan can also spell out an alternative use of the funds in case the primary investment is delayed or rejected — for example, due to inability to get permits.

The plan should give a "reasonable" time period over which the investments will be made. The company can have a separate plan for each batch of repatriated earnings or a single master plan.

The plan *cannot* be amended after the dividend has been paid — with the exception of plans / *continued page 34*

Earnings Repatriation

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drawn up before January 13 this year when the IRS notice was issued. Companies have until March 14 to amend such plans.

The earnings do not have to be put into a new project; they can be applied to investments that the company already planned (including used to pay down debt on past investments). The reinvestment plan must be approved by the president, CEO or a comparable officer of the *ultimate parent company* in the US that files the consolidated income tax return. This approval must come before the dividend is paid. It is that company's board that must also later approve the plan. It does not matter that a US subsidiary received the dividend or will be the one making the investment.

The IRS said that companies do not have to keep repatriated earnings in segregated accounts or otherwise "trace" the money received to the later use of the funds in the United States. It is enough to show that at least $X was invested as suggested in the plan. However, the IRS cautioned that a company would do better on audit if it kept the earnings in a segregated account and had good records showing the uses of the funds in situations where the earnings are invested "over the course of many years."

There is no "cliff." If the reinvestment plan calls for $100 in repatriated earnings to be invested in the United States, but only $60 are, then only $60 qualify for the lower tax rate.

Spending on a project counts as reinvestment of a dividend even if that spending occurred before the dividend was paid as long as it is in the same year the US company is claiming the lower tax rate. Thus, spending in January 2005 on a project would count as reinvestment of a dividend not paid until November 2005 for a taxpayer who elected the lower rate for calendar year 2005.

Permitted Investments

The IRS published a list of permitted uses for the repatriated earnings, but said it is not an exclusive list. It also identified a number of uses that do not qualify.

Investments count only when made in cash. Thus, there is no reinvestment of repatriated earnings when a US company uses its shares to acquire a target company. This could affect how some corporate acquisitions are structured in the future. An investment is not made by giving a note until the note principal is paid.

Spending qualifies as a good investment in "infrastructure" even if it is merely to rent or license such things as telephone equipment or computer software. However, the equipment must be used in the United States. The spending must be allocated to the extent the equipment is used only some of the time in the US. The allocation is done according to the percentage of time the equipment is physically used in the US (rather than what portion of the revenue from using the equipment is considered to come from a US or foreign source).

Many US power companies and others in capital-intensive industries may want to use repatriated earnings to pay down existing debt. Debt repayment is permitted if the company can show it contributes to "financial stabilization of the taxpayer for purposes of job retention or creation in the United States." This is a two-pronged test. However, the IRS suggested both parts should be easy to meet. The agency said debt repayment "ordinarily" helps with financial stabilization since it improves the debt-equity ratio of a company or reduces its obligations for debt service. It suggested that it will take the company's word that the financial stabilization will help keep existing jobs or create new ones if, at the time the CEO approves the dividend reinvestment plan, the company's "reasonable business judgment" is that the debt repayment will be a "positive factor" in helping to keep or

US companies are expected to bring back billions of dollars to the United States this year to take advantage of a special 5.25% tax rate on repatriated earnings.

create jobs in the US. It would be a good idea to explain how it is expected to help in the dividend reinvestment plan.

It is apparently irrelevant whether the assets securing the repaid debt were in the US or abroad.

Some of what passes for earnings repatriation may be little more than a shift of debt offshore. Suppose a foreign subsidiary must borrow from a bank to raise the cash to pay a dividend to the US. The US parent company uses the repatriated earnings to repay its debts. All that has occurred is a domestic debt has been replaced by a foreign one. The IRS suggested it has no problem with this as long as the US parent company or one of its US subsidiaries is not the borrower in substance under the offshore debt. In other words, it wants the debt truly to have shifted offshore. For example, the US parent would effectively remain the borrower if it guaranteed repayment. US companies should consider the other consequences from such debt shifts. For example, the US group would have less foreign source income in future (because of the offshore interest payments), which would reduce its ability to claim foreign tax credits.

The debt repaid cannot be to an affiliate. Money paid by one US company to another US company whose tax results are reported on the same consolidated income tax return do not count as an investment. Such payments are ignored.

A company should be careful when repaying debt not to re-borrow on substantially the same terms within the next six months. In that case, the IRS might argue that there was no reinvestment of the earnings in the United States because the debt was not truly repaid. It was replaced promptly with similar debt. Re-borrowing by another company in the same consolidated group is potentially a problem; all companies that join in filing a consolidated US income tax return are treated as a single company for this purpose.

The IRS said the repatriated earnings can be used to make pension plan contributions. The money cannot be used to pay executive compensation. It does not matter whether the pension plan covers current employees or whether they worked in the United States. However, the dividend reinvestment plan should explain why the US company believes that such contributions will contribute to financial stabilization of the company and how this, in turn, will help keep or create jobs in the United States.

The earnings can be used to acquire an interest in another company — including a company in another country. However, the US company must own at least 10% of the value of the target company after the latest acquisition. Otherwise, it is treated as having made merely a "portfolio" investment, which is not the type of investment Congress wanted to reward. Anyone using earnings to acquire another company must allocate the purchase price among the assets of the target company between those that would be permitted investments if acquired directly and those that would not. If any of the permitted assets is used only parttime in the United States, then there must be a further allocation based on the percentage of domestic use. The bottom line is that only part of the acquisition price will be treated as reinvestment of the repatriated earnings in the US.

The repatriated earnings cannot be used to pay dividends or buy back shares. The tax section of the New York State Bar Association argued that such uses represent a shrinking of the enterprise, or the opposite of an investment. The earnings also cannot be used to acquire debt instruments or to make tax payments.

Tax Planning

Earnings must be repatriated to the US in cash. Wire transfers and checks count as cash. US companies asked the Treasury Department whether they could transfer certificates of deposit, corporate bonds, commodities and other cash equivalents. The IRS said no, but said it would not invoke a "step transaction" theory to claim that no cash dividend was paid in cases where a foreign subsidiary liquidates such a cash equivalent in order to pay a cash dividend, and then its US parent immediately reinvests the money is a similar instrument.

The US company must reinvest the *gross* amount of the dividend, ignoring any "related expenses" that reduced the cash it actually received. For example, suppose a foreign subsidiary pays a dividend to its US parent of $100, but $5 is taken out at the foreign country border for withholding tax. The US parent must reinvest $100.

Most companies will have to do a fair amount of foreign tax planning to take full advantage of the provision.

The amount of earnings that can be repatriated at the low tax rate is limited to $500 million or, if more, the amount that the financial statements of the US group show is "permanently reinvested" outside the United States. A US company can specify which foreign repatriated earnings during the year it wants to qualify for the low rate. / continued page 36

Earnings Repatriation

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Companies would do best to choose earnings that were not heavily taxed abroad — and that carry with them little or no foreign tax credits. Most US companies in capital-intensive industries have a hard time using foreign tax credits because of the fine print in the US foreign tax credit rules. Nevertheless, repatriating heavily taxed earnings releases any such credits and the clock begins to run on their use. (Suppose a foreign subsidiary has \$100 in undistributed earnings and \$35 in foreign income taxes were already paid on the earnings. When the earnings are distributed in cash to the US, they will bring along with them a foreign tax credit. However, because only 15% of the earnings will be taxed in the US, only 15% of the foreign taxes will come with them as a potential foreign tax credit. The remaining foreign taxes are lost as a potential foreign tax credit. The clock will begin to run on use of the 15% of the foreign taxes that are creditable.)

US companies may have to do some reorganizing of their foreign subsidiaries to isolate low-taxed earnings. For example, dividends passing up a chain of foreign subsidiaries will drag whatever foreign tax credits were in the combined earnings pool. In the past, one could leapfrog a subsidiary higher up the chain by having the lower-tier company lend the money directly to the US parent. This caused the earnings to be taxed in the US (since the earnings were effectively repatriated). Since only cash dividends qualify for the tax rate, any repatriation will have to be directly up the ownership chain.

The tax break is expected to create a bonanza for banks since many US companies will have to borrow outside the United States to enable their foreign subsidiaries to pay dividends.

Earnings brought back to the US from abroad but distributed through partnerships or "disregarded entities" (companies that do not exist for US tax purposes) create complications.

The IRS said the earnings are not considered to have reached the US until they are received *in cash* by the US company that is a partner or is the owner of the disregarded entity. They must also reach the US during the year the US company has chosen to benefit from the lower tax rate. For example, suppose US company A chose 2005 for the lower tax rate. Suppose it owns a foreign subsidiary through US subsidiary B and B is disregarded — it does not exist — for US tax purposes. The foreign subsidiary pays a cash dividend in 2005 to B. B must distribute the cash to A in 2005. The same thing is true of dividends paid through partnerships.

Another complication that will require planning is where some of the undistributed earnings of a foreign subsidiary were already taxed in the United States under "subpart F" rules. (The US looks through foreign subsidiaries and taxes US shareholders on any passive income it sees in the ownership chain.) Suppose a foreign subsidiary has \$150 in undistributed earnings. However, \$90 of them were already taxed in the US under subpart F. The subsidiary must pay a cash dividend of at least \$91 before the first dollar of earnings qualifying for the 5.25% tax rate will be considered to have been distributed. Other earnings are considered distributed first. ◎

Ethanol Goes Prime Time

Ethanol plants are another bright spot in an otherwise weak project finance market. Ethanol is an alcohol made most frequently from corn, and it is used both as an additive in gasoline and directly as fuel. There are an estimated 84 ethanol plants in operation currently in the United States, and *at least another 30 are in the market for financing.*

Chadbourne hosted a roundtable discussion in New York about the main issues in ethanol deals, the mistakes that developers make, and how such projects are being financed. The following are excerpts from the discussion. The speakers are Jonathan Phillips, a lawyer in the Chadbourne Houston office, Thomas Byrne, president and chief executive officer of Byrne & Company Limited, a consultancy that has worked with ethanol and bio-diesel developers for 24 years, Tydd Rohrbough, president and chief executive officer of Cornhusker Energy Lexington LLC, an entity that just built an ethanol plant in Nebraska, Peter Nessler, director of the renewable fuels group at FC Stone, a commodity risk firm that helps ethanol producers with hedging strategies, Paul Ho, a vice president of Credit Suisse First Boston, and Keith Martin, a tax partner in the Chadbourne Washington office. The moderator is Todd Alexander, a project finance lawyer with Chadbourne in Houston.

Background

MR. PHILLIPS: The process by which ethanol is derived has been around for several hundred years, with the first commercial application appearing in the US in the early 1900's. Henry Ford designed the Model T to run on ethanol or gasoline and was a major proponent of ethanol. While he was a forward thinker, he was not sure what the predominate fuel would be in the future. Gasoline was eventually chosen by the market, and ethanol went by the wayside until the early 1970's.

Then came the Middle Eastern oil embargo and, by the late 1970's, the US government turned its attention to alternate fuels. Congress gave ethanol an excise tax exemption in 1978. It enacted income tax credits for blenders and small ethanol producers in 1980. The excise tax exemption and the blender credits have played a major role in development of an ethanol industry in the United States. Ten years later, we had the first truly major pro-ethanol legislation, the Clean Air Act Amendments of 1990. By 1999, the harmful effects of a gasoline additive called MTBE came to light, and the first bans on MTBE started being proposed. In October 2004, the JOBS bill passed Congress, and it is probably the most important legislation for the ethanol industry since the Clean Air Act Amendments. The JOBS bill created a "volumetric" excise tax credit for ethanol; instead of an exemption tax exemption, the industry was given a credit against federal gasoline excise taxes tied to the volume of ethanol used in vehicle fuel, and the bill also removed the blending percentage requirements that were contained in the Clean Air Act Amendments.

The MTBE bans are creating significant demand for ethanol as a gasoline additive in place of MTBE. In 1999, annual production capacity in the United States was approximately 1.4 billion gallons. In 2003, production jumped to 2.8 billion gallons primarily due to the MTBE bans. Production for 2004 is expected to be around 3.4 billion gallons. Production in October 2004 — the most recent month for which figures are available — was 226,000 barrels per day, tying the record set in September. Nineteen states have banned MTBE to date, which accounts for 1.37 billion gallons of ethanol demand. The remaining states, if we assume a blend of 5.7 to 10% ethanol in gasoline, account for approximately 1.4 billion gallons in demand. There is a lot of speculation about potential demand, and a key assumption in these estimates is the percentage of ethanol used by blenders.

Another key feature of the JOBS bill is a reporting requirement. April of this year will be the first time that all ethanol producers and blenders will have to report to the Internal Revenue Service, and this should give the public a better idea of how much is being produced.

All the major versions of the energy bill that failed in a close vote in late 2003 to pass Congress contained a renewable fuel standard that would have required a certain number of gallons of ethanol to be mixed each year with gasoline. However, ethanol production is already ahead of the mandated levels. The energy bill would have required that 5 billion gallons of ethanol be used each year in gasoline by 2012. In 2004, domestic production was approximately 3.4 billion gallons, and production in 2005 is expected to reach 4.5 billion gallons. The industry wants Congress to raise the bar higher. Chadbourne held a conference call in early November soon after the presidential election results were in about the prospects this coming year for a national energy bill. They remain murky.

The long-term trend is for US government support for cleaner fuels. Each of the presidential candidates spoke out in favor of clean fuel programs. Bush on numerous occasions has supported ethanol, so it is likely we will continue to have strong presidential and Congressional support along with a pro-ethanol lobby. The political instability in the Middle East has produced strong sentiment toward */ continued page 38*

Ethanol

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reducing our dependency on foreign oil. This has put renewed focus on renewable fuels and ethanol. It is clear that the market is pushing ethanol as the current renewable, but ethanol has other uses as an extender and oxygenate component.

So, if we assume that the market will continue to grow, the question is what does it take to have a successful ethanol project? One of the major things you need is a strong equity sponsor. Historically, the ethanol business was driven by farmer coops. Hundreds of farmers would invest small sums to raise the equity needed to build an ethanol plant, and they were able to leverage it up through the agricultural credit banks on a 50-50 debt-equity basis. Farmer coop-owned ethanol plants account for approximately 1.1 billion gallons of current production. Archer Daniels Midland Company has approximately 1.2 billion gallons of production, and the remaining 1.1 billion gallons is from other industry players. One reason the industry is so fragmented is that it has had difficulty attracting senior lenders due to the fact that there are non-corollary inputs and outputs. You also cannot arrange a long-term output contract, which makes it hard to persuade lenders that the project will have enough cash flow to cover debt service.

A reputable engineering and construction partner is also important. You need a strong construction contract or EPC agreement. An effective hedging program is essential, too. Pete Nessler will speak to this. There are new ethanol hedges available on the Chicago Board of Trade and the mercantile exchanges. Finally, the financial markets will want to see a strong operational team.

Location

MR. ALEXANDER: Tydd Rohrbough, you developed the Cornhusker project in Nebraska. One of the first decisions a developer has to make is where to build. How do you choose a site?

MR. ROHRBOUGH: We had a well-defined process. We had a core matrix containing 69 criteria, but at the end of the day, it is location, location, location. Most ethanol plants are in rural areas. You can't build one downtown because they are industrial plants. Next, you focus on where the corn is located. We wanted to make sure the corn we needed would not require taking more than 15% of the total corn produced within a 40-mile radius, so we laid out the whole United States and targeted areas where we could consume less than 15% of the corn supply. When you get out to the rural parts of Nebraska —a state with only a million and a half people — the infrastructure is just not there. We also focused on rail and natural gas supply. We also wanted a spot where there was not another ethanol plant within 15 miles. We also included cattle production —

> Ethanol plants produce two main products — ethanol and distiller's grains that are used as livestock feed.

MR. ALEXANDER: Please explain, for people who are not familiar, the relevance of cattle to an ethanol facility.

MR. ROHRBOUGH: First you buy corn, and then you process the corn by removing the starch to get ethanol, and you end up with high-value animal feed. The market often overlooks the value of this byproduct.

MR. ALEXANDER: Tom Byrne, you have helped a number of projects find the best site. What do you look for?

MR. BYRNE: Definitely location is the first issue. We work with a number of plants outside of the corn belt where how much corn is growing within 40 miles is not one of the factors in site selection. We look first for strong rail access so that the ethanol can get to market. Distiller's grains are a huge part of making a plant successful. We look at who can use them nearby. For example, we have a project in Texas where there are lots of cattle. If there are chickens or swine nearby, you might look at a little different process that gives you a byproduct closer to a soy meal in place of distiller's grains.

MR. ALEXANDER: What are the one or two major mistakes you see developers who are not as thoughtful as Tydd Rohrbough make? We know there are 80 or so existing plants and many developers are trying to do more deals.

MR. BYRNE: The largest issue is getting your products right in an ethanol plant. The corn can be used for five or six commodities. If you are looking for a site and you see a set of railroad tracks in front of you, you assume you have access to the best markets and you can get the highest price for your products. That is the biggest error. You need a professional analysis of where those rails go, what products can be sold and what it costs to get your product in and out of that market.

MR. ALEXANDER: Pete Nessler is sitting there patiently waiting to talk; this is his area of expertise. Give us your view.

MR. NESSLER: What Tom said is true. You have to split the US between west and east. There are lots of plants being built today in Iowa and a few more in Nebraska. Look at the demographics of where ethanol is going. There are only a million and a half people in Nebraska and a couple million in Iowa. Your best market for the ethanol is California. When you put the matrix together, it should show that one or two of the products from your facility will have to be shipped there.

MR. ALEXANDER: For those of you without the basic knowledge, if we were to put up a map of the United States and show where the 82 existing plants are located, 78 would be right in the center of the country, forming a bull's eye. Do you think there is a lot of potential to develop facilities outside of that bull's eye?

MR. NESSLER: I do. California has a lot of livestock. So does Texas. So does the east coast.

MR. ALEXANDER: Let me question you about rail. You hear about congestion on the rail lines. If you were to build a plant in California or New York, how much additional expense are you talking about to bring the grain to the plant? Do you have to build extra storage so that your plant will not have to rely on just-in-time delivery?

MR. NESSLER: Not to get too deeply into it, but having extra storage makes sense even in the midwest because of the carrying charges. For instance, corn today is $1.65 per bushel, and let's say nine months from now it is expected to be $2.10. If the market is charging 4¢ a month for carrying costs, having storage will bring your costs down. Most plants have only eight days worth of storage. For a plant on the east coast or west coast, or in the southwest, we recommend 45 days worth of storage. There are glitches in the rail system at certain times of the year, but if you plan ahead for them and you have the space for storage, then you will buy cheaper grain. If there is a rail problem, there will be just as much outbound ethanol going west as grain going east, so it works both ways.

Process Design

MR. ALEXANDER: So assuming we picked our site, let's transition with Tydd on picking the proper process design. There are three or four main process designs from which to choose. You looked at them all. How did you choose?

MR. ROHRBOUGH: We did a comprehensive search. We wanted a process that is used in existing plants that have been operating for more than five years, which significantly narrowed the field to just two; at least three years ago, there were only two.

MR. ALEXANDER: In terms of specific factors, what were you looking for? Different people advertise different BTU usage. How did you evaluate them against each other?

MR. ROHRBOUGH: We put up a matrix. One of things we found early on is everyone was selling something different. The first thing we had to do was get a standardized matrix of what the outputs were. Nobody was giving us the same apples-to-apples values. So we started off with something and then broke it down into components. The first thing you have to do is take the corn to starch. You correlate a pound of starch to a pound of fuel and get to a measure of the output. Then we looked at the BTU usage within the process, as to whether or not it was increasing. A lot of people were giving a gallon-to-bushel ratio, but that does not work with corn. You have a wide range of outputs on the back end.

MR. ALEXANDER: Tom Byrne, is that same analysis you would do for your clients?

MR. BYRNE: It goes back to having a comprehensive request for a proposal. The location of the plant is a factor in choice of process. Suppose the plant is in Arizona or Texas where water is an issue. The request for proposals should make clear water is a concern and ask the process providers how they would address it. */ continued page 40*

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Different technologies have different levels of energy utilization; some have different chemical utilizations. The ethanol is basically standard. You will get the same ethanol out of each of them. The distiller's grains have some variation. Look at your potential market for the distiller's grains. A number of plants are looking at fractionation, or taking the corn apart before it goes into the fermentation process. If you want the distiller's grains to be right for your particular market, choose a technology that can provide that for the market.

MR. ALEXANDER: Where do you see the technology going? An interesting thing for me, not being an engineer, is the cost of plants that were built five or 10 years ago was so much higher than it is today. Then you hear people talking about cellulosic-based designs, where you would not even be using corn as the basic input. Where do you see things three or five years from now?

MR. BYRNE: About 10 years ago, the ethanol market was basically the ADMs and Cargills of the world that had their own internal operating departments. There was not enough demand for yeast and enzymes to make it worthwhile for companies that provide these inputs to conduct intensive research. Now, with the industry growing quickly, they are spending lots of money on research and development. The same facilities and the same equipment will likely get considerably better yields in the future. Another point to keep in mind is the number of cattle in the United States is not growing significantly. There are a lot of products in corn that can be used for other than just feed. The technology of the future will pull pharmaceuticals and different fibers out of the corn.

MR. ALEXANDER: So instead of 60% or 70% of revenue from the plant being derived from ethanol, these other processes will decrease that fraction. The plant will get 50% of its revenue from ethanol and the rest from other products, and it will not make distiller's grains?

MR. BYRNE: Ethanol is made strictly from the starch, which happens to be a third of corn, but it is only one component of the corn, and there are other things in a kernel of corn that can be put to better uses than just as feed.

A mistake some project developers make is to assume that a nearby rail line means that they can get their products to market.

MR. ALEXANDER: Tydd Rohrbough, does this worry you, as someone who owns and has just financed a dry mill plant?

MR. ROHRBOUGH: Not particularly, because these projects are commodity based, and we looked as part of our long-term base plan at other products that come out of corn. We identified 30 that are fermentation based. Our plant will not be a single source facility. We are on the same track in the long term.

MR. ALEXANDER: Suppose someone in the audience plans to invest in an existing plant with dry mill technology. Should he or she assume that the plant will require another capital outlay in five years to equip it to produce a different product mix?

MR. NESSLER: You have to have enough space. The environment will determine what it is possible to do.

MR. ALEXANDER: So it's important to have lots of space?

Paul Ho, I don't know whether CSFB has a view on this, but are you worried that you are giving people 7- or 10-year money, given the potential technological changes that may take place?

MR. HO: I think we get comfort from the number of ethanol plants that have been placed into service. You will have to displace the older plants first. We are not overly concerned, and we will also try to get an opinion from an independent engineer that the technology makes sense in the long term.

Construction Contract

MR. ALEXANDER: So hopefully we picked a site for our plant that is big enough to expand to accommodate any new technology. Now we need to pick a construction contractor. For those of you who are familiar with power plants and other types of infrastructure projects but have no experience with ethanol, the construction contracts are not what you are used to. Tydd Rohrbough, how did you identify your contractor and how difficult was it to get the contract you wanted?

MR. ROHRBOUGH: It was very difficult to get the contract we wanted. One of our team members comes from Kiewit, which is a fairly large contractor. Three years ago when we came into the industry, many of the companies that were building ethanol plants could not get bonding. Those construction companies are now a lot of larger and can now bond. We had to eliminate many of the potential contractors early on because not all designs allow for the same technology. You should look forward and anticipate what the bank and investors will need. They will want someone to wrap certain risks. If you have a technology provider and an EPC contractor to build it, you need to ask yourself how do you get the EPC contractor to wrap the product.

MR. ALEXANDER: Let's ask Paul Ho.

MR. HO: We encourage a developer negotiating an EPC contract to spend as much time looking at the financial support for the EPC contract as the technical parameters. The lenders look to the EPC contractor's credit, and many of these contractors do not have good credit in the sense that the lenders can rely on the creditor to live up to its obligations. So you look to bonding 100% of the contract price. In terms of a performance bond, many of these contractors have been able to build these plants in the past without offering the liquidated damages and performance guarantees that lenders require.

MR. ALEXANDER: For the benefit of our audience, Paul, maybe you could identify some key things that lenders will insist be in the construction contract. For example, does CSFB have specific guidelines for liquidated damages?

MR. HO: Yes. With respect to liquidated damages, we used to say we wanted 20% to 25% debt coverage for energy projects generally, but we are not able to get close to that in the ethanol space. We can get 8% to 10% coverage, and that's the best we can do. The lenders will have to be comfortable with less than investment-grade credit. The construction risk itself is single B or BB. We're trying to push the liquidated damages level as much as possible, but at the end of day we have to live with the commercial reality of the industry.

MR. ALEXANDER: Dan Simon from BioFuel Solutions has a question.

MR. SIMON: Are you talking about liquidated damages *in the aggregate* of 8% to 10%?

MR. HO: Yes, performance plus delay liquidated damages.

MR. SIMON: Is it half and half?

MR. HO: More of the liquidated damages are allocated on the delay side, but combined, it is an 8% to 10% range; that is what the contractors are comfortable providing.

MR. SIMON: Then do you ask for limits of liability?

MR. HO: Yes.

MS. FREDERICK: Paul and Tydd, did you consider using insurance to back up some of the construction and technology risk?

MR. ROHRBOUGH: We tried looking at insurance, but found that it was not available. So the contractor had to step up and provide enough comfort to the owners and the lenders. In addition, bankers tend not to like insurance because of the perceived difficulty of recovering on the policies.

MR. ALEXANDER: Paul, have you seen big changes in the terms of EPC contracts in just the past few years?

MR. HO: There have been gradual changes. The EPC contractors realize that the market is moving away from the traditional sources of equity and debt in terms of financing, and the new lenders coming into the market want more commercial-type terms. The contractors realize they need to move the goal posts a little to make the deals financeable. They are receptive to hearing us, but it has been a gradual process.

Government Subsidies

MR. ALEXANDER: Moving on from the EPC agreement, Tydd Rohrbough, you had to look at what types of tax incentives were available once you had had your site, design and contractor. They help with the return.

MR. ROHRBOUGH: That was part of our initial review. When we looked at the differences in tax credits that the states were offering, many looked really good, but they could be gone tomorrow, so we had to evaluate that. One of the reasons why we came to Nebraska is because we have a contract with the state and the */ continued page 42*

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Department of Revenue. It is not a legislative incentive that might disappear. The $22 million that we could get in Nebraska was much better than the Missouri credit, which was nullified. Minnesota also removed and reinstated its credit. The uncertainly made us wary of what we were being offered in other states.

MR. ALEXANDER: Keith Martin, maybe you can address that and can give everyone a two-minute background on the tax credits available and maybe some of the other tax planning ideas beyond just receiving a 51¢ tax credit.

Lenders look at the ethanol market as a single B credit. They are not relying on long-term contracts to do financings.

MR. MARTIN: I will just make four brief points. One is Tydd is smart not to count on locational incentives. A federal appeals court in Ohio declared locational credits unconstitutional last fall. Daimler-Chrysler was given an investment tax credit as an inducement to build an auto plant in Ohio. The court said tax benefits that encourage a company to choose one state over another violate the Commerce Clause of the US constitution. The decision is being appealed.

The ethanol tax subsidy is given to the entity that uses the ethanol to blend with gasoline and not to the developers who decide whether to build plants. The hope is that the credit will have the effect of reducing the cost of ethanol so that more of it will be consumed. This adds to demand for new plants.

The tax subsidy is 51¢ a gallon for ethanol that is at least 190 proof. It is less for ethanol that is at least 150 proof. Blenders have an option of taking it as a credit against federal excise taxes on gasoline or taking it on their income tax returns. Most choose to use it as an excise tax credit.

For the entity that owns the plant, the biggest tax subsidy is the ability to write off the cost of the plant for tax purposes over seven years using the 200% declining-balance method; this is worth 28 cents for each dollar in capital cost. That is the present value of the tax savings from the depreciation deductions. Smaller developers without the tax base to use the depreciation deductions should find a way to share in the benefit indirectly. One way to do this is to bring in a partner with a tax base and allocate him a disproportionate share of the tax benefits in exchange for more cash. Another is to use lease financing for the plant and share in the tax benefits indirectly through a reduced rent. However, before using lease financing, the developer should do a lease-buy analysis. There is an embedded interest rate in the lease rents. The question is whether the embedded rate in the lease is lower than the interest the developer would pay if he borrowed directly to finance the plant.

Those are the main points.

MR. ALEXANDER: Paul Ho, I don't know whether you want to talk about some other structures that you see to capitalize on taxes other than straight bank debt?

MR. HO: We have structures in which people lend based on the expectation that the project will receive the CCC payment; that's not ideal. We like to simplify the structure as much as possible.

MR. ALEXANDER: How much value does a lender put on the CCC payment and tax subsidies?

MR. HO: People assume that they augment the cash flow, but when they look at credit ratios, they exclude the additional value. They generally exclude those incentives in calculating the EBITDA ratio to make sure the project is manageable from a credit standpoint.

MR. ALEXANDER: Explain what the CCC payment is.

MR. ROHRBOUGH: The CCC is the Commodity Credit Corporation, which is part of the US Department of Agriculture. The CCC makes a cash payment based on the amount of gallons that you used. The CCC looks at the local corn price, and then makes a cash payment tied to the increase in consumption of corn that you create when you build a plant. It caps out at $7.5 million a year. It is also pooled, so if there are a lot of producers in one year, then there is a proportionate reduction in all payments. Last year, it came out at 59%.

MR. BYRNE: There is a limited amount of money allocated for the federal program. If all of you in the room actually succeeded in building ethanol plants, then each person would end up with $5 in CCC payments.

MR. NESSLER: You have to look at bio-diesel fuel, as well, when you are factoring in the CCC.

Hedging Strategies

MR. ALEXANDER: The next topic is one that got me interested in the financing of ethanol plants in the first place. You have a feedstock that is a commodity, generally corn, and the offtake is primarily ethanol. The prices for these two commodities are not highly correlated, and it is difficult to enter into a long-term, fixed-price contract for either the corn or the ethanol. The banks, many of whom were also involved in the power market, are concerned about having another overbuild situation, analogous to what occurred in the merchant power sector. Pete Nessler, you assist ethanol producers with the mitigation of the risks that arise as a result of this situation. Describe the problem in more detail and talk about what people can do to mitigate the risks associated with having inputs and outputs of an ethanol facility that are not highly correlated.

MR. NESSLER: The one thing we hear from everyone in this community is the question how to mitigate against crisis. If you go back a year, a three to four month hedge is all you could do. Now you can go out 12 to 18 months.

Ethanol is marketed in two or three different ways. You can put forward a flat price, such as $1.50. Another way ethanol is marketed is gas-plus. You have the basic dilemma of whether to base this off a particular gas price or with with NYMEX. The Gulf Coast is a fixed reference point, but then you take on potential gasoline risk. The other approach is a spot deal, where management wants to keep 20% open or spot 30% or 40%.

We generally look at things a little bit differently. We look at it from a crush margin viewpoint. We look at where the cost of corn is, and whether your corn is tied to a particular reference point. We have looked at how ethanol values move in relation to NYMEX contracts. It is basic risk mitigation techniques. It does not matter whether the prices are tied to hogs, corn, cattle or ethanol; they all fluctuate and move. One way the ethanol market can mitigate risks going forward is by looking at different swaps based on NYMEX. An ethanol contract will trade on the Chicago Board of Trade starting in March, and there will also be a contract on the Mercantile Exchange. Will they be the answer from heaven? I doubt it, but if the contracts attract enough volume, there will be market makers in them, and we will be able to arrange various derivatives off the back end to help us push the curve forward from the current 12 to 18 months.

MR. ALEXANDER: Paul Ho, what do you think, as a lender, about these risks, given we can have suddenly $3.00 corn and $1.20 ethanol, which in turn means your debt coverage ratio is blown?

MR. HO: One of the publications is saying that the ethanol market is a single B credit. So the lenders are looking at it as a single B credit. They're not relying on long-term contracts to finance these type of plants. The lenders realize that the business is what it is, so they have to be comfortable with the long-term commodity risk. Now, having said that, they are looking for ways for the capital structure to mitigate the margin risk.

At CSFB, we are proposing a B loan structure in which the lenders expect you to pay them interest plus a nominal amount of principal every year. You are given the luxury of having to pay little principal to the lender, but in good periods, there is a cash sweep mechanism that requires you to pay back more. Those are the kinds of belts and suspenders you can put on the capital structure to help the lenders get comfortable

MR. ALEXANDER: Tom Byrne, when the developers ask about how to hedge price risk, what do you tell them?

MR. BYRNE: We identify the commodities for the area and look at historical trends. We are often asked whether it makes sense to put a plant in a particular area. History is a good indicator, but history does not always repeat, at least not in the short intervals. We use Monte Carlo simulation to project forward.

MR. ALEXANDER: Pete Nessler, what are some of the biggest mistakes people make?

MR. NESSLER: It's human nature to be greedy. Last October or November, ethanol was $1.65 */ continued page 44*

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a gallon. You had four contracts that were trading at $1.45 to $1.50 for 2005. People might say, "Well, if I can get $1.50 today, why can't I get it later?" That's not the way the world works. They put off their crush until 2005 hoping to do better. Alternatively, you can crush now and be done. How many people do it? Right now, you can mitigate up to where you want for your spot risk, and if you want to crush and buy the corn, you're done; you've got it and you clip the coupon.

MR. BYRNE: You have to consider the cost of trading. Some developers come up to the end of a project with only half a million dollars and too little money to pursue such a strategy.

MR. NESSLER: That is a valid point. Sometimes it is done by the banks. A bank might be willing to go out for a margin of 15¢ a gallon; that's $6 million in a $40 million plant. A developer can try to do inventory financing, securitization against receipts and things like that to raise more money, but the banks will tell you they will lend more if you just take steps to lock in a return. Market profitability is out there for the whole year for people who don't want to gamble.

MR. STIDOLPH: Russell Stidolph for Whitney & Co., LLC. I think the working capital issues at start up, or even 12 months into operations are the biggest issues. Not being able to hedge your forward production is a big problem. Last year, we started with two plants, and they looked at $3 corn and $1.60 for ethanol, and thought it was the greatest thing in the world. It had a great profit margin, but then the market in corn moved against them a buck a bushel. Unfortunately, the lenders won't lend against a margin call like that. On top of the economic risk, there is a huge working capital risk. If the lenders would lend, we might see some evolution in the crush margin marketing.

MR. NESSLER: There are horror stories of people looking at their corn in the $2.80 to $2.90 range, and then after brokering their corn, the price went to $2. When you are looking at $2.80 corn for the whole year, and you don't have the ethanol sold for the balance, that is a recipe for disaster. You are done.

You can hedge as much as you want, but the banks that have worked with most of the ethanol plants are used to commodity margins. You can lock in the price of corn. You lock in the ethanol price. Then the only risk is whether the plant will produce.

The prices for the raw corn used as the main input and for ethanol are not closely correlated.

MR. PETERS: Jerry Peters from Hudson United Capital. When we first got into this business as a lender, we wanted to know why there weren't long-term contracts to buy ethanol and corn. We have quite a few contacts in the petroleum industry. We talked to blenders and producers, and they said the reason they don't enter into long-term contracts is because all the ethanol producers want unleaded fuel prices plus 52¢ cents. I maintain that if the industry is willing to cut into that 52¢ or find another pricing index mechanism, more people will step forward to sign contracts.

MR. NESSLER: I agree, but 52¢ is the old government number. You'll find if they want a long-term offtake contract, there is a window. If they give you $1.40 on the upside, the downside will be narrower because they know they will receive the product. As big as ADM is, how many ADM gas stations are there? They have become more open to different basis trades, but there are still some risks — and opportunities. We have pushed the window to 12 to 18 months. If gasoline goes back to $1.40 again, the blender has every incentive to use as much ethanol as he can, because he's getting the credits.

Financing

MR. ALEXANDER: Let's move to the financing next. We know, two years ago that Paul Ho would not have been sitting here. We would probably have had a banker from CoBank, and most of you would not have been in the audience. The market has changed dramatically in the last year. We are starting to see money from money center banks and not just from the agricultural banks. Paul Ho, what is your sense of how the market is changing?

MR. HO: As a Wall Street bank, we are all about the bottom line and trying to look at it as a B lender —

MR. ALEXANDER: Maybe for people who are not familiar with the term, you can explain what a B lender is?

MR. HO: Hedge funds and institutional lenders usually buy LIBOR-based paper, which is very attractive in light of the current pricing environment. Given that there's not a lot of investment opportunities in the current market, many people are looking at lower-grade paper, down to the single B to BBB spectrum. Things that no one in project finance would touch two or three years ago are now getting attention, because people want good-yielding paper. When ethanol financing can be done at LIBOR plus three or five, people are interested. People are doing more homework, and so far the credit markets have been receptive. We are trying to take advantage of that.

MR. ALEXANDER: Tydd Rohrbough, what was it like for developers trying to raise financing before this year?

MR. ROHRBOUGH: There was not much interest among banks in financing ethanol plants two and a half years ago when we were in the market. Part of the problem is the structure in use at the time. Most structures then were cooperative based. In a cooperative group, if a person puts in $5,000 and someone else puts in $10 million, the person who puts in $5,000 has the same control as the person who put in $10 million. The smart equity today has moved to a mezzanine structure or a B loan structure, and that is where I think the market is going. An ethanol plan is more of a traditional Wall Street venture now.

MR. ALEXANDER: Do you think there is enough liquidity today in the debt markets to support plants whose models show they can cover debt service?

MR. ROHRBOUGH: I think the problem is finding enough good projects for investors. Some 30 projects were announced in the last three months. If all of those projects end up being built, that would mean a lot of dumb money will have been put into the industry. All of the proposed projects are not financeable. There are plants that make sense in every location in the midwest, but not every project in California makes sense.

MR. NESSLER: In certain areas of California it makes tremendous sense. You will make out in the grain end. You are not dealing with the railroad, but primarily trucks, which lets you contact certain markets quickly. If there are problems, you can react within a day, versus two weeks by rail. Those are the different arbs, as we call them. A California project is logistically viable.

MR. ALEXANDER: When you think about the bull's eye in the center of the country where all the plants are, do you think that happened as an historical accident, or do you think there is bias in the financial community of only doing business there?

MR. HO: I think it's both. Lenders are used to understanding the economics and the logistical challenges associated with bringing corn in and shipping ethanol out. We are seeing more coastal plants being proposed.

MR. ROHRBOUGH: We looked at a project in California, and one of the challenges that I see is the environmental side. If you go to the midwest, you need eight months for your air quality permit. If you go to California, it is a year and a half.

The other thing that I think is going to happen with this banking group is the sharing of information on a matrix basis like we never had before. We have never had an industry standard before.

MR. HO: I think the lending community is still on a learning curve. There are not a lot of ethanol deals, so every deal that gets done becomes a data point.

People always ask me what makes a deal financeable. I can't give you a rule of thumb. People are wrestling with a midwest plant versus coastal plant, corn based versus wheat based. Lenders are still reviewing each project on a case-by-case basis to see if it makes sense. In terms of the economics, people are going to give you credit for the visibility of the high ethanol price versus the low corn price. However, in the long run, they need to do more analysis, such as putting in the base case numbers and projecting out 10 years in the forward curve to see if the project still makes sense. They will also look, for example, at the lowest margin year; if it could last for a prolonged period of time, say two or three years, they will look to see if your project would still have liquidity. People are doing different types of analyses, and even running numbers showing what / continued page 46

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happens if there are higher capital cost, construction completion is delayed and so forth. I would like to give you a rule of thumb, but I don't think there is one yet.

MR. ALEXANDER: I have the feeling from talking to people in the banking community that their in-boxes are full of proposals. What things would make a project stand out for you? For example, is it critical to have a well-known sponsor?

There is probably only a two-year window for construction of new ethanol plants in the US before the market becomes saturated.

MR. HO: One thing that is of critical importance to a lender is to have a credible equity player in the deal. A lot of us have seen projects that are farther ahead on the lending side than the equity side. Lenders have put in a lot of time trying to get a deal together only to find that the equity is not there at the end of day. Having a reputable and experienced sponsor, who knows what he is doing, lends a lot credibility to the deal. Also, as I mentioned, having a lender-friendly EPC contract is also a prerequisite.

MR. ALEXANDER: Tom Byrne, what do you see your clients doing to distinguish themselves from the masses?

MR. BYRNE: If you put in $70 million of equity for the benefit of local farmers, they are willing to put at risk the corn. If you build an ethanol plant producing 30 to 40 million gallons a year, the number of people it takes to run that size plant compared to a 20 million gallon plant — which is the minimum size now — is not significantly more. As we look outside the midwest, which is where I think a lot of plants will be, management becomes a key issue. You can attract better management if you have a $60 to 100 million project compared to a $20 million project.

MR. PEARCE: Scott Pearce from BioFuel Solutions. Is there a trend to put new plants in the hands of professional operators?

MR. BYRNE: There are more and more management groups. Look at the individuals in the team because there are not many people who have been around long enough to establish a track record.

MR. ALEXANDER: Does the farmer coop model have the ability to make quick decisions and compete?

MR. NESSLER: When you get into the decisionmaking process, you need to be real quick. You may have three identical plants, but the profitability varies because of the different prices for the commodities: corn, ethanol, and the distiller's grains. The prices should be the same, but the bottom lines may not be. Everyone has an operational arm, and everyone is trying to figure out whether to do a risk management plant.

MR. TORKELSON: Roy Torkelson from JP Morgan. Can one of you talk about foreign production of ethanol and the risk that it will flood the US market?

MR. NESSLER: Certain countries in the Caribbean basin have the ability to bring in ethanol without a duty. I believe last year 160 million gallons were allowed into the US duty free, and they have increased the amount to 240 million gallons this year.

MR. ROHRBOUGH: Imports from the Caribbean basin are linked to sugar prices. If the world sugar price increases, then you will see a lot less ethanol.

MR. ALEXANDER: We don't have much time left. In closing, Paul Ho, maybe you can address the major mistakes you see in ethanol proposals that land on your desk.

MR. HO: We see people coming in with the equity not lined up, and the contractual issues not finalized, and they end up wasting a lot of time. If you have the full commercial package done and you go to the bank for financing, you can generally get it done within a three-to-four month time frame, but that is assuming the commercial package is financeable. Having to go back and renegotiate terms on an

EPC contract can add two months to the process.

MR. ALEXANDER: Tom Byrne, what are the biggest mistakes that developers make?

MR. BYRNE: There are projects that started as tremendous economic development projects. They are out in the middle of never, never land in communities that do not have an opportunity for much industry. They create good jobs. Communities know these are tremendous economic projects, and they try to put them where they should not be located. The most difficult situation is having to say, "Yes, I know it will help your community tremendously. No, you are not in the right place." If you want a financeable project, the plant must be moved to a better location. The biggest mistake is choosing the wrong location.

Outlook

MR. ALEXANDER: Final topic: Tydd Rohrbough, where do you see this industry three years from now?

MR. ROHRBOUGH: We will have a lot more production, but it will require more sophisticated plants. The coop model will have to keep up or it will disappear.

MR. ALEXANDER: How worried are you about an overbuild situation?

MR. ROHRBOUGH: It is a concern. The velocity of the build is much higher than what we saw last year. If everyone is successful, it will drive down the price of ethanol.

MR. ALEXANDER: Pete Nessler, do you think the key to being around in the next five years if we are in an overbuild environment is a hedging program?

MR. NESSLER: Yes. The price of corn in April 2004 was $1.40 a bushel, and in December it was $1.90; that is a 45¢ or 50¢ cent spread. A gallon ethanol runs between $1.35 and $1.40. So between two different variants, you have 80¢ a gallon, which is huge in my opinion. People who want to build plants still think the opportunity is there. I don't know if we will get to 11 billion or 15 billion gallons of ethanol. It will not come out of corn, but corn can support seven or eight billion gallons. The next two years is the window of opportunity to build new plants, to be quite honest.

MR. ALEXANDER: Tom Byrne, do you agree that there is only a two-year window?

MR. BYRNE: I agree there is about a two-year window. The plants are all designed to double in size at a minimum.

MR. ROHRBOUGH: I'll caution you on everyone designing to double output. I did our environmental permitting, and when we looked at the doubling and tripling of our plant, it significantly changed the footprint. Not every state will allow it. If you don't have the right site, or there are other industrial facilities within five miles, you may not be able to expand in some states.

MR. ALEXANDER: Paul Ho, being the lender, I will give you last word, since you usually get it.

MR. HO: Sure. I see in the next two years a lot of big plants getting built. These plants are built, people will look at the supply-demand balance, and they will see less and less need for additional plants. I agree with the panel; it seems like the window is in the next two years.

Restating Earnings From Lease Deals?

Equity participants in the leveraged-lease market are agonizing over whether they have to rerun earnings from a variety of highly-structured equipment lease transactions that were done in the last decade. These deals have names like replacement lease, LILO or SILO. In a typical deal, a European government agency might have leased railroad cars or an electric distribution system to a US institutional equity investor and then leased it back. "LILO" stands for "lease-in-lease-out." "SILO" refers to deals where equipment was sold and then leased back. The deals were also done in the United States between US institutional equity investors and tax-exempt entities.

The Internal Revenue Service is moving to disallow tax benefits in the deals. Some companies have negotiated settlements with the IRS. The Financial Accounting Standards Board is debating whether these companies are required to rerun their earnings from the deals based on the actual pattern in which tax benefits end up being taken.

Chadbourne hosted a conference call to report on the debate and the options that companies have if they are forced to rerun numbers. The participants on the call were Roy Meilman, a tax partner in the Chadbourne New York office, William Bosco, chairman of the accounting committee of the Equipment Leasing Association, and Richard Specker, managing director of Global Capital Finance and a former senior leasing executive with / continued page 48

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NationsBank and Fleet. The moderator is Bob Gillispie, head of the leasing group at Chadbourne in New York.

IRS Update

MR. MEILMAN: The Internal Revenue Service issued guidelines last February indicating the terms on which it would be willing settle tax claims against US companies that participated in LILO transactions.

Companies that enter into audit settlements with the IRS on certain lease deals may have to restate earnings from the deals.

The methodology portion of the guidelines was deleted when they were made publicly available, but in dealings with the IRS, the core of the agency's approach has become generally known. To oversimplify, but not very much, one starts by negotiating a constant percentage with the IRS. The percentage starts at 50 or 50ish and goes to 80%. You then take that percentage and apply it to the bottom-line tax loss or the bottom-line taxable income in the LILO transaction on a year-by-year basis. So that, for example, if the negotiated percentage was 60%, you would take 60% of the year one tax loss and move it from year one to the year of the fixed price purchase option under the sublease. You would take the same 60% of the year two tax loss, move it from year two to year last, move 60% of the tax loss for year three from year three to year last, et cetera, and when the transaction turns tax positive you would, again, take 60% of the positive bottom-line taxable income from that year, move it to the year in which the purchase option becomes exercisable, et cetera, year by year. That methodology results in an underpayment of taxes for pre-settlement years. Interest would also be owed on the back taxes.

A number of investors — a limited number — have settled. The terms of those settlements are known only to those investors. A number of other investors are contesting the IRS claims either under the agency's "fast track" procedure or are in the normal appellate procedure with a view to settling. BB&T has filed suit in the federal district court in Greensboro, North Carolina, seeking a refund on a LILO involving pulp mill equipment in Sweden, and a number of other investors are considering litigation. More generally, over the last couple of years, the IRS has won a number of cases involving corporate tax shelters, and the IRS has lost a number of cases involving corporate tax shelters. None of those involved LILOs or SILOs.

There are two things, among many others, that are notable about the settlement methodology the IRS has adopted. The first is that it is completely arbitrary. There are a dozen theories the IRS has asserted in attacking LILO and SILO transactions, but none of them would lead to the pattern of taxable income and tax deductions on which the settlements are based. So, at the end of the day, it is a formula for coming up with a number of dollars.

Second, when the IRS issued the settlement guidelines, it was trying to be sensitive to the investors' financial accounting considerations. And, indeed, the IRS proceeded on the understanding that because the described methodology affects the timing but not the amount of taxable income and deductions, there would not be an impact on the investors' financial statements. Whether that is where the accounting is coming out, Bill Bosco will address, and one of the other things that I think we wanted to start people thinking about is whether there's a way to give the IRS, in rough justice, the same number of dollars, but package it in a way that does not adversely affect the financial accounting. With that, I will turn it over to Bill.

Accounting Issues

MR. BOSCO: The accounting issue is whether to rerun or not to rerun - that's the question. Let me start with some background: what the accounting questions are, talk about some of the accounting literature and comment on that, talk about what the Financial Accounting Standards Board has done so far, give you an update on the status and what FASB's future plans are to meet on this issue, update you all on the Equipment Leasing Association action plans, and then give my opinion on what's likely to happen after all is said and done.

In terms of the background, LILOs have already been subject to IRS settlements as far back as 1999, and many lessors have, in fact, not rerun their leveraged lease accounting earnings as a result of IRS settlements. Now SILOs will be subject to IRS settlements as a result of the new tax factors. Another point of background is that composite income tax rates have changed in the recent past and some lessors have rerun their leveraged lease earnings, while other lessors have not as a result of income tax rate changes.

The "big four" accounting firms have concerns due to the inconsistency of treatment with some companies rerunning and some not rerunning and the size of potential adjustments. They have met and talked about the issue, but they have also asked the FASB several questions, because the rules regarding when to rerun the leveraged lease earnings are not explicit.

Now, let's talk about what the accounting issues are. This may sound a little confusing, but one accounting question is whether you rerun the leveraged lease earnings if tax deductions are rescheduled, but there is no change in taxable income and after-tax income.

Another question is whether you rerun the leveraged lease earnings if your composite income tax rate changes, with the result that there is a change in net income.

Another question is whether you reschedule tax deductions when you do a rerun of leveraged lease earnings due to a change in the composite income tax rate.

The last question is whether you reconsider the lease classification as to whether or not the transaction is a leveraged lease, as a result of rerunning the earnings.

Those are the four questions. FASB was presented the questions in a slightly different format when it met on November 17.

Let me talk first about the accounting rules that come into play when trying to answer the questions.

With regard to rerunning earnings, paragraph 46 of FAS 13 addresses this but it is a little vague. It says that you must rerun your earnings if there has been a change in the estimated total net income from your original assumptions. A change in scheduling of deductions does not change estimated total after-tax net income, and although it is not explicit in the rules, the practice has been not to rerun deals just because of rescheduling of deductions. In other words, the big four accounting firms have decided that even though it is not explicit, you do not rerun earnings after a mere change in timing. The major accounting firms have enforced this and precluded recalculation of earnings when total estimated net income from the lease did not change.

The next question is what happens if my income tax rate changes? There have been a couple of pieces of accounting literature that dealt with this. Specifically, there is a FASB technical bulletin, 79-16, that confirmed that the income tax rate in the leveraged lease is an important assumption and the change in that income tax rate requires a rerun. A lot of people have not rerun because of income tax rate changes, and I think what they are falling back on is an EITF issue 87-8 that dealt with alternative minimum taxes, where a lessor asked a question about what happens if it does in and out of AMT, does that mean that it must keep rerunning its leveraged lease earnings? FASB said that if your tax position changes between AMT and regular tax, you are not required to recompute each year, unless there is reason to believe that the original assumptions are no longer valid, meaning you are not likely to ever come out of AMT. This would change your tax expense and your total net income. I think people have been using that guidance to say if my income tax rate changes with the possibility of reversing, I should not rerun. Composite income tax rates often change up and down if you book a leveraged lease in a multi-state vehicle as the composite income tax rate will change due merely to apportionment changes that occur every year. The theory is that if I am unsure that my total net income really has changed because the income tax rate will / continued page 50

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fluctuate in the future, then I do not rerun until I know that there has been a change in my total net income.

That is the guidance on the issues in front of us today. To summarize, if there has been a change in the timing of deductions, the practice has been not to rerun earnings. If there has been a change in the tax rate, the rules say you should rerun, but many people have not rerun, probably because they believed that the tax rate change was not permanent.

The other question — the last question that I mentioned — is the question of lease classification. If I rerun my lease, should I re-examine my leveraged lease classification tests? The literature currently says that you really should only retest classification if there has been a change in the agreement, not a change in the assumptions. The issue here is that if I do rerun my leveraged lease earnings and the investment does not phase as a result of the rerun, then I do not meet all of the leveraged lease classification tests. I do not think that will be a question that will result in an adverse accounting decision for the industry. Moreover, in the LILO and SILO examples of reruns that I have seen, the investment still does phase.

FASB View

What does FASB think of this? What actions has it taken and what is the status?

First, I should say that the big four generally agree that leveraged leased earnings should be rerun when there has been a change to the composite income tax rate that is unlikely to reverse. They also agree that you should use the rescheduled tax deductions if rescheduling has occurred. They have asked FASB for clarification. FASB met on this issue on November 17. FASB was asked the questions on whether or not you rerun, and when you rerun, and it was also asked the question whether lease classification should be reconsidered.

It came to two tentative conclusions that the industry does not like.

FASB has tentatively concluded that, when tax deductions are rescheduled, a company should rerun numbers and reconsider whether the transaction is a lease.

The first tentative conclusion is that you should rerun when tax deductions are rescheduled. This answer presumes that you will rerun when the income tax rate changes. Even if the income tax rate has not changed, FASB is saying that you should rerun. The second conclusion is lease classification should be reconsidered. In other words, if the investment no longer phases, or does not phase as a result of the recalculations, then you should reclassify the lease. That would be horrendous, because it would mean having to "gross up" the investment on your books and record the leveraged lease debt as a liability.

The important thing to note here is that the conclusions were tentative. FASB instructed the staff to research the issues and recommend threshold limits, which, if met, would force a rerun. FASB will meet again with the idea of making final decision in early February

After the FASB meeting, the Equipment Leasing Association made some action plans. ELA scheduled a meeting in early January with the FASB board liaison member. The agenda for the meeting is first to present a comment letter that addresses the FASB tentative conclusions. ELA believes it has support for reversing or modifying the tentative conclusions. If FASB holds to its tentative conclusions, that really amounts to an amendment to Statement 13. FASB would rather not add reopening Statement 13 to the board's existing workload.

ELA is also arguing that it is not appropriate to consider reclassification when leveraged lease assumptions change, and there is support in the literature for that conclusion. ELA plans to give FASB a primer on leveraged leases so that the board understands what a leveraged lease is, what the MISF yield calculations are, and some of the background on the accounting issues that FASB is considering. ELA plans also to present a hypothetical case of a LILO where tax deductions are rescheduled, and to show the board several different cuts with and without tax rate changes, so that FASB understands the potential magnitude of the adjustments.

Here are my predictions about the ultimate outcome.

On the issue of reclassification, I believe FASB will change its tentative conclusion. The only time that you are supposed to recalculate, or retest a lease, is when an agreement changes. There is no change in the agreement when tax deductions that were assumed fail to be realized. I think the industry should take comfort in the fact that the LILO and SILO examples that we have seen have not resulted, or are still resulting in phasing, so I think that classification will not be an issue. We still plan to fight FASB because we want to make sure that the principle stands. The bottom line is reclassification is not an issue about which we will have to worry.

On the issue of rerunning, we have to worry about that. ELA may be able to convince FASB that reruns should not be done if there have been merely a change in the timing of deductions, because some literature and the practice supports that conclusion. In other words, if there has been no change in net income, but merely a change in the timing deductions that affects the MISF yield, we may be able to convince FASB that you don't have to rerun.

I believe FASB will require reruns when the composite income tax rate changes. I believe FASB will require using any changes in timing of deductions in the assumptions so that, if there has been a composite income tax rate change, you will have to rerun with the new assumptions,. That will be bad news for the industry.

I have a suggestion about which Roy Meilman started to talk earlier. The only way to avoid a rerun is to negotiate with the IRS to pay interest on the tax adjustment, rather than actually rescheduling deductions and paying under a new schedule of deductions. The reason is if you do not reschedule your deductions, the big four have generally followed the interpretation that you do not have to rerun. They have also held unanimously in the past that payments of interest and penalties to the IRS should not be included in the leveraged lease earnings recalculation.

In other words, if you pay interest and penalties, rather than reschedule, you do not have to rerun.

Business Considerations

MR. SPECKER: I am going to focus on the business considerations tied to management of opportunities that may present themselves, or compel themselves, as a result of changes in the tax profile of LILO and similar structures.

This should include all transaction types that have been done in the cross-border tax-exempt structured markets since the early 1990s. I would include O-FSCs, which are a subset of the traditional Pickle replacement lease structure. This was followed by the Pickle lease with a mini-replacement lease and residual value guarantees. These structures were eliminated in 1996 and gave way to the early leasehold structures, which involved section 178 and the optional prepayment leasehold structure, which then rapidly evolved into the LILO as we came to know it. Then, post Rev. Proc. 99-14, the dominant structure was the lease-to-service contract, which I will begrudgingly refer to as the SILO.

Thus, we have Pickle replacement lease deals, early LILOs, LILOs and SILOs as the transactions in question.

When you look at the situation from the standpoint of an equity investor, the question is, "Why should I consider doing anything at all with my existing portfolio?" Bill Bosco obviously pointed out the grand reason, which is the changes to leveraged lease accounting threatened by FASB. But there is almost a perfect storm of other elements converging to cause the investor to consider making changes in the portfolio to address these issues.

The first issue is the prospective accounting changes that may yet occur. It is clear that if they do not occur in the way that would be most damaging — an automatic rerun because of the change in timing — the investor is still going to be faced with a potential rerun, which would incorporate that change no matter what, if there is a change in some other variable like tax rate. Second, there is the tax environment generally, and a variety of connected audit settlement issues. / continued page 52

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Third, we have a regulatory environment, with Basle 2 coming on, that may cause these transactions to attract more capital; this is more of a balance sheet and capital management issue.

Lastly, in this little perfect storm of negative elements, there is that subjective quality of reputational risk. I think this is probably less of a concern now that the industry is not actively pursuing new transactions and, therefore, these deals will not be in the media, but still it remains something about which most institutions have some lingering concern.

When you consider the business aspects of what action to take given these negative developments, there are six primary issues to consider.

I have to caveat everything with the observation that every individual transaction is, and needs to be, dealt with on a case-by-case basis. However, there are general principles that apply when looking at the opportunities that could be there.

The first issue is, "What is the book position of the asset in the portfolio?" Is the book termination value equal to the document termination value? Did the document termination values originally provide for some padding, so that they protected an amount more than book exposure? Have there been prior reruns for non-settlement related changes? Bill Bosco mentioned the change in state apportionment where a change in the composite tax rate might actually create a potential book termination value that is less than the original termination value in the deal. If a tax settlement is reached, but there is no rerun, then we have to consider what is the potential liability associated with the composite tax rate change; I would break those into two concepts, the current liability created by a non-settlement rerun, and then the contingent liability that we believe will be hanging out there indeterminately unless the IRS comes up with another settlement option.

The contingent liability arises where you do not have to rerun as a result of a settlement or an audit change or any kind of result that involves a changed tax profile, but you will have to incorporate those changes when another important assumption changes subsequently. The long tenor of these transactions should indicate to all that the likelihood of some change occurring down the line is very, very high, so this risk will be hanging over these transactions for a long period of time. The questions are: how do I manage that exposure? How do I quantify it? It can be summed up generally by asking, "Is taking a small loss now better than possibly taking a huge loss later?" Those decisions are individualized, not just in a portfolio sense or an institutional sense, but also from deal to deal.

The Equipment Leasing Association hopes to persuade FASB to reverse or modify these conclusions.

The second aspect is the value and nature of the equity collateral. In the early days of these deals in the cross border market, the Pickle replacement lease structures, in particular, were often done with standalone strong credits. There may have been letters of credit involved, but there typically was some strong standbehind credit such as the Kingdom of Sweden on an SJ rail deal, or Belgium for SNCB, or the Swiss Confederation for a national rail deal in Switzerland. These circumstances might offer less of an opportunity to come to a structured exit from the transaction. It depends, too, in more recent transactions, whether or not the collateral is liquid. Is there a package of treasury securities or highly-rated quasi-government securities, or is it a less liquid payment undertaking agreement or other guaranteed investment contract or deposit type instrument? Of course, the range over the years includes simple bank deposits, time deposits at banks, internal swaps, external swaps, the PUA and basic institutional GIC, and also securities held in a custodial account. This last case typically offers the best opportunity to create some sort of structured settlement.

It is also very important to consider the interest rate environment when the collateral was put in place. Deals done before 1996 or 1997 are more optimal because the rate environment was quite high. The rate environment we find today has substantially lower prevailing interest rates. This, coupled with a shorter remaining term to maturity, can create a break funding environment where the equity collateral has a greater value than might have been originally anticipated when scheduling it from the inception of the lease.

The third aspect involves the individual lessor's need or interest in boosting current income. I mention this because it can drive a decision. If the company is flush with income — although I don't think too many lessors are finding themselves in that position these days — if institutionally there is the ability to absorb smaller losses now, it might argue for arranging exit strategies from transactions. On the other hand, if there is a great need for current income (because of the runoff in the business) that cannot be easily replaced, then there are clear opportunities embedded in many of these transactions that allow for book revisions and portfolio engineering techniques to be applied that can create an increase in current income. This is totally absent from any considerations with respect to tax-structured settlements, and they should be considered in light of the risks and rewards that might come from those events happening.

Looking at the book position and the asset levels on the balance sheet might create a fourth analytical element to consider. A lot of these transactions are going to be coming into periods where the gross investment balance is large, but the transactions are generating little book income. Thus, you have an asset that is attracting capital, and may actually soon be attracting more capital under Basle 2, and that is not providing any meaningful return. This creates no real problem on an individualized-deal basis, but it does produce a significant drag on portfolio returns on equity; dragging down the overall return on equity of the leasing company.

The fifth element for an investor to consider is the benefit of the unwind or termination strategy that could be created in cross-border deals from a foreign source income perspective. Where, by virtue of engineering a sale or a termination or the variety of other mechanisms by which you can exit these transactions, you create a large current amount of foreign source income. This could free up foreign tax credits that would otherwise go unutilized and could compel economics in another side of the corporation's books that might justify taking the small loss that might result from terminating a deal. There may be a small loss. There also may be a small gain. Each transaction needs to be examined individually to ascertain the foreign-source impact.

Last from the standpoint of business considerations, we have to look at the lessees and what their issues are. I think there are three primary ones. Most lessees that entered into these transactions over the years are now finding them a bit of a burden from a variety of different standpoints. First, the deals are often administratively burdensome, although it depends on the individual deal and what the administrative requirements actually are. They produce a hassle factor. Next, the encumbrance on the business ability of the lessee is proving in a number of cases fairly significant and costly. Any lessees that entered into compelled reorganizations, mergers, or other business combinations or who have been interested in making, or have been compelled to make, asset transfers to affiliated entities within the jurisdiction find that the LILO and SILO transactions, that gave them these significant cash benefits up front, now provide a significant impediment to operational flexibility.

The last element is really a cost-related factor pertaining to the lessee's issues; have there been credit triggers which have caused either upgrades in collateral or other additional credit support needed to be posted which will have some cost to the lessee over the remaining term of the transaction? With one transaction that we were involved in, by way of example, the lessee did a simple present value analysis and said if it costs me X on a PV basis to provide a LC for the remainder of this term and this is a new trigger event and I can terminate the transaction for something exceeding the value of X plus the collateral then I've got a net gain. This is the kind of analysis that goes into the thinking there. */ continued page 54*

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Options?

Which options should be pursued, and how should they be engineered? You can't really discuss that on a conceptual basis because each case is different. Solutions that can be employed are not conceptually complicated, but we have found, through a fairly large experience base, that the execution is complex. It can be quite difficult and it requires management of the documentation process, approval issues, expectations of management and then dealing with liquidation of collateral.

The options can be distilled into four basic categories. One is "terminations"; there are several ways they can be effected. Another is an outright sale of your interest in the transaction. Engineered collateral changes, which are more of a book-revenue enhancer or a cash-raising device, have attracted a lot of attention. They are not the only available book management device. There are a variety of simple, in principle, but fairly involved in execution, pure book revision strategies. These are slight modifications to the lease that allow you to accelerate or decelerate income in a way that creates a book benefit in the current period. Again, that is absent any of the gross considerations involved with tax settlements. With the looming threat of an ultimate rebooking, whether in January of 2005 or January of 2007, we believe it is important for lessors to engage in the serious analysis of all the issues and look at the strategies that are available to manage exposure with existing transactions.

For deals that are in a sinking-fund phase, rerunning numbers could lead to a reversal of as much as half the earnings already taken.

Terminating a Transaction

MR. GILLISPIE: Now if Rick Specker was persuasive enough to convince people to terminate one of these deals, then the issue would become how to document the termination?

The documentation itself is simple. It consists of an assignment of the various collateral agreements to the respective parties. For example, there would be a debt assignment agreement whereby the lessee would transfer the defeasance to the lessor — again remembering that the collateral is really the lessee's. Then the lessor would transfer that on to the lenders, thereby terminating the debt side of the transaction. This would entail not only the 90% defeasance but in those cases where there is a 10% defeasance — directly in the documents or outside — you would need basically to roll both of those out.

On the equity side, most of the older deals did not have equity collateral. The more recent deals had the strip collateral and, in those cases, the lessee would transfer the strip collateral to the lessor. An alternative to the foregoing, that Roy Meilman and I would strongly recommend, is for the lessee literally to purchase the leasehold interest from the lessor for a lump-sum amount. This is done in order to respect the formality of the transaction that we had entered into initially, and it would be effected by transferring or liquidating the various defeasances and paying a lump-sum amount to the lessor.

The reason for this approach is that one of the arguments the IRS has asserted in its audits is that in the SILO and LILO transactions, the lessor should be treated really as an owner of the equity collateral, rather than as an owner of the asset. Effectively, the IRS is saying that the lessor is merely buying a stream of principal and interest payments rather than buying an asset. Therefore, that would be our suggestion on the assignment side.

The final documentation would be a termination of the lease agreement whereby all the parties are released from the various operative documents other than any existing indemnities for which the lessee would remain on the hook. The bottom line is that unraveling a lease transaction requires analysis of the underlying operative documents to make sure you turn square corners.

Audience Questions

MR: GILLISPIE: Now to questions for our speakers. The questions are coming in by email from participants on the call.

The first question is for Rick. How big is the SILO-LILO market? And if FASB merely requires a rerunning of leveraged lease earnings and not the reclassification of the leveraged lease, would you expect most equity participants who have entered into IRS settlements to terminate their transactions?

MR. SPECKER: The answer to the first question is there are no hard facts. If you believe the US Treasury Department, the market was $750 billion. I think the actual market size, even including precursor structures, is about $150 billion. That is a significant number, but nowhere near what the government was maintaining.

Now on reclassification versus rerunning for income purposes, there will not be a material difference in the need to find some exit strategy or some management strategy if rerunning is required but reclassification is not. I think reclassification is the worst of all possible worlds because you balloon up your balance sheet, but the negative economic and book impact of the rerun in almost every single situation that we have examined is so significant that the avoidance of loss motivation is tremendous and the exiting of the transaction is almost compelled.

MR. GILLISPIE: A follow up to that question — someone asked if Bill Bosco could quantify what are we talking about? If someone had to rerun a transaction, what does it really mean?

MR. BOSCO: It depends on where you are in the life of the deal, whether you are in a sinking-fund phase or not, and the settlement you work out with the IRS. The reversal of earnings in some cases could be very significant. For deals in the sinking-fund phase, the reversal of earnings was as much as half the earnings already taken. Of course, it is a timing thing: you will be able eventually to re-recognize those earnings, but in some deals the wait is as long as 10 years.

MR. GILLISPIE: Roy Meilman, what impact would there be on IRS settlements if the FASB proposals are adopted?

MR. MEILMAN: The inevitable tax lawyer answer to that is that it depends. I think if the FASB does what it has threatened to do and the IRS is wedded to its settlement methodology, then a lot of people will not settle. On the other hand, if there is a way to give the IRS the same number of dollars in a way that avoids both a current rebooking and a future rebooking on a subsequent event such as a change in tax rate or state apportionment formula, then things will continue as they have to date.

The following idea comes from the four of us talking before this call, so it is not an idea that anybody has vetted with any of the accounting firms, but Bill Bosco believes it has a lot of promise. The thought is to go through the settlement methodology that I described and reach agreement with the IRS. That gives you two things. It gives you a schedule of taxable income and tax deductions under the settlement, and you start out with the schedule of taxable income and tax deductions as reported and as one planned to report it. Take the difference between those two things — the settlement line and the reported line — and treat that, in effect, as a loan from the government to the taxpayer, recognizing that it will all zero out by the end of the sublease term, so you are implicitly repaying that principal. Pay interest on the amount, and the cash settlement is the interest on that hypothetical difference.

Bill Bosco and Rick Specker thought, off the top of the head, that this probably creates about the right number of dollars, although no one has run numbers. Bill may want to elaborate.

MR. BOSCO: I have suggested to the Equipment Leasing Association that we try to advance the concept in our lobbying with the IRS. The big four generally have held that interest and penalties are outside of the leveraged lease calculations. I think that if you do not reschedule, but rather pay interest on what you would have had to pay in taxes, you do not have to rerun because you do not have any rescheduling of tax deductions. One downside to that — probably a minor downside when you look at the earnings adjustment that you face — is that the rate that you would have to pay to the IRS is a lot higher than you would have to pay on internally borrowed funds. It preserves your / continued page 56 *continued from page 55*

earning pattern, but it costs you a little bit more annually in interest costs.

MR. GILLISPIE:Bill Bosco, someone asked the question — what do you see as the timing of the adoption by FASB of any proposal?

MR. GILLISPIE: If FASB does not change its conclusions, it will have to amend Statement 13 and it could take a year for it to make the change because it would have to put out an exposure draft and go through the normal due diligence process. If, instead, it says it is just an interpretation, then FASB could act fairly quickly, finalizing this in a few months.

MR. GILLISPIE: We have another question that came in from an investor. He says he booked a transaction with only the federal rate and not the state tax rate. Given that the federal tax rate has not changed for several years and his company is not booking any state tax rate, has the composite rate really changed and would the company need to rerun the leveraged lease?

MR. BOSCO: I have seen leveraged leases that were booked in legal vehicles that only paid the federal rate and, if that is the case and over the life of the deal the federal rate has not changed, then you have no change in tax rate. You are safe under the current interpretation of the rules, but as I said earlier, FASB is now saying that regardless of whether the rate changed, if your deductions changed, you would have to rerun.

MR. GILLISPIE: Another one for Bill Bosco — if the lease rerun is required, has there been any discussion about how to lock in earnings recorded to date and force the impact of the rerun on future years?

MR. BOSCO: The question is whether you can lock in the interest recorded to date and spread the impact over future years. I would like to see that happen, and the bank regulators would probably like to see that happen for bank-owned leasing companies, because of this quirky accounting rule requiring a huge loss and huge impact on capital and then a slow dribbling o the amount back into income. I doubt there is any basis in accounting for that. It would be a nice result, but I don't think we can get there.

A company's options include terminating the lease, selling its interest in the transaction, or altering the transaction terms to change the timing of when income is reported.

MR. GILLISPIE: Is that not similar to the alternative approach you had suggested, namely having it recharacterized as interest?

MR. BOSCO: This is a different question. Suppose I have a large negative adjustment. Can I prorate it over future years? I would like that result, but I don't know if we have any real basis for persuading the Office of the Comptroller of the Currency or the Federal Reserve to agree to it.

MR. GILLISPIE: Another question — what if I priced my deal without the state tax benefit?

MR. BOSCO: There might be some confusion about pricing and booking. Many lessors choose to do their pricing using a conservative tax rate. Suppose someone priced using only the federal rate. He figures that the state rate might change, and adding in the benefit of deferral on a state and local basis usually increases the yield. But pricing and accounting are two different things. When you run the deal for accounting purposes, you are supposed to use your composite income tax rate and so even if you did the pricing at a different rate, you are bound by accounting rules to use the right tax rate.

MR. GILLISPIE: The last question involves foreign tax credits. Rick Specker mentioned a foreign source issue. Roy Meilman, would you elaborate on the concept of the foreign tax credits and how they might be beneficial?

MR. MEILMAN: Many investors are unable to use foreign tax credits on a current basis because of the way foreign tax credits are set up technically. And in those cases, the credits get carried forward and then used some day. Generating a slug of foreign source income for those investors could well free up tax credits that can be used on a dollar-for-dollar basis currently, rather than only in the future, and if terminating a transaction has the effect of creating a significant amount of current foreign source income, then the cost of the transaction is cushioned by acceleration in the ability to use those foreign tax credits. ◎

Grants For Renewable Energy Projects

by Jana Dimitrova, in Washington

Project developers using nascent renewable energy technologies in the United States may qualify for grants from the US government. Grants are also available for renewable power projects developed on Indian reservations. The Department of Energy administers most of the grants.

Biomass Projects

The Department of Energy, along with the Department of Agriculture, will provide grants for "bioenergy," "biofuel," "biopower" and related processes that show commercial promise under a "biomass research and development initiative."

"Bioenergy" refers to energy produced from organic matter, or material like plants that was once living. The material is called "biomass." "Biofuel" is fuel made from biomass or from processing and conversion derivatives, including ethanol, biodiesel, and methanol. "Biopower" means the use of biomass feedstock to produce electric power or heat through direct combustion of the feedstock, through gasification and then combustion of the resultant gas, or through other thermal conversion processes. Power may be generated with engines, turbines, fuel cells, or other equipment.

A grant applicant must be a US entity. It can be a

Table 1

Winners	Projects
Southern Research Institute	Technology to condition hot syngas while preventing the escape of trace metals through a filter, which will allow integrated-gasification combined-cycle systems to operate with relatively high particulate control device temperatures to obtain high cycle efficiency without damaging the gas turbine blades with metals that have escaped the device.
Research Triangle Institute	A novel fluidized-bed reactor system to remove tar, ammonia and sulfur from raw biomass syngas from a pressurized fluidized-bed biomass gasifier, to be installed at a pressurized fluidized-bed biomass gasification pilot plant.
Antares Group Inc.	Low-temperature catalytic hydrothermal gasification process that converts wet organic residues to medium-Btu gas (methane and carbon dioxide).
Bioengineering Resources, Inc.	Integration of a stover ethanol facility with a conventional grain alcohol plant in the corn belt to maximize gasifier efficiency and throughput.
Membrane Technology and Research, Inc.	Novel membrane-based ethanol recovery technology that allows economical distributed production of ethanol from biomass available throughout rural America, which will reduce the cost of small-scale, localized ethanol production in rural communities.
Technology Management Inc.	Building and operating a modular proof-of-concept solid oxide fuel cell power generation system capable of generating up to 1kW of biopower from biomass or biofuels.
Electric Power Research Institute	Evaluating the economic benefits of using forestry residues for generating power in small-scale, indirectly fired, gas-turbine power plants. Two nominal plants, 2 mw and 15 mw, would be evaluated.

Grants

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private sector entity, an institution of higher education, a national laboratory, a federal or a state research agency, a non-profit organization, or a consortium of two or more of the listed entities. For projects that receive funding from DOE and that include a national laboratory as part of a consortium, the laboratory may not receive more than 50% of the total grant.

An applicant must submit a pre-application by February 15, 2005. The full applications must be submitted by April 15, 2005.

The Department of Energy offers grants for biomass projects and for renewable energy projects on Indian reservations.

An applicant may submit multiple, unique proposals and thus respond to multiple topics. Each individual application must respond to only one of four following technical topic areas: development and production of feedstock, development of biomass-based products, use of biomass and integrated resource management, or an incentive analysis for commercialization of the project.

Each application will be considered by both the Department of Energy and the Department of Agriculture; however, successful applicants will not receive funding from both departments for the same project. The applicant must bear at least 20% of the total project cost. The greater the applicant's share of the total project cost, the more likely the project will receive the grant.

The total grants under this program for 2005 is expected to be $15 million. The maximum individual grant will be $2 million and the minimum will be $200,000. The grant may be disbursed ratably over one to three years.

In 2004, a total of $25 million in grants was awarded to 21 projects. *Table 1* contains a sample of projects selected for the grants.

Indian Reservation Projects

The Department of Energy will provide grants of up to $500,000 per project for renewable energy projects on "tribal lands."

All applications must be received by February 4, 2005 via the Department of Energy's website. There may be another round of grants next year.

A grant may be used for feasibility studies or for the implementation of projects based on such studies. Tribal lands refer to Indian reservations, public domain Indian allotments, former Indian reservations in Oklahoma, land held by incorporated native-American groups, as well as certain other Indian communities.

The applicant must be a federally-recognized Indian tribe, band, nation or other organized group or community, including any Alaska native village, region or village corporation that is federally-recognized as eligible for the special programs and services provided by the US to Indians. There are currently over 550 federally-recognized tribes in the US.

Eligible technologies include photovoltaic, concentrating solar power, solar thermal systems, wind, biomass power, hydroelectric, geothermal electric generation, geothermal resources for direct heating or cooling applications, and other renewable or renewable hybrid systems.

An application for a grant should demonstrate the potential sustainability of renewable energy development, including the potential economic and environmental benefits to the tribal community. The application must identify and provide evidence of the available renewable energy resource, tribal needs for energy within the community or for export off the reservation, the potential for job creation, potential for obtaining commitments for local energy use or power purchase agreements, the potential for economic and environmental benefits to the tribal community, and the potential for future development. The application should also address how renewable energy development will integrate with the cultural, social, and long-term goals of the tribe. The application should finally identify how the proposed project will build "human capacity" within the tribe.

The project must demonstrate the long-term economic sustainability and include a tribal council resolution and a statement of commitment from each project participant. If a tribal council resolution cannot be obtained prior to submission, a statement of commitment from an authorized tribal representative and a plan to obtain a resolution will be accepted. The ability of the applicant to obtain financing and commitments for power purchase agreements (*i.e.*, for local use or for export) will be major factors in the selection of the winners.

The Department of Energy anticipates total grants of $1 million to $1.7 million to be available in 2005. The maximum grant will be $200,000 for a feasibility study and $300,000 for development of a project. Five to 10 feasibility study awards and three to five development project awards are expected in 2005. The grants may be distributed ratably over a period of one to three years.

For feasibility studies, the developer is encouraged to contribute to the cost, but is not required to. For development projects, the developer must bear at least 20% of the project cost. In both cases, applicants that bear a greater portion of the cost than the other applicants will be favored.

In 2003, approximately $2.1 million was awarded under this program, and in 2004, $900,000 was awarded. *Table 2* shows a sample of winners from 2004.

Other Opportunities

A number of other grants were available in 2004 for energy projects from the Department of Energy. These included grants for the development and maintenance of testing standards for solar energy systems, a million solar roofs initiative, a national accreditation and certification program for installation and acceptance of photovoltaic systems, as well as sponsorship of conferences that advance solar energy related dialogue.

The Department of Energy does not expect to provide similar grants in 2005 unless additional funding is provided by Congress. Instead, the department does anticipate grants will be available for studies and development of distributed wind technologies in 2005. ◎

Table 2

Winners	Projects
Kenaitze Indian tribe, Kenai, Alaska	The tribe will study solar and wind energy resources for powering tribal operations, future tribal housing, and possible sale to local energy providers.
Mandan, Hidatsa, and Arikara Nations, Fort Berthold Reservation, New Town, N. D.	The three affiliated tribes will study the feasibility of using wind energy to power the tribes' proposed clean fuels refinery, provide power for the reservation and create jobs.
Ak-Chin Indian community, Maricopa, Ariz.	The tribe will study the economic sustainability of a facility that would turn poultry manure and other biomass materials into electricity and other products for use on the reservation or for sale outside the reservation.
Quinault Indian nation, Taholah, Wash.	The tribe will assess their wind, biomass, solar and wave energy resources to determine their development potential.
S & K Holding Company, Inc., Flathead Reservation, Ronan, Mont.	The Confederated Salish and Kootenai Tribes will study the feasibility of a commercial wind energy facility, as well as the potential for solar and biomass power development. Included in the study will be a look at using pumped water storage to increase the value of these intermittent resources.
Yavapai-Apache Nation, Camp Verde, Ariz.	The tribe will study the economic feasibility of using forest thinnings and other biomass materials to produce electricity for the reservation, or for export. It will also examine whether such a project would be consistent with their cultural and social values.
Mesa Grande Band of Mission Indians, Santa Ysabel, Calif.	The tribe, faced with inadequate electricity resources and rising energy prices, will study the feasibility of meeting some of those needs with photovoltaics, solar hot water and hydronic space heating.

Environmental Update

Kyoto Protocol

With the Kyoto protocol on climate change scheduled to enter into force on February 16, 2005, the jockeying for the post-2012 round of emission reductions has already started.

The Kyoto protocol will require industrial facilities in most of Europe, Japan and Canada to reduce their carbon dioxide, or CO_2, emissions during the first compliance period from 2008 to 2012. In general, the so-called "Annex I" industrialized nations that ratified the protocol must reduce emissions by 5% to 8% below 1990 levels. The United States signed the protocol, but the Bush administration refused to implement it on grounds that requiring substantial reductions in greenhouse gas emissions would have a crippling effect on the US economy.

Most of the countries that signed the Kyoto protocol are scheduled to hold informal talks later this year about how much to reduce emissions after the initial round of reductions is completed in 2012. The US has not agreed to participate in the informal talks. Discussions regarding which nations will commit to achieving greenhouse gas reductions in the post-2012 Kyoto regime are expected to be contentious. In December, Italy said it would pull out of the Kyoto protocol after 2012 if the United States, China and India have not agreed to participate by then.

Meanwhile, the European Union officially launched a CO_2 emission trading program on January 1. Most of the European Union countries are participating; however, four countries — Greece, Italy, Poland, and the Czech Republic — have not yet received approval for their emission allocation plans. In mid-January, the European Commission filed complaints against Greece and Italy in the European Court of Justice for failure to submit allocation plans. Under the European Union CO_2 trading program, allowances were allocated to participating countries for the first trading period that lasts from 2005 to 2007. Each country will then allocate its allowances among the various individual industrial facilities (including power plants, and iron, steel and pulp and paper factories) within its borders. Companies that are allocated too few CO_2 allowances to cover their emissions will have to buy the additional allowances they need on the open market or else reduce their emissions. The European Union is also reportedly considering expanding its trading program to include non-European Union countries, such as Norway and Switzerland, that have agreed to implement the Kyoto protocol.

In the United States, the US Department of Energy announced that it signed an agreement with Power Partners℠, a joint government-industry initiative in which participation is voluntary, to reduce greenhouse gas emissions from power plants. Power Partners℠ has mainly power industry trade associations as members. The members are the American Public Power Association, the Edison Electric Institute, the Electric Power Supply Association, the Large Public Power Council, the National Rural Electric Cooperative Association, the Nuclear Energy Institute and the Tennessee Valley Authority. Each of the members has promised the Department of Energy to encourage its own member companies to undertake voluntary efforts to achieve "greenhouse gas intensity" reductions by using low-emission or no-emission technologies such as nuclear, hydroelectric, wind and other renewables, natural gas and advanced coal technologies.

Power Partners℠ is one of thirteen business groups that have signed on to a voluntary DOE program called Climate VISION (for "Voluntary Innovative Sector Initiatives: Opportunities Now"). After it took the United States out of the Kyoto treaty, the Bush administration said it would try to persuade US businesses to make voluntary reductions in greenhouse gas emissions with the aim of reducing the "greenhouse gas intensity" of the US economy by 18% by 2012. The members of Power Partners℠ have agreed collectively to aim for reductions in greenhouse gas intensity of 3% to 5% (measured as emissions per unit of electricity produced) by 2012 period as compared to baseline emissions during the period 2000 to 2002.

Multi-Pollutant Measures

The "Clear Skies Act" that the Bush administration says it wants to put through Congress appears likely to remain bottled up in the Senate environment committee unless the administration agrees to significant changes in the bill.

The committee chairman, James Inhofe (R-Oklahoma), reintroduced the bill in late January and a Senate subcommittee held the first hearing on it on January 26. Inhofe is expected to proceed to a "mark up" — or session in which the committee votes on the bill and sends it to the full Senate — by the end of February.

The bill that the Bush administration wants would require significant reductions in nitrogen oxide, or NO_x, sulfur dioxide, or SO_2, and mercury emissions from power plants. The reductions would be achieved through a mandatory "cap-and-trade" emission allocation program similar to SO_2 allowance trading under the federal acid rain program. Democrats object to the bill because it does not require any cuts in carbon dioxide emissions. They also complain that the reduction targets are not stringent enough and that the compliance deadlines are too far out into the future.

The legislation died in committee in the last Congress. The administration will need the support of at least one Democrat on the Senate environment committee to move the bill to the full Senate. Republicans have a 10-8 majority on the committee, but Senator Lincoln Chafee (R-Rhode Island) has said publicly that he opposes the bill in its current form. A tie vote in committee would kill the bill unless it can be attached as an amendment to other legislation being considered on the Senate floor. Even then, support among moderate Republicans for the Clear Skies Act is not certain and Senate Democrats could filibuster to block a vote in the full Senate because Republicans would not be able to muster the 60 votes required to cut off debate. Meanwhile, the House of Representatives appears to be taking a wait-and-see approach; there is no point in taking up the measure in the House if it is certain to die in the Senate.

The Bush administration has given Senator Inhofe until March to make progress. If by March the bill is still stalled, then the US Environmental Protection Agency will finalize a proposed "clean air interstate rule" in mid-March in time to coincide with a March 15 court-ordered deadline to take action to reduce mercury emissions. Some of the initial mercury reductions in the clean air mercury rule are linked to the significant NO_x and SO_2 reductions that would be achieved by the installation of control technologies to achieve the reductions mandated under either the clean air interstate rule or the Clear Skies Act. As a result, if the Clear Skies Act is not well on the way to being enacted, then EPA will be compelled to implement the clean air interstate rule.

The administration had previously said it intended to move forward with the clean air interstate rule by the end of 2004; however, it appears to have backed off to give Senator Inhofe more leverage in his negotiations with committee members about the Clear Skies Act. The Bush administration prefers legislation over EPA rules because a new law would not be subject to challenge in the courts and the emission reductions would apply to power plants nationwide. The clean air interstate rule that EPA proposed would require power plants in only 29 eastern, midwestern and southern states and the District of Columbia to reduce NO_x and SO_2 emissions by 2015.

Particulate Matter

The Environmental Protection Agency identified 224 counties in 20 states and the District of Columbia in early January that failed to meet the fine particulate matter, or PM2.5, national ambient air quality standard. The was imposed in July 1997. The states and the District of Columbia will have until April 2010 to act. 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.

Certain environmental groups and public health organizations are expected to file court challenges. These groups complain that EPA should have designated more areas as not meeting the PM2.5 national ambient air quality standard.

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. Fine particulates are believed to pose a health risk, particularly to older individuals and children, / continued page 62

because of their ability to lodge deeply in the lungs due to their small size (less than 1/30th the size of an average human hair).

The PM2.5 nonattainment designations will be effective on April 5, 2005, and states will have three years to adopt rules that will bring them into compliance. States with PM2.5 nonattainment areas will then have until 2010 to achieve compliance, with the possibility of an extension to as late as 2015 for areas where there are more severe PM2.5 problems and emission control measures are not feasible or available. EPA is also in the process of developing a menu of options from which states can choose for achieving reductions. In addition to specific emission standards, EPA is expected to encourage states to consider emissions trading and pollution fees as other mechanisms for achieving needed reductions. EPA plans on issuing a proposed rule outlining implementation measures in the first quarter of 2005.

Many of the new PM2.5 nonattainment areas will face significant PM2.5 emission reduction requirements for the first time. The PM2.5 implementation rules in certain states may require existing power plants and industrial facilities to install costly new pollution control technology or to upgrade existing control equipment to reduce fine particulate emissions.

> The Environmental Protection Agency told 224 counties in 20 US states in January that they must take steps to reduce particulates in the air.

Superfund

The US Supreme Court issued a much-anticipated decision in December in *Cooper Industries, Inc v. Aviall Services, Inc.*, a case that held that private Superfund cost-sharing actions might be brought without having to wait for the federal government or a state government to file a cost recovery lawsuit. In a 7-2 decision, the court held that a federal or state government enforcement proceeding or a judicially- or administratively-approved settlement is a prerequisite before a party liable for Superfund costs can seek a share of the cleanup costs or "contribution" from other responsible private parties.

The decision means that companies will be less willing in the future to take voluntary steps to clean up a site without first having been sued by the federal government or a state government. The Supreme Court's opinion makes it clear that even if the federal government or a state is involved in overseeing a cleanup, there must first be a legal proceeding or a settlement in place. Cleanups under voluntary state brownfields remediation programs would not appear to qualify as a "civil action" or a "settlement" under the court's interpretation. The need to wait in the future until the federal government or a state government initiates an enforcement action will mean delays in cleanups and increased costs associated with added governmental oversight. The decision would also foreclose cost-recovery actions against the federal government in cases where companies took voluntary steps to clean up sites that were previously owned or operated by the federal government.

In the *Aviall* case, Aviall Services purchased contaminated industrial property from Cooper Industries, and it agreed to remediate the site after the state environmental agency threatened to bring an enforcement action. The state was involved in overseeing the voluntary cleanup, and after substantial costs were incurred, Aviall sued Cooper Industries to try to recoup a share of its remediation costs. This scenario is not unlike many other ongoing voluntary cleanup actions at current and former industrial sites.

The court's decision overturns a long-standing interpretation of Superfund adhered to by a majority of the federal appeals courts, and the ruling may prompt Congress to amend the Superfund statute to provide for a specific right of contribution from other responsible parties when a liable party is conducting a voluntary cleanup.

The *Aviall* decision does not affect contribution rights that exist under state statutes and common law; however, it does end what had been a standard procedure for seeking recovery of cleanup costs from other responsible parties. Under Superfund, an "owner or operator" of a "facility" may be jointly, severally and strictly liable for the costs of investigating and cleaning up a release of hazardous substances.

Coal Plants Sued

Two large coal-fired power plant projects are under siege from environmental groups, and certain environmental permits for the plants are being attacked in the courts. A Wisconsin trial court upheld a challenge in late November to a certificate of public convenience and necessity, or CPCN, issued by the Wisconsin Public Service Commission to the Wisconsin Energy Corporation. The CPCN order authorized the construction of two 615-megawatt pulverized-coal units in Wisconsin. Five separate petitions were filed challenging the issuance of the CPCN, with the lead petition being filed by Clean Wisconsin, Inc. The petitioners alleged that the CPCN application was incomplete, and they asserted that various aspects of the CPCN Order were contrary to law. The court concluded that the application was legally deficient because it failed to propose at least two alternative sites for the new plant and it did not include agreements for the use of needed transmission lines. The court also identified several inadequacies in the final CPCN order that were contrary to the applicable law, including a failure to adequately explain why the use of high sulfur coal was preferable to the use of natural gas, oil or low sulfur coal.

The Wisconsin energy priority law provides that it is the policy of the state to consider the following options in the listed order to meet energy demands: energy conservation and efficiency, noncombustible renewable energy resources, renewable energy resources, natural gas, oil or low sulfur coal, and high sulfur coal and other carbon-based fuels. The court set aside the CPCN order and sent the matter back to the Wisconsin Public Service Commission for further proceedings. The Wisconsin Energy Corporation has petitioned the Wisconsin Supreme Court seeking an expedited review of the trial court's decision.

The Sierra Club recently sent a 60-day notice letter to a project company planning to construct a 550-megawatt circulating-fluidized-bed coal- and coal refuse-fired power plant in Illinois. The Sierra Club is alleging that the air permit for the plant is no longer valid because construction did not commence within 18 months after the permit was issued by the Illinois Environmental Protection Agency. The project's air permit was originally issued on July 3, 2001. The Sierra Club reportedly intends to file suit soon after the 60-day notice period expires unless progress is made in reaching a settlement.

Brief Updates

Pennsylvania joined the growing ranks of states that have adopted a renewable energy standard or RPS in late 2004. The Pennsylvania RPS will require that 18% of the state's electricity be generated by alternative energy sources by 2020. A total of 8% of the RPS requirement must be met by so-called "tier I" renewable energy sources, including solar, wind, geothermal, low impact hydropower, biomass, and coal mine methane. The remaining 10% may come from "tier II" alternative energy sources, including waste coal, integrated combined-cycle coal gasification, municipal solid waste, large scale hydropower, pulping and wood manufacturing byproducts, demand side management programs, and distributed generation systems.

Oral argument in *New York v. EPA*, a lawsuit challenging a December 2002 EPA regulation that would modify the applicability provisions in the "new source review" or NSR permitting program, is scheduled for January 25, 2005 in the US appeals court in Washington. Fourteen states and a coalition of environmental groups have challenged the regulation. A decision is expected later in 2005. If the court upholds the regulation, then states will be facing a January 2006 / continued page 64

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deadline for revising applicable regulations implementing the new NSR program requirements.

Cinergy released a report to its shareholders in December that addresses the potential financial risks of implementing future greenhouse gas emission reduction requirements. The report was prepared in response to a shareholder resolution. It also discusses the potential costs of complying with emission reduction targets in the Clear Skies Act that the Bush administration is trying to put through Congress, other versions of the multi-pollutant legislation, and the pending utility mercury reductions rule and clean air interstate rule proposed by EPA. American Electric Power and TXU have also reported on similar potential financial risks to their shareholders. The AEP report was released at the end of August, and the TXU report was issued in September.

The New York Public Service Commission announced that it has moved up the start date of the state's renewable portfolio standard from 2006 to 2005 so that projects can participate in the program and still qualify for federal production tax credits. Projects must be in operation before January 1, 2006 to qualify for federal credits. The credits are worth 1.8 cents a kWh. They can be claimed on the electricity output for 10 years. The New York RPS requires that at least 25% of electricity sold to New York consumers must be generated from renewable energy sources by 2013.

Power plants, refineries, and other industrial facilities in the Los Angeles area will have to reduce their NO_X emissions further starting in 2007 under recent changes to the so-called "regional clean air incentives market" or RECLAIM. The rule changes affect approximately 330 facilities and call for approximately a 20% reduction in NO_X emissions. Affected RECLAIM facilities must reduce NO_X emissions by 7.7 tons a day by 2011, starting with four tons a day in 2007 and increasing by 0.925 tons a day in each of the following four years. There will be a limited exemption for qualifying facilities that have already installed state-of-the-art pollution control. The RECLAIM rule revisions will also restore some of the emission trading authority for power producers that was suspended during the California energy crisis. Full trading rights will be restored on January 1, 2007.

The three major California utilities will now be required to calculate the financial costs of greenhouse gas emissions as part of their long-term energy purchases. The California Public Utilities Commission directed the utilities in mid December to include a "carbon adder" when evaluating the cost to purchase electricity from power producers under long-term contracts. Under the Commission's mandate, the utilities will reportedly need to assume a CO_2 emissions cost of between \$8 and \$25 per ton. The Commission is expected to provide further guidance on the presumptive CO_2 emission cost at a later date. ◎

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