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PROJECT FINANCE
NewsWire

April 2002

A New Depreciation Bonus

by Keith Martin, in Washington

The United States adopted a 30% "depreciation bonus" in March in the hope of persuading US businesses to invest in new plant and equipment.

It only applies to new investments during a window period that started last September 11. Power companies tried immediately to figure out ways to claim the bonus on projects that they already have under development. The bonus is part of an economic stimulus bill that President Bush signed into law on March 9. It would reduce the cost of new power plants by as much as 5.39%.

The stimulus bill also opened the door for companies that will report net operating losses on their tax returns for last year — or that can generate such losses this year — to get refund checks from the US Treasury for taxes they paid as far back as 1996.

Other parts of the bill affect smaller segments of the project finance community.

Depreciation Bonus

The depreciation bonus only applies to new investments made during a window period that runs from September 11, 2001 through the end of either 2004 or 2005.

Assets must be placed in service by the end of the window period in order to qualify for the bonus. Most alternative fuel projects face a deadline of 2004 to be placed in service. Most gas- and coal-fired power plants, gas pipelines and transmission lines have until December 2005.

The key to the later date is that the project must be depreciated / *continued page 2*

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MORE ENERGY TAX INCENTIVES may be on the way.

The Senate will try to finish work in April on the Bush energy plan. The plan is controversial, but if it makes it through the Senate, it will be with a number of new energy tax incentives that the Senate Finance Committee approved in February.

Five main tax benefits are being watched keenly by the project finance community.

One is a tax credit for 10% of the cost of new cogeneration facilities. To qualify, at least 20% of the useful energy produced at the project would have to be in the form of steam or other / *continued page 3*

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for tax purposes over a period of 10 to 20 years. The project must also be expected to take more than a year to build and cost more than $1 million. Thus, for example, a simple-cycle gas-fired power plant built on an Indian reservation would have to be in service by December 2004 to qualify (since it qualifies for special 9-year depreciation by virtue of being on an Indian reservation). Project developers who are facing the shorter deadline may be able to buy more time by electing slower tax depreciation.

A company will not be able to claim the bonus if it was committed to the investment before last September 11.

It is unclear how to apply this principle to many power projects. The Internal Revenue Service is expected to issue guidance sometime this summer.

The depreciation bonus will reduce the cost of new power plants by as much as 5.39%

The economic stimulus bill distinguishes between two kinds of assets — those that a company "acquires" and those that it "self constructs," or builds itself.

The depreciation bonus does not apply to assets that a company "acquires" under a "binding" contract signed before September 11. Just because a contract was signed before September 11 does not mean it was "binding." For example, a contract that requires the buyer to give a notice to proceed before work starts, or that allows the buyer to cancel at will without a meaningful penalty, is not yet binding on the buyer when the contract is signed.

In the case of property that a company "self constructs," the depreciation bonus does not apply if construction "began" before September 11.

It appears Congress intended that all power plants would be treated as "self constructed." If this interpretation holds, then when the construction contract or procurement contracts for parts were signed does not matter; the key is when construction began on the project. The House Ways and Means Committee said in its report on the economic stimulus bill:

> Property that is manufactured, constructed, or produced for the taxpayer by another person under a contract that is entered into prior to the manufacture, construction, or production of the property is considered to be manufactured, constructed, or produced by the taxpayer [*i.e.,* self constructed].

Under this definition, all custom-made equipment that a company contracts with someone else to have built is self constructed. A company only "acquires" equipment that it buys off the shelf. This is a broader definition of "self constructed" than Congress has used in the past. The IRS could still adopt a narrower approach when it issues guidance this summer. Congress is also working on some technical corrections to the new law that, if enacted, would have retroactive effect.

Until Congress or the IRS says otherwise, developers should assume that power plants are self constructed. A project will not qualify for the bonus — at least as long as it remains in the hands of the company that was developing the project on September 11 — if construction "began" before September 11. Construction began if physical work of a significant nature started at the site. The work must go beyond mere site preparation. The IRS has sometimes also treated construction as having begun when assembly of major components for the project starts offsite. It is not clear whether it will do so in this case.

There are many unanswered questions that will have to wait until the IRS issues guidance this summer. For example, many developers signed contracts for multiple turbine slots before September 11. Work may or may not have started on the turbines. In some cases, even where a turbine was built, it was not yet designated for use in a particular project. It is unclear whether the fact that work started on a turbine will rule out claiming a bonus on the cost of the turbine or whether it might even taint the rest of the project.

The IRS is also expected to address this summer whether a new purchaser of a project who acquires it during construction can claim the bonus, even if the original developer who sold it to him could not. The new purchaser was not committed to the investment on September 11.

The depreciation bonus is an acceleration of tax depreciation to which the owner of a project would have been entitled anyway.

The owner gets a much larger depreciation deduction the first year and smaller ones later. His depreciation allowance in the year the project is put into service is a) 30% of his "tax basis" in the project (basically the cost of the project) plus b) depreciation for that year calculated in the regular manner on the remaining 70% of basis. For example, without the bonus, the first-year depreciation deduction on a coal-fired power plant that cost $100 million to build is $3.75 million. With the bonus, it is $32.625 million. Depreciation in later years is reduced commensurately, since only $100 million in depreciation can be claimed in total.

The faster tax write-off can be a significant benefit. The benefit is greater the longer the normal depreciation period for an asset. Thus, the depreciation bonus will reduce the cost of assets that are depreciated over 20 years — for example, transmission lines and coal- and combined-cycle gas-fired power plants — by 5.39%. It will reduce the cost of gas pipelines and other gas-fired power plants that are depreciated over 15 years by 4.52%. The cost of a power plant that burns waste would be reduced by 2.17%. Windpower and biomass projects would cost 1.57% less. These calculations only take into account federal tax savings from the depreciation bonus — not also the state tax savings — and they use a 10% discount rate.

The depreciation bonus can only be claimed on assets in the United States. Assets used in US possessions, like Puerto Rico and the US Virgin Islands, also qualify. The bonus cannot be claimed on property that has been financed with tax-exempt bonds or that is "used" by a municipality.

Only the first company to put the asset in service qualifies for the bonus. The goal is to encourage US businesses to buy new equipment — not churn used assets. The bonus does not apply to buildings. Power plants are usually classified as only about 3% to 5% "building," and the rest is considered "equipment."

Some companies may not be in a position to make efficient use of the tax benefits. Therefore, Congress adopted a special sale-leaseback rule that allows / continued page 4

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thermal output. The project would also have to have an energy conversion ratio of at least 70%, meaning that no more than 30% of the energy content of the fuel can be lost during conversion to electricity. (The required conversion ratio for small projects of 50 megawatts or less in size would be only 60%.)

The Senate bill is also expected to create three new tax credits for using clean coal technologies to generate electricity. One is an investment tax credit for 10% of the cost of new clean coal power plants. Only 4,000 megawatts worth of projects in total would qualify. Taxpayers would have to have their projects certified in advance by the Internal Revenue Service. Certified projects would also receive an additional tax credit tied to the amount of electricity sold each year. The amount would vary between 0.1¢ to 1.4¢ a kilowatt hour, depending on the heat rate and when the project is placed in service. The credit could be claimed on the first 10 years of output from the project. Finally, a credit of 0.34¢ a kilowatt hour could be claimed for 10 years on output from existing power plants that are retrofitted to use clean coal technologies. Companies with retrofit projects would also have to have them certified first by the IRS. The IRS would be authorized to certify only 4,000 megawatts in retrofit projects.

The Senate is expected to expand an existing section 45 tax credit of 1.7¢ a kilowatt hour for generating electricity from certain fuels. The credit is claimed today mainly by owners of windpower projects. Three new fuels would be added to the eligibility list. They are geothermal energy, cow and hog manure, and biomass (but not garbage, landfill gas or recyclable paper).

The Senate would also allow taxpayers more time to place new projects in service to qualify for section 29 tax credits. These are credits for producing / continued page 5

Depreciation Bonus

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the original user of an asset up to three months after he puts the asset in service to sell it to another company that can use the tax benefits and lease it back. That way, the lessee might share in the bonus indirectly in the form of reduced rent.

Projects that are placed in service after September 10, 2004 through the end of 2005 will only qualify for the depreciation bonus if a binding contract to acquire the project is signed or — in cases where the taxpayer is building the project himself — if construction begins during the period September 11, 2001 through September 10, 2004. For projects placed in service during 2005, the depreciation bonus will only apply to the amount the owner spent on the project through September 10, 2004.

There is already speculation among Washington lobbyists that the deadline to place projects in service will be extended. Five Republican members of the House tax-writing committee plan to introduce a bill in early April to make the depreciation bonus permanent.

Loss Carrybacks

The economic stimulus bill opened the door for companies that will report net operating losses on their tax returns for last year — or that can generate such losses this year — to get refund checks from the US Treasury for taxes they paid as far back as 1996.

A corporation can normally carry net operating losses back — and get a refund of past taxes paid — up to two years in the past. The economic stimulus bill authorized a five-year carryback for net operating losses in 2001 and 2002. Thus, 2001 losses could be carried back to 1996.

This could be a significant benefit to Enron — if it paid past taxes — and to western utilities that were caught up last year in the California power crisis.

The US has two different income tax systems for corporations. A corporation must compute its regular tax at a 35% rate and also its "alternative minimum tax" at a 20% rate using a broader definition of income, and then pay whichever amount is greater. The idea was to make it harder for companies not to pay any tax at all. However, a company is given a credit for the extra minimum taxes it pays above what it would have paid in regular taxes, and this credit can be used in future years when the company would otherwise be back on the regular tax to reduce its regular taxes down to the level where minimum taxes kick in.

The new carryback can also be used to get a refund of minimum taxes paid during the past five years. However, the amount of the net operating loss must be recalculated — using a minimum tax definition of loss — before it can be used for this purpose.

A company ordinarily cannot use net operating loss carrybacks to reduce its minimum taxes by more than 90%. However, this limit has been waived in the case of 2001 and 2002 losses.

Section 45 Credits

The stimulus bill extended a deadline for building new projects to generate electricity from wind, "closed-loop" biomass or poultry litter and qualify for a tax credit of 1.7¢ a kilowatt hour on the output. Such projects had to be in service by December last year to qualify for credits. The stimulus bill extended the deadline through December 2003.

The tax credits run for 10 years after the project is placed in service. The credit is adjusted each year for inflation. The figure 1.7¢ was the credit for electricity sold during calendar year 2000. The new figure will be announced in early April.

A "closed-loop" biomass project is a power plant that burns plants grown exclusively for use as fuel in power plants. There are no known such projects in the United States.

There is a chance — if Congress clears the Bush energy plan this year — that the deadline for placing projects in service will be further extended through 2006 and the list of qualifying projects will be expanded to cover other fuels.

Indian Reservations

Projects on Indian reservations qualify potentially for special depreciation allowances and a wage credit tied to the number of Indians hired to work on the project. The deadline for placing projects in service to qualify for these benefits was December 2003. The economic stimulus bill extended it by one year through December 2004.

Subpart F

US multinationals complain that they have a hard time competing abroad because the United States taxes them on worldwide earnings. Most multinationals — if they are careful — can structure foreign operations in a way that lets them defer US taxes on the earnings for as long as the earnings remain offshore. However, this only works for "active" income — for example, income from a real operating business as opposed to from passive investments. Examples of passive income are interest, dividends, rents and royalties.

Banks complained that interest represents active income for them. Congress adopted a special rule in 1997 that treats income as active if it is from the "active conduct of a banking, financing, or similar business." The provision is temporary. The economic stimulus bill extended it through December 2006.

Argentina Adopts More Emergency Measures

by Damiana Ponferrada and Diego Serrano Redonnet, with Perez Alati, Grondona, Benites, Arntsen & Martinez de Hoz in Buenos Aires

The Duhalde government ordered mandatory "pesofication" of debts, and the Argentine Congress formally declared a new emergency — this time a "social and credit emergency" — and passed a heavily criticized new bankruptcy law. Both actions took place in February.

The government has since issued additional decrees to answer questions raised by the pesofication order.

The new emergency will remain in place until December 10, 2003. The legal significance of emergency declarations, like the latest one, is they give the Duhalde administration and the Argentine central bank broad powers to issue decrees, rules and regulations to respond to the emergency.

New Bankruptcy Law

The new bankruptcy law officially took effect on February 14. It eliminated the "cram-down proceeding," a special salvage proceeding under which, after failing to approve the debtor's reorganization plan, creditors and third parties could acquire the company through a special bidding process. Under the new law, rejection of a reorganization plan will be automatically followed by the debtor's bankruptcy.

The 60-day "exclusivity period" in which debtors could file restructuring proposals was extended */ continued page 6*

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gas from coal seams, tight sands, Devonian shale, geopressured brine and biomass or for producing synthetic fuel from coal. Future such projects would qualify for a tax credit of 51.7¢ an mmBtu on output. The bill would tighten the definition of synthetic fuel for future syncoal projects. Output from such projects would qualify for tax credits only if it sells for a price that is at least 50% more than the cost of the raw coal used to produce it and only if sulfur dioxide and nitrogen oxide emissions are reduced by at least 20% compared to such emissions from burning the raw coal.

Finally, the Senate is expected to allow businesses that buy fuel cell power plants a tax credit for 30% of the cost. The credit would be limited to $1,000 for each kilowatt hour of capacity.

The Bush energy plan passed the House last July with many, but not all, of the same tax provisions. If the bill also passes the Senate, then the two houses will have to reconcile differences between the two versions. Most observers expect the process to take until October to play out.

ARGENTINA may impose a one-time 5% tax on companies that benefited by converting their foreign currency loans into peso debts at a 1-to-1 exchange ratio of dollars to pesos.

The Duhalde government said it favors such a tax in March. The peso has lost 70% of its value since the Argentine government allowed it to float against the dollar on February 11. Borrowers were permitted to convert outstanding dollar loans into peso debts at par. Duhalde has said the country is "broke" and is looking for ways to raise money.

The bill introduced in Congress to implement the tax reads in part: "To fulfill the goal [of developing small enterprises], a National Fund for Productive Development is created and will be funded with */ continued page 7*

Argentina

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to 180 days and debtors are now allowed to shed 100% of their debts in bankruptcy. In the past, a debtor could only disavow 60% of each admitted claim.

The law suspends all existing reorganization proceedings for at least 180 days measured from February 14, 2002. It also suspends for 180 days all foreclosure proceedings (other than certain specified exceptions such as alimentary or labor credits), including foreclosures of mortgages and pledges, all preliminary measures affecting a debtor's assets or business — such as attachments and preliminary injunctions — and all bankruptcy proceeding petitions. There is uncertainty as to whether the 180-day period should be counted on the basis of calendar days or court working days.

These new bankruptcy provisions will remain in effect through December 10, 2003. However, many creditors are afraid that the Argentine government may decide to extend them.

Mandatory "Pesofication"

The Duhalde government announced the mandatory conversion of all US dollar-denominated obligations into Argentine pesos on February 3. The announcement is in Decree No. 214/02. Except for bank deposits that are converted at a rate of exchange of one US dollar = 1.40 pesos, all debts with the financial system and all monetary obligations due and payable that are not related to the financial system are converted at an exchange rate of one US dollar = 1 peso.

The lack of clarity of the decree has led to many questions, including whether all future payments arising under long-term contracts should be "pesofied" and whether such "pesofication" is limited to payments maturing within the period of economic emergency declared by Congress (through December 10, 2003). Contracts entered into after January 6, 2002 are not covered by the "pesofication" decree and contracts in foreign currency continue to be permitted in Argentina.

All "pesofied" bank deposits and monetary obligations are to be adjusted pursuant to an index rate called the "*Coeficiente de Estabilización de Referencia,*" or "CER," to be published by the Argentine central bank. This index rate will be tied to the Argentine consumer price index. The central bank has also been given the power to set a minimum interest rate for bank deposits and a maximum interest rate for loans.

In the case of monetary obligations not related to the financial system denominated in foreign currency, if the value of the consideration were to be higher or lesser than the price to be paid at the time of payment after adjustment by the CER, either of the parties may take the case to court.

Pesofication Exceptions

The Duhalde government issued a second decree to answer some of the questions raised by the first one. This is Decree No. 410/02.

It exempts the following obligations from the mandatory pesofication: foreign trade financings, credit card balances corresponding to purchases made outside Argentina, deposits made by foreign banks or financial entities in local financial entities to the extent such deposits are transformed into credit lines for a term not shorter than four years in accordance with regulations to be issued by the central bank, futures and options contracts (including those registered in the self-regulated markets and accounts exclusively allocated to such transactions in such markets), redemption of interest in mutual investment funds, and public and private sector monetary obligations denominated in foreign currency and governed by foreign law.

The exemption from pesofication for obligations governed by foreign law dispels doubts raised earlier about whether judgments issued by foreign courts against Argentine borrowers or companies in relation to obligations arising under contracts not governed by Argentine law can be enforced in Argentina.

Outbound Remittances

The Duhalde administration has dropped its effort to maintain a two-tier exchange rate for pesos into dollars. The peso now floats freely against the dollar with intervention of the central bank through sales and purchases of US dollars.

However, restrictions on foreign exchange transfers outside Argentina remain in place. The central bank decides which transfers of funds out of the country may be made without its prior authorization and which transfers require its prior approval. Regulations have been issued on this subject by the central bank.

The following outbound remittances may be made freely: the payment of expenses related with fairs or exhibitions made for the promotion of exports, payments for imports of goods and services, other payments for services, and the payment of obligations to international organizations or to banks that are party to a project financing cofinanced by international organizations or to official credit agencies.

Remittance of foreign currency outside Argentina starting February 11, 2002 to pay the principal and interest of financial obligations (except for those obligations with international organizations mentioned above) must be authorized by the central bank.

Exports

Argentina reimposed controls on converting sales proceeds from exports. Exporters must transfer into, and negotiate in, the Argentine financial system the funds obtained from their export transactions. The central bank has established certain exceptions by allowing exporters in certain specific cases to allocate their export proceeds to payments abroad. Criminal sanctions will be imposed on entities that breach the exchange control regulations.

The Duhalde government has also imposed export duties on most exports, ranging from 5% to 20% depending on the goods to be exported. ◎

Corporate Inversions

By Keith Martin and Samuel R. Kwon, in Washington

Corporate inversions are generating a lot of heat in Congress.

An inversion transaction is one where a US company with substantial foreign operations turns its ownership structure upside down so that what was formerly a US parent company becomes a subsidiary of a new parent company in Bermuda or another tax haven. In the process, the US company sheds all of its foreign subsidiaries. They become direct subsidiaries of the new parent company in Bermuda. US companies in increasing numbers are doing inversions in order to reduce the amount of taxes they have to pay in the United States.

The US government may move to stop inversions. Senators Max Baucus (D.-Montana) and Charles Grassley (R.-Iowa), the chairman and senior Republican on the Senate tax-writing committee, said they will introduce what they hope will be a bipartisan bill in April to put a halt to inversions. Grassley derided US corporations that invert for having their "butts" in the United States but */ continued page 8*

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. . . a mandatory contribution by enterprises, the debt of which is above US$ 3,000,000 at the time of conversion into pesos . . . . The contribution will be extraordinary, and will be of 5% of the debt amount."

Maximiliano Batista, with the firm Perez Alati, Grondona, Arntsen & Martinez de Hoz in Buenos Aires, said the Argentine Congress is at least three to four weeks away from acting on the proposal, and that its fate will probably be decided ultimately by reaction to it from the International Monetary Fund, from whom Argentina is trying to borrow money.

President Duhalde also spoke in late February about imposing a one-time windfall tax on 2001 earnings of privatized telephone, power, water and natural gas companies, but his government has since backed away from that proposal.

A FURTHER CRACKDOWN ON CORPORATE TAX SHELTERS looks likely.

The US Treasury said in March that it plans to expand the number of transactions that must be reported to the government as possible tax shelters. Reporting is required currently for "listed transactions" — 11 types of transactions that the IRS challenges routinely when it finds them on audit — plus other transactions that possess at least two of five tax-shelter characteristics.

Mark Weinberger, the outgoing assistant Treasury secretary for tax policy, told the Senate Finance Committee that the number of voluntary disclosures by taxpayers has been disappointing. To date, only 99 companies have reported a total of 272 transactions. Only 64 of the disclosures involved "listed transactions." Many of the rest were routine leveraged leases that the government has asked taxpayers not to report, but that some lease advisers have encouraged be reported in the hope of burying the IRS with paper. */ continued page 9*

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their hearts elsewhere.

Two bills introduced by eight members of the House tax-writing committee from both political parties in March would also put a halt to inversions. One of the House bills is retroactive to inversions done after last September 11 and would overturn inversions done earlier starting in 2004.

A bill must pass both houses of Congress to become law. Senate action is considered more likely; the chairman of the House tax-writing committee is lukewarm to action this year.

The Bush administration is doing a study of why inversions occur and promised to release an outline of any recommendations by late April with the full study to follow later.

The Internal Revenue Service is working in the meantime on amendments to its existing tax regulations that could broaden the circumstances in which a "toll charge" is collected at the US border on US companies that invert their ownership structures. Any such change in the regulations would probably be prospective. A "toll charge" is a tax that is collected when assets are moved outside the US tax net. The tax is on the amount the assets have appreciated in value. US law already imposes a toll charge, but perhaps not always in the right circumstances.

The Rush Offshore

US companies that have inverted in recent years include Foster Wheeler, Stanley Works, Tyco International, Coopers Industries, Seagate Technology and Fruit of the Loom. Ingersoll-Rand said in a prospectus filed with the US Securities and Exchange Commission in November that an inversion it had underway would add $40 million a year to earnings, plus a one-time benefit to earnings in the fourth quarter of 2001 of $50 to $60 million. Coopers Industries estimated that inverting would allow the company to reduce its effective tax rate from 35% to 20% and increase earnings by $55 million a year.

Global Grossing and Accenture, the former consulting arm of Arthur Andersen, incorporated their parent companies in Bermuda from the start.

US companies are driven to inversions in an effort to reduce US taxes on earnings from their offshore operations. The United States taxes American companies on worldwide earnings. Foreign operations can usually be set up in a way that allows US taxes to be deferred for as long as the earnings remain offshore. However, this makes the earnings unavailable for reinvestment in the United States without triggering US taxes. In addition, US tax deferral is only possible on "active" income — not "passive" income. Examples of passive income are dividends, interest, rents and royalties. The US looks through offshore subsidiaries of US corporations and taxes the US parent on any passive income it sees in the offshore ownership chain.

US companies are driven to inversions in an effort to reduce US taxes on earnings from their offshore operations.

By inverting, the offshore operations move outside the US tax net altogether.

There is a cost to inverting. The US shareholders are usually taxed on any appreciation in value of the shares they hold in the US company. Tax is triggered when shares in the US company are exchanged for shares in the new foreign parent company. There is also potentially a "toll charge" on the inverting US company when it transfers its foreign subsidiaries to the new foreign parent company, although this tax is usually avoided.

Inversions have been of greater interest recently with the dip in the US stock market. Lower share prices make it an opportune time to invert because the US shareholders are less likely to have a gain on their shares.

Legislation

Eight members of the tax-writing committee in the House introduced two bills in March that would attack inversions by treating the new parent company set up in Bermuda or other tax haven as if it were a US corporation still subject to tax fully on its worldwide income.

Four Republicans on the House tax-writing committee — Scott McInnis (R.-Colorado), Amo Houghton (R.-New York), Nancy Johnson (R.-Connecticut) and Wes Watkins (R.-Oklahoma) — introduced one of the bills. It would treat the new offshore parent company as a US company for tax purposes if more than 80% of the shares in the offshore parent remain owned —- by vote or value — by former shareholders of the US company that is inverting. However, the threshold would drop to 50% if three things are true about the new foreign parent. First, its shares are publicly traded on a US stock exchange. Second, less than 10% of its gross income is expected to come from the tax haven where it is incorporated. Third, fewer than 10% of its employees are based permanently in the tax haven. The McInnis bill would apply to inversions done after December 2001.

The other bill — introduced by Rep. Richard Neal (D.-Massachusetts) and cosponsored mainly by Democrats — takes a similar approach. However, the lines in it are less clear. Under the Neal bill, the new foreign parent company would be taxed in the US if it ends up with "substantially all" the assets of the inverted US company and former shareholders of the inverted US company own more than 80% of it. A lower stock ownership threshold — 50% rather than 80% — would apply if the "principal market" where shares in the new foreign parent are traded is the US and the new foreign parent does not have "substantial business activities (when compared to the total business activities of the expanded affiliated group)" in the tax haven where it is organized.

The Neal bill would apply retroactively to inversions after last September 11. It would also apply to earlier inversions, but not until 2004.

The full House voted down an amendment on March 13 that would have treated foreign parent companies created in inversion transactions as domestic for purposes of class action lawsuits. The vote was 202 to 223. The amendment was offered by three Democrats — John Conyers (D.-Michigan), Sheila Jackson-Lee (D.-Texas) and Richard Neal (D.-Massachusetts).

Lee Sheppard, an influential columnist who is read by tax policymakers in Washington, criticized the approach taken by the House bills in a column in *Tax Notes* magazine on April 1. Sheppard said, "[T]he drafters of the / continued page 10

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Weinberger said the IRS will replace the definition of "reportable transaction" in its current regulations. Under the new definition, four kinds of transactions will have to be reported (in addition to listed transactions). The four are "loss transactions" in which a corporation expects "section 165 losses" of at least $10 million in one year or $20 million over several years, "transactions with brief asset holding periods" where a company gets a tax credit of at least $250,000 after holding an asset for less than 45 days, transactions that create book-tax differences of at least $10 million, and transactions that are marketed under conditions of confidentiality and reduce the taxable income of a corporation by at least $500,000.

Weinberger also called on Congress to give the government more tools to go after aggressive tax planning by corporations. He called for a penalty on companies that fail to disclose "reportable transactions." The penalty would be $200,000 plus 5% of the extra tax owed in the case of listed transactions that are not reported, and $50,000 per failure to report in other cases. He also asked for a penalty on tax shelter promoters who fail to report and turn over customer lists. It would be $200,000 or 50% of the promoter's fees, whichever is greater, in the case of listed transactions, and $50,000 per failure in other situations. Weinberger asked Congress also to require corporations that are caught participating in an undisclosed listed transaction to report the penalties imposed to shareholders in a filing with the US Securities and Exchange Commission.

Senators Max Baucus (D.-Montana) and Charles Grassley (R.-Iowa), the chairman and senior Republican on the Senate Finance Committee, said they hope to move a bill this year imposing stiffer penalties on corporations that engage in tax shelters, as well as on tax shelter promoters / continued page 11

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House bills are focusing on the result of inversion transactions, rather than examining the misguided residence rules and ineffectual outbound transaction rules that let the horse out of the barn in the first place." She argued for adopting the British approach of treating a corporation as having a US residence for tax purposes if it is "managed and controlled" from the United States. Adoption of this approach would have more far-reaching consequences since it might pull into the US tax net the offshore subsidiaries that US multinationals set up today in the Cayman Islands, Mauritius and other tax havens to hold their foreign investments in the hope of deferring US taxes on foreign earnings. ◎

Project Sales: Overlooked Issues

by Stefan Unna, in London

Events over the past year — including the PG&E and Enron bankruptcies, the downturns in US and foreign securities exchanges and the continuing volatility in California and emerging markets — have placed enormous pressure on generators and power marketers to increase cash reserves and shore up their balance sheets. Many power projects are currently for sale.

Many sales transactions are structured as mergers or acquisitions of whole companies. The targets themselves or target subsidiaries are often special-purpose entities with a single power project and outstanding debt structured on a project finance basis. These types of transactions call for familiarity both with practice in the M&A market and with project finance.

The overlap between M&A and project finance can lead to unique issues that would not normally arise in a transaction that is purely one or the other. Here are a few such issues.

Corporate Governance

Projects sold together as a group are usually tied together in a holding structure in which a holding company owns several special-purpose companies, each of which owns a distinct project. This is done to prevent liabilities linked to one project from infecting the others. The officers and directors are often the same for the special-purpose company as for its intermediate parent and even the holding company.

Such a situation is ripe for a claim based on "piercing the corporate veil" that the cash flows of all the projects owned by special-purpose companies with common directors should be available to satisfy the debts of any other special-purpose company in the ownership chain — exactly the opposite of such a structure's intended purpose. The essence of such a claim is that the separate legal entity of two or more different companies should be ignored because those companies have been managed as one entity; their existence as separate entities is a sham.

Claims to pierce a corporate veil are not lightly granted. Courts are reluctant to disregard the distinct legal identity that is the essence of what a company is. Companies can protect themselves by doing the following. Make sure that each company with large debts or potential liabilities is adequately capitalized in relation to its activities. Try to stagger officers and directors to limit overlap across companies. Take care to ensure that separate meetings are held and other corporate formalities are maintained for each company. Make sure that each company has its own bank account and that there is no co-mingling of funds.

For anyone familiar with how project companies and their holding companies are often governed, this list of suggestions may set off alarm bells. Although the likelihood of a successful piercing claim may be remote, just the possibility that such a claim could be raised can have an unsettling effect on a project acquisition.

Assume a scenario in which one project company has been overcome by a large liability or potential liability that exceeds its assets, but its sister companies remain healthy. An acquirer may still be willing to acquire the holding company for the entire group even if it assigns no value to the sick project company on the assumption that the liabilities of the sick project company are entirely contained within it. A claim to pierce the corporate veil could cause the liabilities of the sick project company to infect its holding company and thus reach the cash flows from all other healthy projects owned by that holding company.

A successful claim to pierce the corporate veil transforms a liability that might be large or unquantifiable and that one normally hopes would be limited to the assets of a particular company into one that encumbers cash flow from all of its sister project entities under the same holding company.

Fraudulent Transfers

Older power purchase agreements raise concerns about the ability of the project owner to draw dividends from the project because the dividend may be considered a "fraudulent transfer" in some parts of the United States.

Most US states have some form of fraudulent transfer statute. Approximately 40 states have adopted the "Uniform Fraudulent Transfer Act," with one or more variations. The statutes in the other states vary widely.

The concern with power purchase agreements and dividends arises in a common scenario where electricity from an older power plant is sold under contract at a negotiated fixed price but the price will switch in the near future to a market price, either because the power contract will expire shortly or because it provides for such a switch. Assume further that the financial models for the project predict that the project will be insolvent if its output must be sold at current market prices. Under this scenario, the dividends that an owner may otherwise expect to be able to withdraw from the project before the pricing switch may be put in jeopardy.

The term "fraudulent transfer" is misleading to many non-lawyers because it does not require any act that fits the standard understanding of what constitutes fraud. These laws are meant to bar transfers of money or assets by an entity while that entity was insolvent. An insolvent company can usually not pay money or transfer assets unless it receives "reasonably equivalent value," or else the payment or asset transfer risks being unwound.

Although the specifics vary, almost all states that have adopted the Uniform Fraudulent Transfer Act also have statutes that provide that a transfer made or obligation incurred by a debtor is deemed fraudulent as to creditors if two things are true. First, the debtor must have made the transfer or taken on the new debt without receiving reasonably equivalent value in exchange. Second, the debtor must be engaged in a business for which its remaining assets are unreasonably small in relation to the business or else it must be a situation where a reasonable man would have worried that the debtor would be in the position — as a result of the transfer — of having to incur debts beyond its ability to pay as they became due. It does not matter that the creditor's claim arose after the transfer was made or the new debt incurred. The / continued page 12

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and outside advisers who write opinions that the shelters work. They plan to release the text of their bill in April. Similar proposals the past three years have never been put to a vote. House leaders appear to be less interested in the subject.

Meanwhile, the IRS has an amnesty program underway where corporations that come forward with information about tax shelters in which they participated will have accuracy-related penalties waived if the shelters are found not to work. The deadline for coming forward is April 23. IRS Commissioner Charles Rossotti said the IRS had received 147 voluntary disclosures under the program through March 18.

Enron is considering seeking amnesty under the program, according to news reports. Its tax returns are already being looked at by Congressional staff in anticipation of possible hearings this summer on techniques that the company used to reduce its taxes.

SECTION 29 TAX CREDITS were $1.083 an mmBtu last year. The IRS is expected to make a formal announcement in April.

The United States offers the tax credit as an inducement to look in unusual places for fuel. The credit can be claimed by anyone producing gas from coal seams, tight sands, Devonian shale, geopressured brine or biomass or producing synthetic fuel from coal. The amount of the credit is adjusted each year for inflation.

The credit will phase out automatically if oil prices return to levels reached during the Arab oil embargo in the late 1970's. The average wellhead price for domestic crude oil last year was $21.86 a barrel — well short of the level that oil prices would have had to reach for the credit to phase out. The phaseout would have occurred last year if oil prices had moved across a range of $49.15 to $61.71 a barrel. / continued page 13

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transfer can still be unwound or the new debt declared void.

Most states have statutes providing that a transfer by a debtor is fraudulent as to creditors whose claims arise *before* the transfer if the debtor makes the transfer without reasonably equivalent value and the debtor was insolvent. Insolvency is usually defined to exist if the sum of the debtor's debts is greater than all of its assets at a fair valuation, and it is presumed to exist if the debtor is generally not paying its debts as they become due.

A dividend or other distribution is by definition not in exchange for reasonably equivalent value, but it is a matter of proof whether a reasonable man would have worried that the distribution would cause the company to have to incur debts beyond its ability to pay or become insolvent. In the case where it is clear that a project's revenues will drop due to a switch to market pricing under the power contract, such proof may not be difficult to find.

Depending on the laws of the applicable jurisdiction, a creditor (or a trustee in bankruptcy) may be able to sue for the value of dividends paid by an insolvent project company for a period before its insolvency. As a practical matter, bankruptcy trustees generally do not pursue claims based on transfers more than a few years before bankruptcy because of the difficulties of proof as time elapses, although such difficulties may not be insurmountable. The statutes of limitations for raising such a fraudulent transfer claim vary from state to state, but range generally between four and six years. Remedies generally available include avoidance of the transfer, attachment of the asset transferred, and, subject to equitable principles and applicable rules of procedure, injunctive and similar relief.

For a project whose power contract fits this pattern, any dividends that an acquirer may expected to receive for the few years prior to the switch to market pricing should be discounted accordingly — entirely in some cases — when assigning a value to such a project.

Regulatory Issues

US project finance developers know how complex US regulation of the electricity sector can be, but they often overlook the need for regulatory reviews and approvals that are required when ownership in an electric generating facility changes hands.

Any direct or indirect change in ownership of any power facility brings into play the Public Utility Holding Company Act — called "PUHCA" — and other related bodies of law. As the name implies, the inquiry under PUHCA is not limited to a look at just the company or group of companies that owns a generating asset; it examines the entire ownership structure and activities, up to the ultimate parent company of the new owner. Its wide scope also reaches *any* owner, foreign or domestic, of a US generating asset as well as any relevant non-US facility in which there is a US component. Thus, for example, a US-based financial institution that acquires the stock of a company that owns a foreign power plant by way of exercise of lender remedies could find itself subject to PUHCA regulation. Moreover, PUHCA may have unexpected implications for other projects that do not primarily involve the generation of electricity. Even if electricity generation is only a peripheral activity of a target company, the limited generation and sale of power may subject the new owners of the target company to utility regulation under PUHCA.

> Changes in ownership of power plants may require prior approval by US regulators.

Briefly stated, PUHCA prohibits the ownership of nonexempt electricity and gas distribution companies as part of a wide-ranging, disparate ownership structure.

Unless one can find an exemption, as a general rule, any company that owns a generating plant will be subject to geographic, functional and structural restraints under PUHCA. Starting with geography, PUHCA requires all nonexempt affiliated companies that own power plants to be part of a single, physically interconnected and integrated system. Turning to functional constraints, PUHCA prohibits a nonexempt parent company from owning businesses that are not functionally related to the power business. The structural constraint that PUHCA imposes on nonexempt or "registered" holding companies is that no more than two intermediate companies may exist between the company that owns the power plant and the ultimate parent.

PUHCA is enforced by the US Securities and Exchange Commission.

There are two major exemptions from PUHCA that are familiar to most people involved in the power industry in the US. Power plants that are "qualifying facilities" under the Public Utility Regulatory Policies Act — called "PURPA" — are exempted from regulation under PUHCA. "Qualifying facilities" are certain power plants that use renewable fuels and cogeneration facilities that generate two useful forms of energy from a single fuel.

The other exemption covers "exempt wholesale generators," or EWGs. These are the owners of power plants that sell electricity exclusively to wholesale purchasers rather than to end consumers.

Power plants outside the US are often exempted from PUHCA either as EWGs or under a separate exemption for certain entities classified as "foreign utility companies," or FUCOs.

In any acquisition of a power plant in the US or by a US company outside the US that is not exempted from PUHCA, the Securities and Exchange Commission will require a review of the new owner's activities and ownership structure.

Even if the power plant qualifies for an exemption from PUHCA, unless it is a "qualifying facility" under PURPA, it will not escape regulation under the Federal Power Act. A facility may be exempted from regulation under PUHCA but still be deemed a "public utility" under the Federal Power Act, meaning that a change in control of the public utility will usually require the pre-approval of FERC. It may also require advance approval from a state utility commission.

If PUHCA or the Federal Power Act applies, it can have an effect on the economics and structure of the resulting deal. Obtaining required regulatory approvals or even exemptions, and structuring a transaction to qualify for those approvals or exemptions, may be time-consuming. Buyers of power assets should focus on the regulatory issues early in the transaction. They are a critical path item with a potentially long lead time. / continued page 14

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THE INDIAN GOVERNMENT proposed in its latest budget to resume taxing shareholders on dividends rather than impose a distributions tax on the company paying the dividend.

Companies paying dividends are currently assessed a 10.2% distributions tax. This tax would be scrapped, and the country would revert to taxing shareholders on the dividends they receive. Intercompany dividends within India would be exempted from taxes. The change should revive interest in investing into India through intermediate countries, like Mauritius, with favorable tax treaties.

The government also proposed a 15% "depreciation bonus" for investments in new plant and equipment after April 1. The investment would have either to create a new industrial unit or else expand the installed capacity of an existing industrial unit by at least 25%.

TRANSFERRABLE TAX CREDITS that a state awards for ridding contaminated property of hazardous substances do not have to be reported as income, the IRS said.

Missouri awards a tax credit to companies that voluntarily clean up property. The amount varies. The state may award a credit for the full cost of the cleanup effort or for as little as whatever amount it feels it must offer to cause the cleanup to occur. The recipient can then use the tax credit to reduce its state income taxes or sell the credit to someone else. An active market has developed in the tax credits, with brokers arranging sales. Credits generally sell for 80% to 90% of face amount.

The IRS said in a memo — called a "technical advice assistance" — released in March that recipients do not have to report the value of such tax credits as income. If the recipient uses the credit to reduce state income taxes, this leads / continued page 15

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Environmental Issues

Anyone buying a power plant must verify that the owner has all the permits needed to operate.

A frequent issue in recent deals is the potential loss of air permitting exemptions because the power contract for a project has either been amended or is about to expire. Another common issue is potential penalties for failing to go through appropriate permitting for upgrades to the power plant.

Many older plants benefited from "grandfather" provisions that exempted them from certain new environmental laws or revisions to existing law that were enacted after the plants were constructed. Such grandfather provisions often provide that, in order to maintain grandfather status, the power contract under which output from the plant is sold or the equipment in use at the plant must remain substantially unchanged. The US Environmental Protection Agency has been probing recently into possible violations of these rules.

Anyone acquiring an older power plant should pay particular attention to whether the plant went through any upgrades that increased air emissions. He should also be on the lookout for power contract amendments or power contracts that are about to expire. These are things that could trigger changes in the facility's status under its environmental permits and could lead to permitting violations. A buyer who plans changes to the equipment or the power contract after the acquisition should give careful consideration to the effect these actions will have on the plant's environmental permits. ◎

Training Session: Material Adverse Change Clauses

Chadbourne runs internal training sessions for lawyers in the project finance group and interested clients. The following is an edited transcript of a session on material adverse change clauses in corporate transactions, principally mergers and acquisition transactions, that took place by videoconference in mid-March among the Chadbourne offices in New York, Washington and London. The speakers are Peter Ingerman and Charles Hord in the New York office. Copies of the handouts used for the presentation can be obtained by sending an e-mail to pingerman@chadbourne.com or chord@chadbourne.com.

A material adverse change — or "MAC" — clause is a representation and warranty or a closing condition to a transaction that protects a buyer against adverse changes in the condition of the target. The clause usually applies between some predetermined date, often prior to the date the agreement is executed, through closing of the transaction, which may occur some time after the agreement is executed. We will use the terms "material adverse change" and "material adverse effect" interchangeably in this presentation since the definitions of these terms typically cover both changes and effects.

Two recent developments have focused attention on MAC clauses.

The first is an important decision that the Delaware Chancery Court issued last June. The case involved a merger agreement in which Tyson Foods had proposed to acquire IBP. Tyson Foods canceled the contract, relying in part on a MAC clause.

The second development is the terrorist attacks on September 11, which gave everyone a new appreciation for what sorts of adverse events might overtake a transaction between signing and closing.

Standard Terms

Before we get into more detail on the recent developments, let's take a look at what a MAC clause looks like. If it is incorporated as a closing condition, it would read something like the following:

> Since [a specific date], there shall not have occurred (or reasonably be expected to occur) any events, changes or developments which, individually or in the aggregate, have had or would reasonably be expected to have a Material Adverse Effect with respect to the Company.

MAC language will also typically be found in the representations and warranties section of an agreement. The seller will represent and warrant that since some date — often this date is tied to the most recently audited financial statement of the target — the target has not suffered a MAC. To extend the protection of such a representation through closing, one of the conditions to closing will be that all the representations and warranties are true and correct in all material respects as of the closing date.

A very basic definition of "Material Adverse Effect," taken from a transaction involving the acquisition of a company, looks something like this:

> (a) When used in connection with the Company or its subsidiaries, any change or effect (or any development that, insofar as can reasonably be foreseen, is likely to result in any change or effect) that, individually or in the aggregate with any such other changes or effects, is materially adverse to the condition (financial or otherwise), business, assets, liabilities, results of operations or prospects of the Company and its subsidiaries, taken as a whole; and (b) when used in connection with any Shareholder or Buyer, any change or effect (or any development that insofar as can reasonably be foreseen, is likely to result in any change or effect) that, individually or in the aggregate with any such other changes or effects, will prevent any Shareholder or Buyer, as the case may be, from materially consummating the Transaction or performing his or its obligations under this Agreement.

One interesting thing to note about the definition is that "materiality" is not defined. It almost never is and thus there is no general quantitative or qualitative standard as to what is "material."

Another interesting point is that this definition purports to establish an objective standard. Occasionally a subjective standard will be used instead — that is, whether something is reasonable "in the judgment of" the buyer or seller. This is typical where both the buyer and seller have the right to invoke the clause to get out of their deal.

Uses

MAC clauses are not just at home in mergers and acquisitions. You often see them in underwriting agreements, giving the underwriter the ability to walk away from a deal prior to an IPO. In such an agreement, the clause will often relate to a general disruption in financial markets.

Financing "outs" also appear in commitment letters, loan documents and lease documents. There / continued page 16

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to a smaller deduction on its federal return for state income taxes paid. If, instead, the credit is sold to someone else, then the sales proceeds must be reported as ordinary income at time of sale.

The IRS said the sales proceeds are not capital gain — which would be taxed at lower rates than ordinary income — because the credits are not considered "property." Only sales of "property" produce capital gain. The IRS memo is ITA 200211042.

PRE-FILING AGREEMENTS catch on slowly.

The IRS launched a new program in January 2001 under which a large or medium-sized company can essentially trigger a tax audit of a transaction before filing its tax return. This is called entering into a "pre-filing agreement." Larry Langdon, head of the large and mid-size business division of the IRS, said the agency had received 29 applications under the program by early March, accepted 19, and worked out agreements in six of the cases.

RENEWABLE ENERGY projects get help.

New Mexico adopted a tax credit of 1¢ a kilowatt hour for generating electricity from wind or sunlight. The governor signed the measure in March. To qualify, a company must have at least 20 megawatts of windpower or solar generating capacity in the state. The credit can be claimed on up to 400,000 megawatt hours of electricity in total over a period not to exceed 10 years.

Meanwhile, a new law in South Dakota gives a break to wind and other renewable energy projects. The state collects a 2% contractors excise tax on new construction. The new law reduces the tax to 1% — and allows deferred payment over four years — for renewable energy projects that begin generating at least 10 megawatts of electricity after June 30 this year. / continued page 17

MAC Clauses

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again, the clauses will have slight differences in flavor, but concepts will be similar to the clauses found in M&A agreements. In project finance documents like construction contracts, MAC clauses will often be used to protect a developer from having to build its project if an act of God makes the project uneconomic or unreasonable in some respect.

Broad Protection?

Court decisions teach us that MAC clauses are not substitutes for specific closing conditions that address known risks and contingencies. Courts are hesitant to find that a material adverse effect occurred. Reported decisions are often surprising because there is a very low level of predictability of outcomes.

One court decision — the *Borders v. KRLB Inc.* case — involved an acquisition agreement for a radio station. Between the signing of the agreement and the scheduled closing date, the radio station's ratings fell by about half. The MAC clause in the acquisition agreement was fairly typical. It said, in effect, that 1) since a specified date the target must not have suffered a MAC, 2) the business of the target must have been conducted along its ordinary course, and 3), as is typical in these provisions, the target must not have done anything specified on a long list of items since the given date. The court looked at the provision and concluded that the language was only intended to protect the buyer against volitional acts taken by management of the target. In the court's view, the clause did not provide protection from elements that were beyond the control of management.

I think that most readers, in looking at the MAC clause in the KRLB case, would have separated out the first point, which said that the company had not suffered a MAC, from the second and third points of the provision, which said that the business of the target had been conducted in its ordinary course and certain actions had not been taken. Only the last two provisions address volitional acts. The MAC clause appears to protect the buyer against material adverse change whether or not it resulted from intentional acts by management. That is not how the court read it. The draftsman might have done better to have two separate clauses.

In another case — *Northern Heel v. Compo Industries* — a buyer was seeking to exit an acquisition on the basis that the production of the target had declined dramatically since the parties signed their acquisition agreement. The agreement included a typical, broad MAC clause. It did not include a representation or warranty about the target's production. The court decided that the MAC clause was not broad enough to encompass the decline in production. If the buyer was so concerned about production, chastised the court, it should have asked for a special representation to cover a potential decrease. Again, this seems contrary to how most of us interpret MAC clauses — that they are not tied to specific events like most representations and warranties are.

Courts are reluctant to "interfere" or permit a contract to be broken on the basis of a MAC or for any other reason.

The lesson we must take from these cases is that the traditional interpretation of MAC clauses is unpredictable. It is also safe to say that courts are reluctant to "interfere" or permit a contract to be "broken" on the basis of a MAC or for any other reason. Therefore, one cannot just assume that a MAC provision is a substitute for carefully drafted, specifically tailored representations and warranties or closing conditions addressing specific risks and contingencies of the acquired business that have been identified by the buyer.

IBP v. Tyson Foods

This lesson brings us to the first development that has brought MAC clauses back into focus: the recent decision by the Delaware Chancery Court in *IBP v. Tyson Foods*.

The IBP/Tyson merger agreement resulted from a competitive auction to acquire IBP. The target's principal business was to act as a middleman for fresh beef and pork. It bought live animals, slaughtered them, and sold the butchered meat to supermarkets and other companies that would do further processing.

During the auction process, Tyson was given a great deal of information that suggested IBP was entering a "trough" in the beef business. The beef business is cyclical and there are often troughs and peaks that last several years. In addition, during the due diligence process, Tyson was informed that an IBP subsidiary known as "DFG" had been victimized by accounting fraud of $30 million or more. Tyson Foods had significant information that IBP was projected to fall short of its fiscal year 2000 earning projection.

The evidence indicated that by the end of the auction process, Tyson had very little confidence in the ability of IBP's management to forecast future results and, in particular, thought that DFG was a disaster that should have been written off. Nevertheless, Tyson increased its bid for IBP by about $4 per share. In addition, Tyson signed a merger agreement that essentially provided IBP an unlimited ability to recognize further losses in connection with the DFG accounting problem. This stemmed from a provision that said there were no liabilities of the target, except as disclosed on Schedule 5.11. Schedule 5.11 said in effect that there were no undisclosed liabilities — except for the accounting problem at DFG and any further losses associated with the accounting problems at DFG.

After the merger agreement was signed, both Tyson and IBP saw declines in their operating results, due in large part to adverse weather during the winter of 2000 to 2001. As time went on, Tyson became more and more disenchanted with IBP and finally, by the end of March 2001, sent a letter to IBP saying that it was breaking off the merger. IBP sued Tyson, seeking specific performance of the agreement.

Tyson Foods asserted a number of affirmative defenses to IBP's claim, one of which was that IBP had suffered a material adverse effect because the target's earnings for the first quarter of 2001 were 36% lower than its earnings for the first quarter of 2000. The merger agreement contained a very broad MAC clause; there were no carve-outs. The court held that no material adverse change occurred. The court said:

> "[A] buyer ought to have to make a strong showing to invoke a material adverse effect exception to its obligation to close . . . . [E]ven where a material adverse effect condition is as broadly written as the one in the merger agreement, that provision is best

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FOUR EUROPEAN TAX HAVENS attracted a disproportionate share of US investment in Europe during the period 1996 to 2000, according to a study by Martin Sullivan in *Tax Notes* magazine.

The four countries are Holland, Luxembourg, Ireland and Switzerland. US companies invested $330 billion through the four countries — or about 38% of their total investments during the period in Europe — even though the four countries together account for only 9% of the European economy. The average effective tax rate in Europe during the period was 30%. The effective tax rates in the four countries were as follows: Luxembourg 2.7%, Switzerland 4.5%, Ireland 7.6% and Holland 14.1%. Sullivan speculates — no doubt correctly — that US companies were using the four countries as places to base holding companies and then shifting income from higher tax jurisdictions to the holding companies.

ALABAMA may impose a special tax on power plants that dispose of their output under tolling agreements.

Power plants that furnish "utility services" are subject to property taxes in Alabama at a 6.5% rate on 30% of fair market value. However, an Alabama circuit court ruled recently that a power plant providing "conversion services" under a tolling agreement is subject to property taxes only on 20% of its fair market value because it is not furnishing "utility services." The Alabama Department of Revenue is appealing the decision.

A bill has been introduced in the Alabama legislature to make up the lost revenue by imposing a special annual tax of $1,000 per megawatt of nameplate capacity on any power plant that does not pay property taxes on 30% of its fair market value — in other words, on power plants with tolling agreements. An alternative bill

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> read as a backstop protecting the acquirer from the occurrence of unknown events that substantially threaten the overall earnings potential of the target in a durationally-significant manner. A short-term hiccup in earnings should not suffice; rather the material adverse effect should be material when viewed from the longer-term perspective of a reasonable acquirer."

A couple key points arise. One obvious: the court put the burden on the buyer to show that a material adverse effect occurred. In addition, the court said that the protection against the unknown goes to substantial events — events that threaten the overall earnings potential of the target. Since the target's business was cyclical, the court pointed out that perhaps there was no reason to think a short-term drop in earnings was evidence of any long-term problem. Finally, the court suggested that it was not 100% certain of its decision on the MAC issue, which paves the way for an appeal by Tyson Foods.

As a side note, an interesting fact that played into the court's decision on the MAC issue was that Tyson Foods' publicly-expressed reasons for terminating the merger did not include an assertion that IBP had suffered a material adverse change. The MAC argument was not asserted until later — after the litigation began. This fact helped lead the court to believe that it was really just a case of buyer's regret.

September 11

The other recent event that brought MAC clauses into focus is the terrorist attack on September 11, 2001. Recently, someone performed an informal survey of pre- and post-September 11 acquisition agreements in public deals. The conclusion was that there really has not been much obvious change in public deals, at least not in terms of contract language. One exception is a power industry merger agreement between Reliant and Orion Power that was signed on September 26, 2001. Their agreement included a very complex MAC clause with a carve-out for "any change to financial or securities markets or the economy in general" unless caused by material worsening of current conditions caused by acts of terrorism or war. In this agreement, an economic downturn would not be a MAC unless it stemmed from another terrorist incident.

Enron

Looking forward a bit, it will be interesting to see how the courts deal with the case stemming from the failed Enron-Dynegy merger. Dynegy repudiated its $9 billion merger agreement with Enron right after Enron's bond rating was slashed to junk status by the three major rating agencies. Unlike Tyson Foods, Dynegy claimed publicly that it was relying on the MAC to terminate their agreement. Enron promptly filed a breach of contract suit against Dynegy. ◎

Output Contracts May Be "Leases" Of The Power Plant

by Leslie Knowlton and Henry Phillips, with Deloitte & Touche L.L.P. in Houston and Wilton, Connecticut

Power contracts and tolling agreements may be characterized as "leases" of the power plant with potentially adverse accounting treatment for the parties involved.

The emerging issues task force of the Financial Accounting Standards Board, or "FASB," has a working group focusing on when this should occur. The group has discussed a framework whereby a person taking the output from a power project under contract may be treated as if he leased the power plant in cases where the person has effective control over the use of the power plant or the substantive risks and rewards of ownership.

This same framework may lead to an unhappy conclusion in sale-leasebacks of power plants that the lessee retains too much control or too many ownership attributes in the power plant to take the power plant — and related debt — off its balance sheet.

Background

The emerging issues task force called in 1998 for energy and energy-related contracts — including capacity contracts, requirements contracts and transportation contracts — that meet outlined trading criteria to be carried at fair value, meaning that they must be "marked to market" at the end of each quarter. Marking to market means that the parties to the contract must show it on their books at the current market value of the contract. Each quarter, they figure out what the contract is worth and record a gain or loss since the past quarter. This can lead to volatility in earnings. The emerging issues task force consensus that requires this treatment is EITF Issue No. 98-10.

FASB issued a separate directive in 1998 — called FAS 133 — that generally requires mark-to-market accounting for any energy contracts that are considered "derivatives" beginning in 2001.

However, EITF Issue No. 98-10 and FAS 133 generally do not apply to contracts that accountants consider a lease of the underlying power plant. Lease transactions must be accounted for in accordance with FAS 13 using historical cost accrual accounting rather than fair value mark-to-market accounting, meaning that revenues and expenses appear on a company's books only as they legally accrue.

A lease, as defined in FAS 13, is "an agreement conveying the *right to use* property, plant, or equipment (land and/or depreciable assets) usually *for a stated period of time* [emphasis added]." FAS 13 also states, in part:

> [A]greements that do transfer the right to use property, plant, or equipment meet the definition of a lease for purposes of this Statement even though substantial services by the contractor (lessor) may be called for in connection with the operation or maintenance of such assets.

The difficulty of determining when a contract meets the definition of a lease and the lack of interpretative guidance have led to diversity in practice. As a result, the emerging issues task force formed a working group to focus on when arrangements should be treated as leases, even though they may be labeled something else.

Working Group Discussions

The working group is debating three different views that have been presented to the emerging issues task force for comment. The factors mentioned as possible indications of a lease in the discussion below are based on one or more of these views. However, because of the substantive differences in the evaluation of contract provisions under each proposal, these items may be given more or less significance by the proponents of the different views.

Although the working group has not yet presented its final recommendation, the members / continued page 20

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in the legislature would exempt from this tax those power plants with capacity of less than 200 megawatts.

IDAHO has decided to let taxing districts use construction of a new merchant power plant nearby as an excuse to increase local budgets.

This could lead to an increase in property tax rates across the board in the taxing district, since the district will need to raise the additional money it is allowed to spend. State officials say any tax increases would probably be "immaterial."

Property taxes in Idaho are collected mainly by counties. Property is assessed at full value, and property tax rates vary between 0.5% and 2.5%. Power plants, railroads and other utility property — called "operating property" — are assessed by the state, but taxes are collected by the taxing districts. Local governments are limited to a 3% increase a year in their budgets.

A town in northern Idaho expected to be "rolling in money" after a merchant power plant is built near the town, according to a state official. However, the town was disappointed to learn that the new power plant would have no effect on its budget since property tax collections on "operating property" are not included in the budget for purposes of calculating the 3% annual increase that is allowed. After a plea from the town, the state legislature made a special exception for merchant power plants. The governor signed the bill on March 27. Property tax revenues from merchant plants will be added in the future to budgets for purposes of calculating the 3% increase. The local government must then look at property tax collections from all assessed property to see whether rates need to change to match tax collections to the amount of the money it is allowed to spend in the coming year. Rates may not need to increase if assessed property values have gone up / continued page 21

Output Contracts

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have tentatively agreed that the evaluation of whether an arrangement conveys the right to use the underlying land or depreciable assets — one of the factors that FAS 13 said makes a contract a lease — should be based on the substance of the arrangement regardless of how the contract is labeled.

The focus of the working group's tentative conclusions centers around whether the arrangement conveys the *right to control the use* or the *risks and rewards* of ownership of the underlying asset to the purchaser. The working group members also agreed that the subject of the lease must be specified in the contract at some point, although the identification of the property in the arrangement need not be explicit.

A tolling agreement will be viewed as a lease of the power plant when control over the plant is effectively transferred to the toller.

Tolling Agreements

Tolling agreements provide the toller the right, but not the obligation, to call on the owner of the power plant to convert his natural gas or another fuel into electricity at a predefined heat conversion rate. In exchange, the toller pays a fee just as a farmer would pay a mill to grind his wheat into flour.

With deregulation, power companies are becoming more exposed to the risks that typically accompany a free market, but have historically shown a preference for predictable margins. A tolling arrangement reduces the power company's exposure to commodity price risk. Meanwhile, the toller — which may be a trading company or a gas supplier — may use the tolling agreement as a means to capitalize on arbitrage opportunities between the fuel and electricity prices inherent in the market.

When does such an agreement go from being just an agreement to receive fuel and sell electricity for a fixed price to becoming a lease?

The toller may be viewed as having the right to control the use of the facility when certain activities and decisions related to running the power plant are transferred to the toller in the tolling agreement. Some of the activities and decisions considered by the working group include:

- the right to occupy and control access to the power plant,
- dispatch rights, meaning the right to decide whether to use the power plant to generate power or to buy the power in the market,
- the right to make significant operating decisions, and
- the right to direct the maintenance and other operating practices.

A presumption may exist that the toller has the ability to control the use of or access to the power plant when the toller has effectively contracted for the entire output. A right of first refusal for the toller to take any excess power generated by the power plant or terms precluding the sale of power to anyone other than the toller could lead to a similar conclusion.

The fee the toller pays to have his fuel converted into electricity usually consists of both a capacity payment and an energy payment. These payments look a lot like what the buyer of electricity pays under a standard power purchase agreement, except that there is no reimbursement through the energy payment for the cost of fuel. That's because the toller provides the fuel.

The capacity payment may be viewed as exposing the toller to facility-based risks and rewards, which could cause the contract to be considered a lease. One of the views expressed by the working group presumes that these fixed payments demonstrate that the seller has not retained the significant costs associated with operating the power plant. This is especially the case where the purchaser is required to continue making capacity payments to the power plant owner even when the power delivered is less than the contracted amount.

Lease accounting may also apply when there are no market-based liquidated damages provided for in the tolling arrangement. A typical market-based liquidated damage clause would require the power plant owner to buy replacement power in the market during periods when the power plant is out of service or compensate the toller for the cost of buying such replacement power. Thus, the power plant owner could provide the required power from any source. However, most tolling contracts do not include market-based liquidated damages. Instead, tolling arrangements usually require a reduction in the capacity payment made by the purchaser in the event of the seller's nonperformance. Some members of the working group believe that the lack of market-based liquidated damages signifies that the contract is specific to the power plant and exposes the toller to facility-based risks and rewards.

Even when market-based liquidated damages are provided for in the tolling agreement, other factors may be a problem. For example, the seller must be able to meet its obligations under the contract in all reasonably possible scenarios. An arrangement with a highly-leveraged special-purpose entity could indicate that it is not reasonable to expect that the entity would have the financial resources to meet its liquidated damage penalties. In addition, further analysis would be needed to determine whether a market-based liquidated damage clause that includes a cap on the damage amount effectively removes the plant specificity aspect of the agreement.

Power Purchase Agreements

Power purchase agreements are similar to forward contracts and call options. They obligate the holder to purchase power at a predetermined price. Like tolling agreements, companies that do not own physical assets may enter into a power purchase agreement to take advantage of an arbitrage opportunity. Generators view these agreements as risk management products to mitigate exposure to commodity price risk.

Many of the considerations involved in evaluating a tolling arrangement also apply to power purchase agreements. However, power purchase agreements often provide for financial settlement when the purchaser does not want to take physical delivery of the power. In this regard, it could be argued that the agreement does not transfer the risks and rewards of ownership of the power plant to the purchaser.

The purchaser will often enter into other energy contracts to manage the commodity price risk of the agreement. If the power purchase */ continued page 22*

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enough to bring in the additional revenue at existing rates. Any rate increase would apply to all local property owners.

INTEREST DEDUCTIONS were denied.

The US Tax Court said in a decision on March 27 that a US subsidiary could not deduct interest it owed its French parent as the interest accrued, but rather had to wait until it actually made payments. The court cited an IRS regulation that requires a company to wait until actual payment of interest, before deducting it, when the interest is paid to a related foreign person who will not be subject to US taxes on the interest. The court said the regulation does not violate the US tax treaty with France. This case is *Square D Co. v. Commissioner*.

FOREIGN TAX CREDITS were disallowed.

Sunoco lost an attempt to claim more foreign tax credits for the period 1982 through 1986. The amount of foreign tax credits that a US company can claim is a function of the amount of income it has from foreign sources. The more such income, the more foreign tax credits it is allowed.

US tax law treats borrowed money as fungible. Therefore, it requires that US companies treat a portion of their interest expense — even on purely domestic borrowing — as a cost partly of their foreign operations. Interest expense is allocated to US and foreign operations in the same ratio as assets are deployed at home and abroad. The more interest that is allocated abroad, the less income the US company will have from foreign sources and the fewer foreign tax credits it is allowed.

Sunoco argued that it should have to allocate only its *net* interest expense between US and foreign sources. The company earns millions of dollars each year in interest income that it wanted to use as an offset. The US Tax Court */ continued page 23*

Output Contracts

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agreement is accounted for as a lease of the power plant and the other energy contracts managing the exposure are marked to market, then significant fluctuations in the purchaser's earnings can result even though the economic position has not changed. For example, assume a company enters into a power purchase agreement and subsequently enters into forward sales agreements to manage the exposure of its purchases. The forward sales perfectly offset the purchases at inception. Thus, the company has no economic exposure to changing market prices. In the following year, the market price for power declines. If each of the contracts were marked to market, the losses from the power purchase agreement would be offset by the gains on the forward sales agreements in the company's financial statements for the year of the market decline. However, if the power purchase agreement were treated as a lease, then only the mark-to-market gains from the forward sales agreements would be reflected in the company's financial statements with no offset for the other side of the transaction.

Sale-Leasebacks of Power Plants

A sale-leaseback is a common financing method for power plants. If certain conditions are met, then the seller-lessee records the sale and is permitted to remove the power plant and related debt from its balance sheet. Sale-leaseback accounting is only permissible if, among other things, the transaction is a normal leaseback and excludes continuing involvement provisions or conditions.

Under FAS 98,

> "[a] normal leaseback . . . involves the active use of the property by the seller-lessee . . . and excludes other continuing involvement provisions or conditions . . . . The phrase active use of the property by the seller-lessee refers to the use of the property during the lease term in the seller-lessee's trade or business, provided that subleasing of the leased back property is minor."

In cases where the output of the power plant that is the subject of a sale-leaseback arrangement is sold under a power contract that itself is considered a lease, it could be argued that the seller-lessee is not actively using the property because the power plant has been "subleased." Alternatively, the lessee may be viewed as having too great a continuing involvement in the power plant to be able to take the plant off its books. Failure to meet the criteria for sale-leaseback accounting would prohibit off-balance sheet treatment by the seller-lessee and require the seller-lessee to retain the power plant on its balance sheet and recognize a liability for any cash received in connection with the transaction.

Impact of Lease Accounting Treatment

From the perspective of the purchaser:

- If the contract were considered a "capital lease," then the purchaser would record the lease on its books as a long-term asset and an obligation at an amount equal to the present value of the rent that the lease requires him to pay in the future. He would be allowed to depreciate the asset and record the embedded interest expense in the rent payments.
- If the contract were considered an "operating lease," then the rent required by the lease would simply be expensed, straight-line, over the term of the lease.

From the perspective of the power plant owner:

- If the contract calls for the power plant owner to transfer title to the purchaser at any time during the lease term, then the present value of the lease payments would be reclassified from fixed assets to a long-term lease receivable. Any remaining balance in fixed assets for the facility would be reclassified to unearned income and amortized into income over the life of the lease.
- Otherwise, for existing power plants, the owner would account for the lease as an "operating lease" as if he had leased his power plant to the person who has contracted for the output. The power plant would remain on the owner's balance sheet and would continue to be depreciated over its remaining useful life. The owner would recognize revenue, straight-line, over the lease term.

In either case, accounting for leases requires historical cost, rather than fair value, treatment. In other words, rent payments are expensed or taken into account as they accrue. The lease itself is not marked to market.

If the relationship between the parties is not considered a lease, then the types of contracts discussed in this article are usually subject to mark-to-market accounting. Even if the contract does not meet the trading criteria described in EITF Issue No. 98-10, it will usually be considered a "derivative" under FAS 133. Proponents of mark-to-market accounting argue that the transparency of the risk exposures within a company's portfolio is limited by the application of different accounting methods to different positions.

Conclusion

To the extent the emerging issues task force decides to define "lease" broadly, the impact on the financial statements of energy traders and electricity generators could be significant. The ramifications also extend beyond the energy industry and the types of arrangements discussed above. Until the final guidance is issued, the determination of whether an arrangement should be viewed as a lease remains a subjective one. ◎

New UK Electricity Regulatory Regime: Lessons From Year One

by Adrian Congdon, in London

One year after its introduction is a good time to review how the new regime regulating the English and Welsh electricity industry has settled down and how purchasers of utilities there have sought to protect themselves from the vagaries of the market.

Has the new regime provided a useful model for regulators elsewhere? How effective have tolling agreements been at providing bankable revenue streams? This article looks at the new electricity trading arrangements — or "NETA" — from these two perspectives.

Background

NETA became effective in England and Wales in March 2001, sweeping aside the pool system that had been in place since deregulation in 1990.

Generators used to bid to supply electricity to the pool at a certain price for each half hour, and the National Grid Company dispatched the generators on the comparative merits of those bids, then sold the electricity on to suppliers. The UK government took the view that / *continued page 24*

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said no in a decision in March. *Gross* interest expense must be allocated. IRS regulations have made this point clear since 1986. The case involved earlier years.

STATES cannot make it hard for companies to file consolidated tax returns, the Missouri Supreme Court reaffirmed in late February.

Missouri used to require that a group of affiliated companies must earn at least 50% of its income in Missouri before the group will be allowed to file a consolidated — or single — income tax return for the entire group. The advantage of a consolidated return is that it lets losses in one company be used to shelter income in an affiliated company. The Missouri Supreme Court struck down the requirement in 1998, in a case involving General Motors, on grounds that it violates a prohibition in the US Constitution against states adopting rules that impede interstate commerce.

After the General Motors decision, the clothing company Spiegel applied for a tax refund of back taxes that it paid on grounds that it should have been allowed to file a consolidated tax return for itself and such affiliates as Eddie Bauer. The state tax department refused the refund on the procedural ground that Spiegel should have refused to pay the taxes in the first place and challenged the tax statute as General Motors had done.

The state Supreme Court ordered the tax department to make the refunds, saying that the state had a duty to provide taxpayers with a "fair and meaningful" means of redress.

MINOR MEMOS: The IRS branch that processes private letter ruling requests on electric interties said only one ruling request had been received through the end of March . . . . US Treasury Secretary Paul O'Neill gave taxpayers several good / *continued page 25*

UK Power Market

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the pool was weighted in favor of generators and served to inflate prices generally. NETA was devised with the aim of encouraging competition, promoting market liquidity, and reducing system balancing costs.

The UK regulator reported in February 2002 that, since NETA, electricity prices have been reduced by 20% to 25% and daily balancing costs by 50%, while liquidity is up by multiples of two and three respectively in the case of trades and contracts.

Balancing and Settlement Code

Under NETA, there is no bidding into a central pool, no central dispatch and no centrally-determined price. Instead, generators self-dispatch on the basis of bilateral contracts they have freely entered into with trading parties. These bilateral contracts include contracts for the physical sale of electricity or non-physical trades on power exchanges. However, the contracting parties — be they generators, suppliers or traders — must be party to the "Balancing and Settlement Code," or "BSC," and it is in this respect that the National Grid Company retains its role as ringmaster. The grid company is responsible via the BSC for balancing the system in terms of frequency and voltage as well as in terms of generation and demand.

The BSC applies equally to consumers, traders and generators of electricity.

The grid company carries out its grid balancing functions through a subsidiary called Elexon.

Each wholesale generator, retail supplier and trader must notify Elexon how much electricity it has contracted to generate or take for each half hour period of the day. These notifications give Elexon the data it needs to manage the grid.

A generator may also indicate how far it is willing to increase or decrease the volume specified in the notice and at what price. Each offer to increase generation at a price must be matched by a bid to reduce by the same volume of electricity at another price: together these are each referred to as a "bid-offer pair."

This enables Elexon to accept offers and bids in order to balance the system (in terms of supply and demand and frequency and voltage). To discourage gaming, failure to perform in accordance with a bid-offer acceptance results in liability for a non-delivery charge, which is the cost to the grid of covering the excess or shortfall.

Before NETA was formally implemented, many people wondered whether any generators would take the risk of trading primarily by way of this balancing mechanism of bid-offer pairs rather than through bilateral contracts. This has not occurred, at least not yet.

Imbalance Charges

Any generator or other supplier and customer who fails to match metered output with contracted output must pay "imbalance charges." Because they can be very onerous financially, imbalance charges are probably the most notable feature of NETA. The imbalance charges are not calculated against the amount of power the generator notifies the grid in advance that it will produce, but rather they are payable as against deviations from two other notices, called ECVNs and MVRNs. ECVN stands for "energy contract volume notification," MVRN for "meter volume reallocation notification."

> Under the new regime, there is no bidding into a central pool, no central dispatch and no centrally-determined price.

ECVNs and MRVNs work as follows. Any trading of electricity by a person subject to the BSC regime must be notified centrally. ECVNs or MVRNs are the two alternative ways of trading electricity under the BSC. Each BSC party has an energy account. ECVNs or MVRNs identify the volume of electricity that is to be debited from or credited to the relevant energy account.

Under an ECVN, the two parties to a transaction agree on the specific volume of electricity that is to be accounted for.

For example, if a generator is selling 100 megawatts to a retail supplier, then that 100 megawatts is debited from the generator's energy account and credited to the energy account of the supplier.

MVRNs are used when a generator wishes to transfer its exposure to potential imbalance charges and the risk of fluctuation in electricity prices for a fixed volume or percentage of its metered output to a person responsible for another generating unit. This transfer of liability is in itself a trade. The MVRN is the method generally used in a tolling agreement, particularly one involving 100% of output. The energy account of the toller is debited with the reallocated volume. The toller is treated in all respects as if the output was its own. The result is that it takes all of the regulatory upside and downside in respect of that output (for example, for transmission losses and imbalance charges). The generator — having shed liability — ends up simply with a fixed revenue stream.

Elexon will notify BSC parties if any imbalance charges are payable. If a generator generates more than his notice said he would, Elexon will need to sell that excess by way of accepting bids from other generators or offers from retail suppliers. If a generator generates less than he said he would, Elexon will need to find another generator to generate more or a retail supplier to accept less. It does both of these things by looking at the bid-offer pairs.

Although the term "charge" is used, an imbalance charge may actually be a benefit to a generator or other BSC party. The amount of any imbalance charge is equal to the amount the grid company is able to collect for the excess or must pay to cover the shortage. There is no cap on these prices or, consequently, on imbalance charges; this may be a matter of concern to lenders to a limited recourse project. A generator who generates more than it said it would is paid as an imbalance "charge" what the grid company is able to collect for the excess power. If it generates too little, it must pay an imbalance charge to the grid. Equally, buyers will be charged for uncontracted supply and will be paid for contracted volumes that are less than those consumed. Parties should be alert to the fact that the price for uncontracted generation might at times be negative, meaning that payment is required from the generator: If generators are not inclined to reduce output, then they may well end up being charged for producing excess energy.

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quotes to use during tax audits. O'Neill told a Senate appropriations subcommittee in March that "[t]axpayers should be given the benefit of the doubt where there's a crease in the law put there by Congress." O'Neill blamed the problem the government has with tax shelters on complicated tax laws. "We wouldn't have either evasion or avoidance if we did not have 10,000 pages of tax code that it takes a machine to understand" . . . . A West Virginia court said in late February that rents paid to lease data processing equipment were exempted from sales tax on grounds that what looked on its face like a lease of equipment was really an agreement to provide services. Most states collect sales taxes on rents paid to lease equipment, but not on payments for services. The lease was between two subsidiaries of a bank. The case is *CB&T Operations Company v. Commissioner*.

— contributed by Keith Martin, Heléna Klumpp and Samuel R. Kwon in Washington.

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Issues with NETA

NETA is an apparent success in that liquidity is up while prices and balancing costs are down (although prices might have gone down in any event); but has the new regime thrown up any major problems? The short answer is yes.

Accidental Imbalance Charges. There have been concerns about imbalance charges that have been accidentally incurred. For example, London Electricity is reported to have lost £7.5 million because of faulty reporting on ECVNs and MVRNs. Scottish Power lost £10 million. Having reviewed this, the BSC panel recommended in late 2001 that BSC parties should be able to recover losses resulting from failure of contract reporting systems. This is a problem that has not been wholly resolved and may in any event re-emerge in different contexts.

Electricity "Spilled" During Commissioning. Commissioning of a power plant necessitates generation of electricity. The volumes and timing are unpredictable and can lead to imbalance charges. The upside is that the generator will be entitled to be paid for the volume spilled. However, the generator will not be paid anything by the grid if aggregate generation exceeds aggregate consumption. In such circumstances, recipients will have to be paid to accept more electricity or other generators will need to be paid to shut down; and, in either case, that cost will ultimately be passed on to the generator who is spilling. Generators have looked for ways to mitigate this risk, and there have been proposals for derivatives to cover it.

Renewable Energy Sector. The UK government has made much of increasing the renewable energy sector's share of the UK electricity market. This applies in particular to wind farms. Wind farms do not lend themselves to the NETA regime. In order to reduce the potential for imbalance charges, the possibility has been raised of wind farms clubbing together and selling their product in aggregate through an agent. While this should mitigate the problem, it will surely not solve it given the relatively small size of the UK.

Combined Heat and Power. The same type of problem affects cogeneration facilities as affects wind farms, given that cogeneration plants are designed to be variable while NETA puts a premium on guaranteed output. In the first part of 2002, Powergen dropped the anticipated sale of its cogeneration portfolio, purportedly citing NETA as the source of its difficulty. Perhaps, given that they are less likely to behave uniformly, clubbing together to sell power in aggregate would be more appropriate for cogeneration plants than for wind farms.

Base Load to Ramping. Most of the UK's stock of power plants has historically been designed for base load use rather than ramping up and down. The balancing mechanism of NETA with its bid-offer pairs gives considerable financial incentive to plants being flexible and able to ramp up and down. NETA would therefore appear to favor peaker plants and to be least desirable to nuclear plants.

Tolling Agreements

There have been concerns among developers about the "bankability" of independent power projects in the UK under NETA. These concerns may be exaggerated. Plants previously financed on a merchant basis are still running. In any event, tolling agreements appear to offer lenders protection and have been used in limited recourse financings in the last year. Some points on how tolling agreements have needed to be adjusted in a number of ways to cater for NETA are worth highlighting.

The toller pays the generator a fixed capacity charge in return for an availability commitment. The toller looks to the generator to be responsible for imbalance charges arising from forced outages. The principal mitigation available to the generator is that its liability for imbalance charges should last no longer than 3 1/2 hours. The reason is that that is the minimum prior notice period for any ECVNs and MVRNs. Thus, as soon an outage occurs, the generator will notify that output from 3 1/2 hours onwards will be nil. However, given that the amount of imbalance charges changes every half hour and is potentially uncapped, the generator might still find this liability unmanageable and require a megawatt-hour financial cap on its liability.

Ramping up and down can cause problems. A toller who is entitled to 100% of capacity will want to direct the generator what output should be from time to time. That way, the toller can fulfill its obligations under its bilateral contracts as well as maximize revenues by playing the balancing mechanism. The real money to be made is in being able to generate more — or reduce output — on short notice; premium prices will be paid for this. This means the toller will be directing the generator to ramp the plant up and down. Meanwhile, the generator will be reluctant to push the plant to perform to its limits with the consequential extra maintenance risk and will therefore be keen to exercise its right to reject any direction that requires the plant to be operated outside of its dynamic parameters. The interests of the parties diverge. Perhaps the best way to resolve this is for the toller to share some of the benefit from playing the balancing mechanism and give the generator a financial incentive to enhance the flexibility of the plant.

Problems arise with notices. An ECVN or MVRN is sent to Elexon's agent who acknowledges receipt and may then either accept or reject it. The acknowledgement does not of itself constitute acceptance. The BSC party may not be alert to a problem. For example, a rejection may go unnoticed because it has gone to a different "folder" than that in which the acknowledgement was received. In such circumstances, liability for imbalance charges could follow. This type of problem raises the issue of what level of due diligence should be required of people responsible for managing the notification process. In the context of a tolling agreement, it shows the desirability of defining precisely the boundaries of responsibility between the parties for notification risk instead of, for example, relying on concepts like willful default which may be difficult to apply in practice.

Force majeure has been used as a way of managing notification risk. In such circumstances, the toller may assume the imbalance charges risk and still be obliged to pay the generator a capacity charge, thus keeping both lenders and equity financially whole.

Conclusion

The answer to the two questions raised at the start is NETA appears to have worked fairly smoothly - but not without hitches - and to be cost-efficient. Of most concern are the level of imbalance charges and the lack of flexibility of the regime imposing them. Tolling agreements have been negotiated that have apportioned NETA risks to the satisfaction of lenders, which will be of comfort to potential investors. ◎

New Air Toxics Rules For Power Plants

by Roy Belden, in Washington

The US Environmental Protection Agency issued new rules in March that explain the Clean Air Act air toxics permitting procedures for owners and operators of combustion turbines. Understanding these new rules is crucial to ensuring compliance and avoiding enforcement risks. The new rules were released on the EPA's web page on March 6 and are available at **http://www.epa.gov/ttn/oarpg/t3pfpr.html**.

Background

The 1990 Amendments to the Clean Air Act initially exempted electric steam generating units from compliance with new technology-based air toxics provisions. Many thought that the exemption also covered combined-cycle systems that generate electricity using combustion turbines, heat recovery steam generators, and steam turbines. Compounding the confusion was the fact that different EPA offices reached different conclusions about whether combustion turbines were currently in or out of the air toxics program.

In May 2000, EPA clarified that all combustion turbines are subject to the so-called "section 112" air toxics provisions of the Clean Air Act.

In December that same year, EPA decided that hazardous air pollutant, or "HAP," emissions — in particular mercury emissions — from coal- and oil-fired power plants are a potential concern for public health. The agency added such power plants to the list of pollution sources that are subject to section 112 of the Clean Air Act. (Natural gas-fired electric steam generating units are exempt from the air toxics provisions.) By including coal and oil-fired power plants under the federal air toxics program, EPA obligated itself to propose a final HAP emissions standard, which is scheduled to be issued by December 2004.

The significance of the May 2000 interpretation and the December 2000 finding is that power plant owners must make sure that they are in compliance with the federal air toxic permitting requirements. There are currently two federal air toxics programs under section 112. They are referred to as "112(j)" and "112(g)." The 112(j) program applies to both existing and new plants. The 112(g) program applies to new and reconstructed plants.

112(j)

The idea behind the 112(j) program is to have state pollution control authorities establish pollution control standards on a case-by-case basis for categories of pollution sources for which EPA has not yet issued emissions standards by a specific date — May 15, 2002. The rules issued last month outline the permitting procedures under which state / continued page 28

Air Toxics

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permitting authorities are to determine "maximum achievable control technology," or "MACT," limits for covered sources.

To date, EPA has not announced section 112 air toxic standards for combustion turbines, and the agency will clearly miss the statutory deadline of May 15 this year to do so. Recognizing that it was not going to meet the deadline for more than 60 categories and subcategories of sources, EPA bought itself some time in the new permitting procedures by allowing sources up to 24 additional months to submit detailed case-by-case section 112(j) permit applications.

The agency has established a two-part application process under the section 112(j) program. Existing and new power plants with combustion turbines that will emit air toxics above major source thresholds will have to comply with the new section 112(j) rules. Major source thresholds are 10 tons per year of any one of the 188 listed HAPs or more than 25 tons of any combination of HAPs. Power plants are currently not subject to the section 112(j) permit application requirements because the deadline for proposing MACT standards for the category has not yet expired.

The first part of the 112(j) application is due by May 15, 2002 and involves giving notice that the plant is a major HAP source, identifying the location of the plant, and listing the units subject to the source category. The part one application must be submitted to the permitting authority that is implementing the "Title V" air operating permit program in that particular state. Air toxics requirements will ultimately be incorporated into a plant's Title V permit. Like Title V applications, a responsible official of the company must sign the application.

The second part of the application is much more complex and requires detailed information about emissions and emission units, including identification of applicable emission limitations and any existing control technology, emission rates for controlled and uncontrolled air toxics, and information relevant to establishing the MACT emission standard. The company may also submit a recommended MACT standard. For existing sources, MACT must be at least as stringent as the average emission limitation achieved by the best performing 12% of existing sources in the category. New source MACT is generally based on the emission control achieved in practice by the best-controlled similar source.

The part two application is due 24 months after the part one application is submitted. The permitting authority will have 18 months after the date it receives a complete part two application to issue a case-by-case determination. The section 112(j) rule application process is set up with a sufficiently long lead time to allow EPA an opportunity to announce the remaining air toxics emission standards before permitting authorities are forced to act on case-by-case MACT determinations.

In the event that EPA does not come up with the source category MACT standards in time, then the section 112(j) determination will be incorporated into a plant's Title V permit and the permitting agency has the discretion to leave it in place as long as the case-by-case MACT standard is of at least equivalent stringency to the MACT standard ultimately promulgated by EPA. If the EPA's subsequently-issued standard is more stringent, plants will generally have up to eight years to comply with the new EPA MACT standard.

Failure to file the requisite section 112(j) air permit applications by the appropriate deadlines will constitute a violation, and penalties could run as high as $27,500 a day per violation.

112(g)

New or reconstructed combustion turbines and new or reconstructed coal- and oil-fired electric utility units are also subject to section 112(g) requirements. Section 112(g) requires a case-by-case MACT determination for new or reconstructed sources in a source category where emissions standards have not yet been promulgated.

A "reconstructed" source generally means a source where components of an existing process or unit were replaced, but only if the replacement cost for the new components exceeds 50% of the cost to construct a comparable process or unit. Under the section 112(g) rules, a source must apply for a case-by-case MACT determination as part of its preconstruction approval process. It must submit detailed information similar to that required by the section 112(j) part two application. Section 112(g) determinations will be incorporated into a plant's preconstruction permit or combined preconstruction/Title V permit.

The new section 112(j) rule issued in March provides guidance on how the section 112(j) application process and the section 112(g) determination will interact. A section 112(g) MACT standard will be required to be in place before the plant starts operations, and this determination will typically satisfy the section 112(j) requirements. ◎

Environmental Update

Multi-Pollutant Legislation

The Bush administration unveiled a multi-pollutant proposal in February that, if enacted by Congress, could impose substantial costs on the electric generating industry.

The plan labeled the "Clear Skies Initiative" advocates setting stringent new emission limits for nitrogen oxide, or NO_x, sulfur dioxide, or SO_2, and mercury to reduce air emissions from electric generating stations. The initiative calls for a first phase of steep emissions reductions beginning in 2010, followed by a second phase of cuts commencing in 2018. The plan would implement a new, nationwide "cap and trade," market-based approach to reduce NO_x and mercury emissions by 67% and 69%, respectively. It would also build upon the existing acid rain SO_2 emissions trading program and implement deeper, across-the-board cuts to reduce SO_2 emissions by 73% of current levels.

The initiative is intended to be fuel neutral, but it remains to be seen whether a multi-pollutant measure could lead to increased fuel switching. The mercury reduction requirements in particular may drive a plant's response to the initiative. Unlike pollution control technology to reduce NO_x and SO_2 emissions, there are currently no clear-cut methods of substantially reducing mercury emissions, and new control technologies are now under development. Some existing technologies, such as wet or dry scrubbers and fabric filter, may be effective in capturing a large percentage of mercury emissions; however, this is largely dependent on the type of combustion unit and the type of coal that is burned.

Debate over multi-pollutant legislation is expected to be the primary focus of the Senate Environment and Public Works Committee for the rest of this year. The committee chairman, Senator James Jeffords (I.-Vermont), has introduced his own multi-pollutant bill that calls for even greater reductions in NO_x, SO_2, and mercury emissions as well as mandatory reductions in carbon dioxide, or CO_2, a greenhouse gas. The Jeffords bill imposes tighter implementation timeframes — the reductions are required to be achieved by January 1, 2007 — and more drastic emission reduction targets. The bill would mandate 75% reductions in NO_x and SO_2 from 1997 and 2000 baselines, a 90% cut in mercury levels from 1999 levels, and a reduction to 1990 CO_2 levels.

Senator Jeffords has vowed to push forward with a multi-pollutant bill that includes mandatory CO_2 reductions, and he has expressed disappointment that the administration's initiative did not include such reductions. It remains to be seen whether the parties can broker a compromise on this issue, which has generated a significant degree of controversy. It may end up torpedoing any hope for a compromise multi-pollutant measure in Congress this year.

Another controversial aspect of the administration's proposals is the extent to which they are intended to replace certain existing or expected air regulations that affect power plants. For example, Environmental Protection Agency Administrator Christine Todd Whitman recently confirmed that the agency is committed to eliminating the Clean Air Act's new source review, or "NSR," permitting program once the proposed caps on NO_x, SO_2, and mercury emissions are achieved. Whitman expects that the NSR program — and possibly other air programs — will become obsolete for the power industry after a multi-pollutant regime is fully implemented. Not surprisingly, some members of Congress and environmental organizations are strongly opposed to eliminating the NSR program, and the debate over the potential sunsetting of the NSR program and other air programs will be contentious.

The Senate Environment and Public Works Committee is expected to begin "marking up" a multi-pollutant measure later this year. Several members of the committee from both parties are reportedly already in discussions to find common ground for a compromise measure.

Meanwhile, on the House side, Rep. Joe Barton (R.-Texas), chairman of the House Energy and Air Quality Subcommittee, is expected to hold hearings starting in April with the aim of identifying areas where changes are needed in the Clean Air Act.

Prospects for enactment of a comprehensive multi-pollutant measure for power plants remain low. Senate and House leaders are unlikely to agree on a multi-pollutant measure during an election year. However, clean air measures, including more stringent emission limits for power plants, could turn into a campaign issue and create a catalyst for action in the next Congress. */ continued page 30*

Global Climate Change Initiative

President Bush also announced in February his eagerly-anticipated "global climate change initiative," a plan that is supposed to achieve significant voluntary reductions in greenhouse gases without stalling US economic growth. Most of US industry supported the Bush proposals. However, the initiative has been criticized by many environmental organizations as well as by several European countries.

The global climate change initiative sets a 10-year national goal of reducing by 18% the greenhouse gas intensity of the US economy, as measured against the gross domestic product. The proposal builds on the Bush administration's earlier decision to increase funding for global climate research and for the development of new technologies to reduce greenhouse gas emissions. The plan calls for voluntary measures to achieve an economy-wide emission reduction target that takes into account declining greenhouse gas emissions and projected increases in economic activity. The current US rate of greenhouse gas emissions is 183 metric tons per million dollars of GDP. The Bush proposal sets a target level of 151 metric tons. Administration officials said the voluntary reduction target equates to approximately a 4.5% reduction beyond business-as-usual forecasts.

The initiative focuses on voluntary commitments from industry to reduce greenhouse gas emissions in the short term, while devoting substantial resources to developing science and technology, conservation efforts, renewable fuels, and sequestering carbon as part of a long-term strategy. Under the administration's plan, the US climate change approach will be reassessed by 2012, and if the country is "not on track to meeting our goal, and sound science justifies further policy action," the US will respond with additional measures that may include a "broad, market-based program" and additional incentives for limiting greenhouse gases.

The administration's growth-based approach is a clear departure from the mandated emission reduction targets of the Kyoto protocol. Last year, President Bush rejected the Kyoto protocol, concluding that drastically reducing greenhouse gas emissions would harm the US economy and potentially undermine investments in long-term technological solutions and clean energy. Critics of the President's plan argue that voluntary reduction measures are ineffective and US businesses will be free to continue business as usual.

The President and EPA have already launched a new, voluntary "climate leaders" program. Participating companies will establish individual goals for reducing greenhouse gases and will report on their emission reductions. The list of participants currently stands at 17 companies, including Cinergy, Florida Power & Light and PSEG.

More than 550 power plants may be forced to make significant changes in their cooling water intake arrangements.

In addition to establishing the voluntary emission reduction targets, the global climate change initiative calls for the Department of Energy to improve its voluntary emissions reduction registry and to develop a strategy to ensure that companies are not penalized for registering voluntary emission reductions under any future climate change program. The initiative also calls for $4.6 billion in clean energy tax incentives — such as tax credits for fuel cells and landfill gas conversion — over a 5-year period.

It is not clear if Congress will tackle climate change issues this year. Climate change is a politically-divisive issue, and many companies are divided on the question of whether mandatory greenhouse gas reduction requirements should be imposed. In an election year, it remains highly doubtful that Congress will take action on such a controversial issue.

Cooling Water

More than 550 electric generating facilities may be forced to make significant improvements to their cooling water intake structures if a recently-proposed EPA rule becomes law. On February 28, EPA chief Christine Todd Whitman signed a proposed rule that would impose new requirements on cooling water intake structures at existing power plants in order to reduce the effect of such structures on aquatic life. If the proposed regulations become law, extensive upgrades to existing electric generating facilities could be required.

The proposed rule would cover existing power plants that withdraw 50 million gallons per day or more from waters of the US and use at least 25% of the water for cooling purposes. The proposal establishes location, design, construction and capacity requirements that are based on the best technology available for minimizing the impact on aquatic organisms.

A power plant generally will be able to choose one of three ways to comply. First, the plant could demonstrate that its cooling water intake structure meets specified technology performance standards that are based on a closed-cycle, recirculating cooling system. The second option is to implement design and construction technologies and operational or restoration measures to meet technology performance standards, including measures to reduce harm to aquatic life. The third option is to make a site-specific determination of what is the best technology available, taking into account the costs of compliance. In addition, facility owners can satisfy the applicable performance standards by substituting restoration and other conservation measures to maintain fish and aquatic organism populations in lieu of — or to supplement — improvements in intake systems .

The proposed rule allows existing plants flexibility to implement creative solutions that achieve an equivalent level of environmental performance to the presumptive technology requirements. Nevertheless, the rule is expected to impose significant costs on existing plants, particularly plants withdrawing water from water bodies with sensitive aquatic habitats and species.

The new requirements will be implemented through the existing "national pollutant discharge elimination system," or "NPDES," program. Once the rule is finalized, plants applying for reissuance of a NPDES permit will have to submit information demonstrating how the facility intends to comply with the new requirements. The reissued NPDES permit will incorporate a new section containing the cooling water intake structure provisions. EPA estimates that upgrades to existing cooling water intake systems will cost the industry approximately $182 million a year. Comments on the proposed rule are due within 90 days after the proposed rule is published in the *Federal Register*.

New York

The New York State Department of Environmental Conservation issued proposed regulations in mid-February that will require in-state electric generators to reduce SO_2 emissions by another 50% below current acid rain program levels. The proposed regulations also extend to the entire year the current summer ozone season NO_x requirements. Under the proposal, NO_x emissions would be reduced approximately 18% from 2000 levels. The new regulations, which implement a plan originally proposed by Governor George Pataki, would impose some of the most stringent SO_2 and NO_x emission reduction requirements in the nation.

The proposed regulations call for the new SO_2 reduction regulations to take effect starting on January 1, 2004. If finalized, the regulations may necessitate that plants either install additional SO_2 emission controls, use lower-sulfur coal, or purchase surplus SO_2 allowances. The proposed rule creates a new, state-based SO_2 emissions trading program that would mirror the existing federal acid rain program; however, in-state sources would essentially receive an allowance allocation that is 50% of the current federal allocations. The New York SO_2 program would not affect current SO_2 allowance allocations under the federal acid rain program.

The proposed NO_x regulations call for implementation of the new year-round NO_x standards to take effect starting on October 1, 2004. Under the proposed regulations, the existing five-month ozone season requirements would remain in place, and the new program would apply to the remaining seven months. New York will issue new NO_x allowance allocations to power plants for use during the additional seven months. The new program will base its NO_x allowance allocations on the same emission rate as the summer ozone season NO_x allocations. In order to comply with the new NO_x standards, some plants may need to install additional emissions control equipment, such as selective catalytic reduction, or "SCR," systems.

NYSDEC staff predict that the new regulations will result in a reduction of 130,000 tons per year of SO_2 and an additional 20,000 tons per year of NO_x. The new SO_2 and NO_x rules will provide set-aside allowances (3% and 5%, respectively) for new sources, as well as create / continued page 32

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a set-aside allocation for renewable energy projects and plants that implement energy efficiency projects. The comment period on the rules was recently extended to May 27, 2002, and the rules are expected to be finalized later this year.

Brief Updates

The European Parliament approved the European Union's ratification of the Kyoto protocol plan to reduce greenhouse gas emissions in February. The 15 EU member states also need to agree individually to ratify the Kyoto protocol. The Kyoto protocol commits the EU to a reduction target that is 8% below 1990 levels by 2012. Most EU countries appear to be on track to ratify the protocol by the end of the summer. Four EU countries — Denmark, France, Luxembourg, and Portugal — have already ratified the treaty.

In early March, the US Department of Energy released a solicitation seeking proposals for clean coal projects. The Bush administration's clean coal power initiative will make $300 to $400 million available for the initial round of projects. The department is looking for innovative projects to demonstrate reductions in SO_2, NO_X, mercury and fine particulate matter from coal-based power generation. Projects selected must enter into cooperative agreements with the department and must cover at least 50% of the costs either by cash outlays or in-kind contributions. Accepted projects will also be required to enter into 20-year repayment agreements. Submissions are due by August 1, 2002

On March 21, Tennessee lifted its 7-month moratorium on accepting new power plant permit applications. Tennessee Governor Don Sunquist's order will allow new permit applications for up to four new power plants to begin construction before January 1, 2004. Existing plants may still apply to expand during this period. The order also requires applicants for new merchant plants with a capacity of 50 megawatts or greater to file an environmental and economic impact statement, an analysis of required water usage, a financing statement, and a demonstration of local support with the Tennessee Department of Economic and Community Development.

The EPA has once again delayed its long-awaited revisions to the "new source review," or "NSR," program that applies to new and modified major sources of certain air contaminants. Opposition from several northeastern states, several key members of Congress, and the environmental community appears temporarily to have derailed release of the NSR changes. EPA is expected to release revisions overhauling the program by the end of this year.

Finally, in March, a US appeals court in Washington ruled that the EPA did not act arbitrarily or capriciously when it issued new air quality standards for ozone and fine particulate matter in 1997. The court's decision resolved the remaining legal challenges to the standards, which had been the subject of earlier rulings of both the same appeals court and the US Supreme Court. Now that its path is clear, EPA is expected to proceed with implementing the standards over the next several years.

— contributed by Roy Belden in Washington.

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